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

Form 2 Approved
OMB No.1902-0028
(Expires 09/30/2017)

Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

SUPPLEMENTAL REPORT TO

OREGON PUBLIC UTILITY COMMISSION

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

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Cascade Natural Gas Corporation	End of 2016/Q4

ANNUAL REPORT
OREGON SUPPLEMENT TO FERC FORM 2
FOR MULTI-STATE GAS COMPANIES
2016

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, 2016**

STATE OF OREGON - STATEMENT OF OPERATING INCOME FOR THE YEAR

LINE NO.	ACCOUNT (a)	(REF.) PAGE NO. (b)	GAS UTILITY Current Year (c)	GAS UTILITY Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	2	63,881,403	67,650,226
3	Operating Expenses			
4	Operation Expenses (401)	4-9	43,961,182	48,717,077
5	Maintenance Expenses (402)	4-9	1,478,504	1,342,029
6	Depreciation Expense (403)	10	5,347,120	5,495,388
7	Amortization & Depletion of Utility Plant (404-405)	10	672,897	616,123
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	4,884,659	4,803,910
12	Income Taxes - Federal (409.1)	12	1,123,528	1,277,644
13	Income Taxes - Other (409.1)	13	293,645	57,822
14	Provision for Deferred Income Taxes (410.1)	14-21	537,525	33,062
15	(Less) Provision for Deferred Income Taxes - Cr. (411.1)	14-21	-	-
16	Investment Tax Credit Adjustment - Net (411.4)	22	(11,452)	(12,377)
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)		58,287,608	$ 64,565,332
20	Net Utility Operating Income (Enter Total of line 2 less 19)		5,593,795	5,527,156

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, 2016**

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	$ 35,156,436	$ 36,805,874	3,824,641	3,531,723	60,483	58,875
3	481 Commercial and Industrial Sales						
4	Small or Commercial	$ 20,355,085	$ 22,085,378	2,620,916	2,491,291	9,815	9,687
5	Large or Industrial	$ 4,062,194	$ 4,505,782	616,629	591,033	152	135
6	482 Other Sales to Public Authorities						
7	484 Interdepartmental Sales						
8	TOTAL Sales to Ultimate Consumers	$ 59,573,715	$ 63,397,034	7,062,186	6,614,047	70,450	68,697
9	483 Sales for Resale						
10	TOTAL Natural Gas Service Revenues	$ 59,573,715	$ 63,397,034	7,062,186	6,614,047	70,450	68,697
11	Revenues from Manufactured Gas						
12	TOTAL Gas Service Revenues	$ 59,573,715	$ 63,397,034				
13	OTHER OPERATING REVENUES						
14	485 Intracompany Transfers						
15	487 Forfeited Discounts						
16	488 Miscellaneous Service Revenues	$ 177,915	$ 185,988				
17	489 Revenue from Trans. of Gas of Others	$ 4,044,720	$ 3,992,733				
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	$ 12,000	$ 9,728				
22	494 Interdepartmental Rents	$ 30,053	$ 24,916				
23	495 Other Gas Revenues	$ 43,001	$ 39,828				
24	TOTAL Other Operating Revenues	$ 4,307,689	$ 4,253,193				
25	TOTAL Gas Operating Revenues	$ 63,881,404	$ 67,650,227				
26	(Less) 496 Provision for Rate Refunds						
27	TOTAL Gas Operating Revenues Net of Provision for Refunds						
28	Dist. Type Sales by States (*Incl. Main Line Sales to Residential and Commercial Customers)*	$ 55,511,521		6,445,557			
29	Main Line Industrial Sales *(Incl. Main Line Sales to Public Authorities)*	$ 4,062,194		616,629			
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))*	$ 59,573,715		7,062,186			

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, 2016**

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.	$ 12,000	9,728.00
			$ -	-
			$ -	-
	Total Account 493		$ 12,000	9,728.00

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, 2016

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, 2016**

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, 2016**

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	30,461,643	33,441,077
73	804.1 Liquefied Natural Gas Purchases	0	0
74	805 Other Gas Purchases	0	0
75	(Less) 805.1 Purchased Gas Cost Adjustments	485,265	2,646,632
76	805.2 Incremental Gas Cost Adjustments	0	0
77	Total Purchased Gas (Enter Total of lines 67 to 75)	30,946,908	36,087,709
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	589,317	465,913
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	(12,580)	(18,105)
94	Total Gas Used in Utility Operations - Credit (Lines 91 thru 93)	(12,580)	(18,105)
95	813 Other Gas Supply Expenses	170,587	108,233
96	Total Other Gas Supply Exp (Lines 77, 78, 85, 86 thru 89, 94, 95)	31,694,232	36,643,750
97	Total Production Expenses (Total of lines 3, 30, 58, 65 and 96)	31,694,232	36,643,750

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, 2016**

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, 2016

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, 2016**

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	503,425	502,211
205	871 Distribution Load Dispatching	147,351	140,032
206	872 Compressor Station Labor and Expenses	0	0
207	873 Compressor Station Fuel and Power	0	0
208	874 Mains and Services Expenses	1,113,616	1,073,812
209	875 Measuring and Regulating Station Expenses - General	204,990	223,345
210	876 Measuring and Regulating Station Expenses - Industrial	21,950	12,145
211	877 Measuring & Regulating Station Exp - City Gate Check Station	554,304	0
212	878 Meter and House Regulator Expenses	443,358	543,771
213	879 Customer Installations Expenses	0	451,504
214	880 Other Expenses	1,261,224	1,350,048
215	881 Rents	32,533	20,039
216	Total Operation (Enter Total of lines 204 thru 215)	4,282,751	4,316,907
217	Maintenance		
218	885 Maintenance Supervision and Engineering	103,151	109,200
219	886 Maintenance of Structures and Improvements	235	487
220	887 Maintenance of Mains	472,420	354,201
221	888 Maintenance of Compressor Station Equipment	1,257	781
222	889 Maintenance of Meas. and Reg. Sta. Equip. - General	24,092	33,903
223	890 Maintenance of Meas. and Reg. Sta. Equip. - Industrial	11,217	60,495
224	891 Maint. of Meas. & Reg. Sta. Equip. - City Gate Check Station	0	
225	892 Maintenance of Services	375,979	331,052
226	893 Maintenance of Meters and House Regulators	418,613	375,529
227	894 Maintenance of Other Equipment	60,442	57,136
228	Total Maintenance (Enter Total of lines 218 thru 227)	1,467,406	1,322,784
229	Total Distribution Expenses (Enter Total of lines 216 and 228)	5,750,157	5,639,691
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	(597)	1,621
233	902 Meter Reading Expenses	188,626	196,877
234	903 Customer Records and Collection Expenses	1,550,059	1,344,568
235	904 Uncollectible Accounts	207,281	166,036
236	905 Miscellaneous Customer Accounts Expenses	261	372
237	Total Customer Accounts Expenses (Total of lines 232 thru 236)	1,945,630	1,709,474
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	0	0
241	908 Customer Assistance Expenses	96,451	603,418
242	909 Informational and Instructional Expenses	10,087	9,386
243	910 Miscellaneous Customer Service and Informational Expenses	0	0
244	Total Customer Service & Information Expenses (Lines 240 thru 243)	106,538	612,804
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	0	0
248	912 Demonstrating and Selling Expenses	0	0
249	913 Advertising Expenses	2,059	2,313
250	916 Miscellaneous Sales Expenses	0	0
251	Total Sales Expenses (Enter Total of lines 247 thru 250)	2,059	2,313

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A	(M,D,Y)	**Dec. 31, 2016**

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	1,947,880	1,691,075
255	921 Office Supplies and Expenses	815,786	863,291
256	(Less) 922 Administrative Expenses Transferred - Cr.	(97,825)	(132,396)
257	923 Outside Services Employed	566,996	518,725
258	924 Property Insurance	19,840	19,885
259	925 Injuries and Damages	419,184	350,173
260	926 Employee Pensions and Benefits	1,556,729	1,609,528
261	927 Franchise Requirements	0	0
262	928 Regulatory Commission Expenses	0	4,210
263	(Less) 929 Duplicate Charges - Cr.	0	0
264	930.1 General Advertising Expenses	13,966	9,501
265	930.2 Miscellaneous General Expenses	264,144	184,274
266	931 Rents	423,272	313,563
267	Total Operation (Enter Total lines 254 thru 266)	5,929,972	5,431,829
268	Maintenance		
269	935 Maintenance of General Plant	11,098	19,245
270	Total Administrative and General Exp (Total of lines 267 and 269)	5,941,070	5,451,074
271	Total Gas O. & M. Exp (Lines 97,177,201,229,237,244,251 and 270)	45,439,686	50,059,106

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	31,694,232	0	31,694,232
280	Total Production	31,694,232	0	31,694,232
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	4,282,751	1,467,406	5,750,157
286	Customer Accounts Expenses	1,945,630	0	1,945,630
287	Customer Service and Informational Expenses	106,538	0	106,538
288	Sales Expenses	2,059	0	2,059
289	Admin and General Expenses	5,929,972	11,098	5,941,070
290	Total Gas O. & M. Expenses	43,961,182	1,478,504	45,439,686

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, 2016**

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			672,897			672,897
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	4,910,138					4,910,138
10	General Plant	323,809					323,809
11	Common Plant - Gas	[redacted]					-
12							
13							
14							
15							
16							
17							
18							
19	**TOTAL**	**5,347,120**	**-**	**672,897**	**-**	**-**	**6,020,017**

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, 2016**

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

LINE NO.	KIND OF TAX (a)	AMOUNT (b)
1	Property Taxes	1,427,156
2	Payroll Taxes	557,713
3	Oregon PUC Regulatory Fee	186,038
4	Oregon Department of Energy Fee	80,211
5	City Franchise Taxes	2,622,321
6	Miscellaneous Taxes	11,220
	TOTAL (Must agree with page 1, line 11)	**4,884,659**

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, 2016**

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			269,012,065
2	Operations and Maintenance Expenses			(214,789,355)
3	Taxes, Other than Income			(25,926,633)
4	State Income (Excise) Tax			(295,759)
5	Interest			(11,401,002)
6	Other Income			(1,342,514)
7	Federal Income Tax Depreciation			
8	Pre-1981			-
9	Post-1980			(24,499,290)
10	Other Additions (Subtractions) to Derive Taxable Income			
11	CIAC			4,990,647
12	Book depreciation included in O&M			26,295,149
13	Tax Gain (loss) on disposal of assets:			
14	Pre-1981 assets			(570,372)
15	Post-1980 assets			(1,205,997)
16	Vacation Accrual adjustment			140,625
17	Retiree Medical Accrual adjustment			68,040
18	Amort of loss on reacquired debt (4281)			40,971
19	SFAS No.87 pension plan accrual			(176,629)
20	SFAS No.87 accrual-SERP DO add back bk expense			146,764
21	SERP-perm difference piece			(472,308)
22	Bad Debt Adjustment			9,712
23	Charitable Contributions (5981.4261)			216,468
24	Permanent diff's			
25	50 % of business meals & entertainment			152,305
26	Penalties (5984)			1,001,099
27	Lobbying (5912.4264)			128,096
28	Tax exempt interest			-
29	Interest capitalized adj (IRS>books)			338,455
30	Customer Advances - 2520.000 to 2520.2991			608,407
31	CC&B Deduction			-
32	Repairs Deduction			(3,637,386)
33	Section 174 costs			(2,880,285)
34	Legal Reserve			280,000
35	263A Adjustment - UNICAP			(9,296)
36	401K Dividends (MDUR)			(184,446)
37	Severance accrual adjustment			-
38	STIP accrual adjustment			1,212,601
39	Deferred Gas Costs			(209,142)
40	Prepaid Expenses			(318,120)
41	Royalty Income (15% of royalty income receipts)			-
42	Bremerton MGP expenses			(58,815)
43	Eugene MGP expenses			(123,202)
44	Federal Tax Net Income			16,540,853
45	Show Computation of Tax:			
46	Federal Tax Rate			35%
47	Estimated Federal Tax			5,789,299
48	Adjustments to Estimated Federal Tax			
49	Difference between 12/31/14 accrual and tax return			(1,695,081)
50	Audit adjustment			-
51	Provision for Current Federal Income Tax			4,094,218
52	Allocated to:	409.1	409.2	Total
53	Washington	3,159,843	(142,375)	3,017,468
54	Oregon	1,123,528	(46,778)	1,076,750
55	Total	**4,283,371**	**(189,153)**	**4,094,218**

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, 2016**

RENT 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			269,012,065
2	Operations and Maintenance Expenses			(214,789,355)
3	Taxes, Other than Income			(25,926,633)
4	State Income (Excise) Tax			
5	Interest			(11,401,002)
6	Other Income			(1,342,514)
7	Federal Income Tax Depreciation			
8	Pre-1981			-
9	Post-1980			(24,965,689)
10	Other Additions (Subtractions) to Derive Taxable Income			
11	CIAC			4,990,647
12	Book depreciation included in O&M			26,295,149
13	Tax Gain (loss) on disposal of assets:			
14	Pre-1981 assets			(570,372)
15	Post-1980 assets			(1,214,872)
16	Vacation Accrual adjustment			140,625
17	Retiree Medical Accrual adjustment			68,040
18	Amort of loss on reacquired debt (4281)			40,971
19	SFAS No.87 pension plan accrual			(176,629)
20	SFAS No.87 accrual-SERP DO add back bk expense			146,764
21	SERP-perm difference piece			(472,308)
22	Bad Debt Adjustment			9,712
23	Charitable Contributions (5981.4261)			216,468
24	Permanent diff's			-
25	50 % of business meals & entertainment			152,305
26	Penalties (5984)			1,001,099
27	Lobbying (5912.4264)			128,096
28	Tax exempt interest			-
29	Interest capitalized adj (IRS>books)			338,455
30	Customer Advances - 2520.000 to 2520.2991			608,407
31	CC&B Deduction			-
32	Repairs Deduction			(3,637,386)
33	Section 174 Costs			(2,880,285)
34	Legal Reserve			280,000
35	263A Adjustment - UNICAP			(9,296)
36	401K Dividends (MDUR)			(184,446)
37	Severance accrual adjustment			-
38	STIP accrual adjustment			1,212,601
39	Deferred Gas Costs			(209,142)
40	Prepaid Expenses			(318,120)
41	Royalty Income (15% of royalty income receipts)			-
42	Bremerton MGP expenses deferred			(58,815)
43	Eugene MGP expenses deferred			(123,202)
44	Federal Tax Net Income			16,361,338
45	Oregon Apportionment Rate			23.7851%
46	State Tax Net Income			3,891,561
47	Show Computation of Tax:			
48	State Tax Rate			7.6%
49				295,759
50	Adjustments to Estimated Federal Tax			
51	Difference between 12/31/14 accrual and tax return			(15,081)
52	FIN 48 adjustment			-
53	Provision for Current Federal Income Tax			280,678
54	Allocated to:	409.1	409.2	Total
55	Oregon	**293,645**	**(12,967)**	280,678

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, 2016

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)	Amounts Credited to Account 411.1 (d)
1	Electric			
2				
3	Other			
4	TOTAL ELECTRIC			
5	Gas	26,391,798	(52,362)	-
6				
7	Other	-		
8	TOTAL GAS	26,391,798	(52,362)	-
9	Other (Specify)	-		
10	TOTAL (Account 190)	26,391,798	(52,362)	-
11	Classification of Totals			
12	Federal Income Tax	25,273,741	(53,504)	-
13	State Income Tax	1,118,057	1,142	-
14	Local Income Tax	-	-	-
15				
16	Amounts assigned to jurisdictions as follows:			
17	Federal Income Tax - Washington	See Below	(39,470)	-
18	Federal Income Tax - Oregon	See Below	(14,034)	-
19	State Income Tax - Oregon	1,118,057	1,142	-
20				
21				
22				

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

	Beginning of Year	End of Year
Federal Income Tax related account Balance	25,273,741	25,173,398
	-	-
Balance to be allocated	25,273,741	25,173,398
Washington allocation factor	75.73%	75.27%
Washington Allocated balance	19,139,804	18,948,017
Oregon allocation factor	24.27%	24.73%
Oregon Allocated balance	6,133,937	6,225,381

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, 2016**

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
-	-	Regulatory accounts related to FAS 158 and OR rate change adjustments	273,664	Regulatory accounts related to FAS 158 and OR rate change adjustments	124,773	26,488,327	5
							6
						-	7
-	-		273,664		124,773	26,488,327	8
						-	9
-	-		273,664		124,773	26,488,327	10
							11
-	-		43,331		90,170	25,173,398	12
-	-		230,333		34,603	1,314,929	13
-	-		-		-	-	14
							15
							16
-	-		31,965		66,518	See Below	17
-	-		11,366		23,652	See Below	18
-	-		230,333		34,603	1,314,929	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, 2016**

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	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(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	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2016**

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 (e)	Amounts Credited to Account 411.2 (f)	Account No. (g)	Amount (h)	Account No. (I)	Amount (j)	(k)	
[redacted]							1
							2
							3
							4
							5
							6
							7
-	-	-	-	-	-	-	8
[redacted]							9
							10
							11
							12
							13
							14
-	-	-	-	-	-	-	15
						-	16
-	-	-	-	-	-	-	17
[redacted]							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, 2016**

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	(96,815,260)	(2,357,696)	-
4	Other (Define)	-		
5	Total (Total of Lines 2 thru 4)	(96,815,260)	(2,357,696)	-
6	Other (Specify)	-		
7				
8				
9	Total (Account 282) Lines 5 thru 8	(96,815,260)	(2,357,696)	-
10	Classification of Totals			
11	Federal Income Tax	(93,348,935)	(2,161,856)	-
12	State Income Tax	(3,466,325)	(195,840)	-
13	Local Income Tax	-	-	-

Amounts assigned to jurisdictions as follows:

Federal Income Tax - Washington	See Below	(1,594,801)	-
Federal Income Tax - Oregon	See Below	(567,055)	-
State Income Tax - Oregon	(3,466,325)	(195,840)	-

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

	Beginning of Year	End of Year
Federal Income Tax Acct Balance Relating to utility plant for ratemaking	(95,924,439)	(98,089,299)
Washington allocation factor	76.46%	76.55%
Washington Allocated balance relating to utility plant for ratemaking	(73,343,826)	(75,087,358)
Oregon allocation factor	23.54%	23.45%
Oregon Allocated balance relating to utility plant for ratemaking	(22,580,613)	(23,001,941)
Remaining balance to be allocated on Utility Plant	2,575,504	2,437,659
Oregon allocation factor	22.42%	22.76%
Oregon allocation	577,428	554,811
Plus Oregon Allocation of utility plant for ratemaking related balance	(22,580,613)	(23,001,941)
Total Oregon Allocated Balance	(22,003,185)	(22,447,130)

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, 2016**

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

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

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	DEBITS		CREDITS			
		Account No.	Amount	Account No.	Amount		
(e)	(f)	(g)	(h)	(I)	(j)	(k)	
							1
						-	2
-	-	182.3 & 254	1,053,769	182.3 & 254	1,948,159	(100,067,346)	3
						-	4
-	-		1,053,769		1,948,159	(100,067,346)	5
						-	6
							7
							8
-	-		1,053,769		1,948,159	(100,067,346)	9
							10
-	-	254	904,732	254	1,045,581	(95,651,640)	11
-	-	182.3	149,037	182.3	902,578	(4,415,706)	12
-	-		-		-	-	13
-	-		667,421		771,325	See Below	
-	-		237,311		274,256	See Below	
-	-		149,037		902,578	(4,415,706)	

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, 2016**

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited Account 411.1 (d)
1	Account 283			
2	Electric			
3	Gas	(36,786,388)	840,619	-
4	Other (Define)	-		
5	Total (Total of Lines 2 thru 4)	(36,786,388)	840,619	-
6	Other (Specify)	-		
7				
8				
9	Total (Account 283) Lines 5 thru 8	(36,786,388)	840,619	-
10	Classification of Totals			
11	Federal Income Tax	(34,906,934)	816,534	-
12	State Income Tax	(1,879,454)	24,085	-
13	Local Income Tax	-	-	-
	Amounts assigned to jurisdictions as follows:			
	Federal Income Tax - Washington	See below	602,357	-
	Federal Income Tax - Oregon	See below	214,177	-
	State Income Tax - Oregon	(1,879,454)	24,085	-

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

	Beginning of Year	End of Year
Federal Income Tax Acct Balance Relating to Debt Refinancing	(298,911)	(284,789)
Washington allocation factor	76.46%	76.55%
Washington Allocated balance relating to Debt Refinancing	(228,547)	(218,006)
Oregon allocation factor	23.54%	23.45%
Oregon Allocated balance relating to Debt Refinancing	(70,364)	(66,783)
Remaining balance to be allocated on 3-factor	(34,608,023)	(33,763,266)
Oregon allocation factor	24.27%	24.73%
Oregon allocation	(8,399,367)	(8,349,656)
Plus Oregon Allocation of Debt refinancing related balance	(70,364)	(66,783)
Total Oregon Allocated Balance	(8,469,731)	(8,416,439)

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, 2016**

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		CREDITS			
		Account No.	Amount	Account No.	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	144,991	Regulatory accounts related to FAS 158 and deferred tax effect of OR State Tax Rate increase	356,318	(36,157,096)	3
						-	4
-	-		144,991		356,318	(36,157,096)	5
						-	6
							7
							8
-	-		144,991		356,318	(36,157,096)	9
							10
-	-		103,771		61,426	(34,048,055)	11
-	-		41,220		294,892	(2,109,041)	12
-	-		-		-	-	13
-	-		76,552		45,314	See below	
-	-		27,219		16,112	See below	
-	-		41,220		294,892	(2,109,041)	

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, 2016

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

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

Line No.	Account Subdivision (a)	Balance at Beginning of Year (b)	Deferred For Year: Account No (c)	Deferred For Year: Amount (d)	Allocations to Current Year's Income: Account No (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)	Balance at End of Year (h)	Average period of Allocation to Income (i)
1	Gas utility								
2	3%								
3	4%	NOT			411.4	-		NOT	31 Years
4	7%				411.4	-			31 Years
5	10%	ALLOCATED			411.4	(11,452)		ALLOCATED	23 Years
6	Total	0		0		(11,452)			
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, 2016

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)	186,677,480		186,677,480			
4	Property under capital leases	-					
5	Plant purchased or sold	-					
6	Completed construction not classified	7,154,841		7,154,841			
7	Experimental plant unclassified	-					
8	TOTAL (Enter Total of lines 3 thru 7)	193,832,321	-	193,832,321	-		-
9	Leased to Others	-					
10	Held for Future Use	-					
11	Construction Work In Progress	3,714,175		3,714,175			
12	Acquisition Adjustments	-					
13	Total Utility Plant (Enter Total of lines 8 thru 12)	197,546,496	-	197,546,496	-		-
14	Accumulated Prov For Depr, Amort, & Depl.	(91,880,708)		(91,880,708)			
15	Net Utility Plant (Line 13 less 14)	105,665,788	-	105,665,788	-		-
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation	(91,873,519)		(91,873,519)			
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	(7,189)		(7,189)			
22	Total In-Service (Total of lines 18 thru 21)	(91,880,708)	-	(91,880,708)	-		-
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)	(91,880,708)	-	(91,880,708)	-		-

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, 2016

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	113,374					113,374
5		TOTAL Intangible Plant	187,041	-	-	-	-	187,041
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	☑ An Original (1) ☐ A Resubmission (2)	(M,D,Y)	**Dec. 31, 2016**

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, 2016

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					5,818,921
83	368	Compressor Station Equipment	-					-
84	369	Measuring and Regulating Station Equipment	36,161					36,161
85	370	Communications Equipment	-					-
86	371	Other Equipment	-					-
86.a	372	ARO - Transmission	24,733					24,733
87		TOTAL Transmission Plant	5,900,639	-	-	-	-	5,900,639
88		5. Distribution Plant						
89	374	Land and Land Rights	223,036	(2,124)				220,912
90	375	Structures and Improvements	363,785					363,785
91	376	Mains	82,433,817	4,591,879	(12,800)			87,012,896
92	377	Compressor Station Equipment	-					-
93	378	Measuring and Regulating Equipment - General	7,895,830	818,872	(4,239)			8,710,463
94	379	Measuring and Regulating Equipment - City Gate	-					-
95	380	Services	46,742,011	1,763,706	(28,925)			48,476,792
96	381	Meters	12,802,931	1,432,885	(192,729)	92,403		14,135,490
97	382	Meter Installations	8,242,824	200,227	(1,181)		(8,093)	8,433,777
98	383	House Regulators	2,583,471	68,261	(61,049)	18,646		2,609,329
99	384	House Regulator Installations	-					-
100	385	Industrial Measuring and Regulating Station Equipment	1,670,381	161,625	(11,932)		8,093	1,828,167
101	386	Other Property on Customers' Premises	-					-
102	387	Other Equipment	-					-
102.a	388	ARO - Distribution	3,652,001					3,652,001
103		TOTAL Distribution Plant	166,610,087	9,035,331	(312,855)	111,049	-	175,443,612

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, 2016

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	302,127	191,174				493,301
106	390	Structures and Improvements	4,663,838	(160,806)				4,503,032
107	391	Office Furniture and Equipment	205,569		(22,854)			182,715
108	392	Transportation Equipment	3,403,686	411,050	(272,459)		4,607	3,546,884
109	393	Stores Equipment	-					-
110	394	Tools, Shop and Garage Equipment	1,249,570	83,223	(57,829)			1,274,964
111	395	Laboratory Equipment	-					-
112	396	Power Operated Equipment	1,045,108	562,536	(659,678)			947,966
113	397	Communication Equipment	1,323,600	22,976	(1,617)			1,344,959
114	398	Miscellaneous Equipment	7,209					7,209
115		SUBTOTAL	12,200,707	1,110,153	(1,014,437)	-	4,607	12,301,030
116	399	Other Tangible Property	-					-
117		TOTAL General Plant	12,200,707	1,110,153	(1,014,437)	-	4,607	12,301,030
118		TOTAL (Accounts 101 and 106)	184,898,474	10,145,484	(1,327,292)	111,049	4,607	193,832,322
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	184,898,474	10,145,484	(1,327,292)	111,049	4,607	193,832,322

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, 2016

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				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50				
51				
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, 2016**

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	SUNRIVER GATE STATION	2,367,870	
2	STANFIELD GATE STATION	861,904	
3			
4			
5			
6	Minor installation of mains, service lines, measuring and regulating stations,	484,401	
7	meter sets and telemetering, and etc.		
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43	T O T A L -	3,714,175	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, 2016

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	(87,616,550)	(87,616,550)		
2	Depreciation Provisions for Year, Charged to:				
3	(403) Depreciation Expense	(5,189,177)	(5,189,177)		
4	(413) Exp. of Gas Plant Leased to Others	-			
5	Transportation Expenses - Clearing	(254,126)	(254,126)		
6	Other Clearing Accounts	-			
7	Other Account (specify):				
7.01	ARO Assets	(31,322)	(31,322)		
7.02	Other	-			
8		-			
9	TOTAL Depreciation Provisions for Year (*Enter total of lines 3 thru 8*)	(5,474,625)	(5,474,625)		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	1,344,084	1,344,084		
12	Cost of Removal	238,456	238,456		
13	Salvage (credits)	(693,404)	(693,404)		
14	TOTAL Net Charges for Plant Retired (*enter Total of Lines 11 thru 13*)	889,136	889,136		
15	Other Debit or Credit Items (Describe)				
15.01	Increase/Decrease in Retirement Work in Progress	418,452	418,452		
15.02	Adjustment Due to Transfers/Adjustments & Alloc. Rate Change	(89,932)	(89,932)		
16					
17	Balance End of Year (*Enter Total of Lines 1, 9, 14, 15, & 16*)	(91,873,519)	(91,873,519)		
	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	(3,402,074)	(3,402,074)		
25	Distribution	(85,140,282)	(85,140,282)		
26	General	(3,588,168)	(3,588,168)		
26.01	Intangible	(73,667)	(73,667)		
26.02	Retirement Work-In-Progress	330,672	330,672		
27	TOTAL (*Enter Total of Lines 18 thru 26*)	(91,873,519)	(91,873,519)		

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, 2016**

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)	12,456,679		12,456,679			
4	Property Under Capital Leases	-					
5	Plant Purchased or Sold	-					
6	Completed Construction not Classified	226,697		226,697			
7	Experimental Plant Unclassified	-					
8	TOTAL (*Enter Total of lines 3 thru 7*)	12,683,376	-	12,683,376	-		-
9	Leased to Others	-					
10	Held for Future Use	-					
11	Construction Work In Progress	1,037,030		1,037,030			
12	Acquisition Adjustments	-					
13	Total Utility Plant (*Lines 8 thru 12*)	13,720,406	-	13,720,406	-		-
14	Accumulated Prov For Depr, Amort, & Depl.	(5,375,620)		(5,375,620)			
15	Net Utility Plant (Line 13 less 14)	8,344,786	-	8,344,786	-		-
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation	(2,713,989)		(2,713,989)			
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	(2,661,631)		(2,661,631)			
22	Total In-Service (*Lines 18 thru 21*)	(5,375,620)	-	(5,375,620)	-		-
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*)	(5,375,620)	-	(5,375,620)	-		-

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, 2016**

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	36,907			700		37,607
3	302	Franchises and Consents	-					-
4	303	Miscellaneous Intangible Plant	7,756,815	57,763		147,018		7,961,596
5		TOTAL Intangible Plant	7,793,722	57,763	-	147,718	-	7,999,203
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, 2016**

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 (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2016

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	23,032			436		23,468
90	375	Structures and Improvements	96,883			1,836		98,719
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	119,915	-	-	2,272	-	122,187

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	☑ An Original (1) ☐ A Resubmission (2)	(M,D,Y)	Dec. 31, 2016

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	231,709			4,392		236,101
106	390	Structures and Improvements	1,409,572	13,471		26,716		1,449,759
107	391	Office Furniture and Equipment	1,604,661	53,502		30,414		1,688,577
108	392	Transportation Equipment	463,866	63,621	(16,578)	8,792	(40,553)	479,148
109	393	Stores Equipment	10,458			198		10,656
110	394	Tools, Shop, and Garage Equipment	438,560	19,600	(13,234)	8,312		453,238
111	395	Laboratory Equipment	23,513			446		23,959
112	396	Power Operated Equipment	(18,100)			(343)	1,434	(17,009)
113	397	Communication Equipment	204,925	14,038		3,884		222,847
114	398	Miscellaneous Equipment	14,436			274		14,710
115		SUBTOTAL	4,383,600	164,232	(29,812)	83,085	(39,119)	4,561,986
116	399	Other Tangible Property	-					-
117		TOTAL General Plant	4,383,600	164,232	(29,812)	83,085	(39,119)	4,561,986
118		TOTAL (Accounts 101 and 106)	12,297,237	221,995	(29,812)	233,076	(39,119)	12,683,376
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	12,297,237	221,995	(29,812)	233,076	(39,119)	12,683,376

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, 2016**

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				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
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, 2016**

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	1,037,030	
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			
45			
46			
47			
48	T O T A L -	1,037,030	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, 2016**

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	(2,565,226)	(2,565,226)		
2	Depreciation Provisions for Year, Charged to:				
3	(403) Depreciation Expense	(157,943)	(157,943)		
4	(413) Exp. of Gas Plant Leased to Others	-			
5	Transportation Expenses - Clearing	(26,966)	(26,966)		
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*)	(184,909)	(184,909)		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	29,812	29,812		
12	Cost of Removal	-	-		
13	Salvage (credits)	(7,172)	(7,172)		
14	TOTAL Net Charges for Plant Retired (*enter Total of Lines 11 thru 13*)	22,640	22,640		
15	Other Debit or Credit Items (Describe)				
15.01	Increase/Decrease in Retirement Work in Progress	47,429	47,429		
15.02	Adjustment Due to Change in Allocation Rate	(33,922)	(33,922)		
16					
17	Balance End of Year (*Enter Total of Lines 1, 9, 14, 15, & 16*)	(2,713,988)	(2,713,988)		

Section B. Balances at End of Year According to Functional Classifications

Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant In Service (c)	Gas Plant Held For Future Use (d)	Gas Plant Leased to Others (e)
18	Production - Manufactured Gas	-	-		
19	Production and Gathering - Natural Gas	-	-		
20	Products Extraction - Natural Gas	-	-		
21	Underground Gas Storage	-	-		
22	Other Storage Plant	-	-		
23	Base Load LNG Terminaling and Proc. Plant	-	-		
24	Transmission	-	-		
25	Distribution	(103,655)	(103,655)		
26	General	(2,659,934)	(2,659,934)		
26.01	Intangible	-	-		
26.02	Retirement Work-In-Progress	49,601	49,601		
27	TOTAL (*Total of Lines 18 thru 26*)	(2,713,988)	(2,713,988)		

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, 2016**

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)			$ 83,260		$ 83,260
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	16,631
31	Amount per Mcf	5.01
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		

BLANK PAGE

[Next page is 40]

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, 2016**

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
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2016**

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**		
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			
45			
46			
47			
48			
49			
50			
51			
52			
53			

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, 2016

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
						10.73	6,920,128	$ 21,903,606	316.52	2
										3
								$ 472,562	n/a	4
										5
								$ 8,570,740	n/a	6
										7
							6,920,128	**$ 30,946,908**	n/a	8
										9
										10
										11
										12
										13
										14
										15
										16
										17
										18
										19
										20
										21
										22
										23
										24
										25
										26
										27
										28
										29
										30
										31
										32
										33
										34
										35
										36
										37
										38
										39
										40
										41
										42
										43
										44
										45
										46
										47
										48
										49
										50
										51
										52
										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, 2016

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 us 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	4,042	$ 12,580	0	0	0
6	(Report separately for each principal use. Group minor uses).						
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22	**TOTAL**		4,042	$ 12,580			

BLANK PAGE

[Next page is 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, 2016**

STATE OF OREGON - GAS ACCOUNT - NATURAL GAS

1 The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent taking into consideration differences in pressure bases used in measuring MCF of natural gas received and delivered.
2 Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3 Enter in column (c) the MCF as reported in the schedules indicated for the respective items of receipts and deliveries.

LINE NO.	ITEM (a)	REFERENCE PAGE NO. (b)	MCF (14.73 PSIA AT 60 °F) (c)
1	**GAS RECEIVED**		Mcf
2	Natural gas produced		
3	LPG gas produced and mixed with natural gas		
4	Manufactured gas produced and mixed with natural gas		
5	Purchased gas:		
6	a. Wellhead		
7	b. Field lines		
8	c. Gasoline Plants		
9	d. Transmission line		
10	e. City gate under FERC rate schedules		6,924,169
11	f. LNG		
12	g. Other		
13	TOTAL GAS PURCHASED		6,924,169
14	Gas of others received for transportation		19,586,130
15	Receipts of respondents' gas transported or compressed by others		
16	Exchange gas received		
17	Gas withdrawn from underground storage		184,436
18	Gas received from LNG storage		
19	Gas received from LNG processing		
20	Other receipts: (specify)		
21	TOTAL RECEIPTS		26,694,735

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, 2016**

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		616,628
39	(ii) Other distribution system sales		6,445,557
40	TOTAL DISTRIBUTION SYSTEM SALES		7,062,185
41	d. Interdepartmental sales		
42	TOTAL SALES		7,062,185
43			
44	Deliveries of gas transported or compressed for:		
45	a. Other interstate pipeline companies		
46	b. Others		19,586,130
47	TOTAL, GAS TRANSPORTED OR COMPRESSED FOR OTHERS		19,586,130
48	Deliveries of respondent's gas for transportation or compression by others		
49	Exchange gas delivered		
50	Natural gas used by respondent		4,042
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		26,652,357
57	Production system losses		
58	Storage losses		
59	Transmission system losses		
60	Distribution system losses		42,378
61	Other losses (specify in so far as possible)		
62	TOTAL UNACCOUNTED FOR		42,378
63	TOTAL SALES, OTHER DELIVERIES & UNACCOUNTED FOR		26,694,735

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, 2016**

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.	284,133	76,287	207,846
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)	344,459	83,600	260,859
6	Director's Fees (paid to MDU for CNGC's share of director's expenses)	407,203	98,828	308,375
7	Miscellaneous under $250,000 (6 items)	3,247	763	2,484
8				
9				
10				
	TOTAL	**1,039,042**	**259,478**	**779,564**

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, 2016**

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, 2016**

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 97** Defeat the Tax on Oregon Sales PO Box 5275 Portland, OR 97208-5275	426.1	12,365.00
	TOTAL		**12,365.00**

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, 2016**

STATE OF OREGON - EXPENDITURES TO ANY PERSON OR ORGANIZATION HAVING AN AFFILIATED INTEREST FOR SERVICES, ETC.

1. Report all expenditures to any person or organization having an affiliated interest for service, advice, auditing, associating, sponsoring, engineering, managing, operating, financial, legal or other services. See Oregon Revised Statute 757.015 for definition of "affiliated interest."
2. Give reference if such expenditures have in the past been approved by the Commission.
   Describe the services received and the account or accounts charged. Report whole dollars only.

LINE NO.	DESCRIPTION (a)	ACCOUNT NUMBER (b)	TOTAL AMOUNT (c)	AMOUNT ASSIGNED TO OREGON (d)
1	MDU/MDUR Allocated - approved in Order 07-418	107	1,092,389	270,148
2	MDU/MDUR Allocated - approved in Order 07-418	426.1	12,385	3,063
3	MDU/MDUR Allocated - approved in Order 07-418	426.4	24,026	5,942
4	MDU/MDUR Allocated - approved in Order 07-418	426.5	632	156
5	MDU/MDUR Allocated - approved in Order 07-418	813	204,115	50,477
6	MDU/MDUR Allocated - approved in Order 07-418	875	117,980	29,177
7	MDU/MDUR Allocated - approved in Order 07-418	880	589,845	145,869
8	MDU/MDUR Allocated - approved in Order 07-418	902	148,055	36,614
9	MDU/MDUR Allocated - approved in Order 07-418	903	6,429,386	1,589,987
10	MDU/MDUR Allocated - approved in Order 07-418	909	20,037	4,955
11	MDU/MDUR Allocated - approved in Order 07-418	913	41	10
12	MDU/MDUR Allocated - approved in Order 07-418	920	4,596,118	1,136,620
13	MDU/MDUR Allocated - approved in Order 07-418	921	2,206,639	545,702
14	MDU/MDUR Allocated - approved in Order 07-418	922	(172,133)	(42,569)
15	MDU/MDUR Allocated - approved in Order 07-418	923	339,016	83,839
16	MDU/MDUR Allocated - approved in Order 07-418	925	52	13
17	MDU/MDUR Allocated - approved in Order 07-418	926	(94,212)	(23,298)
18	MDU/MDUR Allocated - approved in Order 07-418	930.1	20,804	5,145
19	MDU/MDUR Allocated - approved in Order 07-418	930.2	427,432	105,704
20	MDU/MDUR Allocated - approved in Order 07-418	931	1,604,465	396,784
21	Other Services	VAR	675,701	211,390
	TOTALS		18,242,773	4,555,727

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, 2016**

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	Boys & Girls Clubs (WA and OR)	426.1	6,000	1,237
3	United Way (WA and OR)	426.1	7,684	1,158
4	CNG Contributions to Winter Help (WA and OR)	426.1	50,000	12,365
5	Neighbor Impact (Redmond OR)	426.1	2,000	2,000
6	Other Organizations (60 organizations)	426.1/880.0/908.0	33,279	14,444
7	Total contributions to and memberships in charitable organizations		98,963	31,204
8	*(b) Organizations of the Utility Industry:*			
9	American Gas Association (Washington D.C.)	426.1/426.4/930.2	137,141	33,915
10	Northwest Gas Association (West Linn, OR)	930.2	62,814	15,534
11	Other Organizations (9 organizations)	908.0/930.2/921.0	36,058	8,754
12	Total contributions to Organizations of the Utility Industry		236,013	58,203
13	*(c) Technical and Professional Organizations*			
14	National Association of Corrosion Engineers (Houston, TX)	921.0	2,370	586
15	Other Organizations (5 organizations)	921.0	1,880	465
16	Total contributions to Professional Organizations		4,250	1,051
17	*(d) Commercial and Trade Organizations*			
18	Association of Washington Business (Olympia, WA)	930.2/921.0	43,000	10,634
19	Chamber of Commerce-34 (WA and OR)	426.4/921.0/930.2	30,295	8,801
20	Economic Development Councils-11 (WA and OR)	426.1/930.2	28,346	13,669
21	Other Organizations (7 organizations)	426.1/908.0/930.2	5,883	1,990
22	Total contributions to Commercial and Trade Organizations		107,524	35,094
23	*(e) Other Organizations & Donations*			
24	MDU Resources expenses (Bismark, ND)	426.1/426.4/921.0	18,701	4,625
25	Grandridge Business Park (Kennewick WA)	930.2	5,630	1,392
26	Other Organizations (5 organizations)	426.1921.0/930.2	4,159	894
27	Total Other Organizations		28,490	6,911
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
	TOTAL		**475,240**	**132,463**

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, 2016**

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-W Region & Bus Development 3/	Scott W. Madison	4/	
4	VP Operations	Eric P. Martuscelli	4/	
5	VP-Regulatory Affairs & Cust Service 3/	Mark A. Chiles	4/	
6	VP-HR 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 & Gas Supply/1	Garret Senger	4/	
12	Controller 1/	Tammy J. Nygard	4/	
13	Chief Information Officer 2/	Margaret (Peggy) A. Link	4/	
14				
15	1/ Salary includes amount allocated to CNGC from MDU			
16	2/ Salary includes amount allocated to CNGC from MDUR			
17	3/ Salary includes amount allocated to CNGC from IGC			
18	4/ Confidential salary data included on filed reports with OPUC.			
19				
20				
21				
22				
23				
24				
25				

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2016**

STATE OF OREGON-DONATIONS OR PAYMENTS FOR SERVICES RENDERED BY PERSONS OTHER THAN EMPLOYEES AND CHARGED TO OREGON OPERATING ACCOUNTS

1. Report for each service rendered (including materials furnished incidental to the service which are impracticable of separation) by recipient and in total the aggregate of all payments made during the year where the aggregate of such payments to a recipient was $25,000 or more including fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payments for services, traffic settlements, amounts paid for general services and licenses, accruals paid to trustees of pension and other employee benefit funds, and amounts paid for construction or maintenance of plant to persons other than *affiliates)* to any one corporation, institution, association, firm, partnership, committee, or person (not an employee of the respondent). Indicate by an asterisk in column (c) each item that includes payments for materials furnished incidental to the service performed. Payments to a recipient by two or more companies within a single system under a cost sharing or other joint arrangement shall be considered a single item for reporting in this schedule and shall be shown in the report of the principal company in the joint arrangement (as measured by gross operating revenues) with references thereto in the reports of the other system companies in the joint agreement.
2. If more convenient, this schedule may be filled out for a group of companies considered as one system and shown only in the report of the principal company in the system, with references thereto in the reports of the other companies.

LINE NO.	NAME OF RECIPIENT (a)	NATURE OF SERVICE (b)	AMOUNT OF PAYMENT (c)
1	Das-Co of Idaho	Construction	170,079
2	ABI Services, LLC	Construction	157,446
3	Black & Veatch	Consulting	125,729
4	Parametrix Inc	Construction	117,021
5	McDowell Rackner & Gibson, PC	Legal	107,352
6	Eugene Water & Electric Board	Construction	76,138
7	Heath Consultants, Inc	Construction	63,607
8	Deloitte & Touche	Audit	50,782
9	Surveys & Analysis, Inc.	Construction	44,292
10	Michels Corporation	Construction	43,823
11	Prosource Technologies, LLC	Construction	38,763
12	Blue Heron Consulting Corporation	Consulting	34,558
13	Teton Law Group, LLC	Legal	32,820
14	Integral Consulting, Inc.	Consulting	32,008
15	Evergreen Financial Services	Collections	28,289
16	Garvey Schubert Barer	Legal	28,247
17	Winston & Cashalt Laywers	Legal	28,035
18	Day Wireless Systems, Inc.	Communications	27,457
19	Others < $25,000	Various	537,557
20			
21			
22			
23			
24			
25			
	TOTAL		**1,744,003**

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, 2016**

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

Oregon Production Statistics (therms)		
Gas Produced		
Gas Purchased		286,369,660
Total Receipts		286,369,660
Gas Sales		285,871,696
Gas used by Company		43,356
Gas Delivered to LNG Storage - Net		
Losses & Billing Delay		454,608
Total Disbursements		286,369,660
Oregon Revenue by Service Class		
Residential	$	35,156,436
Commercial & Industrial	$	24,417,279
Firm		
Interruptible		
Transportation	$	4,044,720
Total	$	63,618,435
Gas Sold in Therms (Oregon)		
Residential		41,029,112
Commercial & Industrial		34,730,989
Firm		
Interruptible		
Transportation		210,111,595
Total		285,871,696
Average Number of Customers		
Residential		60,483
Commercial & Industrial		9,967
Firm		
Interruptible		
Transportation		35
Total		70,485

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, 2016

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	2,944,817			**2,944,817**
34	Customer Accounts	1,018,962			**1,018,962**
35	Customer Service and Informational	987			**987**
36	Sales	-			**-**
37	Administrative and General	1,516,781			**1,516,781**
38	TOTAL Operation (Total of lines 28 thru 37)	**5,481,547**	**-**	**-**	**5,481,547**
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	1,040,335			**1,040,335**
46	Administrative and General				
47	TOTAL Maintenance (Total of lines 40 thru 46)	**1,040,335**	**-**	**-**	**1,040,335**
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)	3,985,152			**3,985,152**
56	Customer Accounts (Total of line 34)	1,018,962			**1,018,962**
57	Customer Service and Informational (Total of line 35)	987			**987**
58	Sales (Total of line 36)	-			**-**
59	Administrative and General (Total of lines 37 and 46)	1,516,781			**1,516,781**
60	Total Operation and Maintenance (Total of lines 50 thru 59)	**6,521,882**	**-**	**-**	**6,521,882**
61	Other Utility Departments				
62	Operation and Maintenance				
63	TOTAL ALL Utility Dept. (Total of lines 25, 60, and 62)	**6,521,882**	**-**	**-**	**6,521,882**
64	Utility Plant				
65	Construction (By Utility Departments)				
66	Electric Plant				
67	Gas Plant	2,002,192			**2,002,192**
68	Other				
69	TOTAL Construction (Total of lines 66 thru 68)	**2,002,192**	**-**	**-**	**2,002,192**
70	Plant Removal (By Utility Departments)				
71	Electric Plant				
72	Gas Plant	115,832			**115,832**
73	Other				
74	TOTAL Plant Removal (Total of lines 71 thru 73)	**115,832**	**-**	**-**	**115,832**
75	PTO/Incentive/Severance Pay Liabilities	299,876			**299,876**
76	TOTAL Other Accounts	**299,876**	**-**	**-**	**299,876**
77	TOTAL SALARIES AND WAGES	**8,939,782**	**-**	**-**	**8,939,782**

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

Form 2 Approved
OMB No.1902-0028
(Expires 09/30/2017)

Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

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** 2016/Q4

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

GENERAL INFORMATION

I Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

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

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

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

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

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

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

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

.

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

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

IV. When to Submit:

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

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

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

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

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS	
I.	Btu per cubic foot – The total heating value, expressed in Btu, produced by the combustion, at constant pressure, of the amount of the gas which would occupy a volume of 1 cubic foot at a temperature of 60°F if saturated with water vapor and under a pressure equivalent to that of 30°F, and under standard gravitational force (980.665 cm. per sec) with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of gas and air when the water formed by combustion is condensed to the liquid state (called gross heating value or total heating value).
II.	Commission Authorization -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.
III.	Dekatherm – A unit of heating value equivalent to 10 therms or 1,000,000 Btu.
IV	Respondent – The person, corporation, licensee, agency, authority, or other legal entity or instrumentality on whose behalf the report is made.

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

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

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

General Penalties

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

BLANK PAGE

QUARTERLY/ANNUAL REPORT OF MAJOR NATURAL GAS COMPANIES
IDENTIFICATION

01 Exact Legal Name of Respondent Cascade Natural Gas Corporation	Year/Period of Report End of 2016/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 Kevin Conwell	06 Title of Contact Person Manager, Accounting & Finance
07 Address of Contact Person (Street, City, State, Zip Code) 8113 West Grandridge Boulevard, Kennwick, WA 99336-7166	

08 Telephone of Contact Person, Including Area Code 509-734-4524	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 12/31/2016

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 Kevin Conwell	12 Title Manager, Accounting & Finance
13 Signature Kevin Conwell	14 Date Signed 03/31/2017

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	12/31/2016	End of 2016/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."

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	12/31/2016	End of 2016/Q4

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."

Line No.	Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
38	Unamortized Loss and Gain on Reacquired Debt	260		
39	Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes	261		
40	Taxes Accrued, Prepaid, and Charged During Year	262-263		
41	Miscellaneous Current and Accrued Liabilities	268		
42	Other Deferred Credits	269		
43	Accumulated Deferred Income Taxes-Other Property	274-275		
44	Accumulated Deferred Income Taxes-Other	276-277		
45	Other Regulatory Liabilities	278		
	INCOME ACCOUNT SUPPORTING SCHEDULES			
46	Monthly Quantity & Revenue Data by Rate Schedule	299		
47	Gas Operating Revenues	300-301		
48	Revenues from Transportation of Gas of Others Through Gathering Facilities	302-303		
49	Revenues from Transportation of Gas of Others Through Transmission Facilities	304-305		
50	Revenues from Storage Gas of Others	306-307		
51	Other Gas Revenues	308		
52	Discounted Rate Services and Negotiated Rate Services	313		
53	Gas Operation and Maintenance Expenses	317-325		
54	Exchange and Imbalance Transactions	328		
55	Gas Used in Utility Operations	331		
56	Transmission and Compression of Gas by Others	332		
57	Other Gas Supply Expenses	334		
58	Miscellaneous General Expenses-Gas	335		
59	Depreciation, Depletion, and Amortization of Gas Plant	336-338		
60	Particulars Concerning Certain Income Deduction and Interest Charges Accounts	340		
	COMMON SECTION			
61	Regulatory Commission Expenses	350-351		
62	Employee Pensions and Benefits (Account 926)	352		
63	Distribution of Salaries and Wages	354-355		
64	Charges for Outside Professional and Other Consultative Services	357		
65	Transactions with Associated (Affiliated) Companies	358		
	GAS PLANT STATISTICAL DATA			
66	Compressor Stations	508-509		
67	Gas Storage Projects	512-513		
68	Transmission Lines	514		
69	Transmission System Peak Deliveries	518		
70	Auxiliary Peaking Facilities	519		
71	Gas Account-Natural Gas	520		
72	Shipper Supplied Gas for the Current Quarter	521		
73	System Map	522		
74	Footnote Reference	551		
75	Footnote Text	552		
76	Stockholder's Reports (check appropriate box)			
	[ ] Four copies will be submitted [ ] No annual report to stockholders is prepared			

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	12/31/2016	End of 2016/Q4

General Information

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

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

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
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				

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

----

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	None				Not used
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/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					

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	12/31/2016	2016/Q4

Important Changes During the Quarter/Year

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

1. Changes in and important additions to franchise rights: Describe the actual consideration and state from whom the franchise rights were acquired. If the franchise rights were acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Briefly describe the property, and the related transactions, and cite Commission authorization, if any was required. Give date journal entries called for by Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other conditions. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and cite Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service.

Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.

6. Obligations incurred or assumed by respondent as guarantor for the performance by another of any agreement or obligation, including ordinary commercial paper maturing on demand or not later than one year after date of issue: State on behalf of whom the obligation was assumed and amount of the obligation. Cite Commission authorization if any was required.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. Estimated increase or decrease in annual revenues caused by important rate changes: State effective date and approximate amount of increase or decrease for each revenue classification. State the number of customers affected.
12. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
13. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

1. None
2. None
3. None
4. None
5. None
6. None
7. None
8. Wages for union employees increased by 3.10% in April 2016.
9. WUTC Complaint (Docket PG-15120 issued against Cascade Natural Gas on 7/12/16 for failure to submit MAOP Compliance Plan by required deadline and failure to maintain records to validate MAOP. Settlement Agreement filed 12/15/16, pending on 12/31/16, and subsequently approved by WUTC on 3/20/17.
10. None
11. WA Rate Increase (WUTC Docket UG-152286 Order 04, Service Date 7/7/16, Rates Effective 9/1/2016)

Revenue Class	Increase	% Increase	Number of Customers
Residential	$ 3,000,000.00	7.40%	181,656
Commercial	$ 569,398.10	2.52%	25,535
Industrial	$ 84,841.58	2.52%	473
Interruptible	$ 6,107.77	2.52%	197
Transportation	$ 339,652.55	2.52%	8
Total	$ 4,000,000.00	1.60%	207,869

OR Rate Increase (OPUC Order 15-412, Entered 12/28/15, Rates Effective 2/1/2016)

Revenue Class	Increase	% Increase	Number of Customers
Residential	$ 375,036.00	2.30%	60,483
Commercial	$ 172,736.00	2.30%	9,815
Industrial	$ 28,372.00	6.00%	152
Large Volume	$ 13,856.00	6.00%	35
Total	$ 590,000.00	0.84%	70,485

12. Changes to Corporate Officers:
    Karl Liepitz became Assistant Secretary taking over position previously held by Daniel Kuntz
    Daniel Kuntz became Secretary taking over position previouly held by Paul Sandness (Retired)
    Tammy Nygard became Controller taking over responsibilities given up by Mark Chiles
    Margaret (Peggy) Link became Chief Information Officer taking over for Michael Gardner (Retired)

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	12/31/2016	End of 2016/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	922,694,564	870,184,135
3	Construction Work in Progress (107)	200-201	12,898,870	10,555,876
4	TOTAL Utility Plant (Total of lines 2 and 3)	200-201	935,593,434	880,740,011
5	(Less) Accum. Provision for Depr., Amort., Depl. (108, 111, 115)		453,344,582	432,381,534
6	Net Utility Plant (Total of line 4 less 5)		482,248,852	448,358,477
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)		482,248,852	448,358,477
11	Utility Plant Adjustments (116)	122	0	0
12	Gas Stored-Base Gas (117.1)	220	0	0
13	System Balancing Gas (117.2)	220	0	0
14	Gas Stored in Reservoirs and Pipelines-Noncurrent (117.3)	220	0	0
15	Gas Owed to System Gas (117.4)	220	0	0
16	**OTHER PROPERTY AND INVESTMENTS**			
17	Nonutility Property (121)		202,030	202,030
18	(Less) Accum. Provision for Depreciation and Amortization (122)		0	0
19	Investments in Associated Companies (123)	222-223	0	0
20	Investments in Subsidiary Companies (123.1)	224-225	0	0
21	(For Cost of Account 123.1 See Footnote Page 224, line 40)			
22	Noncurrent Portion of Allowances		0	0
23	Other Investments (124)	222-223	10,932,832	10,440,344
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)		11,134,862	10,642,374
31	**CURRENT AND ACCRUED ASSETS**			
32	Cash (131)		3,539,113	31,796,378
33	Special Deposits (132-134)		0	0
34	Working Funds (135)		2,750	2,700
35	Temporary Cash Investments (136)	222-223	0	0
36	Notes Receivable (141)		0	0
37	Customer Accounts Receivable (142)		10,813,648	9,489,613
38	Other Accounts Receivable (143)		1,813,282	1,964,217
39	(Less) Accum. Provision for Uncollectible Accounts - Credit (144)		471,151	461,439
40	Notes Receivable from Associated Companies (145)		0	0
41	Accounts Receivable from Associated Companies (146)		60,060	118,405
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)		7,223,893	7,019,222
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	126,656	238,846
53	Liquefied Natural Gas Stored and Held for Processing (164.2 thru 164.3)	220	1,705,164	712,311
54	Prepayments (165)	230	2,456,770	3,572,978
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)		34,522,282	30,740,332
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)		61,792,467	85,193,563
65	**DEFERRED DEBITS**			
66	Unamortized Debt Expense (181)		2,042,178	2,218,763
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	49,627,341	51,471,119
70	Preliminary Survey and Investigation Charges (Electric)(183)		0	0
71	Preliminary Survey and Investigation Charges (Gas)(183.1 and 183.2)		0	0
72	Clearing Accounts (184)		104,615	(57,149)
73	Temporary Facilities (185)		0	0
74	Miscellaneous Deferred Debits (186)	233	70,888,337	66,216,460
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)		826,242	867,213
78	Accumulated Deferred Income Taxes (190)	234-235	26,488,327	26,391,798
79	Unrecovered Purchased Gas Costs (191)		0	0
80	TOTAL Deferred Debits (Total of lines 66 thru 79)		149,977,040	147,108,204
81	TOTAL Assets and Other Debits (Total of lines 10-15,30,64,and 80)		705,153,221	691,302,618

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	160,698,668	152,703,952
7	Other Paid-In Capital (208-211)	253	0	0
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	31,852,511	38,204,913
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reacquired Capital Stock (217)	250-251	0	0
14	Accumulated Other Comprehensive Income (219)	117	0	0
15	TOTAL Proprietary Capital (Total of lines 2 thru 14)		192,552,179	190,909,865
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	214,471,000	214,589,000
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)		214,471,000	214,589,000
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)		15,498,768	14,631,487
29	Accumulated Provision for Pensions and Benefits (228.3)		7,687,634	7,657,939
30	Accumulated Miscellaneous Operating Provisions (228.4)		24,135	24,135
31	Accumulated Provision for Rate Refunds (229)		0	0

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

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance	Prior Year End Balance 12/31 (d)
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		54,807,880	50,960,517
35	TOTAL Other Noncurrent Liabilities (Total of lines 26 thru 34)		78,018,417	73,274,078
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Current Portion of Long-Term Debt		0	0
38	Notes Payable (231)		0	0
39	Accounts Payable (232)		28,763,011	21,019,198
40	Notes Payable to Associated Companies (233)		0	0
41	Accounts Payable to Associated Companies (234)		1,606,767	1,614,644
42	Customer Deposits (235)		874,939	1,061,068
43	Taxes Accrued (236)	262-263	8,418,892	10,490,710
44	Interest Accrued (237)		3,113,255	3,114,287
45	Dividends Declared (238)		4,160,000	4,160,000
46	Matured Long-Term Debt (239)		0	0
47	Matured Interest (240)		0	0
48	Tax Collections Payable (241)		3,542	0
49	Miscellaneous Current and Accrued Liabilities (242)	268	9,694,740	8,325,060
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)		56,635,146	49,784,967
56	**DEFERRED CREDITS**			
57	Customer Advances for Construction (252)		4,482,130	4,075,229
58	Accumulated Deferred Investment Tax Credits (255)		324,288	373,122
59	Deferred Gains from Disposition of Utility Plant (256)		0	0
60	Other Deferred Credits (253)	269	18,664,938	21,159,604
61	Other Regulatory Liabilities (254)	278	3,780,681	3,535,105
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)		100,067,346	96,815,260
65	Accumulated Deferred Income Taxes - Other (283)		36,157,096	36,786,388
66	TOTAL Deferred Credits (Total of lines 57 thru 65)		163,476,479	162,744,708
67	TOTAL Liabilities and Other Credits (Total of lines 15,24,35,55,and 66)		705,153,221	691,302,618

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	12/31/2016	End of 2016/Q4

Statement of Income

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

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

Line No.	Title of Account (a)	Reference Page Number (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
1	UTILITY OPERATING INCOME					
2	Gas Operating Revenues (400)	300-301	269,012,065	283,544,904	0	0
3	Operating Expenses					
4	Operation Expenses (401)	317-325	183,821,254	203,122,805	0	0
5	Maintenance Expenses (402)	317-325	5,729,642	5,473,310	0	0
6	Depreciation Expense (403)	336-338	22,501,731	25,145,321	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	2,736,728	2,538,010	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	25,926,633	26,839,304	0	0
15	Income Taxes-Federal (409.1)	262-263	4,283,371	3,054,373	0	0
16	Income Taxes-Other (409.1)	262-263	293,645	57,822	0	0
17	Provision of Deferred Income Taxes (410.1)	234-235	1,569,439	41,339	0	0
18	(Less) Provision for Deferred Income Taxes-Credit (411.1)	234-235	0	0	0	0
19	Investment Tax Credit Adjustment-Net (411.4)		(48,834)	(52,577)	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)		246,813,609	266,219,707	0	0
26	Net Utility Operating Income (Total of lines 2 less 25) (Carry forward to page 116, line 27)		22,198,456	17,325,197	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

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	269,012,065	283,544,904	0	0
3						
4	0	0	183,821,254	203,122,805	0	0
5	0	0	5,729,642	5,473,310	0	0
6	0	0	22,501,731	25,145,321	0	0
7	0	0	0	0	0	0
8	0	0	2,736,728	2,538,010	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	25,926,633	26,839,304	0	0
15	0	0	4,283,371	3,054,373	0	0
16	0	0	293,645	57,822	0	0
17	0	0	1,569,439	41,339	0	0
18	0	0	0	0	0	0
19	0	0	(48,834)	(52,577)	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	246,813,609	266,219,707	0	0
26	0	0	22,198,456	17,325,197	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/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)		22,198,456	17,325,197	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)		6,276	9,825	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)		610,340	9,338,031	0	0
38	Allowance for Other Funds Used During Construction (419.1)		361,162	461,795	0	0
39	Miscellaneous Nonoperating Income (421)		17,666	18,357	0	0
40	Gain on Disposition of Property (421.1)		0	0	0	0
41	TOTAL Other Income (Total of lines 31 thru 40)		995,444	9,828,008	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	232,468	263,833	0	0
46	Life Insurance (426.2)		0	0	0	0
47	Penalties (426.3)		1,001,184	275,000	0	0
48	Expenditures for Certain Civic, Political and Related Activities (426.4)		128,203	140,881	0	0
49	Other Deductions (426.5)		1,437	213,923	0	0
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)	340	1,363,292	893,637	0	0
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other than Income Taxes (408.2)	262-263	3,164	2,940	0	0
53	Income Taxes-Federal (409.2)	262-263	(189,153)	2,808,147	0	0
54	Income Taxes-Other (409.2)	262-263	(12,967)	53,161	0	0
55	Provision for Deferred Income Taxes (410.2)	234-235	0	0	0	0
56	(Less) Provision for Deferred Income Taxes-Credit (411.2)	234-235	0	0	0	0
57	Investment Tax Credit Adjustments-Net (411.5)		0	0	0	0
58	(Less) Investment Tax Credits (420)		0	0	0	0
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(198,956)	2,864,248	0	0
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		(168,892)	6,070,123	0	0
61	INTEREST CHARGES					
62	Interest on Long-Term Debt (427)		11,144,573	11,047,666	0	0
63	Amortization of Debt Disc. and Expense (428)	258-259	171,932	172,249	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	653,866	255,279	0	0
69	(Less) Allowance for Borrowed Funds Used During Construction-Credit (432)		284,975	301,152	0	0
70	Net Interest Charges (Total of lines 62 thru 69)		11,726,367	11,215,013	0	0
71	Income Before Extraordinary Items (Total of lines 27,60 and 70)		10,303,197	12,180,307	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)		10,303,197	12,180,307	0	0

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) Dec. 31, 2016	Year/Period of Report End of 2016/Q4

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	-	-	22,198,456	17,325,197	-	-
28	[redacted]					
29						
30						
31	-	-	-	-	-	-
32	-	-	-	-	-	-
33	-	-	6,276	9,825	-	-
34	-	-	-	-	-	-
35	-	-	-	-	-	-
36	-	-	-	-	-	-
37	-	-	610,340	9,338,031	-	-
38	-	-	361,162	461,795	-	-
39	-	-	17,666	18,357	-	-
40	-	-	-	-	-	-
41	-	-	995,444	9,828,008	-	-
42	[redacted]					
43			-	-		
44			-	-		
45			232,468	263,833		
46			-	-		
47			1,001,184	275,000		
48			128,203	140,881		
49	-	-	1,437	213,923	-	-
50	-	-	1,363,292	893,637	-	-
51	[redacted]					
52			3,164.00	2,940		
53	-	-	(189,153)	2,808,147	-	-
54	-	-	(12,967)	53,161	-	-
55	-	-	-	-	-	-
56	-	-	-	-	-	-
57	-	-	-	-	-	-
58	-	-			-	-
59	-	-	(198,956)	2,864,248	-	-
60	-	-	(168,892)	6,070,123	-	-
61	[redacted]					
62	-	-	11,144,573	11,047,666	-	-
63	-	-	171,932	172,249	-	-
64	-	-	40,971	40,971	-	-
65	-	-	-	-	-	-
66	-	-	-	-	-	-
67	-	-	-	-	-	-
68	-	-	653,866	255,279	-	-
69	-	-	(284,975)	(301,152)	-	-
70	-	-	11,726,367	11,215,013	-	-
71	-	-	10,303,197	12,180,307	-	-
72	[redacted]					
73	-	-	-	-	-	-
74	-	-	-	-	-	-
75	-	-	-	-	-	-
76	-	-	-	-	-	-
77	-	-	-	-	-	-
78	-	-	10,303,197	12,180,307	-	-

Statement of Accumulated Comprehensive Income and Hedging Activities

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

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

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

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

Statement of Accumulated Comprehensive Income and Hedging Activities(continued)

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert 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					
4				12,180,307	12,180,307
5					
6					
7					
8					
9				10,303,197	10,303,197
10					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

Statement of Retained Earnings

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter Year to Date Balance (c)	Previous Quarter Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS			
1	Balance-Beginning of Period		38,204,913	42,672,119
2	Changes (Identify by prescribed retained earnings accounts)			
3	Adjustments to Retained Earnings (Account 439)			
4	TOTAL Credits to Retained Earnings (Account 439) (footnote details)			
5	TOTAL Debits to Retained Earnings (Account 439) (footnote details)			
6	Balance Transferred from Income (Acct 433 less Acct 418.1)		10,303,197	12,180,307
7	Appropriations of Retained Earnings (Account 436)			
8	TOTAL Appropriations of Retained Earnings (Account 436) (footnote details)			
9	Dividends Declared-Preferred Stock (Account 437)			
10	TOTAL Dividends Declared-Preferred Stock (Account 437) (footnote details)			
11	Dividends Declared-Common Stock (Account 438)			
12	TOTAL Dividends Declared-Common Stock (Account 438) (footnote details)		16,655,599	16,647,513
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)		31,852,511	38,204,913
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		31,852,511	38,204,913
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			

BLANK PAGE

[Next page is 120]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/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)	10,303,197	12,180,307
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	25,238,459	27,683,331
5	Amortization of (Specify) (footnote details): Gas cost changes	(359,810)	14,592,366
6	Deferred Income Taxes (Net)	1,569,439	41,339
7	Investment Tax Credit Adjustments (Net)	(48,834)	(52,577)
8	Net (Increase) Decrease in Receivables	(3,644,653)	9,646,306
9	Net (Increase) Decrease in Inventory	(880,663)	66,102
10	Net (Increase) Decrease in Allowances Inventory		
11	Net Increase (Decrease) in Payables and Accrued Expenses	5,917,519	(482,399)
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	(983,591)	(23,515,294)
17	Net Cash Provided by (Used in) Operating Activities		
18	(Total of Lines 2 thru 16)	37,111,063	40,159,481
19			
20	Cash Flows from Investment Activities:		
21	Construction and Acquisition of Plant (including land):		
22	Gross Additions to Utility Plant (less nuclear fuel)	(56,530,179)	(42,926,611)
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	361,162	461,796
27	Other (footnote details): Net increase in customer advances for construction	406,901	1,173,968
28	Cash Outflows for Plant (Total of lines 22 thru 27)	(56,484,440)	(42,214,439)
29			
30	Acquisition of Other Noncurrent Assets (d)		
31	Proceeds from Disposal of Noncurrent Assets (d)	(105,027)	92,427
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	(20,180)	(20,093)
48	Net Cash Provided by (Used in) Investing Activities		
49	(Total of lines 28 thru 47)	(56,609,647)	(42,142,105)
50			
51	Cash Flows from Financing Activities:		
52	Proceeds from Issuance of:		
53	Long-Term Debt (b)	4,653	24,911,950
54	Preferred Stock		
55	Common Stock	8,000,000	
56	Other (footnote details):	(5,284)	
57	Net Increase in Short-term Debt (c)		
58	Other (footnote details):		
59	Cash Provided by Outside Sources (Total of lines 53 thru 58)	7,999,369	24,911,950
60			
61	Payments for Retirement of:		
62	Long-Term Debt (b)	(118,000)	(73,000)
63	Preferred Stock		
64	Common Stock		
65	Other (footnote details):		
66	Net Decrease in Short-Term Debt (c)		
67			
68	Dividends on Preferred Stock		
69	Dividends on Common Stock	(16,640,000)	(16,640,000)
70	Net Cash Provided by (Used in) Financing Activities		
71	(Total of lines 59 thru 69)	(8,758,631)	8,198,950
72			
73	Net Increase (Decrease) in Cash and Cash Equivalents		
74	(Total of line 18, 49 and 71)	(28,257,215)	6,216,326
75			
76	Cash and Cash Equivalents at Beginning of Period	(31,799,078)	25,582,752
77			
78	Cash and Cash Equivalents at End of Period	3,541,863	31,799,078

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 defined below:

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
ARO	Asset retirement obligation
ASC	FASB Accounting Standards Codification
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
MDU	MDU Resources Group, Inc.
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of MDU
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
OPUC	Oregon Public Utility Commission
PRP	Potentially Responsible Party
RP	Rehabilitation plan
Washington DOE	Washington State Department of Ecology
WUTC	Washington Utilities and Transportation Commission

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 628,000 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 the FERC.

Cascade and Intermountain account for certain income and expense items under the provisions of regulatory accounting, which require 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, 2016, up to the date of the issuance of these consolidated financial statements on March 31, 2017, that would require recognition or disclosure in the 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. The total balance of receivables past due 90 days or more was $1.4 million and $1.1 million as of December 31, 2016 and 2015, 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, 2016 and 2015 was $733,000 and $750,000, 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 average-cost method at Intermountain. Natural gas in storage is expected to be used within one year and the value included in inventories was $7.0 million and $4.1 million at December 31, 2016 and 2015, 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:

	2016	2015
	(In thousands)	
AFUDC - borrowed	**$ 493**	$ 995
AFUDC - equity	**$ 361**	$ 696

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:

	2016	2015	Weighted Average Depreciable Life in Years
	(Dollars in thousands, as applicable)		
Distribution plant	**$ 1,236,906**	$ 1,165,042	48
Transmission plant	**95,896**	95,548	52
Storage plant	**25,345**	21,525	23
General plant	**107,917**	107,485	17
Other plant	**76,498**	72,743	12
Non-depreciable plant	**8,980**	7,964	-
Construction in progress	**14,220**	13,428	-
Less: Accumulated depreciation and amortization	**555,537**	533,176	
Net property, plant and equipment	**$ 1,010,225**	$ 950,559	

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 2016 and 2015. 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, 2016 and 2015, there were no impairment losses recorded. At December 31, 2016, the fair value substantially exceeded the carrying value for the Company level on a separate basis. For more information on goodwill, see Note 2.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the Company's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, weighted average cost of capital, operational plans, and current and future economic conditions, among others. The fair value is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach. Under the income approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the weighted average cost of capital. The weighted average cost of capital of 4.9 percent, and a long-term growth rate projection of 3.3 percent were utilized in the goodwill impairment test performed in the fourth quarter of 2016. Under the market approach, the Company estimates fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies. These multiples are applied to operating data to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued unbilled revenue which is included in receivables, net, represents revenues recognized in excess of amounts billed. Accrued unbilled revenue at Cascade and Intermountain was $70.1 million and $62.8 million at December 31, 2016 and 2015, respectively. The Company recognizes all other revenues when services are rendered or goods are delivered. The Company presents revenue net of taxes collected from customers at the time of sale to be remitted to governmental authorities, including sales and use taxes.

Asset retirement obligations

The Company performed detailed assessments of ARO's for the 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 $25.5 million and $16.7 million at December 31, 2016 and 2015, respectively. Natural gas costs recoverable through rate adjustments was $318,000 at December 31, 2016.

Income taxes

MDU and its subsidiaries file consolidated federal income tax returns and combined and separate state income tax returns. Federal income taxes paid by MDU, as parent of the consolidated group, are allocated to the individual subsidiaries based on the ratio of the separate company computations of tax. MDU makes a similar allocation for state income taxes paid in connection with combined state filings. The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Regulated entities are required to recognize such adjustment to deferred income taxes as regulatory assets or liabilities if it is probable that such amounts will be recovered from or refunded to customers in future rates. Taxes recoverable from customers have been recorded as a regulatory asset and are included in deferred charges and other assets-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-other. These regulatory assets and liabilities are expected to be recovered from or refunded to customers in future rates in accordance with applicable regulatory procedures.
Consistent with orders and directives of the IPUC, Intermountain does not provide state deferred income tax expense for certain income tax temporary differences and instead recognized the tax impact currently (commonly referred to as flow-through accounting) for rate making and financial reporting. Therefore, the Company's effective income tax rate is impacted as these differences arise and reverse.

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

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

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

New accounting standards
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. This guidance was to be effective for the Company on January 1, 2017. In August 2015, the FASB issued guidance deferring the effective date of the revenue guidance one year and allowing entities to early adopt. With this decision, the guidance will be effective for the Company on January 1, 2018. Entities will have the option of using either a full retrospective or modified retrospective approach to adopting the guidance. Under the modified approach, an entity would recognize the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings in the period of adoption. In addition, the modified approach will require additional disclosures. The Company is planning to adopt the guidance using the modified retrospective approach and continues to evaluate the effects it will have on its results of operations, financial position, cash flows and disclosures.

Simplifying the Presentation of Debt Issuance Costs In April 2015, the FASB issued guidance on simplifying the presentation of debt issuance costs in the financial statements. This guidance requires entities to present debt issuance costs as a direct deduction to the related debt liability. The amortization of these costs will be reported as interest expense. The guidance was effective for the Company on January 1, 2016, and was to be applied retrospectively. Early adoption of this guidance was permitted, however the Company did not elect to do so. The guidance required a reclassification of the debt issuance costs on the Consolidated Balance Sheets, but did not impact the Company's results of operations or cash flows. As a result of the retrospective application of this change in accounting principle, the Company reclassified debt issuance costs of $2.6 million from deferred charges and other assets - other to long-term debt on its Consolidated Balance Sheets at December 31, 2015.

Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent) In May 2015, the FASB issued guidance on fair value measurement and disclosure requirements removing the requirement to include investments in the fair value hierarchy for which fair value is measured using the net asset value per share practical expedient. The new guidance also removes the requirement to make certain disclosures for all investments that are eligible to be measured at net asset value using the practical expedient, and rather limits those disclosures to investments for which the practical expedient has been elected. This guidance was effective for the Company on January 1, 2016, with early adoption permitted. The application of this guidance affected the Company's disclosures; however, it did not impact the Company's results of operations, financial position or cash flows.

Simplifying the Measurement of Inventory In July 2015, the FASB issued guidance regarding inventory that is measured using the first-in, first-out or average cost method. The guidance does not apply to inventory measured using the last-in, first-out or the retail inventory method. The guidance requires inventory within its scope to be measured at the lower of cost or net realizable value, which is the estimated selling price in the normal course of business less reasonably predictable costs of completion, disposal and transportation. These amendments more closely align GAAP with IFRS. This guidance was effective for the Company on January 1, 2017, on a prospective basis. The Company does not anticipate the guidance will have a material effect on its results of operations, financial position or cash flows.

Balance Sheet Classification of Deferred Taxes In November 2015, the FASB issued guidance regarding the classification of deferred taxes on the balance sheet. The guidance will require all deferred tax assets and liabilities to be classified as noncurrent. These amendments will align GAAP with IFRS. Entities had the option to apply the guidance prospectively, for all deferred tax assets and liabilities, or retrospectively. The Company adopted the guidance in the fourth quarter of 2016 and applied the retrospective method of adoption. The guidance required a reclassification of current deferred income taxes to noncurrent deferred income taxes on the Consolidated Balance Sheets, but did not impact the Company's results of operations or cash flows. As a result of the retrospective application of this change in accounting principle, the Company reclassified deferred income taxes of $3.0 million from current assets - deferred income taxes to deferred credits and other liabilities - deferred income taxes on its Consolidated Balance Sheets at December 31, 2015.

Recognition and Measurement of Financial Assets and Financial Liabilities In January 2016, the FASB issued guidance regarding the classification and measurement of financial instruments. The guidance revises the way an entity classifies and measures investments in equity securities, the presentation of certain fair value changes for financial liabilities measured at fair value and amends certain disclosure requirements related to the fair value of financial instruments. This guidance will be effective for the Company on January 1, 2018, with early adoption of certain amendments permitted. The guidance should be applied using a modified retrospective approach with the exception of equity securities without readily determinable fair values which will be applied prospectively. 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.

Leases In February 2016, the FASB issued guidance regarding leases. The guidance requires lessees to recognize a liability to make lease payments and a right-of-use asset representing its right to use the underlying asset for the lease term on the statement of financial position for leases with terms of more than 12 months. This guidance also requires additional disclosures. This guidance will be effective for the Company on January 1, 2019, and should be applied using a modified retrospective approach with early adoption permitted. 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.

Improvements to Employee Share-Based Payment Accounting In March 2016, the FASB issued guidance regarding simplification of several aspects of the accounting for share-based payment transactions. The guidance will affect the income tax consequences, classification of awards as either equity or liabilities, classification on the statement of cash flows and calculation of dilutive shares. Certain amendments of this guidance are to be applied retrospectively and others prospectively. The Company adopted the guidance on January 1, 2017. All amendments in the guidance that apply to the Company were adopted on a prospective basis resulting in no adjustments being made to retained earnings. The Company anticipates the guidance will impact the Consolidated Statements of Income and the Consolidated Balance Sheets, as well as the dilutive earnings per share calculation, on a prospective basis with all taxes related to share-based payments recognized as income tax expense or benefit and no longer recognized in additional paid-in capital. The Company anticipates the guidance will not have a material impact on its cash flows.

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. This guidance will be effective for the Company on January 1, 2018, with early adoption permitted. An entity that elects early adoption must adopt all the amendments in the same period and apply any adjustments as of the beginning of the fiscal year. Entities must apply the guidance retrospectively unless it is impracticable to do so, in which case they may apply it prospectively as of the earliest date practicable. The Company is evaluating the effects the adoption of the new guidance will have on its cash flows and disclosures.

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 will also affect other aspects of accounting, such as determining reporting units for goodwill testing. The guidance will be effective for the Company on January 1, 2018, and should be applied on a prospective basis with early adoption permitted for transactions that occur before the issuance or effective date of the amendments and only when the transactions have not been reported in the financial statements or made available for issuance. 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.

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 should be applied on a prospective basis with early adoption permitted. 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.

NOTE 2 – GOODWILL

The carrying amount of goodwill for the years ended December 31, 2016 and 2015 remained unchanged at $340,924. No impairments of goodwill have been recorded.

NOTE 3 – REGULATORY ASSETS AND LIABILITIES

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

	Estimated Recovery Period *	**2016**	2015
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(c)	**$ 53,846**	$ 57,235
Manufactured gas plant remediation (a)	Determined upon filing	**17,787**	18,138
Taxes recoverable from customers (a)	Over plant lives	**11,461**	10,238
Conservation activities (a)	Up to 28 months	**4,014**	4,117
Long-term debt refinancing costs (a)	Up to 21 years	**950**	1,063
Natural gas costs recoverable through rate adjustments	Up to 1 year	**318**	---
Other (a)	Largely determined upon filing	**2,733**	63
Total regulatory assets		**91,109**	90,854
Regulatory liabilities:			
Plant removal costs (b)		**114,074**	112,383
Natural gas costs refundable through rate adjustments		**25,531**	16,667
Taxes refundable to customers (b)		**4,618**	9,292
Other (b)		**5,482**	5,797
Total regulatory liabilities		**149,705**	144,139
Net regulatory position		**$ (58,596)**	$ (53,285)

* *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, 2016 and 2015, approximately $79.6 million and $80.6 million, respectively, of regulatory assets were not earning a rate of return.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of regulatory accounting for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income 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 $3.3 million and $3.1 million as of December 31, 2016 and 2015, respectively, are classified as Investments on the Consolidated Balance Sheets. The net unrealized gains on these investments for the years ended December 31, 2016 and 2015 were $160,000 and $75,000, respectively. The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income.

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, 2016 and 2015, there were no transfers between Levels 1 and 2.

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

	Fair Value Measurements at December 31, 2016, 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, 2016
		(In thousands)		
Assets:				
Money market funds	$ ---	$ 112	$ ---	$ 112
Insurance contract*	---	3,284	---	3,284
Total assets measured at fair value	$ ---	$ 3,396	$ ---	$ 3,396

** The insurance contract invests approximately 52 percent in fixed-income investments, 22 percent in common stock of large-cap companies, 13 percent in common stock of mid-cap companies, 10 percent in common stock of small-cap companies, 1 percent in target date investments and 2 percent in cash equivalents.*

	Fair Value Measurements at December 31, 2015, 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, 2015
		(In thousands)		
Assets:				
Money market funds	$ ---	$ 112	$ ---	$ 112
Insurance contract*	---	3,123	---	3,123
Total assets measured at fair value	$ ---	$ 3,235	$ ---	$ 3,235

** The insurance contract invests approximately 63 percent in fixed-income investments, 19 percent in common stock of large-cap companies, 9 percent in common stock of mid-cap companies, 7 percent in common stock of small-cap companies, 1 percent in target date investments and 1 percent in cash equivalents.*

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

	2016		2015	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
		(In thousands)		
Long-term debt	**$ 488,297**	**$ 515,897**	$ 490,700	$ 493,000

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

NOTE 5 – DEBT

Certain debt instruments of the Company and its subsidiaries, including those discussed later, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company

and its subsidiaries must be in compliance with the applicable covenants and certain other conditions. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.
The following table summarizes the outstanding revolving credit facilities of the Company and its subsidiaries:

Company	Facility	Facility Limit	Amount Outstanding at December 31, 2016	Amount Outstanding at December 31, 2015	Letters of Credit at December 31, 2016	Expiration Date
			(Dollars in millions)			
Cascade Natural Gas Corporation	Revolving credit agreement	$ 50.0 (a)	$ ---	$ ---	$ 2.2 (b)	7/9/18
Intermountain Gas Company	Revolving credit agreement	$ 65.0 (c)	$ 20.9	$ 47.9	$ ----	7/13/18

(a) Certain provisions allow for increased borrowings, up to a maximum of $75.0 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 $90.0 million.

The following includes information related to the preceding table.

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

Cascade Natural Gas Corporation 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. 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.

MDU ENERGY CAPITAL, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years ended December 31, 2016 and 2015

Intermountain Gas Company 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. 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.

On November 9, 2016, Intermountain issued $30.0 million of Senior Notes with a due date of November 9, 2046, at an interest rate of 4.0 percent.

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

	2016	2015
	(In thousands)	
Senior Notes at a weighted average rate of 4.69%, due on dates ranging from August 31, 2017 to January 15, 2055	**$ 395,546**	$ 370,818
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 3.07%, due on July 13, 2018	**20,850**	47,900
Other note, at a rate of 5.25%, due on February 1, 2035	**24,471**	24,589
Unamortized debt issuance costs	**(2,570)**	(2,607)
Total long-term debt	**488,297**	490,700
Less current maturities	**40,273**	5,273
Net long-term debt	**$ 448,024**	$ 485,427

Schedule of Debt Maturities Long-term debt maturities for the five years and thereafter following December 31, 2016, were as follows:

	2017	2018	2019	2020	2021	Thereafter
				(In thousands)		
Long-term debt maturities	$40,273	$26,123	---	$15,000	---	$409,471

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, for the years ended December 31 was as follows:

	2016	2015
	(In thousands)	
Balance at beginning of year	**$ 116,210**	$ 606
Liabilities incurred	**2,371**	---
Liabilities settled	**(898)**	---
Accretion expense	**6,735**	39
Revisions in estimates	**----**	115,565
Balance at end of year	**$ 124,418**	$ 116,210

The 2015 revisions in estimates consist principally of updated natural gas distribution mains and lines asset retirement obligation costs.

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, 2016 and 2015 was $18,462 and $20,436, respectively.

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

	2016	2015
	(In thousands)	
Current:		
Federal	**$ 5,511**	$ 7,184
State	**430**	(518)
	5,941	6,666
Deferred:		
Income taxes –		
Federal	**(897)**	143
State	**250**	(29)
Investment tax credit - net	**(1,020)**	239
	(1,667)	353
Total income tax expense	**$ 4,274**	$ 7,019

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

	2016	2015
	(In thousands)	
Deferred tax assets:		
Contingency reserve	**$ 5,258**	$ 5,309
Accrued pension costs	**13,389**	14,625
Other	**10,434**	12,231
Total deferred tax assets	**29,081**	32,165
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	**163,432**	160,595
Postretirement	**21,813**	22,819
Other	**7,257**	6,924
Total deferred tax liabilities	**192,502**	190,338
Net deferred income tax liability	**$ (163,421)**	$ (158,173)

As of December 31, 2016 and 2015, 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, 2015, to December 31, 2016, to deferred income tax expense:

	2016
	(In thousands)
Change in net deferred income tax liability from the preceding table	**$ 5,248**
Other	**(6,915)**
Deferred income tax benefit for the period	**$ (1,667)**

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,	**2016**		2015	
	Amount	%	Amount	%
		(Dollars in thousands)		
Computed tax at federal statutory rate	**$ 6,462**	**35.0**	$ 7,153	35.0
Increases (reductions) resulting from:				
State income taxes, net of federal income tax	**268**	**1.5**	44	0.2
AFUDC equity	**---**	**---**	591	2.9
Amortization of deferral of investment tax credit	**(2,281)**	**(12.4)**	239	1.2
Resolution of tax matters and uncertain tax positions	**(406)**	**(2.2)**	159	0.8
Flow-through	**(193)**	**(1.0)**	(1,483)	(7.3)
Other	**424**	**2.3**	316	1.5
Total income tax expense	**$ 4,274**	**23.2**	$ 7,019	34.3

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 2012. With few exceptions, as of December 31, 2016, the Company is no longer subject to state and local income tax examinations by tax authorities for years ending prior to 2011.

Included in income tax expense is interest on uncertain tax positions. For the years ended December 31, 2016 and 2015, the Company recognized approximately $25,000 and $205,000, respectively, of interest income in income tax expense. The Company had accrued liabilities of approximately $12,000 and $52,000 at December 31, 2016 and 2015, respectively, for the payment of interest.

NOTE 8 – CASH FLOW INFORMATION

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

	2016	2015
	(In thousands)	
Interest, net of AFUDC-borrowed of $493 and $995 in 2016 and 2015, respectively	**$ 22,799**	$ 22,625
Income taxes paid (refunded), net	**$ 6,633**	$ (2,725)

Noncash investing transactions at December 31 were as follows:

	2016	2015
	(In thousands)	
Property, plant and equipment additions in		

accounts payable	**$ 5,246**	$ 2,411

NOTE 9 – EMPLOYEE BENEFIT PLANS

Pension and other postretirement benefit plans

The Company has a noncontributory defined benefit pension plan and other postretirement benefit plans for certain eligible employees. Prior to 2015, the defined pension plan benefits and accruals were frozen. The Company's pension assets are included in MDU's master trust. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans.

Effective January 1, 2010, eligibility to receive retiree medical benefits was modified at Cascade and Intermountain. Current employees at Intermountain, and those hired before June 1, 1992 at Cascade, who 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, 2016 and 2015 and amounts recognized in the Consolidated Balance Sheets at December 31, 2016 and 2015, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2016	2015	**2016**	2015
		(In thousands)		
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 91,054**	$ 97,789	**$ 20,527**	$ 22,012
Service cost	**---**	---	**214**	230
Interest cost	**3,592**	3,540	**793**	792
Plan participants' contributions	**---**	---	**400**	423
Actuarial (gain) loss	**892**	(5,852)	**183**	(806)
Benefits paid	**(4,431)**	(4,423)	**(1,618)**	(2,124)
Benefit obligation at end of year	**91,107**	91,054	**20,499**	20,527
Change in net plan assets:				
Fair value of plan assets at beginning of year	**76,943**	72,973	**19,884**	21,464
Actual gain (loss) on plan assets	**6,408**	(2,518)	**1,013**	7
Employer contribution	**---**	10,911	**398**	114
Plan participants' contributions	**---**	---	**400**	423
Benefits paid	**(4,431)**	(4,423)	**(1,618)**	(2,124)
Fair value of net plan assets at end of year	**78,920**	76,943	**20,077**	19,884
Funded status – under	**$ (12,187)**	$ (14,111)	**$ (422)**	$ (643)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other assets (noncurrent)	**$ ---**	$ ---	**$ 1,322**	$ 999
Other liabilities (noncurrent)	**(12,187)**	(14,111)	**(1,744)**	(1,642)
Net amount recognized	**$ (12,187)**	$ (14,111)	**$ (422)**	$ (643)
Amounts recognized in regulatory assets (liabilities) consist of:				
Actuarial loss	**$ 44,101**	$ 45,849	**$ 6,644**	$ 7,041
Prior service credit	**---**	---	**(1,706)**	(1,862)
Total	**$ 44,101**	$ 45,849	**$ 4,938**	$ 5,179

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

Unrecognized pension actuarial losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets 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:

	2016	2015
	(In thousands)	
Projected benefit obligation	**$ 91,107**	$91,054
Accumulated benefit obligation	**$ 91,107**	$91,054
Fair value of plan assets	**$ 78,920**	$76,943

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	
	2016	2015	**2016**	2015
		(In thousands)		
Components of net periodic benefit cost (credit):				
Service cost	**$ ---**	$ ---	**$ 214**	$ 230
Interest cost	**3,592**	3,540	**793**	792
Expected return on assets	**(5,039)**	(5,105)	**(1,109)**	(1,258)
Amortization of prior service credit	**---**	---	**(156)**	(156)
Recognized net actuarial loss	**1,270**	1,375	**676**	657
Net periodic benefit cost (credit)	**(177)**	(190)	**418**	265
Other changes in plan assets and benefit obligations recognized in regulatory assets (liabilities):				
Net (gain) loss	**(478)**	1,772	**279**	445
Amortization of actuarial loss	**(1,270)**	(1,375)	**(676)**	(657)
Amortization of prior service credit	**---**	---	**156**	156
Total recognized in regulatory assets (liabilities)	**(1,748)**	397	**(241)**	(56)
Total recognized in net periodic benefit cost and regulatory assets (liabilities)	**$ (1,925)**	$ 207	**$ 177**	$ 209

The estimated net loss for the defined benefit pension plans that will be amortized from regulatory assets into net periodic benefit cost in 2017 is $1.4 million. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from regulatory assets into net periodic benefit cost in 2017 are $645,000 and $156,000, 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	
	2016	2015	**2016**	2015
Discount rate	**3.86%**	4.03%	**3.83%**	4.04%
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	
	2016	2015	**2016**	2015
Discount rate	**4.03%**	3.73%	**4.04%**	3.73%
Expected return on plan assets	**6.75%**	7.00%	**5.75%**	6.00%

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, 2016, 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 30 percent to 40 percent equity securities and 60 percent to 70 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:

	2016	2015
Health care trend rate assumed for next year	**9.0% - 10.7%**	8.0%
Health care cost trend rate – ultimate	**4.5%**	5.0%
Year in which ultimate trend rate achieved	**2024**	2021

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, 2016:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 57	$ (49)
Effect on postretirement benefit obligation	$ 1,421	$ (1,225)

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 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, 2016 and 2015, 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, 2016, 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, 2016
		(In thousands)		
Assets:				
Cash equivalents	$ ---	$ 1,502	$ ---	$ 1,502
Equity securities:				
U.S. companies	2,685	---	---	2,685
International companies	375	---	---	375
Collective and mutual funds*	38,348	15,157	---	53,505
Corporate bonds	---	16,252		16,252
Municipal bonds	---	2,603	---	2,603
U.S. Government securities	1,030	484	---	1,514
Total assets measured at fair value	$ 42,438	$ 35,998	$ ---	$ 78,436

* *Collective and mutual funds invest approximately 29 percent in common stock of international companies, 21 percent in corporate bonds, 20 percent in common stock of large-cap U.S. companies, 8 percent in cash equivalents, 7 percent in U.S. Government securities and 15 percent in other investments.*

	Fair Value Measurements at December 31, 2015, 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, 2015
	(In thousands)			
Assets:				
Cash equivalents	$ ---	$ 1,938	$ ---	$ 1,938
Equity securities:				
U.S. companies	3,501	---	---	3,501
International companies	539	---	---	539
Collective and mutual funds*	35,711	14,703	---	50,414
Corporate bonds	---	14,374		14,374
Municipal bonds	---	2,701	---	2,701
U.S. Government securities	1,223	1,578	---	2,801
Total assets measured at fair value	$ 40,974	$ 35,294	$ ---	$ 76,268

* *Collective and mutual funds invest approximately 29 percent in common stock of international companies, 19 percent in common stock of large-cap U.S. companies, 16 percent in corporate bonds, 16 percent in cash equivalents, 6 percent in common stock of mid-cap U.S. companies, 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, 2016 and 2015, 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, 2016, 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, 2016
			(In thousands)	
Assets:				
Cash equivalents	$ ---	$ 115	$ ---	$ 115
Equity securities:				
U.S. companies	947	---	---	947
International companies	5	---	---	5
Insurance contract*	13	18,997	---	19,010
Total assets measured at fair value	$ 965	$ 19,112	$ ---	$ 20,077

** The insurance contract invests approximately 38 percent in corporate bonds, 25 percent in common stock of large-cap U.S. companies, 20 percent in U.S. Government securities, 9 percent in mortgage-backed securities and 8 percent in other investments.*

	Fair Value Measurements at December 31, 2015, 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, 2015
			(In thousands)	
Assets:				
Cash equivalents	$ ---	$ 809	$ ---	$ 809
Equity securities:				
U.S. companies	1,032	---	---	1,032
International companies	9	---	---	9
Insurance contract*	21	18,013	---	18,034
Total assets measured at fair value	$ 1,062	$ 18,822	$ ---	$ 19,884

** The insurance contract invests approximately 36 percent in corporate bonds, 22 percent in U.S. Government securities, 19 percent in common stock of large-cap U.S. companies, 10 percent in mortgage-backed securities, and 13 percent in other investments.*

The Company does not expect to contribute to its defined benefit pension plan and expects to contribute approximately $332,000 to its postretirement benefit plans in 2017.

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

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
		(In thousands)	
2017	$ 4,649	$ 1,273	$ 2
2018	4,791	1,296	2
2019	4,919	1,303	2
2020	5,043	1,255	2
2021	5,164	1,248	1
2022-2026	27,213	6,476	5

Nonqualified benefit plans
In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans at Cascade and Intermountain for certain executive officers. Cascade's plan provides for defined benefit payments following the employee's retirement or, 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 Company's net periodic benefit cost for these plans was $1.1 million and $1.4 million in 2016 and 2015, respectively, which reflects a curtailment gain of $234,000 in the first quarter of 2016. The total projected benefit obligation for these plans was $14.2 million and $15.2 million at December 31, 2016 and 2015, respectively. The accumulated benefit obligations for these plans were $14.2 million and $15.0 million at December 31, 2016 and 2015, respectively. A weighted average discount rate of 3.7 percent and 3.8 percent at December 31, 2016 and 2015, respectively, and a rate of compensation increase of 4.0 percent at December 31, 2015, were used to determine benefit obligations. No rate of compensation increase was used to determine the benefit obligation at December 31, 2016, due to the plans being froze. A weighted average discount rate of 3.8 percent and 3.5 percent for the years ended December 31, 2016 and 2015, respectively, and a rate of compensation increase of 4.0 percent for both years ended December 31, 2016 and 2015, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $1.1 million in 2017; $1.1 million in 2018; $1.1 million in 2019; $1.0 million in 2020; $1.0 million in 2021; and $4.4 million for the years 2022 through 2026.

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Costs incurred under this plan for 2016 and 2015 were $45,000 and $24,000, respectively.

The Company had investments of $11.1 million and $10.5 million at December 31, 2016 and 2015, respectively, consisting of equity securities of $2.9 million and $2.4 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of $7.5 million and $7.2 million, respectively, and other investments of $632,000 and $930,000, respectively. The Company anticipates using these investments to satisfy obligations under these plans.

Defined contribution plans
The Company sponsors various defined contribution plans for eligible employees and the costs incurred by the Company under these plans were $4.6 million in 2016 and $3.2 million in 2015.

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 2016 and 2015 is for the plan's year-end at December 31, 2015, and December 31, 2014, 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 2016	Pension Protection Act Zone Status 2015	FIP/RP Status Pending/ Implemented	Contributions **2016**	Contributions 2015	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)			
Idaho Plumbers and Pipefitters Pension Plan	82-6010346-001	Green as of 5/31/2016	Green as of 5/31/2015	No	**$ 1,221**	$ 1,169	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, 2015 and 2014.

NOTE 10 – REGULATORY MATTERS

On April 29, 2016, Cascade filed an application with the OPUC for a natural gas rate increase of approximately $1.9 million annually or approximately 2.8 percent above current rates. The request includes rate recovery associated with pipeline replacement and improvement projects to ensure the integrity of Cascade's system. On October 6, 2016, Cascade, staff of the OPUC and the interveners in the case filed a stipulation and settlement agreement reflecting an annual increase of approximately $754,000 to be effective March 1, 2017. The OPUC issued an order approving the stipulation and settlement agreement on December 12, 2016.

On June 1, 2016, Cascade filed an application with the WUTC for an annual pipeline replacement cost recovery mechanism of $4.6 million annually or approximately 2.0 percent of additional revenue. The requested increase includes $2.4 million associated with incremental pipeline replacement investments and $2.2 million for an alternative recovery request of incremental operation and maintenance costs associated with a maximum allowable operating pressure validation plan. On October 17, 2016, Cascade filed an update to the application that reduced the incremental pipeline replacement investment to $1.9 million and removed the operation and maintenance costs associated with a maximum allowable operating pressure validation plan. On October 27, 2016, the WUTC allowed the pipeline replacement cost recovery mechanism which was effective November 1, 2016. On June 1, 2016, Cascade filed an accounting order to defer the costs related to the maximum allowable operating pressure validation plan and on November 10, 2016, the WUTC granted the order.

On August 12, 2016, Intermountain filed an application with the IPUC for a natural gas rate increase of approximately $10.2 million annually or approximately 4.1 percent above current rates. The request includes rate recovery associated with increased investment in facilities and increased operating expenses. On November 23, 2016, Intermountain provided the IPUC with an updated revenue request of approximately $9.4 million. A hearing was held March 1-3, 2017. This matter is pending before the IPUC.

NOTE 11 – COMMITMENTS AND CONTINGENCIES

Claims and Litigation

The Company is subject to claims and lawsuits arising out of its business. The Company accrues a liability for contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, in some circumstances, an estimate of the possible loss. The Company had accrued liabilities of $15.5 million and $14.8 million for contingencies including litigation and environmental matters at December 31, 2016 and 2015, respectively, which include amounts that may have been accrued for matters discussed in Environmental matters within this note.

Environmental matters

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

The first claim is for contamination at a site in Eugene, Oregon which was received in 1995. There are PRPs in addition to Cascade that may be liable for cleanup of the contamination. Some of these PRPs have shared in the investigation costs. It is expected that these and other PRPs will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately $500,000 to $11.0 million. The Oregon State Department of Environmental Quality released a record of decision in January 2015 that selected a remediation alternative for the site as recommended in an earlier staff report. It is not known at this time what share of the cleanup costs will actually be borne by Cascade; however, Cascade anticipates its proportional share could be approximately 50 percent. Cascade has accrued $1.6 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 December 1, 2015. Cascade has requested authority to defer accounting for the 12-month period starting December 1, 2016, which is pending before the OPUC.

The second claim is for contamination at a site in Bremerton, Washington which was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants requiring further investigation and cleanup. The EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from $340,000 to $6.4 million. Data developed through the assessment and previous investigations indicates the contamination likely derived from multiple, different sources and multiple current and former owners of properties and businesses in the vicinity of the site may be responsible for the contamination. In April 2010, the Washington 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. Cascade has accrued $12.5 million for the remedial investigation, feasibility study and remediation of this site. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site. The WUTC approved the petition in September 2010, subject to conditions set forth in the order.

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

Cascade has received notices from and entered into agreement with certain of its insurance carriers that they will participate in defense of Cascade for these contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. Cascade received insurance payments of $36,000 and $51,000 in 2016 and 2015, respectively, for the Eugene defense costs and $618,000 in 2016 for the Bremerton defense costs. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

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

Operating leases

The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2016, were $237,000 in 2017, $165,000 in 2018, $146,000 in 2019, $147,000 in 2020, $135,000 in 2021, and $347,000 thereafter. Rent expense was $541,000 and $520,000 for the years ended December 31, 2016 and 2015, respectively.

Purchase commitments

The Company has entered into various commitments, largely natural gas supply and natural gas transportation and storage contracts, some of which are subject to variability in volume and price. These commitments range from one to 44 years. The commitments under these contracts as of December 31, 2016, were $180.7 million in 2017, $123.2 million in 2018, $102.2 million in 2019, $87.6 million in 2020, $85.4 million in 2021, and $711.5 million thereafter. These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2016 and 2015, respectively, were approximately $184.8 million and $246.6 million.

Guarantees

Cascade has an outstanding letter of credit to a third party related to a remedial investigation feasibility study. At December 31, 2016, the fixed maximum amount guaranteed under this letter of credit was $2.2 million, which is scheduled to expire in 2017. There were no amounts outstanding under this letter of credit at December 31, 2016.

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 $35.8 million and $26.3 million for the years ended December 31, 2016 and 2015, respectively and the amount charged for services received from the Company was $966,000 and $48,000 for the years ended December 31, 2016 and 2015, respectively.

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

	2016	2015
	(In thousands)	
Accounts receivable	**$ 84**	$ 108
Accounts payable	**2,584**	2,706
Dividend payable	**4,800**	5,400
Deferred charges and other assets - other	**5,900**	3,937
Deferred credits and other liabilities - other	**1,615**	2,502

MDU has several stock-based compensation plans in which the Company participates. Total stock-based compensation expense for the years ended December 31, 2016 and 2015, respectively, was $716,000 and $805,000, net of income taxes of $458,000 and $515,000, respectively. As of December 31, 2016, total remaining unrecognized compensation expense related to stock-based compensation was approximately $1.1 million (before income taxes) which will be amortized over a weighted average period of 1.5 years.

BLANK PAGE

[Next page is 200]

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)	889,631,647
4	Property Under Capital Leases	
5	Plant Purchased or Sold	
6	Completed Construction not Classified	33,062,917
7	Experimental Plant Unclassified	
8	TOTAL Utility Plant (Total of lines 3 thru 7)	922,694,564
9	Leased to Others	
10	Held for Future Use	
11	Construction Work in Progress	12,898,870
12	Acquisition Adjustments	
13	TOTAL Utility Plant (Total of lines 8 thru 12)	935,593,434
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	453,344,582
15	Net Utility Plant (Total of lines 13 and 14)	482,248,852
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION	
17	In Service:	
18	Depreciation	442,537,270
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	10,807,312
22	TOTAL In Service (Total of lines 18 thru 21)	453,344,582
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)	453,344,582

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		889,631,647		
4				
5				
6		33,062,917		
7				
8		922,694,564		
9				
10				
11		12,898,870		
12				
13		935,593,434		
14		453,344,582		
15		482,248,852		
16				
17				
18		442,537,270		
19				
20				
21		10,807,312		
22		453,344,582		
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33		453,344,582		

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	33,536,081	35,381
5	TOTAL Intangible Plant (Enter Total of lines 2 thru 4)	33,899,972	35,381
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	12/31/2016	End of 2016/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				33,571,462
5				33,935,353
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				

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	12/31/2016	End of 2016/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	12/31/2016	End of 2016/Q4

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

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

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	12/31/2016	End of 2016/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	21,858,290	310
87	368 Compressor Station Equipment		
88	369 Measuring and Regulating Station Equipment	192,300	
89	370 Communication Equipment		
90	371 Other Equipment		
91	372 Asset Retirement Costs for Transmission Plant	87,147	
92	TOTAL Transmission Plant (Enter Totals of lines 83 thru 91)	23,388,362	310
93	DISTRIBUTION PLANT		
94	374 Land and Land Rights	2,488,653	(2,125)
95	375 Structures and Improvements	1,457,569	1,759
96	376 Mains	395,963,010	33,043,435
97	377 Compressor Station Equipment	2,097,767	
98	378 Measuring and Regulating Station Equipment-General	25,168,603	3,078,265
99	379 Measuring and Regulating Station Equipment-City Gate		
100	380 Services	206,078,067	8,445,368
101	381 Meters	51,334,926	5,704,161
102	382 Meter Installations	30,639,593	758,789
103	383 House Regulators	10,358,745	271,741
104	384 House Regulator Installations		
105	385 Industrial Measuring and Regulating Station Equipment	9,563,460	475,026
106	386 Other Property on Customers' Premises		
107	387 Other Equipment		
108	388 Asset Retirement Costs for Distribution Plant	15,304,939	1,267,219
109	TOTAL Distribution Plant (Enter Total of lines 94 thru 108)	750,455,332	53,043,638
110	GENERAL PLANT		
111	389 Land and Land Rights	3,276,909	191,174
112	390 Structures and Improvements	19,530,223	(2,795)
113	391 Office Furniture and Equipment	7,379,332	244,996
114	392 Transportation Equipment	14,304,623	2,035,676
115	393 Stores Equipment	66,925	
116	394 Tools, Shop, and Garage Equipment	7,155,819	542,608
117	395 Laboratory Equipment	126,158	
118	396 Power Operated Equipment	3,565,233	1,795,728
119	397 Communication Equipment	6,957,666	133,281
120	398 Miscellaneous Equipment	77,581	2,098
121	Subtotal (Enter Total of lines 111 thru 120)	62,440,469	4,942,766
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)	62,440,469	4,942,766
125	TOTAL (Accounts 101 and 106)	870,184,135	58,022,095
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)	870,184,135	58,022,095

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	12/31/2016	End of 2016/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				21,858,600
87				
88		1		192,301
89				
90				
91				87,147
92		1		23,388,673
93				
94				2,486,528
95				1,459,328
96	520,271	1		428,486,175
97				2,097,767
98	127,924			28,118,944
99				
100	446,616			214,076,819
101	767,232			56,271,855
102	20,683		(49,318)	31,328,381
103	243,029			10,387,457
104				
105	53,800	(2)	49,318	10,034,002
106				
107				
108	79,801			16,492,357
109	2,259,356	(1)		801,239,613
110				
111				3,468,083
112				19,527,428
113	98,393			7,525,935
114	898,449			15,441,850
115				66,925
116	352,151			7,346,276
117				126,158
118	1,867,416			3,493,545
119	35,901			7,055,046
120				79,679
121	3,252,310			64,130,925
122				
123				
124	3,252,310			64,130,925
125	5,511,666			922,694,564
126				
127				
128				
129	5,511,666			922,694,564

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	12/31/2016	End of 2016/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				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
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				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45	**Total**			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

Gas Plant Held for Future Use (Account 105)

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

Line No.	Description and Location of Property (a)	Date Originally Included in this Account (b)	Date Expected to be Used in Utility Service (c)	Balance at End of Year (d)
1	None			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45	**Total**			

Construction Work in Progress-Gas (Account 107)

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

Line No.	Description of Project (a)	Construction Work in Progress-Gas (Account 107) (b)	Estimated Additional Cost of Project (c)
1	Sunriver Gate Station Upgrade	2,367,870	
2	Sunnyside Gate Station Upgrade	1,550,041	
3	Southridge Gate Station	1,526,404	
4	GL Essentials Software	1,225,169	
5	IRV Web Implementation	1,080,993	
6			
7			
8	Minor distribution system/general Plant projects each under		
9	$1 million	5,148,393	
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			
45	**Total**	**12,898,870**	

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	12/31/2016	End of 2016/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				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
	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	12/31/2016	End of 2016/Q4

Non-Traditional Rate Treatment Afforded New Projects (continued)

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

Line No.	Accumulated Depreciation (e)	Accumulated Deferred Income Taxes (f)	Operating Expense (g)	Maintenance Expense (h)	Depreciation Expense (i)	Other Expenses (including taxes) (j)	Incremental Revenues (k)
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							

Name of Respondent Cascade Natural Gas Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/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 Assets Analyst and approved by the Manager of General & Asset Accounting which is then applied to the current month activity for all applicable work orders to determine how much should be transferred from the ES/GA pools to the affected work orders. This is accomplished via a system (PowerPant) batch operation. An applicable work order is one that 1) is capital installation/purchase, and not a preliminary survey or investigative in nature. Note that purchase projects only receive GA overhead, not ES. Construction projects receive both.

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

The formula on page 218a is used.

General Description of Construction Overhead Procedure (continued)

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

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

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

Line No.	Title (a)	Amount (b)	Capitalization Ration (percent) (c)	Cost Rate Percentage (d)
	(1) Average Short-Term Debt	S		
	(2) Short-Term Interest			s
	(3) Long-Term Debt	D 211,929,397	52.60	d 5.36
	(4) Preferred Stock	P		p
	(5) Common Equity	C 190,909,865	47.40	c 7.53
	(6) Total Capitalization	402,839,262	100.00	
	(7) Average Construction Work In Progress Balance	W 13,135,280		

2. Gross Rate for Borrowed Funds $s(S/W) + d[(D/(D+P+C))(1-(S/W))]$ 2.82

3. Rate for Other Funds $[1-(S/W)][p(P/(D+P+C)) + c(C/(D+P+C))]$ 3.57

4. Weighted Average Rate Actually Used for the Year:

a. Rate for Borrowed Funds - 2.78

b. Rate for Other Funds - 3.52

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	12/31/2016	End of 2016/Q4

Accumulated Provision for Depreciation of Gas Utility Plant (Account 108)

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

Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant in Service (c)	Gas Plant Held for Future Use (d)	Gas Plant Leased to Others (e)
	Section A. BALANCES AND CHANGES DURING YEAR				
1	Balance Beginning of Year	(424,310,707)	(424,310,707)		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	(22,501,731)	(22,501,731)		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Expense of Gas Plant Leased to Others				
6	Transportation Expenses - Clearing	(1,052,718)	(1,052,718)		
7	Other Clearing Accounts				
8	Other Clearing (Specify) (footnote details):	(148,727)	(148,727)		
9					
10	TOTAL Deprec. Prov. for Year (Total of lines 3 thru 8)	(23,703,176)	(23,703,176)		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	5,511,667	5,511,667		
13	Cost of Removal	1,687,016	1,687,016		
14	Salvage (Credit)	1,887,287	1,887,287		
15	TOTAL Net Chrgs for Plant Ret. (Total of lines 12 thru 14)	5,311,396	5,311,396		
16	Other Debit or Credit Items (Describe) (footnote details):	165,217	165,217		
17					
18	Book Cost of Asset Retirement Costs				
19	Balance End of Year (Total of lines 1,10,15,16 and 18)	(442,537,270)	(442,537,270)		
	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	(15,092,214)	(15,092,214)		
28	Distribution	(401,047,028)	(401,047,028)		
29	General	(26,398,028)	(26,398,028)		
30	TOTAL (Total of lines 21 thru 29)	(442,537,270)	(442,537,270)		

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	12/31/2016	End of 2016/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					238,846	712,311		951,157
2	Gas Delivered to Storage						1,792,949		1,792,949
3	Gas Withdrawn from						800,096		800,096
4	Other Debits and Credits					(112,190)			(112,190)
5	Balance at End of Year					126,656	1,705,164		1,831,820
6	Dth					40,354	512,200		552,554
7	Amount Per Dth					3.1386	3.3291		3.3152

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		10,359,340	466,627
6	SISP Plan Assets		81,004	25,861
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				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				

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			10,825,967	466,627	
6			106,865	5,772	
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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	12/31/2016	End of 2016/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				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40	**TOTAL Cost of Account 123.1 $**		**TOTAL**	

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/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				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				

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	146,719
2	Prepaid Rents	1,381,150
3	Prepaid Taxes	719,759
4	Prepaid Interest	
5	Miscellaneous Prepayments	209,142
6	TOTAL	2,456,770

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**						

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**						

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	12/31/2016	End of 2016/Q4

Other Regulatory Assets (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning Current Quarter/Year (b)	Debits (c)	Written off During Quarter/Year Account Charged (d)	Written off During Period Amount Recovered (e)	Written off During Period Amount Deemed Unrecoverable (f)	Balance at End of Current Quarter/Year (g)
1							
2	OR Tax Rate Change	(355,127)	114,013	various			(241,114)
3							
4	SFAS 109 Regulatory Asset	175,416	697,470	various			872,886
5	(OR regulatory asset)						
6							
7	FAS 158 Regulatory Asset	51,650,830	(2,655,261)				48,995,569
8	(Total system asset)						
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40	**Total**	51,471,119	(1,843,778)		0	0	49,627,341

Miscellaneous Deferred Debits (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	Credits Account Charged (d)	Credits Amount (e)	Balance at End of Year (f)
1	WA Conservation Programs	3,496,248	6,503,889	4800-4813	5,894,119	4,106,018
2	(amortization period 11/10-present)					
3						
4	WA Bremerton Manufactured Gas Plant	16,255,321	203,395		617,701	15,841,015
5	Remediation					
6						
7	WA Gas Management Sharing Margin	(9,370)	21,043	4800-4813	11,673	
8	(amortization period 11/10-present)			4890		
9						
10	WA Over-refunded Temporary Revenue	(3,994)	4,085		91	
11	Credit					
12						
13	WA Decoupling Deferral		1,737,479		1,829,812	(92,333)
14						
15	WA MAOP Deferred Costs		2,219,857			2,219,857
16						
17	OR Conservation Programs					
18	(amortization period 11/10-present)	620,538	4,438,436	4800-4813	5,372,368	(313,394)
19				4890		
20	OR Eugene Manufactured Gas Plant					
21	Remediation	1,882,523	121,560		57,956	1,946,127
22						
23	OR Intervenor Funding					
24	(amortization period 11/10-present)	76,148	360,474	4800-4813	304,181	132,441
25				4890		
26	OR Over-refunded Temporary Revenue	480	8		488	
27	Credit					
28						
29	I/C Asset - Net Benefit Funds	3,597,416			41,545	3,555,871
30						
31	Post Retirement FAS 158	998,936	1,444,767		1,121,888	1,321,815
32						
33	ARO	39,302,214	43,633,427		40,764,721	42,170,920
34						
35						
36						
37						
38						
39	Miscellaneous Work in Progress					
40	**Total**	66,216,460	60,688,420		56,016,543	70,888,337

BLANK PAGE

[Next page is 234]

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	26,391,798	52,362	
4	Other (Define) (footnote details)			
5	Total (Total of lines 2 thru 4)	26,391,798	52,362	
6	Other (Specify) (footnote details)			
7	TOTAL Account 190 (Total of lines 5 thru 6)	26,391,798	52,362	
8	Classification of TOTAL			
9	Federal Income Tax	25,273,741	53,504	
10	State Income Tax	1,118,057	(1,142)	
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) 12/31/2016	Year/Period of Report End of 2016/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			see	(273,664)	see	(124,773)	26,488,327
4			footnote		footnote		
5				(273,664)		(124,773)	26,488,327
6							
7				(273,664)		(124,773)	26,488,327
8							
9				(43,331)		(90,170)	25,173,398
10				(230,333)		(34,603)	1,314,929
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	12/31/2016	End of 2016/Q4

Capital Stock (Accounts 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Exchange (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)
1	Account 201			
2	Common stock - not publicly traded	1,000	1.00	
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				

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						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						

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	12/31/2016	End of 2016/Q4

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	160,698,668
3				
4	Represents excess received over $1.00 par value			
5	of common stock			
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40	**Total**		**1,000**	**160,698,668**

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	12/31/2016	End of 2016/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		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
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	12/31/2016	End of 2016/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		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
	TOTAL	

CAPITAL STOCK EXPENSE (ACCOUNT 214)

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

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

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

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

None

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

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

Line No.	Class and Series of Obligation and Name of Stock Exchange (a)	Nominal Date of Issue (b)	Date of Maturity (c)	Outstanding (Total amount outstanding without reduction for amts held by respondent) (d)
1	Account 224			
2				
3	Other Long Term Debt	09/15/1997	09/15/2027	20,000,000
4	Medium Term Notes	03/16/1999	03/16/2029	15,000,000
5	Medium Term Notes	02/01/2005	02/01/2035	24,471,000
6	Insured Quarterly Notes	09/01/2005	09/01/2020	15,000,000
7	Notes	03/08/2007	03/08/2037	40,000,000
8	Senior Notes (Series A)	08/23/2013	08/23/2025	25,000,000
9	Senior Notes (Series B)	08/23/2013	08/23/2028	25,000,000
10	Senior Notes (Series A)	11/24/2014	11/24/2044	12,500,000
11	Senior Notes (Series B)	11/24/2014	11/24/2054	12,500,000
12	Senior Notes (Series C)	01/15/2015	01/15/2045	12,500,000
13	Senior Notes (Series D)	01/15/2015	01/15/2055	12,500,000
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40	**TOTAL**			214,471,000

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	12/31/2016	End of 2016/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	7.480	1,496,000			
4	7.100	1,064,700			
5	5.250	1,286,373			
6	5.210	781,500			
7	5.790	2,316,000			
8	4.110	1,027,500			
9	4.360	1,090,000			
10	4.090	511,250			
11	4.240	530,000			
12	4.090	511,250			
13	4.240	530,000			
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40		11,144,573			

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	12/31/2016	End of 2016/Q4

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

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

Line No.	Designation of Long-Term Debt (a)	Principal Amount of Debt Issued (b)	Total Expense Premium or Discount (c)	Amortization Period Date From (d)	Amortization Period Date To (e)
1	Unamortized Debt Expense (Account 181)				
2					
3	Medium Term Notes 7.48%	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%	24,589,000	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		207,500	07/09/2013	07/09/2018
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
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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	12/31/2016	End of 2016/Q4

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

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

Line No.	Balance at Beginning of Year (f)	Debits During Year (g)	Credits During Year (h)	Balance at End of Year (i)
1				
2				
3	78,604		6,713	71,891
4	66,295		5,035	61,260
5	1,240,690		65,014	1,175,676
6	73,827		16,177	57,650
7	164,515		7,770	156,745
8	120,597		12,584	108,013
9	126,679		10,067	116,612
10	103,750		41,500	62,250
11	61,144		3,199	57,945
12	60,452		2,657	57,795
13	61,498		3,207	58,291
14	60,712		2,662	58,050
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				

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	12/31/2016	End of 2016/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)	867,213	826,242
7						
8	See footnote					
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						

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	12/31/2016	End of 2016/Q4

Reconciliation of Reported Net Income with Taxable Income for Feder Income Taxes

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal Income Tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group that files consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group members, tax assigned to each group member, and basis of allocation, assignments, or sharing of the consolidated tax among the group members.

Line No.	Details (a)	Amount (b)
1	Net Income for the Year (Page 116)	10,303,197
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	See footnote	3,822,685
6		
7		
8	TOTAL	3,822,685
9	Deductions Recorded on Books Not Deducted for Return	
10	See footnote	38,955,082
11		
12		
13	TOTAL	38,955,082
14	Income Recorded on Books Not Included in Return	
15	AFUDC Equity	(361,162)
16	Interest capitalized adj. (IRS>books)	53,480
17		
18	TOTAL	(307,682)
19	Deductions on Return Not Charged Against Book Income	
20	See footnote	(36,232,429)
21		
22		
23		
24		
25		
26	TOTAL	(36,232,429)
27	Federal Tax Net Income	16,540,853
28	Show Computation of Tax:	
29	Rate - 35.00%	
30	Estimated Tax Return Federal Income Tax	5,789,299
31	Adjustments:	
32	Difference between 12/31/15 accrual and tax return	(1,695,081)
33	Provision for Current Federal Income Tax (see footnote)	4,094,218
34	Oregon State Tax Calculation (see footnote)	280,678
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	12/31/2016	End of 2016/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	185,483	
3	Federal Accrued	2,960,588	
4	Fin 48 - current		
5	Gross Revenue		
6	Washington	439,856	
7	Oregon		
8	Dept of Energy - Oregon		34,538
9	City Franchise & Occupation		
10	Washington	1,430,109	
11	Oregon	780,287	
12	Property		
13	Washington	2,617,352	
14	Oregon		677,407
15	Payroll Taxes	122,306	
16	State Excise - Washington	1,954,729	
17			
18	Miscellaneous		
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
	TOTAL	10,490,710	711,945

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	12/31/2016	End of 2016/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		293,645		12,967
3		4,283,371		189,153
4				
5				
6		399,877		
7		186,038		
8		80,211		
9				
10		8,592,298		
11		2,622,321		
12				
13		2,529,433		(3,164)
14		1,366,666		
15		2,104,800		
16		7,954,166		
17				
18		90,823		
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
TOTAL		30,503,649		198,956

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	12/31/2016	End of 2016/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	280,678	345,930		120,231	
3	4,094,218	5,886,299		1,168,507	
4					
5					
6	399,877	431,740		407,993	
7	186,038	186,038			
8	80,211	78,297			32,624
9					
10	8,592,298	8,691,616		1,330,791	
11	2,622,321	2,667,832		734,776	
12					
13	2,532,597	2,605,425		2,544,524	
14	1,366,666	1,376,394			687,135
15	2,162,164	2,165,776		118,694	
16	8,267,464	8,228,817		1,993,376	
17					
18	90,823	90,823			
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
TOTAL	30,675,355	32,754,987		8,418,892	719,759

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	12/31/2016	End of 2016/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				57,364	
16				313,298	
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
TOTAL				370,662	

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	12/31/2016	End of 2016/Q4

Miscellaneous Current and Accrued Liabilities (Account 242)

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

Line No.	Item (a)	Balance at End of Year (b)
1	Accrued Paid Time Off Liability	1,970,913
2	Pipeline Imbalances	1,551,285
3	Wages Payable	1,306,114
4	Variable Pay Incentive	1,212,601
5	Accrued 401K Defined Contributions	1,154,612
6	Washington Low Income Assist Liability	618,515
7	SERP Defined Contributions	582,558
8	Accounts Payable Accrual	466,561
9	Energy Trust of Oregon Liability	426,858
10	Other Misc Current Liabilities (aggregate)	404,723
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45	**Total**	**9,694,740**

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	1,999,526	805.1	39,306,137	36,988,491	(318,120)
2	(ammortization period 11/11-present)					
3						
4	OR Deferred Gas Costs	3,669,390	805.1	13,209,369	15,167,206	5,627,227
5	(ammortization period 11/11-present)					
6						
7	SGL Deposit	120,675	134/228.4	24,135		96,540
8	Customer Unclaimed Credits	2,735	131	46,973	47,156	2,918
9	MDUR Interco NC Payable - FAS 158	1,255,781	228.3/182.	186,120		1,069,661
10	Pension Contribution	14,111,497	various	2,280,455	355,670	12,186,712
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45	**Total**	21,159,604		55,053,189	52,558,523	18,664,938

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	(96,815,260)	(2,357,696)	
4	Other (Define) (footnote details)			
5	Total (Enter Total of lines 2 thru 4)	(96,815,260)	(2,357,696)	
6	Other (Specify) (footnote details)			
7	TOTAL Account 282 (Enter Total of lines 5 thr	(96,815,260)	(2,357,696)	
8	Classification of TOTAL			
9	Federal Income Tax	(93,348,935)	(2,161,856)	
10	State Income Tax	(3,466,325)	(195,840)	
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) 12/31/2016	Year/Period of Report End of 2016/Q4

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	1,053,769	182.3&254	1,948,159	(100,067,346)
4							
5				1,053,769		1,948,159	(100,067,346)
6							
7				1,053,769		1,948,159	(100,067,346)
8							
9			254	904,732	254	1,045,581	(95,651,640)
10			182.3	149,037	182.3	902,578	(4,415,706)
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	12/31/2016	End of 2016/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	(36,786,388)	840,619	
4	Other (Define) (footnote details)			
5	Total (Total of lines 2 thru 4)	(36,786,388)	840,619	
6	Other (Specify) (footnote details)			
7	TOTAL Account 283 (Total of lines 5 thru	(36,786,388)	840,619	
8	Classification of TOTAL			
9	Federal Income Tax	(34,906,934)	816,534	
10	State Income Tax	(1,879,454)	24,085	
11	Local Income Tax			

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	12/31/2016	End of 2016/Q4

Accumulated Deferred Income Taxes-Other (Account 283) (continued)

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

Line No.	Changes during Year Amounts Debited to Account 410.2 (e)	Changes during Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Acct. No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1							
2							
3			see	144,991	see	356,318	(36,157,096)
4			footnote		footnote		
5				144,991		356,318	(36,157,096)
6							
7				144,991		356,318	(36,157,096)
8							
9				103,771		61,426	(34,048,055)
10				41,220		294,892	(2,109,041)
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	12/31/2016	End of 2016/Q4

Other Regulatory Liabilities (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	Written off during Quarter/Period Account Credited (c)	Written off During Period Amount Refunded (d)	Written off During Period Amount Deemed Non-Refundable (e)	Credits (f)	Balance at End of Current Quarter/Year (g)
1	SFAS 109 Regulatory Liability	2,737,402	282	286,759		138,120	2,588,763
2	Oregon Tax RAte Change	(49,445)	282			3,296	(46,149)
3	Regulatory Liability - Post Ret FAS 158	847,148	186			390,919	1,238,067
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45	**Total**	3,535,105		286,759	0	532,335	3,780,681

BLANK PAGE

[Next page is 300]

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	12/31/2016	End of 2016/Q4

Gas Operating Revenues

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

Line No.	Title of Account (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transition Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)
1	480 Residential Sales				
2	481 Commercial and Industrial Sales				
3	482 Other Sales to Public Authorities				
4	483 Sales for Resale				
5	484 Interdepartmental Sales				
6	485 Intracompany Transfers				
7	487 Forfeited Discounts				
8	488 Miscellaneous Service Revenues				
9	489.1 Revenues from Transportation of Gas of Others Through Gathering Facilities				
10	489.2 Revenues from Transportation of Gas of Others Through Transmission Facilities				
11	489.3 Revenues from Transportation of Gas of Others Through Distribution Facilities				
12	489.4 Revenues from Storing Gas of Others				
13	490 Sales of Prod. Ext. from Natural Gas				
14	491 Revenues from Natural Gas Proc. by Others				
15	492 Incidental Gasoline and Oil Sales				
16	493 Rent from Gas Property				
17	494 Interdepartmental Rents				
18	495 Other Gas Revenues				
19	Subtotal:				
20	496 (Less) Provision for Rate Refunds				
21	TOTAL:				

Gas Operating Revenues

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

Line No.	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (i)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
1	148,255,469	155,857,090	148,255,469	155,857,090	15,149,586	13,868,795
2	94,221,079	102,005,833	94,221,079	102,005,833	13,777,345	12,847,173
3						
4						
5						
6						
7						
8	988,098	862,217	988,098	862,217		
9						
10						
11	25,261,174	24,419,536	25,261,174	24,419,536	93,425,359	100,460,563
12						
13						
14						
15						
16	133,624	114,760	133,624	114,760		
17						
18	152,621	285,468	152,621	285,468		
19	269,012,065	283,544,904	269,012,065	283,544,904		
20						
21	269,012,065	283,544,904	269,012,065	283,544,904		

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	12/31/2016	End of 2016/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					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/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)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/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					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/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)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

Revenues from Storing Gas of Others (Account 489.4)

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

Line No.	Rate Schedule (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transaction Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)
1	N/A				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

Revenues from Storing Gas of Others (Account 489.4)

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

Line No.	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (i)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

Other Gas Revenues (Account 495)

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

Line No.	Description of Transaction (a)	Amount (in dollars) (b)
1	Commissions on Sale or Distribution of Gas of Others	
2	Compensation for Minor or Incidental Services Provided for Others	
3	Profit or Loss on Sale of Material and Supplies not Ordinarily Purchased for Resale	
4	Sales of Stream, Water, or Electricity, including Sales or Transfers to Other Departments	
5	Miscellaneous Royalties	
6	Revenues from Dehydration and Other Processing of Gas of Others except as provided for in the Instructions to Account 495	
7	Revenues for Right and/or Benefits Received from Others which are Realized Through Research, Development, and Demonstration Ventures	
8	Gains on Settlements of Imbalance Receivables and Payables	
9	Revenues from Penalties earned Pursuant to Tariff Provisions, including Penalties Associated with Cash-out Settlements	
10	Revenues from Shipper Supplied Gas	
11	Other revenues (Specify):	
12	Miscellaneous Sales	152,621
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
	Total	**152,621**

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	12/31/2016	End of 2016/Q4

Discounted Rate Services and Negotiated Rate Services

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

Line No.	Account (a)	Discounted Rate Services Revenue (b)	Discounted Rate Services Volumes (c)	Negotiated Rate Services Revenue (d)	Negotiated Rate Services Volumes (e)
1	Account 489.1, Revenues from transportation of gas of others through gathering facilities.				
2	Account 489.2, Revenues from transportation of gas of others through transmission facilities.				
3	Account 489.4, Revenues from storing gas of others.				
4	Account 495, Other gas revenues.				
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
	Total				

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	139,769,802	144,386,647
74	804.1 Liquefied Natural Gas Purchases	0	0
75	805 Other Gas Purchases	0	0
76	(Less) 805.1 Purchases Gas Cost Adjustments	5,106,494	(10,352,083)
77	TOTAL Purchased Gas (Total of lines 68 thru 76)	134,663,308	154,738,730
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	4,676,111	4,898,359
87	(Less) 808.2 Gas Delivered to Storage-Credit	4,183,655	3,274,658
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	38,254	57,224
94	TOTAL Gas Used in Utility Operations-Credit (Total of lines 91 thru 93)	38,254	57,224
95	813 Other Gas Supply Expenses	689,576	445,955
96	TOTAL Other Gas Supply Exp. (Total of lines 77,78,85,86 thru 89,94,95)	135,807,086	156,751,162
97	TOTAL Production Expenses (Total of lines 3, 30, 58, 65, and 96)	135,807,086	156,751,162
98	2. NATURAL GAS STORAGE, TERMINALING AND PROCESSING EXPENSES		
99	A. Underground Storage Expenses		
100	Operation		
101	814 Operation Supervision and Engineering	0	0
102	815 Maps and Records	0	0
103	816 Wells Expenses	0	0
104	817 Lines Expense	0	0
105	818 Compressor Station Expenses	0	0
106	819 Compressor Station Fuel and Power	0	0
107	820 Measuring and Regulating Station Expenses	0	0
108	821 Purification Expenses	0	0
109	822 Exploration and Development	0	0
110	823 Gas Losses	0	0
111	824 Other Expenses	0	0
112	825 Storage Well Royalties	0	0
113	826 Rents	0	0
114	TOTAL Operation (Total of lines of 101 thru 113)	0	0

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
115	Maintenance		
116	830 Maintenance Supervision and Engineering	0	0
117	831 Maintenance of Structures and Improvements	0	0
118	832 Maintenance of Reservoirs and Wells	0	0
119	833 Maintenance of Lines	0	0
120	834 Maintenance of Compressor Station Equipment	0	0
121	835 Maintenance of Measuring and Regulating Station Equipment	0	0
122	836 Maintenance of Purification Equipment	0	0
123	837 Maintenance of Other Equipment	0	0
124	TOTAL Maintenance (Total of lines 116 thru 123)	0	0
125	TOTAL Underground Storage Expenses (Total of lines 114 and 124)	0	0
126	B. Other Storage Expenses		
127	Operation		
128	840 Operation Supervision and Engineering	0	0
129	841 Operation Labor and Expenses	0	0
130	842 Rents	0	0
131	842.1 Fuel	0	0
132	842.2 Power	0	0
133	842.3 Gas Losses	0	0
134	TOTAL Operation (Total of lines 128 thru 133)	0	0
135	Maintenance		
136	843.1 Maintenance Supervision and Engineering	0	0
137	843.2 Maintenance of Structures	0	0
138	843.3 Maintenance of Gas Holders	0	0
139	843.4 Maintenance of Purification Equipment	0	0
140	843.5 Maintenance of Liquefaction Equipment	0	0
141	843.6 Maintenance of Vaporizing Equipment	0	0
142	843.7 Maintenance of Compressor Equipment	0	0
143	843.8 Maintenance of Measuring and Regulating Equipment	0	0
144	843.9 Maintenance of Other Equipment	0	0
145	TOTAL Maintenance (Total of lines 136 thru 144)	0	0
146	TOTAL Other Storage Expenses (Total of lines 134 and 145)	0	0

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
147	C. Liquefied Natural Gas Terminaling and Processing Expenses		
148	Operation		
149	844.1 Operation Supervision and Engineering	0	0
150	844.2 LNG Processing Terminal Labor and Expenses	0	0
151	844.3 Liquefaction Processing Labor and Expenses	0	0
152	844.4 Liquefaction Transportation Labor and Expenses	0	0
153	844.5 Measuring and Regulating Labor and Expenses	0	0
154	844.6 Compressor Station Labor and Expenses	0	0
155	844.7 Communication System Expenses	0	0
156	844.8 System Control and Load Dispatching	0	0
157	845.1 Fuel	0	0
158	845.2 Power	0	0
159	845.3 Rents	0	0
160	845.4 Demurrage Charges	0	0
161	(less) 845.5 Wharfage Receipts-Credit	0	0
162	845.6 Processing Liquefied or Vaporized Gas by Others	0	0
163	846.1 Gas Losses	0	0
164	846.2 Other Expenses	0	0
165	TOTAL Operation (Total of lines 149 thru 164)	0	0
166	Maintenance		
167	847.1 Maintenance Supervision and Engineering	0	0
168	847.2 Maintenance of Structures and Improvements	0	0
169	847.3 Maintenance of LNG Processing Terminal Equipment	0	0
170	847.4 Maintenance of LNG Transportation Equipment	0	0
171	847.5 Maintenance of Measuring and Regulating Equipment	0	0
172	847.6 Maintenance of Compressor Station Equipment	0	0
173	847.7 Maintenance of Communication Equipment	0	0
174	847.8 Maintenance of Other Equipment	0	0
175	TOTAL Maintenance (Total of lines 167 thru 174)	0	0
176	TOTAL Liquefied Nat Gas Terminaling and Proc Exp (Total of lines 165 and 175)	0	0
177	TOTAL Natural Gas Storage (Total of lines 125, 146, and 176)	0	0

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
178	3. TRANSMISSION EXPENSES		
179	Operation		
180	850 Operation Supervision and Engineering	0	0
181	851 System Control and Load Dispatching	0	0
182	852 Communication System Expenses	0	0
183	853 Compressor Station Labor and Expenses	0	0
184	854 Gas for Compressor Station Fuel	0	0
185	855 Other Fuel and Power for Compressor Stations	0	0
186	856 Mains Expenses	0	0
187	857 Measuring and Regulating Station Expenses	0	0
188	858 Transmission and Compression of Gas by Others	0	0
189	859 Other Expenses	0	0
190	860 Rents	0	0
191	TOTAL Operation (Total of lines 180 thru 190)	0	0
192	Maintenance		
193	861 Maintenance Supervision and Engineering	0	0
194	862 Maintenance of Structures and Improvements	0	0
195	863 Maintenance of Mains	0	0
196	864 Maintenance of Compressor Station Equipment	0	0
197	865 Maintenance of Measuring and Regulating Station Equipment	0	0
198	866 Maintenance of Communication Equipment	0	0
199	867 Maintenance of Other Equipment	0	0
200	TOTAL Maintenance (Total of lines 193 thru 199)	0	0
201	TOTAL Transmission Expenses (Total of lines 191 and 200)	0	0
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering	1,951,637	1,817,712
205	871 Distribution Load Dispatching	632,872	609,642
206	872 Compressor Station Labor and Expenses	111,564	90,025
207	873 Compressor Station Fuel and Power	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
208	874 Mains and Services Expenses	4,625,388	4,461,823
209	875 Measuring and Regulating Station Expenses-General	794,942	769,463
210	876 Measuring and Regulating Station Expenses-Industrial	174,094	123,243
211	877 Measuring and Regulating Station Expenses-City Gas Check Station	0	0
212	878 Meter and House Regulator Expenses	1,875,765	1,893,006
213	879 Customer Installations Expenses	1,492,616	1,456,585
214	880 Other Expenses	4,549,422	4,882,518
215	881 Rents	182,434	123,515
216	TOTAL Operation (Total of lines 204 thru 215)	16,390,734	16,227,532
217	Maintenance		
218	885 Maintenance Supervision and Engineering	236,971	274,022
219	886 Maintenance of Structures and Improvements	16,070	11,329
220	887 Maintenance of Mains	1,726,516	1,503,525
221	888 Maintenance of Compressor Station Equipment	44,493	26,009
222	889 Maintenance of Measuring and Regulating Station Equipment-General	357,344	328,764
223	890 Maintenance of Meas. and Reg. Station Equipment-Industrial	32,497	91,173
224	891 Maintenance of Meas. and Reg. Station Equip-City Gate Check Station	0	0
225	892 Maintenance of Services	1,553,005	1,562,654
226	893 Maintenance of Meters and House Regulators	1,511,787	1,376,621
227	894 Maintenance of Other Equipment	207,018	246,145
228	TOTAL Maintenance (Total of lines 218 thru 227)	5,685,701	5,420,242
229	TOTAL Distribution Expenses (Total of lines 216 and 228)	22,076,435	21,647,774
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	(3,325)	5,770
233	902 Meter Reading Expenses	711,524	714,363
234	903 Customer Records and Collection Expenses	6,634,133	5,837,210

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
235	904 Uncollectible Accounts	985,349	812,273
236	905 Miscellaneous Customer Accounts Expenses	1,058	1,561
237	TOTAL Customer Accounts Expenses (Total of lines 232 thru 236)	8,328,739	7,371,177
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	0	0
241	908 Customer Assistance Expenses	880,645	1,695,038
242	909 Informational and Instructional Expenses	49,989	42,579
243	910 Miscellaneous Customer Service and Informational Expenses	0	0
244	TOTAL Customer Service and Information Expenses (Total of lines 240 thru 243)	930,634	1,737,617
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	0	0
248	912 Demonstrating and Selling Expenses	0	0
249	913 Advertising Expenses	6,975	14,938
250	916 Miscellaneous Sales Expenses	0	0
251	TOTAL Sales Expenses (Total of lines 247 thru 250)	6,975	14,938
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	7,532,035	6,636,013
255	921 Office Supplies and Expenses	3,273,649	3,548,681
256	(Less) 922 Administrative Expenses Transferred-Credit	382,790	498,601
257	923 Outside Services Employed	1,564,701	1,613,208
258	924 Property Insurance	80,228	81,931
259	925 Injuries and Damages	1,492,958	1,306,947
260	926 Employee Pensions and Benefits	6,031,552	6,293,369
261	927 Franchise Requirements	0	0
262	928 Regulatory Commission Expenses	0	4,210
263	(Less) 929 Duplicate Charges-Credit	0	0
264	930.1General Advertising Expenses	63,766	39,528
265	930.2Miscellaneous General Expenses	1,039,042	756,261
266	931 Rents	1,661,945	1,238,832
267	TOTAL Operation (Total of lines 254 thru 266)	22,357,086	21,020,379
268	Maintenance		
269	932 Maintenance of General Plant	43,941	53,068
270	TOTAL Administrative and General Expenses (Total of lines 267 and 269)	22,401,027	21,073,447
271	TOTAL Gas O&M Expenses (Total of lines 97,177,201,229,237,244,251, and 270)	189,550,896	208,596,115

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	12/31/2016	End of 2016/Q4

Exchange and Imbalance Transactions

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

Line No.	Zone/Rate Schedule (a)	Gas Received from Others Amount (b)	Gas Received from Others Dth (c)	Gas Delivered to Others Amount (d)	Gas Delivered to Others Dth (e)
1	None				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25	**Total**	0	0	0	0

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/Q4

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	12,040	38,254		
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25	**Total**		12,040	38,254		

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			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25	**Total**			

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	12/31/2016	End of 2016/Q4

Other Gas Supply Expenses (Account 813)

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

Line No.	Description (a)	Amount (in dollars) (b)
1	Labor Expenses and applicable overhead charges	533,404
2	Training materials	137,867
3	Lodging	30,060
4	Office Supplies	28,238
5	Commercial Air service	26,335
6	Meals & Entertainment	20,994
7	Software Maintenance	17,555
8	Cell Phone	632
9	Vehicle Mileage	211
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25	**Total**	795,296

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.	284,133
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 for CNGC's share of	
6	corporate banking fees)	344,459
7	Director's Fees (paid to MDU for CNGC's share of director's expenses)	407,203
8	Miscellaneous under $250,000 (2 items)	3,247
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25	**Total**	1,039,042

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	12/31/2016	End of 2016/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				2,736,728
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	414,825			
9	Distribution plant	20,836,355			
10	General plant	1,250,551			
11	Common plant-gas				
12	TOTAL	22,501,731			2,736,728

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

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

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

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

Line No.	Amortization of Other Limited-term Gas Plant (Account 404.3) (f)	Amortization of Other Gas Plant (Account 405) (g)	Total (b to g) (h)	Functional Classification (a)
1			2,736,728	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			414,825	Transmission plant
9			20,836,355	Distribution plant
10			1,250,551	General plant
11				Common plant-gas
12			25,238,459	TOTAL

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

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

Section B. Factors Used in Estimating Depreciation Charges

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

Particulars Concerning Certain Income Deductions and Interest Charges Accounts

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

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

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

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

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

Line No.	Item (a)	Amount (b)
1	(a) Miscellaneous Amortization (Account 425)	
2		
3	(b) Miscellaneous Income Deductions (Account426)	
4	Donations (Account 426.1)	232,468
5	Life Insurance (Account 426.2)	
6	Penalties (Account 426.3)	
7	Various Tax Authorities (late payment penalties)	1,184
8	WA Utilities & Trade Commission (Improper documentation of MAOP	
9	for high-pressuer pipelines)	1,000,000
10	Expenditures for Certain Civic, Poliitical and Related Activities	
11	(Account 426.4)	128,203
12	Other Deductions (Account 426.5)	1,437
13	Total Miscellaneous Income Deductions (Account 426)	1,363,292
14		
15	(c) Interest on Debt to Associated Companies (Acount 430)	
16		
17	(d) Other Interest Expense (Account 431)	
18	Description Interest Rate	
19	Customer Deposits-OR Various	744
20	Customer Deposits-WA Various	3,359
21	Deferral Accounts-OR ***	361,237
22	Deferral Accounts-WA FERC Interest Rate	224,984
23	Interest on Short-Term Debt Various	63,542
24	Other Various	
25	Total Other Interst Expense (Account 431)	653,866
26		
27	***Accounts not amortizing-7.468% (Overall rate of return granted in the last	
28	Oregon general rate filing; Accounts amortizing-2.20%	
29		
30		
31		
32		
33		
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	12/31/2016	End of 2016/Q4

Regulatory Commission Expenses (Account 928)

1. Report below details of regulatory commission expenses incurred during the current year (or in previous years, if being amortized) relating to formal cases before a regulatory body, or cases in which such a body was a party.
2. In column (b) and (c), indicate whether the expenses were assessed by a regulatory body or were otherwise incurred by the utility.

Line No.	Description (Furnish name of regulatory commission or body, the docket number, and a description of the case.) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses to Date (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	None				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25	**Total**				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

Regulatory Commission Expenses (Account 928)

3. Show in column (k) any expenses incurred in prior years that are being amortized. List in column (a) the period of amortization.
4. Identify separately all annual charge adjustments (ACA).
5. List in column (f), (g), and (h) expenses incurred during year which were charges currently to income, plant, or other accounts.
6. Minor items (less than $250,000) may be grouped.

Line No.	Expenses Incurred During Year Charged Currently To Department (f)	Expenses Incurred During Year Charged Currently To Account No. (g)	Expenses Incurred During Year Charged Currently To Amount (h)	Expenses Incurred During Year Deferred to Account 182.3 (i)	Amortized During Year Contra Account (j)	Amortized During Year Amount (k)	Deferred in Account 182.3 End of Year (l)
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							

Employee Pensions and Benefits (Account 926)

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

Line No.	Expense (a)	Amount (b)
1	Pensions – defined benefit plans	(70,403)
2	Pensions – other	2,408,416
3	Post-retirement benefits other than pensions (PBOP)	275,548
4	Post- employment benefit plans	169,401
5	Other (Specify)	
6	Medical/Dental	3,061,756
7	Various	186,834
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
	Total	**6,031,552**

BLANK PAGE

[Next page is 354]

Distribution of Salaries and Wages

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

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Payroll Billed by Affiliated Companies (c)	Allocation of Payroll Charged for Clearing Accounts (d)	Total (e)
1	Electric				
2	Operation				
3	Production				
4	Transmission				
5	Distribution				
6	Customer Accounts				
7	Customer Service and Informational				
8	Sales				
9	Administrative and General				
10	TOTAL Operation (Total of lines 3 thru 9)				
11	Maintenance				
12	Production				
13	Transmission				
14	Distribution				
15	Administrative and General				
16	TOTAL Maintenance (Total of lines 12 thru 15)				
17	Total Operation and Maintenance				
18	Production (Total of lines 3 and 12)				
19	Transmission (Total of lines 4 and 13)				
20	Distribution (Total of lines 5 and 14)				
21	Customer Accounts (line 6)				
22	Customer Service and Informational (line 7)				
23	Sales (line 8)				
24	Administrative and General (Total of lines 9 and 15)				
25	TOTAL Operation and Maintenance (Total of lines 18 thru 24)				
26	Gas				
27	Operation				
28	Production - Manufactured Gas				
29	Production - Natural Gas(Including Exploration and Development)				
30	Other Gas Supply				
31	Storage, LNG Terminaling and Processing				
32	Transmission				
33	Distribution	11,235,485			11,235,485
34	Customer Accounts	4,357,209			4,357,209
35	Customer Service and Informational	987			987
36	Sales				
37	Administrative and General	5,833,185			5,833,185
38	TOTAL Operation (Total of lines 28 thru 37)	21,426,866			21,426,866
39	Maintenance				
40	Production - Manufactured Gas				
41	Production - Natural Gas(Including Exploration and Development)				
42	Other Gas Supply				
43	Storage, LNG Terminaling and Processing				
44	Transmission				
45	Distribution	3,813,051			3,813,051

Distribution of Salaries and Wages (continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Payroll Billed by Affiliated Companies (c)	Allocation of Payroll Charged for Clearing Accounts (d)	Total (e)
46	Administrative and General				
47	TOTAL Maintenance (Total of lines 40 thru 46)	3,813,051			3,813,051
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)	15,048,536			15,048,536
56	Customer Accounts (Total of line 34)	4,357,209			4,357,209
57	Customer Service and Informational (Total of line 35)	987			987
58	Sales (Total of line 36)				
59	Administrative and General (Total of lines 37 and 46)	5,833,185			5,833,185
60	Total Operation and Maintenance (Total of lines 50 thru 59)	25,239,917			25,239,917
61	Other Utility Departments				
62	Operation and Maintenance				
63	TOTAL ALL Utility Dept. (Total of lines 25, 60, and 62)	25,239,917			25,239,917
64	Utility Plant				
65	Construction (By Utility Departments)				
66	Electric Plant				
67	Gas Plant	7,294,046			7,294,046
68	Other				
69	TOTAL Construction (Total of lines 66 thru 68)	7,294,046			7,294,046
70	Plant Removal (By Utility Departments)				
71	Electric Plant				
72	Gas Plant	489,532			489,532
73	Other				
74	TOTAL Plant Removal (Total of lines 71 thru 73)	489,532			489,532
75	Other Accounts (Specify) (footnote details)	1,212,813			1,212,813
76	TOTAL Other Accounts	1,212,813			1,212,813
77	TOTAL SALARIES AND WAGES	34,236,308			34,236,308

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	12/31/2016	End of 2016/Q4

Charges for Outside Professional and Other Consultative Services

1. Report the information specified below for all charges made during the year included in any account (including plant accounts) for outside consultative and other professional services. These services include rate, management, construction, engineering, research, financial, valuation, legal, accounting, purchasing, advertising,labor relations, and public relations, rendered for the respondent under written or oral arrangement, for which aggregate payments were made during the year to any corporation partnership, organization of any kind, or individual (other than for services as an employee or for payments made for medical and related services) amounting to more than $250,000, including payments for legislative services, except those which should be reported in Account 426.4 Expenditures for Certain Civic, Political and Related Activities.
 (a) Name of person or organization rendering services.
 (b) Total charges for the year.
2. Sum under a description "Other", all of the aforementioned services amounting to $250,000 or less.
3. Total under a description "Total", the total of all of the aforementioned services.
4. Charges for outside professional and other consultative services provided by associated (affiliated) companies should be excluded from this schedule and be reported on Page 358, according to the instructions for that schedule.

Line No.	Description (a)	Amount (in dollars) (b)
1	Infrasource Services, LLC	5,835,941
2	Northwest Metal Fab & Pipe, Inc.	5,306,112
3	Snelson Companies, Inc.	5,129,714
4	Michels Corporation	4,951,164
5	Brothers Pipeline Corp.	3,670,065
6	Prosource Technologies, LLC	1,895,405
7	Gas Transmission NW Corp.	1,816,000
8	Coffman Engineers	1,403,330
9	Das-Co of Idaho	747,567
10	Q3 Contracting	677,429
11	ABI Services, LLC	636,660
12	Parametrix, Inc.	632,032
13	Northwest Pipeline, LLC	364,853
14	Deloitte & Touche	352,250
15	McKenzie Cascade Heavy Excavation	346,268
16	Vessey & Sons, Inc.	345,936
17	Snyder Gas Consulting, LLC	334,000
18	Northwest Pipeline	330,000
19	Mesa Products, Inc.	294,579
20	Northwest Inspection, Inc.	285,464
21	Other	5,031,552
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		

Transactions with Associated (Affiliated) Companies

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

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	Goods or Services Provided by Affiliated Company			
2		IGC/MDU/MDU RESOURCES	107	1,092,389
3			426.1	12,385
4			426.4	24,026
5			426.5	632
6			813	204,115
7			875	117,980
8			880	589,845
9			902	148,055
10			903	6,429,386
11			909	20,037
12			913	41
13				
14				
15				
16				
17				
18				
19				
20	Goods or Services Provided for Affiliated Company			
21			920	4,596,118
22			921	2,206,639
23			922	(172,133)
24			923	339,016
25			925	52
26			926	(94,212)
27			930.1	20,804
28			930.2	427,432
29			931	1,604,465
30			Various	675,701
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				

Compressor Stations

1. Report below details concerning compressor stations. Use the following subheadings: field compressor stations, products extraction compressor stations, underground storage compressor stations, transmission compressor stations, distribution compressor stations, and other compressor stations.
2. For column (a), indicate the production areas where such stations are used. Group relatively small field compressor stations by production areas. Show the number of stations grouped. Identify any station held under a title other than full ownership. State in a footnote the name of owner or co-owner, the nature of respondent's title, and percent of ownership if jointly owned.

Line No.	Name of Station and Location (a)	Number of Units at Station (b)	Certificated Horsepower for Each Station (c)	Plant Cost (d)
1	Compressor Station at Burlington, WA	1	1,350	2,000,731
2	Placed in Service: August 2001			
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/Q4

Compressor Stations

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

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

Line No.	Expenses (except depreciation and taxes) Fuel (e)	Expenses (except depreciation and taxes) Power (f)	Expenses (except depreciation and taxes) Other (g)	Gas for Compressor Fuel in Dth (h)	Electricity for Compressor Station in kWh (i)	Operational Data Total Compressor Hours of Operation During Year (j)	Operational Data Number of Compressors Operated at Time of Station Peak (k)	Date of Station Peak (l)
1	7,045		176,273				1	
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

Gas Storage Projects

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

Line No.	Item (a)	Gas Belonging to Respondent (Dth) (b)	Gas Belonging to Others (Dth) (c)	Total Amount (Dth) (d)
	STORAGE OPERATIONS (in Dth)			
1	Gas Delivered to Storage			
2	January			
3	February			
4	March			
5	April			
6	May			
7	June			
8	July			
9	August			
10	September			
11	October			
12	November			
13	December			
14	TOTAL (Total of lines 2 thru 13)			
15	Gas Withdrawn from Storage			
16	January			
17	February			
18	March			
19	April			
20	May			
21	June			
22	July			
23	August			
24	September			
25	October			
26	November			
27	December			
28	TOTAL (Total of lines 16 thru 27)			

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	12/31/2016	End of 2016/Q4

Gas Storage Projects

1. On line 4, enter the total storage capacity certificated by FERC.
2. Report total amount in Dth or other unit, as applicable on lines 2, 3, 4, 7. If quantity is converted from Mcf to Dth, provide conversion factor in a footnote.

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

Transmission Lines

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

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

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/Q4

Transmission System Peak Deliveries

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

Auxiliary Peaking Facilities

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

Gas Account - Natural Gas

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

Line No.	Item (a)	Ref. Page No. of (FERC Form Nos. 2/2-A) (b)	Total Amount of Dth Year to Date (c)	Current Three Months Ended Amount of Dth Quarterly Only (d)
01	Name of System:			
2	GAS RECEIVED			
3	Gas Purchases (Accounts 800-805)		29,287,134	
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)		1,570,269	
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)		93,425,359	
16	Total Receipts (Total of lines 3 thru 15)		124,282,762	
17	GAS DELIVERED			
18	Gas Sales (Accounts 480-484)		28,926,930	
19	Deliveries of Gas Gathered for Others (Account 489.1)	303		
20	Deliveries of Gas Transported for Others (Account 489.2)	305	93,425,359	
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)		1,688,915	
28	Gas Used for Compressor Station Fuel	509		
29	Other Deliveries and Gas Used for Other Operations		12,040	
30	Total Deliveries (Total of lines 18 thru 29)		124,053,244	
31	GAS LOSSES AND GAS UNACCOUNTED FOR			
32	Gas Losses and Gas Unaccounted For		229,518	
33	TOTALS			
34	Total Deliveries, Gas Losses & Unaccounted For (Total of lines 30 and 32)		124,282,762	

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	12/31/2016	2016/Q4

System Maps

1. Furnish five copies of a system map (one with each filed copy of this report) of the facilities operated by the respondent for the production, gathering, transportation, and sale of natural gas. New maps need not be furnished if no important change has occurred in the facilities operated by the respondent since the date of the maps furnished with a previous year's annual report. If, however, maps are not furnished for this reason, reference should be made in the space below to the year's annual report with which the maps were furnished.
2. Indicate the following information on the maps:
   (a) Transmission lines.
   (b) Incremental facilities.
   (c) Location of gathering areas.
   (d) Location of zones and rate areas.
   (e) Location of storage fields.
   (f) Location of natural gas fields.
   (g) Location of compressor stations.
   (h) Normal direction of gas flow (indicated by arrows).
   (i) Size of pipe.
   (j) Location of products extraction plants, stabilization plants, purification plants, recycling areas, etc.
   (k) Principal communities receiving service through the respondent's pipeline.
3. In addition, show on each map: graphic scale of the map; date of the facts the map purports to show; a legend giving all symbols and abbreviations used; designations of facilities leased to or from another company, giving name of such other company.
4. Maps not larger than 24 inches square are desired. If necessary, however, submit larger maps to show essential information. Fold the maps to a size not larger then this report. Bind the maps to the report.

See attached map

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

FOOTNOTE DATA

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

Regulatory accounts related to FAS158 and OR rate change adjustments

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

Regulatory accounts related to FAS158 and OR rate change adjustments

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

The loss associated with each reacquisition consists of a reacquisition premium, other reacquisition expenses, and remaining unamortized issuance costs (Account 181) at the time of reacquisition.

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

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

CIAC		4,990,647
Customer Advances - 2520.000 to 2520.2991		608,407
Tax Gain (loss) on disposal of assets:		
Pre-1981 assets		(570,372)
Post-1980 assets		(1,205,997)
	Total	**3,822,685**

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

Tax Expense		5,895,500
Vacation Accrual - current year		1,746,437
Retiree Medical Accrual		427,529
Amort of loss on reacquired debt (4281)		40,971
SFAS No. 87 pension plann accrual		(176,629)
SFAS No. 87 accrual-SERP/SISP expense		750,207
Incentive accrual		1,212,601
Bad Debt Expense		985,349
Charitable Contributions (5981,4261)		216,468
Legal Reserve		280,000
Depreciation provision:		
Pre-1981		544,605
Post-1980		25,750,544
Permanent Diff's:		
50% of business meals & entertainment		152,305
Penalties (5984)		1,001,099
Lobbying (5912,4264)		128,096
	Total	**38,955,082**

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

Vacation accrual-prior year		(1,605,812)
Depreciation & ammortization of plant:		
Post-1980		(24,499,290)
Repairs Deduction		(3,637,386)
Section 174 costs		(2,880,285)
Bad debts written off		(975,637)
SERP-benefit payments out of plan		(603,443)
SERP/SISP-perm difference piece		(472,308)
Retiree Medical payments		(359,489)
Deferred Gas Costs		(318,120)
Prepaid Expenses		(209,142)
401K Dividends (MDUR)		(184,446)
Bremerton & Eugene MGP expenses		(182,016)
263A Adjustment-UNICAP		(9,296)
Oregon State Income Tax		(295,759)
	Total	**(36,232,429)**

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

Allocated to:	409.1	409.2	Total
Washington	3,159,843	(142,375)	3,017,468
Oregon	1,123,528	(46,778)	1,076,750

Total	**4,283,371**	**(189,153)**	**4,094,218**

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

Taxable Income for Federal Tax	16,540,853
Oregon adjustments to Federal Taxable Income:	
Oregon State Income Tax expense deducted from Federal Return	295,759
Bonus Depreciation adjustment	(475,273)
Taxable Income for Oregon Tax	16,361,339
Oregon Apportionment Factor	23.7851%
Oregon Taxable Income	3,891,561
Oregon Tax Rate	7.60%
Estimated Tax Return Oregon Income Tax	295,759
Adjustments:	
Difference between 12/31/15 accrual and tax return	(15,081)
Provision for Current Oregon Income Tax	**280,678**

Allocated to:	409.1	409.2	Total
Total	**293,645**	**(12,967)**	**280,678**

FOOTNOTE DATA

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

Regulatory accounts related to FAS158 and deferred tax effect of OR State Tax Rate increase

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

Regulatory accounts related to FAS158 and deferred tax effect of OR State Tax Rate increase

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

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

	Washington		Oregon	
Description (a)	Depreciable Plant Base (Thousands) (b)	Composite Rate (Percent) (c)	Depreciable Plant Base (Thousands) (d)	Composite Rate (Percent) (e)
Intangible plant	25,749		8,186	
Manufactured gas production	0		0	
Transmission plant	17,214	1.75%	5,863	1.93%
Distribution plant	612,514	2.60%	171,748	2.86%
General plant	47,260	3.59%	16,134	3.75%
Total -	702,737	2.84%	201,931	3.12%

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

PTO/Incentive/Severance Pay Liabilities	1,212,601
Miscellaneous Services	212
	1,212,813

INDEX

MDU Resources Group, Inc.

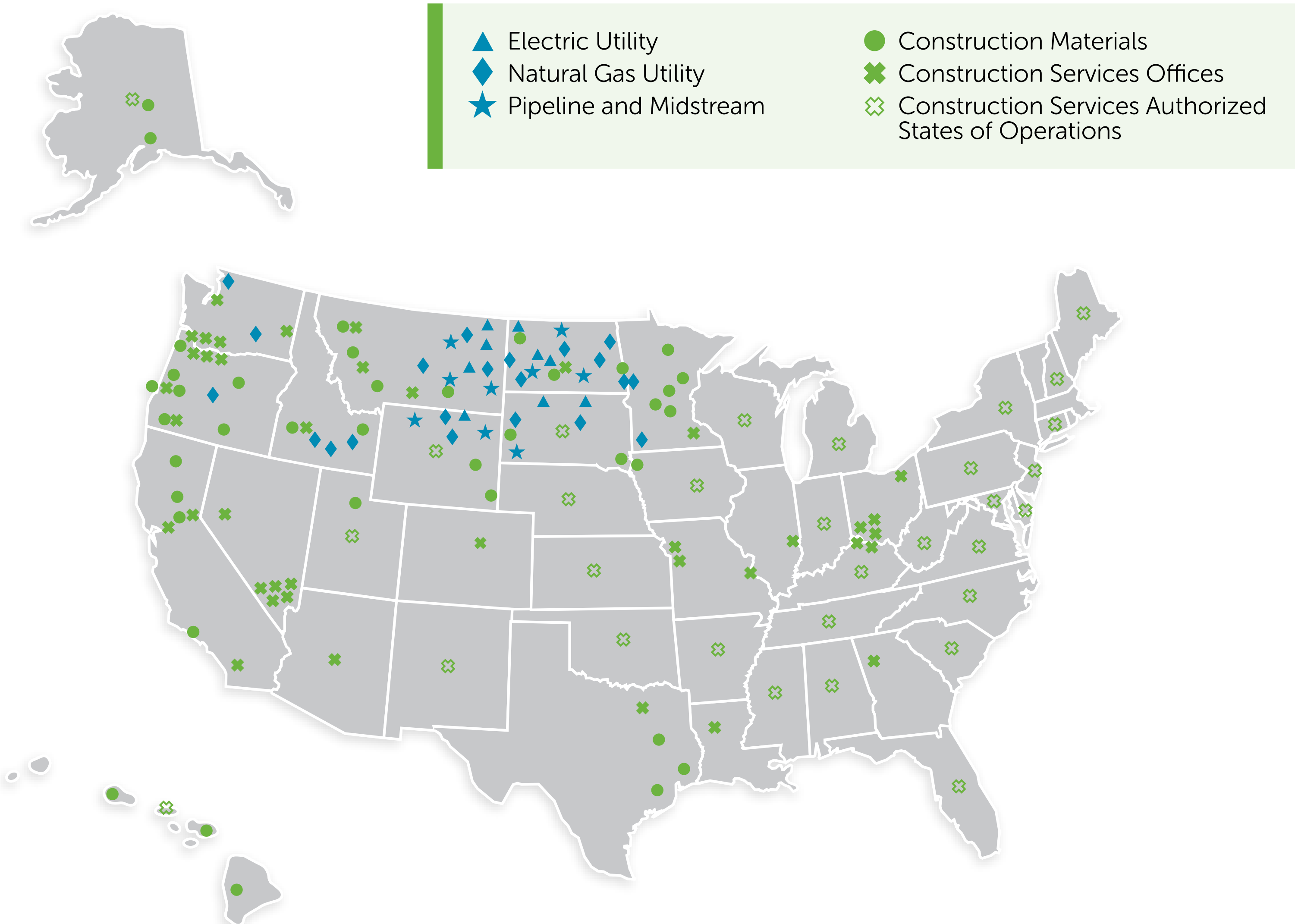
Building a Strong America®

2016

Annual Report / Form 10-K / Proxy Statement

MDU RESOURCES GROUP, INC.

MDU Resources Group, Inc.



Building a Strong America®

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

Highlights

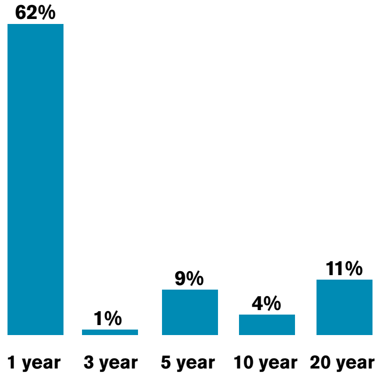
Years ended December 31,	2016	2015
	(In millions, where applicable)	
Operating revenues	$4,128.8	$4,014.0
Operating income	$ 409.1	$ 319.8
Earnings on common stock from continuing operations	$ 232.4	$ 175.7
Earnings (loss) on common stock, including discontinued operations	$ 63.7	$ (623.1)
Earnings per common share from continuing operations	$ 1.19	$ .90
Earnings (loss) per common share, including discontinued operations	$ .33	$ (3.20)
Dividends declared per common share	$ .7550	$ .7350
Weighted average common shares outstanding — diluted	195.6	195.0
Total assets	$ 6,284	$ 6,565
Total equity	$ 2,316	$ 2,521
Total debt	$ 1,790	$ 1,796
Capitalization ratios:		
Total equity	56.4%	58.4%*
Total debt	43.6	41.6*
	100%	100%
Price/earnings from continuing operations ratio (12 months ended)	24.2x	20.4x
Book value per common share	$ 11.78	$ 12.83
Market value as a percent of book value	244.2%	142.8%
Employees	9,598	8,689

*Includes noncontrolling interest.

Forward-looking statements: This Annual Report contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Forward-looking statements should be read with the cautionary statements and important factors included in Part I, Forward-Looking Statements and Item 1A — Risk Factors of the company's 2016 Form 10-K. Forward-looking statements are all statements other than statements of historical fact, including without limitation those statements that are identified by the words anticipates, estimates, expects, intends, plans, predicts and similar expressions.

Total Shareholder Returns

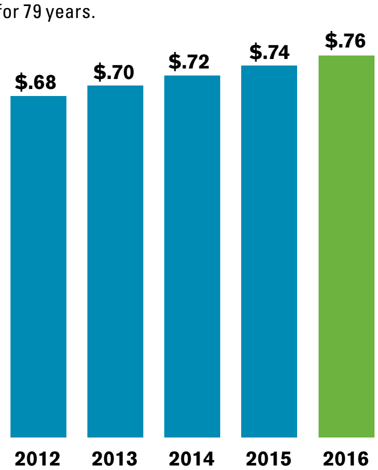
(as of December 31, 2016)



Dividends

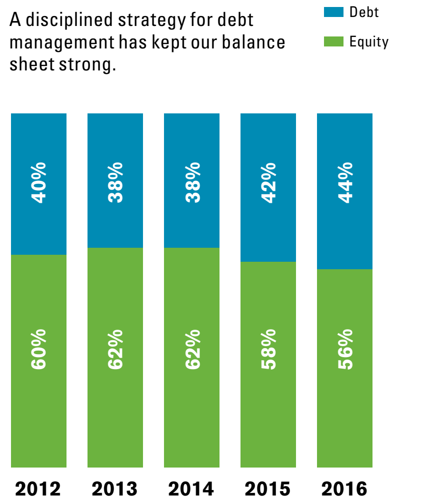
(per common share)

We have paid dividends uninterrupted for 79 years.



Capitalization Ratios

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

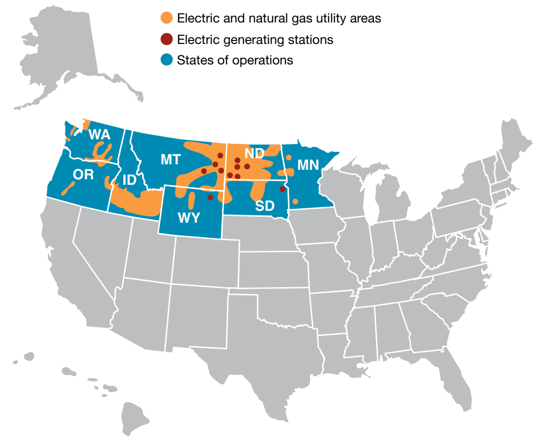


Our Businesses

Regulated Energy Delivery

Electric and Natural Gas Utilities

MDU Resources Group's utility companies serve approximately 1.07 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.

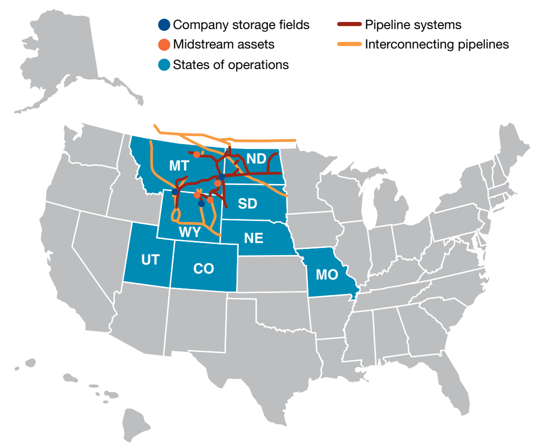


2016 Key Statistics

Revenues (millions)	
Electric	$322.3
Natural gas	$766.1
Earnings (millions)	
Electric	$42.2
Natural gas	$27.1
Electric retail sales (million kWh)	3,258.5
Natural gas distribution (MMdk)	
Sales	99.3
Transportation	147.6

Pipeline and Midstream

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.



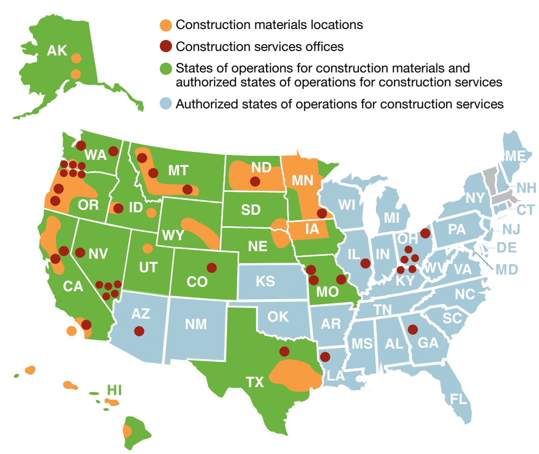
2016 Key Statistics

Revenues (millions)	$141.6
Earnings (millions)	$23.4
Pipeline (MMdk)	
Transportation	285.3
Gathering	20.0

Construction Materials and Services

Construction Materials and Contracting

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



Construction Services

MDU Construction Services Group specializes in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization. It also provides utility excavation and inside electrical and mechanical services, and manufactures and distributes transmission line construction equipment and supplies.

2016 Key Statistics

Revenues (millions)	
Construction materials	$1,874.3
Construction services	$1,073.3
Earnings (millions)	
Construction materials	$102.7
Construction services	$33.9
Construction materials sales (thousands)	
Aggregates (tons)	27,580
Asphalt (tons)	7,203
Ready-mix concrete (cubic yards)	3,655
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.

In 2016, we made great strides as we transitioned to a more streamlined company with two lines of business: construction materials and services and regulated energy delivery. We reduced MDU Resources Group's exposure to commodity price volatility by successfully selling our remaining oil and natural gas exploration and production assets, our interests in a diesel refinery in North Dakota and our interests in a natural gas processing plant in North Dakota. Our financial results for 2016 reflect that these changes have provided strong momentum, and we are excited about the opportunities that exist for our continuing operations.

2016 earnings from continuing operations increased 32 percent to $232.4 million, or $1.19 per share, compared to 2015 earnings from continuing operations of $175.7 million, or 90 cents per share. Including discontinued operations, primarily the exploration and production and refining businesses that we sold, MDU Resources reported 2016 earnings of $63.7 million, or 33 cents per share, compared to a loss of $623.1 million, or $3.20 per share, in 2015.

Our company provided shareholders with a 62 percent total return in 2016, and in November we increased our dividend for the 26th consecutive year. Fewer than 100 of the more than 2,400 other U.S.-listed, dividend-paying companies have increased their dividend as many consecutive years as MDU Resources.

Standard & Poor's in the fourth quarter of 2016 improved our company's credit rating outlook from negative to stable, a reflection of our reduced exposure to commodity price risk. MDU Resources now has a BBB+ credit rating with stable outlook from both S&P and Fitch Ratings.

Construction materials has record year

Our construction materials business, Knife River Corporation, finished 2016 with record results for the second consecutive year. Although revenues were down slightly, earnings were up 15 percent to $102.7 million with an increase in aggregate and asphalt volumes and margins. All of Knife River's regions continue to perform well. We saw higher construction demand and margins in all but the North Central region, where we have seen a slowdown in North Dakota.

While Knife River has experienced two consecutive years of record earnings, it has capacity with existing resources to take on additional work. For example, we sold 27.6 million tons of aggregate in 2016, but in 2006 we sold 45.6 million tons of aggregate. This indicates that while we have achieved record earnings, we are at only about 60 percent of our prior peak volumes. We believe the $305 billion, five-year Fixing America's Surface Transportation (FAST) Act, which was passed in late 2015, will provide opportunities to utilize some of Knife River's additional capacity. The impacts we saw from the FAST Act were minimal in 2016, as states and municipalities worked to identify projects on which to invest the federal funds. We expect to see more substantial impacts this year and going forward as projects are released for bids.

Knife River is the fifth largest sand and gravel producer in the U.S. and has more than a 30-year supply of aggregates with its 1 billion tons of reserves. We finished 2016 with record year-end backlog of $538 million, which is 10 percent higher than the 2015 record year-end backlog, and we are well-positioned to serve our markets.

Construction services building momentum

Earnings from our construction services business in 2016 were up 43 percent, to $33.9 million, on just 16 percent revenue growth. The increase was mainly from higher construction workloads and margins in the Western Region.

MDU Construction Services Group closed on the sale in the fourth quarter of one of the largest community solar projects in the U.S., on which it provided turnkey engineering, procurement and construction. The project was part of the approximately 300 megawatts of solar construction this business provided in 2016. Also in the fourth quarter, MDU Construction Services Group successfully completed a 135-mile, 345-kilovolt transmission line project for Transource Missouri. The project, awarded in 2015, involved constructing 843 transmission line structures and was the largest transmission construction project ever completed by MDU Construction Services Group.

Harry J. Pearce
Chairman of the Board

David L. Goodin
President and Chief Executive Officer

Our construction services business is the 13th largest specialty contractor in the U.S., as ranked on Engineering News-Record's 2016 Top 600 Specialty Contractors list. Backlog was down slightly to $475 million at the end of 2016, but this business is well-positioned with our strong performance history and safety record to respond to the bidding opportunities that we anticipate will escalate in 2017. We are focused on growing our inside construction services work, particularly in the high-tech, mission-critical arena, health care facilities and the gaming and hospitality industry, where activity is picking up. Our services are in demand in the industrial and manufacturing sector, where we often work with auto and petrochemical manufacturers, and in the electrical transmission and distribution industry. Our transmission and distribution equipment sales and rentals business is strategically located with two manufacturing facilities to meet demand as the country's infrastructure development continues.

Utility continues focus on rate recovery

Our electric and natural gas utility businesses also had higher earnings in 2016, up 16 percent to $69.3 million. The increase was mainly related to cost recovery through regulatory relief. Natural gas retail sales volumes were up 4 percent for the year as well, a result of customer growth and colder weather in certain areas.

The utility continues to seek regulatory recovery for investments associated with upgrading and expanding facilities to provide safe, reliable service to our customers at economic prices. Regulatory activity in 2016 and to date has resulted in an additional $32.7 million in final rates. That brings our total finalized rate increases for the past two years to $56.8 million. We also have $55.4 million in rate increases awaiting regulatory agency approval, with $43.6 million implemented in interim rates. We have grown our rate base at a record 12 percent, compounded annually, over the past five years, and we expect our rate base to continue to grow by approximately 4 percent annually.

In 2016, our utility customer base grew 1.6 percent to approximately 1.07 million. We expect our customer base across our eight-state service territory to continue to grow at a rate of 1 to 2 percent annually. Our electric utility will issue its Integrated Resource Plan this year, which we expect will identify a future large-scale generation option to meet customer growth. Also to meet customer needs, we announced at the beginning of this year an agreement to buy power from an expansion of the Thunder Spirit Wind farm in southwestern North Dakota, which is expected to be on line in late 2018. We already own the original 107.5-MW Thunder Spirit Wind farm, and our agreement gives us the option to buy the expansion when completed. The additional wind generation will increase our renewable portfolio to approximately 27 percent of our generation capacity.

Pipeline business pursuing growth projects

Earnings at our pipeline and midstream business were $23.4 million in 2016. This is slightly higher than 2015 when considering that this business recorded impairments associated with asset sales of $1.4 million, after tax, in 2016 and $10.6 million, after tax, in 2015. Customer utilization of our natural gas storage services was 59 percent higher in 2016.

We closed January 1, 2017, on the sale of our 50 percent non-operating ownership interest in the Pronghorn natural gas processing plant in North Dakota. This further reduces our company's risks associated with oil and natural gas commodity prices, and the company received proceeds of approximately $100 million from the sale.

We are focused on pipeline system growth. In 2016, we completed two expansion projects in northwestern North Dakota that add capacity and reliability. We have another project in the Bakken region that will be completed in the second quarter this year to add volume. We also secured the commitments necessary from customers in 2016 to proceed with our Valley Expansion project. This 38-mile pipeline will connect our existing system in eastern North Dakota with another company's pipeline in far western Minnesota. We will have an opportunity to provide natural gas to towns and customers along the route that have not been served or have been underserved in the past. The pipeline initially will be built to transport 40 million cubic feet of natural gas per day, and it can be enhanced to transport significantly more as demand grows. We have approval from the Federal Energy Regulatory Commission on our pre-filing and have nearly completed survey work. We expect to start construction in early 2018 and complete the project late that year.

Our employees are the difference

Our employees work hard to provide results for our shareholders, our customers and our communities. We thank them for their commitment to operating safely and maintaining the integrity that is a vital part of our culture, while being good stewards in the communities where they live. Along with our day-to-day safety practices, we have stepped up our attention on cybersecurity in recent years to ensure our customer, employee and company proprietary information is secure. We know we must be vigilant every day to keep our people and our systems safe.

We are excited about our company's future as we continue Building a Strong America.® We believe the new administration's goals for our country will provide additional opportunities for our businesses.

We will maintain our conservative fiscal approach to managing your investment in MDU Resources, while providing the results you expect. We are proud of the fact that we have paid uninterrupted dividends to our shareholders for 79 years, and our commitment to paying dividends is reflected in our membership in the S&P High-Yield Dividend Aristocrats index.

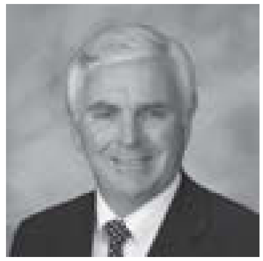
Thank you for your continued support of MDU Resources. We look forward to growing our company while providing you with the long-term value you expect from your investment.

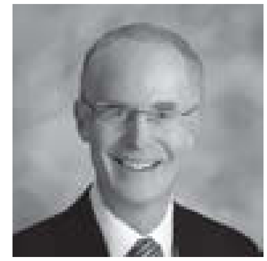
Harry J. Pearce
Chairman of the Board

David L. Goodin
President and Chief Executive Officer

February 24, 2017

Board of Directors





Harry J. Pearce
74 (20)
Detroit, Michigan

Chairman of MDU Resources Board of Directors

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

Expertise: Multinational business management, leadership, finance, engineering and law

David L. Goodin
55 (4)
Bismarck, North Dakota

President and chief executive officer of MDU Resources

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

Thomas Everist
67 (22)
Sioux Falls, South Dakota

President and chairman of The 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
63 (12)
Billings, Montana

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

Expertise: Engineering, construction and business management

Mark A. Hellerstein
64 (4)
Denver, Colorado

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

Expertise: Energy industry, business management, accounting and finance

A. Bart Holaday
74 (9)
Denver, Colorado, and Grand Forks, North Dakota

Retired, formerly managing director of Private Markets Group of UBS Asset Management; on the board of several organizations

Expertise: Energy industry, business development, finance and law

Dennis W. Johnson
67 (16)
Dickinson, North Dakota

Chairman, president and chief executive officer 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 finance

William E. McCracken
74 (4)
Warren, New Jersey

Retired, formerly chairman and chief executive officer of CA Technologies; previously held executive positions with IBM Corp.; on the board of several organizations; a former director of IKON Office Solutions Inc.

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

Patricia L. Moss
63 (14)
Bend, Oregon

Vice chairman of Cascade Bancorp and Bank of the Cascades, formerly president and chief executive officer of Cascade Bancorp and Bank of the Cascades; on the board of several organizations

Expertise: Finance, banking, business development and human resources

John K. Wilson
62 (14)
Omaha, Nebraska

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

Expertise: Public utilities, accounting and finance

Audit Committee
Dennis W. Johnson, Chair
Mark A. Hellerstein
A. Bart Holaday
John K. Wilson

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

Nominating and Governance Committee
Karen B. Fagg, Chair
A. Bart Holaday
William E. McCracken
Patricia L. Moss

Numbers indicate age and years of service ( ) on the MDU Resources Board of Directors as of December 31, 2016.

Corporate Management

David L. Goodin
55 (34)

President and Chief Executive Officer of MDU Resources

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

David C. Barney
61 (31)

President and Chief Executive Officer of Knife River Corporation

Formerly held executive and management positions with Knife River

Martin A. Fritz
52 (2)

President and Chief Executive Officer of WBI Holdings, Inc.

Formerly an executive with a natural gas production and midstream company

Dennis L. Haider
64 (39)

Executive Vice President of Business Development of MDU Resources

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

Anne M. Jones
53 (35)

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
43 (22)

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

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

Daniel S. Kuntz
63 (13)

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
50 (12)

Chief Information Officer of MDU Resources

Formerly assistant vice president of technology and cybersecurity officer of MDU Resources

Doran N. Schwartz
47 (12)

Vice President and Chief Financial Officer of MDU Resources

Serves as the senior financial officer and member of the board of directors of all major subsidiary companies; formerly chief accounting officer of MDU Resources

Jeffrey S. Thiede
54 (13)

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

Formerly held executive and management positions with MDU Construction Services Group

Other Corporate and Senior Company Officers

Jason L. Vollmer, 39 (12)
Vice President, Treasurer and Chief Accounting Officer of MDU Resources

Management Changes

Peggy A. Link was named chief information officer effective January 1, 2016, and was designated a company officer effective January 1, 2017.

Jason L. Vollmer was named vice president, chief accounting officer and treasurer of MDU Resources effective March 19, 2016. He replaced Nathan W. Ring, who resigned March 18, 2016.

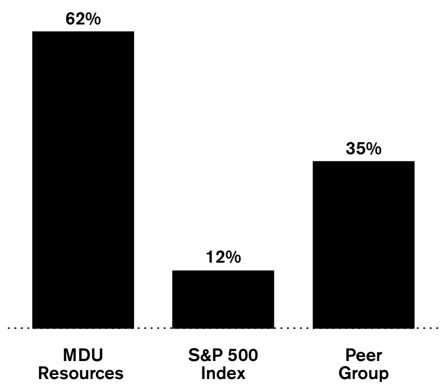
Cynthia J. Norland, vice president of administration of MDU Resources, retired effective January 20, 2017.

Numbers indicate age and years of service ( ) as of December 31, 2016.

Stockholder Return Comparison

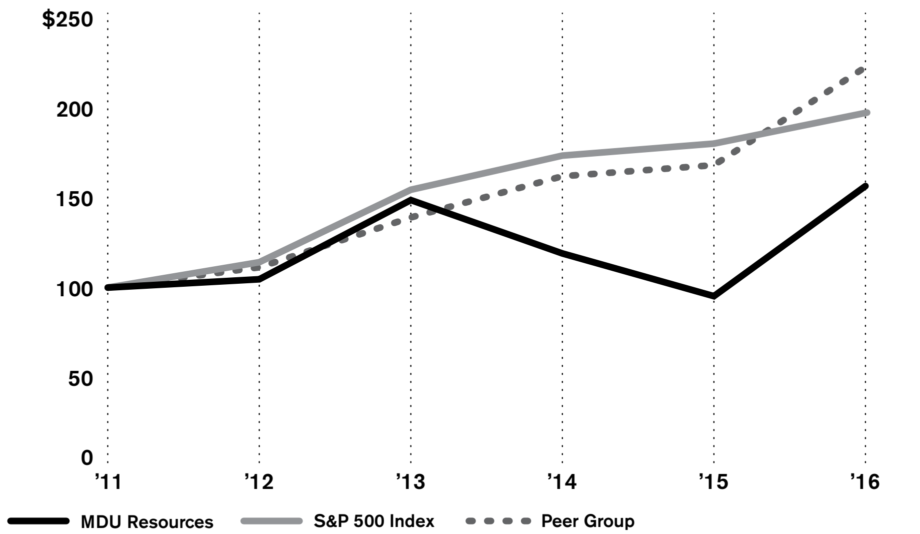
Comparison of One-Year Total Stockholder Return

(as of December 31, 2016)



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

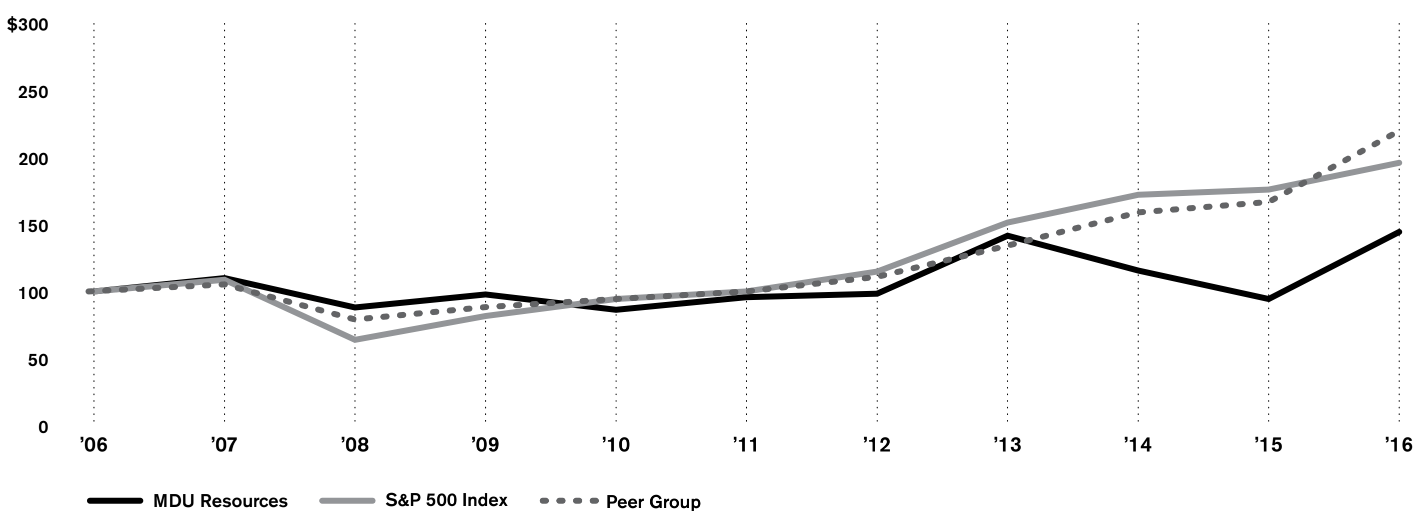
$100 invested December 31, 2011, in MDU Resources was worth $155.84 at year-end 2016.



	2011	2012	2013	2014	2015	2016
MDU Resources Group, Inc.	$100.00	$102.07	$150.60	$118.70	$96.17	$155.84
S&P 500 Index	100.00	116.00	153.57	174.60	177.01	198.18
Peer Group	100.00	113.41	138.85	158.33	166.15	225.13

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

$100 invested December 31, 2006, in MDU Resources was worth $149.51 at year-end 2016.



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
MDU Resources Group, Inc.	$100.00	$109.85	$87.82	$99.13	$87.90	$95.94	$97.93	$144.48	$113.87	$92.26	$149.51
S&P 500 Index	100.00	105.49	66.46	84.05	96.71	98.76	114.56	151.66	172.42	174.81	195.72
Peer Group	100.00	103.68	85.92	90.09	96.79	99.81	113.20	138.59	158.03	165.84	224.70

Stockholder Return Comparison

Data is indexed to December 31, 2015, for the one-year total stockholder return comparison, December 31, 2011, for the five-year total stockholder return comparison and December 31, 2006, for the 10-year total stockholder return comparison for MDU Resources, the S&P 500 and the peer group. Total stockholder return is calculated using the December 31 price for each year. It is assumed that all dividends are reinvested in stock at the frequency paid, and the returns of each component peer issuer of the group are weighted according to the issuer's stock market capitalization at the beginning of the period.

Peer group issuers are ALLETE, Inc., Alliant Energy Corporation, Atmos Energy Corporation, Avista Corporation, Black Hills Corporation, EMCOR Group, Inc., Granite Construction Incorporated, IDACORP, Inc., IES Holdings, Inc. (formerly Integrated Electrical Services, 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.

During 2016, Questar Corporation was merged with another company. As a result, the company was removed from the peer group for the entire period shown in the performance graphs.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____________ to _____________
Commission file number 1-3480

MDU RESOURCES GROUP, INC.

(Exact name of registrant as specified in its charter)

Delaware	41-0423660
(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:

Preferred Stock, par value $100
(Title of Class)

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No ☒.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐.

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐.

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act (Check one):

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

State the aggregate market value of the voting common stock held by nonaffiliates of the registrant as of June 30, 2016: $4,687,305,024.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of February 16, 2017: 195,304,376 shares.

DOCUMENTS INCORPORATED BY REFERENCE
Relevant portions of the registrant's 2017 Proxy Statement 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
ATBs	Atmospheric tower bottoms
BART	Best available retrofit technology
Bcf	Billion cubic feet
Bicent	Bicent Power LLC
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
BOE	One barrel of oil equivalent - determined using the ratio of one barrel of crude oil, condensate or natural gas liquids to six Mcf of natural gas
Brazilian Transmission Lines	Company's former investment in companies owning three electric transmission lines
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
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial'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.
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)
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
GVTC	Generation Verification Test Capacity
IBEW	International Brotherhood of Electrical Workers

ICWU	International Chemical Workers Union
IFRS	International Financial Reporting Standards
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
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
MBbls	Thousands of barrels
MBOE	Thousands of BOE
Mcf	Thousand cubic feet
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Mdk	Thousand 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
MEPP	Multiemployer pension plan
MISO	Midcontinent Independent System Operator, Inc.
MMBOE	Millions of BOE
MMBtu	Million Btu
MMcf	Million cubic feet
MMdk	Million dk
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
Montana DEQ	Montana Department of Environmental Quality
Montana Seventeenth Judicial District Court	Montana Seventeenth Judicial District Court, Phillips County
MPPAA	Multiemployer Pension Plan Amendments Act of 1980
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
NGL	Natural gas liquids
Oil	Includes crude oil and condensate
Omimex	Omimex Canada, Ltd.
OPUC	Oregon Public Utility Commission
Oregon DEQ	Oregon State Department of Environmental Quality
PCBs	Polychlorinated biphenyls
Pronghorn	Natural gas processing plant located near Belfield, North Dakota (WBI Energy Midstream previously held a 50 percent non-operating ownership interest)
Proxy Statement	Company's 2017 Proxy Statement
PRP	Potentially Responsible Party
PUD	Proved undeveloped
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
SEC Defined Prices	The average price of oil and natural gas during the applicable 12-month period, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions

Securities Act	Securities Act of 1933, as amended
Securities Act Industry Guide 7	Description of Property by Issuers Engaged or to be Engaged in Significant Mining Operations
Sheridan System	A separate electric system owned by Montana-Dakota
South Dakota DENR	South Dakota Department of Environment and Natural Resources
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan which was terminated effective December 5, 2016
Tesoro	Tesoro Refining & Marketing Company LLC
Tesoro Logistics	QEP Field Services, LLC doing business as Tesoro Logistics Rockies 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 District Court for the District of Montana	United States District Court for the District of Montana, Great Falls Division
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., an indirect 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 - Prospective Information.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including without limitation, management's examination of historical operating trends, data contained in the Company's records and other data available from third parties. Nonetheless, the Company's expectations, beliefs or projections may not be achieved or accomplished.

Any forward-looking statement contained in this document speaks only as of the date on which the statement is made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements in this Form 10-K, including statements contained within Item 1A - Risk Factors.

Items 1 and 2. Business and Properties

General

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

Montana-Dakota, Great Plains, Cascade and Intermountain comprise 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 comprised of the pipeline and midstream segment and Fidelity, formerly the Company's exploration and production business. 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.

In the second quarter of 2016, the Company sold all of the outstanding membership interests in Dakota Prairie Refining and exited that line of business. Therefore, the results of Dakota Prairie Refining are reflected in discontinued operations, other than certain general and administrative costs and interest expense which are reflected in the Other category.

In the second quarter of 2015, the Company announced its plan to market Fidelity and exit that line of business. The Company completed the sale of its oil and natural gas assets. Therefore, the results of Fidelity are reflected in discontinued operations, other than certain general and administrative costs and interest expense which are reflected in the Other category.

For more information on the Company's business segments and discontinued operations, see Item 8 - Notes 2 and 13.

As of December 31, 2016, the Company had 9,598 employees with 138 employed at MDU Resources Group, Inc., 1,030 at Montana-Dakota, 35 at Great Plains, 342 at Cascade, 236 at Intermountain, 342 at WBI Holdings, 3,099 at Knife River and 4,376 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, 2016.

At Montana-Dakota and WBI Energy Transmission, 359 and 68 employees, respectively, are represented by the IBEW. Labor contracts with such employees are in effect through April 30, 2018, and March 31, 2018, respectively.

At Cascade, 195 employees are represented by the ICWU. The labor contract with the field operations group is effective through March 31, 2018.

At Intermountain, 127 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 505 of its construction materials employees. Knife River is in negotiations on seven of its labor contracts.

MDU Construction Services has 142 labor contracts representing the majority of its employees. MDU Construction Services is in negotiations on five 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 13 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 17. 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.

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 142,948 residential, commercial, industrial and municipal customers in 178 communities and adjacent rural areas as of December 31, 2016. For more information on the customer classes served, see the table below. The principal properties owned by Montana-Dakota for use in its electric operations include interests in 13 electric generating facilities and three small portable diesel generators, as further described under System Supply, System Demand and Competition, approximately 3,100 and 4,800 miles of transmission and distribution lines, respectively, and 74 transmission and 316 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, 2016, Montana-Dakota's net electric plant investment was $1.3 billion, and the rate base was $1.0 billion.

Montana-Dakota's customers served and revenues by class are as follows:

	2016		2015		2014	
	Customers Served	**Revenues**	Customers Served	Revenues	Customers Served	Revenues
			(Dollars in thousands)			
Residential	**118,483**	**$ 117,014**	118,413	$ 107,767	115,164	$ 109,279
Commercial	**22,693**	**135,390**	22,423	121,463	21,890	118,026
Industrial	**244**	**31,913**	240	32,786	245	30,457
Other	**1,528**	**7,580**	1,511	6,791	1,497	6,750
	142,948	**$ 291,897**	142,587	$ 268,807	138,796	$ 264,512

The percentage of Montana-Dakota's retail electric utility operating revenues by jurisdiction is as follows:

	2016	2015	2014
North Dakota	**68%**	65%	64%
Montana	**19%**	21%	21%
Wyoming	**8%**	9%	10%
South Dakota	**5%**	5%	5%

Retail electric rates, service, accounting and certain security issuances are subject to regulation by the NDPSC, MTPSC, SDPUC and WYPSC. The interstate transmission and wholesale electric power operations of Montana-Dakota also are subject to regulation by the FERC under provisions of the Federal Power Act, as are interconnections with other utilities and power generators, the issuance of securities, accounting and other matters.

Through MISO, Montana-Dakota has access to wholesale energy, ancillary services and capacity markets for its 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, including Bismarck, Mandan, Dickinson, Williston and Watford City; eastern Montana, including Sidney, Glendive and Miles City; and northern South Dakota, including Mobridge. The maximum electric peak demand experienced to date attributable to Montana-Dakota's sales to retail customers on the interconnected system was 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 2021 will approximate two percent annually. The interconnected system consists of 12 electric generating facilities and three small portable diesel generators, which have an aggregate nameplate rating attributable to Montana-Dakota's interest of 704,143 kW and total net ZRCs of 521.0 in 2016. ZRCs are a MW of demand equivalent measure and are allocated to individual generators to meet planning reserve margin requirements within MISO. For 2016, Montana-Dakota's total ZRCs, including its firm purchase power contracts, were 559.7. Montana-Dakota's planning reserve margin requirement within MISO was 559.7 for 2016. Montana-Dakota's interconnected system electric generating capability includes five steam-turbine generating units at four facilities using coal for fuel, three combustion turbine peaking stations, three wind electric generating facilities, two reciprocating internal combustion engines at one facility, a heat recovery electric generating facility and three small portable diesel generators.

In June 2016, Montana-Dakota and a partner began building a 345-kilovolt transmission line within the footprint of MISO from Ellendale, North Dakota, to Big Stone City, South Dakota, a distance of about 160 miles, which will facilitate public policy goals and objectives, including delivery of renewable wind energy from North Dakota to eastern markets. The project has been approved as a MISO multivalue project. Approximately 97 percent of the necessary easements have been secured. The Company expects the project to be completed in 2019.

In December 2016, Montana-Dakota signed a 25-year agreement to purchase the power from a wind farm expansion in southwest North Dakota. The agreement also includes an option to buy the project at the close of construction. The expansion of the wind farm will boost the combined production at the wind farm to approximately 150 MW of renewable energy and will increase Montana-Dakota's nameplate generation portfolio from approximately 22 percent renewables to 27 percent. The original 107.5-MW wind farm includes 43 turbines; it was purchased by Montana-Dakota in December 2015. The expansion includes 13 to 16 turbines, depending on the turbine size selected. It is expected to be online in December 2018. Construction costs for the project are estimated to be $85 million. Additional energy will be purchased as needed, or if more economical, from the MISO market. In 2016, Montana-Dakota purchased approximately 26 percent of its net kWh needs for its interconnected system through the MISO market.

Through the Sheridan System, Montana-Dakota serves Sheridan, Wyoming, and neighboring communities. The maximum peak demand experienced to date attributable to Montana-Dakota sales to retail customers on that system was approximately 61,501 kW in July 2012. Montana-Dakota has a power supply contract with Black Hills Power, 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)	2016 ZRCs (a)	2016 Net Generation (kWh in thousands)
Interconnected System:				
North Dakota:				
Coyote (b)	Steam	103,647	80.6	615,730
Heskett	Steam	86,000	87.3	458,788
Heskett	Combustion Turbine	89,038	57.0	2,868
Glen Ullin	Heat Recovery	7,500	4.2	39,383
Cedar Hills	Wind	19,500	4.9	60,790
Diesel Units	Oil	5,475	3.8	9
Thunder Spirit	Wind	107,500	17.2	427,960
South Dakota:				
Big Stone (b)	Steam	94,111	99.7	440,834
Montana:				
Lewis & Clark	Steam	44,000	51.9	261,058
Lewis & Clark	Reciprocating Internal Combustion Engine	18,700	14.1	11,918
Glendive	Combustion Turbine	75,522	72.5	6,277
Miles City	Combustion Turbine	23,150	21.6	712
Diamond Willow	Wind	30,000	6.2	100,119
		704,143	521.0	2,426,446
Sheridan System:				
Wyoming:				
Wygen III (b)	Steam	28,000	N/A	200,317
		732,143	521.0	2,626,763

(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 2017, 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 17.

The owners of Big Stone Station, including Montana-Dakota, have coal supply agreements, which meet a portion of the Big Stone Station's fuel requirements, for the purchase of 750,000 tons in 2017 from Alpha Coal Sales Co., LLC at contracted pricing. The remainder of the Big Stone Station fuel requirements will be secured through separate future contracts.

Montana-Dakota has a coal supply agreement with Wyodak Resources Development Corp., 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,		2016		2015		2014
Average cost of coal per MMBtu	**$**	**1.89**	$	1.75	$	1.74
Average cost of coal per ton	**$**	**27.45**	$	25.41	$	25.11

Montana-Dakota expects that it has secured adequate capacity available through existing baseload generating stations, renewable generation, turbine peaking stations, demand reduction programs and firm contracts to meet the peak customer demand requirements of its customers through mid-2022. Future capacity that is needed to replace contracts and meet system growth requirements is expected to be met by constructing new generation resources, or acquiring additional capacity through power purchase contracts or the MISO capacity auction. For more information regarding potential power generation projects, see Item 7 - MD&A - Prospective Information - Electric and natural gas distribution.

Montana-Dakota has major interconnections with its neighboring utilities and considers these interconnections adequate for coordinated planning, emergency assistance, exchange of capacity and energy and power supply reliability.

Montana-Dakota is subject to competition in varying degrees, in certain areas, from rural electric cooperatives, on-site generators, co-generators and municipally owned systems. In addition, competition in varying degrees exists between electricity and alternative forms of energy such as natural gas.

Regulatory Matters and Revenues Subject to Refund In North Dakota, Montana-Dakota's results of operations reflect monthly increases or decreases in fuel and purchased power costs (including demand charges) and is deferring those electric fuel and purchased power costs that are greater or less than amounts presently being recovered through its existing rate schedules. In Montana, a monthly Fuel and Purchased Power Tracking Adjustment mechanism allows Montana-Dakota's results of operations to reflect 90 percent of the increases or decreases in fuel and purchased power costs (including demand charges) and Montana-Dakota is deferring 90 percent of costs that are greater or less than amounts presently being recovered through its existing rate schedules. A fuel adjustment clause contained in South Dakota jurisdictional electric rate schedules allows Montana-Dakota's results of operations to reflect monthly increases or decreases in fuel and purchased power costs (excluding demand charges). In Wyoming, an annual Electric Power Supply Cost Adjustment mechanism allows Montana-Dakota'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. As of March 1, 2017, Montana-Dakota's results of operations will reflect 95 percent of the increases or decreases from the base purchased power costs and in addition will also reflect 85 percent of the increases or decreases from the base coal price, which will also be recovered through the Electric Power Supply Cost Adjustment. For more information, see Item 8 - Note 4.

In North Dakota, Montana-Dakota recovers in rates the costs associated with environmental upgrades at Big Stone Station and Lewis & Clark Station. Montana-Dakota will maintain a tracker account until all costs are recovered or until the associated costs are reflected in base rates as a part of a general rate case.

In North Dakota, Montana-Dakota has the ability to recover the costs associated with new generation through a rider mechanism. Montana-Dakota will utilize this rider mechanism for new generation until such time as the costs and investment are included in base rates. For the Thunder Spirit Wind project, Montana-Dakota implemented a renewable resource cost adjustment rider. 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 systems serving Montana-Dakota, 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 systems serving Montana-Dakota, along with certain of the transmission investments not recovered through retail rates. The tracking mechanism has an annual true-up.

For more information on regulatory matters, see Item 8 - Note 16.

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 Big Stone Station was submitted timely to the South Dakota DENR in November 2013. Big Stone Station continues to operate under conditions of the Title V Operating Permit issued by the South Dakota DENR in June 2009. It is expected that a final renewed permit will be issued in 2017 as the South Dakota DENR incorporates the completed BART air quality control system into the permit. 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 2017. An application to modify the Title V Operating Permit for incorporation of two new natural gas-fired engines at Lewis & Clark Station was submitted to the Montana DEQ timely in December 2016, with a final permit expected to be issued in 2017. The Title V Operating Permit applications for the Miles City and Glendive stations were submitted timely in 2016 and final permits were issued by the Montana DEQ for each facility in August 2016 and July 2016, respectively.

State water discharge permits issued under the requirements of the Clean Water Act are maintained for power production facilities on the Yellowstone and Missouri rivers. These permits also have five-year lives. Montana-Dakota renews these permits as necessary prior to expiration. Other permits held by these facilities may include an initial siting permit, which is typically a one-time, preconstruction permit issued by the state; state permits to dispose of combustion by-products; state authorizations to withdraw water for operations; and Army Corps permits to construct water intake structures. Montana-Dakota's Army Corps permits grant one-time permission to construct and do not require renewal. Other permit terms vary and the permits are renewed as necessary.

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

Montana-Dakota incurred $14.2 million of environmental capital expenditures in 2016, mainly for ash management projects at Lewis & Clark Station and air emission control projects at Heskett Station and Coyote Station. Environmental capital expenditures are estimated to be $3.5 million, $9.0 million and $6.5 million in 2017, 2018 and 2019, respectively, for various environmental upgrades and improvements for air emission and water and coal ash management at power plants. Montana-Dakota's capital and operational expenditures could also be affected by future air emission regulations and coal ash management requirements, including the Clean Power Plan rule published by the EPA in October 2015. The Clean Power Plan requires existing fossil fuel-fired electric generation facilities to reduce carbon dioxide emissions. Montana-Dakota is evaluating the Clean Power Plan and has not included estimates for capital expenditures in 2017 through 2019 for potential compliance requirements. On February 9, 2016, 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.

Natural Gas Distribution

General The Company's natural gas distribution operations consist of Montana-Dakota, Great Plains, Cascade and Intermountain, which sell natural gas at retail, serving 922,408 residential, commercial and industrial customers in 335 communities and adjacent rural areas across eight states as of December 31, 2016, and provide natural gas transportation services to certain customers on the Company's systems. For more information on the 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, 2016, the natural gas distribution operations' net natural gas distribution plant investment was $1.5 billion, and the rate base was $868 million.

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

	2016		2015		2014	
	Customers Served	**Revenues**	Customers Served	Revenues	Customers Served	Revenues
	(Dollars in thousands)					
Residential	**818,163**	**$ 429,828**	803,846	$ 455,301	791,870	$ 513,373
Commercial	**103,438**	**253,333**	101,688	277,022	100,288	324,203
Industrial	**807**	**23,337**	811	26,568	756	30,917
	922,408	**$ 706,498**	906,345	$ 758,891	892,914	$ 868,493

The percentage of the natural gas distribution operations' natural gas utility operating sales revenues by jurisdiction is as follows:

	2016	2015	2014
Idaho	**34%**	32%	29%
Washington	**26%**	26%	25%
North Dakota	**13%**	15%	16%
Montana	**8%**	8%	9%
Oregon	**8%**	8%	8%
South Dakota	**6%**	6%	7%
Minnesota	**3%**	3%	4%
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, including Boise, Nampa, Twin Falls, Pocatello and Idaho Falls; western Minnesota, including Fergus Falls, Marshall and Crookston; eastern Montana, including Billings, Glendive and Miles City; North Dakota, including Bismarck, Mandan, Dickinson, Wahpeton, Williston, Watford City, Minot and Jamestown; central and eastern Oregon, including Bend, Pendleton, Ontario and Baker City; western and north-central South Dakota, including Rapid City, Pierre, Spearfish and Mobridge; western, southeastern and south-central Washington, including Bellingham, Bremerton, Longview, Aberdeen, Wenatchee/ Moses Lake, Mount Vernon, Tri-Cities, Walla Walla and Yakima; and northern Wyoming, including Sheridan and Lovell. 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, 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, Questar Pipeline Company, 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.

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 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. The decoupling mechanism will reflect the period October 1 through September 30 with the first adjustment to be billed to customers effective December 1 each year for the 3 year pilot project.

For more information on regulatory matters, see Item 8 - Note 16.

Environmental Matters The natural gas distribution operations are subject to federal, state and local environmental, facility-siting, zoning and planning laws and regulations. The natural gas distribution operations believe they are in substantial compliance with those regulations.

The Company's natural gas distribution operations are conditionally exempt small-quantity hazardous waste generators and subject only to minimum regulation under the RCRA. Certain locations of the natural gas distribution operations routinely handle PCBs from their natural gas operations in accordance with federal requirements. PCB storage areas are registered with the EPA as required. Capital and operational expenditures for natural gas distribution operations could be affected in a variety of ways by potential new GHG legislation or regulation. In particular, such legislation or regulation would likely increase capital expenditures for energy efficiency and conservation programs and operational costs associated with GHG emissions compliance. Natural gas distribution operations expect to recover the operational and capital expenditures for GHG regulatory compliance in rates consistent with the recovery of other reasonable costs of complying with environmental laws and regulations.

The natural gas distribution operations did not incur any material environmental expenditures in 2016. 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 2019.

Montana-Dakota and Great Plains have 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 will seek recovery in its natural gas rates charged to customers for any 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 17 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 transmission, gathering and storage lines in Montana, North Dakota, South Dakota and Wyoming. Three underground storage fields in Montana and Wyoming provide storage services to local distribution companies, 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 13 interconnecting points with other pipeline facilities allowing for the receipt and/or delivery of natural gas to and from other regions of the country and from Canada. Under the Natural Gas Act, as amended, WBI Energy Transmission is subject to the jurisdiction of the FERC regarding certificate, rate, service and accounting matters, and at December 31, 2016, its net plant investment was $388.0 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, contract compression operations, measurement services, and energy efficiency product sales and installation services to large end-users. In November 2016, the Company entered into an agreement to sell its ownership in the Pronghorn assets, which included a 50 percent undivided interest in a natural gas processing plant, both oil and gas gathering pipelines, an oil storage terminal and an oil pipeline in western North Dakota. The transaction closed in January 2017.

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

For information regarding natural gas gathering operations litigation, see Item 8 - Note 17.

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 will continue to look for opportunities to increase transportation, gathering and storage services through system expansion and/or other pipeline interconnections or enhancements that could provide substantial future benefits.

WBI Energy Transmission's underground natural gas storage facilities have a certificated storage capacity of approximately 353 Bcf, including 193 Bcf of working gas capacity, 85 Bcf of cushion gas and 75 Bcf of native gas. These storage facilities enable customers to purchase natural gas throughout the year and meet winter peak requirements.

WBI Energy Transmission competes with several pipelines for its customers' transportation, storage and gathering business and at times may discount rates in an effort to retain market share. However, the strategic location of its system near five natural gas producing basins and the availability of underground storage and gathering services, along with interconnections with other pipelines, serve to enhance its competitive position.

Although certain of WBI Energy Transmission's firm customers, including its largest firm customer Montana-Dakota, serve relatively secure residential and commercial end-users, they generally all have some price-sensitive end-users that could switch to alternate fuels.

WBI Energy Transmission transports substantially all of Montana-Dakota's natural gas, primarily utilizing firm transportation agreements, which for 2016 represented 39 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 with several midstream companies for existing customers, the expansion of its systems and the installation of new systems. Its strong position in the fields in which it operates, its focus on customer service and the variety of services it offers, along with its interconnection with various other pipelines, serve to enhance its competitive position.

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 2016 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2019.

Construction Materials and Contracting

General Knife River operates construction materials and contracting businesses headquartered in Alaska, California, Hawaii, Idaho, Iowa, Minnesota, Montana, North Dakota, Oregon, Texas, Washington and Wyoming. These operations mine, process and sell construction aggregates (crushed stone, sand and gravel); produce and sell asphalt mix and supply ready-mixed concrete for use in most types of construction, including roads, freeways and bridges, as well as homes, schools, shopping centers, office buildings and industrial parks. Although not common to all locations, other products include the sale of cement, liquid asphalt for various commercial and roadway applications, various finished concrete products and other building materials and related contracting services.

The construction materials business had approximately $538 million in backlog at December 31, 2016, compared to $491 million at December 31, 2015. The Company anticipates that a significant amount of the current backlog will be completed during 2017.

Competition Knife River's construction materials products are marketed under highly competitive conditions. Price is the principal competitive force to which these products are subject, with service, quality, delivery time and proximity to the customer also being significant factors. The number and size of competitors varies in each of Knife River's principal market areas and product lines.

The demand for construction materials products is significantly influenced by the cyclical nature of the construction industry in general. In addition, construction materials activity in certain locations may be seasonal in nature due to the effects of weather. The key economic factors affecting product demand are changes in the level of local, state and federal governmental spending, general economic conditions within the market area that influence both the commercial and residential sectors, and prevailing interest rates.

Knife River is not dependent on any single customer or group of customers for sales of its products and services, the loss of which would have a material adverse effect on its construction materials businesses.

Reserve Information Aggregate reserve estimates are calculated based on the best available data. This data is collected from drill holes and other subsurface investigations, as well as investigations of surface features such as mine high walls and other exposures of the aggregate reserves. Mine plans, production history and geologic data also are utilized to estimate reserve quantities. Most acquisitions are made of mature businesses with established reserves, as distinguished from exploratory-type properties.

Estimates are based on analyses of the data described above by experienced internal mining engineers, operating personnel and geologists. Property setbacks and other regulatory restrictions and limitations are identified to determine the total area available for mining. Data described previously are used to calculate the thickness of aggregate materials to be recovered. Topography associated with alluvial sand and gravel deposits is typically flat and volumes of these materials are calculated by applying the thickness of the resource over the areas available for mining. Volumes are then converted to tons by using an appropriate conversion factor. Typically, 1.5 tons per cubic yard in the ground is used for sand and gravel deposits.

Topography associated with the hard rock reserves is typically much more diverse. Therefore, using available data, a final topography map is created and computer software is utilized to compute the volumes between the existing and final topographies. Volumes are then converted to tons by using an appropriate conversion factor. Typically, 2 tons per cubic yard in the ground is used for hard rock quarries.

Estimated reserves are probable reserves as defined in Securities Act Industry Guide 7. Remaining reserves are based on estimates of volumes that can be economically extracted and sold to meet current market and product applications. The reserve estimates include only salable tonnage and thus exclude waste materials that are generated in the crushing and processing phases of the operation. Approximately 911 million tons of the 989 million tons of aggregate reserves are permitted reserves. The remaining reserves are on properties that are expected to be permitted for mining under current regulatory requirements. The data used to calculate the remaining reserves may require revisions in the future to account for changes in customer requirements and unknown geological occurrences. The years remaining were calculated by dividing remaining reserves by the three-year average sales from 2014 through 2016. 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, 2016, and sales for the years ended December 31, 2016, 2015 and 2014:

	Number of Sites (Crushed Stone)		Number of Sites (Sand & Gravel)		Tons Sold (000's)			Estimated Reserves (000's tons)	Lease Expiration	Reserve Life (years)
Production Area	owned	leased	owned	leased	**2016**	2015	2014			
Anchorage, AK	—	—	1	—	**1,343**	1,837	1,665	15,972	N/A	10
Hawaii	—	6	—	—	**1,901**	1,892	1,840	52,091	2017-2064	28
Northern CA	—	—	9	1	**1,604**	1,580	1,340	46,411	2018	31
Southern CA	—	2	—	—	**224**	118	147	91,622	2035	Over 100
Portland, OR	1	3	5	3	**4,044**	3,562	3,244	217,712	2025-2055	60
Eugene, OR	3	4	7	—	**662**	819	928	155,090	2021-2046	Over 100
Central OR/WA/ID	—	1	6	2	**1,685**	1,493	1,254	88,467	2020-2077	60
Southwest OR	5	6	11	7	**2,689**	1,872	1,624	102,151	2017-2053	50
Central MT	—	—	3	2	**1,135**	1,383	1,260	29,310	2023-2027	23
Northwest MT	—	—	8	2	**1,514**	1,423	1,486	66,287	2017-2020	45
Wyoming	—	—	1	2	**742**	888	952	9,988	2019	12
Central MN	—	1	37	12	**2,831**	2,556	1,674	52,087	2017-2028	22
Northern MN	2	—	14	7	**537**	595	491	24,887	2017-2021	46
ND/SD	—	—	2	22	**1,643**	1,959	2,377	26,108	2017-2031	13
Texas	1	2	1	—	**1,243**	1,138	903	10,901	2022-2029	10
Sales from other sources					**3,783**	3,844	4,642			
					27,580	26,959	25,827	989,084		

The 989 million tons of estimated aggregate reserves at December 31, 2016, are comprised of 467 million tons that are owned and 522 million tons that are leased. Approximately 31 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 21 years, including options for renewal that are at Knife River's discretion. Based on a three-year average of sales from 2014 through 2016 of leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 52 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:

	2016	2015	2014
		(000's of tons)	
Aggregate reserves:			
Beginning of year	**1,022,513**	1,061,156	1,083,376
Acquisitions	**24,993**	7,406	12,343
Sales volumes*	**(23,797)**	(23,115)	(21,185)
Other**	**(34,625)**	(22,934)	(13,378)
End of year	**989,084**	1,022,513	1,061,156

* Excludes sales from other sources.
** 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 Clean Air Act and Clean Water Act requirements for controlling air emissions and water discharges. Some mining and construction activities also are subject to these laws. In most of the states where Knife River operates, these regulatory programs have been delegated to state and local regulatory authorities. Knife River's facilities also are subject to 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 operates several such operations, including gravel bar skimming and dredging operations, and Knife River has the associated permits as required. The expiration dates of these permits vary, with five years generally being the longest term.

Knife River's operations also are occasionally subject to the ESA. For example, land use regulations often require environmental studies, including wildlife studies, before a permit may be granted for a new or expanded mining facility or an asphalt or concrete plant. If endangered species or their habitats are identified, ESA requirements for protection, mitigation or avoidance apply. Endangered species protection requirements are usually included as part of land use permit conditions. Typical conditions include avoidance, setbacks, restrictions on operations during certain times of the breeding or rearing season, and construction or purchase of mitigation habitat. Knife River's operations also are subject to state and federal cultural resources protection laws when new areas are disturbed for mining operations or processing plants. Land use permit applications generally require that areas proposed for mining or other surface disturbances be surveyed for cultural resources. If any are identified, they must be protected or managed in accordance with regulatory agency requirements.

The most comprehensive environmental permit requirements are usually associated with new mining operations, although requirements vary widely from state to state and even within states. In some areas, land use regulations and associated permitting requirements are minimal. However, some states and local jurisdictions have very demanding requirements for permitting new mines. Environmental impact reports are sometimes required before a mining permit application can even be considered for approval. These reports can take up to several years to complete. The report can include projected impacts of the proposed project on air and water quality, wildlife, noise levels, traffic, scenic vistas and other environmental factors. The reports generally include suggested actions to mitigate the projected adverse impacts.

Provisions for public hearings and public comments are usually included in land use permit application review procedures in the counties where Knife River operates. After taking into account environmental, mine plan and reclamation information provided by the permittee as well as comments from the public and other regulatory agencies, the local authority approves or denies the permit application. Denial is rare, but land use permits often include conditions that must be addressed by the permittee. Conditions may include property line setbacks, reclamation requirements, environmental monitoring and reporting, operating hour restrictions, financial guarantees for reclamation, and other requirements intended to protect the environment or address concerns submitted by the public or other regulatory agencies.

Knife River has been successful in obtaining mining and other land use permit approvals so 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 2016 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 2019.

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 17.

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 utility construction services specializing in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization. This segment also provides utility excavation and inside electrical and mechanical services, and manufactures and distributes transmission line construction equipment and other supplies. These services are provided to utilities and large manufacturing, commercial, industrial, institutional and government customers.

Construction and maintenance crews are active year round. However, activity in certain locations may be seasonal in nature due to the effects of weather.

MDU Construction Services operates a fleet of owned and leased trucks and trailers, support vehicles and specialty construction equipment, such as backhoes, excavators, trenchers, generators, boring machines and cranes. In addition, as of December 31, 2016, MDU Construction Services owned or leased facilities in 16 states. This space is used for offices, equipment yards, manufacturing, warehousing, storage and vehicle shops.

MDU Construction Services' backlog is comprised of the uncompleted portion of services to be performed under job-specific contracts. The backlog at December 31, 2016, was approximately $475 million compared to $493 million at December 31, 2015. MDU Construction Services expects to complete a significant amount of this backlog during 2017. Due to the nature of its contractual arrangements, in many instances MDU Construction Services' customers are not committed to the specific volumes of services to be purchased under a contract, but rather MDU Construction Services is committed to perform these services if and to the extent requested by the customer. Therefore, there can be no assurance as to the customers' requirements during a particular period or that such estimates at any point in time are predictive of future revenues.

MDU Construction Services works with the National Electrical Contractors Association, the IBEW and other trade associations on hiring and recruiting a qualified workforce.

Competition MDU Construction Services operates in a highly competitive business environment. Most of MDU Construction Services' work is obtained on the basis of competitive bids or by negotiation of either cost-plus or fixed-price contracts. The workforce and equipment are highly mobile, providing greater flexibility in the size and location of MDU Construction Services' market area. Competition is based primarily on price and reputation for quality, safety and reliability. The size and location of the services provided, as well as the state of the economy, will be factors in the number of competitors that MDU Construction Services will encounter on any particular project. MDU Construction Services believes that the diversification of the services it provides, the markets it serves throughout the United States and the management of its workforce will enable it to effectively operate in this competitive environment.

Utilities and independent contractors represent the largest customer base for this segment. Accordingly, utility and subcontract work accounts for a significant portion of the work performed by MDU Construction Services and the amount of construction contracts is dependent to a certain extent on the level and timing of maintenance and construction programs undertaken by customers. MDU Construction Services relies on repeat customers and strives to maintain successful long-term relationships with these customers.

Environmental Matters MDU Construction Services' operations are subject to regulation customary for the industry, including federal, state and local environmental compliance. MDU Construction Services believes it is in substantial compliance with these regulations.

The nature of MDU Construction Services' operations is such that few, if any, environmental permits are required. Operational convenience supports the use of petroleum storage tanks in several locations, which are permitted under state programs authorized by the EPA. MDU Construction Services has no ongoing remediation related to releases from petroleum storage tanks. MDU Construction Services' operations are conditionally exempt small-quantity waste generators, subject to minimal regulation under the RCRA. Federal permits for specific construction and maintenance jobs that may require these permits are typically obtained by the hiring entity, and not by MDU Construction Services.

MDU Construction Services did not incur any material environmental expenditures in 2016 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2019.

Discontinued Operations

General Discontinued operations includes the results of Dakota Prairie Refining and Fidelity other than certain general and administrative costs and interest expense. In the second quarter of 2016, the Company sold all of the outstanding membership interests in Dakota Prairie Refining. Between September 2015 and March 2016, the Company entered into purchase and sale agreements to sell all of Fidelity's oil and natural gas assets. The completion of these sales occurred between October 2015 and April 2016. For more information on discontinued operations, see Item 8 - Note 2 and Supplementary Financial Information.

Item 1A. Risk Factors

The Company's business and financial results are subject to a number of risks and uncertainties, including those set forth below and in other documents that it files with the SEC. The factors and the other matters discussed herein are important factors that could cause actual results or outcomes for the Company to differ materially from those discussed in the forward-looking statements included elsewhere in this document.

Economic Risks

The Company's pipeline and midstream business is dependent on factors, including commodity prices and commodity price basis differentials, that are subject to various external influences that cannot be controlled.

These factors include: fluctuations in oil, NGL and natural gas production and prices; fluctuations in commodity price basis differentials; domestic and foreign supplies of oil, NGL and natural gas; political and economic conditions in oil producing countries; actions of the Organization of Petroleum Exporting Countries; and other risks incidental to the development and operations of natural gas pipeline systems. Continued prolonged depressed prices for oil, NGL and natural gas could impede the growth of the pipeline and midstream business, and could negatively affect the results of operations, cash flows and asset values of the Company's pipeline and midstream business.

The regulatory approval, permitting, construction, startup and/or operation of pipelines and power generation and transmission facilities may involve unanticipated events or delays that could negatively impact the Company's business and its results of operations and cash flows.

The construction, startup and operation of 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.

Economic volatility, including volatility in North Dakota's Bakken region, affects the Company's operations, as well as the demand for its products and services and the value of its investments and investment returns including its pension and other postretirement benefit plans, and may have a negative impact on the Company's future revenues and cash flows.

The global demand and price volatility for natural resources, interest rate changes, governmental budget constraints and the ongoing threat of terrorism can create volatility in the financial markets. Unfavorable economic conditions can negatively affect the level of public and private expenditures on projects and the timing of these projects which, in turn, can negatively affect the demand for the Company's products and services, primarily at the Company's construction businesses. The level of demand for construction products and services could be adversely impacted by the economic conditions in the industries the Company serves, as well as in the economy in general. State and federal budget issues may negatively affect the funding available for infrastructure spending. The ability of the Company's electric and natural gas distribution businesses to grow service territory and customer base is affected by the economic environments of the markets served. This economic volatility could have a material adverse effect on the Company's results of operations, cash flows and asset values.

Changing market conditions could negatively affect the market value of assets held in the Company's pension and other postretirement benefit plans and may increase the amount and accelerate the timing of required funding contributions.

The Company relies on financing sources and capital markets. Access to these markets may be adversely affected by factors beyond the Company's control. If the Company is unable to obtain cost effective financing in the future, the Company's ability to execute its business plans, make capital expenditures or pursue acquisitions that the Company may otherwise rely on for future growth could be impaired. As a result, the market value of the Company's common stock may be adversely affected. If the Company issues a substantial amount of common stock it could have a dilutive effect on its existing shareholders.

The Company relies on access to short-term borrowings, including the issuance of commercial paper, long-term capital markets and asset sales as sources of liquidity for capital requirements not satisfied by its cash flow from operations. If the Company is not able to access capital at competitive rates, the ability to implement its business plans may be adversely affected. Market disruptions or a downgrade of the Company's credit ratings may increase the cost of borrowing or adversely affect its ability to access one or more financial markets. Such disruptions could include:

- A 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

Economic turmoil, market disruptions and volatility in the securities trading markets, as well as other factors including changes in the Company's results of operations, financial position and prospects, may adversely affect the market price of the Company's common stock.

The 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, may adversely affect the market price of the Company's common stock.

***The Company is exposed to credit risk and the risk of loss resulting from the nonpayment and/or nonperformance by the Company's customers and counterparties*.**

If the Company's customers or counterparties were to experience financial difficulties or file for bankruptcy, the Company could experience difficulty in collecting receivables. The nonpayment and/or nonperformance by the Company's customers and counterparties could have a negative impact on the Company's results of operations and cash flows.

The backlogs at the Company's construction materials and contracting and construction services businesses are subject to delay or cancellation and may not be realized.

Backlog consists of the uncompleted portion of services to be performed under job-specific contracts. Contracts are subject to delay, default or cancellation and the contracts in the Company's backlog are subject to changes in the scope of services to be provided as well as adjustments to the costs relating to the applicable contracts. Backlog may also be affected by project delays or cancellations resulting from weather conditions, external market factors and economic factors beyond the Company's control. Accordingly, there is no assurance that backlog will be realized.

Environmental and Regulatory Risks

The Company's operations are subject to environmental laws and regulations that may increase costs of operations, impact or limit business plans, or expose the Company to environmental liabilities.

The Company is subject to environmental laws and regulations affecting many aspects of its operations, including laws and regulations regarding 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. These laws and regulations generally require the Company to obtain and comply with a variety of environmental licenses, permits, inspections and other approvals. Although the Company strives to comply with all applicable environmental laws and regulations, public and private entities 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. The rule requires ground water and location restriction evaluations to be conducted by October 2017 at ash impoundments and landfills not located at coal mines. In 2015, one ash impoundment at Lewis & Clark Station was replaced with a new concrete basin. Additional site and groundwater analyses may identify the need to upgrade or close additional impoundments or the Company may need to install replacement ash management systems. The cost of replacement ash impoundments or landfills may be material. If these costs are not fully recoverable from customers, they could have a material adverse effect on the Company's results of operations and cash flows.

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 Company's primary GHG emission is carbon dioxide from fossil fuels combustion at Montana-Dakota's electric generating facilities, particularly its coal-fired facilities. Approximately 50 percent of Montana-Dakota's owned generating capacity and approximately 75 percent of the electricity it generated in 2016 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. As published, the rule required that by September 6, 2016, states submit to the EPA either a request for a two-year extension to submit a final state plan or a final plan demonstrating how emissions reductions will be achieved including emission limits in the form of an annual emission cap or an emission rate that will be applied to each fossil fuel-fired electric generating facility within the state starting in 2022. Emissions limits become more stringent from 2022 to 2030, with the 2030 emission limits applying thereafter. It is unknown at this time what each state will require for emissions limits or reductions from each of Montana-Dakota's owned and jointly owned fossil fuel-fired electric generating units. Compliance costs will become clearer as final state plans are submitted to the EPA. The effective date and compliance dates in the rule are expected to be addressed in a future decision made by the United States Supreme Court.

On January 14, 2015, the federal government of the United States announced a goal to reduce methane emissions from the oil and natural gas industry by 40 percent 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. The rule impacts new and modified natural gas gathering and boosting stations and transmission and storage compressor stations. WBI Energy is developing implementation plans for complying with the rule. 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 gather information on existing sources of methane emissions, technologies to reduce emissions and the costs of those technologies in the oil and natural gas industry. Several companies, including WBI Energy, were selected to respond to the Information Collection Request. The information collected will be used to develop comprehensive regulations to reduce methane emissions from existing sources. It is unknown at this time how the Company will be impacted or if compliance costs will be material.

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 assert that the Washington DOE undertook this rulemaking without the requisite statutory authority. The Thurston County Superior Court is scheduled to hear oral arguments on April 14, 2017, while litigation in the United States District Court for the Eastern District of Washington has been held in abeyance until there is a ruling in the Thurston County Superior Court.

Additional treaties, legislation or regulations to reduce GHG emissions may be adopted that affect the Company's utility operations by requiring additional energy conservation efforts or renewable energy sources, 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 Company's 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.

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.

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 is subject to regulation or governmental actions by federal, state and local regulatory agencies with respect to, among other things, allowed rates of return and recovery of investment and cost, financing, rate structures, health care coverage and cost, taxes, franchises and recovery of purchased power and purchased gas costs. These governmental regulations significantly influence the Company's operating environment and may affect its ability to recover costs from its customers. The Company is unable to predict the impact on operating results from the future regulatory activities of any of these agencies. Changes in regulations or the imposition of additional regulations could have an adverse impact on the Company's results of operations and cash flows. Approval from a number of federal and state regulatory agencies would need to be obtained by any potential acquirer of the Company as well as for acquisitions by the Company. The approval process could be lengthy and the outcome uncertain.

The Company's electric and natural gas transmission and distribution operations involve risks that may result in accidents. These events and pipeline safety regulation costs could adversely affect the Company's business and its results of operations and cash flows.

The Company's electric and natural gas transmission and distribution activities include a variety of operating risks, such as leaks, explosions and mechanical problems, which could result in loss of human life, personal injury, property damage, environmental pollution, impairment of operations and substantial losses. The Company maintains insurance against some, but not all, of these risks and losses. The occurrence of these losses not fully covered by insurance could have a material effect on the Company's financial position, results of operations and cash flows.

Additionally, the operating or other costs that may be 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 issues 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 Company's results of operations and cash flows.

Other Risks

Weather conditions 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, affect the price of energy commodities, affect the ability to perform services at the construction materials and contracting and construction services businesses and affect ongoing operation and maintenance and construction activities for the pipeline and midstream business. In addition, severe weather can be destructive, causing outages, and/or property damage, which could require additional costs to be incurred. As a result, adverse weather conditions could negatively affect the Company's results of operations, financial position and cash flows.

Competition exists in all of the Company's businesses.

All of 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 such competitive forces as price, service, delivery time and proximity to the customer. The electric utility and natural gas industries also are experiencing increased competitive pressures as a result of consumer demands, technological advances and other factors. The pipeline and midstream business competes with several pipelines for access to natural gas supplies and gathering, transportation and storage business. Competition could negatively affect the Company's results of operations, financial position and cash flows.

The Company could be subject to limitations on its ability to pay dividends.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on its common stock. Regulatory, contractual and legal limitations, as well as capital requirements and the Company's financial performance or cash flows, could limit the earnings of the Company's divisions and subsidiaries which, in turn, could restrict the Company's ability to pay dividends on its common stock and adversely affect the Company's stock price.

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 75 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 35 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 participants 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, government regulations and the actual return on assets held in the plans, among others. The Company may experience increased operating expenses as a result of the required contributions to MEPPs, which may have a material adverse effect on the Company's results of operations, financial position or cash flows.

In addition, pursuant to ERISA, as amended by MPPAA, the Company could incur a partial or complete withdrawal liability upon withdrawing from a plan, exiting a market in which it does business with a union workforce or upon termination of a plan to the extent these plans are underfunded. The Company could also incur additional withdrawal liability if its withdrawal from a plan is determined by that plan to be part of a mass withdrawal.

The Company's operations may be negatively impacted by cyberattacks or acts of terrorism.

The Company operates in industries that require continual operation of sophisticated information technology systems and network infrastructure. While the Company has developed procedures and processes that are designed to strengthen and protect these systems, they may be vulnerable to failures or unauthorized access due to hacking, theft, sabotage, viruses, acts of terrorism, acts of war or other causes. If the technology systems were to fail or be breached and these systems were not recovered in a timely manner, the Company's operational systems and infrastructure, such as the Company's electric generation, transmission and distribution facilities and its natural gas storage and pipeline systems, may be unable to fulfill critical business functions, including an inability to generate or distribute some part of our energy services and other products to customers. Such disruption could result in decreased revenues and/or significant remediation costs which could have a material adverse effect on the Company's results of operations, financial position and cash flows. Additionally, because electric generation and transmission systems and natural gas pipelines are part of an interconnected system with other operators, a disruption elsewhere in the system could negatively impact the Company's business.

The Company's business requires access to sensitive customer, employee and Company data in the ordinary course of business. Despite the Company's implementation of security measures, a failure or breach of a security system could compromise sensitive data. Such an event could result in negative publicity and reputational harm, remediation costs and possible legal claims and fines which could adversely affect the Company's financial results. The Company's third-party service providers that perform critical business functions or have access to sensitive information may also be vulnerable to security breaches and other risks that could have an adverse effect on the Company.

The Company may be subject to potential material liabilities relating to the past sale of assets or businesses, primarily arising from events prior to sale.

The Company previously sold its oil and natural gas assets and its membership interests in Dakota Prairie Refining. The Company may be subject to potential liabilities, either directly or through indemnification of the buyers or others, relating to these transactions or other sales, primarily arising from events prior to the sale, or from breaches of any representations, warranties or covenants in the purchase and sale agreements.

Other factors that could impact the Company's businesses.

The following are other factors that should be considered for a better understanding of the financial condition of the Company. These other factors may impact the Company's financial results in future periods.

- Acquisition, disposal and impairments of assets or facilities
- Changes in operation, performance and construction of plant facilities or other assets
- Changes in present or prospective generation
- The ability to obtain adequate and timely cost recovery for the Company's regulated operations through regulatory proceedings
- The availability of economic expansion or development opportunities
- Population growth rates and demographic patterns
- Market demand for, available supplies of, and/or costs of, energy- and construction-related products and services
- The cyclical nature of large construction projects at certain operations
- Changes in tax rates, policies or tax reform
- 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
- The ability to effectively integrate the operations and the internal controls of acquired companies
- The ability to attract and retain skilled labor and key personnel
- Increases in employee and retiree benefit costs and funding requirements

Item 1B. Unresolved Staff Comments

The Company has no unresolved comments with the SEC.

Item 3. Legal Proceedings

For information regarding legal proceedings, see Item 8 - Note 17, which is incorporated herein by reference.

Item 4. Mine Safety Disclosures

For information regarding mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Act and Item 104 of Regulation S-K, see Exhibit 95 to this Form 10-K, which is incorporated herein by reference.

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

The Company's common stock is listed on the New York Stock Exchange under the symbol "MDU." The price range of the Company's common stock as reported by The Wall Street Journal composite tape during 2016 and 2015 and dividends declared thereon were as follows:

	Common Stock Price (High)	Common Stock Price (Low)	Common Stock Dividends Declared Per Share
2016			
First quarter	**$19.55**	**$15.57**	**$.1875**
Second quarter	**24.01**	**18.70**	**.1875**
Third quarter	**25.79**	**22.47**	**.1875**
Fourth quarter	**29.92**	**24.49**	**.1925**
			$.7550
2015			
First quarter	$24.51	$20.01	$.1825
Second quarter	23.12	19.22	.1825
Third quarter	19.73	16.15	.1825
Fourth quarter	19.66	16.26	.1875
			$.7350

As of December 31, 2016, the Company's common stock was held by approximately 12,400 stockholders of record.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. For more information on factors that may limit the Company's ability to pay dividends, see Item 8 - Note 9.

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, 2016	—			
November 1 through November 30, 2016	34,974	$28.30		
December 1 through December 31, 2016	2,244	28.96		
Total	37,218			

(1) Represents shares of common stock purchased on the open market in connection with annual stock grants made to the Company's non-employee directors and for those directors who elected to receive additional shares of common stock in lieu of a portion of their cash retainer.
(2) Not applicable. The Company does not currently have in place any publicly announced plans or programs to purchase equity securities.

Item 6. Selected Financial Data

	2016	2015	2014	2013	2012	2011
Selected Financial Data						
Operating revenues (000's):						
Electric	$ **322,356**	$ 280,615	$ 277,874	$ 257,260	$ 236,895	$ 225,468
Natural gas distribution	**766,115**	817,419	921,986	851,945	754,848	907,400
Pipeline and midstream	**141,602**	154,904	157,292	144,568	142,610	152,972
Construction materials and contracting	**1,874,270**	1,904,282	1,765,330	1,712,137	1,617,425	1,510,010
Construction services	**1,073,272**	926,427	1,119,529	1,039,839	938,558	854,389
Other	**8,643**	9,191	9,364	9,620	10,370	11,446
Intersegment eliminations	**(57,430)**	(78,786)	(136,302)	(95,201)	(74,595)	(68,482)
	$ **4,128,828**	$ 4,014,052	$ 4,115,073	$ 3,920,168	$ 3,626,111	$ 3,593,203
Operating income (loss) (000's):						
Electric	$ **68,497**	$ 57,955	$ 61,331	$ 54,274	$ 49,852	$ 49,096
Natural gas distribution	**65,014**	53,810	65,633	78,829	67,579	82,856
Pipeline and midstream	**43,374**	29,988	46,713	20,896	49,139	45,365
Construction materials and contracting	**178,719**	146,026	86,462	93,629	57,864	51,092
Construction services	**53,705**	43,376	82,309	85,246	66,531	39,144
Other	**(189)**	(8,438)	(5,366)	(4,384)	(5,325)	(7,079)
Intersegment eliminations	**—**	(2,942)	(9,900)	(7,176)	—	—
	$ **409,120**	$ 319,775	$ 327,182	$ 321,314	$ 285,640	$ 260,474
Earnings (loss) on common stock (000's):						
Electric	$ **42,222**	$ 35,914	$ 36,731	$ 34,837	$ 30,634	$ 29,258
Natural gas distribution	**27,102**	23,607	30,484	37,656	29,409	38,398
Pipeline and midstream	**23,435**	13,250	24,666	7,701	26,588	23,082
Construction materials and contracting	**102,687**	89,096	51,510	50,946	32,420	26,430
Construction services	**33,945**	23,762	54,432	52,213	38,429	21,627
Other	**(3,231)**	(14,941)	(7,386)	(10,776)	(7,209)	(5,918)
Intersegment eliminations	**6,251**	5,016	(6,095)	(4,307)	—	—
Earnings on common stock before income (loss) from discontinued operations	**232,411**	175,704	184,342	168,270	150,271	132,877
Income (loss) from discontinued operations, net of tax*	**(300,354)**	(834,080)	109,311	109,615	(151,710)	79,464
Loss from discontinued operations attributable to noncontrolling interest	**(131,691)**	(35,256)	(3,895)	(363)	—	—
	$ **63,748**	$ (623,120)	$ 297,548	$ 278,248	$ (1,439)	$ 212,341
Earnings (loss) per common share before discontinued operations - diluted	$ **1.19**	$ .90	$ .96	$ .89	$ .80	$ .70
Discontinued operations attributable to the Company, net of tax	**(.86)**	(4.10)	.59	.58	(.81)	.42
	$ **.33**	$ (3.20)	$ 1.55	$ 1.47	$ (.01)	$ 1.12
Common Stock Statistics						
Weighted average common shares outstanding - diluted (000's)	**195,618**	194,986	192,587	189,693	188,826	188,905
Dividends declared per common share	$ **.7550**	$ .7350	$ .7150	$ .6950	$ .6750	$ .6550
Book value per common share	$ **11.78**	$ 12.83	$ 16.66	$ 15.01	$ 13.95	$ 14.62
Market price per common share (year end)	$ **28.77**	$ 18.32	$ 23.50	$ 30.55	$ 21.24	$ 21.46
Market price ratios:						
Dividend payout**	**63%**	82%	74%	78%	84%	94%
Yield	**2.7%**	4.1%	3.1%	2.3%	3.2%	3.1%
Market value as a percent of book value	**244.2%**	142.8%	141.1%	203.5%	152.3%	146.8%

* Reflects oil and natural gas properties noncash write-downs of $315.3 million (after tax) and $246.8 million (after tax) in 2015 and 2012, respectively, 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)

	2016	2015	2014	2013	2012	2011
General						
Total assets (000's)	**$ 6,284,467**	$ 6,565,154	$ 7,805,405	$ 7,043,365	$ 6,675,609	$ 6,539,676
Total long-term debt (000's)	**$ 1,790,159**	$ 1,796,163	$ 2,016,198	$ 1,773,050	$ 1,738,833	$ 1,418,693
Capitalization ratios:						
Total equity	**56%**	58%	62%	62%	60%	66%
Total debt	**44**	42	38	38	40	34
	100%	100%	100%	100%	100%	100%
Electric						
Retail sales (thousand kWh)	**3,258,537**	3,316,017	3,308,358	3,173,086	2,996,528	2,878,852
Electric system summer and firm purchase contract ZRCs (Interconnected system)	**559.7**	547.3	584.0	583.5	552.8	572.8
Electric system peak demand obligation, including firm purchase contracts, planning reserve margin requirement (Interconnected system)	**559.7**	547.3	522.4	508.3	550.7	524.2
All-time demand peak - kW (Interconnected system)	**611,542**	611,542	582,083	573,587	573,587	535,761
Electricity produced (thousand kWh)	**2,626,763**	1,898,160	2,519,938	2,430,001	2,299,686	2,488,337
Electricity purchased (thousand kWh)	**904,702**	1,658,002	1,010,422	971,261	870,516	645,567
Average cost of fuel and purchased power per kWh	**$ .021**	$ .024	$ .025	$ .025	$ .023	$ .021
Natural Gas Distribution						
Sales (Mdk)	**99,296**	95,559	104,297	108,260	93,810	103,237
Transportation (Mdk)	**147,592**	154,225	145,941	149,490	132,010	124,227
Degree days (% of normal)						
Montana-Dakota/Great Plains	**89%**	88%	103%	105%	84%	101%
Cascade	**87%**	83%	89%	98%	96%	103%
Intermountain	**96%**	89%	95%	110%	91%	107%
Pipeline and Midstream						
Transportation (Mdk)	**285,254**	290,494	233,483	178,598	137,720	113,217
Gathering (Mdk)	**20,049**	33,441	38,372	40,737	47,084	66,500
Customer natural gas storage balance (Mdk)	**26,403**	16,600	14,885	26,693	43,731	36,021
Construction Materials and Contracting						
Sales (000's):						
Aggregates (tons)	**27,580**	26,959	25,827	24,713	23,285	24,736
Asphalt (tons)	**7,203**	6,705	6,070	6,228	5,988	6,709
Ready-mixed concrete (cubic yards)	**3,655**	3,592	3,460	3,223	3,157	2,864
Aggregate reserves (000's tons)	**989,084**	1,022,513	1,061,156	1,083,376	1,088,236	1,088,833

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

Overview

The Company's strategy is to apply its expertise in the regulated energy delivery and construction materials and services businesses to increase market share, increase profitability and enhance shareholder value through:

- Organic growth as well as a continued disciplined approach to the acquisition of well-managed companies and properties
- The elimination of system-wide cost redundancies through increased focus on integration of operations and standardization and consolidation of various support services and functions across companies within the organization
- The development of projects that are accretive to earnings per share and return on invested capital
- Divestiture of certain assets to fund capital growth projects throughout the Company

The Company has capabilities to fund its growth and operations through various sources, including internally generated funds, commercial paper facilities, revolving credit facilities, the issuance from time to time of debt and equity securities and asset sales. For more information on the Company's capital expenditures, see Liquidity and Capital Commitments.

The key strategies for each of the Company's business segments and certain related business challenges are summarized below. For a summary of the Company's businesses, see Item 8 - Note 13.

Key Strategies and Challenges

Electric and Natural Gas Distribution

Strategy Provide safe and reliable competitively priced energy and related services to customers. The electric and natural gas distribution segments continually seek opportunities to retain, grow and expand their customer base through extensions of existing operations, including building and upgrading electric generation and transmission and natural gas systems, and through selected acquisitions of companies and properties at prices that will provide stable cash flows and an opportunity for the Company to earn a competitive return on investment.

Challenges Both segments are subject to extensive regulation in the state jurisdictions where they conduct operations with respect to costs and timely recovery and permitted returns on investment as well as subject to certain operational, system integrity and environmental regulations. These regulations can require substantial investment to upgrade facilities. The ability of these segments to grow through acquisitions is subject to significant competition. In addition, the ability of both segments to grow service territory and customer base is affected by the economic environment of the markets served and competition from other energy providers and fuels. The construction of any new electric generating facilities, transmission lines and other service facilities is subject to increasing cost and lead time, extensive permitting procedures, and federal and state legislative and regulatory initiatives, which will necessitate increases in electric energy prices. Legislative and regulatory initiatives to increase renewable energy resources and reduce GHG emissions could impact the price and demand for electricity and natural gas and could result in the retirement of certain electric generating facilities before they are fully depreciated.

Pipeline and Midstream

Strategy Utilize the segment's existing expertise in energy infrastructure and related services to increase market share and profitability through optimization of existing operations, internal growth, and investments in and acquisitions of energy-related assets and companies both in its current operating areas and beyond its Rocky Mountain and northern Great Plains base. Incremental and new growth opportunities include: access to new energy sources for storage, gathering and transportation services; expansion of existing storage, gathering and transmission facilities; incremental pipeline projects which expand pipeline capacity; and expansion of the pipeline and midstream business to include liquid pipelines and processing activities.

Challenges Challenges for this segment include: energy price volatility; basis differentials; environmental and regulatory requirements; securing permits and easements; recruitment and retention of a skilled workforce; and competition from other pipeline and midstream companies.

Construction Materials and Contracting

Strategy Focus on high-growth strategic markets located near major transportation corridors and desirable mid-sized metropolitan areas; strengthen long-term, strategic aggregate reserve position through purchase and/or lease opportunities; enhance profitability through cost containment, margin discipline and vertical integration of the segment's operations; develop and recruit talented employees; and continue growth through organic and acquisition opportunities. Vertical integration allows the segment to manage operations from aggregate mining to final lay-down of concrete and asphalt, with control of and access to permitted aggregate reserves being significant. A key element of the Company's long-term strategy for this business is to further expand its market presence in the higher-margin materials business (rock, sand, gravel, liquid asphalt, asphalt concrete, ready-mixed concrete and related products), complementing and expanding on the Company's expertise.

Challenges Recruitment and retention of key personnel and volatility in the cost of raw materials such as diesel, gasoline, liquid asphalt, cement and steel, are ongoing challenges. This business unit expects to continue cost containment efforts, positioning its operations for the resurgence in the private market, while continuing the emphasis on industrial, energy and public works projects.

Construction Services

Strategy Provide a superior return on investment by: building new and strengthening existing customer relationships; effectively controlling costs; retaining, developing and recruiting talented employees; growing through organic and acquisition opportunities; and focusing efforts on projects that will permit higher margins while properly managing risk.

Challenges This segment operates in highly competitive markets with many jobs subject to competitive bidding. Maintenance of effective operational and cost controls, retention of key personnel, managing through downturns in the economy and effective management of working capital are ongoing challenges.

For more information on the risks and challenges the Company faces as it pursues its growth strategies and other factors that should be considered for a better understanding of the Company's financial condition, see Item 1A - Risk Factors. For more information on key growth strategies, projections and certain assumptions, see Prospective Information. For information pertinent to various commitments and contingencies, see Item 8 - Notes to Consolidated Financial Statements.

Earnings Overview

The following table summarizes the contribution to consolidated earnings (loss) by each of the Company's businesses.

Years ended December 31,	**2016**	2015	2014
	(Dollars in millions, where applicable)		
Electric	**$ 42.2**	$ 35.9	$ 36.7
Natural gas distribution	**27.1**	23.6	30.5
Pipeline and midstream	**23.4**	13.3	24.7
Construction materials and contracting	**102.7**	89.1	51.5
Construction services	**33.9**	23.8	54.5
Other	**(3.2)**	(15.0)	(7.4)
Intersegment eliminations	**6.3**	5.0	(6.2)
Earnings before discontinued operations	**232.4**	175.7	184.3
Income (loss) from discontinued operations, net of tax	**(300.4)**	(834.1)	109.3
Loss from discontinued operations attributable to noncontrolling interest	**(131.7)**	(35.3)	(3.9)
Earnings (loss) on common stock	**$ 63.7**	$ (623.1)	$ 297.5
Earnings (loss) per common share - basic:			
Earnings before discontinued operations	**$ 1.19**	$ .90	$ .96
Discontinued operations, net of tax	**(.86)**	(4.10)	.59
Earnings (loss) per common share - basic	**$ .33**	$ (3.20)	$ 1.55
Earnings (loss) per common share - diluted:			
Earnings before discontinued operations	**$ 1.19**	$ .90	$ .96
Discontinued operations, net of tax	**(.86)**	(4.10)	.59
Earnings (loss) per common share - diluted	**$ .33**	$ (3.20)	$ 1.55

2016 compared to 2015 The Company recognized consolidated earnings of $63.7 million in 2016, compared to a consolidated loss of $623.1 million in 2015. This increase was due to:

- Discontinued operations which reflect the absence in 2016 of fair value impairments of the exploration and production business's assets of $475.4 million (after tax) and a noncash write-down of oil and natural gas properties of $315.3 million (after tax) offset in part by a fair value impairment of the refining business of $156.7 million (after tax) in 2016
- Higher construction margins and revenues and higher asphalt and aggregate volumes and margins at the construction materials and contracting business
- Other loss decreased primarily the result of lower operation and maintenance and interest expense due to the sales of the exploration and production and refining businesses
- Higher inside electrical workloads and margins in the Western region offset in part by lower equipment sales and rental margins at the construction services business

- Absence in 2016 of impairments of natural gas gathering assets of $10.6 million (after tax) partially offset by a fair value impairment in 2016 of $1.4 million (after tax) associated with the sale of Pronghorn at the pipeline and midstream business
- Increased electric retail sales margins, largely due to approved rate recovery, partially offset by higher operation and maintenance expense and higher depreciation, depletion and amortization expense at the electric business

2015 compared to 2014 The Company recognized a consolidated loss of $623.1 million in 2015, compared to consolidated earnings of $297.5 million in 2014. This decrease was due to:

- Discontinued operations which had fair value impairments of the exploration and production business's assets of $475.4 million (after tax), a $315.3 million after-tax noncash write-down of oil and natural gas properties, decreased average realized commodity prices and decreased production
- Lower workloads and margins in the Western region and lower equipment rental sales and margins at the construction services business
- Impairments of natural gas gathering assets of $10.6 million (after tax) at the pipeline and midstream business
- Higher depreciation, depletion and amortization expense due to plant additions and lower natural gas sales volumes offset in part by natural gas retail rate increases at the natural gas distribution business

Partially offsetting these increases were higher earnings on all product lines at the construction materials and contracting business.

Financial and Operating Data

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

Electric

Years ended December 31,		**2016**		2015		2014
		(Dollars in millions, where applicable)				
Operating revenues	**$**	**322.3**	$	280.6	$	277.9
Operating expenses:						
Fuel and purchased power		**75.5**		86.2		89.3
Operation and maintenance		**115.2**		87.7		81.1
Depreciation, depletion and amortization		**50.2**		37.6		35.0
Taxes, other than income		**12.9**		11.1		11.1
		253.8		222.6		216.5
Operating income		**68.5**		58.0		61.4
Earnings	**$**	**42.2**	$	35.9	$	36.7
Retail sales (million kWh):						
Residential		**1,132.5**		1,173.9		1,225.3
Commercial		**1,491.8**		1,499.6		1,471.3
Industrial		**544.2**		550.3		520.4
Other		**90.0**		92.2		91.4
		3,258.5		3,316.0		3,308.4
Average cost of fuel and purchased power per kWh	**$**	**.021**	$	.024	$	.025

2016 compared to 2015 Electric earnings increased $6.3 million (18 percent) compared to the prior year due to:

- Increased electric retail sales margins, largely due to approved final and interim rate increases reduced in part by decreased electric sales volumes of 2 percent, largely decreased residential customer volumes
- Favorable income tax changes, which includes $10.1 million due to higher production tax credits

Partially offsetting these increases were:

- Higher operation and maintenance expense of $17.1 million (after tax) primarily due to higher contract services and higher payroll-related costs
- Higher depreciation, depletion and amortization expense of $7.8 million (after tax) due to increased property, plant and equipment balances
- Lower other income, which includes $7.1 million (after tax) primarily related to AFUDC
- Higher interest expense, which includes $4.4 million (after tax) largely the result of higher long-term debt

Certain of the higher operation and maintenance expense, higher depreciation, depletion and amortization expense and higher production tax credits in 2016, due to increased capital investments, are potentially recoverable and/or refundable through the rate recovery process. The previous table also reflects lower average cost of fuel and purchased power per kWh due to no fuel and purchased power costs associated with the Thunder Spirit Wind farm.

2015 compared to 2014 Electric earnings decreased $800,000 (2 percent) compared to the prior year due to:

- Higher operation and maintenance expense, which includes $4.3 million (after tax) largely related to higher contract services, primarily related to a planned outage at an electric generation station, and higher payroll and benefit-related costs
- Higher depreciation, depletion and amortization expense of $1.6 million (after tax) due to increased property, plant and equipment balances
- Higher net interest expense, which includes $1.1 million (after tax) due to higher long-term debt

Partially offsetting these decreases were:

- Increased electric retail sales margins, primarily due to rate recovery of new generation
- Higher other income, which includes $3.5 million (after tax) primarily related to AFUDC

Natural Gas Distribution

Years ended December 31,	**2016**	2015	2014
	(Dollars in millions, where applicable)		
Operating revenues	**$ 766.1**	$ 817.4	$ 922.0
Operating expenses:			
Purchased natural gas sold	**431.5**	499.0	603.2
Operation and maintenance	**158.1**	153.5	150.2
Depreciation, depletion and amortization	**65.4**	64.8	54.7
Taxes, other than income	**46.1**	46.3	48.3
	701.1	763.6	856.4
Operating income	**65.0**	53.8	65.6
Earnings	**$ 27.1**	$ 23.6	$ 30.5
Volumes (MMdk)			
Sales:			
Residential	**56.2**	54.0	58.8
Commercial	**38.9**	37.6	41.0
Industrial	**4.2**	4.0	4.5
	99.3	95.6	104.3
Transportation:			
Commercial	**1.8**	1.8	1.9
Industrial	**145.8**	152.4	144.0
	147.6	154.2	145.9
Total throughput	**246.9**	249.8	250.2
Degree days (% of normal)*			
Montana-Dakota/Great Plains	**89%**	88%	103%
Cascade	**87%**	83%	89%
Intermountain	**96%**	89%	95%
Average cost of natural gas, including transportation, per dk	**$ 4.35**	$ 5.22	$ 5.78

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

2016 compared to 2015 The natural gas distribution business experienced an increase in earnings of $3.5 million (15 percent) compared to the prior year due to higher natural gas retail sales margins resulting from increased retail sales volumes of 4 percent to all customer classes due to customer growth and colder weather in certain regions, as well as final and interim rate increases, partially offset by higher operation and maintenance expense, which includes $4.6 million (after tax) largely higher payroll-related costs, and higher depreciation, depletion and amortization expense from increased property, plant and equipment balances.

The previous table also includes lower nonutility project costs reflected in operation and maintenance expense, as well as the pass-through of lower natural gas prices which are reflected in the decrease in both sales revenue and purchased natural gas sold in 2016.

2015 compared to 2014 The natural gas distribution business experienced a decrease in earnings of $6.9 million (23 percent) compared to the prior year due to:

- Higher depreciation, depletion and amortization expense of $6.3 million (after tax), largely resulting from increased property, plant and equipment balances
- Lower natural gas sales margins, primarily lower retail sales volumes of 8 percent to all customer classes due to warmer weather than the prior year, partially offset by approved rate increases effective in 2015 and increased transportation volumes

The pass-through of lower natural gas prices is reflected in the decrease in both sales revenue and purchased natural gas sold in 2015.

Pipeline and Midstream

Years ended December 31,	2016	2015	2014
		(Dollars in millions)	
Operating revenues	$ 141.6	$ 154.9	$ 157.3
Operating expenses:			
Operation and maintenance	61.4	84.7	68.0
Depreciation, depletion and amortization	24.9	28.0	29.8
Taxes, other than income	11.9	12.2	12.8
	98.2	124.9	110.6
Operating income	43.4	30.0	46.7
Earnings	$ 23.4	$ 13.3	$ 24.7
Transportation volumes (MMdk)	285.3	290.5	233.5
Natural gas gathering volumes (MMdk)	20.0	33.4	38.4
Customer natural gas storage balance (MMdk):			
Beginning of period	16.6	14.9	26.7
Net injection (withdrawal)	9.8	1.7	(11.8)
End of period	26.4	16.6	14.9

2016 compared to 2015 Pipeline and midstream earnings increased $10.1 million (77 percent) largely due to:

- Lower operation and maintenance expense, which includes $13.6 million (after tax) largely due to the absence in 2016 of impairments of natural gas gathering assets of $10.6 million (after tax), as discussed in Item 8 - Notes 1 and 5, lower payroll-related costs and lower material costs partially offset by a fair value impairment in 2016 of $1.4 million (after tax) associated with the sale of Pronghorn, as discussed in Item 8 - Note 2
- Lower depreciation, depletion and amortization of $1.9 million (after tax), largely due to the sale of certain non-strategic natural gas gathering assets in the fourth quarter of 2015
- Higher storage services earnings, primarily due to higher average interruptible storage balances
- Lower interest expense of $1.2 million (after tax), primarily the result of lower debt interest rates and balances

Partially offsetting the earnings increase was lower gathering and processing earnings of $8.0 million (after tax) resulting from lower natural gas gathering volumes, primarily due to the sale of certain non-strategic assets, as previously discussed, and lower oil gathering volumes, partially offset by higher oil gathering rates at Pronghorn.

2015 compared to 2014 Pipeline and midstream earnings decreased $11.4 million (46 percent) largely due to:

- Impairments of natural gas gathering assets of $10.6 million (after tax) included in operation and maintenance expense, as discussed in Item 8 - Notes 1 and 5
- Lower gathering and processing earnings of $5.2 million (after tax), primarily lower processing prices and natural gas gathering volumes

- Lower storage services earnings, primarily due to lower interruptible storage withdrawal volumes and lower average balances

Partially offsetting the earnings decrease was higher earnings of $5.7 million (after tax) due to higher transportation revenue, primarily resulting from higher rates due to a rate case settlement effective in May 2014, and increased volumes.

Construction Materials and Contracting

Years ended December 31,	2016	2015	2014
		(Dollars in millions)	
Operating revenues	$ 1,874.3	$ 1,904.3	$ 1,765.3
Operating expenses:			
Operation and maintenance	1,595.4	1,652.3	1,571.5
Depreciation, depletion and amortization	58.4	65.9	68.6
Taxes, other than income	41.8	40.1	38.8
	1,695.6	1,758.3	1,678.9
Operating income	178.7	146.0	86.4
Earnings	$ 102.7	$ 89.1	$ 51.5
Sales (000's):			
Aggregates (tons)	27,580	26,959	25,827
Asphalt (tons)	7,203	6,705	6,070
Ready-mixed concrete (cubic yards)	3,655	3,592	3,460

2016 compared to 2015 Earnings at the construction materials and contracting business increased $13.6 million (15 percent) due to:

- Higher earnings of $8.1 million (after tax) resulting from higher construction margins and revenues due to more available work in most regions
- A $6.7 million (after tax) reduction in 2016 to a previously recorded MEPP withdrawal liability compared to an increase to a MEPP withdrawal liability of $1.5 million (after tax) in 2015, as discussed in Item 8 - Note 14
- Higher earnings of $2.9 million (after tax) resulting from higher asphalt volumes and margins, which includes lower asphalt oil and production costs
- Higher earnings of $2.3 million (after tax) resulting from higher aggregate volumes and margins due to increased demand

Partially offsetting these increases were:

- Higher effective income tax rates
- Lower earnings of $1.3 million (after tax) from other product lines

Lower diesel fuel costs contributed to higher earnings from all product lines.

2015 compared to 2014 Earnings at the construction materials and contracting business increased $37.6 million (73 percent) due to:

- Higher earnings of $9.1 million (after tax) resulting from higher ready-mixed concrete margins and volumes
- Higher earnings of $7.2 million (after tax) resulting from higher asphalt margins and volumes, which includes lower asphalt oil costs
- An increase to a MEPP withdrawal liability of $1.5 million (after tax) in 2015, compared to $8.4 million (after tax) in 2014, as discussed in Item 8 - Note 14
- Higher earnings of $6.1 million (after tax) resulting from higher construction revenues and margins including the effects of favorable weather
- Higher earnings of $1.6 million (after tax) resulting from higher aggregate margins and volumes
- Higher earnings resulting from higher other product line margins and volumes

Partially offsetting these increases were higher selling, general and administrative expense of $5.7 million (after tax), largely related to higher payroll-related and other costs.

Lower diesel fuel costs contributed to higher earnings from all product lines.

Construction Services

Years ended December 31,	2016	2015	2014
		(In millions)	
Operating revenues	$ 1,073.3	$ 926.4	$ 1,119.5
Operating expenses:			
Operation and maintenance	965.3	838.5	990.7
Depreciation, depletion and amortization	15.3	13.4	12.9
Taxes, other than income	39.0	31.1	33.6
	1,019.6	883.0	1,037.2
Operating income	53.7	43.4	82.3
Earnings	$ 33.9	$ 23.8	$ 54.5

2016 compared to 2015 Construction services earnings increased $10.1 million (43 percent) largely due to:

- Higher earnings of $15.8 million (after tax) in the Western region largely due to higher workloads and margins resulting from the successful completion of construction projects in certain markets, as well as lower labor costs due to increased efficiencies and lower workers' compensation claim costs
- Higher earnings of $3.5 million (after tax) resulting from the sale of a non-strategic asset in 2015

These increases were partially offset by:

- Higher selling, general and administrative expense of $4.0 million (after tax), primarily due to higher payroll and benefit-related costs and higher bad debt expense
- Lower equipment sales and rental margins due to decreased customer demand
- Lower earnings of $1.6 million (after tax) in the Central region due to lower margins, largely the result of the loss on a project

2015 compared to 2014 Construction services earnings decreased $30.7 million (56 percent) due to:

- Lower earnings of $25.1 million (after tax) largely due to lower workloads and margins in the Western region resulting from substantial completion of significant projects in 2014, lower equipment sales and rental margins, lower margins in the Central region and lower electrical supply sales and margins
- The absence of the favorable resolution of certain income tax matters and higher income tax benefits in 2014

These decreases were partially offset by lower selling, general and administrative expense of $3.0 million (after tax), largely related to lower payroll and benefit-related costs.

Other

Years ended December 31,	2016	2015	2014
		(In millions)	
Operating revenues	$ 8.6	$ 9.2	$ 9.4
Operating expenses:			
Operation and maintenance	6.6	15.4	12.3
Depreciation, depletion and amortization	2.1	2.1	2.2
Taxes, other than income	.1	.1	.2
	8.8	17.6	14.7
Operating loss	(.2)	(8.4)	(5.3)
Loss	$ (3.2)	$ (15.0)	$ (7.4)

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.

2016 compared to 2015 Other loss decreased $11.8 million compared to the prior year primarily due to lower operation and maintenance expense and interest expense previously allocated to the exploration and production business, due to the sale of that business which included the repayment of long-term debt. Also contributing to the decreased loss was lower operation and maintenance expense in 2016 due to the absence of a 2015 corporate asset impairment and the absence of a 2015 foreign currency translation loss including the effects of the sale of the Company's remaining interest in the Brazilian Transmission Lines.

2015 compared to 2014 Other loss increased $7.6 million compared to the prior year primarily due to the absence of prior year income tax benefits; higher operation and maintenance expense, largely a corporate asset impairment; as well as a foreign currency translation loss including the effects of the sale of the Company's remaining interest in the Brazilian Transmission Lines.

Discontinued Operations

Years ended December 31,	2016	2015	2014
		(In millions)	
Income (loss) from discontinued operations before intercompany eliminations, net of tax	**$ (303.2)**	$ (829.9)	$ 108.8
Intercompany eliminations*	**2.8**	(4.2)	.5
Income (loss) from discontinued operations, net of tax	**(300.4)**	(834.1)	109.3
Loss from discontinued operations attributable to noncontrolling interest	**(131.7)**	(35.3)	(3.9)
Income (loss) from discontinued operations attributable to the Company, net of tax	**$ (168.7)**	$ (798.8)	$ 113.2

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

2016 compared to 2015 The loss from discontinued operations attributable to the Company was $168.7 million compared to a loss of $798.8 million in the prior year. The decreased loss is primarily due to the completion of the sales of Company's exploration and production and refining businesses. The decreased loss was largely the result of the absence in 2016 of a noncash write-down of oil and natural gas properties of $315.3 million (after tax) and fair value impairments of the exploration and production business's assets held for sale of $475.4 million (after tax), as discussed in Item 8 - Note 2, partially offset by a fair value impairment of the refining business of $156.7 million (after tax) in 2016, as discussed in Item 8 - Note 2.

2015 compared to 2014 Discontinued operations attributable to the Company recognized a loss of $798.8 million compared to income of $113.2 million in the prior year. The decrease in income was primarily due to the marketing and sale of the Company's exploration and production business's assets. The decrease was largely the result of a noncash write-down of oil and natural gas properties of $315.3 million (after tax) and fair value impairments of the exploration and production business's assets held for sale of $475.4 million (after tax), as discussed in Item 8 - Note 2, as well as decreased average realized commodity prices and decreased production.

Intersegment Transactions

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

Years ended December 31,	2016	2015	2014
		(In millions)	
Intersegment transactions:			
Operating revenues	**$ 57.4**	$ 78.8	$ 136.3
Purchased natural gas sold	**48.7**	48.9	44.7
Operation and maintenance	**8.7**	26.9	81.7
Income from continuing operations*	**(6.3)**	(5.0)	6.2

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

For more information on intersegment eliminations, see Item 8 - Note 13.

Prospective Information

The following information highlights the key growth strategies, projections and certain assumptions for the Company and its subsidiaries and other matters for certain of the Company's businesses. Many of these highlighted points are "forward-looking statements." There is no assurance that the Company's projections, including estimates for growth and changes in earnings, will in fact be achieved. Please refer to assumptions contained in this section, as well as the various important factors listed in Item 1A - Risk Factors. Changes in such assumptions and factors could cause actual future results to differ materially from the Company's growth and earnings projections.

MDU Resources Group, Inc.

- The Company continually seeks opportunities to expand through organic growth opportunities and strategic acquisitions.

Electric and natural gas distribution

- The Company expects to grow its rate base by approximately 4 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. The utility operations are spread across eight states where customer growth is expected to be higher than the national average. 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 electric and natural gas distribution. Rate base at December 31, 2016, was $1.9 billion.
- The Company expects its customer base to grow by 1.0 percent to 2.0 percent per year.
- In June 2016, the Company, along with a partner, began to build a 345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota, a distance of about 160 miles. The project has been approved as a MISO multivalue project. Approximately 97 percent of the necessary easements have been secured. The Company expects the project to be completed in 2019.
- The Company signed a 25-year agreement to purchase the power from a wind farm expansion in southwest North Dakota. The agreement also includes an option to buy the project at the close of construction. The expansion of the Thunder Spirit Wind farm will boost the combined production at the wind farm to approximately 150 MW of renewable energy and will increase the Company's nameplate generation portfolio from approximately 22 percent renewables to 27 percent. The original 107.5-MW Thunder Spirit Wind farm includes 43 turbines; it was purchased by the Company in December 2015. The expansion includes 13 to 16 turbines, depending on the turbine size selected. It is expected to be online in December 2018. If the Company buys the project, the capital will be incremental to the capital expenditures forecast. Construction costs for the project are estimated to be $85 million.
- The Company is in the process of completing its 2017 integrated resource plan and is evaluating its future generation and power supply portfolio options, including a large-scale resource. The plan will be finalized and will be required to be filed by mid-2017. Future resource requirements identified in the plan could require investment that would be incremental to the capital expenditures forecast.
- The Company is involved with a number of pipeline projects to enhance the reliability and deliverability of its system.
- The Company is focused on organic growth, while monitoring potential merger and acquisition opportunities.
- The Company is evaluating the final Clean Power Plan rule published by the EPA in October 2015, which requires existing fossil fuel-fired electric generation facilities to reduce carbon dioxide emissions. It is unknown at this time what each state will require for emissions limits or reductions from each of the Company's owned and jointly owned fossil fuel-fired electric generating units. In February 2016, the United States Supreme Court granted an application for a stay of the Clean Power Plan pending the outcome of legal challenges. The Company has not included capital expenditures in 2017 through 2019 for the potential compliance requirements of the Clean Power Plan.
- Regulatory actions

  <u>Completed Cases:</u>
  Since January 1, 2015, the Company has finalized rate increases totaling $56.8 million in annual revenue. This includes electric rate proceedings in Montana, North Dakota, South Dakota, Wyoming and before the FERC, and natural gas proceedings in Minnesota, Montana, North Dakota, Oregon, South Dakota, Washington and Wyoming. Cases recently completed were:

  - On April 29, 2016, the Company filed an application with the OPUC for a natural gas rate increase, as discussed in Item 8 - Note 16.
  - On June 10, 2016, the Company filed an application for an increase in electric rates with the WYPSC, as discussed in Item 8 - Note 16.
  - On December 2, 2016, the Company filed an application with the MTPSC requesting authority to implement gas and electric tax tracking adjustments, as discussed in Item 8 - Note 16.
  - On September 1, 2016, and as amended on January 10, 2017, the Company submitted an update to its transmission formula rate under the MISO tariff, as discussed in Item 8 - Note 16.

  <u>Pending Cases:</u>
  The Company is requesting rate increases totaling $55.4 million in annual revenue, which includes $43.6 million in implemented interim rates. Cases pending are:

  - On October 26, 2015, the Company filed an application with the NDPSC requesting a renewable resource cost adjustment rider, as discussed in Item 8 - Note 16.
  - On October 26, 2015, the Company filed an application with the NDPSC for an update to the electric generation resource recovery rider, as discussed in Item 8 - Note 16.

- ◦ On November 25, 2015, the Company filed an application with the NDPSC for an update of its transmission cost adjustment rider for recovery of MISO-related charges and two transmission projects in North Dakota, as discussed in Item 8 - Note 16.
- ◦ On August 12, 2016, the Company filed an application with the IPUC for a natural gas rate increase, as discussed in Item 8 - Note 16.
- ◦ On October 14, 2016, the Company filed an application with the NDPSC for an electric rate increase, as discussed in Item 8 - Note 16.
- ◦ On December 2, 2016, the Company filed an application with the MTPSC requesting authority to implement gas and electric tax tracking adjustments, as previously discussed in the completed cases and in Item 8 - Note 16.
- ◦ On December 21, 2016, the Company filed an application with the MNPUC requesting authority to implement a gas utility infrastructure cost tariff, as discussed in Item 8 - Note 16.

Pipeline and midstream

- In September 2016, the Company secured sufficient capacity commitments and started survey work on a 38-mile pipeline that will deliver natural gas supply to eastern North Dakota and far western Minnesota. The Valley Expansion project will connect the Viking Gas Transmission Company pipeline near Felton, Minnesota, to the Company's existing pipeline near Mapleton, North Dakota. Cost of the expansion is estimated at $55 million to $60 million. The project, which is designed to transport 40 MMcf of natural gas per day, is under the jurisdiction of the FERC. In October 2016, the Company received FERC approval on its pre-filing for the Valley Expansion project. With minor enhancements, the pipeline will be able to transport significantly more volume if required, based on capacity requested or as needed in the future as the region's demand grows. Following receipt of necessary permits and regulatory approvals, construction is expected to begin in early 2018 with completion expected in late 2018.
- The Company signed agreements to complete expansion projects, including the Charbonneau and Line Section 25 expansion project. The Charbonneau and Line Section 25 expansion project will include a new compression station as well as other compression modifications and is expected to be in service in the second quarter of 2017. In addition, the Company completed the North Badlands project, which includes a 4-mile loop of the Garden Creek pipeline segment and other ancillary facilities, and it was placed in service on August 1, 2016. The Northwest North Dakota project, which includes modification of existing compression, a new compression unit and re-cylindering, was put into service in June 2016.
- The Company continues to target profitable growth by means of both organic projects in areas of existing operations and by looking for potential acquisitions that fit existing expertise and capabilities.
- The Company is focused on improving existing operations and accelerating growth in its current markets while evaluating expansion into other basins.

Construction materials and contracting

- Approximate work backlog at December 31, 2016, was $538 million, compared to $491 million a year ago.
- Projected revenues are in the range of $1.85 billion to $1.95 billion in 2017.
- The Company anticipates margins in 2017 to be slightly higher compared to 2016 margins.
- In December 2015, a $305 billion, five-year federal highway bill was passed for funding of transportation infrastructure projects that are a key part of the construction materials market.
- As the country's fifth-largest sand and gravel producer, the Company will continue 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.

Construction services

- Approximate work backlog at December 31, 2016, was $475 million, compared to $493 million a year ago. The backlog includes transmission, distribution, substation, industrial, petrochemical, high technology, solar energy renewables, research and development, higher education, government, transportation, health care, hospitality, gaming, commercial, institutional and service work.
- Projected revenues are in the range of $1.0 billion to $1.1 billion in 2017.
- The Company anticipates margins in 2017 to be comparable to 2016 margins.
- The Company continues to pursue opportunities for expansion in energy projects, such as petrochemical, transmission, substations, utility services, and renewables. Initiatives are aimed at capturing additional market share and expanding into new markets.
- As the 13th-largest specialty contractor, the Company continues to pursue opportunities for expansion and execute initiatives in current and new markets that align with the Company's expertise, resources and strategic growth plan.

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 assets held for sale, 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; 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 testing of assets held for sale

The Company evaluates disposal groups classified as held for sale based on the lower of carrying value or fair value less cost to sell. The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the first quarter of 2016, the estimated fair value of Fidelity's assets was determined using the market approach largely based on a purchase and sale agreement. In the second quarter of 2016, the fair value of Fidelity's assets was determined using the income and market approaches. The income approach was determined by using the present value of estimated future cash flows. The market approach was based on market transactions of similar properties. Also in the second quarter of 2016, the estimated fair value of Dakota Prairie Refining was determined using the market approach based on the sale transaction to Tesoro. In the fourth quarter of 2016, the estimated fair value of Pronghorn was determined using the market approach based on the purchase and sale agreement with Tesoro Logistics.

There is risk involved when determining the fair value of assets, 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 assets 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 its assets held for sale are reasonable based on the information that is known when the estimates are made. For more information related to impairment testing of assets held for sale, see Item 8 - Note 2.

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 13. 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, 2016, 2015, and 2014, there were no significant impairment losses recorded. At December 31, 2016, the fair value substantially exceeded the carrying value at all reporting units.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the Company's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, weighted average cost of capital, operational plans, and current and future economic conditions, among others. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach. Under the income approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the weighted average cost of capital at each reporting unit. The weighted average cost of capital, which varies by reporting unit and is in the range of 5 percent to 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 2016. Under the market approach, the Company estimates fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated.

Long-Lived Assets Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows could negatively affect the fair value of the Company's assets and result in an impairment charge. If an impairment indicator exists for tangible and intangible assets, excluding goodwill, the asset group held and used is tested for recoverability by comparing an estimate of undiscounted future cash flows attributable to the assets compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value.

There is risk involved when determining the fair value of assets, tangible and intangible, as there may be unforeseen events and changes in circumstances and market conditions that have a material impact on the estimated amount and timing of future cash flows. In addition, the fair value of the asset could be different using different estimates and assumptions in the valuation techniques used.

The Company believes its estimates used in calculating the fair value of long-lived assets, including goodwill and identifiable intangibles, are reasonable based on the information that is known when the estimates are made.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The recognition of revenue requires the Company to make estimates and assumptions that affect the reported amounts of revenue. Critical estimates related to the recognition of revenue include costs on construction contracts under the percentage-of-completion method.

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. This method depends largely on the ability to make reasonably dependable estimates related to the extent of progress toward completion of the contract, contract revenues and contract costs. Inasmuch as contract prices are generally set before the work is performed, the estimates pertaining to every project could contain significant unknown risks such as volatile labor, material and fuel costs, weather delays, adverse project site conditions, unforeseen actions by regulatory agencies, performance by subcontractors, job management and relations with project owners. Changes in estimates could have a material effect on the Company's results of operations, financial position and cash flows.

Several factors are evaluated in determining the bid price for contract work. These include, but are not limited to, the complexities of the job, past history performing similar types of work, seasonal weather patterns, competition and market conditions, job site conditions, work force safety, reputation of the project owner, availability of labor, materials and fuel, project location and project completion dates. As a project commences, estimates are continually monitored and revised as information becomes available and actual costs and conditions surrounding the job become known. If a loss is anticipated on a contract, the loss is immediately recognized.

The Company believes its estimates surrounding percentage-of-completion accounting are reasonable based on the information that is known when the estimates are made. The Company has contract administration, accounting and management control systems in place that allow its estimates to be updated and monitored on a regular basis. Because of the many factors that are evaluated in determining bid prices, it is inherent that the Company's estimates have changed in the past and will continually change in the future as new information becomes available for each job. There were no material changes in contract estimates at the individual contract level in 2016.

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 $1.3 million (after tax) for the year ended December 31, 2016.

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 14.

Income taxes

Income taxes require significant judgments and estimates including the determination of income tax expense, deferred tax assets and liabilities and, if necessary, any valuation allowances that may be required for deferred tax assets and accruals for uncertain tax positions. The effective income tax rate is subject to variability from period to period as a result of changes in federal and state income tax rates and/or changes in tax laws. In addition, the effective tax rate may be affected by other changes including the allocation of property, payroll and revenues between states. The Company estimates that a one percent change in the effective tax rate would affect the income tax expense by less than $3.3 million for the year ended December 31, 2016.

The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as a regulatory liability and are included in other liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

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

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

Significant federal tax credit carryforwards and federal and state net operating loss carryforwards have been generated. The Company may not be able to utilize all of these carryforwards prior to their expiration. As a result, the Company has recorded valuation allowances for the amounts it may not be able to utilize. Changes in tax regulations or assumptions regarding current and future taxable income could require a change to the estimated valuation allowances in the future resulting in a material impact to the Company's financial position and results of operations. For more information related to federal and state net operating loss carryforwards, see Item 8 - Notes 2 and 11.

The Company believes its estimates surrounding income taxes are reasonable based on the information that is known when the estimates are made.

Liquidity and Capital Commitments

At December 31, 2016, the Company had cash and cash equivalents of $46.1 million and available capacity of $504.9 million under the outstanding credit facilities of the Company and its subsidiaries. The Company expects to meet its obligations for debt maturing within one year from various sources, including internally generated funds; the Company's credit facilities, as described later; and through the issuance of long-term debt.

Cash flows

Operating activities The changes in cash flows from operating activities generally follow the results of operations as discussed in Financial and Operating Data and also are affected by changes in working capital. 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 2016 decreased $199.6 million from 2015. The decrease in cash flows provided by operating activities was largely from lower cash flows at the exploration and production business. The decrease was also due to higher working capital requirements at the electric, natural gas distribution and pipeline and midstream businesses. Partially offsetting the decrease in cash flows provided by operating activities was higher cash flows from continuing operations (excluding working capital) at the electric, pipeline and midstream and construction materials and contracting businesses.

Cash flows provided by operating activities in 2015 increased $74.8 million from 2014. The increase was primarily due to lower working capital requirements of $232.2 million, primarily at the natural gas distribution business, largely related to lower natural gas sales and the construction services business, largely due to lower workloads; as well as lower income tax payments. Partially offsetting this increase was lower earnings primarily due to lower commodity prices at the exploration and production business.

Investing activities Cash flows used in investing activities in 2016 decreased $77.4 million from 2015 primarily due to lower capital expenditures largely at the electric and refining businesses. Partially offsetting this decrease is lower proceeds from the sale of properties at the exploration and production business.

Cash flows used in investing activities in 2015 decreased $521.7 million from 2014 primarily due to lower capital expenditures (including discontinued operations) and higher proceeds from the sale of properties, largely at the exploration and production business.

Financing activities Cash flows used in financing activities in 2016 decreased $60.8 million from 2015 primarily due to the lower repayment of long-term debt of $250.9 million, partially offset by debt repayment in connection with the sale of the refining business, lower capital contributions at the refining business and lower issuance of long-term debt of $36.9 million.

Cash flows used in financing activities was $255.7 million in 2015 compared to cash flows provided by financing activities of $325.2 million in 2014. The change was primarily due to the lower issuance of long-term debt of $260.2 million, higher repayment of long-term debt of $201.3 million and lower issuance of common stock.

Defined benefit pension plans

The Company has qualified noncontributory defined benefit pension plans for certain employees. Plan assets consist of investments in equity and fixed-income securities. Various actuarial assumptions are used in calculating the benefit expense (income) and liability (asset) related to the pension plans. Actuarial assumptions include assumptions about the discount rate, expected return on plan assets and rate of future compensation increases as determined by the Company within certain guidelines. At December 31, 2016, the pension plans' accumulated benefit obligations exceeded these plans' assets by approximately $102.8 million. Pretax pension expense reflected in the years ended December 31, 2016, 2015 and 2014, was $2.1 million, $2.0 million and $1.1 million, respectively. The Company's pension expense is currently projected to be approximately $2.5 million to $3.5 million in 2017. Funding for the pension plans is actuarially determined. The minimum required contributions for 2015 and 2014 were approximately $3.9 million and $10.8 million, respectively. There were no minimum required contributions for 2016. For more information on the Company's pension plans, see Item 8 - Note 14.

Capital expenditures

The Company's capital expenditures from continuing operations for 2014 through 2016 and as anticipated for 2017 through 2019 are summarized in the following table.

	Actual (a)			Estimated		
	2014	2015	**2016**	2017	2018	2019
			(In millions)			
Capital expenditures:						
Electric	$ 185	$ 333	**$ 111**	$ 142	$ 140	$ 110
Natural gas distribution	121	131	**126**	135	134	147
Pipeline and midstream	62	18	**35**	41	57	120
Construction materials and contracting	38	48	**38**	43	55	46
Construction services	27	38	**60**	9	9	10
Other (b)	2	4	**2**	153	152	2
Total capital expenditures	$ 435	$ 572	**$ 372**	$ 523	$ 547	$ 435

(a) Capital expenditures for 2016, 2015 and 2014 include noncash capital expenditure-related accounts payable and AFUDC, totaling $(15.8) million, $35.3 million and $5.1 million, respectively.
(b) Other includes additional growth capital in 2017 and 2018 not allocated to a specific business unit.

The 2016 capital expenditures were met from internal sources and the issuance of long-term debt. Estimated capital expenditures for the years 2017 through 2019 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, including certain costs for additional electric generating capacity
- Environmental upgrades
- Other growth opportunities

The Company continues to evaluate potential future acquisitions and other growth opportunities; however, they are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the estimates in the preceding table. It is anticipated that all of the funds required for capital expenditures for the years 2017 through 2019 will be met from various sources, including internally generated funds; the Company's credit facilities, as described later; through the issuance of long-term debt; and asset sales.

Capital resources

Certain debt instruments of the Company and its subsidiaries, including those discussed later, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions, all of which the Company and its subsidiaries, as applicable, were in compliance with at December 31, 2016. 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 6.

The following table summarizes the outstanding revolving credit facilities of the Company and its subsidiaries at December 31, 2016:

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		$ 111.0	(b)	$ —		5/8/19
Cascade Natural Gas Corporation	Revolving credit agreement		$ 50.0	(c)	$ —		$ 2.2	(d)	7/9/18
Intermountain Gas Company	Revolving credit agreement		$ 65.0	(e)	$ 20.9		$ —		7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(f)	$ 500.0		$ 151.0	(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). There were no amounts outstanding under the credit agreement.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $75.0 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 $90.0 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 credit agreement.

The Company's and Centennial's respective commercial paper programs are supported by revolving credit agreements. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements. The commercial paper borrowings may vary during the period, largely the result of fluctuations in working capital requirements due to the seasonality of the construction businesses.

The following includes information related to the preceding table.

MDU Resources Group, Inc. The Company's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. The Company's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Downgrades in the Company's credit ratings have not limited, nor are currently expected to limit, the Company's ability to access the capital markets. If the Company were to experience a downgrade of its credit ratings, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings.

Prior to the maturity of the credit agreement, the Company expects that it will negotiate the extension or replacement of this agreement. If the Company is unable to successfully negotiate an extension of, or replacement for, the credit agreement, or if the fees on this facility become too expensive, which the Company does not currently anticipate, the Company would seek alternative funding.

The Company's coverage of fixed charges including preferred stock dividends was 3.9 times and 3.1 times for the 12 months ended December 31, 2016 and 2015, respectively.

On November 21, 2016, the Company entered into a $100.0 million note purchase agreement. The Company issued $40.0 million of Senior Notes under the agreement on November 21, 2016, with a due date of November 21, 2046, at an interest rate of 4.15 percent. The Company contracted to issue an additional $60.0 million of Senior Notes under the agreement on March 21, 2017, with due dates ranging from March 2032 to March 2037 at a weighted average interest rate of 3.61 percent.

Total equity as a percent of total capitalization was 56 percent and 58 percent at December 31, 2016 and 2015, 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 indicates how a company is financing its operations, as well as its financial strength.

On May 20, 2013, the Company entered into an Equity Distribution Agreement with Wells Fargo Securities, LLC with respect to the issuance and sale of up to 7.5 million shares of the Company's common stock. The agreement terminated on February 28, 2016. The common stock was offered for sale, from time to time, in accordance with the terms and conditions of the agreement. Proceeds from the shares of common stock under the agreement were used for corporate development purposes and other general corporate purposes. Under the agreement, the Company did not issue any shares of stock between January 1, 2016 and February 28, 2016. Since inception of the Equity Distribution Agreement, the Company issued a cumulative total of 4.4 million shares of stock receiving net proceeds of $144.7 million through February 28, 2016.

Intermountain Gas Company On November 9, 2016, Intermountain issued $30.0 million of Senior Notes with a due date of November 9, 2046, at an interest rate of 4.0 percent.

Centennial Energy Holdings, Inc. On September 23, 2016, Centennial amended its revolving credit agreement to decrease the borrowing limit by $150.0 million to $500.0 million and extend the termination date to September 23, 2021. The 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. Other covenants include restricted payments, restrictions on the sale of certain assets, limitations on subsidiary indebtedness and the making of certain loans and investments.

Centennial's revolving credit agreement contains 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 obligations, 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 revolving credit agreement will be in default.

Centennial's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. Centennial's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Downgrades in Centennial's credit ratings have not limited, nor are currently expected to limit, Centennial's ability to access the capital markets. If Centennial were to experience a downgrade of its credit ratings, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings.

Prior to the maturity of the Centennial credit agreement, Centennial expects that it will negotiate the extension or replacement of this agreement, which provides credit support to access the capital markets. In the event Centennial is unable to successfully negotiate this agreement, or in the event the fees on this facility become too expensive, which Centennial does not currently anticipate, it would seek alternative funding.

WBI Energy Transmission, Inc. On May 17, 2016, WBI Energy Transmission entered into an amendment to its amended and restated uncommitted note purchase and private shelf agreement to increase the aggregate issuance capacity from $175.0 million to $200.0 million and extend the issuance period to May 16, 2019. WBI Energy Transmission had $100.0 million of notes outstanding at December 31, 2016, which reduced capacity under this uncommitted private shelf agreement to $100.0 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. Other covenants include a limitation on priority debt and restrictions on the sale of certain assets and the making of certain investments.

Off balance sheet arrangements

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 totaled $63.8 million at December 31, 2016, and are expected to mature by 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.

In March 2016, a sale agreement was signed to sell Fidelity's assets in the Paradox Basin. In connection with the sale, Centennial agreed to guarantee Fidelity's indemnity obligations associated with the Paradox Basin assets. The guarantee was required by the buyer as a condition to the sale of the Paradox Basin assets.

In connection with the sale of the Brazilian Transmission Lines, Centennial has agreed to guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries who 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.

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 6 and 17. At December 31, 2016, the Company's commitments under these obligations were as follows:

	2017	2018	2019	2020	2021	Thereafter	Total
				(In millions)			
Long-term debt	$ 43.6	$ 169.4	$ 162.2	$ 15.0	$ 151.0	$ 1,254.9	$ 1,796.1
Estimated interest payments*	77.4	74.5	65.2	62.7	61.3	543.0	884.1
Operating leases	51.7	43.3	33.9	23.2	9.4	42.0	203.5
Purchase commitments	367.7	215.7	189.4	138.0	130.6	859.5	1,900.9
	$ 540.4	$ 502.9	$ 450.7	$ 238.9	$ 352.3	$ 2,699.4	$ 4,784.6

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

At December 31, 2016, the Company had total liabilities of $315.0 million related to asset retirement obligations that are excluded from the table above. Of the total asset retirement obligations, the current portion was $4.3 million at December 31, 2016, and was included in other accrued liabilities on the Consolidated Balance Sheet. The remainder, which constitutes the long-term portion of asset retirement obligations, was included in other liabilities on the Consolidated Balance Sheet. Due to the nature of these obligations, the Company cannot determine precisely when the payments will be made to settle these obligations. For more information, see Item 8 - Note 7.

The Company has no uncertain tax positions and no minimum funding requirements for its defined benefit pension plans for 2017.

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 14.

Effects of Inflation

Inflation did not have a significant effect on the Company's operations in 2016, 2015 or 2014.

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.

At December 31, 2016 and 2015, the Company had no outstanding interest rate hedges.

The following table shows the amount of debt, including current portion, and related weighted average interest rates, both by expected maturity dates, as of December 31, 2016.

	2017	2018	2019	2020	2021	Thereafter	Total	Fair Value
				(Dollars in millions)				
Long-term debt:								
Fixed rate	$ 43.6	$ 148.5	$ 51.2	$ 15.0	—	$ 1,254.9	$ 1,513.2	$ 1,559.0
Weighted average interest rate	6.3%	6.1%	4.3%	5.2%	—	4.8%	4.9%	—
Variable rate	—	$ 20.9	$ 111.0	—	$ 151.0	—	$ 282.9	$ 282.9
Weighted average interest rate	—	3.1%	1.1%	—	1.4%	—	1.4%	—

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, 2016. 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, 2016.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2016, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.

/s/ David L. Goodin

David L. Goodin
President and Chief Executive Officer

/s/ Doran N. Schwartz

Doran N. Schwartz
Vice President and Chief Financial Officer

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of MDU Resources Group, Inc.

We have audited the accompanying consolidated balance sheets of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included the financial statement schedules listed in the Index at Item 15. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of MDU Resources Group, Inc. and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2017 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 24, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of MDU Resources Group, Inc.

We have audited the internal control over financial reporting of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2016, based on criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2016 of the Company and our report dated February 24, 2017 expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 24, 2017

Consolidated Statements of Income

Years ended December 31,	2016	2015	2014
	(In thousands, except per share amounts)		
Operating revenues:			
Electric, natural gas distribution and regulated pipeline and midstream	**$ 1,141,454**	$ 1,149,038	$ 1,246,903
Nonregulated pipeline and midstream, construction materials and contracting, construction services and other	**2,987,374**	2,865,014	2,868,170
Total operating revenues	**4,128,828**	4,014,052	4,115,073
Operating expenses:			
Fuel and purchased power	**75,512**	86,238	89,312
Purchased natural gas sold	**382,753**	450,114	558,463
Operation and maintenance:			
Electric, natural gas distribution and regulated pipeline and midstream	**312,404**	278,171	269,175
Nonregulated pipeline and midstream, construction materials and contracting, construction services and other	**2,580,895**	2,527,052	2,523,039
Depreciation, depletion and amortization	**216,318**	211,747	203,084
Taxes, other than income	**151,826**	140,955	144,818
Total operating expenses	**3,719,708**	3,694,277	3,787,891
Operating income	**409,120**	319,775	327,182
Other income	**4,956**	18,457	9,138
Interest expense	**87,848**	91,179	86,871
Income before income taxes	**326,228**	247,053	249,449
Income taxes	**93,132**	70,664	64,422
Income from continuing operations	**233,096**	176,389	185,027
Income (loss) from discontinued operations, net of tax (Note 2)	**(300,354)**	(834,080)	109,311
Net income (loss)	**(67,258)**	(657,691)	294,338
Loss from discontinued operations attributable to noncontrolling interest (Note 2)	**(131,691)**	(35,256)	(3,895)
Dividends declared on preferred stocks	**685**	685	685
Earnings (loss) on common stock	**$ 63,748**	$ (623,120)	$ 297,548
Earnings (loss) per common share - basic:			
Earnings before discontinued operations	**$ 1.19**	$ .90	$ .96
Discontinued operations attributable to the Company, net of tax	**(.86)**	(4.10)	.59
Earnings (loss) per common share - basic	**$ .33**	$ (3.20)	$ 1.55
Earnings (loss) per common share - diluted:			
Earnings before discontinued operations	**$ 1.19**	$ .90	$ .96
Discontinued operations attributable to the Company, net of tax	**(.86)**	(4.10)	.59
Earnings (loss) per common share - diluted	**$ .33**	$ (3.20)	$ 1.55
Weighted average common shares outstanding - basic	**195,299**	194,928	192,507
Weighted average common shares outstanding - diluted	**195,618**	194,986	192,587

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

Consolidated Statements of Comprehensive Income

Years ended December 31,	2016	2015	2014
		(In thousands)	
Net income (loss)	**$ (67,258)**	$ (657,691)	$ 294,338
Other comprehensive income (loss):			
Net unrealized gain on derivative instruments qualifying as hedges:			
Reclassification adjustment for loss on derivative instruments included in net income (loss), net of tax of $226, $233 and $240 in 2016, 2015 and 2014, respectively	**367**	404	399
Reclassification adjustment for loss on derivative instruments included in income (loss) from discontinued operations, net of tax of $0, $0 and $173 in 2016, 2015 and 2014, respectively	**—**	—	295
Net unrealized gain on derivative instruments qualifying as hedges	**367**	404	694
Postretirement liability adjustment:			
Postretirement liability losses arising during the period, net of tax of $(836), $(55) and $(7,665) in 2016, 2015 and 2014, respectively	**(1,470)**	(88)	(12,409)
Amortization of postretirement liability losses included in net periodic benefit cost (credit), net of tax of $1,425, $1,128 and $492 in 2016, 2015 and 2014, respectively	**2,506**	1,794	796
Reclassification of postretirement liability adjustment to regulatory asset, net of tax of $0, $1,416 and $4,509 in 2016, 2015 and 2014, respectively	**—**	2,255	7,202
Postretirement liability adjustment	**1,036**	3,961	(4,411)
Foreign currency translation adjustment:			
Foreign currency translation adjustment recognized during the period, net of tax of $31, $(105) and $(99) in 2016, 2015 and 2014, respectively	**51**	(173)	(162)
Reclassification adjustment for loss on foreign currency translation adjustment included in net income (loss), net of tax of $0, $490 and $0 in 2016, 2015 and 2014, respectively	**—**	802	—
Foreign currency translation adjustment	**51**	629	(162)
Net unrealized loss on available-for-sale investments:			
Net unrealized loss on available-for-sale investments arising during the period, net of tax of $(98), $(91) and $(83) in 2016, 2015 and 2014, respectively	**(182)**	(170)	(154)
Reclassification adjustment for loss on available-for-sale investments included in net income (loss), net of tax of $77, $70 and $73 in 2016, 2015 and 2014, respectively	**143**	131	135
Net unrealized loss on available-for-sale investments	**(39)**	(39)	(19)
Other comprehensive income (loss)	**1,415**	4,955	(3,898)
Comprehensive income (loss)	**(65,843)**	(652,736)	290,440
Comprehensive loss from discontinued operations attributable to noncontrolling interest	**(131,691)**	(35,256)	(3,895)
Comprehensive income (loss) attributable to common stockholders	**$ 65,848**	$ (617,480)	$ 294,335

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

Consolidated Balance Sheets

December 31,	2016	2015
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 46,107	$ 83,903
Receivables, net	630,243	582,475
Inventories	238,273	240,551
Prepayments and other current assets	48,461	29,528
Current assets held for sale	14,391	54,847
Total current assets	977,475	991,304
Investments	125,866	119,704
Property, plant and equipment (Note 1)	6,510,229	6,387,702
Less accumulated depreciation, depletion and amortization	2,578,902	2,489,322
Net property, plant and equipment	3,931,327	3,898,380
Deferred charges and other assets:		
Goodwill (Note 3)	631,791	635,204
Other intangible assets, net (Note 3)	5,925	7,342
Other	415,419	351,603
Noncurrent assets held for sale	196,664	561,617
Total deferred charges and other assets	1,249,799	1,555,766
Total assets	$ 6,284,467	$ 6,565,154
Liabilities and Equity		
Current liabilities:		
Long-term debt due within one year	$ 43,598	$ 238,539
Accounts payable	279,962	286,061
Taxes payable	48,164	46,880
Dividends payable	37,767	36,784
Accrued compensation	65,867	45,192
Other accrued liabilities	184,377	167,322
Current liabilities held for sale	9,924	126,483
Total current liabilities	669,659	947,261
Long-term debt (Note 6)	1,746,561	1,557,624
Deferred credits and other liabilities:		
Deferred income taxes	668,226	663,629
Other	883,777	812,342
Noncurrent liabilities held for sale	—	63,750
Total deferred credits and other liabilities	1,552,003	1,539,721
Commitments and contingencies (Notes 14, 16 and 17)		
Equity:		
Preferred stocks (Note 8)	15,000	15,000
Common stockholders' equity:		
Common stock (Note 9) Authorized - 500,000,000 shares, $1.00 par value Issued - 195,843,297 shares in 2016 and 195,804,665 shares in 2015	195,843	195,805
Other paid-in capital	1,232,478	1,230,119
Retained earnings	912,282	996,355
Accumulated other comprehensive loss	(35,733)	(37,148)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total common stockholders' equity	2,301,244	2,381,505
Total stockholders' equity	2,316,244	2,396,505
Noncontrolling interest	—	124,043
Total equity	2,316,244	2,520,548
Total liabilities and equity	$ 6,284,467	$ 6,565,154

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

Consolidated Statements of Equity

Years ended December 31, 2016, 2015 and 2014

	Preferred Stock		Common Stock					Treasury Stock			
	Shares	Amount	Shares	Amount	Other Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Shares	Amount	Noncontrolling Interest	Total
	(In thousands, except shares)										
Balance at December 31, 2013	150,000	$15,000	189,868,780	$189,869	$1,056,996	$1,603,130	$(38,205)	(538,921)	$(3,626)	$ 32,738	$2,855,902
Net income (loss)	—	—	—	—	—	298,233	—	—	—	(3,895)	294,338
Other comprehensive loss	—	—	—	—	—	—	(3,898)	—	—	—	(3,898)
Dividends declared on preferred stocks	—	—	—	—	—	(685)	—	—	—	—	(685)
Dividends declared on common stock	—	—	—	—	—	(137,851)	—	—	—	—	(137,851)
Stock-based compensation	—	—	—	—	6,191	—	—	—	—	—	6,191
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	—	—	326,122	326	(5,890)	—	—	—	—	—	(5,564)
Excess tax benefit on stock-based compensation	—	—	—	—	4,729	—	—	—	—	—	4,729
Issuance of common stock	—	—	4,559,910	4,560	145,162	—	—	—	—	—	149,722
Contribution from noncontrolling interest	—	—	—	—	—	—	—	—	—	86,900	86,900
Balance at December 31, 2014	150,000	15,000	194,754,812	194,755	1,207,188	1,762,827	(42,103)	(538,921)	(3,626)	115,743	3,249,784
Net loss	—	—	—	—	—	(622,435)	—	—	—	(35,256)	(657,691)
Other comprehensive income	—	—	—	—	—	—	4,955	—	—	—	4,955
Dividends declared on preferred stocks	—	—	—	—	—	(685)	—	—	—	—	(685)
Dividends declared on common stock	—	—	—	—	—	(143,352)	—	—	—	—	(143,352)
Stock-based compensation	—	—	—	—	3,689	—	—	—	—	—	3,689
Net tax deficit on stock-based compensation	—	—	—	—	(1,606)	—	—	—	—	—	(1,606)
Issuance of common stock	—	—	1,049,853	1,050	20,848	—	—	—	—	—	21,898
Contribution from noncontrolling interest	—	—	—	—	—	—	—	—	—	52,000	52,000
Distribution to noncontrolling interest	—	—	—	—	—	—	—	—	—	(8,444)	(8,444)
Balance 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
Balance 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**

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

Consolidated Statements of Cash Flows

Years ended December 31,	2016	2015	2014
		(In thousands)	
Operating activities:			
Net income (loss)	$ **(67,258)**	$ (657,691)	$ 294,338
Income (loss) from discontinued operations, net of tax	**(300,354)**	(834,080)	109,311
Income from continuing operations	**233,096**	176,389	185,027
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	**216,318**	211,747	203,084
Deferred income taxes	**(2,049)**	(25,356)	54,963
Excess tax benefit on stock-based compensation	**—**	—	(4,729)
Changes in current assets and liabilities, net of acquisitions:			
Receivables	**(25,641)**	4,704	6,652
Inventories	**2,433**	2,265	(17,484)
Other current assets	**(17,925)**	60,182	(45,830)
Accounts payable	**7,039**	37,224	(47,092)
Other current liabilities	**36,146**	6,864	(17,252)
Other noncurrent changes	**(26,459)**	(10,240)	(18,144)
Net cash provided by continuing operations	**422,958**	463,779	299,195
Net cash provided by discontinued operations	**39,251**	198,053	287,867
Net cash provided by operating activities	**462,209**	661,832	587,062
Investing activities:			
Capital expenditures	**(388,183)**	(536,832)	(429,336)
Net proceeds from sale or disposition of property and other	**44,826**	54,569	28,899
Investments	**(1,396)**	1,515	(1,041)
Net cash used in continuing operations	**(344,753)**	(480,748)	(401,478)
Net cash provided by (used in) discontinued operations	**39,658**	98,295	(502,712)
Net cash used in investing activities	**(305,095)**	(382,453)	(904,190)
Financing activities:			
Repayment of short-term borrowings	**—**	—	(11,500)
Issuance of long-term debt	**309,064**	345,920	606,168
Repayment of long-term debt	**(315,647)**	(566,498)	(365,247)
Proceeds from issuance of common stock	**—**	21,898	150,060
Dividends paid	**(147,156)**	(142,835)	(136,712)
Excess tax benefit on stock-based compensation	**—**	—	4,729
Tax withholding on stock-based compensation	**(323)**	—	(5,564)
Net cash provided by (used in) continuing operations	**(154,062)**	(341,515)	241,934
Net cash provided by (used in) discontinued operations	**(40,852)**	85,785	83,262
Net cash provided by (used in) financing activities	**(194,914)**	(255,730)	325,196
Effect of exchange rate changes on cash and cash equivalents	**4**	(225)	(155)
Increase (decrease) in cash and cash equivalents	**(37,796)**	23,424	7,913
Cash and cash equivalents - beginning of year	**83,903**	60,479	52,566
Cash and cash equivalents - end of year	$ **46,107**	$ 83,903	$ 60,479

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 13. 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 4 for more information regarding the nature and amounts of these regulatory deferrals.

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

Management has also evaluated the impact of events occurring after December 31, 2016, up to the date of issuance of these consolidated financial statements.

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 reduces the Company’s risk by decreasing exposure to commodity prices.

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 all of Fidelity's oil and natural gas assets. The completion of these sales occurred between October 2015 and April 2016. 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 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. The Company's consolidated financial statements and accompanying notes for current and prior periods have been restated. 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 2.

Cash and cash equivalents

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

Accounts receivable and allowance for doubtful accounts

Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts, and costs and estimated earnings in excess of billings on uncompleted contracts. For more information, see Percentage-of-completion method in this note. The total balance of receivables past due 90 days or more was $29.2 million and $27.8 million at December 31, 2016 and 2015, 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, 2016 and 2015, was $10.5 million and $9.8 million, respectively.

Inventories and natural gas in storage

Natural gas in storage for the Company's regulated operations is generally carried at average cost, or cost using the last-in, first-out method. All other inventories are stated at the lower of average cost or market 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:

	2016	2015
	(In thousands)	
Aggregates held for resale	**$ 115,471**	$ 115,854
Asphalt oil	**29,103**	36,498
Natural gas in storage (current)	**25,761**	21,023
Materials and supplies	**18,372**	16,997
Merchandise for resale	**16,437**	15,318
Other	**33,129**	34,861
Total	**$ 238,273**	$ 240,551

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 $49.5 million and $49.1 million at December 31, 2016 and 2015, 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 5 and 14.

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 and interest capitalized for the years ended December 31 were as follows:

	2016	2015	2014
		(In thousands)	
Interest capitalized	**$ —**	$ 4,381	$ 7,046
AFUDC - borrowed	**$ 914**	$ 4,907	$ 3,023
AFUDC - equity	**$ 565**	$ 7,971	$ 5,803

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 other liabilities.

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

	2016	2015	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	$ 1,036,373	$ 1,003,173	39
Distribution	398,382	375,612	44
Transmission	284,048	255,842	57
Construction in progress	62,212	42,436	-
Other	107,598	109,085	14
Natural gas distribution:			
Distribution	1,718,633	1,624,645	46
Construction in progress	19,934	20,530	-
Other	440,846	431,406	18
Pipeline and midstream:			
Transmission	490,143	460,305	54
Gathering	37,831	37,831	20
Storage	45,350	44,011	62
Construction in progress	16,507	7,549	-
Other	40,873	40,168	33
Nonregulated:			
Pipeline and midstream:			
Gathering and processing	31,682	158,949	19
Construction in progress	13	89	-
Other	9,800	9,827	10
Construction materials and contracting:			
Land	94,625	95,870	-
Buildings and improvements	102,347	96,864	19
Machinery, vehicles and equipment	930,471	937,084	12
Construction in progress	16,181	18,615	-
Aggregate reserves	405,751	404,995	*
Construction services:			
Land	5,346	5,025	-
Buildings and improvements	26,693	25,259	26
Machinery, vehicles and equipment	132,217	121,940	6
Other	7,105	11,055	4
Other:			
Land	2,837	2,837	-
Other	46,431	46,700	23
Less accumulated depreciation, depletion and amortization	2,578,902	2,489,322	
Net property, plant and equipment	$ 3,931,327	$ 3,898,380	

* 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. In the third quarter of 2015, the Company recognized an impairment of $14.1 million (before tax), largely related to the sale of certain non-strategic natural gas gathering assets that were written down to their estimated fair value that was determined using the market approach. In the second quarter of 2015, the Company recognized an impairment of $3.0 million (before tax) related to coalbed natural gas gathering assets located in Wyoming where there had been continued decline in natural gas development and production activity due to low natural gas prices. The coalbed natural gas gathering assets were written down to their estimated fair value that was determined using the income approach. The impairments are recorded in operation and maintenance expense on the Consolidated Statements of Income. For more information on these nonrecurring fair value measurements, see Note 5.

No significant impairment losses were recorded in 2016, other than those related to the Company's assets held for sale and discontinued operations. For more information regarding these impairments, see Note 2.

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 13. 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, 2016, 2015 and 2014, there were no significant impairment losses recorded. At December 31, 2016, the fair value substantially exceeded the carrying value at all reporting units.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the Company's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, weighted average cost of capital, operational plans, and current and future economic conditions, among others. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach. Under the income approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the weighted average cost of capital at each reporting unit. The weighted average cost of capital, which varies by reporting unit and is in the range of 5 percent to 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 2016. Under the market approach, the Company estimates fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued unbilled revenue which is included in receivables, net, represents revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota, Cascade and Intermountain was $117.7 million and $102.1 million at December 31, 2016 and 2015, respectively. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed later. The Company recognizes all other revenues when services are rendered or goods are delivered. The Company presents revenues net of taxes collected from customers at the time of sale to be remitted to governmental authorities, including sales and use taxes.

Percentage-of-completion method

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. If a loss is anticipated on a contract, the loss is immediately recognized.

Costs and estimated earnings in excess of billings on uncompleted contracts represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs and estimated earnings on uncompleted contracts represent billings in excess of revenues recognized and were included in accounts payable. Costs and estimated earnings in excess of billings and billings in excess of costs and estimated earnings on uncompleted contracts at December 31 were as follows:

		2016		2015
		(In thousands)		
Costs and estimated earnings in excess of billings on uncompleted contracts	$	**64,558**	$	64,369
Billings in excess of costs and estimated earnings on uncompleted contracts	$	**64,832**	$	68,048

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

		2016		2015
		(In thousands)		
Short-term retainage*	$	**45,109**	$	46,207
Long-term retainage**		**1,506**		1,605
Total retainage	$	**46,615**	$	47,812

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

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 7.

Legal costs

The Company expenses external legal fees as they are incurred.

Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public 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 $25.6 million and $20.9 million at December 31, 2016 and 2015, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $2.2 million and $547,000 at December 31, 2016 and 2015, respectively, which is included in prepayments and other current assets.

Income taxes

The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as a regulatory liability and are included in other liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

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

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

Earnings (loss) per common share

Basic earnings (loss) per common share were computed by dividing earnings (loss) on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings (loss) per common share were computed by dividing earnings (loss) on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding performance share awards. In 2016, 2015 and 2014, there were no shares excluded from the calculation of diluted earnings per share. Common stock outstanding includes issued shares less shares held in treasury. Net income (loss) was the same for both the basic and diluted earnings (loss) per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings (loss) per share calculation was as follows:

	2016	2015	2014
		(In thousands)	
Weighted average common shares outstanding - basic	**195,299**	194,928	192,507
Effect of dilutive performance share awards	**319**	58	80
Weighted average common shares outstanding - diluted	**195,618**	194,986	192,587
Shares excluded from the calculation of diluted earnings per share	**—**	—	—

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 assets held for sale, 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; 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

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. This guidance was to be effective for the Company on January 1, 2017. In August 2015, the FASB issued guidance deferring the effective date of the revenue guidance one year and allowing entities to early adopt. With this decision, the guidance will be effective for the Company on January 1, 2018. Entities will have the option of using either a full retrospective or modified retrospective approach to adopting the guidance. Under the modified approach, an entity would recognize the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings in the period of adoption. In addition, the modified approach will require additional disclosures. The Company is planning to adopt the guidance using the modified retrospective approach and continues to evaluate the effects it will have on its results of operations, financial position, cash flows and disclosures.

Simplifying the Presentation of Debt Issuance Costs In April 2015, the FASB issued guidance on simplifying the presentation of debt issuance costs in the financial statements. This guidance requires entities to present debt issuance costs as a direct deduction to the related debt liability. The amortization of these costs will be reported as interest expense. The guidance was effective for the Company on January 1, 2016, and was to be applied retrospectively. Early adoption of this guidance was permitted, however the Company did not elect to do so. The guidance required a reclassification of the debt issuance costs on the Consolidated Balance Sheets, but did not impact the Company's results of operations or cash flows. As a result of the retrospective application of this change in accounting principle, the Company reclassified debt issuance costs of $100,000 from prepayments and other current assets and $6.0 million from deferred charges and other assets - other to long-term debt on its Consolidated Balance Sheets at December 31, 2015.

Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent) In May 2015, the FASB issued guidance on fair value measurement and disclosure requirements removing the requirement to include investments in the fair value hierarchy for which fair value is measured using the net asset value per share practical expedient. The new guidance also removes the requirement to make certain disclosures for all investments that are eligible to be measured at net asset value using the practical expedient, and rather limits those disclosures to investments for which the practical expedient has been elected. This guidance was effective for the Company on January 1, 2016, with early adoption permitted. The application of this guidance affected the Company's disclosures; however, it did not impact the Company's results of operations, financial position or cash flows.

Simplifying the Measurement of Inventory In July 2015, the FASB issued guidance regarding inventory that is measured using the first-in, first-out or average cost method. The guidance does not apply to inventory measured using the last-in, first-out or the retail inventory method. The guidance requires inventory within its scope to be measured at the lower of cost or net realizable value, which is the estimated selling price in the normal course of business less reasonably predictable costs of completion, disposal and transportation. These amendments more closely align GAAP with IFRS. This guidance was effective for the Company on January 1, 2017, on a prospective basis. The Company does not anticipate the guidance will have a material effect on its results of operations, financial position or cash flows.

Balance Sheet Classification of Deferred Taxes In November 2015, the FASB issued guidance regarding the classification of deferred taxes on the balance sheet. The guidance will require all deferred tax assets and liabilities to be classified as noncurrent. These amendments will align GAAP with IFRS. Entities had the option to apply the guidance prospectively, for all deferred tax assets and liabilities, or retrospectively. The Company adopted the guidance in the fourth quarter of 2016 and applied the retrospective method of adoption. The guidance required a reclassification of current deferred income taxes to noncurrent deferred income taxes on the Consolidated Balance Sheets, but did not impact the Company's results of operations or cash flows. As a result of the retrospective application of this change in accounting principle, the Company reclassified deferred income taxes of $33.1 million from current assets - deferred income taxes to deferred credits and other liabilities - deferred income taxes on its Consolidated Balance Sheets at December 31, 2015.

Recognition and Measurement of Financial Assets and Financial Liabilities In January 2016, the FASB issued guidance regarding the classification and measurement of financial instruments. The guidance revises the way an entity classifies and measures investments in equity securities, the presentation of certain fair value changes for financial liabilities measured at fair value and amends certain disclosure requirements related to the fair value of financial instruments. This guidance will be effective for the Company on January 1, 2018, with early adoption of certain amendments permitted. The guidance should be applied using a modified retrospective approach with the exception of equity securities without readily determinable fair values which will be applied prospectively. 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.

Leases In February 2016, the FASB issued guidance regarding leases. The guidance requires lessees to recognize a liability to make lease payments and a right-of-use asset representing its right to use the underlying asset for the lease term on the statement of financial position for leases with terms of more than 12 months. This guidance also requires additional disclosures. This guidance will be effective for the Company on January 1, 2019, and should be applied using a modified retrospective approach with early adoption permitted. 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.

Improvements to Employee Share-Based Payment Accounting In March 2016, the FASB issued guidance regarding simplification of several aspects of the accounting for share-based payment transactions. The guidance will affect the income tax consequences, classification of awards as either equity or liabilities, classification on the statement of cash flows and calculation of dilutive shares. Certain amendments of this guidance are to be applied retrospectively and others prospectively. The Company adopted the guidance on January 1, 2017. All amendments in the guidance that apply to the Company were adopted on a prospective basis resulting in no adjustments being made to retained earnings. The Company anticipates the guidance will impact the Consolidated Statements of Income and the Consolidated Balance Sheets, as well as the dilutive earnings per share calculation, on a prospective basis with all taxes related to share-based payments recognized as income tax expense or benefit and no longer recognized in additional paid-in capital. The Company anticipates the guidance will not have a material impact on its cash flows.

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. This guidance will be effective for the Company on January 1, 2018, with early adoption permitted. An entity that elects early adoption must adopt all the amendments in the same period and apply any adjustments as of the beginning of the fiscal year. Entities must apply the guidance retrospectively unless it is impracticable to do so, in which case they may apply it prospectively as of the earliest date practicable. The Company is evaluating the effects the adoption of the new guidance will have on its cash flows and disclosures.

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 will also affect other aspects of accounting, such as determining reporting units for goodwill testing. The guidance will be effective for the Company on January 1, 2018, and should be applied on a prospective basis with early adoption permitted for transactions that occur before the issuance or effective date of the amendments and only when the transactions have not been reported in the financial statements or made available for issuance. 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.

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 should be applied on a prospective basis with early adoption permitted. 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.

Variable interest entities

The Company evaluates its arrangements and contracts with other entities to determine if they are VIEs and if so, if the Company is the primary beneficiary. GAAP provides a framework for identifying VIEs and determining when a company should include the assets, liabilities, noncontrolling interest and results of activities of a VIE in its consolidated financial statements.

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

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

Comprehensive income (loss)

Comprehensive income (loss) is the sum of net income (loss) as reported and other comprehensive income (loss). The Company's other comprehensive income (loss) resulted from gains (losses) on derivative instruments qualifying as hedges, postretirement liability adjustments, foreign currency translation adjustments and gains (losses) on available-for-sale investments.

The after-tax changes in the components of accumulated other comprehensive loss as of December 31, 2016, 2015 and 2014, 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, 2014	$ (3,071)	$ (38,218)	$ (829)	$ 15	$ (42,103)
Other comprehensive income (loss) before reclassifications	—	(88)	(173)	(170)	(431)
Amounts reclassified from accumulated other comprehensive loss	404	1,794	802	131	3,131
Amounts reclassified from accumulated other comprehensive loss to a regulatory asset	—	2,255	—	—	2,255
Net current-period other comprehensive income (loss)	404	3,961	629	(39)	4,955
Balance at December 31, 2015	(2,667)	(34,257)	(200)	(24)	(37,148)
Other comprehensive income (loss) before reclassifications	—	(1,470)	51	(182)	(1,601)
Amounts reclassified from accumulated other comprehensive loss	367	2,506	—	143	3,016
Net current-period other comprehensive income (loss)	367	1,036	51	(39)	1,415
Balance at December 31, 2016	**$ (2,300)**	**$ (33,221)**	**$ (149)**	**$ (63)**	**$ (35,733)**

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

	2016	2015	Location on Consolidated Statements of Income
	(In thousands)		
Reclassification adjustment for loss on derivative instruments included in net income (loss):			
Interest rate derivative instruments	$ **(593)**	$ (637)	Interest expense
	226	233	Income taxes
	(367)	(404)	
Amortization of postretirement liability losses included in net periodic benefit cost (credit)	**(3,931)**	(2,922)	(a)
	1,425	1,128	Income taxes
	(2,506)	(1,794)	
Reclassification adjustment for loss on foreign currency translation adjustment included in net income (loss)	—	(1,292)	Other income
	—	490	Income taxes
	—	(802)	
Reclassification adjustment for loss on available-for-sale investments included in net income (loss)	**(220)**	(201)	Other income
	77	70	Income taxes
	(143)	(131)	
Total reclassifications	$ **(3,016)**	$ (3,131)	

(a) Included in net periodic benefit cost (credit). For more information, see Note 14.

Note 2 - Assets Held for Sale and Discontinued Operations

Assets held for sale

The assets and liabilities of Pronghorn have been classified as held for sale. Pronghorn's results of operations are included in the pipeline and midstream segment. The Company's consolidated financial statements and accompanying notes for the current period reflect Pronghorn classified as held for sale.

Pronghorn On November 21, 2016, WBI Energy Midstream announced it had entered into a purchase and sale agreement to sell its 50 percent non-operating ownership interest in Pronghorn to Tesoro Logistics. The transaction closed on January 1, 2017. The sale of Pronghorn further reduces the Company's risk exposure to commodity prices.

The carrying amounts of the major classes of assets and liabilities that are classified as held for sale associated with Pronghorn on the Company's Consolidated Balance Sheets at December 31 were as follows:

	2016
	(In thousands)
Assets	
Current assets:	
Prepayments and other current assets	$ **68**
Total current assets held for sale	**68**
Noncurrent assets:	
Net property, plant and equipment	**93,424**
Goodwill	**9,737**
Less allowance for impairment of assets held for sale	**2,311**
Total noncurrent assets held for sale	**100,850**
Total assets held for sale	$ **100,918**

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the fourth quarter of 2016, the fair value assessment was determined using the market approach based on the purchase and sale agreement with Tesoro Logistics. 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 $2.3 million ($1.4 million after tax) in the quarter ended December 31, 2016. The fair value of Pronghorn's assets has been categorized as Level 3 in the fair value hierarchy. The impairment was recorded in operation and maintenance expense on the Consolidated Statement of Income.

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. The Company's consolidated financial statements and accompanying notes for current and prior periods have been restated. 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 reduces the Company's risk by decreasing exposure to commodity prices.

The Company retained certain liabilities of Dakota Prairie Refining which are reflected in current liabilities held for sale on the Consolidated Balance Sheet at December 31, 2016. Centennial continues to guarantee certain debt obligations of Dakota Prairie Refining; however, Tesoro has agreed to indemnify Centennial for any losses and litigation expenses arising for the guarantee. For more information related to the guarantee, see Note 17.

The carrying amounts of the major classes of assets and liabilities that are 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:

	2016	2015
	(In thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$ —	$ 688
Receivables, net	—	7,693
Inventories	—	13,176
Income taxes receivable	13,987	2,495
Prepayments and other current assets	—	6,214
Total current assets held for sale	13,987	30,266
Noncurrent assets:		
Net property, plant and equipment	—	412,717
Other	—	9,627
Total noncurrent assets held for sale	—	422,344
Total assets held for sale	$ 13,987	$ 452,610
Liabilities		
Current liabilities:		
Short-term borrowings	$ —	$ 45,500
Long-term debt due within one year	—	5,250
Accounts payable	7,425	24,468
Taxes payable	—	1,391
Accrued compensation	—	938
Other accrued liabilities	—	4,953
Total current liabilities held for sale	7,425	82,500
Noncurrent liabilities:		
Long-term debt	—	63,750
Deferred income taxes	14 (a)	23,841 (a)
Total noncurrent liabilities held for sale	14	87,591
Total liabilities held for sale	$ 7,439	$ 170,091

(a) On the Company's Consolidated Balance Sheets, these amounts were reclassified to noncurrent deferred income tax assets and are reflected in noncurrent assets held for sale.

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. At December 31, 2016, the Company has not incurred any material exit and disposal costs related to Dakota Prairie Refining, and does not expect to incur any material exit and disposal costs.

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 all of Fidelity's oil and natural gas assets. The completion of the majority of these sales occurred between October 2015 and April 2016. 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 that are classified as held for sale related to the operations of Fidelity on the Company's Consolidated Balance Sheets at December 31 were as follows:

		2016		2015
		(In thousands)		
Assets				
Current assets:				
Receivables, net	$	**355**	$	13,387
Inventories		**—**		1,308
Income taxes receivable		**—**		9,665
Prepayments and other current assets		**—**		221
Total current assets held for sale		**355**		24,581
Noncurrent assets:				
Investments		**—**		37
Net property, plant and equipment		**5,507**		793,422
Deferred income taxes		**91,098**		124,035
Other		**161**		161
Less allowance for impairment of assets held for sale		**938**		754,541
Total noncurrent assets held for sale		**95,828**		163,114
Total assets held for sale	$	**96,183**	$	187,695
Liabilities				
Current liabilities:				
Accounts payable	$	**141**	$	25,013
Taxes payable		**19** (a)		1,052
Accrued compensation		**—**		13,080
Other accrued liabilities		**2,358**		4,838
Total current liabilities held for sale		**2,518**		43,983
Total liabilities held for sale	$	**2,518**	$	43,983

(a) On the Company's Consolidated Balance Sheets, this amount was reclassified to prepayments and other current assets and is reflected in current assets held for sale.

At December 31, 2016 and 2015, the Company’s deferred tax assets included in assets held for sale were largely comprised of $89.3 million and $78.9 million, respectively, of federal and state net operating loss carryforwards.

The Company had federal income tax net operating loss carryforwards of $297.2 million and $208.2 million at December 31, 2016 and 2015, respectively. At December 31, 2016 and 2015, the Company had various state income tax net operating loss carryforwards of $189.1 million and $201.4 million, respectively. The federal net operating loss carryforwards expire in 2036 and 2037 if not utilized. The state net operating loss carryforwards are due to expire between 2023 and 2037. It is likely a portion of the benefit from the state carryforwards will not be realized; therefore, valuation allowances of $500,000 and $300,000 have been provided in 2016 and 2015, respectively.

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 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. 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 2015, the estimated fair value was determined using the income and the market approaches. The income approach was determined by using the present value of future estimated cash flows. The income approach considered management’s views on current operating measures as well as assumptions pertaining to market forces in the oil and gas industry including estimated reserves, estimated prices, market differentials, estimates of well operating and future development costs and timing of operations. The estimated cash flows were discounted using a rate believed to be consistent with those used by principal market participants. The market approach was provided by a third party and based on market transactions involving similar interests in oil and natural gas properties. The fair value assessment indicated an impairment based on the carrying value exceeding the estimated fair value, which resulted in the Company writing down Fidelity’s assets at June 30, 2015, and recording an impairment of $400.0 million ($252.0 million after tax) during the second quarter of 2015. In the third quarter of 2015, the estimated fair value of Fidelity was determined by agreed upon pricing in the purchase and sale agreements for the assets subject to the agreements, the majority of which closed during the fourth quarter of 2015, including customary purchase price adjustments. The values received in the bid proposals were lower than originally anticipated due to lower commodity prices than those projected in the second quarter of 2015. For those assets for which a purchase and sale agreement had not been entered into at that time, the fair value was based on the market approach utilizing multiples based on similar interests in oil and natural gas properties. The fair value assessment indicated an impairment based on the carrying value exceeding the estimated fair value, which resulted in the Company writing down Fidelity's assets at September 30, 2015, and recording an impairment of $356.1 million ($224.4 million after tax). In the fourth quarter of 2015, the fair value assessment was determined using the market approach based on purchase and sale agreements. The estimated fair value exceeded the carrying value and the Company recorded an impairment reversal of $1.6 million ($1.0 million after tax) in the fourth quarter of 2015. The impairments were included in operating expenses from discontinued operations. The estimated fair value of Fidelity's assets have been categorized as Level 3 in the fair value hierarchy.

The Company incurred transaction costs of approximately $300,000 in the first quarter of 2016 and $2.5 million in 2015. In addition to the transaction costs, and due in part to the change in plans to sell the assets of Fidelity rather than sell Fidelity as a company, Fidelity incurred and expensed approximately $5.6 million of exit and disposal costs in 2016, and has incurred $10.5 million of exit and disposal costs to date. The Company does not expect to incur any additional material exit and disposal costs. 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. The Company incurred lease payments of approximately $900,000 in 2016. Lease termination payments of $3.2 million and $3.3 million were made during the second quarter of 2016 and fourth quarter of 2015, respectively. Existing office furniture and fixtures were relinquished to the lessor in the second quarter of 2016.

Historically, the Company used the full-cost method of accounting for its oil and natural gas production activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized and amortized on the units-of-production method based on total proved reserves.

Prior to the oil and natural gas properties being classified as held for sale, capitalized costs were subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties not subject to amortization, plus the effects of cash flow hedges, less applicable income taxes. Proved reserves and associated future cash flows are determined based on SEC Defined Prices and exclude cash outflows associated with asset retirement obligations that have been accrued on the balance sheet. If capitalized costs, less accumulated amortization and related deferred income taxes, exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter regardless of subsequent price changes.

The Company's capitalized cost under the full-cost method of accounting exceeded the full-cost ceiling at March 31, 2015. SEC Defined Prices, adjusted for market differentials, were used to calculate the ceiling test. Accordingly, the Company was required to write down its oil and natural gas producing properties. The Company recorded a $500.4 million ($315.3 million after tax) noncash write-down in operating expenses from discontinued operations in the first quarter of 2015.

Fidelity previously held commodity derivatives that were not designated as hedging instruments. The amount of gain (loss) recognized in discontinued operations, before tax, was $(18.3) million and $23.4 million in the years ended December 31, 2015 and 2014, respectively.

On February 10, 2014, the Company entered into agreements to purchase working interests and leasehold positions in oil and natural gas production assets in the southern Powder River Basin of Wyoming. The effective date of the acquisition was October 1, 2013, and the closing occurred on March 6, 2014. The total purchase price, including purchase price adjustments, for acquisitions in 2014 was approximately $209.2 million, including the above acquisition which is reflected in discontinued operations. Pro forma financial amounts reflecting the effects of the acquisitions are not presented, as such acquisitions were not material to the Company's financial position or results of operations.

CEM In 2007, Centennial Resources sold CEM to Bicent. In connection with the sale, Centennial Resources agreed to indemnify Bicent and its affiliates from certain third party claims arising out of or in connection with Centennial Resources' ownership or operation of CEM prior to the sale. In addition, Centennial had previously guaranteed CEM's obligations under a construction contract. The Company incurred legal expenses and had a benefit related to the resolution of this matter in the second quarter of 2014, which are reflected in discontinued operations in the consolidated financial statements and accompanying notes.

Dakota Prairie Refining, Fidelity and CEM The reconciliation of the major classes of income and expense constituting pretax income (loss) from discontinued operations, which includes Dakota Prairie Refining, Fidelity and CEM, to the after-tax net income (loss) from discontinued operations on the Company's Consolidated Statements of Income at December 31 were as follows:

	2016	2015	2014
		(In thousands)	
Operating revenues	**$ 123,024**	$ 363,115	$ 547,571
Operating expenses	**513,813**	1,666,941	386,651
Operating income (loss)	**(390,789)**	(1,303,826)	160,920
Other income	**306**	3,149	1,898
Interest expense	**1,753**	2,124	145
Income (loss) from discontinued operations before income taxes	**(392,236)**	(1,302,801)	162,673
Income taxes	**(91,882)**	(468,721)	53,362
Income (loss) from discontinued operations	**(300,354)**	(834,080)	109,311
Loss from discontinued operations attributable to noncontrolling interest	**(131,691)**	(35,256)	(3,895)
Income (loss) from discontinued operations attributable to the Company	**$ (168,663)**	$ (798,824)	$ 113,206

The pretax loss from discontinued operations attributable to the Company, related to the operations of and activity associated with Dakota Prairie Refining, was $253.5 million, $31.5 million and $3.2 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Note 3 - Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December 31, 2016, were as follows:

	Balance at January 1, 2016 *	Goodwill Acquired During the Year	Held for Sale	Balance at December 31, 2016
		(In thousands)		
Natural gas distribution	$ 345,736	$ —	$ —	$ 345,736
Pipeline and midstream	9,737	—	(9,737)	—
Construction materials and contracting	176,290	—	—	176,290
Construction services	103,441	6,324	—	109,765
Total	$ 635,204	$ 6,324	$ (9,737)	$ 631,791

* Balance is presented net of accumulated impairment of $12.3 million at the pipeline and midstream segment, which occurred in prior periods.

The changes in the carrying amount of goodwill for the year ended December 31, 2015, were as follows:

	Balance at January 1, 2015 *	Goodwill Acquired During the Year	Balance at December 31, 2015 *
		(In thousands)	
Natural gas distribution	$ 345,736	$ —	$ 345,736
Pipeline and midstream	9,737	—	9,737
Construction materials and contracting	176,290	—	176,290
Construction services	103,441	—	103,441
Total	$ 635,204	$ —	$ 635,204

* Balance is presented net of accumulated impairment of $12.3 million at the pipeline and midstream segment, which occurred in prior periods.

Other amortizable intangible assets at December 31 were as follows:

	2016	2015
	(In thousands)	
Customer relationships	$ 17,145	$ 20,975
Less accumulated amortization	13,917	16,845
	3,228	4,130
Noncompete agreements	2,430	4,409
Less accumulated amortization	1,658	3,655
	772	754
Other	7,768	8,304
Less accumulated amortization	5,843	5,846
	1,925	2,458
Total	$ 5,925	$ 7,342

Amortization expense for amortizable intangible assets for the years ended December 31, 2016, 2015 and 2014, was $2.5 million, $2.5 million and $3.2 million, respectively. Estimated amortization expense for intangible assets is $2.2 million in 2017, $1.2 million in 2018, $1.0 million in 2019, $500,000 in 2020, $200,000 in 2021 and $800,000 thereafter.

Note 4 - Regulatory Assets and Liabilities

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

	Estimated Recovery Period *	2016	2015
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(e)	$ 176,025	$ 185,832
Taxes recoverable from customers (a)	Over plant lives	28,278	27,682
Manufactured gas plant sites remediation (a)	—	18,259	18,617
Asset retirement obligations (a)	—	42,580	8,000
Natural gas costs recoverable through rate adjustments (b)	Up to 1 year	2,242	547
Long-term debt refinancing costs (a)	Up to 21 years	6,248	7,031
Costs related to identifying generation development (a)	Up to 10 years	3,407	3,808
Other (a) (b)	Largely within 1- 4 years	30,281	11,741
Total regulatory assets		307,320	263,258
Regulatory liabilities:			
Plant removal and decommissioning costs (c)		176,972	182,981
Taxes refundable to customers (c)		11,010	17,060
Pension and postretirement benefits (c)		9,099	4,764
Natural gas costs refundable through rate adjustments (d)		25,580	20,884
Other (c) (d)		19,191	17,429
Total regulatory liabilities		241,852	243,118
Net regulatory position		$ 65,468	$ 20,140

* 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, 2016 and 2015, approximately $255.4 million and $224.7 million, respectively, of regulatory assets were not earning a rate of return.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of regulatory accounting for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income or accumulated other comprehensive income (loss) in the period in which the discontinuance of regulatory accounting occurs.

Note 5 - Fair Value Measurements

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments, which consist of an insurance 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 $70.9 million and $67.5 million at December 31, 2016 and 2015, respectively, are classified as investments on the Consolidated Balance Sheets. The net unrealized gains on these investments for the years ended December 31, 2016, 2015 and 2014, were $3.4 million, $1.7 million and $3.4 million, respectively. The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income.

The 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, 2016	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Mortgage-backed securities	$ 10,546	$ 8	$ (105)	$ 10,449
Total	$ 10,546	$ 8	$ (105)	$ 10,449

December 31, 2015	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Mortgage-backed securities	$ 9,128	$ 19	$ (49)	$ 9,098
U.S. Treasury securities	1,315	—	(6)	1,309
Total	$ 10,443	$ 19	$ (55)	$ 10,407

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, 2016 and 2015, there were no transfers between Levels 1 and 2.

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

	Fair Value Measurements at December 31, 2016, 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, 2016
		(In thousands)		
Assets:				
Money market funds	$ —	$ 1,602	$ —	$ 1,602
Insurance contract*	—	70,921	—	70,921
Available-for-sale securities:				
Mortgage-backed securities	—	10,449	—	10,449
Total assets measured at fair value	$ —	$ 82,972	$ —	$ 82,972

* The insurance contract invests approximately 52 percent in fixed-income investments, 22 percent in common stock of large-cap companies, 13 percent in common stock of mid-cap companies, 10 percent in common stock of small-cap companies, 1 percent in target date investments and 2 percent in cash equivalents.

	Fair Value Measurements at December 31, 2015, 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, 2015
		(In thousands)		
Assets:				
Money market funds	$ —	$ 1,420	$ —	$ 1,420
Insurance contract*	—	67,459	—	67,459
Available-for-sale securities:				
Mortgage-backed securities	—	9,098	—	9,098
U.S. Treasury securities	—	1,309	—	1,309
Total assets measured at fair value	$ —	$ 79,286	$ —	$ 79,286

* The insurance contract invests approximately 63 percent in fixed-income investments, 19 percent in common stock of large-cap companies, 9 percent in common stock of mid-cap companies, 7 percent in common stock of small-cap companies, 1 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.

During the second quarter of 2015, coalbed natural gas gathering assets at the pipeline and midstream segment were reviewed for impairment and found to be impaired and were written down to their estimated fair value using the income approach. Under this approach, fair value is determined by using the present value of future estimated cash flows. The factors used to determine the estimated future cash flows include, but are not limited to, internal estimates of gathering revenue, future commodity prices and operating costs and equipment salvage values. The estimated cash flows are discounted using a rate that approximates the weighted average cost of capital of a market participant. These fair value inputs are not typically observable. At June 30, 2015, natural gas gathering assets were written down to the nonrecurring fair value measurement of $1.1 million.

During the third quarter of 2015, the Company was negotiating the sale of certain non-strategic natural gas gathering assets at the pipeline and midstream segment and as a result these assets were found to be impaired and were written down to their estimated fair value using the market approach. The estimated fair value of natural gas gathering assets that were impaired at September 30, 2015, was largely determined by agreed upon pricing in a purchase and sale agreement that the Company was negotiating, and these assets were sold in the fourth quarter of 2015. At September 30, 2015, natural gas gathering assets were written down to the nonrecurring fair value measurement of $10.8 million.

The fair value of these natural gas gathering assets have been categorized as Level 3 in the fair value hierarchy.

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 2.

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:

	2016		2015	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
		(In thousands)		
Long-term debt	**$ 1,790,159**	**$ 1,841,885**	$ 1,796,163	$ 1,819,828

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

Note 6 - Debt

Certain debt instruments of the Company and its subsidiaries, including those discussed later, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions. 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, 2016	Amount Outstanding at December 31, 2015	Letters of Credit at December 31, 2016	Expiration Date
				(In millions)		
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	$ 175.0	$ 111.0 (b)	$ 44.5 (b)	$ —	5/8/19
Cascade Natural Gas Corporation	Revolving credit agreement	$ 50.0 (c)	$ —	$ —	$ 2.2 (d)	7/9/18
Intermountain Gas Company	Revolving credit agreement	$ 65.0 (e)	$ 20.9	$ 47.9	$ —	7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (f)	$ 500.0	$ 151.0 (b)	$ 18.0 (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). There were no amounts outstanding under the credit agreement.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $75.0 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 $90.0 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 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. 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 November 21, 2016, the Company entered into a $100.0 million note purchase agreement. The Company issued $40.0 million of Senior Notes under the agreement on November 21, 2016, with a due date of November 21, 2046, at an interest rate of 4.15 percent. The Company contracted to issue an additional $60.0 million of Senior Notes under the agreement on March 21, 2017, with due dates ranging from March 2032 to March 2037 at a weighted average interest rate of 3.61 percent.

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

Cascade Natural Gas Corporation 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. 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 Gas Company 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. 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.

On November 9, 2016, Intermountain issued $30.0 million of Senior Notes with a due date of November 9, 2046, at an interest rate of 4.0 percent.

Centennial Energy Holdings, Inc. On September 23, 2016, Centennial amended its revolving credit agreement to decrease the borrowing limit by $150.0 million to $500.0 million and extend the termination date to September 23, 2021. Centennial's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings.

Centennial's revolving credit agreement and certain debt outstanding under an expired uncommitted long-term master shelf agreement contain customary covenants and provisions, including a covenant of Centennial, not to permit, as of the end of any fiscal quarter, the ratio of total consolidated debt to total consolidated capitalization to be greater than 65 percent (for the revolving credit agreement) and a covenant of Centennial and certain of its subsidiaries, not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 60 percent (for the master shelf agreement). The master shelf agreement also includes a covenant that does not permit the ratio of Centennial's EBITDA to interest expense, for the 12-month period ended each fiscal quarter, to be less than 1.75 to 1. Other covenants include 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, Inc. On May 17, 2016, WBI Energy Transmission entered into an amendment to its amended and restated uncommitted note purchase and private shelf agreement to increase the aggregate issuance capacity from $175.0 million to $200.0 million and extend the issuance period to May 16, 2019. WBI Energy Transmission had $100.0 million of notes outstanding at December 31, 2016, which reduced the remaining capacity under this uncommitted private shelf agreement to $100.0 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. Other covenants include a limitation on priority debt and restrictions on the sale of certain assets and the making of certain investments.

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

	2016	2015
	(In thousands)	
Senior Notes at a weighted average rate of 4.87%, due on dates ranging from August 31, 2017 to January 15, 2055	**$ 1,437,831**	$ 1,616,246
Commercial paper at a weighted average rate of 1.27%, supported by revolving credit agreements	**262,000**	62,500
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
Other notes at a weighted average rate of 5.25%, due on February 1, 2035	**24,471**	24,589
Credit agreements at a weighted average rate of 3.14%, due on dates ranging from July 13, 2018 to November 30, 2038	**21,793**	48,906
Unamortized debt issuance costs	**(5,832)**	(6,069)
Discount	**(104)**	(9)
Total long-term debt	**1,790,159**	1,796,163
Less current maturities	**43,598**	238,539
Net long-term debt	**$ 1,746,561**	$ 1,557,624

Schedule of Debt Maturities Long-term debt maturities for the five years and thereafter following December 31, 2016, were as follows:

	2017	2018	2019	2020	2021	Thereafter
			(In thousands)			
Long-term debt maturities	$ 43,598	$ 169,449	$ 162,154	$ 15,021	$ 151,013	$ 1,254,860

Note 7 - 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:

		2016		2015
		(In thousands)		
Balance at beginning of year	**$**	**242,224**	$	27,211
Liabilities incurred		**15,114**		2,751
Liabilities settled		**(4,338)**		(1,708)
Accretion expense		**13,918**		2,134
Revisions in estimates		**48,052**		211,836
Balance at end of year	**$**	**314,970**	$	242,224

The 2016 revisions in estimates consist principally of updated asset retirement obligation costs associated with natural gas transmission lines and storage facilities at the pipeline and midstream segment. The 2015 revisions in estimates consist principally of updated asset retirement obligation costs associated with natural gas distribution mains and lines at the natural gas distribution segment.

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 4.

Note 8 - Preferred Stocks

Preferred stocks at December 31 were as follows:

		2016		2015
		(In thousands, except shares and per share amounts)		
Authorized:				
Preferred -				
500,000 shares, cumulative, par value $100, issuable in series				
Preferred stock A -				
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)				
Preference -				
500,000 shares, cumulative, without par value, issuable in series (none outstanding)				
Outstanding:				
4.50% Series - 100,000 shares	**$**	**10,000**	$	10,000
4.70% Series - 50,000 shares		**5,000**		5,000
Total preferred stocks	**$**	**15,000**	$	15,000

For the years 2016, 2015 and 2014, dividends declared on the 4.50% Series and 4.70% Series preferred stocks were $4.50 and $4.70 per share, respectively. The 4.50% Series and 4.70% Series preferred stocks outstanding are subject to redemption, in whole or in part, at the option of the Company with certain limitations on 30 days notice on any quarterly dividend date at a redemption price, plus accrued dividends, of $105 per share and $102 per share, respectively.

In the event of a voluntary or involuntary liquidation, all preferred stock series holders are entitled to $100 per share, plus accrued dividends.

The affirmative vote of two-thirds of a series of the Company's outstanding preferred stock is necessary for amendments to the Company's charter or bylaws that adversely affect that series; creation of or increase in the amount of authorized stock ranking senior to that series (or an affirmative majority vote where the authorization relates to a new class of stock that ranks on parity with such series); a voluntary liquidation or sale of substantially all of the Company's assets; a merger or consolidation, with certain exceptions; or the partial retirement of that series of preferred stock when all dividends on that series of preferred stock have not been paid. The consent of the holders of a particular series is not required for such corporate actions if the equivalent vote of all outstanding series of preferred stock voting together has consented to the given action and no particular series is affected differently than any other series.

Subject to the foregoing, the holders of common stock exclusively possess all voting power. However, if cumulative dividends on preferred stock are in arrears, in whole or in part, for one year, the holders of preferred stock would obtain the right to one vote per share until all dividends in arrears have been paid and current dividends have been declared and set aside.

Note 9 - Common Stock

For the years 2016, 2015 and 2014, dividends declared on common stock were $.7550, $.7350 and $.7150 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. From January 2014 through August 2015, the Stock Purchase Plan and K-Plan, with respect to Company stock, purchased shares of authorized but unissued common stock from the Company. From September 2015 through December 2016, the K-Plan purchased shares of common stock on the open market. At December 31, 2016, there were 7.8 million shares of common stock reserved for original issuance under the K-Plan. From September 2015 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 have been de-registered.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. In addition, the Company and Centennial are generally restricted to paying dividends out of capital accounts or net assets. The following discusses the most restrictive limitations.

Pursuant to a covenant under a credit agreement, Centennial may only 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; and after giving effect to such distribution, all distributions made during the 12-month period ending on the last day of the fiscal quarter in which such distribution is made will not exceed the remainder of Centennial's Consolidated EBITDA minus Centennial's capital expenditures less the net cash proceeds from all sales of capital assets from continuing operations, for the immediately preceding 12-month period. Intermountain and Cascade have regulatory limitations on the amount of dividends each can pay. Based on these limitations, approximately $1.3 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2016. 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 $351 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, 2016. 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 10 - Stock-Based Compensation

The Company has several stock-based compensation plans under which it is currently authorized to grant restricted stock and stock. As of December 31, 2016, there are 5.5 million remaining shares available to grant under these plans. The Company generally issues new shares of common stock to satisfy employee performance share awards and purchases shares on the open market for nonemployee director stock awards.

Total stock-based compensation expense (after tax) was $3.3 million, $2.9 million and $4.4 million in 2016, 2015 and 2014, respectively.

As of December 31, 2016, total remaining unrecognized compensation expense related to stock-based compensation was approximately $4.9 million (before income taxes) which will be amortized over a weighted average period of 1.5 years.

Stock awards

Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. There were 37,218 shares with a fair value of $1.1 million, 58,181 shares with a fair value of $1.1 million and 43,088 shares with a fair value of $1.1 million issued under this plan during the years ended December 31, 2016, 2015 and 2014, respectively.

Performance share awards

Since 2003, key employees of the Company have been awarded performance share awards each year. Entitlement to performance shares is based on the Company's total shareholder return over designated performance periods as measured against a selected peer group.

Target grants of performance shares outstanding at December 31, 2016, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2014	2014-2016	136,901
February 2015	2015-2017	200,112
June 2015	2015-2017	14,441
February 2016	2016-2018	310,583
March 2016	2016-2018	2,151

Participants may earn from zero to 200 percent of the target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value as determined by Monte Carlo simulation. The blended volatility term structure ranges are comprised of 50 percent historical volatility and 50 percent implied volatility. Risk-free interest rates were based on U.S. Treasury security rates in effect as of the grant date. Assumptions used for grants of performance shares issued in 2016, 2015 and 2014 were:

	2016	2015	2014
Weighted average grant-date fair value	**$14.60**	$18.98	$41.13
Blended volatility range	**29.25% – 32.51%**	22.86% – 24.61%	18.94% – 20.43%
Risk-free interest rate range	**.47% – .92%**	.05% – 1.07%	.03% – .74%
Weighted average discounted dividends per share	**$1.56**	$1.57	$2.15

The fair value of the performance shares that vested during the years ended December 31, 2016 and 2014, was $953,000 and $16.6 million, respectively. There were no performance shares that vested in 2015.

A summary of the status of the performance share awards for the year ended December 31, 2016, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	565,896	$ 27.90
Granted	324,205	14.60
Less:		
Vested	58,401	29.01
Forfeited	167,512	27.30
Nonvested at end of period	664,188	$ 21.47

Note 11 - Income Taxes

The components of income before income taxes from continuing operations for each of the years ended December 31 were as follows:

	2016	2015	2014
		(In thousands)	
United States	**$ 326,252**	$ 248,379	$ 249,501
Foreign	**(24)**	(1,326)	(52)
Income before income taxes from continuing operations	**$ 326,228**	$ 247,053	$ 249,449

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

	2016	2015	2014
		(In thousands)	
Current:			
Federal	$ 81,989	$ 85,897	$ 8,837
State	13,190	10,093	622
Foreign	2	30	—
	95,181	96,020	9,459
Deferred:			
Income taxes:			
Federal	(2,102)	(19,632)	52,041
State	1,184	(5,304)	1,913
Investment tax credit - net	(1,131)	(420)	1,009
	(2,049)	(25,356)	54,963
Total income tax expense	$ 93,132	$ 70,664	$ 64,422

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

	2016	2015
	(In thousands)	
Deferred tax assets:		
Postretirement	$ 87,872	$ 97,666
Compensation-related	44,995	33,714
Alternative minimum tax credit carryforward	29,338	28,169
Federal renewable energy credit	16,944	3,400
Customer advances	13,524	12,623
Legal and environmental contingencies	9,895	6,377
Asset retirement obligations	8,867	8,694
Other	46,957	43,306
Total deferred tax assets	258,392	233,949
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	774,838	756,444
Postretirement	70,670	71,835
Intangible asset amortization	26,413	23,950
Other	45,580	36,359
Total deferred tax liabilities	917,501	888,588
Valuation allowance	9,117	8,990
Net deferred income tax liability	$ 668,226	$ 663,629

As of December 31, 2016 and 2015, the Company had various state income tax net operating loss carryforwards of $114.7 million and $116.2 million, respectively, and federal and state income tax credit carryforwards, excluding alternative minimum tax credit carryforwards, of $43.3 million and $21.3 million, respectively. Included in the state credits are various regulatory investment tax credits of approximately $20.7 million and $13.9 million at December 31, 2016 and 2015, respectively. The federal income tax credit carryforwards expire in 2036 and 2037 if not utilized and state income tax credit carryforwards are due to expire between 2019 and 2042. It is likely that a portion of the benefit from the state carryforwards will not be realized; therefore, valuation allowances have been provided. 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 do not expire. For information regarding net operating loss carryforwards and valuation allowances related to discontinued operations, see Note 2.

The following table reconciles the change in the net deferred income tax liability from December 31, 2015, to December 31, 2016, to deferred income tax expense:

		2016
		(In thousands)
Change in net deferred income tax liability from the preceding table	$	4,597
Deferred taxes associated with other comprehensive income		(825)
Other		(5,821)
Deferred income tax benefit for the period	$	(2,049)

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,		2016			2015			2014	
		Amount	%		Amount	%		Amount	%
		(Dollars in thousands)							
Computed tax at federal statutory rate	$	114,179	35.0	$	86,468	35.0	$	87,308	35.0
Increases (reductions) resulting from:									
State income taxes, net of federal income tax		9,027	2.8		8,208	3.3		7,019	2.8
Federal renewable energy credit		(13,544)	(4.2)		(3,400)	(1.4)		(3,655)	(1.5)
Tax compliance and uncertain tax positions		(3,028)	(.9)		(2,607)	(1.0)		(8,568)	(3.4)
Domestic production activities		(6,251)	(1.9)		(6,842)	(2.8)		(3,993)	(1.6)
Other		(7,251)	(2.3)		(11,163)	(4.5)		(13,689)	(5.5)
Total income tax expense	$	93,132	28.5	$	70,664	28.6	$	64,422	25.8

Deferred income taxes have been accrued with respect to temporary differences related to the Company's foreign operations. The amount of cumulative undistributed earnings for which there are temporary differences is approximately $2.4 million at December 31, 2016. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2016, was approximately $889,000.

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 2012. With few exceptions, as of December 31, 2016, the Company is no longer subject to state and local income tax examinations by tax authorities for years ending prior to 2011.

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

		2016		2015		2014
				(In thousands)		
Balance at beginning of year	$	—	$	105	$	7,845
Settlements		—		—		(7,740)
Lapse of statute of limitations		—		(105)		—
Balance at end of year	$	—	$	—	$	105

Included in income tax expense is interest on uncertain tax positions. For the years ended December 31, 2016, 2015 and 2014, the Company recognized approximately $(92,000), $122,000 and $387,000, respectively, of interest (income) expense in income tax expense. At December 31, 2016 and 2015, the Company had accrued receivables of approximately $54,000 and interest payable of $94,000, respectively, for the receipt or payment of interest.

Note 12 - Cash Flow Information

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

	2016	2015	2014
		(In thousands)	
Interest, net of amount capitalized and AFUDC - borrowed of $914, $9,288 and $10,069 in 2016, 2015 and 2014, respectively	**$ 87,920**	$ 88,775	$ 81,195
Income taxes paid, net*	**$ 105,908**	$ 61,405	$ 80,090

* Income taxes paid, net of discontinued operations, were $1.3 million, $2.4 million and $69.8 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Noncash investing transactions at December 31 were as follows:

	2016	2015	2014
		(In thousands)	
Property, plant and equipment additions in accounts payable	**$ 22,712**	$ 39,754	$ 12,791

Note 13 - 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, gathering and processing services, as well as oil gathering, through regulated and nonregulated pipeline systems and processing facilities primarily in the Rocky Mountain and northern Great Plains regions of the United States. This segment also provides cathodic protection and other energy-related services.

The construction materials and contracting segment mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mixed concrete, cement, asphalt, liquid asphalt and other value-added products. It also performs integrated contracting services. This segment operates in the central, southern and western United States and Alaska and Hawaii.

The construction services segment provides utility construction services specializing in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization. This segment also provides utility excavation and inside electrical and mechanical services, and manufactures and distributes transmission line construction equipment and other supplies.

The Other category includes the activities of Centennial Capital, which insures various types of risks as a captive insurer for certain of the Company's subsidiaries. The function of the captive insurer is to fund the deductible layers of the insured companies' general liability, automobile liability and pollution liability coverages. Centennial Capital also owns certain real and personal property. The Other category also includes 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 the Brazilian Transmission Lines.

Discontinued operations includes the results of Dakota Prairie Refining and Fidelity other than certain general and administrative costs and interest expense as described above. Dakota Prairie Refining refined crude oil and produced and sold diesel fuel, naphtha, ATBs and other by-products of the production process. In the second quarter of 2016, the Company sold all of the outstanding membership interests in Dakota Prairie Refining. Fidelity engaged in oil and natural gas development and production activities in the Rocky Mountain and Mid-Continent/Gulf States regions of the United States. Between September 2015 and March 2016, the Company entered into purchase and sale agreements to sell all of Fidelity's oil and natural gas assets. The completion of these sales occurred between October 2015 and April 2016. Discontinued operations also includes legal expenses and a benefit related to the vacation of an arbitration award in 2014 related to Centennial Resources. For more information on discontinued operations, see Note 2.

The information below follows the same accounting policies as described in the Summary of Significant Accounting Policies. Information on the Company's businesses as of December 31 and for the years then ended was as follows:

	2016	2015	2014
		(In thousands)	
External operating revenues:			
Regulated operations:			
Electric	**$ 322,356**	$ 280,615	$ 277,874
Natural gas distribution	**766,115**	817,419	921,986
Pipeline and midstream	**52,983**	51,004	47,043
	1,141,454	1,149,038	1,246,903
Nonregulated operations:			
Pipeline and midstream	**39,602**	54,281	64,494
Construction materials and contracting	**1,873,696**	1,901,530	1,740,089
Construction services	**1,072,663**	907,767	1,062,055
Other	**1,413**	1,436	1,532
	2,987,374	2,865,014	2,868,170
Total external operating revenues	**$ 4,128,828**	$ 4,014,052	$ 4,115,073
Intersegment operating revenues:			
Regulated operations:			
Electric	**$ —**	$ —	$ —
Natural gas distribution	**—**	—	—
Pipeline and midstream	**48,794**	49,065	45,013
	48,794	49,065	45,013
Nonregulated operations:			
Pipeline and midstream	**223**	554	742
Construction materials and contracting	**574**	2,752	25,241
Construction services	**609**	18,660	57,474
Other	**7,230**	7,755	7,832
	8,636	29,721	91,289
Intersegment eliminations	**(57,430)**	(78,786)	(136,302)
Total intersegment operating revenues	**$ —**	$ —	$ —
Depreciation, depletion and amortization:			
Electric	**$ 50,220**	$ 37,583	$ 35,008
Natural gas distribution	**65,426**	64,756	54,700
Pipeline and midstream	**24,885**	27,981	29,749
Construction materials and contracting	**58,413**	65,937	68,557
Construction services	**15,307**	13,420	12,874
Other	**2,067**	2,070	2,196
Total depreciation, depletion and amortization	**$ 216,318**	$ 211,747	$ 203,084
Interest expense:			
Electric	**$ 24,982**	$ 17,421	$ 15,595
Natural gas distribution	**30,405**	29,471	27,217
Pipeline and midstream	**7,903**	9,895	9,946
Construction materials and contracting	**15,265**	15,183	16,368
Construction services	**4,059**	3,959	4,176
Other	**5,854**	15,853	13,823
Intersegment eliminations	**(620)**	(603)	(254)
Total interest expense	**$ 87,848**	$ 91,179	$ 86,871

	2016	2015	2014
		(In thousands)	
Income taxes:			
Electric	**$ 1,449**	$ 11,523	$ 12,442
Natural gas distribution	**9,181**	11,377	11,350
Pipeline and midstream	**12,408**	7,505	12,232
Construction materials and contracting	**60,625**	41,619	18,586
Construction services	**17,748**	16,432	24,753
Other	**(2,028)**	(9,834)	(11,136)
Intersegment eliminations	**(6,251)**	(7,958)	(3,805)
Total income taxes	**$ 93,132**	$ 70,664	$ 64,422
Earnings (loss) on common stock:			
Regulated operations:			
Electric	**$ 42,222**	$ 35,914	$ 36,731
Natural gas distribution	**27,102**	23,607	30,484
Pipeline and midstream	**22,060**	20,680	15,440
	91,384	80,201	82,655
Nonregulated operations:			
Pipeline and midstream	**1,375**	(7,430)	9,226
Construction materials and contracting	**102,687**	89,096	51,510
Construction services	**33,945**	23,762	54,432
Other	**(3,231)**	(14,941)	(7,386)
	134,776	90,487	107,782
Intersegment eliminations (a)	**6,251**	5,016	(6,095)
Earnings on common stock before income (loss) from discontinued operations	**232,411**	175,704	184,342
Income (loss) from discontinued operations, net of tax (a)	**(300,354)**	(834,080)	109,311
Loss from discontinued operations attributable to noncontrolling interest	**(131,691)**	(35,256)	(3,895)
Total earnings (loss) on common stock	**$ 63,748**	$ (623,120)	$ 297,548
Capital expenditures:			
Electric	**$ 111,134**	$ 332,876	$ 185,121
Natural gas distribution	**126,272**	130,793	120,613
Pipeline and midstream	**34,467**	18,315	61,754
Construction materials and contracting	**37,845**	48,126	37,896
Construction services	**60,344**	38,269	26,942
Other	**2,358**	3,755	2,131
Total capital expenditures (b)	**$ 372,420**	$ 572,134	$ 434,457
Assets:			
Electric (c)	**$ 1,406,694**	$ 1,325,858	$ 1,028,001
Natural gas distribution (c)	**2,099,296**	2,038,433	1,935,271
Pipeline and midstream	**550,615**	591,651	651,925
Construction materials and contracting	**1,220,459**	1,261,963	1,260,534
Construction services	**513,093**	442,845	437,322
Other (d)	**283,255**	287,940	315,495
Assets held for sale	**211,055**	616,464	2,176,857
Total assets	**$ 6,284,467**	$ 6,565,154	$ 7,805,405

	2016	2015	2014
		(In thousands)	
Property, plant and equipment:			
Electric (c)	$ **1,888,613**	$ 1,786,148	$ 1,457,101
Natural gas distribution (c)	**2,179,413**	2,076,581	1,904,759
Pipeline and midstream	**672,199**	758,729	818,388
Construction materials and contracting	**1,549,375**	1,553,428	1,529,942
Construction services	**171,361**	163,279	144,395
Other	**49,268**	49,537	50,937
Less accumulated depreciation, depletion and amortization	**2,578,902**	2,489,322	2,385,202
Net property, plant and equipment	$ **3,931,327**	$ 3,898,380	$ 3,520,320

(a) Includes eliminations for the presentation of income tax adjustments between continuing and discontinued operations.
(b) Capital expenditures for 2016, 2015 and 2014 include noncash capital expenditure-related accounts payable and AFUDC, totaling $(15.8) million, $35.3 million and $5.1 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 14 - Employee Benefit Plans

Pension and other postretirement benefit plans

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans.

Prior to 2013, defined pension plan benefits and accruals for all nonunion and certain union plans were frozen. On June 30, 2015, an additional union plan was frozen. As of June 30, 2015, all of the Company's defined pension plans were frozen. These employees were eligible to receive additional defined contribution plan benefits.

Effective January 1, 2010, eligibility to receive retiree medical benefits was modified at certain of the Company's businesses. Employees who 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, 2016 and 2015, and amounts recognized in the Consolidated Balance Sheets at December 31, 2016 and 2015, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2016	2015	**2016**	2015
		(In thousands)		
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 442,960**	$ 475,337	**$ 92,734**	$ 99,012
Service cost	**—**	86	**1,647**	1,816
Interest cost	**17,218**	17,141	**3,688**	3,607
Plan participants' contributions	**—**	—	**1,405**	1,408
Actuarial (gain) loss	**1,882**	(24,875)	**(3,872)**	(5,873)
Benefits paid	**(25,753)**	(24,729)	**(6,298)**	(7,236)
Benefit obligation at end of year	**436,307**	442,960	**89,304**	92,734
Change in net plan assets:				
Fair value of plan assets at beginning of year	**332,667**	354,363	**82,593**	87,586
Actual gain (loss) on plan assets	**26,595**	(10,879)	**4,184**	258
Employer contribution	**—**	13,912	**962**	577
Plan participants' contributions	**—**	—	**1,405**	1,408
Benefits paid	**(25,753)**	(24,729)	**(6,298)**	(7,236)
Fair value of net plan assets at end of year	**333,509**	332,667	**82,846**	82,593
Funded status - under	**$ (102,798)**	$ (110,293)	**$ (6,458)**	$ (10,141)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other assets (noncurrent)	**$ —**	$ —	**$ 13,131**	$ 5,095
Other accrued liabilities (current)	**—**	—	**(538)**	(421)
Other liabilities (noncurrent)	**(102,798)**	(110,293)	**(19,051)**	(14,815)
Net amount recognized	**$ (102,798)**	$ (110,293)	**$ (6,458)**	$ (10,141)
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial loss	**$ 198,668**	$ 208,671	**$ 17,470**	$ 22,484
Prior service cost (credit)	**—**	—	**(13,003)**	(14,374)
Total	**$ 198,668**	$ 208,671	**$ 4,467**	$ 8,110

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. Accumulated other comprehensive (income) loss in the above table includes amounts related to regulated operations, which are recorded as regulatory assets (liabilities) and are expected to be reflected in rates charged to customers over time. For more information on regulatory assets (liabilities), see Note 4.

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:

	2016	2015
	(In thousands)	
Projected benefit obligation	**$ 436,307**	$ 442,960
Accumulated benefit obligation	**$ 436,307**	$ 442,960
Fair value of plan assets	**$ 333,509**	$ 332,667

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		
	2016	2015	2014	**2016**	2015	2014
			(In thousands)			
Components of net periodic benefit cost (credit):						
Service cost	**$ —**	$ 86	$ 129	**$ 1,647**	$ 1,816	$ 1,518
Interest cost	**17,218**	17,141	17,682	**3,688**	3,607	3,521
Expected return on assets	**(20,924)**	(22,254)	(21,218)	**(4,533)**	(4,795)	(4,617)
Amortization of prior service cost (credit)	**—**	36	71	**(1,371)**	(1,371)	(1,393)
Recognized net actuarial loss	**6,215**	7,016	4,869	**1,491**	1,960	649
Curtailment loss	**—**	258	—	**—**	—	—
Net periodic benefit cost (credit), including amount capitalized	**2,509**	2,283	1,533	**922**	1,217	(322)
Less amount capitalized	**381**	316	388	**(52)**	120	(21)
Net periodic benefit cost (credit)	**2,128**	1,967	1,145	**974**	1,097	(301)
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	**(3,789)**	8,257	77,238	**(3,523)**	(1,336)	15,114
Amortization of actuarial loss	**(6,215)**	(7,016)	(4,869)	**(1,491)**	(1,960)	(649)
Amortization of prior service (cost) credit	**—**	(294)	(71)	**1,371**	1,371	1,393
Total recognized in accumulated other comprehensive (income) loss	**(10,004)**	947	72,298	**(3,643)**	(1,925)	15,858
Total recognized in net periodic benefit cost (credit) and accumulated other comprehensive (income) loss	**$ (7,876)**	$ 2,914	$ 73,443	**$ (2,669)**	$ (828)	$ 15,557

The estimated net loss for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2017 is $6.4 million. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2017 are $900,000 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	
	2016	2015	**2016**	2015
Discount rate	**3.83%**	4.00%	**3.86%**	4.06%
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 for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2016	2015	**2016**	2015
Discount rate	**4.00%**	3.70%	**4.06%**	3.74%
Expected return on plan assets	**6.75%**	7.00%	**5.75%**	6.00%
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, 2016, 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 30 percent to 40 percent equity securities and 60 percent to 70 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:

	2016	2015
Health care trend rate assumed for next year	**8.6% – 10.7%**	4.0% – 8.0%
Health care cost trend rate - ultimate	**4.5%**	5.0% – 6.0%
Year in which ultimate trend rate achieved	**2024**	2021

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, 2016:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 255	$ (210)
Effect on postretirement benefit obligation	$ 5,741	$ (4,834)

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 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, 2016 and 2015, 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, 2016, 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, 2016
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 6,347	$ —	$ 6,347
Equity securities:				
U.S. companies	11,348	—	—	11,348
International companies	1,584	—	—	1,584
Collective and mutual funds*	162,055	64,052	—	226,107
Corporate bonds	—	68,677	—	68,677
Municipal bonds	—	11,002	—	11,002
U.S. Government securities	4,352	2,044	—	6,396
Total assets measured at fair value	$ 179,339	$ 152,122	$ —	$ 331,461

* Collective and mutual funds invest approximately 29 percent in common stock of international companies, 21 percent in corporate bonds, 20 percent in common stock of large-cap U.S. companies, 8 percent in cash equivalents, 7 percent in U.S. Government securities and 15 percent in other investments.

	Fair Value Measurements at December 31, 2015, 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, 2015
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 8,379	$ —	$ 8,379
Equity securities:				
U.S. companies	15,135	—	—	15,135
International companies	2,332	—	—	2,332
Collective and mutual funds*	154,400	63,568	—	217,968
Corporate bonds	—	62,145	—	62,145
Municipal bonds	—	11,680	—	11,680
U.S. Government securities	5,288	6,823	—	12,111
Total assets measured at fair value	$ 177,155	$ 152,595	$ —	$ 329,750

* Collective and mutual funds invest approximately 29 percent in common stock of international companies, 19 percent in common stock of large-cap U.S. companies, 16 percent in corporate bonds, 16 percent in cash equivalents, 6 percent in common stock of mid-cap U.S. companies 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, 2016 and 2015, 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, 2016, 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, 2016
		(In thousands)		
Assets:				
Cash equivalents	$ —	$ 250	$ —	$ 250
Equity securities:				
U.S. companies	2,328	—	—	2,328
International companies	5	—	—	5
Insurance contract*	—	80,263	—	80,263
Total assets measured at fair value	$ 2,333	$ 80,513	$ —	$ 82,846

* The insurance contract invests approximately 38 percent in corporate bonds, 25 percent in common stock of large-cap U.S. companies, 20 percent in U.S. Government securities, 9 percent in mortgage-backed securities and 8 percent in other investments.

	Fair Value Measurements at December 31, 2015, 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, 2015
		(In thousands)		
Assets:				
Cash equivalents	$ —	$ 3,261	$ —	$ 3,261
Equity securities:				
U.S. companies	2,274	—	—	2,274
International companies	9	—	—	9
Insurance contract*	—	77,044	—	77,044
Total assets measured at fair value	$ 2,283	$ 80,305	$ —	$ 82,588

* The insurance contract invests approximately 36 percent in corporate bonds, 22 percent in U.S. Government securities, 19 percent in common stock of large-cap U.S. companies, 10 percent in mortgage-backed securities and 13 percent in other investments.

The Company expects to contribute approximately $2.0 million to its defined benefit pension plans and approximately $900,000 to its postretirement benefit plans in 2017.

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

Years		Pension Benefits		Other Postretirement Benefits		Expected Medicare Part D Subsidy
				(In thousands)		
2017	$	24,798	$	5,410	$	168
2018		25,054		5,573		165
2019		25,271		5,603		160
2020		25,616		5,500		154
2021		25,987		5,511		146
2022 - 2026		132,224		27,956		568

Nonqualified benefit plans

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or, 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 Company's net periodic benefit cost for these plans was $1.8 million, $7.1 million and $6.6 million in 2016, 2015 and 2014, respectively, which reflects a curtailment gain of $3.3 million in the first quarter of 2016 . The total projected benefit obligation for these plans was $101.8 million and $110.8 million at December 31, 2016 and 2015, respectively. The accumulated benefit obligation for these plans was $101.8 million and $104.6 million at December 31, 2016 and 2015, respectively. A weighted average discount rate of 3.56 percent and 3.77 percent at December 31, 2016 and 2015, respectively, and a rate of compensation increase of 4.00 percent at December 31, 2015, were used to determine benefit obligations. No rate of compensation increase was used to determine the benefit obligation at December 31, 2016, due to the plans being froze. A discount rate of 3.77 percent and 3.51 percent for the years ended December 31, 2016 and 2015, respectively, and a rate of compensation increase of 4.00 percent and 4.00 percent for the years ended December 31, 2016 and 2015, respectively, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $6.7 million in 2017; $7.1 million in 2018; $7.3 million in 2019; $7.7 million in 2020; $7.7 million in 2021 and $36.4 million for the years 2022 through 2026.

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Expenses incurred under this plan for 2016, 2015 and 2014 were $395,000, $207,000 and $104,000, respectively.

The Company had investments of $111.0 million and $105.2 million at December 31, 2016 and 2015, respectively, consisting of equity securities of $62.5 million and $54.2 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of $35.5 million and $34.3 million, respectively, and other investments of $13.0 million and $16.7 million, respectively. The Company anticipates using these investments to satisfy obligations under these plans.

Defined contribution plans

The Company sponsors various defined contribution plans for eligible employees and the costs incurred under these plans were $40.9 million in 2016, $36.8 million in 2015 and $34.4 million in 2014.

Multiemployer plans

The Company contributes to a number of multiemployer defined benefit pension plans under the terms of collective-bargaining agreements that cover its union-represented employees. The risks of participating in these multiemployer plans are different from single-employer plans in the following aspects:

- Assets contributed to the 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 2016 and 2015 is for the plan's year-end at December 31, 2015, and December 31, 2014, 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 2016	Pension Protection Act Zone Status 2015	FIP/RP Status Pending/ Implemented	Contributions 2016	Contributions 2015	Contributions 2014	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)				
Alaska Laborers-Employers Retirement Fund	91-6028298-001	Yellow as of 6/30/2016	Yellow as of 6/30/2015	Implemented	**$ 766**	$ 917	$ 666	No	12/31/2016
Edison Pension Plan	93-6061681-001	Green as of 12/31/2016	Green as of 12/31/2015	No	**6,242**	5,517	9,061	No	12/31/2017
IBEW Local No. 82 Pension Plan	31-6127268-001	Green as of 6/30/2016	Red as of 6/30/2015	Implemented	**2,560**	2,252	1,392	No	12/1/2019
IBEW Local No. 357 Pension Plan A	88-6023284-001	Green	Green	No	**3,016**	1,896	3,575	No	5/31/2018
IBEW Local 648 Pension Plan	31-6134845-001	Red as of 2/29/2016	Red as of 2/28/2015	Implemented	**773**	745	1,110	No	9/2/2018
Idaho Plumbers and Pipefitters Pension Plan	82-6010346-001	Green as of 5/31/2016	Green as of 5/31/2015	No	**1,221**	1,169	1,125	No	9/30/2019
Local Union 212 IBEW Pension Trust Fund	31-6127280-001	Yellow as of 4/30/2016	Yellow as of 4/30/2015	Implemented	**1,146**	937	568	No	6/2/2019
National Automatic Sprinkler Industry Pension Fund	52-6054620-001	Red as of 12/31/2016	Red as of 12/31/2015	Implemented	**775**	677	608	No	7/31/2018-3/31/2021
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	**6,366**	5,271	6,476	No	1/1/2017-5/31/2020
Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming**	83-6011320-001	Red as of 12/31/2016	Red as of 12/31/2015	Implemented	**—**	—	68	No	10/31/2005*
Sheet Metal Workers' Pension Plan of Southern CA, AZ and NV	95-6052257-001	Red as of 12/31/2016	Red as of 12/31/2015	Implemented	**1,087**	714	676	No	6/30/2017
Southwest Marine Pension Trust	95-6123404-001	Red	Red	Implemented	**50**	26	31	No	1/31/2019
Other funds					**20,525**	18,991	17,461		
Total contributions					**$ 44,527**	$ 39,112	$ 42,817		

* Plan includes collective bargaining agreements which have expired. The agreements contain provisions that automatically renew the existing contracts in lieu of a new negotiated collective bargaining agreement.

** The Company withdrew from the plan as of October 26, 2014, as discussed later.

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	2015 and 2014
IBEW Local No. 82 Pension Plan	2015 and 2014
Local Union No. 124 IBEW Pension Trust Fund	2015 and 2014
Local Union 212 IBEW Pension Trust Fund	2015 and 2014
IBEW Local Union No. 357 Pension Plan A	2015 and 2014
IBEW Local 573 Pension Plan	2014
IBEW Local 648 Pension Plan	2015 and 2014
Idaho Plumbers and Pipefitters Pension Plan	2015 and 2014
Minnesota Teamsters Construction Division Pension Fund	2015 and 2014
Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming*	2014
Pension and Retirement Plan of Plumbers and Pipefitters Union Local No. 525	2015 and 2014

* The Company withdrew from the plan as of October 26, 2014, as discussed later.

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 River’s 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.

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 $36.1 million, $31.4 million and $34.6 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Amounts contributed in 2016, 2015 and 2014 to defined contribution multiemployer plans were $23.8 million, $19.5 million and $22.0 million, respectively.

Note 15 - Jointly Owned Facilities

The consolidated financial statements include the Company's ownership interests in the assets, liabilities and expenses of the Big Stone Station, Coyote Station and Wygen III. Each owner of the stations is responsible for financing its investment in the jointly owned facilities.

The Company's share of the stations operating expenses was reflected in the appropriate categories of operating expenses (fuel, operation and maintenance and taxes, other than income) in the Consolidated Statements of Income.

At December 31, the Company's share of the cost of utility plant in service and related accumulated depreciation for the stations was as follows:

		2016		2015
		(In thousands)		
Big Stone Station:				
Utility plant in service	**$**	**157,144**	$	157,761
Less accumulated depreciation		**49,568**		48,242
	$	**107,576**	$	109,519
Coyote Station:				
Utility plant in service	**$**	**156,334**	$	140,895
Less accumulated depreciation		**105,928**		94,755
	$	**50,406**	$	46,140
Wygen III:				
Utility plant in service	**$**	**66,251**	$	65,023
Less accumulated depreciation		**7,550**		6,788
	$	**58,701**	$	58,235

Note 16 - Regulatory Matters

On September 30, 2015, Great Plains filed an application for a natural gas rate increase with the MNPUC. Great Plains requested a total increase of approximately $1.6 million annually or approximately 6.4 percent above current rates to recover increased operating expenses along with increased investment in facilities, including the related depreciation expense and taxes. An interim increase of approximately $1.5 million or approximately 6.4 percent, subject to refund, was effective with service rendered on and after January 1, 2016. The MNPUC issued an order on September 6, 2016, authorizing an increase of approximately $1.1 million annually or approximately 5.2 percent with the requirement that Great Plains submit a compliance filing within 30 days. On September 22, 2016, Great Plains submitted the required compliance filing which included a refund plan to return the amount of interim revenues collected above the final rates. On December 22, 2016, the MNPUC issued an order approving the rates to be implemented January 1, 2017. Great Plains will issue refunds for the difference with interest to customers no later than March 1, 2017.

On October 26, 2015, Montana-Dakota filed an application with the NDPSC requesting a renewable resource cost adjustment rider for the recovery of the Thunder Spirit Wind project. On January 5, 2016, the NDPSC approved the rider to be effective January 7, 2016, resulting in an annual increase on an interim basis, subject to refund, of $15.1 million based upon a 10.5 percent return on equity. The interim rate is pending the determination of the return on equity in the general rate case application filed on October 14, 2016, as discussed in this note.

On October 26, 2015, Montana-Dakota filed an application with the NDPSC for an update to the electric generation resource recovery rider. On March 9, 2016, the NDPSC approved the rider to be effective with service rendered on and after March 15, 2016, which resulted in interim rates, subject to refund, of $9.7 million based upon a 10.5 percent return on equity. The interim rates include recovery of Montana-Dakota's investment in the 88-MW simple-cycle natural gas turbine and associated facilities near Mandan, North Dakota, and the 19 MW of new generation from natural gas-fired internal combustion engines and associated facilities near Sidney, Montana. The net investment authorized for the natural gas-fired internal combustion engines and the return on equity on both investments are pending in the general rate case application filed October 14, 2016, as discussed in this note.

On November 25, 2015, Montana-Dakota filed an application with the NDPSC for an update of its transmission cost adjustment rider for recovery of MISO-related charges and two transmission projects in North Dakota. On February 10, 2016, the NDPSC approved the transmission cost adjustment effective with service rendered on and after February 12, 2016, resulting in an annual increase on an interim basis, subject to refund, of $6.8 million based upon a 10.5 percent return on equity. The interim rate is pending the determination of the return on equity in the general rate case application filed October 14, 2016, as discussed in this note.

On April 29, 2016, Cascade filed an application with the OPUC for a natural gas rate increase of approximately $1.9 million annually or approximately 2.8 percent above current rates. The request includes rate recovery associated with pipeline replacement and improvement projects to ensure the integrity of Cascade's system. On October 6, 2016, Cascade, staff of the OPUC and the interveners in the case filed a stipulation and settlement agreement reflecting an annual increase of approximately $754,000 to be effective March 1, 2017. The OPUC issued an order approving the stipulation and settlement agreement on December 12, 2016.

On June 1, 2016, Cascade filed an application with the WUTC for an annual pipeline replacement cost recovery mechanism of $4.6 million annually or approximately 2.0 percent of additional revenue. The requested increase includes $2.4 million associated with incremental pipeline replacement investments and $2.2 million for an alternative recovery request of incremental operation and maintenance costs associated with a maximum allowable operating pressure validation plan. On October 17, 2016, Cascade filed an update to the application that reduced the incremental pipeline replacement investment to $1.9 million and removed the operation and maintenance costs associated with a maximum allowable operating pressure validation plan. On October 27, 2016, the WUTC allowed the pipeline replacement cost recovery mechanism which was effective November 1, 2016. On June 1, 2016, Cascade filed an accounting order to defer the costs related to the maximum allowable operating pressure validation plan and on November 10, 2016, the WUTC granted the order.

On June 10, 2016, Montana-Dakota filed an application for an increase in electric rates with the WYPSC. Montana-Dakota requested an increase of approximately $3.2 million annually or approximately 13.1 percent above current rates to recover Montana-Dakota's increased investment in facilities along with additional depreciation, operation and maintenance expenses including increased fuel costs, and taxes associated with the increases in investment. On December 28, 2016, Montana-Dakota and the interveners of the case filed a stipulation and agreement reflecting an increase of approximately $2.7 million annually or approximately 11.1 percent above current rates effective for service rendered on and after March 1, 2017. The WYPSC rendered a bench decision approving the stipulation and agreement on January 18, 2017.

On August 12, 2016, Intermountain filed an application with the IPUC for a natural gas rate increase of approximately $10.2 million annually or approximately 4.1 percent above current rates. The request includes rate recovery associated with increased investment in facilities and increased operating expenses. On November 23, 2016, Intermountain provided the IPUC with an updated revenue request of approximately $9.6 million. A hearing has been scheduled for March 1-2, 2017. This matter is pending before the IPUC.

On September 1, 2016, and as amended on January 10, 2017, Montana-Dakota submitted an update to its transmission formula rate under the MISO tariff including a revenue requirement for the Company's multivalue project along with a true-up of prior year expenditures of $11.1 million, which was effective January 1, 2017.

On October 14, 2016, Montana-Dakota filed an application with the NDPSC for an electric rate increase of approximately $13.4 million annually or 6.6 percent above current rates. The request includes rate recovery associated with increased investment in facilities, along with the related depreciation, operation and maintenance expenses and taxes associated with the increased investment. Montana-Dakota requested an interim increase of approximately $13.0 million or approximately 6.5 percent, subject to refund, to be effective within 60 days of the filing. On November 21, 2016, Montana-Dakota filed a revised interim increase of approximately $11.7 million, based on adjustments accepted by the NDPSC, or approximately 5.8 percent above current rates, subject to refund. The NDPSC approved the revised interim rates effective with service rendered on or after December 13, 2016. A technical hearing is scheduled for April 10, 2017. This matter is pending before the NDPSC.

On December 2, 2016, Montana-Dakota filed an application with the MTPSC requesting authority to implement gas and electric tax tracking adjustments for Montana state and local taxes and fees that reflect the changes in state and local property taxes applicable to gas and electric utilities pursuant to Montana law. The requested tax tracking adjustments would result in an increase in revenues of approximately $814,000. On January 17, 2017, the MTPSC issued an order on the tax tracking adjustments. The gas tracking adjustment was approved as an increase to revenues of approximately $474,000 effective January 1, 2017. The electric tax tracking adjustment was approved as an increase to revenues of approximately $251,000 effective May 15, 2017. Montana-Dakota filed a motion for reconsideration of the electric tax tracking adjustment on January 27, 2017. The motion for reconsideration is pending before the MTPSC.

On December 21, 2016, Great Plains filed an application with the MNPUC requesting authority to implement a gas utility infrastructure cost tariff of approximately $456,000 annually effective beginning with service rendered May 20, 2017. The tariff will allow Great Plains to recover infrastructure investments, not previously included in rates, mandated by federal or state agencies associated with Great Plains' pipeline integrity programs. This matter is pending before the MNPUC.

Note 17 - Commitments and Contingencies

The Company is party to claims and lawsuits arising out of its business and that of its consolidated subsidiaries. The Company accrues a liability for those contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, in some circumstances, an estimate of the possible loss. The Company had accrued liabilities of $31.8 million and $19.5 million, which include liabilities held for sale, for contingencies, including litigation, production taxes, royalty claims and environmental matters at

December 31, 2016 and 2015, respectively, including amounts that may have been accrued for matters discussed in Litigation and Environmental matters within this note.

Litigation

Natural Gas Gathering Operations Omimex filed a complaint against WBI Energy Midstream in Montana Seventeenth Judicial District Court in July 2010 alleging WBI Energy Midstream breached a gathering contract with Omimex as a result of the increased operating pressures demanded by a third party on a natural gas gathering system in Montana. In December 2011, Omimex filed an amended complaint alleging WBI Energy Midstream breached obligations to operate its gathering system as a common carrier under United States and Montana law. WBI Energy Midstream removed the action to the United States District Court for the District of Montana. The parties subsequently settled the breach of contract claim and, subject to final determination on liability, stipulated to the damages on the common carrier claim, for amounts that are not material. A trial on the common carrier claim was held during July 2013. On December 9, 2014, the United States District Court for the District of Montana issued an order determining WBI Energy Midstream breached its obligations as a common carrier and ordered judgment in favor of Omimex for the amount of the stipulated damages. WBI Energy Midstream filed an appeal from the United States District Court for the District of Montana's order and judgment.

The Company also is subject to other litigation, and actual and potential claims in the ordinary course of its business which may include, but are not limited to, matters involving property damage, personal injury, and environmental, contractual, statutory and regulatory obligations. Accruals are based on the best information available but actual losses in future periods are affected by various factors making them uncertain. After taking into account liabilities accrued for the foregoing matters, management believes that the outcomes with respect to the above issues and other probable and reasonably possible losses in excess of the amounts accrued, while uncertain, will not have a material effect upon the Company's financial position, results of operations or cash flows.

Environmental matters

Portland Harbor Site In December 2000, Knife River - Northwest was named by the EPA as a PRP in connection with the cleanup of a riverbed site adjacent to a commercial property site acquired by Knife River - Northwest from Georgia-Pacific West, Inc. in 1999. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. To date, costs of the overall remedial investigation and feasibility study of the harbor site are being recorded, and initially paid, through an administrative consent order by the LWG, a group of several entities, which does not include Knife River - Northwest or Georgia-Pacific West, Inc. Investigative costs are indicated to be in excess of $100 million. On January 6, 2017, Region 10 of the EPA issued a 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 first claim is for contamination at a site in Eugene, Oregon which was received in 1995. There are PRPs in addition to Cascade that may be liable for cleanup of the contamination. Some of these PRPs have shared in the investigation costs. It is expected that these and other PRPs will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately $500,000 to $11.0 million. The Oregon DEQ released a ROD in January 2015 that selected a remediation alternative for the site as recommended in an earlier staff report. It is not known at this time what share of the cleanup costs will actually be borne by

Cascade; however, Cascade anticipates its proportional share could be approximately 50 percent. Cascade has accrued $1.6 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 and December 1, 2015. Cascade has requested authority to defer accounting for the 12-month period starting December 1, 2016, which is pending before the OPUC.

The second claim is for contamination at a site in Bremerton, Washington which was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants requiring further investigation and cleanup. The EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from $340,000 to $6.4 million. Data developed through the assessment and previous investigations indicates the contamination likely derived from multiple, different sources and multiple current and former owners of properties and businesses in the vicinity of the site may be responsible for the contamination. In April 2010, the Washington 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. Cascade has accrued $12.5 million for the remedial investigation, feasibility study and remediation of this site. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site. The WUTC approved the petition in September 2010, subject to conditions set forth in the order.

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

Cascade has received notices from and entered into agreement with certain of its insurance carriers that they will participate in defense of Cascade for these contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers. The accruals related to these matters are reflected in regulatory assets. For more information, see Note 4.

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, 2016, were $51.7 million in 2017, $43.3 million in 2018, $33.9 million in 2019, $23.2 million in 2020, $9.4 million in 2021 and $42.0 million thereafter. Rent expense was $65.0 million, $53.9 million and $46.9 million for the years ended December 31, 2016, 2015 and 2014, 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. These commitments range from one to 44 years. The commitments under these contracts as of December 31, 2016, were $367.7 million in 2017, $215.7 million in 2018, $189.4 million in 2019, $138.0 million in 2020, $130.6 million in 2021 and $859.5 million thereafter. These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2016, 2015 and 2014, were $539.3 million, $842.1 million and $759.0 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 totaled $63.8 million at December 31, 2016, and are expected to mature by 2023. Tesoro agreed to indemnify Centennial for any losses and litigation expenses arising from the guarantee. The estimated fair values of the indemnity asset and guarantee liability are reflected in deferred charges and other assets - other and deferred credits and other liabilities - other, respectively, on the Consolidated Balance Sheets. Continuation of the guarantee was required as a condition to the sale of Dakota Prairie Refining.

In March 2016, a sale agreement was signed to sell Fidelity's assets in the Paradox Basin. In connection with the sale, Centennial agreed to guarantee Fidelity's indemnity obligations associated with the Paradox Basin assets. The guarantee was required by the buyer as a condition to the sale of the Paradox Basin assets.

In 2009, multiple sales agreements were signed to sell the Company's ownership interests in the Brazilian Transmission Lines. In connection with the sale, Centennial has agreed to guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries who are the sellers in three purchase and sale agreements for periods ranging up to 10 years from the date of sale. The guarantees were required by the buyers as a condition to the sale of the Brazilian Transmission Lines.

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, 2016, the fixed maximum amounts guaranteed under these agreements aggregated $98.7 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $33.6 million in 2017; $4.5 million in 2018; $56.6 million in 2019; and $4.0 million, which has no scheduled maturity date. There were no amounts outstanding under the above guarantees at December 31, 2016. 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, 2016, the fixed maximum amounts guaranteed under these letters of credit aggregated $30.8 million, all of which expire in 2017. There were no amounts outstanding under the above letters of credit at December 31, 2016. In the event of default under these letter of credit obligations, the subsidiary issuing the letter of credit for that particular obligation would be required to make payments under its 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 and MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these guarantees were reflected on the Consolidated Balance Sheet at December 31, 2016.

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. As of December 31, 2016, approximately $516.1 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Variable interest entities

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

Dakota Prairie Refining, LLC On February 7, 2013, WBI Energy and Calumet formed a limited liability company, Dakota Prairie Refining, and entered into an operating agreement to develop, build and operate Dakota Prairie Refinery in southwestern North Dakota. WBI Energy and Calumet each had a 50 percent ownership interest in Dakota Prairie Refining. WBI Energy's and Calumet's capital commitments, based on a total project cost of $300 million, under the agreement were $150 million and $75 million, respectively. Capital commitments in excess of $300 million were shared equally between WBI Energy and Calumet. Dakota Prairie Refining entered into a term loan for project debt financing of $75 million on April 22, 2013. The operating agreement provided for allocation of profits and losses consistent with ownership interests; however, deductions attributable to project financing debt was allocated to Calumet. Calumet's cash distributions from Dakota Prairie Refining were decreased by the principal and interest paid on the project debt, while the cash distributions to WBI Energy were not decreased. Pursuant to the operating agreement, Centennial agreed to guarantee Dakota Prairie Refining's obligation under the term loan. The net loss attributable to noncontrolling interest on the Consolidated Statements of Income is pretax as Dakota Prairie Refining was a limited liability company. For more information related to the guarantee, see Guarantees in this note.

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

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. 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. For more information on the Company's discontinued operations, see Note 2.

Dakota Prairie Refinery commenced operations in May 2015. The assets of Dakota Prairie Refining were used solely for the benefit of Dakota Prairie Refining. The total assets and liabilities of Dakota Prairie Refining at December 31 were as follows:

		2015
		(In thousands)
Assets		
Current assets:		
Cash and cash equivalents	$	851
Accounts receivable		7,693
Inventories		13,176
Other current assets		6,215
Total current assets		27,935
Net property, plant and equipment		425,123
Deferred charges and other assets:		
Other		9,626
Total deferred charges and other assets		9,626
Total assets	$	462,684
Liabilities		
Current liabilities:		
Short-term borrowings	$	45,500
Long-term debt due within one year		5,250
Accounts payable		24,766
Taxes payable		1,391
Accrued compensation		938
Other accrued liabilities		4,953
Total current liabilities		82,798
Long-term debt		63,750
Total liabilities	$	146,548

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 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, 2016, 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 $43.3 million.

Supplementary Financial Information

Quarterly Data (Unaudited)

The following unaudited information shows selected items by quarter for the years 2016 and 2015:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
2016				
Operating revenues	$ **860,214**	$ **1,043,948**	$ **1,208,567**	$ **1,016,099**
Operating expenses	**798,229**	**954,983**	**1,061,883**	**904,613**
Operating income	**61,985**	**88,965**	**146,684**	**111,486**
Income from continuing operations	**31,865**	**46,298**	**88,386**	**66,547**
Loss from discontinued operations attributable to the Company, net of tax	**(6,996)**	**(155,451)**	**(5,400)**	**(816)**
Net income (loss) attributable to the Company	**24,869**	**(109,153)**	**82,986**	**65,731**
Earnings (loss) per common share - basic:				
Earnings before discontinued operations	**.16**	**.24**	**.45**	**.34**
Discontinued operations attributable to the Company, net of tax	**(.03)**	**(.80)**	**(.03)**	**—**
Earnings (loss) per common share - basic	**.13**	**(.56)**	**.42**	**.34**
Earnings (loss) per common share - diluted:				
Earnings before discontinued operations	**.16**	**.24**	**.45**	**.33**
Discontinued operations attributable to the Company, net of tax	**(.03)**	**(.80)**	**(.03)**	**—**
Earnings (loss) per common share - diluted	**.13**	**(.56)**	**.42**	**.33**
Weighted average common shares outstanding:				
Basic	**195,284**	**195,304**	**195,304**	**195,304**
Diluted	**195,284**	**195,699**	**195,811**	**195,889**
2015				
Operating revenues	$ 860,845	$ 938,039	$ 1,198,342	$ 1,016,826
Operating expenses	810,537	878,330	1,070,514	934,896
Operating income	50,308	59,709	127,828	81,930
Income from continuing operations	20,540	26,061	73,886	55,902
Loss from discontinued operations attributable to the Company, net of tax	(326,457)	(255,665)	(213,334)	(3,368)
Net income (loss) attributable to the Company	(305,917)	(229,604)	(139,448)	52,534
Earnings (loss) per common share - basic:				
Earnings before discontinued operations	.10	.13	.38	.29
Discontinued operations attributable to the Company, net of tax	(1.67)	(1.31)	(1.10)	(.02)
Earnings (loss) per common share - basic	(1.57)	(1.18)	(.72)	.27
Earnings (loss) per common share - diluted:				
Earnings before discontinued operations	.10	.13	.38	.29
Discontinued operations attributable to the Company, net of tax	(1.67)	(1.31)	(1.10)	(.02)
Earnings (loss) per common share - diluted	(1.57)	(1.18)	(.72)	.27
Weighted average common shares outstanding:				
Basic	194,479	194,805	195,151	195,266
Diluted	194,566	194,838	195,169	195,324

Notes:

- Fourth quarter 2016 reflects a reduction to a previously recorded MEPP withdrawal liability of $11.1 million (before tax). For more information, see Note 14.
- 2015 and first quarter 2016 have been recast to present the results of operations of Dakota Prairie Refining as discontinued operations, other than certain general and administrative costs and interest expense which were previously allocated to the former refining segment and do not meet the criteria for income (loss) from discontinued operations.
- First quarter 2015 has been recast to present the results of operations of Fidelity as discontinued operations, other than certain general and administrative costs and interest expense which were previously allocated to the former exploration and production segment and do not meet the criteria for income (loss) from discontinued operations.
- First quarter 2015 reflects a MEPP withdrawal liability of $2.4 million (before tax). For more information, see Note 14.
- Second quarter 2015 reflects an impairment of coalbed natural gas gathering assets of $3.0 million (before tax). For more information, see Note 1.
- Third quarter 2015 reflects an impairment of coalbed natural gas gathering assets of $14.1 million (before tax). For more information, see Note 1.

Certain Company operations are highly seasonal and revenues from and certain expenses for such operations may fluctuate significantly among quarterly periods. Accordingly, quarterly financial information may not be indicative of results for a full year.

Exploration and Production Activities (Unaudited)

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 all of Fidelity's oil and natural gas assets. The completion of these sales occurred between October 2015 and April 2016. At the time the Company committed to a plan to sell Fidelity, the Company stopped the use of the full-cost method of accounting for its oil and natural gas production activities. The assets and liabilities have been classified as held for sale and the results of operations included 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. Prior to the asset sales, Fidelity was significantly involved in the development and production of oil and natural gas resources. For more information, see Note 2.

Previously, Fidelity shared revenues and expenses from the development of specified properties in proportion to its ownership interests. The information that follows includes Fidelity's proportionate share of all its previously owned oil and natural gas interests.

The following table sets forth capitalized costs and accumulated depreciation, depletion and amortization related to oil and natural gas producing activities, prior to Fidelity's assets being held for sale, at December 31:

	2014
	(In thousands)
Subject to amortization	$ 3,205,036
Not subject to amortization	132,141
Total capitalized costs	3,337,177
Less accumulated depreciation, depletion and amortization	1,752,566
Net capitalized costs	$ 1,584,611

Capital expenditures, including those not subject to amortization, related to oil and natural gas producing activities prior to Fidelity's assets being held for sale, excluding the years ended December 31, 2016 and 2015, due to no wells being drilled during that time, were as follows:

Year ended December 31,	2014 *
	(In thousands)
Acquisitions:	
Proved properties	$ 87,919
Unproved properties	138,683
Exploration	16,879
Development	331,400
Total capital expenditures	$ 574,881

* Excludes net reductions to property, plant and equipment related to the recognition of future liabilities for asset retirement obligations associated with the plugging and abandonment of oil and natural gas wells of $9.0 million for the year ended December 31, 2014.

Estimates of proved reserves were prepared in accordance with guidelines established by the industry and the SEC. The estimates are arrived at using actual historical wellhead production trends and/or standard reservoir engineering methods utilizing available geological, geophysical, engineering and economic data. The proved reserve estimates as of December 31, 2015 and 2014, were calculated using SEC Defined Prices. Other factors used in the proved reserve estimates were current estimates of well operating and future development costs (which include asset retirement costs), taxes, timing of operations, and the interests owned by the Company in the properties. These estimates are refined as new information becomes available.

The reserve estimates were prepared by internal engineers assigned to an asset team by geographic area. Senior management reviewed and approved the reserve estimates to ensure they were materially accurate.

Estimates of economically recoverable oil, NGL and natural gas reserves and future net revenues therefrom are based upon a number of variable factors and assumptions. For these reasons, estimates of economically recoverable reserves and future net revenues may vary from actual results.

The changes in the Company's estimated quantities of proved oil, NGL and natural gas reserves for the year ended December 31, 2016, were as follows:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed and undeveloped reserves:				
Balance at beginning of year	12,687	211	2,531	13,321
Production	—	—	—	—
Extensions and discoveries	—	—	—	—
Improved recovery	—	—	—	—
Purchases of proved reserves	—	—	—	—
Sales of proved reserves	(12,687)	(211)	(2,531)	(13,321)
Revisions of previous estimates	—	—	—	—
Balance at end of year	—	—	—	—

Significant changes in proved reserves for the year ended December 31, 2016, include:

- Sales of proved reserves of (13.3) MMBOE, due to the Company's decision to sell Fidelity and exit the exploration and production business

The changes in the Company's estimated quantities of proved oil, NGL and natural gas reserves for the year ended December 31, 2015, were as follows:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed and undeveloped reserves:				
Balance at beginning of year	43,918	7,187	245,011	91,940
Production	(3,286)	(393)	(16,747)	(6,471)
Extensions and discoveries	744	29	681	888
Improved recovery	—	—	—	—
Purchases of proved reserves	—	—	—	—
Sales of proved reserves	(16,474)	(6,864)	(202,560)	(57,097)
Revisions of previous estimates	(12,215)	252	(23,854)	(15,939)
Balance at end of year	12,687	211	2,531	13,321

Significant changes in proved reserves for the year ended December 31, 2015, include:

- Sales of proved reserves of (57.1) MMBOE, primarily due to the Company's decision to sell Fidelity and exit the exploration and production business
- Revisions of previous estimates of (15.9) MMBOE, largely the result of lower commodity prices

The changes in the Company's estimated quantities of proved oil, NGL and natural gas reserves for the year ended December 31, 2014, were as follows:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed and undeveloped reserves:				
Balance at beginning of year	41,019	6,602	198,445	80,695
Production	(4,919)	(609)	(20,822)	(8,998)
Extensions and discoveries	9,654	3,634	64,420	24,025
Improved recovery	—	—	—	—
Purchases of proved reserves	5,463	—	7,711	6,748
Sales of proved reserves	(4,945)	(3,109)	(40,451)	(14,796)
Revisions of previous estimates	(2,354)	669	35,708	4,266
Balance at end of year	43,918	7,187	245,011	91,940

Significant changes in proved reserves for the year ended December 31, 2014, include:

- Extensions and discoveries of 24.0 MMBOE, primarily due to drilling activity at the Company's East Texas, Bakken and Powder River Basin properties

- Purchases of proved reserves of 6.7 MMBOE, primarily due to the purchase of working interests and leasehold positions in the Powder River Basin
- Sales of proved reserves of (14.8) MMBOE, primarily at the Company's South Texas and Bakken properties
- Revisions of previous estimates of 4.3 MMBOE, largely the result of higher natural gas prices and well performance revisions

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

	2016	2015	2014
Proved developed reserves:			
Oil (MBbls)	—	11,380	30,130
NGL (MBbls)	—	144	4,217
Natural Gas (MMcf)	—	2,033	184,437
Total (MBOE)	—	11,865	65,086
PUD reserves:			
Oil (MBbls)	—	1,307	13,788
NGL (MBbls)	—	67	2,970
Natural Gas (MMcf)	—	498	60,574
Total (MBOE)	—	1,456	26,854
Total proved reserves:			
Oil (MBbls)	—	12,687	43,918
NGL (MBbls)	—	211	7,187
Natural Gas (MMcf)	—	2,531	245,011
Total (MBOE)	—	13,321	91,940

As of December 31, 2016, the Company had no PUD reserves, which is a decrease of 1.5 MMBOE from December 31, 2015. The decrease relates to the asset sales during 2016.

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
ATBs	Atmospheric tower bottoms
Bicent	Bicent Power LLC
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
BOE	One barrel of oil equivalent - determined using the ratio of one barrel of crude oil, condensate or natural gas liquids to six Mcf of natural gas
Brazilian Transmission Lines	Company's former investment in companies owning three electric transmission lines
Calumet	Calumet Specialty Products Partners, L.P.
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial'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.
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
IBEW	International Brotherhood of Electrical Workers
IFRS	International Financial Reporting Standards
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
IPUC	Idaho Public Utilities Commission
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
MBbls	Thousands of barrels
MBOE	Thousands of BOE
Mcf	Thousand cubic feet
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
MEPP	Multiemployer pension plan

MISO	Midcontinent Independent System Operator, Inc.
MMBOE	Millions of BOE
MMcf	Million cubic feet
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
Montana Seventeenth Judicial District Court	Montana Seventeenth Judicial District Court, Phillips County
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
NGL	Natural gas liquids
Oil	Includes crude oil and condensate
Omimex	Omimex Canada, Ltd.
OPUC	Oregon Public Utility Commission
Oregon DEQ	Oregon State Department of Environmental Quality
Pronghorn	Natural gas processing plant located near Belfield, North Dakota (WBI Energy Midstream previously held a 50 percent non-operating ownership interest)
PRP	Potentially Responsible Party
PUD	Proved undeveloped
ROD	Record of Decision
RP	Rehabilitation plan
SEC	United States Securities and Exchange Commission
SEC Defined Prices	The average price of oil and natural gas during the applicable 12-month period, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan which was terminated effective December 5, 2016
Tesoro	Tesoro Refining & Marketing Company LLC
Tesoro Logistics	QEP Field Services, LLC doing business as Tesoro Logistics Rockies LLC
United States District Court for the District of Montana	United States District Court for the District of Montana, Great Falls Division
VIE	Variable interest entity
WBI Energy	WBI Energy, Inc., an indirect wholly owned subsidiary of WBI Holdings
WBI Energy Midstream	WBI Energy Midstream, LLC, an indirect wholly owned subsidiary of WBI Holdings
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 quarter ended December 31, 2016, 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 is included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 11. Executive Compensation

Information required by this item is 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, 2016, 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)	664,188	(2)	$ —	(3)	4,824,267	(4)(5)
Equity compensation plans not approved by stockholders	N/A		N/A		N/A	

(1) Consists of the Non-Employee Director Long-Term Incentive Compensation Plan, the Long-Term Performance-Based Incentive Plan and the Non-Employee Director Stock Compensation Plan.
(2) Consists of performance shares.
(3) No weighted average exercise price is shown for the performance shares.
(4) 357,757 shares remain available for future issuance under the Non-Employee Director Long-Term Incentive Compensation Plan in connection with grants of restricted stock, performance units, performance shares or other equity-based awards. 4,429,239 shares under the Long-Term Performance-Based Incentive Plan remain available for future issuance in connection with grants of restricted stock, performance units, performance shares or other equity-based awards.
(5) This amount also includes 37,271 shares available for issuance under the Non-Employee Director Stock Compensation Plan. Under this plan, in addition to a cash retainer, non-employee directors are awarded shares equal in value to $110,000 annually. A non-employee director may acquire additional shares under the plan in lieu of receiving the cash portion of the director's retainer or fees.

The remaining information required by this item is included 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 is included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

Information required by this item is included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements, Financial Statement Schedules and Exhibits

Index to Financial Statements and Financial Statement Schedules

1. Financial Statements

The following consolidated financial statements required under this item are included under Item 8 - Financial Statements and Supplementary Data.

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,	2016	2015	2014
		(In thousands)	
Operating revenues	$ **561,266**	$ 556,112	$ 628,578
Operating expenses	**469,062**	478,198	547,820
Operating income	**92,204**	77,914	80,758
Other income	**1,491**	8,318	5,271
Interest expense	**31,519**	23,562	21,055
Income before income taxes	**62,176**	62,670	64,974
Income taxes	**6,355**	15,882	16,819
Equity in earnings of subsidiaries from continuing operations	**177,275**	129,601	136,872
Net income from continuing operations	**233,096**	176,389	185,027
Equity in earnings (loss) of subsidiaries from discontinued operations attributable to the Company	**(168,663)**	(798,824)	113,206
Dividends declared on preferred stocks	**685**	685	685
Earnings (loss) on common stock	$ **63,748**	$ (623,120)	$ 297,548
Comprehensive income (loss)	$ **65,848**	$ (617,480)	$ 294,335

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,	2016	2015
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 4,159	$ 2,921
Receivables, net	80,467	70,511
Accounts receivable from subsidiaries	34,424	33,129
Inventories	17,352	16,883
Prepayments and other current assets	24,531	7,876
Total current assets	160,933	131,320
Investments	70,370	66,784
Investment in subsidiaries	1,603,874	1,722,351
Property, plant and equipment	2,502,264	2,378,994
Less accumulated depreciation, depletion and amortization	756,191	711,209
Net property, plant and equipment	1,746,073	1,667,785
Deferred charges and other assets:		
Goodwill	4,812	4,812
Other	183,654	184,080
Total deferred charges and other assets	188,466	188,892
Total assets	$ 3,769,716	$ 3,777,132
Liabilities and Stockholders' Equity		
Current liabilities:		
Long-term debt due within one year	$ 110	$ 109
Accounts payable	37,697	54,275
Accounts payable to subsidiaries	5,592	6,622
Taxes payable	14,992	10,995
Dividends payable	37,767	36,784
Accrued compensation	16,086	7,539
Other accrued liabilities	34,929	40,931
Total current liabilities	147,173	157,255
Long-term debt	679,667	623,048
Deferred credits and other liabilities:		
Deferred income taxes	270,126	255,069
Other	356,506	345,255
Total deferred credits and other liabilities	626,632	600,324
Commitments and contingencies		
Stockholders' equity:		
Preferred stocks	15,000	15,000
Common stockholders' equity:		
Common stock		
Authorized - 500,000,000 shares, $1.00 par value		
Issued - 195,843,297 shares in 2016 and 195,804,665 shares in 2015	195,843	195,805
Other paid-in capital	1,232,478	1,230,119
Retained earnings	912,282	996,355
Accumulated other comprehensive loss	(35,733)	(37,148)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total common stockholders' equity	2,301,244	2,381,505
Total stockholders' equity	2,316,244	2,396,505
Total liabilities and stockholders' equity	$ 3,769,716	$ 3,777,132

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,	2016	2015	2014
		(In thousands)	
Net cash provided by operating activities	$ **238,125**	$ 255,273	$ 208,208
Investing activities:			
Capital expenditures	**(159,570)**	(349,985)	(223,251)
Net proceeds from sale or disposition of property and other	**3,784**	3,268	1,552
Investments in and advances to subsidiaries	**(5,000)**	(7,000)	(134,451)
Advances from subsidiaries	**15,000**	100,000	64,500
Investments	**(129)**	5	(794)
Net cash used in investing activities	**(145,915)**	(253,712)	(292,444)
Financing activities:			
Issuance of long-term debt	**106,420**	224,185	148,959
Repayment of long-term debt	**(50,010)**	(108,008)	(76,432)
Proceeds from issuance of common stock	**—**	21,898	150,060
Dividends paid	**(147,156)**	(142,835)	(136,712)
Excess tax benefit on stock-based compensation	**—**	—	3,326
Tax withholding on stock-based compensation	**(226)**	—	(3,896)
Net cash provided by (used in) financing activities	**(90,972)**	(4,760)	85,305
Increase (decrease) in cash and cash equivalents	**1,238**	(3,199)	1,069
Cash and cash equivalents - beginning of year	**2,921**	6,120	5,051
Cash and cash equivalents - end of year	$ **4,159**	$ 2,921	$ 6,120

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

Notes to Condensed Financial Statements

Note 1 - Summary of Significant Accounting Policies

Basis of presentation The condensed financial information reported in Schedule I is being presented to comply with Rule 12-04 of Regulation S-X. The information is unconsolidated and is presented for the parent company only, which is comprised of MDU Resources Group, Inc. (the Company) and Montana-Dakota and Great Plains, public utility divisions of the Company. In Schedule I, investments in subsidiaries are presented under the equity method of accounting where the assets and liabilities of the subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded on the Condensed Balance Sheets. The income (loss) from subsidiaries is reported as equity in earnings (loss) of subsidiaries on the Condensed Statements of Income. The consolidated financial statements of MDU Resources Group, Inc. reflect certain businesses as discontinued operations. These statements should be read in conjunction with the consolidated financial statements and notes thereto of MDU Resources Group, Inc.

Earnings (loss) per common share Please refer to the Consolidated Statements of Income of the registrant for earnings (loss) per common share. In addition, see Item 8 - Note 1 for information on the computation of earnings (loss) per common share.

Note 2 - Debt The Company has long-term debt obligations outstanding of $681.8 million at December 31, 2016, with annual maturities of $100,000 in 2017, $100.1 million in 2018, $111.1 million in 2019, $100,000 in 2020 and $470.4 million scheduled to mature in years after 2021.

For more information on debt, see Item 8 - Note 6.

Note 3 - Dividends The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. Cash dividends paid to the Company by subsidiaries were $115.8 million, $110.6 million and $105.6 million for the years ended December 31, 2016, 2015 and 2014, respectively.

MDU RESOURCES GROUP, INC.

Schedule II - Consolidated Valuation and Qualifying Accounts

For the years ended December 31, 2016, 2015 and 2014

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:					
2016	**$ 9,835**	**$ 8,302**	**$ 851**	**$ 8,509**	**$ 10,479**
2015	9,511	11,343	1,012	12,031	9,835
2014	10,085	8,548	1,335	10,457	9,511

* Recoveries.
** Uncollectible accounts written off.

All other schedules are omitted because of the absence of the conditions under which they are required, or because the information required is included in the Company's Consolidated Financial Statements and Notes thereto.

3. Exhibits

2(a) Membership Interest Purchase Agreement, dated as of June 24, 2016, between WBI Energy, Inc. and Tesoro Refining & Marketing Company LLC, filed as Exhibit 2.1 to Form 8-K/A dated June 24, 2016, filed on July 21, 2016, in File No. 1-3480*

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., filed as Exhibit 2.2 to Form 8-K/A dated June 24, 2016, filed on July 21, 2016, in File No. 1-3480*

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., filed as Exhibit 2.3 to Form 8-K/A dated June 24, 2016, filed on July 21, 2016, in File No. 1-3480*

3(a) Restated Certificate of Incorporation of MDU Resources Group, Inc., as amended, dated May 13, 2010, filed as Exhibit 3(a) to Form 10-Q for the quarter ended September 30, 2010, filed on November 3, 2010, in File No. 1-3480*

3(b) Bylaws of MDU Resources Group, Inc., as amended and restated on February 16, 2017, filed as Exhibit 3.1 to Form 8-K dated February 16, 2017, filed on February 21, 2017, in File No. 1-3480*

4(a) Indenture, dated as of December 15, 2003, between MDU Resources Group, Inc. and The Bank of New York, as trustee, filed as Exhibit 4(f) to Form S-8 on January 21, 2004, in Registration No. 333-112035*

4(b) First Supplemental Indenture, dated as of November 17, 2009, between MDU Resources Group, Inc. and The Bank of New York Mellon, as trustee, filed as Exhibit 4(c) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

4(c) Centennial Energy Holdings, Inc. 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, filed as Exhibit 4(a) to Form 10-Q for the quarter ended June 30, 2005, filed on August 3, 2005, in File No. 1-3480*

4(d) Letter Amendment No. 1 to Amended and Restated Master Shelf Agreement, dated May 17, 2006, among Centennial Energy Holdings, Inc., the Prudential Insurance Company of America, and certain investors described in the Letter Amendment, filed as Exhibit 4(a) to Form 10-Q for the quarter ended June 30, 2006, filed on August 4, 2006, in File No. 1-3480*

4(e) 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, filed as Exhibit 4(e) to Form 10-K for the year ended December 31, 2015, filed on February 19, 2016, in File No. 1-3480*

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, filed as Exhibit 4(f) to Form 10-K for the year ended December 31, 2015, filed on February 19, 2016, in File No. 1-3480*

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, filed as Exhibit 4(e) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*

4(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, filed as Exhibit 4 to Form 10-Q for the quarter ended September 30, 2012, filed on November 7, 2012, in File No. 1-3480*

4(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, filed as Exhibit 4(a) to Form 10-Q for the quarter ended June 30, 2014, filed on August 8, 2014, in File No. 1-3480*

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, filed as Exhibit 4(b) to Form 10-Q for the quarter ended June 30, 2014, filed on August 8, 2014, in File No. 1-3480*

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, filed as Exhibit 4 to Form 10-Q for the quarter ended September 30, 2016, filed on November 7, 2016, in File No. 1-3480*

4(l) 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, filed as Exhibit 4 to Form 8-K dated August 16, 2007, filed on August 16, 2007, in File No. 1-3480*

4(m) Amendment No. 1 to Master Shelf Agreement, dated October 1, 2008, among MDU Energy Capital, LLC, Prudential Investment Management, Inc., the Prudential Insurance Company of America, and the holders of the notes thereunder, filed as Exhibit 4(b) to Form 10-Q for the quarter ended September 30, 2008, filed on November 5, 2008, in File No. 1-3480*

4(n) Indenture dated as of August 1, 1992, between Cascade Natural Gas Corporation and The Bank of New York relating to Medium-Term Notes, filed by Cascade Natural Gas Corporation as Exhibit 4 to Form 8-K dated August 12, 1992, in File No. 1-7196*

4(o) First Supplemental Indenture dated as of October 25, 1993, between Cascade Natural Gas Corporation and The Bank of New York relating to Medium-Term Notes and the 7.5% Notes due November 15, 2031, filed by Cascade Natural Gas Corporation as Exhibit 4 to Form 10-Q for the quarter ended June 30, 1993, in File No. 1-7196*

4(p) Second Supplemental Indenture, dated January 25, 2005, between Cascade Natural Gas Corporation and The Bank of New York, as trustee, filed by Cascade Natural Gas Corporation as Exhibit 4.1 to Form 8-K dated January 25, 2005, filed on January 26, 2005, in File No. 1-7196*

4(q) Third Supplemental Indenture dated as of March 8, 2007, between Cascade Natural Gas Corporation and The Bank of New York Trust Company, N.A., as Successor Trustee, filed by Cascade Natural Gas Corporation as Exhibit 4.1 to Form 8-K dated March 8, 2007, filed on March 8, 2007, in File No. 1-7196*

+10(a) MDU Resources Group, Inc. Supplemental Income Security Plan, as amended and restated February 11, 2016, filed as Exhibit 10(a) to Form 10-Q for the quarter ended March 31, 2016, filed on May 6, 2016, in File No. 1-3480*

+10(b) Director Compensation Policy, as amended May 15, 2014, filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2014, filed on August 8, 2014, in File No. 1-3480*

+10(c) Deferred Compensation Plan for Directors, as amended May 15, 2008, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2008, filed on August 7, 2008, in File No. 1-3480*

+10(d) Non-Employee Director Stock Compensation Plan, as amended May 12, 2011, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2011, filed on August 5, 2011, in File No. 1-3480*

+10(e) MDU Resources Group, Inc. Non-Employee Director Long-Term Incentive Compensation Plan, as amended May 17, 2012, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2012, filed on August 7, 2012, in File No. 1-3480*

+10(f) MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan, as amended February 11, 2016, filed as Exhibit 10(f) to Form 10-K for the year ended December 31, 2015, filed on February 19, 2016, in File No. 1-3480*

+10(g) MDU Resources Group, Inc. Executive Incentive Compensation Plan, as amended February 11, 2016, and Rules and Regulations, as amended March 4, 2013, filed as Exhibit 10(b) to Form 10-Q for the quarter ended March 31, 2016, filed on May 6, 2016, in File No. 1-3480*

+10(h) Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 12, 2014, filed as Exhibit 10(a) to Form 10-Q for the quarter ended March 31, 2014, filed on May 7, 2014, in File No. 1-3480*

+10(i) Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 11, 2015, filed as Exhibit 10.3 to Form 8-K dated February 11, 2015, filed on February 18, 2015, in File No. 1-3480*

+10(j) Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 10, 2016, filed as Exhibit 10.3 to Form 8-K dated February 10, 2016, filed on February 18, 2016, in File No. 1-3480*

+10(k) Form of Annual Incentive Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 10, 2016, filed as Exhibit 10.2 to Form 8-K dated February 10, 2016, filed on February 18, 2016, in File No. 1-3480*

+10(l) Form of MDU Resources Group, Inc. Indemnification Agreement for Section 16 Officers and Directors, filed as Exhibit 10.1 to Form 8-K dated May 15, 2014, filed on May 15, 2014, in File No. 1-3480*

+10(m) Form of Amendment No. 1 to Indemnification Agreement, filed as Exhibit 10.2 to Form 8-K dated May 15, 2014, filed on May 15, 2014, in File No. 1-3480*

+10(n) MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart, as of January 27, 2017**

+10(o) MDU Resources Group, Inc. Nonqualified Defined Contribution Plan, as amended and restated November 17, 2016, filed as Exhibit 10.1 to Form 8-K dated November 17, 2016, filed on November 21, 2016, in File No. 1-3480*

+10(p) MDU Resources Group, Inc. 401(k) Retirement Plan, as restated March 1, 2011, filed as Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2011, filed on November 4, 2011, in File No. 1-3480*

+10(q) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 29, 2011, filed as Exhibit 10(b) to Form 10-Q for the quarter ended March 31, 2011, filed on May 5, 2011, in File No. 1-3480*

+10(r) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated June 30, 2011, filed as Exhibit 10(d) to Form 10-Q for the quarter ended June 30, 2011, filed on August 5, 2011, in File No. 1-3480*

+10(s) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2011, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2011, filed on November 4, 2011, in File No. 1-3480*

+10(t) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 29, 2011, filed as Exhibit 10(ac) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*

+10(u) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated May 24, 2012, filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2012, filed on August 7, 2012, in File No. 1-3480*

+10(v) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 29, 2012, filed as Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2012, filed on November 7, 2012, in File No. 1-3480*

+10(w) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 29, 2012, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2012, filed on November 7, 2012, in File No. 1-3480*

+10(x) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 19, 2012, filed as Exhibit 10(z) to Form 10-K for the year ended December 31, 2012, filed on February 28, 2013, in File No. 1-3480*

+10(y) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2013, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2013, filed on November 7, 2013, in File No. 1-3480*

+10(z) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2013, filed as Exhibit 10(c) to Form 10-Q for the quarter ended September 30, 2013, filed on November 7, 2013, in File No. 1-3480*

+10(aa) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 23, 2013, filed as Exhibit 10(d) to Form 10-Q for the quarter ended September 30, 2013, filed on November 7, 2013, in File No. 1-3480*

+10(ab) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 31, 2013, filed as Exhibit 10(aa) to Form 10-K for the year ended December 31, 2013, filed on February 21, 2014, in File No. 1-3480*

+10(ac) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 13, 2014, filed as Exhibit 10(b) to Form 10-Q for the quarter ended March 31, 2014, filed on May 7, 2014, in File No. 1-3480*

+10(ad) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated June 5, 2014, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2014, filed on August 8, 2014, in File No. 1-3480*

+10(ae) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated July 7, 2014, filed as Exhibit 4.20 to Form S-8, filed on August 26, 2014, in Registration No. 333-198364*

+10(af) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 18, 2014, filed as Exhibit 4.21 to Form S-8, filed on August 26, 2014, in Registration No. 333-198364*

+10(ag) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 30, 2014, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2014, filed on November 7, 2014, in File No. 1-3480*

+10(ah) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated November 25, 2014, filed as Exhibit 10(ah) to Form 10-K for the year ended December 31, 2014, filed on February 20, 2015, in File No. 1-3480*

+10(ai) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 11, 2014, filed as Exhibit 10(ai) to Form 10-K for the year ended December 31, 2014, filed on February 20, 2015, in File No. 1-3480*

+10(aj) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 11, 2014, filed as Exhibit 10(aj) to Form 10-K for the year ended December 31, 2014, filed on February 20, 2015, in File No. 1-3480*

+10(ak) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 30, 2014, filed as Exhibit 10(ak) to Form 10-K for the year ended December 31, 2014, filed on February 20, 2015, in File No. 1-3480*

+10(al) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated February 17, 2015, filed as Exhibit 10(a) to Form 10-Q for the quarter ended March 31, 2015, filed on May 8, 2015, in File No. 1-3480*

+10(am)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 13, 2015, filed as Exhibit 10(b) to Form 10-Q for the quarter ended March 31, 2015, filed on May 8, 2015, in File No. 1-3480*
+10(an)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated June 30, 2015, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2015, filed on August 4, 2015, in File No. 1-3480*
+10(ao)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated November 19, 2015, filed as Exhibit 10(ap) to Form 10-K for the year ended December 31, 2015, filed on February 19, 2016, in File No. 1-3480*
+10(ap)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated January 22, 2016, filed as Exhibit 10(c) to Form 10-Q for the quarter ended March 31, 2016, filed on May 6, 2016, in File No. 1-3480*
+10(aq)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 10, 2016, filed as Exhibit 10(d) to Form 10-Q for the quarter ended March 31, 2016, filed on May 6, 2016, in File No. 1-3480*
+10(ar)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 19, 2016, filed as Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2016, filed on November 7, 2016, in File No. 1-3480*
+10(as)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 29, 2016**
+10(at)	Employment Letter for Jeffrey S. Thiede, dated May 16, 2013, filed as Exhibit 10(ab) to Form 10-K for the year ended December 31, 2013, filed on February 21, 2014, in File No. 1-3480*
+10(au)	Martin A. Fritz Offer Letter, dated July 1, 2015, filed as Exhibit 10.2 to Form 8-K dated June 30, 2015, filed on July 2, 2015, in File No. 1-3480*
+10(av)	Jason L. Vollmer Offer Letter, dated March 7, 2016, filed as Exhibit 10.2 to Form 8-K dated March 2, 2016, file on March 8, 2016, in file No. 1-3480*
12	Computation of Ratio of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividends**
21	Subsidiaries of MDU Resources Group, Inc.**
23	Consent of Independent Registered Public Accounting Firm**
31(a)	Certification of Chief Executive Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**
31(b)	Certification of Chief Financial Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**
32	Certification of Chief Executive Officer and Chief Financial Officer furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002**
95	Mine Safety Disclosures**
99(a)	Equity Distribution Agreement entered into between MDU Resources Group, Inc. and Wells Fargo Securities, LLC, filed as Exhibit 1 to Form 8-K dated May 20, 2013, filed on May 20, 2013, in File No. 1-3480*
99(b)	First Amendment to Equity Distribution Agreement, dated December 2, 2013, entered into between MDU Resources Group, Inc. and Wells Fargo Securities, LLC, filed as Exhibit 99(c) to Form 10-K for the year ended December 31, 2013, filed on February 21, 2014, in File No. 1-3480*
101	The following materials from MDU Resources Group, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2016, formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Balance Sheets, (iv) the Consolidated Statements of Equity, (v) the Consolidated Statements of Cash Flows, (vi) the Notes to Consolidated Financial Statements, tagged in summary and detail, (vii) Schedule I - Condensed Financial Information of Registrant, tagged in summary and detail and (viii) Schedule II - Consolidated Valuation and Qualifying Accounts, tagged in summary and detail

* Incorporated herein by reference as indicated.

** Filed herewith.

\+ Management contract, compensatory plan or arrangement.

MDU Resources Group, Inc. agrees to furnish to the SEC upon request any instrument with respect to long-term debt that MDU Resources Group, Inc. has not filed as an exhibit pursuant to the exemption provided by Item 601(b)(4)(iii)(A) of Regulation S-K.

Signatures

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

MDU Resources Group, Inc.

Date: February 24, 2017 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 24, 2017
/s/ Doran N. Schwartz Doran N. Schwartz (Vice President and Chief Financial Officer)	Chief Financial Officer	February 24, 2017
/s/ Jason L. Vollmer Jason L. Vollmer (Vice President, Chief Accounting Officer and Treasurer)	Chief Accounting Officer	February 24, 2017
/s/ Harry J. Pearce Harry J. Pearce (Chairman of the Board)	Director	February 24, 2017
/s/ Thomas Everist Thomas Everist	Director	February 24, 2017
/s/ Karen B. Fagg Karen B. Fagg	Director	February 24, 2017
/s/ Mark A. Hellerstein Mark A. Hellerstein	Director	February 24, 2017
/s/ A. Bart Holaday A. Bart Holaday	Director	February 24, 2017
/s/ Dennis W. Johnson Dennis W. Johnson	Director	February 24, 2017
/s/ William E. McCracken William E. McCracken	Director	February 24, 2017
/s/ Patricia L. Moss Patricia L. Moss	Director	February 24, 2017
/s/ John K. Wilson John K. Wilson	Director	February 24, 2017

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 24, 2017

Fellow Stockholders:

I invite you to join me, our board of directors, and members of our senior management team at our Annual Meeting of Stockholders at 11 a.m., Central Daylight Saving Time, on May 9, 2017, at 909 Airport Road in Bismarck, North Dakota.

In addition to the business that will be conducted at the meeting, I will explain some of the significant, positive changes we made at MDU Resources Group in 2016. During the year, we streamlined our operations into two lines of business: regulated energy delivery and construction materials and services. We reduced our exposure to commodity price volatility by completing the sale of our oil and natural gas exploration and production assets and by selling our interests in a diesel refinery and in a natural gas processing plant both located in North Dakota.

With a business presence in 48 states, we remain committed to Building a Strong America.® Our continuing businesses performed well in 2016, providing a 32 percent increase in earnings per share. We delivered a total stockholder return of 62 percent for the year, including increasing our dividend for the 26th consecutive year.

Another positive change we made this year is to our proxy statement. We simplified the proxy statement to what we believe is an easier-to-read format, while still adhering to regulations that outline what information we must provide to stockholders. Our goal is to make it easier for you to understand MDU Resources Group's governance and how we tie the company's results to executive compensation. We also hope the proxy statement more clearly describes the business we will conduct at our annual meeting.

We have streamlined our annual report and proxy statement delivery process this year as well, moving to a notice-and-access model of providing the report. You likely received notice in the mail that you can vote your shares and view our annual report and proxy statement online, along with instructions on how to request a printed copy if you would like one.

I look forward to you joining us on May 9. Even if you are not able to attend the annual meeting, your vote is important to us. Please follow the instructions on your proxy card to vote and make sure your shares are represented.

We appreciate your continued investment in MDU Resources Group.

Sincerely yours,

David L. Goodin
President and Chief Executive Officer

MDU RESOURCES GROUP, INC.

1200 West Century Avenue

Mailing Address:
P.O. Box 5650
Bismarck, North Dakota 58506-5650
(701) 530-1000

NOTICE OF ANNUAL MEETING OF STOCKHOLDERS
TO BE HELD MAY 9, 2017

Important Notice Regarding the Availability of Proxy Materials for the Stockholder Meeting to be Held on May 9, 2017

The 2017 Notice of Annual Meeting and Proxy Statement and 2016 Annual Report to Stockholders are available at www.mdu.com/proxymaterials.

March 24, 2017

NOTICE IS HEREBY GIVEN that the Annual Meeting of Stockholders of MDU Resources Group, Inc. will be held at 909 Airport Road, Bismarck, North Dakota, on Tuesday, May 9, 2017, at 11:00 a.m., Central Daylight Saving Time, for the following purposes:

(1) Election of directors;

(2) Advisory vote to approve the frequency of the vote to approve the compensation paid to the company's named executive officers;

(3) Advisory vote to approve the compensation paid to the company's named executive officers;

(4) Ratification of the appointment of Deloitte & Touche LLP as the company's independent registered public accounting firm for 2017;

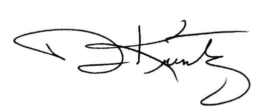
(5) Advisory vote to approve an amendment to the company's bylaws to adopt an exclusive forum for internal corporate claims; and

(6) Transaction of any other business that may properly come before the meeting or any adjournment(s) thereof.

The board of directors has set the close of business on March 10, 2017, 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. We expect to begin mailing the Notice of Availability of Proxy Materials (Notice) on or about March 24, 2017. The Notice will contain 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 30, 2017.

All stockholders as of the record date of March 10, 2017, are cordially invited and urged to attend the meeting in person. Registered stockholders who receive a full set of proxy materials will receive a request for admission ticket(s) with their proxy card that can be completed and returned to us postage-free. Registered stockholders who receive a notice regarding the availability of proxy materials and stockholders whose shares are held in the name of a bank or broker will not receive a request for admission ticket(s). They should, instead: (1) call (701) 530-1000 to request an admission ticket(s); (2) if shares are held in the name of a bank or broker, obtain a statement from their bank or broker showing proof of stock ownership as of March 10, 2017; and (3) present their admission ticket(s), the stock ownership statement, and photo identification, such as a driver's license, at the annual meeting.

By order of the Board of Directors,



Daniel S. Kuntz
Secretary

TABLE OF CONTENTS

PROXY STATEMENT SUMMARY

To assist you in reviewing the company's 2016 performance and voting your shares, we call your attention to key elements of our 2017 Proxy Statement and our 2016 Annual Report to Stockholders. The following is only a summary and does not contain all of the information you should consider. You should read the entire Proxy Statement carefully before voting. For more complete information about these topics, please review the complete Proxy Statement and our 2016 Annual Report to Stockholders.

Meeting Information

Time and Date:
11:00 a.m. Central Daylight Saving Time (CDT) Tuesday, May 9, 2017
Place:
MDU Service Center 909 Airport Road Bismarck, ND

Summary of Stockholder Voting Matters

Voting Matters		Board Vote Recommendation	See Page
Item 1 -	Election of Directors	FOR each nominee	6
Item 2 -	Advisory Vote to Approve the Frequency of the Vote to Approve the Compensation Paid to the Company's Named Executive Officers	FOR ONE YEAR	22
Item 3 -	Advisory Vote to Approve the Compensation Paid to the Company's Named Executive Officers	FOR	23
Item 4 -	Ratification of the Appointment of Deloitte & Touche LLP as the Company's Independent Registered Public Accounting Firm for 2017	FOR	48
Item 5 -	Advisory Vote to Approve an Amendment to the Company's Bylaws to Adopt an Exclusive Forum for Internal Corporate Claims	FOR	51

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:

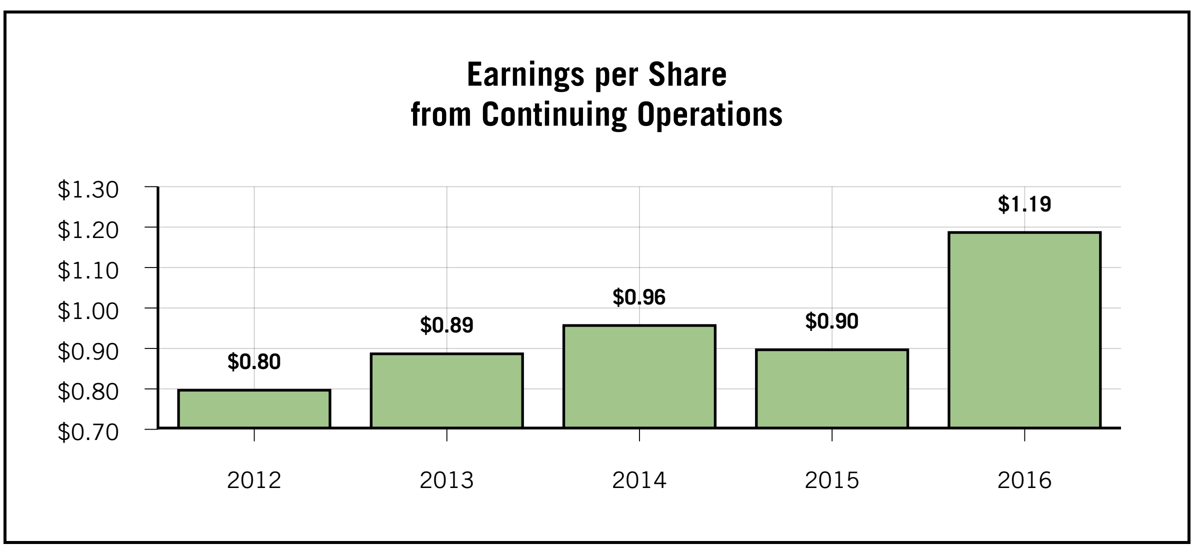
- ✓ Annual Election of All Directors
- ✓ Majority Voting for Directors
- ✓ Separate Chairman and CEO
- ✓ Executive Sessions of Independent Directors at Every Regularly Scheduled Meeting
- ✓ Annual Board and Committee Self-Evaluations
- ✓ Risk Oversight by Full Board and Committees
- ✓ All Directors are Independent Other Than our CEO
- ✓ All Three Standing Committees Consist of Independent Directors
- ✓ Active Investor Outreach Program
- ✓ Stock Ownership Requirements for Directors and Executives
- ✓ Anti-Hedging and Anti-Pledging Policies
- ✓ Compensation Recovery/Clawback Policy
- ✓ Code of Business Conduct and Ethics for Directors, Officers, and Employees
- ✓ Annual Advisory Approval on Executive Compensation

Business Performance Highlights

Our overall performance in 2016 was consistent with our long-term strategy as we executed on priorities to reduce our risk to oil and natural gas commodity price fluctuations and focus on our regulated energy delivery and construction materials and services business segments. In 2016, we accomplished:

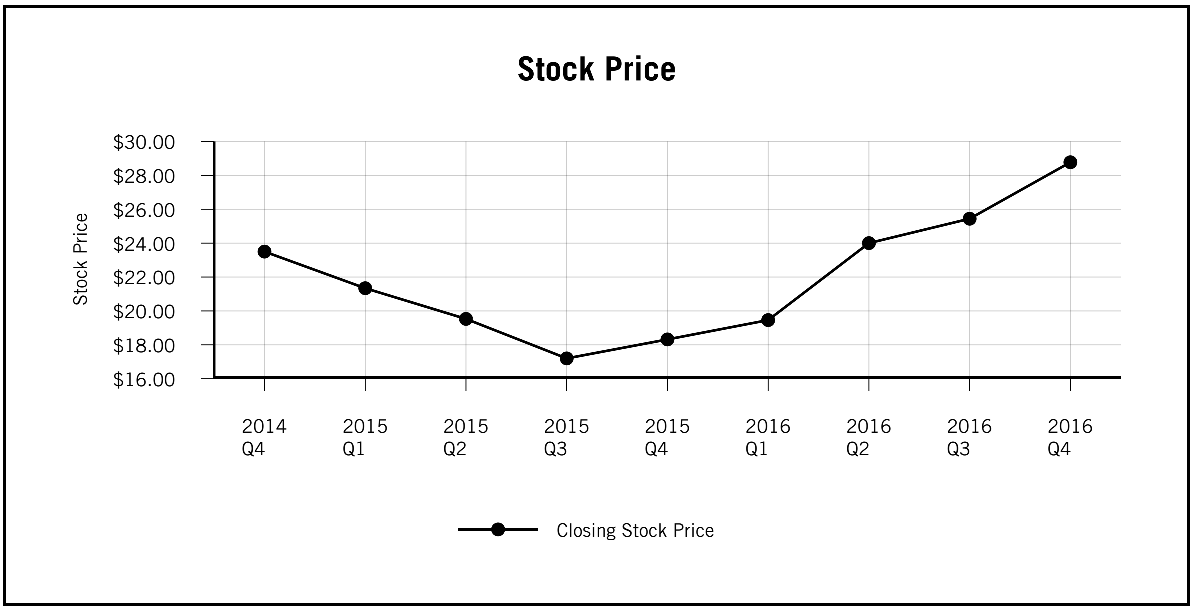
- The sale of Dakota Prairie Refining, LLC in June, the completion of the sale of our oil and gas exploration and production business assets in April, and the sale of our interest in the Pronghorn natural gas processing plant in January 2017 reduced the company's risk by decreasing its exposure to commodity price fluctuations.
- Our construction materials & contracting segment achieved record earnings, and its backlog at December 31, 2016, was $538 million compared to $491 million a year earlier.
- Earnings from our construction services segment were up 43%, to $33.9 million, on 16% revenue growth.
- We acquired the Thunder Spirit wind farm providing an additional 107.5 megawatts of renewable generation. We also signed an agreement in 2016 to purchase power from an expansion of the Thunder Spirit wind farm which includes an option to buy the expansion at the completion of construction. This will bring the total capacity of the Thunder Spirit wind farm to 150 megawatts which will increase the company's nameplate electric renewable generation portfolio to 27%.
- Our electric & natural gas distribution segment achieved regulatory relief of an additional $32.7 million in final implemented rates in 2016 through February 2017.
- We, along with a partner, began construction of approximately 160-miles of 345 kilovolt electric transmission line which will facilitate delivery of renewable wind energy from North Dakota to eastern markets.
- Our pipeline & midstream segment secured sufficient capacity commitments and started survey work on a 38-mile transmission pipeline that will deliver natural gas supply to eastern North Dakota and far western Minnesota. Following receipt of necessary permits and regulatory approvals, construction is expected to start in early 2018 and be complete late that year. This segment also signed agreements for and completed construction of other natural gas transmission pipeline projects.
- Our construction services segment constructed and sold a large scale solar project in Nevada. This segment also completed a 135-mile 345-kilovolt electric transmission line project which was the largest transmission construction project ever completed by the construction services segment.
- Our pipeline & midstream segment experienced a 59% increase in natural gas storage levels.

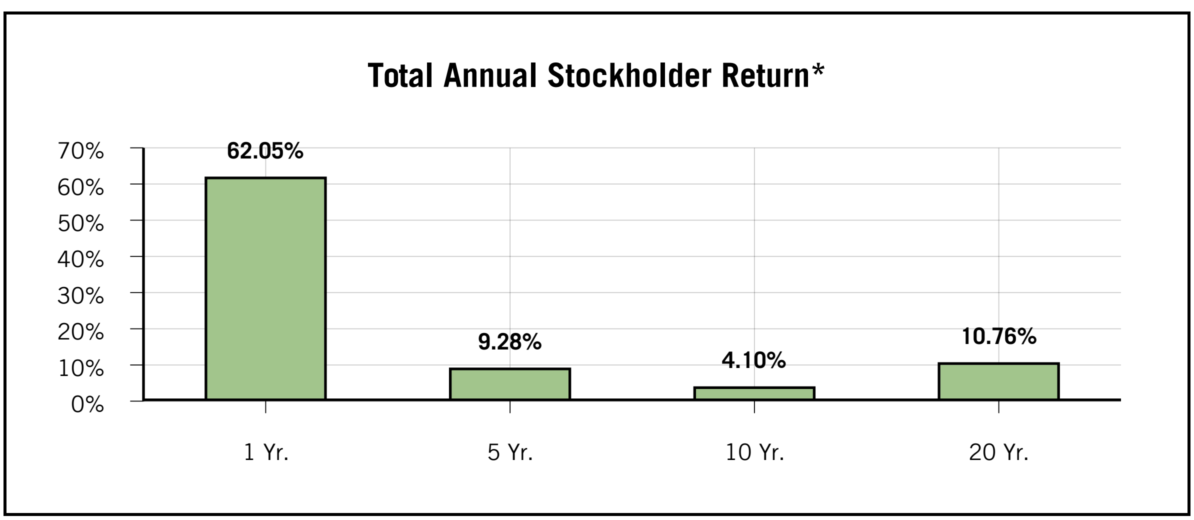
With our accomplishments in 2016, we are optimistic about the company's future financial performance. The charts below show our progress over the last five years.



2016 Financial Performance Highlights

- Strong year-over-year performance from continuing operations resulted in an increase in earnings per share from continuing operations to $1.19 per share compared to $0.90 per share in 2015, an increase of 32%
  - Electric & natural gas distribution segment earnings increased by 16%
  - Pipeline & midstream segment earnings increased by 77%
  - Construction materials & contracting segment earnings increased by 15%
  - Construction services segment earnings increased by 43%
- Return of stockholder value through the dividend
  - Increased dividend for 26th straight year
  - Paid uninterrupted dividend for 79th straight year
- Improved credit rating outlook from Standard & Poor's (S&P) from negative to stable
  - BBB+ credit ratings with stable outlooks from both S&P and Fitch Ratings
- Stock price increased from $18.32 per share on December 31, 2015, to $28.77 per share on December 31, 2016, reflecting appreciation of 57%
- One year total stockholder return of 62% including our dividends





* The calculation of Total Annual Stockholder Return assumes the reinvestment of dividends in additional shares of common stock.

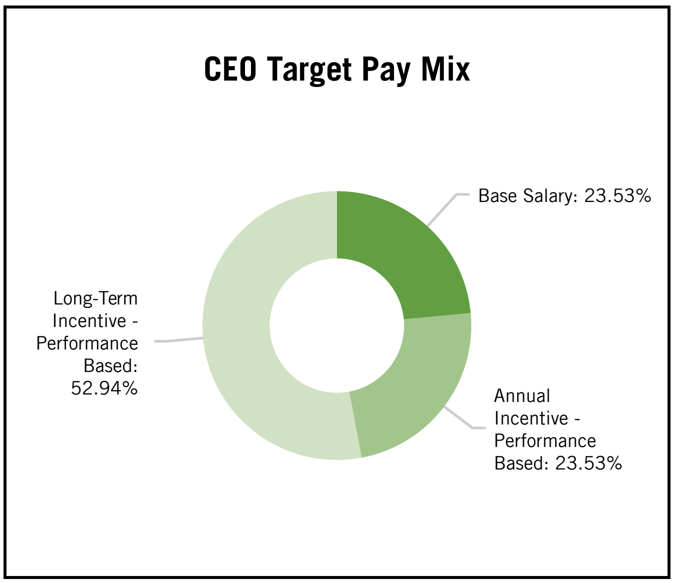
26 Years of Consecutive Dividend Increases	Dividends Paid $692 Million Over the Last 5 Years	79 Years of Uninterrupted Dividend Payments

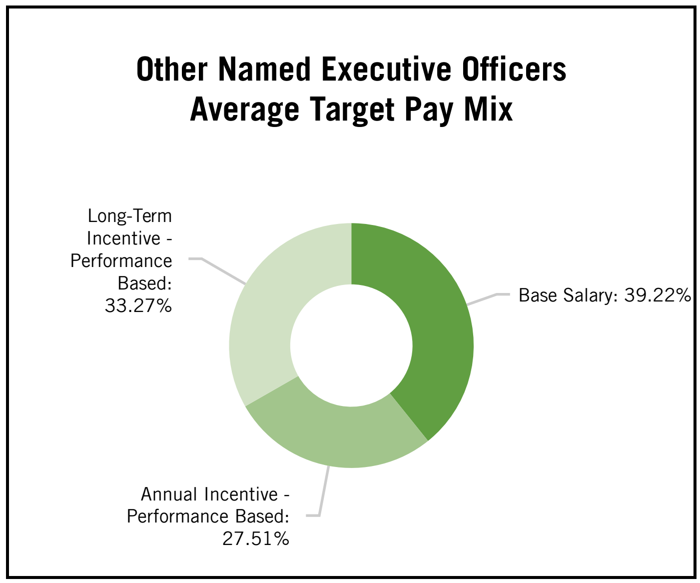
Compensation Highlights

Executive compensation at the company is focused on performance. Our compensation program is structured to strongly align compensation with the company's performance with a substantial portion of our executive compensation based upon performance incentive awards.

- Over 76% of our chief executive officer's target compensation and 61% of our other named executive officers' target compensation is performance based.
- 100% of annual incentive compensation and 100% of long-term incentive compensation are tied to performance against pre-established, specific, measurable financial and operational goals.
- We require all executive officers to own a significant amount of company stock based upon a multiple of their base salary.

2016 Named Executive Officer Target Pay Mix





- With the exception of the president of our construction materials & contracting segment, which achieved record earnings in 2015, base salaries for our named executive officers were frozen in 2016 following a challenging year in 2015 as a result of impairments at our exploration & production segment, which has since been sold.
- Annual incentive award payout to our CEO for 2016, which was based upon the strong performance at all four of our business units, was 139.8% of his annual incentive target.
- Long-term incentive award payouts in 2017 for the 2014-2016 performance cycle were at 68% of target based upon total stockholder return at the 40th percentile of our peers over the performance cycle reflecting a challenging operating environment in 2014 and 2015.

Key Features of our Executive Compensation Program

What We Do

- ☑ **Pay for Performance** - All annual and long-term incentives are performance-based and tied to performance measures set by the compensation committee.
- ☑ **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 the executive's performance, experience, relative value compared to other positions within the company, relationship to competitive market value compensation, and the economic environment of the executive's business segment.
- ☑ **Annual Compensation Risk Analysis** - We regularly analyze the risks related to our compensation programs and conduct a broad risk assessment annually.
- ☑ **Stock Ownership & 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 must retain at least 50% of the net after tax shares of stock vested through the long-term incentive plan for the earlier of 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 company executive officers within the last three years.

What We Don't Do

- ☒ **Stock Options** - The company does not use stock options as a form of incentive compensation.
- ☒ **Perquisites** - Executives do not receive perquisites which materially differ from those available to employees in general.
- ☒ **Tax Gross-ups** - Executive officers do not receive tax gross-ups on any compensation.
- ☒ **Hedge or Pledge Stock** - Executives and directors are not allowed to hedge or pledge company securities.
- ☒ **No Time Based Awards** - All long-term incentives are performance-based and vest only upon the achievement of specific performance measures.

BOARD OF DIRECTORS

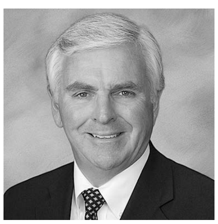
ITEM 1. ELECTION OF DIRECTORS

The nominating and governance committee of the board, reflecting the criteria for election to the board, identifies and reviews possible candidates for the board and recommends the nominees for directors to the board for approval. The committee considers and evaluates suggestions from many sources, including stockholders, regarding possible candidates for directors. Additional information on our board composition and director nomination process is further discussed in our Proxy Statement under "Nominating and Governance Committee" in the section entitled "Corporate Governance."

All nominees for director are nominated to serve one-year terms until the annual meeting of stockholders in 2018 and their respective successors are elected and qualified, or until their earlier resignation, removal from office, or death.

We have provided information below about our nominees, all of whom are incumbent directors, including their ages, years of service as directors, business experience, and service on other boards of directors, including any other directorships on boards of public companies. We have also included information about each nominee's specific experience, qualifications, attributes, or skills that led the board to conclude that he or she should serve as a director of MDU Resources Group, Inc. at the time we file our Proxy Statement, in light of our business and structure. Unless we specifically note below, no corporation or organization referred to below is a subsidiary or other affiliate of MDU Resources Group, Inc.

Director Nominees



Thomas Everist
Age 67

Independent Director Since 1995
Compensation Committee

Other Current Public Boards:
--Raven Industries, Inc.

Mr. Everist has more than 43 years of business experience in the construction materials and aggregate mining industry. He has business leadership and management experience serving as president and chairman of his companies for over 29 years. Mr. Everist also has experience serving as a director and chairman of another public company, which enhances his contributions to our board.

Career Highlights

- President and chairman 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 chairman 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 chairman 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 chairman of the board since April 2009.
- Director of Showplace Wood Products, 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 63

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 chairman 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, d/b/a DOWL HKM, an engineering and design firm, from April 2008 until her retirement on December 31, 2011.
- President of HKM Engineering, Inc., Billings, Montana, an engineering and physical science services firm, from April 1, 1995 to June 2000, and chairman, 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

- Board member of St. Vincent’s Healthcare since January 2016 and previously from October 2003 until October 2009, 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 55

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 33 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.

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

- Bachelor of science degree in electrical and electronics engineering from North Dakota State University.
- Masters 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 64

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 chairman 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

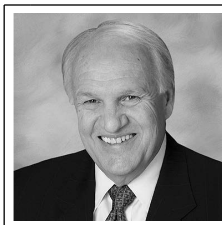
- Chief executive officer of St. Mary Land & Exploration Company (now SM Energy Company), an energy company engaged in the acquisition, exploration, development, and production of crude oil, natural gas, and natural gas liquids, from 1995 until February 2007; president from 1992 until June 2006; and 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 chairman of the board 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 chairman for the last three years.

Education and Professional

- Bachelor's degree in accounting from the University of Colorado.
- Certified public accountant, on inactive status.



A. Bart Holaday
Age 74

Independent Director Since 2008
Audit Committee
Nominating and Governance Committee

Mr. Holaday has extensive business knowledge and experience in the energy and financial management industries. Mr. Holaday brings to the board extensive finance and investment experience, as well as business development skills, through his senior management experience with investment funds and energy companies. Mr. Holaday is also a chartered financial analyst.

Career Highlights

- President and owner of Dakota Renewable Energy Fund, LLC, which invests in small companies in North Dakota, since August 2007.
- Head of the Private Markets Group of UBS Asset Management and its predecessor entities, managing more than $19 billion in investments, from December 1985 until retirement in 2001.
- Vice president and principal of the InnoVen Venture Capital Group, a venture capital investment firm, from 1983 through 1985.
- Founder and president of Tenax Oil and Gas Corporation, an onshore Gulf Coast exploration and production company, from 1980 through 1982.
- Four years of senior management experience with Gulf Oil Corporation, a global energy and petrochemical company.
- Eight years of senior management experience with the federal government, including the Department of Defense, Department of the Interior, and the Federal Energy Administration.

Other Leadership Experience

- Member of the investment advisory board of Commons Capital LLC, a venture capital firm, since 1999.
- Director of Hull Investments, LLC, a private entity firm that combines nonprofit activities and investments, since August 2011; Alerus Financial, a financial services company, since September 2007; and Adams Street Partners, LLC, a private equity investment firm, from January 2001 to March 2017.
- Former member of the U.S. Securities and Exchange Commission advisory committee on the regulation of capital markets.

Education and Professional

- Bachelor's degree in engineering sciences from the U.S. Air Force Academy.
- Rhodes Scholar, earning a bachelor's degree and a master's degree in politics, philosophy, and economics from Oxford University.
- Law degree from George Washington Law School.
- Honorary Doctor of Letters from the University of North Dakota.
- Chartered Financial Analyst.

Dennis W. Johnson
Age 67

Independent Director Since 2001
Audit Committee

Mr. Johnson brings to our board over 42 years of experience in business management, manufacturing, and finance, holding positions as chairman, president, and chief executive officer of TMI Corporation for 34 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

- Chairman, president, and chief executive officer of TMI Corporation and chairman and chief executive officer of TMI Transport Corporation (as well as TMI Systems Design Corporation and TMI Storage Systems Corporation before they merged into TMI Corporation the end of 2015), 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

- President of the Dickinson City Commission from July 2000 through October 2015.
- Director of the Federal Reserve Bank of Minneapolis for six years 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.

William E. McCracken
Age 74

Independent Director Since 2013
Compensation Committee
Nominating and Governance Committee

Mr. McCracken is experienced in information technology and cybersecurity through his tenure at CA, Inc. and International Business Machines Corporation (IBM). This experience coupled with his service as the chair or a member of the board of other public companies and the National Association of Corporate Directors (NACD) enables him to provide insight into the operations, challenges, and complex issues our company is facing in today's environment and to make significant contributions to the board's oversight of operational risk management functions and corporate governance.

Career Highlights

- President of Executive Consulting Group, LLC, a general business consulting firm, from 2002 to present.
- Chief executive officer of CA, Inc., one of the world's largest information technology management software companies, from January 2010 until January 7, 2013, after which he served as executive adviser to the new chief executive officer until March 31, 2013, and as a consultant to the company until December 31, 2013; also as director of CA, Inc. from May 2005 until January 7, 2013, serving as non-executive chairman of the board from June 2007 to September 2009, interim executive chairman from September 2009 to January 2010, and executive chairman from January 2010 to May 2010.
- Several executive positions during his 36-year career with IBM, including serving on its Chairman's Worldwide Management Council, a group of the top 30 executives at IBM, from 1995 to 2001.

Other Leadership Experience

- Director of the NACD, a nonprofit membership organization for corporate board members, since 2010, and named by the NACD as one of the top 100 most influential people in the boardroom in 2009; served on that organization's 2009 blue ribbon commission on risk governance, co-chaired its blue ribbon commission on board diversity in 2012, and co-chaired its blue ribbon commission on the board and long-term value creation in 2015.
- Director of IKON Office Solutions, Inc., a provider of document management systems and services, from 2003 to 2008, where he served on its audit committee, compensation committee, and strategy committee.
- Chair of the advisory board of the Millstein Center for Global Markets and Corporate Ownership at Columbia University and member since 2013, and the New York chairman of the Chairmen's Forum since 2011.

Education

- Bachelor of science in physics and mathematics from Shippensburg University.

Patricia L. Moss
Age 63

Independent Director Since 2003
Compensation Committee
Nominating and Governance Committee

Other Current Public Boards:
--Cascade Bancorp
--Aquila Tax Free Trust of Oregon

Ms. Moss has business experience and knowledge of the Pacific Northwest economy and state, local, and region 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

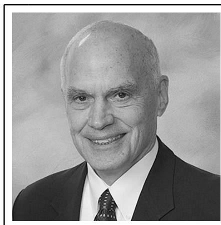
- President and chief executive officer of Cascade Bancorp, a financial holding company, Bend, Oregon, from 1998 to January 3, 2012; chief executive officer of Cascade Bancorp's principal subsidiary, Bank of the Cascades, from 1998 to January 3, 2012, serving also as president from 1998 to 2003; and chief operating officer, chief financial officer and secretary of Cascade Bancorp from 1987 to 1998.

Other Leadership Experience

- Director of Cascade Bancorp and Bank of the Cascades since 1993, and vice chair of both boards since January 3, 2012.
- Chair of the Bank of the Cascades Foundation Inc. since 2014; co-chair of the Oregon Growth Board, a state board created to improve access to capital and create private-public partnerships, since May 2012; and member of the Board of Trustees for the Aquila Tax Free Trust of Oregon, a mutual fund created especially for the benefit of Oregon residents, since June 2015 and January 2002 to May 2005.
- 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.



Harry J. Pearce
Age 74

Independent Director Since 1997
Chairman of the Board

Mr. Pearce provides our board with public company leadership with his multinational business management experience and proven leadership skills through his position as vice chairman at General Motors Corporation, as well as through his extensive service on the boards of large public companies, including Marriott International, Inc., Hughes Electronics Corporation, where he was chairman, and Nortel Networks Corporation, where he also was chairman. He also brings to our board his long experience as a practicing attorney. In addition, Mr. Pearce has focused on corporate governance issues and was the founding chair of Yale University's Chairmen's Forum, an organization comprised of non-executive chairmen of publicly traded companies.

Career Highlights

- Chairman of the board of the company effective August 17, 2006; lead director from February 15, 2001 until August 17, 2006; and vice chairman of the board from November 16, 2000 until February 15, 2001.
- Vice chairman and director of General Motors Corporation from January 1, 1996 to May 31, 2001; general counsel from 1987 to 1994.
- Senior partner in the Pearce & Durick law firm in Bismarck, North Dakota, prior to joining General Motors in 1987.

Other Leadership Experience

- Director of Hughes Electronics Corporation, a General Motors Corporation subsidiary and provider of digital television entertainment, broadband satellite network, and global video and data broadcasting, from 1992 to December 2003, and retiring as chairman in 2003.
- Director of Marriott International, Inc., a major hotel chain, from 1995 to May 2015, and served on the audit, finance, compensation, and excellence committees.
- Director of Nortel Networks Corporation, a global telecommunications company, from January 2005 to August 2009, also served as chairman of the board from June 2005.
- Fellow of the American College of Trial Lawyers, and a member of the International Society of Barristers.
- Founding chair of the Yale University's Chairmen's Forum; former member of the President's Council on Sustainable Development, and co-chair of the President's Commission on the United States Postal Service.

Education

- Bachelor's degree in engineering sciences from the U.S. Air Force Academy.
- Juris doctor degree from Northwestern University's School of Law.

John K. Wilson
Age 62

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.

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.

The board of directors recommends a vote "for" each nominee.

A majority of votes cast is required to elect a director in an uncontested election. A majority of votes cast means the number of votes cast "for" a director's election must exceed the number of votes cast "against" the director's election. "Abstentions" and "broker non-votes" do not count as votes cast "for" or "against" the director's election. In a contested election, which is an election in which the number of nominees for director exceeds the number of directors to be elected and which we do not anticipate, directors will be elected by a plurality of the votes cast.

Unless you specify otherwise when you submit your proxy, the proxies will vote your shares of common stock "for" all directors nominated by the board of directors. If a nominee becomes unavailable for any reason or if a vacancy should occur before the election, which we do not anticipate, the proxies will vote your shares in their discretion for another person nominated by the board.

Our policy on majority voting for directors contained in our corporate governance guidelines requires any proposed nominee for re-election as a director to tender to the board, prior to nomination, his or her irrevocable resignation from the board that will be effective, in an uncontested election of directors only, upon:

- receipt of a greater number of votes "against" than votes "for" election at our annual meeting of stockholders; and
- acceptance of such resignation by the board of directors.

Following certification of the stockholder vote, the nominating and governance committee will promptly recommend to the board whether or not to accept the tendered resignation. The board will act on the nominating and governance committee's recommendation no later than 90 days following the date of the annual meeting.

Brokers may not vote your shares on the election of directors if you have not given your broker specific instructions on how to vote. Please be sure to give specific voting instructions to your broker so your vote can be counted.

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. The board of directors has determined that, except for Mr. Goodin, all current directors have no material relationship with us and are independent in accordance with our corporate governance guidelines and the New York Stock Exchange listing standards.

In determining director independence, the board of directors reviewed and considered information about any transactions, relationships, and arrangements between the non-employee directors and their immediate family members and affiliated entities on the one hand, and the company and its affiliates on the other, and in particular the following transactions, relationships, and arrangements:

- *Charitable contributions by the MDU Resources Foundation (Foundation) to the following nonprofit organizations, where a director, or a director's spouse, serves or has served as a director, chair, or vice chair of the board of trustees, trustee or member of the organization or related entity:* Charitable contributions by the Foundation to Sanford Health Foundation, Billings Catholic Schools Foundation, Community Resources Inc., the University of North Dakota Foundation, and the University of Jamestown and its foundation. None of the contributions made to any of these nonprofit entities during the last three fiscal years exceeded in any single year the greater of $1 million or 2% of the relevant entity's consolidated gross revenues.

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 2016, the company held meetings, conference calls, and webcasts with a diverse mix of stockholders. Throughout the year, we held meetings with nine of the actively managed institutional investors included in our year-end top 30 stockholders. We engage periodically with our index fund investors, however, no direct meetings were held with this investor class in 2016. In our meetings, we discussed a variety of topics with stockholders including longer-term company strategy and our capital expenditure forecast, shorter-term operational and financial updates, and previously announced strategic initiatives. The company also met with proxy advisory firms to discuss corporate governance and executive compensation practices.

Board Leadership Structure

The board separated the positions of chairman of the board and chief executive officer in 2006, and our bylaws and corporate governance guidelines currently require that our chairman 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 chairman of the board to lead the board in its fundamental role of providing advice to and independent oversight of management. The chairman 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 chairman, particularly as the board's oversight responsibilities continue to grow and demand more time and attention. The fundamental role of the board of directors is to provide oversight of the management of the company in good faith and in the best interests of the company and its stockholders. Having an independent chairman is a means to ensure the chief executive officer is accountable for managing the company in close alignment with the interests of stockholders, including with respect to risk management as discussed below. An independent chairman is in a position to encourage frank and lively discussions and to assure that the company has adequately assessed all appropriate business risks before adopting its final business plans and strategies. The board believes that having separate positions and having an independent outside director serve as chairman is the appropriate leadership structure for the company at this time and demonstrates our commitment to good corporate governance.

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, environmental and regulatory risks, the impact of competition, 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 the day-to-day management of risks the company faces, while the board, as a whole and through its committees, has responsibility for the oversight of risk management. In its risk oversight role, the board of directors has the responsibility to satisfy itself that the risk management processes designed and implemented by management are adequate and functioning as designed.

The board believes 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 chairman meets regularly with our president and chief executive officer and other senior officers to discuss strategy and risks facing the company. Senior management attends the quarterly board meetings and is available to address any questions or concerns raised by the board on risk management-related and any other matters. Each quarter, the board of directors receives presentations from senior management on strategic matters involving our operations. At least annually, the board holds strategic planning sessions with senior management to discuss strategies, key challenges, and risks and opportunities for the company.

While the board is ultimately responsible for risk oversight at our company, our three 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 and compliance with legal and regulatory requirements, and, in accordance with New York Stock Exchange requirements, discusses policies with respect to risk assessment and risk management and their adequacy and effectiveness. Risk assessment reports are regularly provided by management to the audit committee or the full board. This opens the opportunity for discussions about areas where the company may have material risk exposure, steps taken to manage 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 2016, the board of directors held four regular meetings and three 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 2016. Director attendance at our annual meeting of stockholders is encouraged. All directors attended our 2016 Annual Meeting of Stockholders.

Harry J. Pearce was elected non-employee chairman of the board on August 17, 2006, and previously served as lead director from February 15, 2001 to August 17, 2006. He presides at the executive session of the non-employee directors held in connection with each regularly scheduled quarterly board of directors meeting. The non-employee directors also meet in executive session both with and without the chief executive officer at each regularly scheduled quarterly board of directors meeting. All of our non-employee directors are independent, as defined in our corporate governance guidelines and New York Stock Exchange listing standards.

The board has a standing audit committee, compensation committee, and nominating and governance committee. These committees are composed entirely of independent directors.

Nominating and Governance Committee

The nominating and governance committee met four times during 2016. The committee members are Karen B. Fagg, chair, A. Bart Holaday, William E. McCracken, and Patricia L. Moss.

The nominating and governance committee provides recommendations to the board with respect to:

- board organization, membership, and function;
- committee structure and membership;
- succession planning for our executive management and directors; and
- 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, our management, consultants, and other individuals likely to possess an understanding of our business and knowledge concerning suitable director candidates.

Our corporate governance guidelines include our policy on consideration of director candidates recommended to us. We will consider candidates that our stockholders recommend 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 procedures set forth in section 2.08 of our bylaws. Our bylaws are available on our website. See "Stockholder Proposals, Director Nominations, and Other Items of Business for 2018 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 our 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 reflects diversity in business and professional experience, skills, and gender.

Audit Committee

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 2016. The audit committee members are Dennis W. Johnson, chair, Mark A. Hellerstein, A. Bart Holaday, and John K. Wilson. The board of directors has determined that Messrs. Johnson, Hellerstein, Holaday, and Wilson are "audit committee financial experts" as defined by Securities and Exchange Commission rules and are financially literate within meaning of the listing standards of the New York Stock Exchange. They also meet the independence standard for audit committee members under our director independence guidelines, the New York Stock Exchange listing standards, and Securities and Exchange Commission 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;
  - the independent registered public accounting firm's qualifications and independence;
  - the performance of our internal audit function and independent registered public accounting firm; and
  - management of risk in the audit committee's areas of responsibility; and
- arranges for the preparation of and approves the report that Securities and Exchange Commission rules require we include in our annual proxy statement. See the section entitled "Audit Committee Report" for further information.

Compensation Committee

During 2016, the compensation committee met five times. The compensation committee consists entirely of independent directors within the meaning of the company's corporate governance guidelines and the New York Stock Exchange listing standards and who meet the definitions of outside or non-employee directors for purposes of Section 162(m) of the Internal Revenue Code and 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 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. Prior to retaining an adviser, the committee will consider 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 its compensation consultant, Willis Towers Watson, to assist in its potential conflicts of interest assessment. Based on its review and analysis, the compensation committee did not identify any conflicts of interest with respect to Willis Towers Watson.

The board of directors determines compensation for our non-employee directors based upon recommendations from the compensation committee. The compensation committee's practice has been to retain a compensation consultant every other year to conduct a competitive analysis on director compensation. The compensation committee employed a compensation consultant for an analysis of director compensation in 2015 but not in 2016 as the study was performed by the human resources department.

Narrative Disclosure of our Compensation Policies and Practices as They Relate to Risk Management

The human resources department has conducted an assessment of the risks arising from our compensation policies and practices for all employees and concluded that none of these risks is reasonably likely to have a material adverse effect on the company. Based on the human resources department's assessment and taking into account information received from the risk identification process, senior management and our management policy committee concluded that risks arising from our compensation policies and practices for all employees are not reasonably likely to have a material adverse effect on the company. After review and discussion with senior management, the compensation committee concurred with this assessment.

As part of its assessment of the risks arising from our compensation policies and practices for all employees, the human resources department identified the principal areas of risk faced by the company that may be affected by our compensation policies and practices for all employees, including any risks resulting from our operating businesses' compensation policies and practices. In assessing the risks arising from our compensation policies and practices, the human resources department identified the following practices designed to prevent excessive risk taking:

- Business management and governance practices:
  - risk management is a specific performance competency included in the annual performance assessment of Section 16 officers;
  - board oversight on capital expenditure and operating plans that promotes careful consideration of financial assumptions;
  - limitation on business acquisitions without board approval;
  - employee integrity training programs and anonymous reporting systems;
  - quarterly risk assessment 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 comparison of executive compensation to total stockholder return ratio to the ratio for 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 to the company's financial performance;
  - use of interpolation for annual and long-term incentive awards to avoid payout cliffs;
  - negative discretion to adjust any annual or long-term incentive award payment downward;
  - use of caps on annual incentive awards (maximum of 250% of target) and long-term incentive stock grant awards (200% target);
  - clawback availability on incentive payments in the event of a financial restatement;
  - use of performance shares, rather than stock options or stock appreciation rights, as the equity component of incentive compensation;
  - use of performance shares with a relative total stockholder return performance measure and mandatory reduction in award if total stockholder return over the performance period is negative;
  - use of three-year performance periods to discourage short-term risk-taking;
  - substantive incentive goals measured primarily by return on invested capital, earnings, and earnings per share criteria, which encourage balanced performance and are important to stockholders;
  - use of financial performance metrics that are readily monitored and reviewed;

- regular review of the appropriateness of the companies in the peer group;
- stock ownership requirements for the board and for executives receiving long-term incentive awards under the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan;
- mandatory holding periods for 50% of any net after-tax shares earned under long-term incentive awards; and
- use of independent consultants in establishing pay targets 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 chairman or non-employee directors as a group, should address a communication in care of the secretary at MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506-5650. The secretary will forward all communications.

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 2017, Mr. Everist submitted his resignation in connection with the sale by The Everist Company of its aggregate, concrete, and asphalt production interests. After considering his background, experience on the board, skills and character, and contribution to the company in light of the company's business and structure, the board determined Mr. Everist's resignation should not be accepted.

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, 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. In connection with our mandatory retirement for directors, three of our current directors are expected to retire within the next two years.

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 New York Stock Exchange listing standards, by posting such information on our website.

Corporate Governance Materials

Stockholders can see our bylaws, corporate governance guidelines, board committee charters, and Leading With Integrity Guide on our website.

- Audit, compensation, and nominating and governance committees' charters are available at http://www.mdu.com/integrity/governance/board-charters-and-committees.
- Bylaws and corporate governance guidelines are available at http://www.mdu.com/integrity/governance/guidelines-and-bylaws.
- Leading With Integrity Guide is available at http://www.mdu.com/docs/default-source/governance/leadingwithintegrity.pdf.

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 provides that the audit committee review any transaction, arrangement or relationship, or series thereof:

- in which we are or will be a participant;
- the amount involved exceeds $120,000; and
- a related person has 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 Securities and Exchange Commission's rules, the general counsel furnishes the information to the chairman 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 2016.

COMPENSATION OF NON-EMPLOYEE DIRECTORS

Director Compensation for 2016

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)[1]	All Other Compensation ($)[2]	Total ($)
Thomas Everist	75,000	110,000	83	185,083
Karen B. Fagg	75,000	110,000	83	185,083
Mark A. Hellerstein	65,000	110,000	83	175,083
A. Bart Holaday	65,000	110,000	83	175,083
Dennis W. Johnson	80,000	110,000	83	190,083
William E. McCracken	65,000	110,000	83	175,083
Patricia L. Moss	65,000	110,000	83	175,083
Harry J. Pearce	155,000	110,000	83	265,083
John K. Wilson	65,000 [3]	110,000	83	175,083

[1] The annual retainer of $110,000 in company common stock is awarded pursuant to the MDU Resources Group, Inc. Non-Employee Director Stock Compensation Plan. The amount shown for each director represents the aggregate grant date fair value of 3,886 shares of MDU Resources Group, Inc. common stock 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 21, 2016, which was $28.30 per share. The $10.66 in cash paid to each director in lieu of fractional shares is included in the amount reported in the stock awards column to this table. As of December 31, 2016, there are no outstanding stock awards or options associated with the Non-Employee Director Stock Compensation Plan.

[2] Group life insurance premium.

[3] Mr. Wilson elected to receive shares of our common stock in lieu of his cash retainer pursuant to the Non-Employee Director Stock Compensation Plan. The amount shown includes 2,244 shares of our common stock purchased on December 7, 2016, at $28.96 per share.

The following table shows the cash and stock retainers payable to our non-employee directors.

Base Retainer	$ 65,000
Additional Retainers:	
Non-Executive Chair	90,000
Lead Director, if any	33,000
Audit Committee Chair	15,000
Compensation Committee Chair	10,000
Nominating and Governance Committee Chair	10,000
Annual Stock Grant[1]	110,000

[1] The annual stock grant is a grant of shares equal in value to $110,000.

There are no meeting fees paid to directors.

In addition to liability insurance, we maintain group life insurance in the amount of $100,000 on each non-employee director for the benefit of each director's beneficiaries during the time each director serves on the board. The annual cost per director is $82.80.

Directors may defer all or any portion of the annual cash retainer and any other cash compensation paid for service as a director pursuant to the Deferred Compensation Plan for Directors. Deferred amounts are held as phantom stock with dividend accruals and are paid out in cash over a five-year period after the director leaves the board.

Directors are reimbursed for all reasonable travel expenses, including spousal expenses in connection with attendance at meetings of the board and its committees. All reimbursable expense amounts, together with any other perquisites, were below the disclosure threshold for 2016.

Our post-retirement income plan for directors was terminated in May 2001 for current and future directors. The net present value of each director's benefit was calculated and converted into phantom stock. Payment is deferred pursuant to the Deferred Compensation Plan for Directors and will be made in cash over a five-year period after the director's retirement from the board.

Our director stock ownership policy contained in our corporate governance guidelines requires each director to own our common stock equal in value to five times the director's annual cash base retainer. Shares acquired through purchases on the open market and participation in our director stock plans 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 that director's initial election to the board to meet the requirements. The level of common stock ownership is monitored with an annual report made to the compensation committee of the board. All directors are in compliance with the stock ownership policy. For stock ownership, see the section below.

SECURITY OWNERSHIP

Security Ownership Table

The table below sets forth the number of shares of our capital stock that each director and each nominee for director, each named executive officer, and all directors and executive officers as a group owned beneficially as of February 28, 2017. 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	Common Shares Beneficially Owned	Percent of Class	Deferred Director Fees Held as Phantom Stock[1]
David C. Barney	12,055 [2,3]	*	
Thomas Everist	853,458	*	32,977
Karen B. Fagg	61,164	*	
Martin A. Fritz	—	*	
David L. Goodin	101,788 [2]	*	
Mark A. Hellerstein	15,766	*	8,637
A. Bart Holaday	60,911	*	8,637
Dennis W. Johnson	80,330 [4]	*	
William E. McCracken	15,766	*	
Patricia L. Moss	75,418	*	
Harry J. Pearce	235,885	*	54,221
Doran N. Schwartz	54,897 [2,5]	*	
Jeffrey S. Thiede	7,149 [2]	*	
John K. Wilson	118,916	*	
All directors and executive officers as a group (20 in number)	1,853,142	0.95 %	104,472

* Less than one percent of the class. Percent of class is calculated based on 195,304,376 outstanding shares as of February 28, 2017.

1 These shares are not included in the "Common Shares Beneficially Owned" column. Directors may defer all or a portion of their cash compensation pursuant to the Deferred Compensation Plan for Directors. Deferred amounts are held as phantom stock with dividend accruals and are paid out in cash over a five-year period after the director leaves the board.

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 1,300 shares owned by Mr. Schwartz's spouse.

We prohibit our directors and executive officers from hedging their ownership of company common stock. They may not enter into transactions that allow them to benefit from devaluation of our stock or otherwise own stock technically but without the full benefits and risks of such ownership.

Directors, executive officers, and related persons are prohibited from holding our common stock in a margin account, with certain exceptions, or pledging company securities as collateral for a loan. Company common stock may be held in a margin brokerage account only if the stock is explicitly excluded from any margin, pledge, or security provisions of the customer agreement. Company common stock may be held in a cash account, which is a brokerage account that does not allow any extension of credit on securities. "Related person" means an executive officer's or director's spouse, minor child, and any person (other than a tenant or domestic employee) sharing the household of a director or executive officer, as well as any entities over which a director or executive officer exercises control.

The table below sets forth information with respect to any person we know to be the beneficial owner of more than five percent of any class of our voting securities.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common Stock	BlackRock, Inc. 55 East 52nd Street New York, NY 10055	15,934,262 [1]	8.20 %
Common Stock	State Street Corporation State Street Financial Center One Lincoln Street Boston, MA 02111	13,420,759 [2]	6.87 %
Common Stock	The Vanguard Group 100 Vanguard Blvd. Malvern, PA 19355	20,142,541 [3]	10.31 %
Common Stock	Parnassus Investments 1 Market Street, Suite 1600 San Francisco, CA 94105	13,875,527 [4]	7.10 %

[1] Based solely on the Schedule 13G, Amendment No. 7, filed on January 25, 2017, BlackRock, Inc. reported sole voting power with respect to 15,053,491 shares and sole dispositive power with respect to 15,934,262 shares as the parent holding company or control person of BlackRock (Luxembourg) S.A., BlackRock (Netherlands) B.V., BlackRock Advisors (UK) Limited, BlackRock Advisors, LLC, BlackRock Asset Management Canada Limited, BlackRock Asset Management Ireland Limited, BlackRock Asset Management North Asia Limited, BlackRock Asset Management Schweiz AG, BlackRock Capital Management, BlackRock Financial Management, Inc., BlackRock Fund Advisors, BlackRock Fund Managers Ltd, BlackRock Institutional Trust Company, N.A., BlackRock Investment Management (Australia) Limited, BlackRock Investment Management (UK) Ltd, BlackRock Investment Management, LLC, and BlackRock Life Limited.

[2] Based solely on the Schedule 13G, filed on February 9, 2017, State Street Corporation reported shared voting and dispositive power with respect to all shares as the parent holding company or control person of State Street Bank and Trust Company, SSGA Funds Management, Inc., State Street Global Advisors, Ltd, State Street Global Advisors, Australia, Limited, State Street Global Advisors (Asia) Limited, and State Street Global Advisors France, S.A.

[3] Based solely on the Schedule 13G, Amendment No. 5, filed on February 10, 2017, The Vanguard Group reported sole dispositive power with respect to 20,014,996 shares, shared dispositive power with respect to 127,545 shares, sole voting power with respect to 115,860 shares, and shared voting power with respect to 21,119 shares. These shares includes 106,426 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 30,553 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.

[4] Based solely on the Schedule 13G, Amendment No. 2, filed on February 14, 2017, Parnassus Investments reported sole voting and dispositive power with respect to all shares.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16 of the Securities Exchange Act of 1934, as amended, requires that officers, directors, and holders of more than 10% of our common stock file reports of their trading in our equity securities with the Securities and Exchange Commission. Based solely on a review of Forms 3, 4, and 5 and any amendments to these forms furnished to us during and with respect to 2016 or written representations that no Forms 5 were required, we believe that all such reports were timely filed, except that in May 2016, Mr. Daniel S. Kuntz filed an amended Form 3 to report beneficial ownership of 631 additional shares that were omitted from his original Form 3 filed in January 2016. Mr. Kuntz disclaims beneficial ownership of these additional shares.

EXECUTIVE COMPENSATION

ITEM 2. ADVISORY VOTE TO APPROVE THE FREQUENCY OF THE VOTE TO APPROVE THE COMPENSATION PAID TO THE COMPANY'S NAMED EXECUTIVE OFFICERS

In accordance with Section 14A of the Securities Exchange Act of 1934 and Rule 14a-21(b), we are asking our stockholders to indicate, on an advisory basis, whether future advisory votes to approve the compensation paid to our named executive officers should be held every year, every two years, or every three years.

Our board of directors has determined that our stockholders should have the opportunity to vote on the compensation of our named executive officers every year. The board of directors believes that giving our stockholders the right to cast an advisory vote every year on the compensation of our named executive officers is a good corporate governance practice and is in the best interests of our stockholders. Annual advisory votes provide the highest level of accountability and direct communication with our stockholders.

By voting on this Item 2, stockholders are not approving or disapproving the board of directors' recommendation, but rather are indicating whether they prefer an advisory vote on named executive officer compensation be held every year, every two years, or every three years. Stockholders may also abstain from voting.

Although the board of directors intends to carefully consider the voting results of this proposal, it is an advisory vote and the results will not be binding on the board of directors or the company, and the board of directors may decide that it is in the best interests of our stockholders and the company to hold an advisory vote on executive compensation more or less frequently than the option selected by our stockholders. We will provide our stockholders with the opportunity to vote on the frequency of advisory votes on our named executive officer compensation at our annual meetings at least once every six calendar years.

The board of directors recommends that an advisory vote on compensation paid to our named executive officers be held every year.

The frequency of every year, every two years, or every three years that receives the most votes of our common stock present in person or represented by proxy at the meeting and entitled to vote on the proposal will be the frequency for the advisory vote on executive compensation that has been recommended by our stockholders. Abstentions will not count as votes for or against any frequency. Broker non-votes are not counted as voting power present and, therefore, are not counted in the vote.

ITEM 3. ADVISORY VOTE TO APPROVE THE COMPENSATION PAID TO THE COMPANY'S NAMED EXECUTIVE OFFICERS

In accordance with Section 14A of the Securities Exchange Act of 1934 and Rule 14a-21(a), we are asking our stockholders to approve, in a separate advisory vote, the compensation of our named executive officers as disclosed in this Proxy Statement pursuant to Item 402 of Regulation S-K. As discussed in the Compensation Discussion and Analysis, our compensation committee and board of directors believe that our current executive compensation program directly links compensation of our named executive officers to our financial performance and aligns the interests of our named executive officers with those of our stockholders. Our compensation committee and board of directors also believe that our executive compensation program provides our named executive officers with a balanced compensation package that includes an appropriate base salary along with competitive annual and long-term incentive compensation targets. These incentive programs are designed to reward our named executive officers on both an annual and long-term basis if they attain specified goals.

Our overall compensation program and philosophy is built on a foundation of these guiding principles:

- we pay for performance, with over 60% of our 2016 total target direct compensation for our named executive officers in the form of performance-based incentive compensation;
- we review competitive compensation data for our named executive officers, to the extent available, and incorporate internal equity in the final determination of target compensation levels;
- we 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 return on invested capital; and
- we align executive compensation and performance by using long-term performance incentives based on total stockholder return relative to our peer group.

We are asking our stockholders to indicate their approval of our named executive officer compensation as disclosed in this Proxy Statement, including the Compensation Discussion and Analysis, the executive compensation tables, and narrative discussion. This vote is not intended to address any specific item of compensation, but rather the overall compensation of our named executive officers for 2016. Accordingly, the following resolution is submitted for stockholder vote at the 2017 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 our named executive officers remains with our compensation committee and our board of directors, although our board and compensation committee will consider the outcome of this vote when making future compensation decisions. In a separate vote, we are also providing our stockholders with the opportunity to vote, on an advisory basis, on whether the vote on our named executive officer compensation should occur every year, every two years, or every three years.

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 our named executive officers requires the affirmative vote of a majority of our common stock present in person or represented by proxy at the meeting and entitled to vote on the proposal. Abstentions will count as votes against this proposal. Broker non-vote shares are not entitled to vote on this proposal and, therefore, are not counted in the vote.

INFORMATION CONCERNING EXECUTIVE OFFICERS

At the first annual meeting of the board after the annual meeting of stockholders, our board of directors elects our executive officers, who serve until their successors are chosen and qualify. A majority of our board of directors may remove any executive officer at any time. Information concerning our executive officers, including their ages as of December 31, 2016, 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	55	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	61	Mr. Barney was elected president and chief executive officer of Knife River Corporation effective April 30, 2013, and president effective January 1, 2012.
Martin A. Fritz	52	Mr. Fritz was elected president and chief executive officer of WBI Holdings, Inc. effective July 20, 2015. Prior to joining WBI Holdings, Inc., he had his own energy consulting firm, Fritz Consulting, from February 2014 to July 2015, where he provided strategy, operations, business development, and business brokerage services. Prior to that, Mr. Fritz was employed by EQT Corporation, a petroleum and natural gas exploration and pipeline company, in positions of increasing responsibility, most recently serving as its executive vice president midstream operations, land and construction from 2013 through January 2014 and vice president EQT and president EQT midstream operations from 2008 to 2013.
Dennis L. Haider	64	Mr. Haider was elected executive vice president-business development effective June 1, 2013. Prior to that, he was executive vice president-business development and gas supply of Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation, and Intermountain Gas Company from January 1, 2012 to May 31, 2013.
Anne M. Jones	53	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	43	Ms. Kivisto was elected president and chief executive officer of Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation, and Intermountain Gas Company effective January 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	63	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	50	Ms. Link was elected chief information officer effective January 1, 2016. Prior to that, she was assistant vice president-technology and cybersecurity officer effective January 1, 2015, and director shared IT services effective June 2, 2009.
Doran N. Schwartz	47	Mr. Schwartz was elected vice president and chief financial officer effective February 17, 2010.
Jeffrey S. Thiede	54	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	39	Mr. Vollmer was elected vice president, chief accounting officer and treasurer effective March 19, 2016. Prior to that, he was treasurer and director of cash and risk management effective November 29, 2014, assistant treasurer of Centennial Energy Holdings, Inc. and 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 2016 and how their 2016 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 2016 compensation of our 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.

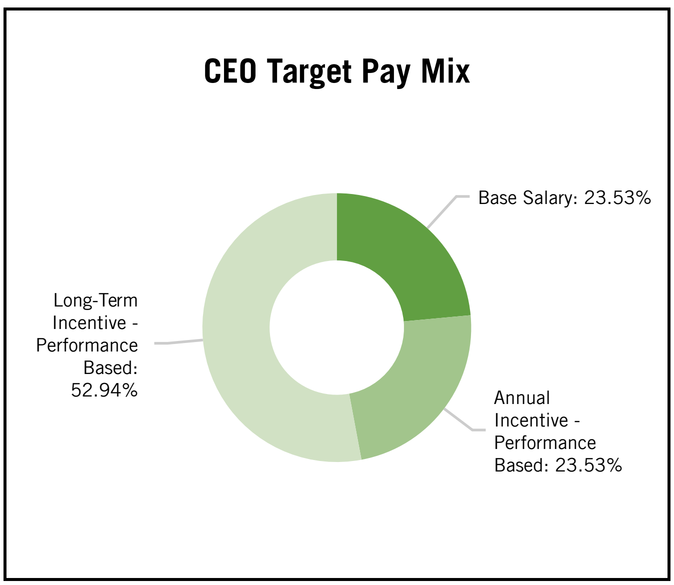
Our Named Executive Officers for 2016 were:

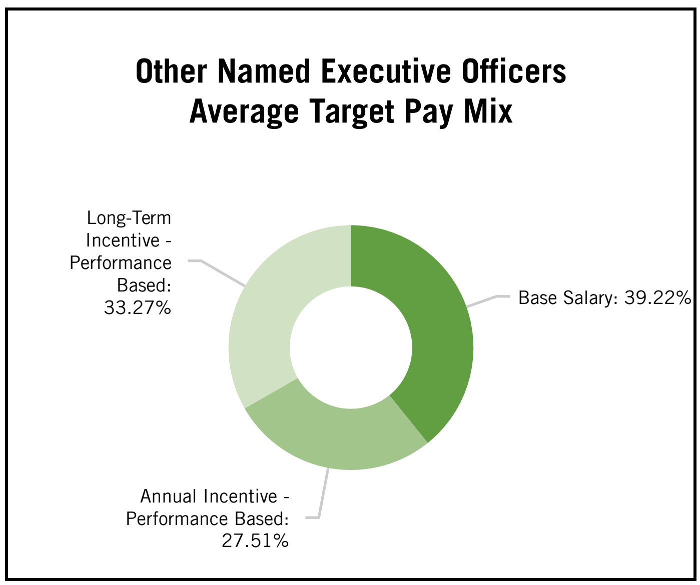
David L. Goodin	President and Chief Executive Officer (CEO)
Doran N. Schwartz	Vice President and Chief Financial Officer (CFO)
David C. Barney	President and Chief Executive Officer - Construction Materials & Contracting Segment
Jeffrey S. Thiede	President and Chief Executive Officer - Construction Services Segment
Martin A. Fritz	President and Chief Executive Officer - Pipeline & Midstream Segment

Executive Summary

Pay for Performance

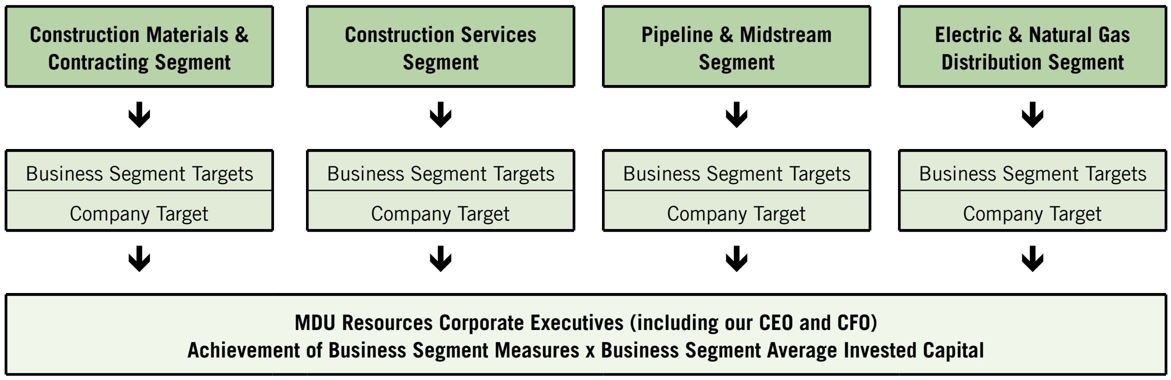
To ensure management's interests are aligned with those of our stockholders and the performance of the company, over 76% of the CEO's target compensation and 61% of the other named executive officers' target compensation is dependent on the achievement of company performance targets. The charts below 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 at-risk performance incentives.



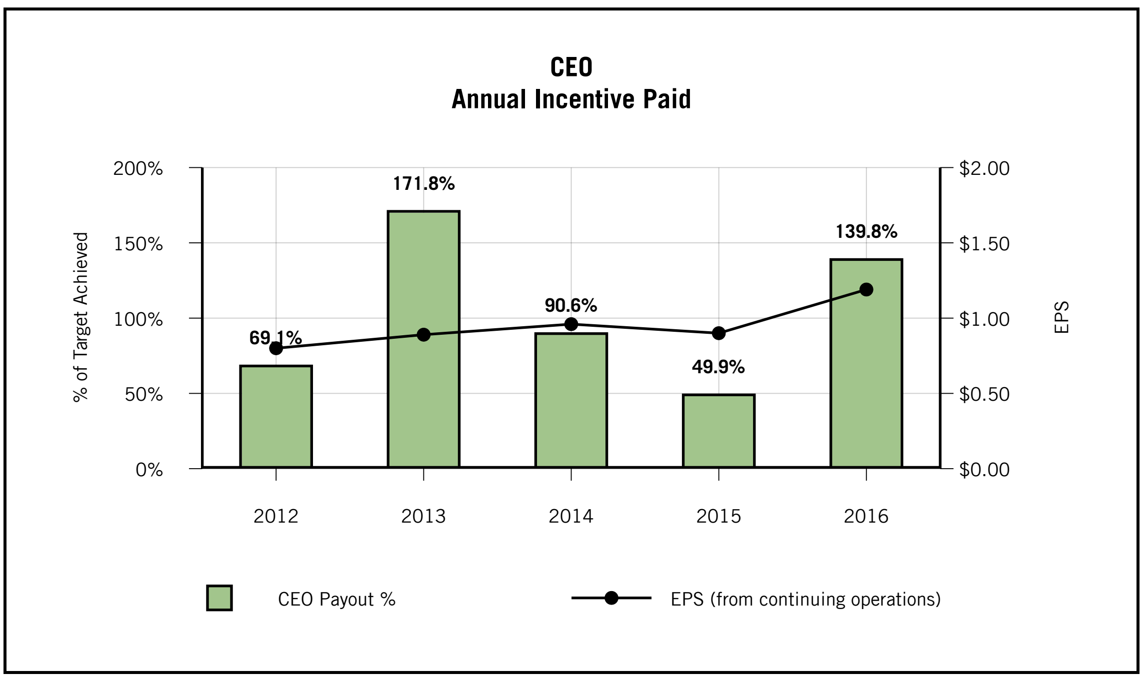


Annual incentive opportunities for our executive officers are linked to performance by tying them to the achievement of specific business and financial goals. The 2016 annual incentive opportunities for business segment executives are based on the achievement of specific performance measures selected by the compensation committee. The performance measures included targets specific to the business segment and one performance measure tied to the success of the company as a whole. This incentivized 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.

For corporate executives (including our CEO and CFO), annual incentive opportunities are based on the business segments' achievement of their performance measures. The business segment performance measures are then weighted by its average invested capital. The sum of the weighted business unit achieved performance measures results in the annual incentive payout for corporate executives. This incentivizes the corporate executives to assist the business segments in their success and performance.

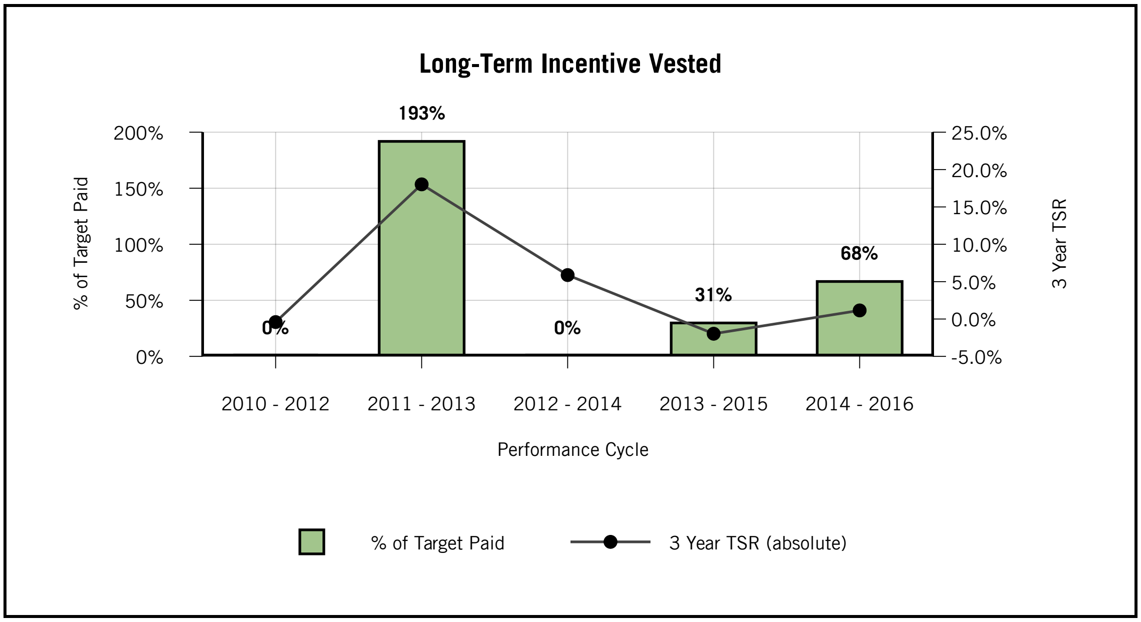


The following chart shows the annual incentive payout of target realized by our CEO with a comparison to earnings per share from continuing operations for the last five years and demonstrates the alignment between our financial performance and realized annual incentive compensation.



See “Annual Incentives” in this section for further details on our company’s annual incentive program.

Vesting of long-term incentives is based on our company’s total stockholder return in comparison to that of our peers measured over a three year period. The following chart depicts the actual vesting percentage for the last five performance cycles and demonstrates the alignment between total return to our stockholders and our realized long-term incentive compensation.



See "Long-Term Incentives" in this section 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 2016 Annual Meeting of Stockholders, 85.2% of the votes cast on the "Say on Pay" proposal approved the compensation of our named executive officers. Although the compensation committee viewed the 2016 vote as a strong expression of the stockholders general satisfaction with the company's executive compensation programs, the 85.2% approval is lower than the results of our 88.2% "Say on Pay" vote at the 2015 Annual Meeting of Stockholders. The compensation committee believes the lower approval vote was largely attributable to a negative recommendation of a proxy advisor largely caused by comparative analysis to a peer group that was not reflective of the company's business mix and an analysis that gave inadequate recognition to the distinction between target incentive award opportunities and realized incentive compensation. The compensation committee reviewed and considered the 2016 vote on "Say on Pay" in setting compensation for 2017.

Total Realized Pay

Total Realized Pay reflects the compensation actually paid to our executive officers based on performance, which can differ substantially from compensation as presented in the Summary Compensation Table. For example, total compensation presented in the Summary Compensation Table contains estimated values of performance share grants based on multiple assumptions which may or may not be achieved and can only be realized at the end of a three-year performance period. In addition, the Summary Compensation Table may show an increase in pension value based on valuation assumptions and discount rates used to calculate present value; however, any change in the pension value is not realized until the future period when the executive actually retires. We believe presenting information on Total Realized Pay provides additional perspective on the renumeration actually received by an executive in a given year. We define 2016 Total Realized Pay to include:

- Base salary for 2016;
- Annual incentive earned for 2016;
- Performance shares (long-term incentive) plus dividend equivalents vesting as of December 31, 2016 and paid in 2017; and
- Other compensation which includes company contributions to the 401(k) plan and company paid life insurance premiums.

Name	2016 Base Salary ($)	2016 Annual Incentive Earned ($)	Vested and Paid Performance Shares[1] ($)	2016 Other Compensation ($)	2016 Total Realized Pay ($)	Summary Compensation Table Total Compensation ($)
David L. Goodin	755,000	1,055,490	654,368	40,246	2,505,104	3,510,991
Doran N. Schwartz	380,000	351,481	171,936	35,772	939,189	1,134,629
David C. Barney	406,800	593,114	145,190	22,905	1,168,009	1,376,616
Jeffrey S. Thiede	425,000	489,600	152,848	22,708	1,090,156	1,325,906
Martin A. Fritz	400,000	416,000	—	21,670	837,670	1,243,248

[1] Performance shares and dividend equivalents for the 2014-2016 performance cycle vested on December 31, 2016 and were approved in February 2017. The performance share value is based on our stock price on February 16, 2017, which was $26.37 per share.

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** - All annual and long-term incentives are performance-based and tied to performance measures set by the compensation committee.

☑ **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 the executive's performance, experience, relative value compared to other positions within the company, relationship to competitive market value compensation, and the economic environment of the executive's business segment.

☑ **Annual Compensation Risk Analysis** - We regularly analyze the risks related to our compensation programs and conduct a broad risk assessment annually.

☑ **Stock Ownership & 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 must retain at least 50% of the net after tax shares of stock vested through the long-term incentive plan for the earlier of 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 company executive officers within the last three years.

What We Don't Do

☒ **Stock Options** - The company does not use stock options as a form of incentive compensation.

☒ **Perquisites** - Executives do not receive perquisites which materially differ from those available to employees in general.

☒ **Tax Gross-ups** - Executive officers do not receive tax gross-ups on any compensation.

☒ **Hedge or Pledge Stock** - Executives and directors are not allowed to hedge or pledge company securities.

☒ **No Time Based Awards** - All long-term incentives are performance-based and vest only upon the achievement of specific performance measures.

2016 Compensation Framework

Objectives of our Compensation Program

We have a written executive compensation policy for our executive officers, including all our named executive officers. Our policy's stated objectives are to:

- recruit, motivate, reward, and retain high performing executive talent required to create superior long-term total stockholder return in comparison to our peer group;
- reward executives for short-term performance, as well as 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 2016

For 2016, 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 the 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 2016. They also certified the achievement of performance measures associated with annual and long-term incentive compensation.

At least every two years, the compensation committee hires an independent consulting firm to assess 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 2015, the human resources department prepared the analysis for 2016 compensation.

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 executives with sufficient, regularly paid income to recruit and retain executives with knowledge, skills, and abilities necessary to successfully execute their job responsibilities.	Compared to 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 be competitive from a total renumeration standpoint and to ensure focus on annual financial and operating results.	Annual incentives calculated as a percentage of base salary based on the achievement of performance measures established by the compensation committee.	Annual incentive performance measures are tied to the achievement of financial and operational goals aimed to drive the success of the company.
Performance Shares	Performance Based At Risk	Provides an opportunity to earn long-term compensation to be competitive from a total renumeration standpoint and to ensure focus on stockholder return.	Performance share award opportunities are calculated as a percentage of base salary and pay out is based on the company's total stockholder return over a three-year period in comparison to the company's peer group.	Fosters ownership in company stock and aligns the executive's interests with those of the stockholder in increasing stockholder value.

Allocation of Total Target Compensation for 2016

Total target compensation consists of base salary plus target annual and long-term incentive compensation. Performance-based compensation accounts for over 76% of our CEO's and on average approximately 61% of our other named executive officers' total target compensation. 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 our long-term performance. The long-term incentive awards, if earned by achieving performance 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, as stockholders, the executive officers will be motivated to deliver financial 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 to be representative of the industries in which we operate. During 2015, as we decided to exit the oil and gas exploration and production business, we re-evaluated our peer group and removed the remaining exploration and production companies, which were Bill Barrett Corporation and SM Energy Company from the peer group. To more closely reflect our regulated energy delivery and construction materials and services businesses, we added IDACORP, Inc., NorthWestern Corporation, U.S. Concrete, Inc., IES Holdings, Inc., and MYR Group, Inc. to our peer group. MarkWest Energy Partners L.P., which was added as a peer company in 2015, merged with another company and was removed from our 2015 peer group. Likewise, Questar Corporation merged with another company in 2016 and was removed from our 2016 peer group. The following chart depicts the companies included in our 2016 peer group.

2016 Peer Companies

Regulated Energy Delivery		Construction Materials and Services	
Utility	**Pipeline**	**Construction Materials & Contracting**	**Construction Services**
ALLETE, Inc.	Atmos Energy Corporation	Granite Construction Incorporated	EMCOR Group, Inc.
Alliant Energy Corporation	National Fuel Gas Company	Martin Marietta Materials, Inc.	Quanta Services, Inc.
Avista Corporation		Sterling Construction Company, Inc.	IES Holdings, Inc.
Black Hills Corporation		Vulcan Materials Company	MYR Group, Inc.
Northwest Natural Gas Company		U.S. Concrete, Inc.	
Vectren Corporation			
IDACORP, Inc.			
NorthWestern Corporation			

2016 Compensation for Our Named Executive Officers

2016 Salary and Incentive Targets

For 2016, Mr. Goodin considered the 2015 financial results as well as the economic challenges facing the company and recommended a base salary freeze for the named executive officers during 2016, with the exception of Mr. Barney where he recommended a 3% increase based on the outstanding performance of the construction materials & contracting segment in achieving record earnings and exceeding its risk adjusted capital cost in 2015. The compensation committee approved the salary recommendations of the CEO. The compensation committee reviewed and determined to freeze Mr. Goodin's base salary for 2016 consistent with the freeze of other named executive officers.

The following is information related to each named executive officer's base salary, target annual incentive, target long-term incentive, and total direct compensation:

David L. Goodin	2016 ($)	% Increase from Prior Year	Compensation Component as a % of Base Salary
Base Salary	755,000	0%	n/a
Target Annual Incentive Opportunity	755,000	0%	100 %
Target Long-Term Incentive Opportunity	1,698,750	0%	225 %
Target Total Potential Direct Compensation	3,208,750	0%	425 %

Doran N. Schwartz	2016 ($)	% Increase from Prior Year	Compensation Component as a % of Base Salary
Base Salary	380,000	0%	n/a
Target Annual Incentive Opportunity	247,000	0%	65 %
Target Long-Term Incentive Opportunity	342,000	0%	90 %
Target Total Potential Direct Compensation	969,000	0%	255 %

David C. Barney	2016 ($)	% Increase from Prior Year	Compensation Component as a % of Base Salary
Base Salary	406,800	3 %	n/a
Target Annual Incentive Opportunity	305,100	(3)%	75 %
Target Long-Term Incentive Opportunity	325,440	18 %	80 %
Target Total Potential Direct Compensation	1,037,340	5 %	255 %

Mr. Barney continues to transition from an all annual incentive target to a combination of annual and long-term incentive targets in connection with his promotion in 2013. Mr. Barney's annual incentive target as a percent of base salary decreased from 80% in 2015 to 75% for 2016, while his long-term incentive target as a percent of base salary increased from 70% in 2015 to 80% for 2016.

Jeffrey S. Thiede	2016 ($)	% Increase from Prior Year	Compensation Component as a % of Base Salary
Base Salary	425,000	0 %	n/a
Target Annual Incentive Opportunity	318,750	(6)%	75 %
Target Long-Term Incentive Opportunity	340,000	14 %	80 %
Target Total Potential Direct Compensation	1,083,750	2 %	255 %

Mr. Thiede continues to transition from an all annual incentive target to a combination of annual and long-term incentive targets in connection with his promotion in 2013. Mr. Thiede's annual incentive target as a percent of base salary decreased from 80% in 2015 to 75% for 2016, while his long-term incentive target as a percent of base salary increased from 70% in 2015 to 80% for 2016.

Martin A. Fritz	2016 ($)	% Increase from Prior Year	Compensation Component as a % of Base Salary
Base Salary	400,000	0 %	n/a
Target Annual Incentive Opportunity	260,000	0 %	65 %
Target Long-Term Incentive Opportunity	360,000	0 %	90 %
Target Total Potential Direct Compensation	1,020,000	0 %	255 %

Annual Incentives

Annual incentive opportunities are determined for business segment executives by the achievement of specific performance measures selected by the compensation committee. For corporate executives, annual incentive opportunities are determined by the average of the business segments' achievement of their performance measures weighted by its average invested capital. Through this, our business segment executives are incentivized to primarily focus on the success and performance of their business segment while corporate executives focus on the success and performance of all lines of business.

The compensation committee developed and reviewed financial and other corporate performance measures to ensure compensation to the executives reflect the success of their respective business segments and the company, as well as the value provided to our stockholders. Each business segment's performance measures are weighted with a corporate earnings per share performance measure representing 20% of the target award opportunity and the business segment specific performance measures representing 80% of the award opportunity. The following incentive plan performance measures for 2016 were established by the compensation committee for the business segment presidents (exclusive of the MDU Resources corporate executive officers) at the February 2016 meeting:

Measure	Applies to	Purpose	Measurement	Target	Weight	Why Measure Selected
MDU Resources Diluted Adjusted Earnings per Share (EPS)	All the business segments	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 in the earnings of the company as a whole.	GAAP EPS less discontinued operations (as reported as discontinued on or prior to December 31, 2015) and adjusted to exclude: - effects of intersegment eliminations, - noncash gains/losses resulting from hedge accounting, - losses on asset sales/dispositions approved by the board, and - assessed withdrawal liabilities relating to multiemployer pension plans.	$1.02	20%	Reflects anticipated EPS performance within the range of EPS guidance for 2016.
Return on Invested Capital (ROIC)	Electric & Natural Gas Distribution Segment	Provides a measure of how effective the business segment uses its capital and generates a return from its capital. These segments are primarily regulated entities requiring significant capital investment. ROIC is important in providing a return to our stockholders.	Business segment earnings, without regard to after tax interest expense and preferred stock dividends divided by the business segment's average capitalization for the calendar year.	4.4%	40%	Reflects anticipated returns considering additional capital investments made in 2015.
	Pipeline & Midstream Segment			5.9%	28%	Reflects anticipated returns considering additional capital investments made in 2015.
Business Segment Earnings	Electric & Natural Gas Distribution Segment	Provides a measure of financial performance.	GAAP business segment earnings adjusted to exclude: - effects of intersegment eliminations, - noncash gains/losses resulting from hedge accounting, - losses on asset sales/dispositions approved by the board, and - assessed withdrawal liabilities relating to multiemployer pension plans.	$68.0 million	40%	Reflects anticipated earnings associated with the business segment.
	Pipeline & Midstream Segment			$18.5 million	28%	Reflects anticipated earnings associated with the business segment.
	Construction Materials & Contracting Segment			$62.8 million	80%	Reflects earnings necessary to meet or exceed the business segment's risk adjusted capital cost.
	Construction Services Segment			$26.4 million	80%	Reflects earnings necessary to meet or exceed the business segment's risk adjusted capital cost.
Optimum Refining Production	Refining Segment	Promotes the achievement of plant reliability based on optimum production.	Barrels of diesel produced in 2016.	5,865 bbls	24%	Reflects plant production based on the plant design with consideration for planned maintenance outages.

Actual performance results are compared to the target performance measure to arrive at a percent of target achieved. The percent of target achieved is then translated into a payout percentage of the target award opportunity. Generally, to receive a payout requires achievement of 85% of the target performance measure which results in a payout of 25% of the award opportunity. Maximum payouts vary by business segment. For the regulated energy delivery companies, maximum payout of 200% of the award opportunity is received if the percent of target achieved is 115% or greater. For the construction materials and services companies, maximum payout is 250% of the award opportunity if the percent of target achieved is 167.2% of target for the construction materials & contracting segment and 210% of target for the construction services segment. Results achieved between the threshold, target, and maximum levels are calculated using linear interpolation. The following tables show the 2016 performance measure results and the relative award opportunity payout:

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	$1.08	105.9 %	139.2 %	20 %	27.8 %
Electric & Natural Gas Distribution Segment	Earnings	$69.3 million	101.9 %	112.7 %	40 %	45.1 %
	ROIC	4.5 %	102.3 %	115.1 %	40 %	46.0 %
Pipeline & Midstream and Refining Segments	Earnings	$24.9 million	134.6 %	200.0 %	28 %	56.0 %
	ROIC	7.5 %	127.1 %	200.0 %	28 %	56.0 %
	Optimum Refining Production [1]	2,796 bbls	82.9 %	84.0 %	24 %	20.2 %
Construction Materials & Contracting Segment	Earnings	$96.0 million	152.9 %	208.3 %	80 %	166.6 %
Construction Services Segment	Earnings	$33.9 million	128.6 %	157.2 %	80 %	125.8 %

[1] The compensation committee determined the economic conditions that led to the sale of Dakota Prairie Refining, LLC in June 2016, as well as the sale itself, were unforeseen changes and significant factors beyond the control of management that substantially affected the ability of the refining segment to achieve the specified annual production performance measure at Dakota Prairie Refining, LLC. Due to these unforeseen circumstances, the compensation committee determined the annual production performance measure at the refining segment was achieved for Mr. Fritz at the same percentage as the annual production rate at Dakota Prairie Refining, LLC was being achieved during 2016 prior to the sale.

For the MDU Resources Group, Inc. corporate named executive officers, namely Messrs. Goodin and Schwartz, the compensation committee continued to base the payment of the annual incentive on the achievement of performance measures at the business segments weighted by each business segment's weighted average invested capital. The compensation committee's rationale for this approach was to provide alignment between the MDU Resources Group, Inc. executives and business segment performance. The compensation committee determined achievement of the optimum refining production performance measure for Mr. Schwartz's award opportunity payout in the same manner as it determined the achievement of the performance measure for Mr. Fritz. The compensation committee did not modify Mr. Goodin's award opportunity payout for the effects of the optimum refining production performance measure. As a result, Messrs. Goodin's and Schwartz's 2016 annual incentives were earned at 139.8% and 142.3% of the target award opportunity, respectively, based on the following weighted average of annual business segment incentives achieved:

	Column A Business Segment Award Opportunity Payout		Column B	Column A x Column B	
Business Segment	Mr. Goodin	Mr. Schwartz	Percentage of Average Invested Capital	Mr. Goodin	Mr. Schwartz
Construction Materials & Contracting Segment [1]	187.8 %	187.8 %	22.2 %	41.7 %	41.7 %
Construction Services Segment	153.6 %	153.6 %	8.8 %	13.5 %	13.5 %
Pipeline & Midstream and Refining Segments	139.8 %	160.0 %	12.4 %	17.3 %	19.8 %
Electric & Natural Gas Distribution Segment	118.9 %	118.9 %	56.6 %	67.3 %	67.3 %
Total Payout Percentage				139.8 %	142.3 %

[1] For purposes of calculating the incentive award opportunities for Messrs. Goodin and Schwartz, the award opportunity payout associated with the earnings performance measure for the construction materials & contracting segment was limited to 200%, which resulted in a weighted construction materials & contracting segment award opportunity payout percentage of 187.8% versus the 194.4% for the business segment.

Based on the achievement of the performance targets, the named executive officers received the following annual incentive compensation:

2016 Annual Incentives Earned

		Annual Incentive Earned	
Name	Target Annual Incentive ($)	Payout (%)	Amount ($)
David L. Goodin	755,000	139.8	1,055,490
Doran N. Schwartz	247,000	142.3	351,481
David C. Barney	305,100	194.4	593,114
Jeffrey S. Thiede	318,750	153.6	489,600
Martin A. Fritz	260,000	160.0	416,000

Long-Term Incentives

We use the Long-Term Performance-Based Incentive Plan, which has been approved by our stockholders, for long-term incentive compensation. As in the past, the compensation committee used performance shares as the form of long-term incentive compensation for 2016 and established the company's total stockholder return in comparison to the total stockholder return for the peer group companies over a three-year period as the performance measure for vesting of long-term incentive compensation.

Total stockholder return is the percentage change in the value of an investment in the common stock of a company from the closing price on the last trading day in the calendar year preceding the beginning of the performance period through the last trading day in the final year of the performance period. It is assumed that dividends are reinvested in additional shares of common stock at the frequency paid during the performance period. The compensation committee selected total stockholder return as the performance measure because long-term executive incentive compensation should align with our long-term performance in stockholder return as compared to other public companies in our industries.

Depending on our total three-year stockholder return compared to the total three-year stockholder returns of our peer group companies, performance share award opportunities for our named executive officers may or may not vest. Vesting of performance shares can range from 0% to 200% of the target award. Vesting of the performance share opportunities will be a function of our rank over the performance period against our peer group companies as delineated in the following table:

The Company's Peer TSR Percentile Rank	Vesting Percentage of Award Target
75th or higher	200%
50th	100%
25th	20%
Less than 25th	0%

Vesting for percentile ranks falling between the intervals will be interpolated. If our total stockholder return is negative, the shares and dividend equivalents otherwise earned based on the payout percentages above, if any, will be reduced in accordance with the following table:

Total Stockholder Return	Reduction in Vesting
0% through -5%	50%
-5.01% through -10%	60%
-10.01% through -15%	70%
-15.01% through -20%	80%
-20.01% through -25%	90%
-25.01% or below	100%

Dividend equivalents are paid in cash based on the number of shares actually vested for the performance period. No dividend equivalents are paid on unvested performance shares.

Actual vesting of performance share awards under the plan have varied over the last five years as shown below:

Performance Period	Vesting Percentage
2014-2016	68%
2013-2015	31%
2012-2014	0%
2011-2013	193%
2010-2012	0%

Results of 2014-2016 Performance Period

We awarded performance share opportunities to our named executive officers on February 14, 2014 for the 2014-2016 performance period. Our total stockholder return for the three-year performance period was 1.15% which corresponded to a percentile ranking of 40% with our 2014 peer group companies, and resulted in 68% vesting of performance shares and dividend equivalents. The named executive officers received the following for the 2014-2016 performance period:

Name	Target Performance Shares (#)	Performance Shares Vested (#)	Dividend Equivalents ($)	Value of Vested Shares and Dividend Equivalents at 2/16/17 ($)[1]
David L. Goodin	33,677	22,900	50,495	654,368
Doran N. Schwartz	8,849	6,017	13,267	171,936
David C. Barney	7,472	5,081	11,204	145,190
Jeffrey S. Thiede	7,866	5,349	11,795	152,848
Martin A. Fritz	None [2]	—	—	—

[1] Closing share price at February 16, 2017 was $26.37.

[2] Mr. Fritz joined the company in 2015, therefore was not eligible for award for the 2014-2016 performance period.

2016-2018 Performance Period

On February 11, 2016, for the 2016-2018 performance period, the compensation committee determined the target number of performance shares for each named executive officer by multiplying the named executive officer's base salary by his target long-term incentive percentage and then dividing by the average of the closing prices of our stock from January 1 through January 22, 2016, which was $17.20 per share. Based on this price, the board of directors, upon recommendation of the compensation committee, awarded the following performance share opportunities to the named executive officers:

Name	Base Salary to Determine Target ($)	Target Long-Term Incentive % (%)	Long-Term Incentive Target ($)	Resulting Number of Performance Share Opportunities (#)
David L. Goodin	755,000	225	1,698,750	98,764
Doran N. Schwartz	380,000	90	342,000	19,883
David C. Barney	406,800	80	325,440	18,920
Jeffrey S. Thiede	425,000	80	340,000	19,767
Martin A. Fritz	400,000	90	360,000	20,930

The named executive officers must retain 50% of the net after-tax performance shares vested pursuant to the long-term incentive award until the earlier of 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 performance shares 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 2016 which are described below:

Plans	David L. Goodin	Doran N. Schwartz	David C. Barney	Jeffrey S. Thiede	Martin A. Fritz
401(k)	Yes	Yes	Yes	Yes	Yes
Pension	Yes	Yes	No	No	No
Supplemental Income Security Plan	Yes	Yes	Yes	No	No
Non-Qualified Defined Contribution Plan	No	No	No	Yes	Yes

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% of the employee's elected deferral rate. Contributions and the company match are invested in various funds 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, the added retirement contribution is 5% of plan eligible compensation. For participants hired prior to 2006, the added retirement contributions are based on the participant's age as of December 31, 2009. The retirement contribution is 11.5% for Mr. Goodin, 10.5% for Mr. Schwartz, and 5% for Messrs. Barney, Thiede, and Fritz. These amounts may be reduced in accordance with the provisions of the 401(k) plan to meet 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 2016."

Supplemental Income Security Plan

We offer 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 so no new participants will be added to the plan and current benefit levels are frozen for existing participants. For further details regarding the company's SISP, please refer to the section entitled "Pension Benefits for 2016." Named executive officers participating in the SISP are Messrs. Goodin, Schwartz, and Barney.

The following table reflects our named executive officers' SISP benefits as of December 31, 2016:

	SISP Benefits	
Name	Annual Death Benefit ($)	Annual Retirement Benefit ($)
David L. Goodin	552,960	276,480
Doran N. Schwartz	262,464	131,232
David C. Barney	262,464	131,232
Jeffrey S. Thiede	—	—
Martin A. Fritz	—	—

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 or 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 to the executive in accordance with the terms of the plan commencing upon the later of separation from service or age 65. For further details regarding the company's NQDCP, please refer to the section entitled "Nonqualified Deferred Compensation for 2016."

For 2016, the compensation committee selected and approved contributions of $100,000 each to Mr. Thiede and Mr. Fritz. The contribution awarded to Mr. Thiede represents 23.5% of his base salary at December 31, 2015 and recognized his strong leadership at the construction services segment, which delivered a favorable return on invested capital in comparison to the median return on invested capital of similar companies in the peer group. The contribution awarded to Mr. Fritz represents 25% of his base salary at December 31, 2015 and recognized his performance in revitalizing the pipeline & midstream segment, pursuing new opportunities, and steps taken to control costs and align the operations of the refinery in 2015.

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 unless the compensation qualifies as performance-based compensation under Section 162(m). Generally, long-term incentive compensation and annual incentive awards for our CEO and those executive officers whose overall compensation is likely to exceed $1 million are structured to be deductible for purposes of Section 162(m). All incentive compensation in excess of $1 million paid to our named executive officers in 2016 satisfied the requirements for deductibility.

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. Unvested performance shares are not considered in ownership calculations. The level of stock ownership compared to the ownership requirements 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 as of December 31, 2016:

Name	Ownership Policy Multiple of Base Salary within 5 Years	Actual Holdings as a Multiple of Base Salary as of 12/31/2016	Ownership requirement must be met by:
David L. Goodin	4X	3.26	1/1/2018
Doran N. Schwartz	3X	3.81	Ownership requirement met
David C. Barney	3X	0.61	1/1/2019
Jeffrey S. Thiede	3X	0.20	1/1/2019
Martin A. Fritz	3X	—	1/1/2020

Deferral of Annual Incentive Compensation

We provide executives the opportunity to defer receipt of earned annual incentives. If an executive chooses to defer an annual incentive, we credit the deferral with interest at a rate determined by the compensation committee. For 2016, the committee chose to use an interest rate of 4.5% 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 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, Chairman
Karen B. Fagg
William E. McCracken
Patricia L. Moss

EXECUTIVE COMPENSATION TABLES

Summary Compensation Table for 2016

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Bonus ($) (d)[1]	Stock Awards ($) (e)[2]	Option Awards ($) (f)	Non-Equity Incentive Plan Compensation ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)	All Other Compensation ($) (i)	Total ($) (j)
David L. Goodin	2016	755,000	—	1,441,954	—	1,055,490	218,301 [3]	40,246 [4]	3,510,991
President and CEO	2015	755,000	—	1,386,992	—	376,745	—	39,411	2,558,148
	2014	685,000	—	1,385,135	—	830,915	631,901	38,686	3,571,637
Doran N. Schwartz	2016	380,000	6,175	290,292	—	345,306	77,084 [3]	35,772 [4]	1,134,629
Vice President	2015	380,000	—	279,228	—	123,253	—	35,571	818,052
and CFO	2014	360,000	—	363,959	—	163,080	273,974	34,956	1,195,969
David C. Barney	2016	406,800	—	276,232	—	593,114	77,565 [3]	22,905 [4]	1,376,616
President and CEO of	2015	395,000	—	225,739	—	637,588	9,530	22,556	1,290,413
Knife River	2014	—	—	—	—	—	—	—	—
Corporation									
Jeffrey S. Thiede	2016	425,000	—	288,598	—	489,600	—	122,708 [4]	1,325,906
President and CEO of	2015	425,000	—	242,902	—	161,857	—	172,506	1,002,265
MDU Construction	2014	400,000	—	323,529	—	730,150	—	96,481	1,550,160
Services Group, Inc.									
Martin A. Fritz	2016	400,000	52,520	305,578	—	363,480	—	121,670 [4]	1,243,248
President and CEO of	2015	—	—	—	—	—	—	—	—
WBI Energy, Inc.	2014	—	—	—	—	—	—	—	—

[1] Amounts shown represent the incentive compensation determined by the compensation committee for the optimum refining production performance measure for 2016 due to the unforeseen economic conditions which lead to the sale of Dakota Prairie Refining, LLC. See "Annual Incentives" in the section entitled "Compensation Discussion and Analysis" for further information.

[2] 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 using the Monte Carlo simulation, as described in Note 10 of our audited financial statements in our Annual Report on Form 10-K for the year ended December 31, 2016. For 2016, 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	2,883,909
Doran N. Schwartz	580,584
David C. Barney	552,464
Jeffrey S. Thiede	577,196
Martin A. Fritz	611,156

[3] Amounts shown for 2016 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, 2016.

Name	Accumulated Pension Change ($)	Above Market Interest ($)
David L. Goodin	215,917	2,384
Doran N. Schwartz	77,084	—
David C. Barney	77,565	—

[4] All Other Compensation is comprised of:

Name	401(k) ($)[a]	Life Insurance Premium ($)	Matching Charitable Contributions ($)	Nonqualified Defined Contribution Plan ($)	Total ($)
David L. Goodin	38,425	621	1,200	—	40,246
Doran N. Schwartz	35,000	472	300	—	35,772
David C. Barney	21,200	505	1,200	—	22,905
Jeffrey S. Thiede	21,200	528	980	100,000	122,708
Martin A. Fritz	21,173	497	—	100,000	121,670

[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.

Grants of Plan-Based Awards in 2016

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			
Name (a)	Grant Date (b)	Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	Grant Date Fair Value of Stock and Option Awards ($) (l)
David L. Goodin	2/11/2016 [1]	188,750	755,000	1,510,000	—	—	—	—
	2/11/2016 [2]	—	—	—	19,753	98,764	197,528	1,441,954
Doran N. Schwartz	2/11/2016 [3]	61,750	247,000	494,000	—	—	—	—
	2/11/2016 [2]	—	—	—	3,977	19,883	39,766	290,292
David C. Barney	2/11/2016 [1]	76,275	305,100	732,240	—	—	—	—
	2/11/2016 [2]	—	—	—	3,784	18,920	37,840	276,232
Jeffrey S. Thiede	2/11/2016 [1]	79,688	318,750	765,000	—	—	—	—
	2/11/2016 [2]	—	—	—	3,953	19,767	39,534	288,598
Martin A. Fritz	2/11/2016 [3]	65,000	260,000	520,000	—	—	—	—
	2/11/2016 [2]	—	—	—	4,186	20,930	41,860	305,578

[1] Annual incentive for 2016 granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

[2] Performance shares for the 2016-2018 performance period granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

[3] Annual incentive for 2016 granted pursuant to the MDU Resources Group, Inc. Executive Incentive Compensation Plan.

Narrative Discussion Relating to the Summary Compensation Table and Grants of Plan-Based Awards Table

Annual Incentive

The compensation committee recommended the 2016 annual incentive award opportunities for our named executive officers and the board approved these opportunities at its meeting on February 11, 2016. 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 2016 performance is reflected in column (g) of the Summary Compensation Table.

As described in "Annual Incentives" in the section entitled "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 & contracting and construction services segments which may range from 0% to 250% for achievement of certain performance measures.

Messrs. Goodin, Barney, and Thiede received their 2016 annual incentive award opportunities pursuant to the Long-Term Performance-Based Incentive Plan. To be eligible to receive a payment, they must remain employed by the company through December 31, 2016. The performance measures associated with their annual incentive may not be adjusted if the adjustment would increase their annual incentive award payment, unless the compensation committee determined and established the adjustment in writing within 90 days of the beginning of the performance period. The compensation committee may at its sole discretion use negative discretion based on subjective or objective measures and adjust any annual incentive award payment downward.

Messrs. Schwartz and Fritz 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 age 65 remain eligible to receive an award, but executives who terminate employment for other reasons are not eligible for an award. The 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 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 2016 incentive plan performance measures and results, see "Annual Incentives" in the section entitled "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 11, 2016. 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 our 2016-2018 total stockholder return compared to the total three-year stockholder returns of our peer group companies, executives will receive from 0% to 200% of the target awards in February 2019. 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 2019 at the same time as the performance share awards vest. In the event the company's 2016-2018 total stockholder return is negative, the number of shares that would otherwise vest for the performance period will be reduced from 50% to 100%. For further discussion of the specific long-term incentive plan, see "Long-Term Incentives" in the section entitled "Compensation Discussion and Analysis."

Nonqualified Defined Contribution Plan

The compensation committee selects participants and approves contributions to the Nonqualified Defined Contribution Plan based on recommendations from the CEO. 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 $100,000 each for Messrs. Thiede and Fritz. For further information, see the section entitled "Nonqualified Deferred Compensation for 2016."

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	755,000	—	3,510,991	21.5%
Doran N. Schwartz	380,000	6,175	1,134,629	34.0%
David C. Barney	406,800	—	1,376,616	29.6%
Jeffrey S. Thiede	425,000	—	1,325,906	32.1%
Martin A. Fritz	400,000	52,520	1,243,248	36.4%

Outstanding Equity Awards at Fiscal Year-End 2016

	Stock Awards			
Name (a)	Number of Shares or Units of Stock That Have Not Vested (#) (g)	Market Value of Shares or Units of Stock That Have Not Vested ($) (h)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (i)[1]	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)[2]
David L. Goodin	—	—	375,533	10,804,084
Doran N. Schwartz	—	—	77,671	2,234,595
David C. Barney	—	—	68,802	1,979,434
Jeffrey S. Thiede	—	—	72,676	2,090,889
Martin A. Fritz	—	—	70,742	2,035,247

[1] Below is a breakdown by year of the outstanding performance share plan awards:

	2014 Award	2015 Award	2016 Award	
Performance Period End	12/31/2016	12/31/2017	12/31/2018	Total
David L. Goodin	33,677	144,328	197,528	375,533
Doran N. Schwartz	8,849	29,056	39,766	77,671
David C. Barney	7,472	23,490	37,840	68,802
Jeffrey S. Thiede	7,866	25,276	39,534	72,676
Martin A. Fritz	—	28,882	41,860	70,742

Shares for the 2014 award are shown at the target level (100%) based on results for the 2014-2016 performance cycle between threshold and target.

Shares for the 2015 award are shown at the maximum level (200%) based on results for the first two years of the 2015-2017 performance cycle above target.

Shares for the 2016 award are shown at the maximum level (200%) based on results for the first year of the 2016-2018 performance cycle above target.

[2] Value based on the number of performance shares reflected in column (i) multiplied by $28.77, the year-end per share closing stock price for 2016.

While for purposes of the Outstanding Equity Awards at Fiscal Year End 2016 table, the number of shares and value shown for the 2014-2016 performance cycle is at 100% of target, the actual results for the performance period certified by the compensation committee and approved by the board of directors on February 16, 2017 resulted in vesting at 68% of target. For further information, see "Long-Term Incentives" in the section entitled "Compensation Discussion and Analysis."

Option Exercises and Stock Vested During 2016

	Stock Awards	
Name (a)	Number of Shares Acquired on Vesting (#) (d)[1]	Value Realized on Vesting ($) (e)[2]
David L. Goodin	13,264	244,787
Doran N. Schwartz	3,661	67,564
David C. Barney	—	—
Jeffrey S. Thiede	—	—
Martin A. Fritz	—	—

[1] Reflects performance shares for the 2013-2015 performance period that vested on December 31, 2015, and were approved February 11, 2016.

[2] Reflects the value of vested performance shares based on the closing stock price of $16.31 per share on February 11, 2016, and the dividend equivalents paid on the vested shares.

Pension Benefits for 2016

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)[1]	Present Value of Accumulated Benefit ($) (d)	Payments During Last Fiscal Year ($) (e)
David L. Goodin	Pension	26	1,107,307	—
	Basic SISP [2]	10	2,285,113	—
	Excess SISP [3]	26	36,888	—
Doran N. Schwartz	Pension	4	110,012	—
	Basic SISP [2]	9	821,142	—
	Excess SISP [3]	n/a	—	—
David C. Barney	Pension [3]	n/a	—	—
	Basic SISP [2]	10	1,383,697	—
	Excess SISP [3]	n/a	—	—
Jeffrey S. Thiede	Pension [3]	n/a	—	—
	Basic SISP [3]	n/a	—	—
	Excess SISP [3]	n/a	—	—
Martin A. Fritz	Pension [3]	n/a	—	—
	Basic SISP [3]	n/a	—	—
	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, Thiede, and Fritz are not eligible to participate in the pension plans. Messrs. Thiede and Fritz 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, 2016, calculated using:

- a 3.54% discount rate for the Basic SISP and Excess SISP;
- a 3.80% discount rate for the pension plan;
- the Society of Actuaries RP-2014 Adjusted to 2006 Total Dataset Mortality with Scale MP-2016 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 65 for Basic and Excess 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 plan was amended so no new participants would be added to the plan and current benefit levels were frozen 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.

Basic SISP benefits vested as of December 31, 2004, are grandfathered under Section 409A of the Internal Revenue Code (Section 409A) and are subject to the SISP provisions then in effect. Typically, the grandfathered Section 409A SISP benefits are paid over 15 years, with benefits commencing when the participant attains age 65 or when the participant retires if they work beyond age 65. Basic SISP benefits vesting after December 31, 2004 are governed by amended provisions in the plan intended to comply with Section 409A. The SISP benefits for key employees as defined by Section 409A commence six months after the participant attains age 65 or when the participant retires if they work beyond age 65. The benefits are paid over a 173 month period where the first payment includes the equivalent of six-months of payments plus interest equal to one-half of the annual prime interest rate on the participant's last date of employment.

The following are Messrs. Goodin and Barney's benefits under the grandfathered provision and those subject to Section 409A.

	Grandfathered ($)	Subject to §409A ($)	Total ($)
David L. Goodin	247,951	2,037,162	2,285,113
David C. Barney	339,092	1,044,605	1,383,697

Excess SISP Benefits

Excess SISP is an excess 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 2016

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 2016 was 4.5% 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 an 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 determines 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 which individually vest four years after each contribution in accordance with the terms of the plan. Amounts shown as aggregate earnings in the table below for Messrs. Thiede and Fritz reflect the change in investment value at market rates. 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	188,373	—	7,305	—	195,677 [1]
Doran N. Schwartz	—	—	—	—	—
David C. Barney	—	—	—	—	—
Jeffrey S. Thiede	—	100,000	28,044	—	396,929 [2]
Martin A. Fritz	—	100,000	13,936	—	211,748 [2]

[1] Mr. Goodin deferred 50% of his 2015 annual incentive compensation which was $376,745 as reported in the Summary Compensation Table for 2015.

[2] Messrs. Thiede and Fritz each received $100,000 under the Nonqualified Defined Contribution Plan for 2016. Mr. Thiede's balance also includes contributions of $150,000 for 2015, $75,000 for 2014, and $33,000 for 2013. Mr. Fritz's balance includes contributions of $100,000 for 2015. 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. For the named executive officers, the information assumes the terminations or the change of control occurred on December 31, 2016.

The table excludes compensation and benefits that our named executive officers would have already earned during their employment with us whether or not a termination or change of control event had occurred or provided under plans or arrangements that do not discriminate in favor of the named executive officers and that are generally available to all salaried employees, such as benefits under our qualified defined benefit pension plan (for employees hired before 2006), accrued vacation pay, continuation of health care benefits, and life insurance benefits. The tables also do not include nonqualified defined contribution or deferred annual compensation amounts which are shown and explained in the Nonqualified Deferred Compensation for 2016 table.

Compensation

Upon a change of control, annual incentives granted under our Long-Term Performance-Based Incentive Plan (LTIP) would vest at target and be paid in cash. Messrs. Goodin, Barney, and Thiede were awarded their annual incentives for 2016 under the LTIP and would receive the value of their annual incentive compensation at the target amount under the change of control scenarios. No amounts are shown for annual incentives in the tables for Messrs. Goodin, Barney, and Thiede under termination scenarios, as they would be eligible to receive their annual incentives at the level of performance measures were achieved for the performance period regardless of termination scenarios occurring on December 31, 2016.

Messrs. Schwartz and Fritz were granted their annual incentive awards 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 and requires participants to remain employed with the company through the service year to be eligible for a payout. No amounts are shown for annual incentives in the tables for Messrs. Schwartz and Fritz, as they would be eligible to receive their annual incentive at the level performance measures were achieved for the performance period regardless of termination or change of control scenarios occurring on December 31, 2016.

Upon a change of control, performance share awards under the LTIP would be deemed fully earned and vest at their target levels for all 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, performance share awards are forfeited if the participant’s employment terminates for any reason 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.

Based on the above criteria, the named executive officers would earn performance shares upon termination or a change of control as follows:

	David L. Goodin	Doran N. Schwartz	David C. Barney	Jeffrey S. Thiede	Martin A. Fritz
As of December 31, 2016, has the participant reached age 55 and have 10 years of service?	Yes	No	Yes	No	No
Performance Share Cycle 2014-2016	Fully Earned	Forfeited	Fully Earned	Forfeited	Forfeited
Performance Share Cycle 2015-2017	Prorated	Forfeited	Prorated	Forfeited	Forfeited
Performance Share Cycle 2016-2018	Forfeited	Forfeited	Forfeited	Forfeited	Forfeited

For purposes of calculating the performance share value, the number of vesting shares was multiplied by the closing stock price for the last market day of the year, which was December 30, 2016. Dividend equivalents based on the number of vesting shares are also included in the amounts presented.

Benefits and Perquisites

Basic SISP benefits presented in the table represent the present value of vested Basic SISP as of December 31, 2016 commencing at age 65 and payable for 15 years. Only Messrs. Goodin, Schwartz, and Barney are eligible for Basic SISP benefits. Present value was determined using a 3.54% discount rate. The terms of the Basic SISP benefit are described following the Pension Benefits for 2016 table. In the event of death, Messrs. Goodin, Schwartz, and Barney's beneficiaries would receive monthly death benefit payments for 15 years.

The monthly SISP retirement and death benefits used in the present value calculations were:

	Monthly SISP Retirement Payment ($)	Monthly SISP Death Payment ($)
David L. Goodin	23,040	46,080
Doran N. Schwartz	8,744	21,872
David C. Barney	9,125	21,872

The Basic SISP amounts under a disability scenario as shown for Messrs. Schwartz and Barney reflect credit for an additional year of vesting of their 2014 SISP upgrades which would result in full vesting of the upgrade.

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 amounts in the 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 Schwartz, 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 3.8%. Because Mr. Goodin's retirement benefit is greater than the disability benefit, the amount shown is zero. For Messrs. Barney, Thiede, and Fritz, 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 3.54% which is associated with the SISP plan which is considered a reasonable rate for purposes of the calculation.

Severance

The compensation committee generally considers providing severance benefits on a case-by-case basis. Because severance payments are at the discretion of the compensation committee, no amounts are presented in the tables with the exception of Mr. Fritz. Mr. Fritz's offer letter provided for a lump sum payment if his employment terminates during the two years after his date of hire as a result of: (1) a change of control of the company; (2) the company divests WBI Holdings, Inc. or a significant portion of its assets; (3) a material diminution of his authority or job duties and/or a change to whom he reports; or (4) a reduction in his base salary other than a reduction in base salary imposed on all senior officers.

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:						
Annual Incentive	—	—	—	—	755,000	755,000
Performance Shares	2,498,923	2,498,923	2,498,923	2,498,923	6,142,835	6,142,835
Benefits and Perquisites:						
Basic SISP	2,283,801	2,283,801	—	2,283,801	2,283,801	—
SISP Death Benefits	—	—	6,447,100	—	—	—
Disability Benefits	—	—	—	—	—	—
Total	**4,782,724**	**4,782,724**	**8,946,023**	**4,782,724**	**9,181,636**	**6,897,835**
Doran N. Schwartz						
Compensation:						
Annual Incentive	—	—	—	—	—	—
Performance Shares	—	—	—	—	1,300,761	1,300,761
Benefits and Perquisites:						
Basic SISP	659,072	659,072	—	824,254	659,072	—
SISP Death Benefits	—	—	3,060,134	—	—	—
Disability Benefits	—	—	—	713,381	—	—
Total	**659,072**	**659,072**	**3,060,134**	**1,537,635**	**1,959,833**	**1,300,761**
David C. Barney						
Compensation:						
Annual Incentive	—	—	—	—	305,100	305,100
Performance Shares	468,381	468,381	468,381	468,381	1,145,462	1,145,462
Benefits and Perquisites:						
Basic SISP	1,141,490	1,141,490	—	1,368,036	1,141,490	—
SISP Death Benefits	—	—	3,060,134	—	—	—
Disability Benefits	—	—	—	275,389	—	—
Total	**1,609,871**	**1,609,871**	**3,528,515**	**2,111,806**	**2,592,052**	**1,450,562**
Jeffrey S. Thiede						
Compensation:						
Annual Incentive	—	—	—	—	318,750	318,750
Performance Shares	—	—	—	—	1,209,696	1,209,696
Benefits and Perquisites:						
Disability Benefits	—	—	—	506,165	—	—
Total	**—**	**—**	**—**	**506,165**	**1,528,446**	**1,528,446**
Martin A. Fritz						
Compensation:						
Annual Incentive	—	—	—	—	—	—
Performance Shares	—	—	—	—	1,054,943	1,054,943
Benefits and Perquisites:						
Disability Benefits	—	—	—	600,673	—	—
Severance	—	500,000	—	—	500,000	—
Total	**—**	**500,000**	**—**	**600,673**	**1,554,943**	**1,054,943**

AUDIT MATTERS

ITEM 4: RATIFICATION OF THE APPOINTMENT OF DELOITTE & TOUCHE LLP AS THE COMPANY'S INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM FOR 2017

The audit committee at its February 2017 meeting appointed Deloitte & Touche LLP as our independent registered public accounting firm for fiscal year 2017. 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 2017, 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 2017.

Ratification of the appointment of Deloitte & Touche LLP as our independent registered public accounting firm for 2017 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, 2017, is in the best interests of our company and its stockholders.

The audit committee also oversees the process for, and ultimately approves, the selection of our independent registered public accounting firm's lead engagement partner at the five-year mandatory rotation period. Prior to the mandatory rotation period in 2017, at the audit committee's instruction, Deloitte & Touche LLP selected candidates to be considered for the lead engagement partner role, who were then interviewed by members of our company's senior management. After considering the candidates recommended by Deloitte & Touche LLP, senior management made a recommendation to the audit committee regarding the new engagement partner. After discussing the qualifications of the proposed lead engagement partner with the current lead engagement partner, the audit committee chair interviewed the leading candidate, and the audit committee then considered the appointment and voted as an audit committee on the selection. The change in lead engagement partner after the current five-year rotation period occurred in February 2017.

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 2016 and 2015:

	2016	2015
Audit Fees [a]	$ 2,526,900	$ 2,755,400
Audit-Related Fees [b]	16,710	437,979
Tax Fees [c]	—	36,400
All Other Fees [d]	3,087	47,569
Total Fees [e]	$ 2,546,697	$ 3,277,348
Ratio of Tax and All Other Fees to Audit and Audit-Related Fees	0.1 %	2.6 %

[a] Audit fees for 2016 and 2015 consisted of fees for services rendered for the audit of our annual financial statements, reviews of quarterly financial statements, subsidiary, statutory and regulatory audits, filing a Form S-8 Registration Statement (2016), and discontinued operations for Dakota Prairie Refining, LLC (DPR) (2016).

b Audit-related fees for 2016 and 2015 are associated with accounting research assistance, Intermountain Gas Company public utility review (2016), agreed upon procedures associated report for Knife River Corporation's JTL Group, Inc. (Wyoming) (2015), and due diligence work associated with a potential acquisition (2015).

[c] Tax fees for 2015 include the preparation of federal and state tax returns for DPR. The fees associated with DPR were paid by DPR, but are included in this table because DPR was considered a variable interest entity with respect to MDU Resources Group, Inc. and is consolidated in its financial statements.

[d] All other fees for 2016 are associated with a pollution control project at Big Stone electric generating facility. All other fees for 2015 are associated with a cost segregation study and research on R&D credits, in each case for DPR. The fees associated with DPR were paid by DPR, but are included in this table because DPR was considered a variable interest entity with respect to MDU Resources Group, Inc. and consolidated in its financial statements.

[e] Total fees reported above include out-of-pocket expenses related to the services provided of $350,000 for 2016 and $382,965 for 2015.

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 2016 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 Securities and Exchange Commission.

The policy defines the permitted services in each of the audit, audit-related, tax, and all other services categories, as well as prohibited services. The pre-approval policy requires management to submit annually for approval to the audit committee a service plan describing the scope of work and anticipated cost associated with each category of service. At each regular audit committee meeting, management reports on services performed by Deloitte & Touche LLP and the fees paid or accrued through the end of the quarter preceding the meeting. Management may submit requests for additional permitted services before the next scheduled audit committee meeting to the designated member of the audit committee, Dennis W. Johnson, for approval. The designated member updates the audit committee at the next regularly scheduled meeting regarding any services 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, 2016, 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, 2016, for filing with the Securities and Exchange Commission.

Dennis W. Johnson, Chairman
Mark A. Hellerstein
A. Bart Holaday
John K. Wilson

OTHER MATTERS

ITEM 5. ADVISORY VOTE TO APPROVE AN AMENDMENT TO THE COMPANY'S BYLAWS TO ADOPT AN EXCLUSIVE FORUM FOR INTERNAL CORPORATE CLAIMS

Description of the Amendment

On November 17, 2016, the board approved an amendment (the "Amendment") to the company's bylaws adding a new Section 7.09 which provides that Internal Corporate Claims (as defined in the Amendment) may only be brought in Delaware courts. Stockholder ratification of the Amendment is not required under Delaware law, our bylaws, or otherwise. The board believes, however, that a stockholder vote on this matter is appropriate because of the importance of this issue. For the reasons described below, the board recommends that stockholders vote in favor of the proposal to ratify the Amendment. Broker non-vote shares are not entitled to vote on this item and, therefore, are not counted in the vote. The full text of the Amendment is set forth below and on Exhibit A to this Proxy Statement.

7.09 **Forum Selection.**

(a) **Forum Selection.** Unless the Corporation consents in writing to the selection of an alternative forum, to the fullest extent permitted by law, all Internal Corporate Claims shall be brought solely and exclusively in the Court of Chancery of the State of Delaware (or, if the Court of Chancery of the State of Delaware does not have jurisdiction, another state court located within the State of Delaware or, if no state court located within the State of Delaware has jurisdiction, the United States District Court for the District of Delaware). "Internal Corporate Claims" means claims, including claims in the right of the Corporation, (i) that are based upon a violation of a duty by a current or former director or officer or stockholder in such capacity or (ii) as to which the General Corporation Law of the State of Delaware confers jurisdiction upon the Court of Chancery of the State of Delaware.

(b) **Personal Jurisdiction.** If any action the subject matter of which is within the scope of Section 7.09(a) is filed in a court other than a court located within the State of Delaware (a "Foreign Action") by or in the name of any stockholder (including in the right of the Corporation), such stockholder shall be deemed to have consented to (i) the personal jurisdiction of the state and federal courts located within the State of Delaware in connection with any action brought in any such court to enforce Section 7.09(a) and (ii) having service of process made upon such stockholder in any such action by service upon such stockholder's counsel in the Foreign Action as agent for such stockholder.

Purposes of the Amendment

The Amendment's requirement to bring internal litigation claims in Delaware avoids the waste of corporate assets that would arise from litigation of the same claims in multiple jurisdictions.

Public companies, particularly if involved in merger and acquisition transactions, are often targeted in litigation brought purportedly on behalf of stockholders in multiple jurisdictions with respect to similar, if not identical, corporate claims. The company has historically entered into a number of merger and acquisition transactions to foster growth at its business segments. Although the company has not yet faced internal corporate claims arising from these transactions, a forum selection bylaw would avoid such multi-jurisdiction litigation and the waste of corporate assets and diversion of management time that results from litigating essentially duplicative cases in multiple jurisdictions. By requiring internal corporate claims to be brought in a single jurisdiction, a forum selection bylaw serves the interests of stockholders in resolving claims efficiently and without the waste of financial and other resources that are better devoted to the company's business.

The Delaware Courts designated by the Amendment can provide the most authoritative and efficient resolution of internal corporate claims.

Because the company, like many public companies, is incorporated in Delaware, the law applicable to any internal corporate claims would be the Delaware General Corporation Law. By requiring corporate claims to be brought in Delaware courts, a forum selection bylaw avoids the risk that Delaware General Corporation Law will be misapplied by a court in another jurisdiction, a risk that would be compounded if internal corporate claims were pending in multiple jurisdictions outside Delaware which could reach inconsistent interpretations. Additionally, Delaware offers a system of specialized chancery courts to deal with corporate law questions, with streamlined procedures and processes that help provide relatively quick decisions. This serves the interests of all stockholders in limiting the time, cost, and uncertainty of protracted litigation.

Approval of the Amendment at this time will discourage potentially harmful litigation practices in the future.

The board believes it is in the best interests of the company's stockholders to approve the amendment at this time. Following a series of Delaware court decisions upholding similar corporate provisions, the Delaware legislature in June 2015 enacted a law explicitly authorizing Delaware corporations to adopt bylaw provisions designating Delaware courts as the exclusive forum for resolving internal corporate claims. By adopting the forum selection bylaw at this time as authorized by the Delaware courts and the 2015 legislation, and subject to an advisory vote of the stockholders at the 2017 annual meeting, the company can discourage future litigation that is brought in a particular jurisdiction on the basis of tactical maneuvering rather than efficiency and predictable and authoritative outcomes.

For the foregoing reasons, the board of directors believes the Amendment is in the best interests of the company and its stockholders and recommends that stockholders vote in favor of the proposal to ratify the Amendment.

The board of directors recommends a vote "for" the advisory vote to approve an amendment to the company's bylaws to adopt an exclusive forum for internal corporate claims.

If ratification of the bylaws is not approved by a majority of the shares of common stock represented at the annual meeting and entitled to vote on this item, the board intends to rescind the Amendment. Abstentions will count as votes against the Amendment.

INFORMATION ABOUT THE ANNUAL MEETING

Who can Vote?

Stockholders of record at the close of business on March 10, 2017, 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 10, 2017, we had 195,304,376 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 Securities and Exchange Commission'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 24, 2017, we mailed a Notice Regarding the Availability of Proxy Materials (Notice) that contains basic information about our 2017 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 30, 2017.

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 2017 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 www.proxypush.com/mdu and follow the instructions on the website.

By Telephone: Call 877-536-3553 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. CDT on May 8, 2017.

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. (See "Notice of Annual Meeting" and "Annual Meeting Admission.")

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 in the MDU Resources Group, Inc. 401(k) Plan for voting instructions for shares held under our 401(k) plans.

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.

A majority of votes cast is required to elect a director in an uncontested election. A majority of votes cast means the number of votes cast "for" a director's election must exceed the number of votes cast "against" the director's election. "Abstentions" and "broker non-votes" do not count as votes cast "for" or "against" the director's election. In a contested election, which is an election in which the number of nominees for director exceeds the number of directors to be elected, directors will be elected by a plurality of the votes cast.

Approval of each of the other matters on the agenda, other than Item 2, requires the affirmative vote of a majority of the shares of common stock present or represented by proxy during the meeting. For each of these proposals, abstentions have the same effect as "against" votes. For Item 2, the frequency that receives the most votes will be the frequency deemed recommended by our stockholders. Abstentions have no effect on Item 2. 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 2017. Abstentions and broker non-votes are counted for purposes of determining whether a quorum is present at the annual meeting.

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 Frequency of the Vote to Approve the Compensation Paid to the Company's Named Executive Officers	One year, two years, three years, or abstain	The frequency that receives the most votes will be deemed the frequency recommended by our stockholders	No effect	No effect
3	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
4	Ratification of the Appointment of Deloitte & Touche LLP as the Company's Independent Registered Public Accounting Firm for 2017	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
5	Advisory Vote to Approve an Amendment to the Company's Bylaws to Adopt an Exclusive Forum for Internal Corporate Claims	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

Proxy Solicitation

The board of directors is furnishing proxy materials to solicit proxies for use at the Annual Meeting of Stockholders on May 9, 2017 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 $8,000 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 at www.proxypush.com/mdu, simply follow the prompts for enrolling in the electronic proxy delivery service. You may enroll in the electronic proxy delivery service at any time in the future by going directly to www.shareowneronline.com or by calling Wells Fargo Stockholder Services at 877-536-3553 to request electronic delivery. You may also 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. Please 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.

Annual Meeting Admission

All stockholders as of the record date of March 10, 2017, are cordially invited and urged to attend the meeting in person. Registered stockholders who receive a full set of proxy materials will receive a request for admission ticket(s) with their proxy card that can be completed and returned to us postage-free. Registered stockholders who receive a Notice and stockholders whose shares are held in the name of a bank or broker will not receive a request for admission ticket(s). They should instead: (1) call (701) 530-1000 to request an admission ticket(s), (2) if shares are held in the name of a bank or broker, obtain a statement from their bank or broker showing proof of stock ownership as of March 10, 2017, and (3) present their admission tickets(s), the stock ownership statement, and photo identification, such as a driver's license, at the annual meeting.

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 2018 Annual Meeting	**Stockholder Proposals for Inclusion in Next Year's Proxy Statement.** To be included in the proxy materials for our 2018 annual meeting, a stockholder proposal must be received by the corporate secretary no later than November 24, 2017, and must comply with all applicable requirements of Rule 14a-18 under the Securities and Exchange Act of 1934. **Director Nominations and Other Stockholder Proposals Raised From the Floor at the 2018 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 at least 90 days prior to the anniversary of the most recent annual meeting. Notice of director nominations or stockholder proposals for our 2018 annual meeting must be received by February 9, 2018, 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 http://www.mdu.com/integrity/governance/guidelines-and-bylaws.

We will make available to our stockholders to whom we furnish this Proxy Statement a copy of our Annual Report on Form 10-K, excluding exhibits, for the year ended December 31, 2016, which is required to be filed with the Securities and Exchange Commission. You may obtain a copy, without charge, upon written or oral request to the Office of the Treasurer of MDU Resources Group, Inc., 1200 West Century Avenue, Mailing Address: P.O. Box 5650, Bismarck, ND 58506-5650, Telephone Number: (701) 530-1000. You may also access our Annual Report on Form 10-K through our website at www.mdu.com.

By order of the Board of Directors,

Daniel S. Kuntz
Secretary
March 24, 2017

EXHIBIT A

AMENDMENT TO THE BYLAWS
OF
MDU RESOURCES GROUP, INC.

7.09 **Forum Selection.**

(a) **Forum Selection.** Unless the Corporation consents in writing to the selection of an alternative forum, to the fullest extent permitted by law, all Internal Corporate Claims shall be brought solely and exclusively in the Court of Chancery of the State of Delaware (or, if the Court of Chancery of the State of Delaware does not have jurisdiction, another state court located within the State of Delaware or, if no state court located within the State of Delaware has jurisdiction, the United States District Court for the District of Delaware). "Internal Corporate Claims" means claims, including claims in the right of the Corporation, (i) that are based upon a violation of a duty by a current or former director or officer or stockholder in such capacity or (ii) as to which the General Corporation Law of the State of Delaware confers jurisdiction upon the Court of Chancery of the State of Delaware.

(b) **Personal Jurisdiction.** If any action the subject matter of which is within the scope of Section 7.09(a) is filed in a court other than a court located within the State of Delaware (a "Foreign Action") by or in the name of any stockholder (including in the right of the Corporation), such stockholder shall be deemed to have consented to (i) the personal jurisdiction of the state and federal courts located within the State of Delaware in connection with any action brought in any such court to enforce Section 7.09(a) and (ii) having service of process made upon such stockholder in any such action by service upon such stockholder's counsel in the Foreign Action as agent for such stockholder.

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 2016 was 1,095,215 shares.

Common Stock Prices

	High	Low	Close
2016			
First Quarter	$19.55	$15.57	$19.46
Second Quarter	24.01	18.70	24.00
Third Quarter	25.79	22.47	25.44
Fourth Quarter	29.92	24.49	28.77
2015			
First Quarter	$24.51	$20.01	$21.34
Second Quarter	23.12	19.22	19.53
Third Quarter	19.73	16.15	17.20
Fourth Quarter	19.66	16.26	18.32

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 Wells Fargo Shareowner Services, transfer agent and registrar for MDU Resources. For more information, contact Shareowner Services at 877-536-3553 or visit www.shareowneronline.com.

2017 Key Dividend Dates

	Ex-Dividend Date	Record Date	Payment Date
First Quarter	March 7	March 9	April 1
Second Quarter	June 6	June 8	July 1
Third Quarter	September 12	September 14	October 1
Fourth Quarter	December 12	December 14	January 1, 2018

Key dividend dates are subject to the discretion of the Board of Directors.

Annual Meeting

11 a.m. CDT May 9, 2017
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

Doran N. Schwartz
Telephone: 701-530-1750
Email: Doran.Schwartz@mduresources.com

Transfer Agent and Registrar for All Classes of Stock

Wells Fargo Bank, N.A.
Stock Transfer Department
P.O. Box 64874
St. Paul, MN 55164-0874
Telephone: 651-450-4064
Toll-Free Telephone: 877-536-3553
www.shareowneronline.com

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.

Design: MDU Resources
Printing: AFPI

FSC
www.fsc.org
MIX
Paper from responsible sources
FSC® C015410

The paper used in this annual report is certified by the Forest Stewardship Council® and contains a minimum of 10 percent post-consumer recycled paper fibers.

2016

Building a Strong America®

Street Address

1200 W. Century Ave.
Bismarck, ND 58503

Mailing Address

P.O. Box 5650
Bismarck, ND 58506-5650

701-530-1000
866-760-4852

Trading Symbol: MDU
www.mdu.com

MDU LISTED NYSE

MDU RESOURCES GROUP, INC.