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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. 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 confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
MDU Resources Group, Inc.	**End of** 2013/Q4

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent MDU Resources Group, Inc.	02 Year/Period of Report End of 2013/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 400 North Fourth Street, Bismarck, ND 58506-5650	
05 Name of Contact Person Nathan Ring	06 Title of Contact Person VP, Controller and CAO
07 Address of Contact Person *(Street, City, State, Zip Code)* 1200 West Century Ave, Bismarck, ND 58506-5650	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
701-530-1035	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Nathan Ring		
02 Title VP, Controller and CAO	Nathan Ring	3-26-2014

Title 18, U.S.C. 1001 makes it a crime for any person to 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
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

LIST OF SCHEDULES (Electric Utility)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

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LIST OF SCHEDULES (Electric Utility) (continued)

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

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

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.

Nathan Ring - Vice President, Controller and Chief Accounting Officer
400 North Fourth Street
Bismarck, North Dakota 58501-4092

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.

Delaware - March 14, 1924

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.

None

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

Electric Service - Montana, North Dakota, South Dakota, and Wyoming
Natural Gas Service - Minnesota, Montana, North Dakota, South Dakota, and Wyoming
Propane Service - North Dakota
Nonutility Operations - Minnesota, Montana, North Dakota, South Dakota, and Wyoming
Gas Transmission - Minnesota and North Dakota

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

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.

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Centennial Energy Holdings, Inc. (1)	Holding Company	100	
2	MDU Energy Capital, LLC (1)	Holding Company	100	
3	Prairie Cascade Energy Holdings, LLC - Z	Holding Company	100	
4	Cascade Natural Gas Corporation - AH	Gas Utility Company	100	
5	CGC Resources, Inc. - AD	General Purposes	100	
6	Prairie Intermountain Energy Holdings, LLC - Z	Holding Company	100	
7	Intermountain Gas Company - U	Gas Utility Company	100	
8	Knife River Corporation - A	Construction Materials&Mining	100	
9	KRC Holdings, Inc. - B	Holding Company	100	
10	Alaska Basic Industries, Inc. - C	Construction Materials	100	
11	Ames Sand & Gravel, Inc. - T	Construction Materials	100	
12	Anchorage Sand and Gravel Company, Inc. - H	Construction Materials	100	
13	Baldwin Contracting Company, Inc. - C	Construction Materials	100	
14	Central Oregon Redi-Mix, LLC - O	Construction Materials	78	
15	Concrete, Inc. - C	Construction Materials	100	
16	Connolly-Pacific Co. - C	Construction Materials	100	
17	D S S Company - C	Construction Materials	100	
18	Fairbanks Materials, Inc. - H	Construction Materials	100	
19	Granite City Ready Mix, Inc. - C	Construction Materials	100	
20	Hawaiian Cement - I	Construction Materials	100	
21	JTL Group, Inc. - Montana - C	Construction Materials	100	
22	JTL Group, Inc. - Wyoming - C	Construction Materials	100	
23	Jebro Incorporated - C	Construction Materials	100	
24	Kent's Oil Service - C	Construction Materials	100	
25	Knife River Corporation - North Central - C	Construction Materials	100	
26	Knife River Corporation - Northwest - C	Construction Materials	100	
27	Knife River Corporation - South - C	Construction Materials	100	

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Knife River Dakota, Inc. - C	Construction Materials	100	
2	Knife River Equipment, Inc. - Y	Construction Materials	100	
3	Knife River Hawaii, Inc. - C	Construction Materials	100	
4	Knife River Marine, Inc. - C	Construction Materials	100	
5	Knife River Midwest, LLC - C	Construction Materials	100	
6	LTM, Incorporated - C	Construction Materials	100	
7	Northstar Materials, Inc. - C	Construction Materials	100	
8	WHC, Ltd. - C	Construction Materials	100	
9	MDU Construction Services Group, Inc. - A	Holding Company	100	
10	MDU United Construction Solutions, Inc. - F	Holding Company	100	
11	BEH Electric Holdings, LLC - F	Holding Company	100	
12	Bell Electrical Contractors, Inc. - F	Construction Services	100	
13	BMH Mechanical Holdings, LLC - F	Holding Company	100	
14	Bombard Electric, LLC - AG	Construction Services	100	
15	Bombard Mechanical, LLC - AI	Construction Services	100	
16	Capital Electric Construction Company, Inc.-F	Construction Services	100	
17	Capital Electric Line Builders, Inc. - F	Construction Services	100	
18	Continental Line Builders, Inc. - F	Construction Services	100	
19	Coordinating and Planning Services, Inc. - F	Construction Services	100	
20	Desert Fire Holdings, Inc. - F	Holding Company	100	
21	Desert Fire Protection, LLC - AN	Holding Company	100	
22	Desert Fire Protection, a Nevada	Construction Services	100	
23	Limited Partnership - AO			
24	Desert Fire Protection, Inc. - AN	Construction Services	100	
25	E.S.I., Inc. - P	Construction Services	100	
26	Frebco, Inc. - AM	Construction Services	100	
27	Hamlin Electric Company - Q	Construction Services	100	

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1	Harp Engineering, Inc. - F	Engineering Services	100	
2	Independent Fire Fabricators, LLC - AN	Construction Services	100	
3	International Line Builders, Inc. - F	Construction Services	100	
4	ILB Hawaii, Inc. - G	Construction Services	100	
5	LME&U Holdings, LLC - F	Holding Company	100	
6	Lone Mountain Excavation & Utilities, LLC - AF	Construction Services	100	
7	Loy Clark Pipeline Co. - F	Construction Services	100	
8	MDU Industrial Services, Inc. - F	Holding Company	100	
9	Midland Technical Crafts, Inc. - AM	Construction Services	100	
10	Oregon Electric Construction, Inc. - F	Construction Services	100	
11	Pouk & Steinle, Inc. - F	Construction Services	100	
12	Rocky Mountain Contractors, Inc. - F	Construction Services	100	
13	USI Industrial Services, Inc. - AM	Construction Services	100	
14	Wagner Group, Inc., The - F	Holding Company	100	
15	Wagner Industrial Electric, Inc. - AM	Holding Company	100	
16	Wagner-Smith Company, The - P	Construction Services	100	
17	Wagner-Smith Equipment Co. - F	Construction Services	100	
18	Wagner-Smith Pumps & Systems, Inc. - P	Construction Services	100	
19	Warner Enterprises, Inc. - F	Construction Services	100	
20	WBI Holdings, Inc. - A	Holding Company	100	
21	Fidelity Exploration & Production Company - E	Oil & Natural Gas Production	100	
22	Fidelity Oil Co. - K	Oil & Natural Gas Production	100	
23	Netricity LLC - Y	Electrition Generation	75	
24	WBI Energy, Inc. (f/k/a WBI Pipeline & Storage	Holding Company	100	
25	Group, Inc.) - E			
26	WBI Energy Transmission, Inc. (f/k/a Williston	Natural Gas Transmission	100	
27	Basin Interstate Pipeline Company) - L			

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	WBI Canadian Pipeline, Ltd. - L	Natural Gas Trans & Storage	100	
2	WBI Energy Midstream, LLC (f/k/a Bitter Creek	Natural Gas Gathering	100	
3	Pipelines, LLC) - L			
4	WBI Energy Midstream Utah, LLC - L	Natural Gas Gathering	100	
5	WBI Energy Services, Inc. - E	Holding Company	100	
6	Prairielands Energy Marketing, Inc. - J	Energy Marketing	100	
7	Prairielands Magnetics Limited (f/k/a	Pipeline and Cable Mag/Locate	100	
8	Innovatum International Limited) - Y			
9	Centennial Holdings Capital LLC - A	Holding Company	100	
10	FutureSource Capital Corp. - R	Asset Management	100	
11	Nevada Solar Solutions, LLC - AL	Alternative Energy	100	
12	InterSource Insurance Company - R	Captive Insurance Company	100	
13	Centennial Energy Resources LLC - A	Holding Company	100	
14	Centennial Energy Resources	Holding Company	100	
15	International, Inc. - D			
16	MDU Resources International LLC - W	Holding Company	100	
17	MDU Resources Luxembourg I LLC S.a.r.l. - W	Holding Company	100	
18	MDU Resources Luxembourg II LLC S.a.r.l. - AC	Holding Company	100	
19	MDU Brasil Ltda. - X	Holding Company	100	
20	(1)-Direct subsidiary of MDU Resources			
21	Group, Inc.			
22	A-100% held by Centennial Energy Holdings, Inc			
23	B-100% held by Knife River Corporation			
24	C-100% held by KRC Holdings, Inc.			
25	D-100% held by Centennial Energy Resources LLC			
26	E-100% held by WBI Holdings, Inc.			
27				

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	F-100% held by MDU Construction Services			
2	Group, Inc.			
3	G-100% held by International Line Builders,			
4	Inc.			
5	H-100% held by Alaska Basic Industries, Inc.			
6	I-Partners include Knife River Hawaii, Inc.			
7	(50%) and Knife River Dakota, Inc. (50%)			
8	J-100% held by WBI Energy Services, Inc.			
9	K-100% held by Fidelity Exploration &			
10	Production Company			
11	L-100% held by WBI Energy, Inc.			
12	M-Reserved for future use			
13	N-Reserved for future use			
14	O-78% held by Knife River Corporation -			
15	Northwest			
16	P-100% held by The Wagner Group, Inc.			
17	Q-100% held by Rocky Mountain			
18	Contractors, Inc.			
19	R-100% held by Centennial Holdings			
20	Capital LLC			
21	S-Reserved for future use			
22	T-100% held by Knife River Corporation -			
23	North Central			
24	U-100% held by Prairie Intermountain			
25	Energy Holdings, LLC			
26	V-Equity interest held by Fidelity Exploration			
27	& Production Company - 75%			

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1	W-100% held by Centennial Energy Resources			
2	International, Inc.			
3	X-99.9999% held by MDU Resources Luxembourg			
4	II LLC S.a.r.l. and .0001% held by			
5	Centennial Energy Resources International,			
6	Inc.			
7	Y-Entity was dissolved through merger with			
8	affiliate or dissolution			
9	Z-100% held by MDU Energy Capital, LLC			
10	AA-Reserved for future use			
11	AB-Reserved for future use			
12	AC-100% held by MDU Resources Luxembourg I			
13	LLC S.a.r.l.			
14	AD-100% held by Cascade Natural			
15	Gas Corporation			
16	AE-100% held by Prairielands Energy Marketing,			
17	Inc.			
18	AF-100% held by LME&U Holdings, LLC			
19	AG-100% held by BEH Electric Holdings, LLC			
20	AH-100% held by Prairie Cascade			
21	Energy Holdings, LLC			
22	AI-100% held by BMH Mechanical Holdings, LLC			
23	AJ-Reserved for future use			
24	AK-Reserved for future use			
25	AL-100% held by FutureSource Capital Corp.			
26	AM-100% held by MDU Industrial Services, Inc.			
27	AN-100% held by Desert Fire Holdings, Inc.			

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	AO-Partners include Desert Fire Protection,			
2	LLC (1%) and Desert Fire Holdings,			
3	Inc. (99%)			
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OFFICERS

1. Report below the name, title and salary 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 principal 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 the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1			
2	President and Chief Executive Officer	David L Goodin	614,846
3			
4	President and Chief Executive Officer of Cascade	K. Frank Morehouse	291,600
5	Natural Gas Corporation, Great Plains Natural Gas		
6	Co., Intermountain Gas Company and Montana-		
7	Dakota Utilities Co.		
8			
9	Vice President - Administration	Cynthia J. Norland	207,629
10			
11	Vice President - Human Resources	Mark Del Vecchio	217,233
12			
13	General Counsel and Secretary	Paul K. Sandness	343,577
14			
15	Vice President, Controller and Chief	Nicole A. Kivisto	229,365
16	Accounting Officer		
17			
18	Vice President and Chief Financial Officer	Doran N. Schwartz	343,096
19			
20	Vice President - Strategic Planning	John P. Stumpf	212,938
21			
22	Vice President - Renewable Resources	William R. Connors	193,501
23			
24	Treasurer and Assistant Secretary	Douglass A. Mahowald	195,183
25			
26	Executive Vice President - Business Development	Dennis L. Haider	137,501
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Schedule Page: 104 Line No.: 15 Column: b

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

Schedule Page: 104 Line No.: 26 Column: b

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

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MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Harry J. Pearce, Chairman of the Board	Detroit, Michigan
2		
3	David L. Goodin , President and Chief Executive Officer	Bismarck, North Dakota
4		
5	Thomas Everist	Sioux Falls, South Dakota
6		
7	Karen B. Fagg	Billings, Montana
8		
9	Mark A. Hellerstein	Denver, Colorado
10		
11	Dennis W. Johnson	Dickinson, North Dakota
12		
13	A. Bart Holaday	Placitas, New Mexico, and Grand Forks, North Dakota
14		
15	Patricia L. Moss	Bend, Oregon
16		
17	J. Kent Wells	Denver, Colorado
18		
19	John K. Wilson	Omaha, Nebraska
20		
21	Thomas C. Knudson	Houston, Texas
22		
23	William E. McCracken	Warren, New Jersey
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FOOTNOTE DATA

Schedule Page: 105   Line No.: 9   Column: a

Mark A. Hellerstein joined the Board of Directors on August 1, 2013.

Schedule Page: 105   Line No.: 23   Column: a

William E. McCracken joined the Board of Directors on August 1, 2013.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? [X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Montana-Dakota Utilities Co.	Electric Rate Filing Establishing OATT
2	MonDak System	
3	FERC Electric Tariff 2nd Revised Volume No. 1	
4		
5	Midwest ISO FERC Electric Tariff	Electric Rate Filing
6	First Revised Volume No. 1	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[ ] Yes
[X] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	19990225-0444	02/24/1999	OA97-704	Open Access Transmission	Schedule 7 and Schedule 8
2					Superceded by MISO
3					Attachment O
4					
5	20020301-0303	02/27/2002	ER-02-1138	Umbrella Service Agreements with	MISO Attachment O
6				Montana-Dakota Utilities Co	
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Schedule Page: 1061 Line No.: 5 Column: e

MISO Attachment O Revisions:

Formula Rate FERC Rate Schedule Number or Tariff Number	Docket Number
Midwest ISO FERC Electric Tariff Original Volume No. 1	ER98-1438
Midwest ISO FERC Electric Tariff First Revised Volume No. 1	ER98-1438
Midwest ISO FERC Electric Tariff Second Revised Volume No. 1	ER04-458
Midwest ISO FERC Electric Tariff Second Revised Volume No. 1	ER04-895
Midwest ISO FERC Electric Tariff Second Revised Volume No. 1	ER05-122
Midwest ISO FERC Electric Tariff Third Revised Volume No. 1	ER05-1085;ER04-458
Midwest ISO FERC Electric Tariff Third Revised Volume No. 1	ER04-691; EL04-104
Midwest ISO FERC Electric Tariff Third Revised Volume No. 1	ER06-159
Midwest ISO FERC Electric Tariff Third Revised Volume No. 1	ER07-113
Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	OA08-4
Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	ER09-15
Midwest ISO FERC Electric Tariff Third Revised Volume No. 1	ER09-91
Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	ER09-91; ER09-571
Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	ER09-1657
Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	ER09-1779
Midwest ISO FERC Electric Tariff Fourth Revised Volume No. 1	ER10-1492
Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1	ER10-1997
Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1	ER11-2700
Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1	ER11-3251
Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1	ER11-3704
Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1	ER12-297
Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1	ER12-310
Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1	ER12-578
Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1	ER12-1667
Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1	ER13-307
Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1	ER13-674
Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1	ER13-751
Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1	ER13-1547
Midwest ISO FERC Electric Tariff Fifth Revised Volume No. 1	ER13-1827

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1	205 & 207	Electric Plant in Service	g	5 & 99
2	207	Electric Plant in Service	g	58
3	207	Electric Plant in Service	g	75
4	219	Accumulated Provision for Depreciation of	c	25
5		Electic Utility Plant		
6	219	Accumulated Provision for Depreciation of	c	26
7		Electic Utility Plant		
8	219	Accumulated Provision for Depreciation of	c	28
9		Electic Utility Plant		
10	234	Accumulated Deferred Income Taxes	c	8
11		(Account 190)		
12	263.1	Taxes Accrued, Prepaid and Charged During Year	i	16
13	263.1	Taxes Accrued, Prepaid and Charged During Year	i	17
14	263.1	Taxes Accrued, Prepaid and Charged During Year	i	2
15	263	Taxes Accrued, Prepaid and Charged During Year	i	22
16	263.1	Taxes Accrued, Prepaid and Charged During Year	i	23
17	275	Accumulated Deferred Income Taxes - Other	k	2
18		Property (Account 282)		
19	277	Accumulated Deferred Income Taxes - Other	k	9
20		(Account 283)		
21	321	Electric Operation and Maintenance Expenses	b	112
22	323	Electric Operation and Maintenance Expenses	b	197
23	336	Depreciation and Amortization of Electric Plan	b	7
24	336	Depreciation and Amortization of Electric Plan	b	10
25	336	Depreciation and Amortization of Electric Plan	b	11
26	356	Common Utility Plant and Expenses		
27				
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Schedule Page: 1062 Line No.: 1 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 2 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 3 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 4 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 6 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 8 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 10 Column: a
Include electric portion of FAS 109

Schedule Page: 1062 Line No.: 12 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 13 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 14 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO

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Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 16 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 17 Column: a
Include electric portion of FAS 109

Schedule Page: 1062 Line No.: 19 Column: a
Include electric portion of FAS 109

Schedule Page: 1062 Line No.: 21 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 22 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO

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Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 24 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 25 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO

Schedule Page: 1062 Line No.: 26 Column: a
Exclude Wyoming jurisdiction not interconnected with MISO

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If 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: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the 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 condition. 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 give reference to 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 as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
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 reported on Page 104 or 105 of the Annual Report Form No. 1, 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. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. 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.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1. The Respondent renewed franchises in 2013 in the following North Dakota cities: Scranton, Golva, Linton, Bowman, Dickinson, Beach and Watford City. The Respondent also renewed franchises in 2013 in Danube, Minnesota and Ismay, Montana.

2. None.

3. None.

4. None.

5. None.

6. The company's short-term indebtedness was $153,924,000 at December 31, 2013. This debt included commercial paper borrowings of $78,924,000 and a funded bank line of $75,000,000. The issuance of commercial paper and other short-term debt is authorized pursuant to the following orders:

On September 12, 2013 the Respondent received a FERC Order and an Errata Notice dated October 8, 2013 authorizing the Respondent to incur short-term indebtedness in an amount not to exceed $250 million. This authorization was granted in Docket No. ES13-38-000.

On August 21, 2013 the Respondent received the same type of authorization from the state of Montana. This order authorized the Respondent to issue up to $250 million in short-term indebtedness. This authorization was granted in Docket No. D2013.7.58, Default order No.7301.

7. None.

8. Wage increases to nonunion employees averaged 4.07% in 2013. Wage increases to union employees averaged 2.48% effective May 1, 2013. The estimated annualized impact of the increases amounted to approximately $2,701,000.

9. See Note 14 in Notes To Financial Statements beginning on page 122.

10. None.

11. None.

12. None.

13. Nicole A. Kivisto, Vice President, Controller and Chief Accounting Officer of MDU Resources Group, Inc. (the “Company”), has been appointed Vice President of Operations for Montana-Dakota Utilities Co., a public utility division of the Company, effective January 3, 2014. As a result of this appointment, Ms. Kivisto will resign as Vice President, Controller and Chief Accounting Officer of the Company on that date. Ms. Kivisto indicated that she would accept her new position on November 15, 2013.

On December 3, 2013, MDU Resources Group, Inc. (the “Company”) announced that Nathan W. Ring will become Vice President, Controller and Chief Accounting Officer, effective January 3, 2014. Mr. Ring will replace Nicole A. Kivisto.

On January 21, 2014, Thomas C. Knudson notified MDU Resources Group, Inc. (the “Company”) that he does not intend to seek re-election to the Board of Directors (the “Board”) at the Company’s 2014 Annual Meeting of Stockholders. Mr. Knudson has served with distinction on the Board since 2008 and is a member of the Compensation Committee.

14. Not applicable.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	1,618,679,070	1,481,687,123
3	Construction Work in Progress (107)	200-201	151,552,008	95,503,974
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,770,231,078	1,577,191,097
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	760,970,889	719,531,360
6	Net Utility Plant (Enter Total of line 4 less 5)		1,009,260,189	857,659,737
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		1,009,260,189	857,659,737
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		1,558,796	2,968,462
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		15,629,869	4,584,951
19	(Less) Accum. Prov. for Depr. and Amort. (122)		2,901,889	1,636,553
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	2,380,828,521	2,253,293,721
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		60,687,111	52,122,735
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		0	0
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		2,454,243,612	2,308,364,854
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		4,718,520	3,444,688
36	Special Deposits (132-134)		260,505	255,310
37	Working Fund (135)		332,668	150,850
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		29,796,719	24,120,553
41	Other Accounts Receivable (143)		4,403,590	20,937,588
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		443,629	275,241
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		31,371,687	2,957,114
45	Fuel Stock (151)	227	4,751,688	5,129,837
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	19,097,488	18,983,774
49	Merchandise (155)	227	75,479	451,882
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		5,386,681	16,903,055
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		5,074,231	4,829,235
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		49,648,010	39,447,024
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		154,473,637	137,335,669
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		1,219,120	1,407,362
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	3,698,596	4,959,490
72	Other Regulatory Assets (182.3)	232	83,915,120	115,340,807
73	Prelim. Survey and Investigation Charges (Electric) (183)		336,423	431,776
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		61,412	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		-6,513	-18,477
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	26,225,949	27,076,963
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		7,407,081	8,126,591
82	Accumulated Deferred Income Taxes (190)	234	49,133,806	68,164,363
83	Unrecovered Purchased Gas Costs (191)		8,019,627	2,915,460
84	Total Deferred Debits (lines 69 through 83)		180,010,621	228,404,335
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,799,546,855	3,534,733,057

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	189,868,780	189,369,450
3	Preferred Stock Issued (204)	250-251	15,000,000	15,000,000
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		1,061,253,848	1,043,190,134
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)	254b	4,257,578	4,110,305
11	Retained Earnings (215, 215.1, 216)	118-119	540,130,502	520,210,825
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	1,062,999,041	936,934,577
13	(Less) Reaquired Capital Stock (217)	250-251	3,625,813	3,625,813
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-38,204,576	-48,720,612
16	Total Proprietary Capital (lines 2 through 15)		2,823,164,204	2,648,248,256
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	280,000,000	280,000,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	154,705,972	76,867,452
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		0	0
24	Total Long-Term Debt (lines 18 through 23)		434,705,972	356,867,452
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)		1,355,445	1,064,262
29	Accumulated Provision for Pensions and Benefits (228.3)		51,449,261	59,754,547
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		191,185	4,364,636
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)		7,142,915	6,789,483
35	Total Other Noncurrent Liabilities (lines 26 through 34)		60,138,806	71,972,928
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		44,138,862	41,180,110
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		4,839,083	6,422,842
41	Customer Deposits (235)		1,428,796	1,593,246
42	Taxes Accrued (236)	262-263	12,336,506	12,398,861
43	Interest Accrued (237)		4,973,368	4,926,930
44	Dividends Declared (238)		33,737,408	170,817
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	end of 2013/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		1,143,473	968,815
48	Miscellaneous Current and Accrued Liabilities (242)		29,444,730	22,283,490
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		132,042,226	89,945,111
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		18,726,550	13,769,060
57	Accumulated Deferred Investment Tax Credits (255)	266-267	767,331	813,836
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	62,138,894	106,324,544
60	Other Regulatory Liabilities (254)	278	16,286,380	9,543,392
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		214,082,765	189,991,813
64	Accum. Deferred Income Taxes-Other (283)		37,493,727	47,256,665
65	Total Deferred Credits (lines 56 through 64)		349,495,647	367,699,310
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,799,546,855	3,534,733,057

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
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 column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. 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.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	537,576,406	459,784,750		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	382,247,971	313,072,463		
5	Maintenance Expenses (402)	320-323	25,406,376	22,478,074		
6	Depreciation Expense (403)	336-337	42,314,537	39,549,976		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	2,737,335	1,037,766		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	231,063	231,061		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		1,211,546	3,267,152		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)					
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	17,934,787	17,955,005		
15	Income Taxes - Federal (409.1)	262-263	-10,458,570	-15,341,917		
16	- Other (409.1)	262-263	-454,446	-2,276,998		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	187,255,016	70,057,494		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	162,112,789	39,478,324		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		486,312,826	410,551,752		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		51,263,580	49,232,998		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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 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 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.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
255,395,710	235,516,533	282,180,696	224,268,217			2
						3
139,938,907	124,959,511	242,309,064	188,112,952			4
20,782,627	18,573,149	4,623,749	3,904,925			5
29,894,582	28,182,718	12,419,955	11,367,258			6
						7
1,252,120	647,628	1,485,215	390,138			8
228,244	228,242	2,819	2,819			9
1,211,546	3,267,152					10
						11
						12
						13
10,159,529	10,360,754	7,775,258	7,594,251			14
-8,188,163	-6,494,719	-2,270,407	-8,847,198			15
-223,021	-979,384	-231,425	-1,297,614			16
96,931,979	44,304,872	90,323,037	25,752,622			17
77,327,334	26,575,453	84,785,455	12,902,871			18
						19
						20
						21
						22
						23
						24
214,661,016	196,474,470	271,651,810	214,077,282			25
40,734,694	39,042,063	10,528,886	10,190,935			26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		51,263,580	49,232,998		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		6,363,713	5,449,364		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,793,254	4,396,820		
33	Revenues From Nonutility Operations (417)		3,469,323	4,787,658		
34	(Less) Expenses of Nonutility Operations (417.1)		2,122,588	2,833,454		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119	230,807,415	-42,791,235		
37	Interest and Dividend Income (419)		1,848,997	2,844,361		
38	Allowance for Other Funds Used During Construction (419.1)		3,071,017	3,097,868		
39	Miscellaneous Nonoperating Income (421)		211,336	33,208		
40	Gain on Disposition of Property (421.1)			210,236		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		241,855,959	-33,598,814		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		397,805	382,297		
46	Life Insurance (426.2)		-3,086,000	-278,041		
47	Penalties (426.3)		10,463	6,236		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		119,927	57,785		
49	Other Deductions (426.5)		4,557	25,644		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		-2,553,248	193,921		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	3,919	3,653		
53	Income Taxes-Federal (409.2)	262-263	-1,598,864	-376,409		
54	Income Taxes-Other (409.2)	262-263	-235,475	-198,872		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,698,920	713,997		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	468,043	1,187,102		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		46,505	57,381		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-646,048	-1,102,114		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		245,055,255	-32,690,621		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		18,140,295	17,867,333		
63	Amort. of Debt Disc. and Expense (428)		189,843	123,332		
64	Amortization of Loss on Reaquired Debt (428.1)		719,510	719,510		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		273,566	302,073		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,936,973	1,715,437		
70	Net Interest Charges (Total of lines 62 thru 69)		17,386,241	17,296,811		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		278,932,594	-754,434		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		278,932,594	-754,434		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. 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)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. 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.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		520,210,825	505,281,931
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Dividend equivalents on stock based compensation		-591,531	(40,268)
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-591,531	(40,268)
16	Balance Transferred from Income (Account 433 less Account 418.1)		48,125,179	42,036,801
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24	4.50%		-450,003	(450,003)
25	4.70%		-235,000	(235,000)
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-685,003	(685,003)
30	Dividends Declared-Common Stock (Account 438)			
31			-131,285,968	(127,460,636)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-131,285,968	(127,460,636)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		104,357,000	101,078,000
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		540,130,502	520,210,825
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. 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)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. 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.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		540,130,502	520,210,825
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		936,934,577	1,080,840,155
50	Equity in Earnings for Year (Credit) (Account 418.1)		230,807,415	(42,791,235)
51	(Less) Dividends Received (Debit)		104,357,000	101,078,000
52			-385,951	(36,343)
53	Balance-End of Year (Total lines 49 thru 52)		1,062,999,041	936,934,577

Schedule Page: 118 Line No.: 52 Column: c

Dividend equivalents on stock based compensation - CEHI	($315,930)
Dividend equivalents on stock based compensation - MDU EC	($ 70,021)

Schedule Page: 118 Line No.: 52 Column: d

Dividend equivalents on stock based compensation - CEHI	($ 15,242)
Dividend equivalents on stock based compensation - MDU EC	($ 21,101)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) 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 Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	278,932,594	-754,434
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	46,494,481	44,085,955
5	Amortization of		
6	Loss on Reaquired Debt, Bond Discount and Debt Exp	907,752	359,112
7			
8	Deferred Income Taxes (Net)	26,373,104	30,106,065
9	Investment Tax Credit Adjustment (Net)	-46,505	-57,381
10	Net (Increase) Decrease in Receivables	-34,739,156	27,095,103
11	Net (Increase) Decrease in Inventory	12,157,212	1,127,458
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	10,683,423	-6,116,385
14	Net (Increase) Decrease in Other Regulatory Assets	415,753	8,529,038
15	Net Increase (Decrease) in Other Regulatory Liabilities	585,554	-316,175
16	(Less) Allowance for Other Funds Used During Construction	3,071,017	3,097,868
17	(Less) Undistributed Earnings from Subsidiary Companies	126,450,415	-143,869,235
18	Other (provide details in footnote):		
19	Unrecovered Purchased Gas Costs	-5,104,167	-293,197
20	Net Change in Other Current & Accrued Assets	-10,451,177	-7,775,549
21	Other Noncurrent Changes	10,593,863	-9,561,512
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	207,281,299	227,199,465
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-207,441,433	-142,641,971
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant	-11,460,903	-16,753,764
29	Gross Additions to Nonutility Plant	-172,830	-247,878
30	(Less) Allowance for Other Funds Used During Construction	-3,071,017	-3,097,868
31	Other (provide details in footnote):		
32	Gas in Underground Storage - Noncurrent	1,409,666	583,451
33	Customer Advances for Construction	4,957,490	5,328,566
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-209,636,993	-150,633,728
35			
36	Acquisition of Other Noncurrent Assets (d)	612,311	11,802
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-1,016,076	-1,387,573
40	Contributions and Advances from Assoc. and Subsidiary Companies	10,000,000	5,000,000
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2013	Year/Period of Report End of 2013/Q4

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 31) 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 Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54	Depreciation of Nonutility Plant	226,482	184,926
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-199,814,276	-146,824,573
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		
62	Preferred Stock		
63	Common Stock	14,554,486	87,945
64	Other (provide details in footnote):	77,924,000	76,000,000
65	Tax Benefit on Stock Based Compensation		22,423
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	92,478,486	76,110,368
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-85,480	-21,401
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock	-685,003	-685,003
81	Dividends on Common Stock	-97,719,376	-159,083,992
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-6,011,373	-83,680,028
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	1,455,650	-3,305,136
87			
88	Cash and Cash Equivalents at Beginning of Period	3,595,538	6,900,674
89			
90	Cash and Cash Equivalents at End of period	5,051,188	3,595,538

FOOTNOTE DATA

Schedule Page: 120 Line No.: 64 Column: b

Proceeds from issuance of Term Loan	$75,000,000
Proceeds from issuance of Commercial Paper	$ 2,924,000

Schedule Page: 120 Line No.: 64 Column: c

Proceeds from issuance of Commercial Paper	$76,000,000

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. 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.
8. 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.
9. 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.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

Definitions

The following abbreviations and acronyms used in the Notes are defined below:

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
ASC	FASB Accounting Standards Codification
BART	Best available retrofit technology
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Company	MDU Resources Group, Inc.
Coyote Station	427-MW coal fired electric generating facility near Beulah, North Dakota (25 percent ownership)
EBITDA	Earnings before interest, taxes, depreciation and amortization
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
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
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
K-Plan	Company’s 401(k) Retirement Plan
MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of the Company
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
SDPUC	South Dakota Public Utilities Commission
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
WYPSC	Wyoming Public Service Commission

Notes to Financial Statements

Note 1 - Summary of Significant Accounting Policies
Basis of presentation
The Company is a diversified natural resource company, which was incorporated under the laws of the state of Delaware in 1924. Montana-Dakota and Great Plains are public utility divisions of the Company.

Montana-Dakota generates, transmits, and distributes electricity and distributes natural gas in Montana, North Dakota, South Dakota, and Wyoming. Great Plains distributes natural gas in western Minnesota and southeastern North Dakota. These operations also supply related value-added services. The Company provides service to more than 134,000 electric and 280,000 natural gas residential, commercial, industrial and municipal customers in 277 communities and adjacent rural areas as of December 31, 2013.

Montana-Dakota is subject to regulation by the FERC, NDPSC, MTPSC, SDPUC, and WYPSC. Great Plains is subject to regulation by the MNPUC and the NDPSC.

The Company owns two wholly owned subsidiaries, Centennial and MDU Energy Capital, as well as ownership interests in the assets, liabilities and expenses of jointly owned electric generating facilities.

The financial statements were prepared in accordance with the accounting requirements of the FERC set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than GAAP. These requirements differ from GAAP related to the presentation of certain items including, but not limited to, the current portion of long-term debt, deferred income taxes, cost of removal liabilities, and current unrecovered purchased gas costs. As required by the FERC for Form 1 report purposes, the Company reports its subsidiary investments using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiaries, as required by GAAP. If GAAP were followed, utility plant, other property and investments would increase by $1.6 billion; current and accrued assets would increase by $962.2 million; deferred debits would increase by $720.3 million; long-term debt would increase by $1.4 billion; other noncurrent liabilities and current and accrued liabilities would increase by $592.7 million; deferred credits would increase by $1.2 billion; and capital would increase by $32.7 million as of December 31, 2013. Furthermore, operating revenues would increase by $3.9 billion and operating expenses, excluding income taxes, would increase by $3.5 billion for the twelve months ended December 31, 2013. In addition, net cash provided by operating activities would increase by $534.9 million; net cash used in investing activities would increase by $582.8 million; net cash provided by financing activities would increase by $42.9 million; the effect of exchange rate changes on cash would decrease by $215,000; and the net change in cash and cash equivalents would be a decrease of $5.3 million for the twelve months ended December 31, 2013. Reporting its subsidiary investments using the equity method rather than GAAP has no effect on net income or retained earnings.

The Notes to Financial Statements accompanying this FERC Form No. 1 relate to the nonconsolidated parent company and its two public utility divisions. For information on disclosures of the subsidiary companies, refer to the Company’s Form 10-K.

Montana-Dakota and Great Plains are regulated businesses which 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 3 for more information regarding the nature and amounts of these regulatory deferrals.

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

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

Accounts receivable and allowance for doubtful accounts
Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount. The total balance of receivables past due 90 days or more was $623,000 and $92,000 as of December 31, 2013 and 2012, respectively.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts as of December 31, 2013 and 2012, was $444,000 and $275,000, respectively.

Inventories and natural gas in storage
Inventories, other than natural gas in storage, were stated at the lower of average cost or market value. Natural gas in storage is carried at cost using the last-in, first-out method. The portion of the cost of natural gas in storage expected to be used within one year was included in inventories. Inventories at December 31 consisted of:

	2013	2012
	(In thousands)	
Plant materials and operating supplies	$ 19,097	$ 18,984
Gas stored underground-current	5,387	16,903
Fuel stock	4,752	5,130
Merchandise	75	452
Total	$ 29,311	$ 41,469

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was $1.6 million and $3.0 million at December 31, 2013 and 2012, respectively.

Investments
The Company's investments include its investment in subsidiary companies, the cash surrender value of life insurance policies, an insurance contract, and other miscellaneous investments. The Company measures its investment in the insurance contract at fair value with any unrealized gains and losses recorded on the Statement of Income. The Company has not elected the fair value option for its other investments. For more information, see Notes 4 and 11.

Property, plant and equipment
Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize AFUDC on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. The amount of AFUDC capitalized was $5.0 million and $4.8 million in 2013 and 2012, respectively. 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. These amounts are included in accumulated provision for depreciation, amortization and depletion.

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

	2013	2012	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Electric:			
Generation	**$ 570,394**	$ 546,011	42
Distribution	**308,202**	276,446	39
Transmission	**196,824**	180,543	48
Construction in progress	**141,365**	62,123	-
Other	**94,286**	81,553	14
Natural gas distribution:			
Distribution	**348,167**	308,090	41
Construction in progress	**10,219**	33,389	-
Other	**100,774**	89,036	13
Less accumulated depreciation, depletion and amortization	**760,971**	719,531	
Net utility plant	**$ 1,009,260**	$ 857,660	
Nonutility property	**$ 15,630**	$ 4,585	
Less accumulated depreciation, depletion and amortization	**2,902**	1,637	
Net nonutility property	**$ 12,728**	$ 2,948	

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 significant impairment losses were recorded in 2013 and 2012. Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. Goodwill is required to be tested for impairment annually, which is completed in the fourth quarter, or more frequently if events or changes in circumstances indicate that goodwill may be impaired.

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. 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 the impairment loss, if any. The impairment is computed by comparing the implied fair value of the affected reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2013 and 2012, there were no impairment losses recorded. At December 31, 2013, the fair value of the natural gas distribution reporting unit substantially exceeded its carrying value. 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 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 of approximately 5 percent, and a long-term growth rate projection of approximately 3 percent were utilized in the goodwill impairment test performed in the fourth quarter of 2013. Under the market approach, the Company estimates fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies 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 utility revenues represent revenues recognized in excess of amounts billed. Accrued utility revenues were $49.6 million and $39.4 million at December 31, 2013 and 2012, respectively. The Company recognizes all other revenues when services are rendered or goods are delivered. The Company presents revenues 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 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 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 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 over a 12 month period. Natural gas costs recoverable or refundable, as applicable, through rate adjustments were $8.0 million and $2.9 million at December 31, 2013 and 2012, respectively, which is included in unrecovered purchased gas costs.

Insurance
The Company is insured for workers' compensation losses in guaranteed cost programs. Automobile liability and general liability losses are insured, subject to self insured retentions of $500,000 per accident or occurrence. The Company also has coverage above the self insured retentions on a claims made basis. The Company is retaining losses within its retentions on the basis of estimates of liability for claims incurred but not reported.

Income taxes
The Company and its subsidiaries file consolidated method federal income tax returns and combined and separate state income tax returns. Federal income taxes paid by the Company, as parent of the consolidated group, are allocated to the individual subsidiaries based on the ratio of the separate company computations of tax. The Company 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. Taxes recoverable from customers have been recorded as regulatory assets. Taxes refundable to customers and excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as regulatory liabilities. These regulatory assets and liabilities are expected to be recovered from or refunded to customers in future rates in accordance with applicable regulatory procedures.

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 interest and penalties, respectively.

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 value of acquired assets and liabilities under the acquisition method of accounting; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; 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.

Cash flow information

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

	2013	2012
	(In thousands)	
Interest, net of amount capitalized	**$ 16,152**	$ 15,802
Income taxes refunded, net	**$ (11,453)**	$ (10,137)

Noncash investing transactions at December 31 were as follows:

	2013	2012
	(In thousands)	
Property, plant and equipment additions in accounts payable	**$ 7,075**	$ 14,323

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 loss resulted from postretirement liability adjustments and other comprehensive loss recorded by its subsidiaries.

The postretirement liability adjustment in other comprehensive income was $454,000 and $396,000, net of tax of $(304,000) and $(245,000), for the years ended December 31, 2013 and 2012, respectively.

The after-tax changes in the components of accumulated other comprehensive loss as of December 31, 2013, were as follows:

	Postretirement Liability Adjustment	Subsidiary Other Comprehensive Loss	Total Accumulated Other Comprehensive Loss
		(In thousands)	
Balance at December 31, 2012	$ (4,913)	$ (43,808)	$ (48,721)
Other comprehensive gain before reclassifications	348	12,104	12,452
Amounts reclassified from accumulated other comprehensive loss	106	(2,042)	(1,936)
Net current-period other comprehensive gain	454	10,062	10,516
Balance at December 31, 2013	**$ (4,459)**	**$ (33,746)**	**$ (38,205)**

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

		2013	Location on Statement of Income
		(In thousands)	
Amortization of postretirement liability losses included in net periodic benefit cost	$	**(176)**	(a)
		70	Income taxes
		(106)	
Subsidiary reclassifications out of accumulated other comprehensive loss		**2,042**	Equity in earnings of Subsidiary Companies
Total reclassifications	$	**1,936**	

(a) Included in net periodic benefit cost (credit). For more information, see Note 11.

Note 2 - Goodwill and Other Intangible Assets
The carrying amount of goodwill, which is related to the natural gas distribution business, remained unchanged at $4.8 million for the years ended December 31, 2013 and 2012. This amount is included in miscellaneous deferred debits. No impairments have been recorded in any periods.

Note 3 - Regulatory Assets and Liabilities

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

	Estimated Recovery Period*	2013	2012
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(f)	**$ 67,130**	$ 103,937
Taxes recoverable from customers (a)	Over plant lives	**10,902**	---
Unrecovered purchased gas costs	Up to 12 months	**8,020**	2,915
Unamortized loss on required debt	Up to 13 years	**7,407**	8,127
Costs related to identifying generation development (a) (e)	Up to 13 years	**4,512**	5,773
Plant costs (a)	Up to 3 years	**4,333**	9,194
Other (a) (b) (g)	Largely within 1 year	**6,026**	5,912
Total regulatory assets		**108,330**	135,858
Regulatory liabilities:			
Plant removal and decommissioning costs (c)		**110,790**	106,858
Pension and postretirement benefits (d)		**8,017**	---
Taxes refundable to customers (d)		**7,802**	9,020
Accumulated provision for rate refunds		**191**	4,365
Other (h)		**2,369**	1,058
Total regulatory liabilities		**129,169**	121,301
Net deferred income tax assets (liabilities)**		**6,797**	(6,229)
Net regulatory position		**$ (14,042)**	$ 8,328

* Estimated recovery period for regulatory assets currently being recovered in rates charged to customers.

** Represents deferred income taxes related to regulatory assets and liabilities. The deferred income tax assets are not earning a rate of return.

(a) Included in other regulatory assets on the Comparative Balance Sheet.
(b) Included in prepayments on the Comparative Balance Sheet.
(c) Included in accumulated provision for depreciation, amortization and depletion and asset retirement obligations on the Comparative Balance Sheet.
(d) Included in other regulatory liabilities on the Comparative Balance Sheet.
(e) Included in unrecovered plant and regulatory study costs on the Comparative Balance Sheet.
(f) Recovered as expense is incurred.
(g) Included in miscellaneous deferred debits on the Comparative Balance Sheet.
(h) Included in miscellaneous deferred debits and other regulatory assets on the Comparative Balance Sheet.

The regulatory assets are expected to be recovered in rates charged to customers. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates. Excluding deferred income taxes, as of December 31, 2013 and 2012, approximately $92.8 million and $122.6 million respectively, of regulatory assets were not earning a rate of return.

If, for any reason, the Company's regulated business ceases to meet the criteria for application of regulatory accounting for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income as an extraordinary item in the period in which the discontinuance of regulatory accounting occurs.

Note 4 - Fair Value Measurements

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments, which consist of an insurance contract, to satisfy its obligations under its unfunded, nonqualified benefit plan 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 $41.6 million and $32.6 million as of December 31, 2013 and 2012, respectively, are classified as Other Investments on the Comparative Balance Sheet. The net unrealized gains on these investments for the years ended December 31, 2013 and 2012, were $9.0 million and $3.5 million, respectively. The change in fair value, which is considered part of the cost of the plan, is classified in Other Income and Deductions as Life Insurance on the Statement of Income.

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

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

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

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

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

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2013 and 2012, there were no transfers between Levels 1 and 2.

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

	Fair Value Measurements at December 31, 2013, Using			
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Signficant Unobservable Inputs (Level 3)	Balance at December 31, 2013
	(In thousands)			
Assets:				
Money market funds	$ —	$ 1,110	$ —	$ 1,110
Insurance contract*	—	41,564	—	41,564
Total assets measured at fair value	$ —	$ 42,674	$ —	$ 42,674

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

	Fair Value Measurements at December 31, 2012, Using			
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Signficant Unobservable Inputs (Level 3)	Balance at December 31, 2012
	(In thousands)			
Assets:				
Money market funds	$ —	$ 620	$ —	$ 620
Insurance contract*	—	32,586	—	32,586
Total assets measured at fair value	$ —	$ 33,206	$ —	$ 33,206

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

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

	2013		2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	**$ 434,706**	**$ 469,787**	$ 356,867	$ 411,210

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, including those discussed later, contain restrictive covenants and provisions. In order to borrow under the respective credit agreements, the Company must be in compliance with the applicable covenants and certain other conditions. In the event the Company does 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:

Company	Facility		Facility Limit		Amount Outstanding at December 31, 2013			Amount Outstanding at December 31, 2012			Letters of Credit at December 31, 2013	Expiration Date
					(Dollars in millions)							
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement	(a)	$ 125.0	$	78.9	(b)	$	76.0	(b)	$	—	10/4/17

(a) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $150 million). There were no amounts outstanding under the credit agreement.

(b) Amount outstanding under commercial paper program included in other long-term debt on the Comparative Balance Sheet.

The Company's commercial paper program is supported by a revolving credit agreement. While the amount of commercial paper outstanding does not reduce available capacity under the revolving credit agreement, the Company does not issue commercial paper in an aggregate amount exceeding the available capacity under its credit agreement.

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.

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

		2013		2012
		(In thousands)		
Senior Notes at a weighted average rate of 6.24%, due on dates ranging from September 30, 2016 to December 15, 2033	**$**	**280,000**	$	280,000
Credit agreement and other at a weighted average rate of 2.59%, due on dates ranging from January 1, 2017 to April 15, 2044		**154,706**		76,867
Total long-term debt	**$**	**434,706**	$	356,867

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2013, aggregate $108,000 in 2014; $109,000 in 2015; $50.1 million in 2016; $78.9 million in 2017; $100.0 million in 2018 and $205.5 million thereafter.

Note 6 - Asset Retirement Obligations

The Company records obligations related to the decommissioning of certain electric generating facilities, special handling and disposal of hazardous materials at certain electric generating facilities, natural gas distribution facilities and buildings, and certain other obligations.

A reconciliation of the Company's liability for the years ended December 31 was as follows:

	2013	2012
	(In thousands)	
Balance at beginning of year	**$ 6,789**	$ 6,645
Liabilities settled	**---**	(10)
Revisions in estimates	**(17)**	(195)
Accretion expense	**371**	349
Balance at end of year	**$ 7,143**	$ 6,789

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

Note 7 - Preferred Stocks

Preferred stocks at December 31 were as follows:

	2013	2012
	(In thousands, except shares and per share amounts)	
Authorized:		
Preferred -		
500,000 shares, cumulative, par value $100, issuable in series		
Preferred stock A -		
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Preference -		
500,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Outstanding:		
4.50% Series - 100,000 shares	**$ 10,000**	$ 10,000
4.70% Series - 50,000 shares	**5,000**	5,000
Total preferred stocks	**$ 15,000**	$ 15,000

For the years 2013 and 2012, 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 8 - Common Stock
For the years 2013 and 2012, dividends declared on common stock were $.6950 and $.6750 per common share, respectively.

The Company’s Stock Purchase Plan provides interested investors the opportunity to make optional cash investments and to reinvest all or a percentage of their cash dividends in shares of the Company's common stock. The K-Plan is partially funded with the Company's common stock. From January 2012 through December 2013, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2013, there were 15.6 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. In addition, the Company and Centennial are generally restricted to paying dividends out of capital accounts or net assets. The following discusses the most restrictive limitations.

Pursuant to a covenant under a credit agreement, Centennial may only make distributions to the Company in an amount up to 100 percent of Centennial’s consolidated net income after taxes, excluding noncash write-downs, for the immediately preceding fiscal year. Intermountain and Cascade have regulatory limitations on the amount of dividends each can pay. Based on these limitations, approximately $2.1 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2013. In addition, the Company's credit agreement also contains restrictions on dividend payments. The most restrictive limitation requires the Company not to permit the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Based on this limitation, approximately $219 million of the Company's (excluding its subsidiaries) net assets, which represents common stockholders’ equity including retained earnings, would be restricted from use for dividend payments at December 31, 2013. In addition, state regulatory commissions may require the Company to maintain certain capitalization ratios. These requirements are not expected to affect the Company's ability to pay dividends in the near term.

Note 9 - Stock-Based Compensation

The Company has several stock-based compensation plans under which it is currently authorized to grant restricted stock and stock. As of December 31, 2013, there are 6.2 million remaining shares available to grant under these plans. The Company generally issues new shares of common stock to satisfy restricted stock, stock and performance share awards.

Total stock-based compensation expense (after tax), excluding the amount recognized by the Company’s subsidiaries, was $629,000 and $548,000 in 2013 and 2012, respectively.

As of December 31, 2013, total remaining unrecognized compensation expense, excluding the amount to be recognized by the Company’s subsidiaries, related to stock-based compensation was approximately $1.2 million (before income taxes) which will be amortized over a weighted average period of 1.7 years.

Stock options

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

The Company received cash of $88,000 from the exercise of stock options for the year ended December 31, 2012. The aggregate intrinsic value of options exercised during the year ended December 31, 2012, was $60,000.

Stock awards

Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. There were 36,713 shares with a fair value of $1.1 million and 53,888 shares with a fair value of $1.1 million issued under this plan during the years ended December 31, 2013 and 2012, respectively.

A key employee of a subsidiary of the Company received an award of 43,103 shares of common stock under a long-term incentive plan with a fair value of $930,000 during the year ended December 31, 2012.

Performance share awards

Since 2003, key employees of the Company and its subsidiaries have been awarded performance share awards each year. Entitlement to performance shares is based on the Company's total shareholder return over designated performance periods as measured against a selected peer group.

Target grants of performance shares outstanding at December 31, 2013, were as follows:

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

Participants may earn from zero to 200 percent of the target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value as determined by Monte Carlo simulation. The blended volatility term structure ranges are comprised of 50 percent historical volatility and 50 percent implied volatility. Risk-free interest rates were based on U.S. Treasury security rates in effect as of the grant date. Assumptions used for grants of performance shares issued in 2013 and 2012 were:

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

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

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

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

Note 10 - Income Taxes

Income before income taxes for the years ended December 31, 2013 and 2012, respectively was $61,704 and $53,891.

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

	2013	2012
	(In thousands)	
Current:		
Federal*	**$ (12,057)**	$ (15,719)
State	**(690)**	(2,476)
Deferred:		
Income taxes:		
Federal	**24,572**	27,118
State	**1,801**	2,988
Investment tax credit - net	**(47)**	(57)
Total income tax expense	**$ 13,579**	$ 11,854

* There was no change in uncertain tax benefits for the years ended December 31, 2013 and 2012.

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

		2013		2012
		(In thousands)		
Deferred tax assets:				
Accrued pension costs	**$**	**26,146**	$	41,955
Compensation-related		**12,675**		9,009
Legal and environmental contingencies		**515**		407
Other		**10,575**		13,803
Total deferred tax assets		**49,911**		65,174
Deferred tax liabilities:				
Depreciation and basis differences on property, plant and equipment		**256,026**		226,833
Other		**3,125**		1,196
Total deferred tax liabilities		**259,151**		228,029
Net regulatory matters deferred tax asset (liability)		**6,797**		(6,229)
Net deferred income tax liability	**$**	**(202,443)**	$	(169,084)

As of December 31, 2013 and 2012, no valuation allowance has been recorded associated with the previously identified deferred tax assets.

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

		2013
		(In thousands)
Change in net deferred income tax liability from the preceding table	**$**	**33,359**
Deferred taxes associated with other comprehensive loss		**(304)**
Other		**(6,729)**
Deferred income tax expense for the period	**$**	**26,326**

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

Years ended December 31,		**2013**			2012	
		Amount	%		Amount	%
		(Dollars in thousands)				
Computed tax at federal statutory rate	**$**	**21,596**	**35.0**	$	18,862	35.0
Increases (reductions) resulting from:						
Nonqualified benefit plan		**(3,504)**	**(5.7)**		(1,460)	(2.7)
Federal renewable energy credit		**(3,404)**	**(5.5)**		(3,401)	(6.3)
AFUDC equity		**(1,075)**	**(1.7)**		(1,084)	(2.0)
Deductible K-Plan dividends		**(866)**	**(1.4)**		(1,529)	(2.8)
Amortization and deferral of investment tax credit		**(47)**	**(0.1)**		(57)	(0.1)
State income taxes, net of federal income tax benefit (expense)		**1,491**	**2.4**		1,449	2.7
Other		**(612)**	**(1.0)**		(926)	(1.8)
Total income tax expense (benefit)	**$**	**13,579**	**22.0**	$	11,854	22.0

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

The amount of the unrecognized tax benefits (excluding interest) for the years ended December 31, 2013 and 2012 remained unchanged at $95,000.

The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $116,000, including approximately $21,000 for the payment of interest and penalties at December 31, 2013 and December 31, 2012, respectively.

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

For the years ended December 31, 2013 and 2012, the Company recognized approximately $8,000 and $4,000, respectively, in interest expense. Penalties were not material in 2013 and 2012. The Company recognized interest income of approximately $102,000 and $60,000 for the years ended December 31, 2013 and 2012, respectively. The Company had accrued assets of approximately $526,000 and $267,000 at December 31, 2013 and 2012, respectively, for the receipt of interest income.

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

Note 11 - 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. Other postretirement plans presented here include certain of the Company’s subsidiaries.

Defined pension plan benefits to all nonunion and certain union employees hired after December 31, 2005, were discontinued. In 2010, all benefit and service accruals for nonunion and certain union plans were frozen. Effective June 30, 2011, all benefit and service accruals for an additional union plan were frozen. These employees will be eligible to receive additional defined contribution plan benefits.

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

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

Changes in benefit obligation and plan assets for the years ended December 31, 2013 and 2012, and amounts recognized in the Comparative Balance Sheet at December 31, 2013 and 2012, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	**2013**	2012
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 262,910**	$ 249,823	**$ 49,593**	$ 57,161
Service cost	**—**	—	**906**	881
Interest cost	**9,240**	10,127	**1,700**	2,080
Plan participants' contributions	**—**	—	**830**	1,767
Amendments	**—**	—	**—**	(9,227)
Actuarial (gain) loss	**(24,667)**	18,532	**(5,998)**	1,276
Benefits paid	**(17,204)**	(15,572)	**(3,825)**	(4,345)
Benefit obligation at end of year	**230,279**	262,910	**43,206**	49,593
Change in net plan assets:				
Fair value of plan assets at beginning of year	**177,801**	161,284	**43,411**	38,975
Actual gain on plan assets	**20,324**	20,050	**7,944**	3,696
Employer contribution	**10,014**	12,039	**301**	3,318
Plan participants' contributions	**—**	—	**830**	1,767
Benefits paid	**(17,204)**	(15,572)	**(3,825)**	(4,345)
Fair value of net plan assets at end of year	**190,935**	177,801	**48,661**	43,411
Funded status – (under) over	**$ (39,344)**	$ (85,109)	**$ 5,455**	$ (6,182)
Amounts recognized in the Comparative Balance Sheet at December 31:				
Other deferred debits (credits)	**$ (39,344)**	$ (85,109)	**$ 5,455**	$ (6,182)
Net amount recognized	**$ (39,344)**	$ (85,109)	**$ 5,455**	$ (6,182)
Amounts recognized in accumulated other comprehensive (income) loss/regulatory assets (liabilities) consist of:				
Actuarial loss	**$ 74,036**	$ 111,617	**$ 6,776**	$ 19,133
Prior service credit	**—**	—	**(12,132)**	(13,108)
Total	**$ 74,036**	$ 111,617	**$ (5,356)**	$ 6,025

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. 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 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 expected average remaining service lives of active participants for non-frozen plans and over the average life expectancy of plan participants for frozen plans. The market-related value of assets is determined using a five-year average of assets. Unrecognized postretirement net transition obligation was amortized over a 20-year period ending 2012.

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

	2013	2012
	(In thousands)	
Projected benefit obligation	$ **230,279**	$ 262,910
Accumulated benefit obligation	$ **230,279**	$ 262,910
Fair value of plan assets	$ **190,935**	$ 177,801

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

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	**2013**	2012
	(In thousands)			
Components of net periodic benefit cost (credit):				
Service cost	$ **—**	$ —	$ **906**	$ 881
Interest cost	**9,240**	10,127	**1,700**	2,079
Expected return on assets	**(11,438)**	(13,668)	**(2,546)**	(2,895)
Amortization of prior service credit	**—**	—	**(976)**	(580)
Recognized net actuarial loss	**4,028**	2,801	**961**	613
Amortization of net transition obligation	**—**	—	**—**	3,284
Net periodic benefit cost (credit)	**1,830**	(740)	**45**	3,382
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:				
Net (gain) loss	**(33,553)**	12,149	**(11,396)**	475
Prior service credit	**—**	—	**—**	(9,227)
Amortization of actuarial loss	**(4,028)**	(2,801)	**(961)**	(613)
Amortization of prior service credit	**—**	—	**976**	580
Amortization of net transition obligation	**—**	—	**—**	(3,284)
Total recognized in accumulated other comprehensive (income) loss/regulatory assets (liabilities)	**(37,581)**	9,348	**(11,381)**	(12,069)
Total recognized in net periodic benefit cost and accumulated other comprehensive (income) loss/regulatory assets (liabilities)	$ **(35,751)**	$ 8,608	$ **(11,336)**	$ (8,687)

The estimated net loss for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss or regulatory asset(liability), as applicable, into net periodic benefit cost in 2014 is $2.7 million. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss or regulatory asset(liability), as applicable, into net periodic benefit cost in 2014 are $686,000 and $1.2 million, respectively. Prior service cost is amortized on a straight line basis over the average remaining service period of active participants.

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

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	**2013**	2012
Discount rate	**4.50%**	3.63%	**4.49%**	3.65%
Expected return on plan assets	**7.00%**	7.00%	**6.00%**	6.00%

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

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	**2013**	2012
Discount rate	**3.62 %**	4.18%	**3.65%**	4.12%
Expected return on plan assets	**7.00 %**	7.75%	**6.00%**	6.75%

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

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

	2013	2012
Health care trend rate assumed for next year	**6.0%**	6.0%
Health care cost trend rate - ultimate	**6.0%**	6.0%
Year in which ultimate trend rate achieved	**1999**	1999

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

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2013:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 33	$ (30)
Effect on postretirement benefit obligation	$ 947	$ (853)

The Company's pension assets are managed by 16 outside investment managers. The Company's other postretirement assets are managed by one outside investment manager. The Company's investment policy with respect to pension and other postretirement assets is to make investments solely in the interest of the participants and beneficiaries of the plans and for the exclusive purpose of providing benefits accrued and defraying the reasonable expenses of administration. The Company strives to maintain investment diversification to assist in minimizing the risk of large losses. The Company's policy guidelines allow for investment of funds in cash equivalents, fixed-income securities and equity securities. The guidelines prohibit investment in commodities and futures contracts, equity private placement, employer securities, leveraged or derivative securities, options, direct real estate investments, precious metals, venture capital and limited partnerships. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

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

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

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

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

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

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

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

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

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2013 and 2012, there were no transfers between Levels 1 and 2.

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

	Fair Value Measurements at December 31, 2013, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2013
	(In thousands)			
Assets:				
Cash equivalents	$ 1,454	$ 5,364	$ —	$ 6,818
Equity securities:				
U.S. companies	35,696	—	—	35,696
International companies	22,488	—	—	22,488
Collective and mutual funds *	66,296	24,225	—	90,521
Corporate bonds	—	24,360	—	24,360
Municipal bonds	—	4,311	—	4,311
U.S. Treasury securities	4,269	2,472	—	6,741
Total assets measured at fair value	$ 130,203	$ 60,732	$ —	$ 190,935

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

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

	Fair Value Measurements at December 31, 2012, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2012
	(In thousands)			
Assets:				
Cash equivalents	$ 1,234	$ 6,015	$ —	$ 7,249
Equity securities:				
U.S. companies	50,019	—	—	50,019
International companies	22,898	—	—	22,898
Collective and mutual funds *	47,608	11,539	—	59,147
Corporate bonds	—	25,942	—	25,942
Municipal bonds	—	5,349	—	5,349
U.S. Treasury securities	4,589	2,608	—	7,197
Total assets measured at fair value	$ 126,348	$ 51,453	$ —	$ 177,801

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

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

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Corporate Bonds	Collateral Held on Loaned Securities	Total
	(In thousands)		
Balance at beginning of year	$ 168	$ —	$ 168
Total realized/unrealized losses	(29)	—	(29)
Purchases, issuances and settlements (net)	(139)	—	(139)
Balance at end of year	$ —	$ —	$ —

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

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

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

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

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2013 and 2012, there were no transfers between Levels 1 and 2.

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

	Fair Value Measurements at December 31, 2013, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2013
	(In thousands)			
Assets:				
Cash equivalents	$ 444	$ 756	$ —	$ 1,200
Equity securities:				
U.S. companies	1,060	—	—	1,060
Insurance contract*	—	46,401	—	46,401
Total assets measured at fair value	$ 1,504	$ 47,157	$ —	$ 48,661

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

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

	Fair Value Measurements at December 31, 2012, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2012
	(In thousands)			
Assets:				
Cash equivalents	$ 600	$ 1,163	$ —	$ 1,763
Equity securities:				
U.S. companies	660	—	—	660
Insurance contract*	—	40,988	—	40,988
Total assets measured at fair value	$ 1,260	$ 42,151	$ —	$ 43,411

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

The Company expects to contribute approximately $19.1 million to its defined benefit pension plans in 2014. The Company does not expect to contribute to its postretirement benefit plans in 2014.

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

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
		(In thousands)	
2014	$ 13,794	$ 3,017	$ 184
2015	13,972	2,984	178
2016	14,132	2,950	171
2017	14,328	2,944	163
2018	14,513	2,927	155
2019 – 2023	75,584	13,769	638

Nonqualified benefit plans

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or to their beneficiaries upon death for a 15-year period. The Company's net periodic benefit cost for these plans was $4.1 million and $4.6 million in 2013 and 2012, respectively. The total projected benefit obligation for these plans was $61.9 million and $64.7 million at December 31, 2013 and 2012, respectively. The accumulated benefit obligation for these plans was $57.2 million and $61.1 million at December 31, 2013 and 2012, respectively. A weighted average discount rate of 4.32 percent and 3.45 percent at December 31, 2013 and 2012, respectively, and a rate of compensation increase of 4.00 percent and 3.00 percent at December 31, 2013 and 2012, respectively, were used to determine benefit obligations. A discount rate of 3.45 percent and 4.00 percent at December 31, 2013 and 2012, respectively, and a rate of compensation increase of 3.00 percent and 4.00 percent at December 31, 2013 and 2012, respectively, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $3.1 million in 2014; $3.8 million in 2015; $3.7 million in 2016; $3.8 million in 2017, $4.0 million in 2018 and $21.6 million for the years 2019 through 2023.

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Costs incurred under this plan for 2013 and 2012 were $36,000 and $17,000, respectively.

The Company had investments of $60.4 million and $51.9 million at December 31, 2013 and 2012, respectively, consisting of equity securities of $35.6 million and $25.6 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of $17.8 million and $18.7 million, respectively, and other investments of $7.0 million and $5.2 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 costs incurred under these plans were $11.1 million in 2013 and $10.0 million in 2012.

Note 12 - Jointly Owned Facilities

The 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 station’s operating expenses was reflected in the appropriate categories of operating expenses (fuel, operation and maintenance, and taxes, other than income) in the Statement of Income.

At December 31, the Company's share of the cost of utility plant in service and related accumulated depreciation for the stations was as follows:

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

Note 13 - Regulatory Matters and Revenues Subject to Refund

On September 26, 2012, Montana-Dakota filed an application with the MTPSC for a natural gas rate increase. Montana-Dakota requested a total increase of $3.5 million annually or approximately 5.9 percent above current rates. The requested increase includes the costs associated with the increased investment in facilities, including ongoing investment in new and replacement distribution facilities, an operations building, automated meter reading and a new customer billing system. Montana-Dakota requested an interim increase, subject to refund, of $1.7 million or approximately 2.9 percent. On April 12, 2013, the MTPSC issued an interim order authorizing an interim increase of $850,000 annually to be effective with service rendered on or after April 15, 2013, subject to refund. A hearing was held August 5-6, 2013. On December 5, 2013, Montana-Dakota and the Montana Consumer Counsel filed a stipulation with the MTPSC with an increase of $1.5 million annually. On December 12, 2013, the MTPSC approved the stipulation to be effective with service rendered on or after December 15, 2013.

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

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

On February 27, 2014, Montana-Dakota filed an application with the NDPSC for approval of an electric generation resource recovery rider for recovery of Montana-Dakota’s investment in the Heskett III generator, located near Mandan, ND. Montana-Dakota requested recovery of $7.4 million annually or approximately 4.6 percent above current rates. The NDPSC had previously approved an advance determination of prudence and issued a certificate of public convenience and necessity for Heskett III on April 11, 2012. On March 12, 2014, the NDPSC suspended the filing pending further review.

Note 14 - Commitments and Contingencies

Claims and Litigation

The Company is party to claims and lawsuits arising out of its business. The Company accrues a liability for those contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, in some circumstances, an estimate of the possible loss. The Company had accrued liabilities of $1.4 million and $1.1 million for contingencies related to litigation as of December 31, 2013 and 2012, respectively.

Operating leases

The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2013, were $4.2 million in 2014, $2.8 million in 2015, $2.7 million in 2016, $2.5 million in 2017, $1.4 million in 2018 and $19.6 million thereafter. Rent expense was $3.3 million and $2.8 million for the years ended December 31, 2013 and 2012, respectively.

Purchase commitments

The Company has entered into various commitments, largely natural gas and coal supply, purchased power, and natural gas transportation and storage contracts, some of which are subject to variability in volume and price. These commitments range from one to 11 years. The commitments under these contracts as of December 31, 2013, were $172.0 million in 2014, $76.8 million in 2015, $51.9 million in 2016, $17.1 million in 2017, $6.9 million in 2018 and $17.4 million thereafter. These commitments were not reflected in the Company's financial statements. Amounts purchased under various commitments for the years ended December 31, 2013 and 2012, were $305.9 million and $241.5 million, respectively.

Note 15 – Subsequent Event

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

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2013	Year/Period of Report End of 2013/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) 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.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year	82,256	(53,319,766)		(37,820)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value	37,074	(1,027,059)		(472,856)
4	Total (lines 2 and 3)	37,074	(1,027,059)		(472,856)
5	Balance of Account 219 at End of Preceding Quarter/Year	119,330	(54,346,825)		(510,676)
6	Balance of Account 219 at Beginning of Current Year	119,330	(54,346,825)		(510,676)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	108,858	2,000,634		142,921
8	Current Quarter/Year to Date Changes in Fair Value	(193,967)	18,538,980		(298,924)
9	Total (lines 7 and 8)	(85,109)	20,539,614		(156,003)
10	Balance of Account 219 at End of Current Quarter/Year	34,221	(33,807,211)		(666,679)

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	(3,078,643)	9,352,977	(47,000,996)		
2					
3	(1,678,096)	1,421,321	(1,719,616)		
4	(1,678,096)	1,421,321	(1,719,616)		(1,719,616)
5	(4,756,739)	10,774,298	(48,720,612)		
6	(4,756,739)	10,774,298	(48,720,612)		
7	727,236	(4,915,591)	(1,935,942)		
8	559,357	(6,153,468)	12,451,978		
9	1,286,593	(11,069,059)	10,516,036		10,516,036
10	(3,470,146)	(294,761)	(38,204,576)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	1,545,200,634	1,058,520,652
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	62,993,527	41,242,816
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	1,608,194,161	1,099,763,468
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	151,552,008	135,575,579
12	Acquisition Adjustments	10,484,909	10,387,643
13	Total Utility Plant (8 thru 12)	1,770,231,078	1,245,726,690
14	Accum Prov for Depr, Amort, & Depl	760,970,889	510,226,261
15	Net Utility Plant (13 less 14)	1,009,260,189	735,500,429
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	720,090,853	493,075,562
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	30,446,197	6,774,890
22	Total In Service (18 thru 21)	750,537,050	499,850,452
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	10,433,839	10,375,809
33	Total Accum Prov (equals 14) (22,26,30,31,32)	760,970,889	510,226,261

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
373,491,829				113,188,153	3
					4
					5
19,190,017				2,560,694	6
					7
392,681,846				115,748,847	8
					9
					10
7,702,991				8,273,438	11
97,266					12
400,482,103				124,022,285	13
203,210,815				47,533,813	14
197,271,288				76,488,472	15
					16
					17
201,662,531				25,352,760	18
					19
					20
1,490,254				22,181,053	21
203,152,785				47,533,813	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
58,030					32
203,210,815				47,533,813	33

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. 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)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant	9,098,948	42,217
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	9,098,948	42,217
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,018,687	
9	(311) Structures and Improvements	55,358,104	16,161,428
10	(312) Boiler Plant Equipment	206,009,051	4,157,147
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	79,723,793	4,438,791
13	(315) Accessory Electric Equipment	19,315,176	231,758
14	(316) Misc. Power Plant Equipment	16,752,688	560,238
15	(317) Asset Retirement Costs for Steam Production	854,230	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	379,031,729	25,549,362
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights	66,533	
38	(341) Structures and Improvements	6,774,663	55,121
39	(342) Fuel Holders, Products, and Accessories	2,619,628	100,800
40	(343) Prime Movers		
41	(344) Generators	128,094,467	21,715
42	(345) Accessory Electric Equipment	15,662,048	98,301
43	(346) Misc. Power Plant Equipment	231,854	44,526
44	(347) Asset Retirement Costs for Other Production	3,142,677	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	156,591,870	320,463
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	535,623,599	25,869,825

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (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 end of year.

7. 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, 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.

8. 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 requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, 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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
					3
			9,141,165		4
			9,141,165		5
					6
					7
			1,018,687		8
66,023			71,453,509		9
947,506			209,218,692		10
					11
257,029			83,905,555		12
12,604			19,534,330		13
204,045			17,108,881		14
			854,230		15
1,487,207			403,093,884		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
			66,533		37
			6,829,784		38
			2,720,428		39
					40
			128,116,182		41
			15,760,349		42
			276,380		43
			3,142,677		44
			156,912,333		45
1,487,207			560,006,217		46

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	3,942,365	300,411
49	(352) Structures and Improvements	1,789	
50	(353) Station Equipment	91,977,175	8,820,371
51	(354) Towers and Fixtures	4,992,886	
52	(355) Poles and Fixtures	42,569,370	4,367,679
53	(356) Overhead Conductors and Devices	32,014,425	2,940,030
54	(357) Underground Conduit	1,942,210	
55	(358) Underground Conductors and Devices	3,101,857	
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant	797	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	180,542,874	16,428,491
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	2,630,860	17,135
61	(361) Structures and Improvements		
62	(362) Station Equipment	47,221,850	2,287,377
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	30,539,213	3,710,249
65	(365) Overhead Conductors and Devices	21,290,753	3,680,283
66	(366) Underground Conduit	218,154	
67	(367) Underground Conductors and Devices	67,495,091	11,860,259
68	(368) Line Transformers	54,833,271	6,128,729
69	(369) Services	27,146,157	3,463,535
70	(370) Meters	16,026,767	1,602,836
71	(371) Installations on Customer Premises	2,474,932	281,302
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	6,529,365	387,623
74	(374) Asset Retirement Costs for Distribution Plant	39,748	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	276,446,161	33,419,328
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	8,137	
87	(390) Structures and Improvements	688,290	-1,595
88	(391) Office Furniture and Equipment	1,011,928	
89	(392) Transportation Equipment	6,682,554	701,267
90	(393) Stores Equipment	14,774	
91	(394) Tools, Shop and Garage Equipment	2,553,274	214,466
92	(395) Laboratory Equipment	466,251	60,947
93	(396) Power Operated Equipment	10,109,136	1,032,467
94	(397) Communication Equipment	2,796,162	240,853
95	(398) Miscellaneous Equipment	30,800	26,674
96	SUBTOTAL (Enter Total of lines 86 thru 95)	24,361,306	2,275,079
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	24,361,306	2,275,079
100	TOTAL (Accounts 101 and 106)	1,026,072,888	78,034,940
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	1,026,072,888	78,034,940

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			4,242,776		48
			1,789		49
62,938			100,734,608		50
			4,992,886		51
64,956			46,872,093		52
19,830			34,934,625		53
			1,942,210		54
			3,101,857		55
					56
			797		57
147,724			196,823,641		58
					59
		25,378	2,673,373		60
					61
40,027		-25,378	49,443,822		62
					63
189,379			34,060,083		64
81,822			24,889,214		65
			218,154		66
443,661			78,911,689		67
577,260			60,384,740		68
148,391			30,461,301		69
40,962			17,588,641		70
64,892			2,691,342		71
					72
77,039			6,839,949		73
			39,748		74
1,663,433			308,202,056		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			8,137		86
			686,695		87
510,382			501,546		88
159,151		59,979	7,284,649		89
			14,774		90
66,653			2,701,087		91
11,420			515,778		92
278,523			10,863,080		93
79,846			2,957,169		94
			57,474		95
1,105,975		59,979	25,590,389		96
					97
					98
1,105,975		59,979	25,590,389		99
4,404,339		59,979	1,099,763,468		100
					101
					102
					103
4,404,339		59,979	1,099,763,468		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (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 Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Install 88 MW combustion turbine in Mandan, ND	64,238,808
2	Install air quality control system for Big Stone Station in Milbank, SD	38,941,775
3	Construct 115/41.6KV west junction substation in Dickinson, ND	5,057,239
4	Construct Little Muddy junction substation near Williston, ND	4,152,932
5	Construct 345KV transmission line near Ellendale, ND	2,637,128
6	Construct 115KV transmission line loop in Dickinson, ND	1,536,795
7	Construct 115KV substation in Bismarck, ND	1,529,934
8	Purchase bed ash/limestone equipment at Heskett Station in Mandan, ND	1,251,247
9	Construct 115/69KV bay in substation near Stanley, ND	1,072,587
10		
11	Minor projects less than $1,000,000:	
12	Steam Production	2,960,602
13	Other Production	134,161
14	Transmission	4,944,534
15	Distribution	5,504,996
16	General	1,612,841
17		
18		
19		
20		
21		
22		
23		
24		
25		
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42		
43	TOTAL	135,575,579

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC 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 electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional 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 Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	466,606,769	466,606,769		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	29,894,582	29,894,582		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	913,437	913,437		
7	Other Clearing Accounts	-168,452	-168,452		
8	Other Accounts (Specify, details in footnote):	-1,262,123	-1,262,123		
9		392,565	392,565		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	29,770,009	29,770,009		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	4,404,339	4,404,339		
13	Cost of Removal	3,276,983	3,276,983		
14	Salvage (Credit)	4,303,675	4,303,675		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	3,377,647	3,377,647		
16	Other Debit or Cr. Items (Describe, details in footnote):	76,431	76,431		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	493,075,562	493,075,562		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	222,163,669	222,163,669		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	37,277,088	37,277,088		
25	Transmission	91,945,558	91,945,558		
26	Distribution	130,709,243	130,709,243		
27	Regional Transmission and Market Operation				
28	General	10,980,004	10,980,004		
29	TOTAL (Enter Total of lines 20 thru 28)	493,075,562	493,075,562		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2	CENTENNIAL ENERGY HOLDINGS, INC. (100% OWNED)	12/88		
3	Capital investment in subsidiaries			918,442,432
4				
5	Equity in undistributed subsidiary earnings since acquisition			900,464,331
6				
7				
8	MDU ENERGY CAPITAL, LLC (100% OWNED)	07/07		
9	Capital investment in subsidiaries			397,916,712
10				
11	Equity in undistributed subsidiary earnings since acquisition			36,470,246
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
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35				
36				
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38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 2,380,828,521		TOTAL	2,253,293,721

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, 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 column (f) interest and dividend revenues form investments, including such revenues form 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 difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
		919,912,768		3
				4
205,754,412	83,457,000	1,022,445,814		5
				6
				7
				8
		397,916,712		9
				10
25,053,003	20,900,000	40,553,227		11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
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				27
				28
				29
				30
				31
				32
				33
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				40
				41
230,807,415	104,357,000	2,380,828,521		42

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2013	Year/Period of Report End of 2013/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	5,129,837	4,751,688	Electric & Gas
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	15,375,314	15,099,039	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	2,536,407	2,580,877	Electric
8	Transmission Plant (Estimated)	145,920	486,746	Electric
9	Distribution Plant (Estimated)	1,087,205	1,259,293	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	-161,072	-328,467	Electric & Gas
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	18,983,774	19,097,488	
13	Merchandise (Account 155)	451,882	75,479	
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	24,565,493	23,924,655	

Schedule Page: 227 Line No.: 11 Column: b

Allowance for inventory shrinkage - materials and supplies.

Schedule Page: 227 Line No.: 11 Column: c

Allowance for inventory shrinkage - materials and supplies.

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2014 No. (d)	2014 Amt. (e)
1	Balance-Beginning of Year	42,074.00		11,607.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	9,178.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Transfer-Heskett Station				
23	to Wygen III	40.00			
24	Transfer-Lewis & Clark				
25	Station to Wygen III	40.00			
26					
27					
28	Total	80.00			
29	Balance-End of Year	32,816.00		11,607.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	168.00		168.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	67.00			
40	Balance-End of Year	101.00		168.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	67.00	19		
45	Gains	67.00	19		
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2015		2016		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
11,607.00		11,607.00		278,568.00		355,463.00		1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						9,178.00		18
								19
								20
								21
								22
						40.00		23
								24
						40.00		25
								26
								27
						80.00		28
11,607.00		11,607.00		278,568.00		346,205.00		29
								30
								31
								32
								33
								34
								35
168.00		167.00		7,044.00		7,715.00		36
								37
								38
				67.00		134.00		39
168.00		167.00		6,977.00		7,581.00		40
								41
								42
								43
				67.00	3	134.00	22	44
				67.00	3	134.00	22	45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (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 Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Electric Generation Development	8,531,231			912,789	
22	Costs: ND Public Service					
23	Commission authorization granted					
24	6/25/10 due to cancellation of					
25	construction; North Dakota					
26	electric amortization over					
27	36 months					
28						
29	Electric Generation Development	1,718,605		407	171,860	1,288,954
30	Costs: ND Public Service					
31	Commission authorization granted					
32	6/8/11 due to cancellation of					
33	construction; North Dakota					
34	electric amortization over					
35	120 months					
36						
37	Electric Generation Development	3,424,185			176,245	2,409,642
38	Costs: MT Public Service					
39	Commission authorization granted					
40	8/2/11 due to cancellation of					
41	construction; Montana electric					
42	amortization over 180 months					
43						
44						
45						
46						
47						
48						
49	TOTAL	13,674,021			1,260,894	3,698,596

Schedule Page: 230 Line No.: 21 Column: d

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407        $797,457
182.3       115,332
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Schedule Page: 230 Line No.: 37 Column: d

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407        $242,228
419         (65,983)
```

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter /Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Deferred Postretirement Implementation Costs;	70,890		G-926	38,668	32,222
2	Montana gas amortization over 240 months					
3	beginning 11/94					
4						
5						
6	Unamortized AFUDC on portion of Coyote I Station	506,978		E-403	132,255	374,723
7	that had been disallowed in rate base by Montana;					
8	amortization of 12/83 balance over 388 months end-					
9	ing 10/16 and amortization of 6/84 balance over					
10	356 months					
11						
12	Deferred depreciation on portion of Coyote I	118,022		E-403	30,788	87,234
13	Station that had been disallowed in rate base by					
14	Montana; amortization of 12/83 balance over 388					
15	months ending 10/16 and amortization of 6/84					
16	balance over 356 months					
17						
18	Interest deferred on portion of Coyote I Station	20,732		E-403	5,408	15,324
19	AFUDC which had been disallowed in rate base by					
20	Montana; amortization of interest on 6/84 AFUDC					
21	balance over 356 months					
22						
23	Unamortized Regulatory Commission Expense:	284,221	792,795		681,048	395,968
24	South Dakota gas amortization over 60 months					
25	beginning 12/13; North Dakota electric					
26	amortization over 36 months beginning 7/11;					
27	Montana gas amortization over 36 months					
28	beginning 12/13					
29						
30						
31	Accumulated costs associated with a gas rate	76,329	299,611	182	76,329	299,611
32	case in North Dakota and an electric rate case					
33	in North Dakota					
34	Asset Retirement Obligations	3,110,766	1,116,473		371,657	3,855,582
35						
36						
37						
38						
39						
40						
41						
42						
43						

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter /Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Deferred Fuel and Purchased Power Costs -					
2	North Dakota - Electric	(70,140)			1,248,816	-1,318,956
3	Wyoming - Electric	1,047,819			534,516	513,303
4	Montana - Electric	(176,510)	481,729			305,219
5						
6	Deferred Pension	100,951,115			33,852,991	67,098,124
7						
8	Manufactured Gas Plant Site - Bismarck, ND	453,873		G-928	90,780	363,093
9	amortization over 120 months ending 12/17					
10						
11	Regulatory Matters -Deferred Tax Related	5,437,381	5,464,388			10,901,769
12						
13	Deferred Other Postretirement	2,915,281	11,809	253	2,927,090	
14						
15	Electric Generation Development Costs	813,345				813,345
16						
17	Transmission Cost Recovery Adjustment -	(219,295)	723,888		628,610	-124,017
18	North Dakota - Electric [PU-11-672]					
19						
20	Montana Public Service Commission/Montana		302,576			302,576
21	Consumer Counsel tax deferral [Docket No.					
22	D2013.10.72 and Docket No. D2013.73]					
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	**TOTAL :**	115,340,807	9,193,269		40,618,956	83,915,120

FOOTNOTE DATA

Schedule Page: 232 Line No.: 23 Column: d

E-928	$ 600,897
G-928	80,151

Schedule Page: 232 Line No.: 34 Column: d

230	$ 344,716
421	19,196
417.1	7,745

Schedule Page: 232.1 Line No.: 2 Column: d

E-555 (Amortization)	$ (1,532,397)
E-419	489
E-431	(70)
E-555 (Deferral)	283,162

Schedule Page: 232.1 Line No.: 3 Column: d

E-555 (Amortization)	$ (877,247)
E-431	(80)
E-555 (Deferral)	342,811

Schedule Page: 232.1 Line No.: 4 Column: c

E-555 (Deferral)	$ 476,067
E-431	(11,805)
E-447	64,855
E-555 (Amortization)	(47,388)

Schedule Page: 232.1 Line No.: 6 Column: d

253	$ 33,841,182
182	11,809

Schedule Page: 232.1 Line No.: 17 Column: d

E-565	$ 627,265
E-456	1,160
E-431	185

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) 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	Deferred capital stock expense	197,512	415,745	214	147,273	465,984
2						
3	Conservation programs	-215,154	2,131,756		2,544,568	-627,966
4						
5	Advance to FutureSource Capital	756,330		146	23,703	732,627
6	Corp. for land					
7						
8	Goodwill - Great Plains Natural	4,812,244				4,812,244
9	Gas Co.					
10						
11	Subsidiary post-retirement	21,526,031	259,430		6,397,481	15,387,980
12	trust assets					
13						
14	Post-retirement Benefit Costs		5,455,080			5,455,080
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
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45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	27,076,963				26,225,949

Schedule Page: 233 Line No.: 3 Column: d

142	$2,541,357
143	2,800
421	86
131	325

Schedule Page: 233 Line No.: 11 Column: d

123.1	$2,100,569
228.3	557,287
253	3,739,625

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Pension Expense	10,667,784	2,648,137
3	Management Incentive	932,780	1,053,910
4	Customer Advances	2,079,473	2,426,112
5	Performance Share Program	1,186,870	1,422,676
6	WAPA Fiber Demand Revenue	301,413	281,099
7	Other	5,384,730	5,988,397
8	TOTAL Electric (Enter Total of lines 2 thru 7)	20,553,050	13,820,331
9	Gas		
10	Pension Expense	12,656,002	6,058,273
11	Customer Advances	3,105,922	4,701,332
12	Performance Share Program	968,009	1,099,799
13	Management Incentive	584,213	386,875
14	Prepaid Demand Charge	-1,016,257	-1,061,071
15	Other	1,027,521	5,983,190
16	TOTAL Gas (Enter Total of lines 10 thru 15	17,325,410	17,168,398
17	Other (Specify) *	30,285,903	18,145,077
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	68,164,363	49,133,806

Notes

	Balance at Beginning of Year	Balance at End of Year
*Utility		
Vacation Pay	$2,580,630	**
Property Insurance	406,553	**
Sundry Reserves	253,426	**
Postrement Benefit Costs	2,005,838	**
Deferred Compensation - Directors	1,634,282	**
Deferred Postretirement Benefit Costs	(908,334)	**
Bonus Accrual & 401K Profit Sharing	1,011,400	**
Reserved Revenues	0	**
Retired Power Plant	0	**
Regulatory Matters	3,814,205	**
Total Utility	$10,798,000	**
*Non-utility		
Uniform Capitalization	96,355	57,891
C.I.A.C.'s	272,395	339,614
Excess Contributions	258,088	0
Management Incentive	111,174	0
ITC - State	0	304,975
SISP Expense	18,631,467	17,439,319
Postretirement Benefit Costs	321,557	0
AMT/NOL Carryforward	0	3,500
Deferred Postretirement Benefit Costs	(205,305)	0
Bad Debts Expense	2,172	(222)
Total Non-Utility	$19,487,903	$18,145,077
*Total Other	$30,285,903	$18,145,077

**Balance at End of Year included in line 7 or 15 as appropriate. As of 12/31/13, line 17 "Other" includes non-utility only.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (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. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (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	500,000,000	1.00	
3	Total Account 201	500,000,000		
4				
5	Account 204			
6	Preferred Stock	500,000	100.00	
7	4.50% Cumulative			105.00
8	4.70% Cumulative			102.00
9				
10	Total Account 204	500,000		
11				
12	Preferred Stock A - Cumulative	1,000,000		
13				
14	Preference Stock - Cumulative	500,000		
15				
16				
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18				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
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 purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
189,868,780	189,868,780	538,921	3,625,813			2
189,868,780	189,868,780	538,921	3,625,813			3
						4
						5
						6
100,000	10,000,000					7
50,000	5,000,000					8
						9
150,000	15,000,000					10
						11
						12
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Schedule Page: 250 Line No.: 2 Column: a

See Note 8 in Notes To Financial Statements beginning on page 122.

Schedule Page: 250 Line No.: 7 Column: d

Plus accrued dividends

Schedule Page: 250 Line No.: 8 Column: d

Plus accrued dividends

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (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)
1		
2	Common Stock, $1.00 par value	4,257,578
3	(Primarily stock expense related to the issuance of common stock through public offering	
4	during February 2004.)	
5		
6		
7		
8		
9		
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21		
22	TOTAL	4,257,578

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. 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.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (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.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221		
2	Unsecured Senior Note		
3	6.33%	100,000,000	344,061
4	6.04%	100,000,000	362,431
5	6.66%	25,000,000	68,308
6	6.61%	25,000,000	68,308
7	5.98%	30,000,000	624,465
8			
9	SUBTOTAL	280,000,000	1,467,573
10			
11	Account 222 (None)		
12	Account 223 (None)		
13	Account 224		
14	5.1% Preferred Stock, Cumulative, subject to redemption	5,000,000	
15	Commercial Paper - 0.372% average for 2013		479,754
16			
17	Libor Floating Rate Note - Term Loan	75,000,000	
18	Minot Air Force Base Note Payable	509,197	
19	SUBTOTAL	80,509,197	479,754
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	360,509,197	1,947,327

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, 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) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
082406	082426	082406	082426	100,000,000	6,330,000	3
091608	091618	091608	091618	100,000,000	6,040,000	4
100109	093016	100109	093016	25,000,000	1,665,000	5
090109	093016	090109	093016	25,000,000	1,652,500	6
121503	121533	121503	121533	30,000,000	1,794,000	7
						8
				280,000,000	17,481,500	9
						10
						11
						12
						13
052361				308,600	19,691	14
				78,924,000	386,213	15
						16
090613	100314			75,000,000	224,235	17
092308	113038			473,372	28,656	18
				154,705,972	658,795	19
						20
						21
						22
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						32
				434,705,972	18,140,295	33

Schedule Page: 256 Line No.: 14 Column: e

The Respondent intends to make annual sinking fund contributions to retire 1,000 shares of 5.1% Series preferred stock at par. The redemption price is $102 plus accrued dividends.

Schedule Page: 256 Line No.: 15 Column: i

This amount includes a commitment fee of $159,160.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax 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 which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	278,932,594
2		
3		
4	Taxable Income Not Reported on Books	
5	Dividends Received from Subsidiary Companies	104,357,000
6	See Footnote	6,562,191
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation and Amortization	45,467,454
11	Federal Income Tax Provision	12,455,608
12	See Footnote	14,215,803
13		
14	Income Recorded on Books Not Included in Return	
15	Equity in Earnings of Subsidiaries	230,807,415
16	AFUDC Equity	3,071,017
17	See Footnote	4,883,152
18		
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation and Amortization	106,591,373
21	Dividends Received from Subsidiaries	104,357,000
22	Supplemental Income Security Plan	12,134,148
23	Unrecovered Purchased Gas Cost	5,096,283
24	See Footnote	13,228,948
25		
26		
27	Federal Tax Net Income	-18,178,688
28	Show Computation of Tax:	
29	Federal at 35% of line 27	-6,362,541
30	Wind Production Credit	-4,580,949
31	Closing/Filing True-Up & Out of Period Adjustments	-1,086,562
32	Other Credits and Adjustments	-27,382
33		
34	TOTAL 2013 FEDERAL INCOME TAX	-12,057,434
35		
36	Response to instruction #2 - See Footnote	
37		
38		
39		
40		
41		
42		
43		
44		

Schedule Page: 261 Line No.: 6 Column: b

Customer Advances	$ 4,957,490
State Income Tax Benefit	926,189
Contributions in Aid of Construction	651,131
Miscellaneous	27,381
Total Carried to page 261, line 6	$ 6,562,191

Schedule Page: 261 Line No.: 12 Column: b

Bonus Accrual & 401(k) Profit Sharing	$ 7,934,479
Abandoned Power Plant Cost Recovery	1,260,894
State Income Tax Provision	1,064,136
Performance Share Program	996,969
Deferred Compensation-Directors	764,779
Amortization of Loss on Bond Retirements	719,511
Vacation Accrual	388,209
Contingency Reserve	291,183
F&PP Deferral	229,298
Bad Debts	168,388
Disallowed Meals & Entertainment Expense-50%	157,095
Regulatory Assets Awaiting Recovery	90,781
Preferred Stock Expense	19,691
Miscellaneous	130,390
Total Carried to page 261, line 12	$14,215,803

Schedule Page: 261 Line No.: 17 Column: b

Reserved Revenues	$ 4,173,450
Medicare Part D	446,533
WAPA Fiber Demand Revenue	49,315
Miscellaneous	213,854
Total Carried to page 261, line 17	$ 4,883,152

Schedule Page: 261 Line No.: 24 Column: b

Pension Expense	$ 8,184,240
401(k) Dividend Deduction	2,473,123
Charitable Contributions	615,215
Management Incentive	470,728
Uniform Capitalization	436,000
Regulatory Commission Expense	335,028
Montana PSC/MCC Tax Deferral	302,576
Dividend Paid Deduction	180,002
Prepaid Demand Charges	90,922
Retired Power Plant	56,210
Board of Directors-Retirement Benefits	52,262
Post Retirement Benefits Accrued	13,662
Miscellaneous	18,980
Total Carried to page 260, line 24	$13,228,948

Schedule Page: 261 Line No.: 36 Column: a

The Respondent files a consolidated return; however, the information above has been prepared on a separate return basis. The consolidated group elected to allocate tax liabilities in accordance with method #2 under Internal Revenue Code Section 1552 (Earnings and Profits). The 2013 federal tax provisions were:

Centennial Energy Holdings, Inc.	$57,158,545
MDU Energy Capital	1,459,369
Total	$58,617,914

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2013	Year/Period of Report End of 2013/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (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 know, 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 proportions of prepaid taxes chargeable 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 BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	CORPORATE INCOME					
2	Federal	2,875,030		-12,057,434	-10,824,285	1,048,769
3	State	-341,048		-689,921	-645,832	-225,120
4	SUBTOTAL	2,533,982		-12,747,355	-11,470,117	823,649
5						
6	UNEMPLOYMENT					
7	Federal	19,424		62,486	57,232	
8	Idaho	42,195		156,128	163,273	
9	Minnesota	7,660		42,302	46,307	
10	Montana	7,505		48,947	50,657	
11	Nevada	-948				
12	North Dakota	12,627		82,355	86,824	
13	Oregon					
14	South Dakota	1,167		5,155	4,878	
15	Washington	3,702		32,200	32,940	
16	Wyoming	4,377		35,181	36,704	
17	SUBTOTAL	97,709		464,754	478,815	
18						
19	GROSS REVENUE					
20	Montana	79,980		406,667	340,670	
21	South Dakota			80,842	80,842	
22	Wyoming	42,933		105,622	95,744	
23	SUBTOTAL	122,913		593,131	517,256	
24						
25	USE					
26	Minnesota	2,502		13,994	16,176	
27	North Dakota	-25		737,361	692,960	
28	South Dakota	3,903		32,877	32,001	
29	Washington	511		223	511	
30	Wyoming	2,620		12,329	13,722	
31	Idaho	21		15,502	15,315	
32	Iowa					
33	Nebraska					
34	SUBTOTAL	9,532		812,286	770,685	
35						
36	PROPERTY					
37	Minnesota (GPNG)	558,000		584,795	578,795	
38	Montana	3,480,138		7,143,190	7,053,712	
39	North Dakota	3,011,332		2,676,804	3,011,332	
40	North Dakota (GPNG)	25,484		26,333	25,484	
41	TOTAL	12,398,861		9,806,843	10,692,375	823,649

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then 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 foot- note. 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. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
2,690,650		-8,188,163			-3,869,271	2
-610,257		-223,021			-466,900	3
2,080,393		-8,411,184			-4,336,171	4
						5
						6
24,678		14,894			47,592	7
35,050		18,566			137,562	8
3,655		273			42,029	9
5,795		22,288			26,659	10
-948						11
8,158		25,493			56,862	12
						13
1,444		877			4,278	14
2,962		338			31,862	15
2,854		8,952			26,229	16
83,648		91,681			373,073	17
						18
						19
145,977		-80,160			486,827	20
		19,955			60,887	21
52,811		68,328			37,294	22
198,788		8,123			585,008	23
						24
						25
320					13,994	26
44,376					737,361	27
4,779					32,877	28
223					223	29
1,227					12,329	30
208					15,502	31
						32
						33
51,133					812,286	34
						35
						36
564,000					584,795	37
3,569,616		3,696,884			3,446,306	38
2,676,804		1,900,482			776,322	39
26,333					26,333	40
12,336,506		1,748,345			8,058,498	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (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 know, 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 proportions of prepaid taxes chargeable 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 BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	South Dakota	1,248,825		1,331,520	1,251,355	
2	Wyoming	144,548		299,804	294,450	
3	SUBTOTAL	8,468,327		12,062,446	12,215,128	
4						
5						
6	FRANCHISE					
7	Delaware	36,050		180,050	180,050	
8	Wyoming	98,898		251,939	238,711	
9	Hettinger, ND			16,749	13,717	
10						
11	SUBTOTAL	134,948		448,738	432,478	
12						
13						
14						
15	MISCELLANEOUS					
16	Federal-FICA	758,747		7,036,467	6,618,456	
17	Federal-Highway Use			3,873	3,873	
18	Montana WET Tax	28,084		116,678	115,592	
19	Montana-Electric License	18,683		78,785	77,000	
20	ND-Coal Conversion	37,615		926,025	926,025	
21						
22						
23	Secretaries of State			2,731	2,731	
24	(annual filing fees)					
25	Fort Peck Tribal	184,000				
26	Crow Agency Tribal	3,866		7,800	3,866	
27	Federal CNG Tax	22		9	16	
28	Montana CNG Tax	429		104	125	
29	North Dakota CNG Tax	4		371	446	
30	South Dakota CNG Tax					
31	SUBTOTAL	1,031,450		8,172,843	7,748,130	
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	12,398,861		9,806,843	10,692,375	823,649

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then 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 foot- note. 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. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
1,328,990		662,335			669,185	1
149,902		231,309			68,495	2
8,315,645		6,491,010			5,571,436	3
						4
						5
						6
36,050		101,548			78,502	7
112,126		170,535			81,404	8
3,032					16,749	9
						10
151,208		272,083			176,655	11
						12
						13
						14
						15
1,176,758		2,170,711			4,865,756	16
		2,893			980	17
29,170		116,678				18
20,468		78,785				19
		520,885				20
37,143		405,140				21
						22
		1,540			1,191	23
						24
184,000						25
7,800					7,800	26
15					9	27
408					104	28
-71					371	29
						30
1,455,691		3,296,632			4,876,211	31
						32
						33
						34
						35
						36
						37
						38
						39
						40
12,336,506		1,748,345			8,058,498	41

Schedule Page: 262 Line No.: 3 Column: a

Idaho, Minnesota, Montana and North Dakota state income taxes.

Schedule Page: 262 Line No.: 6 Column: a

Allocated between electric and gas operations on the basis of payroll charges. The amounts charged to other include allocation of payroll taxes to various electric and gas construction, clearing or expense accounts based on a company-wide derived payroll loading factor.

Schedule Page: 262 Line No.: 19 Column: a

Allocated on a gross revenue ratio by state.

Schedule Page: 262 Line No.: 25 Column: a

Charged directly to various inventory and construction accounts.

Schedule Page: 262 Line No.: 36 Column: a

Allocated based on specific identification.

Schedule Page: 262.1 Line No.: 7 Column: a

Allocated on a corporate overhead ratio basis.

Schedule Page: 262.1 Line No.: 8 Column: a

Allocated based on specific identification.

Schedule Page: 262.1 Line No.: 9 Column: a

Allocated based on specific identification.

Schedule Page: 262.1 Line No.: 16 Column: a

Allocated between electric and gas operations on the basis of payroll charges. The amounts charged to other include allocation of payroll taxes to various electric and gas construction, clearing or expense accounts based on a company-wide derived payroll loading factor.

Schedule Page: 262.1 Line No.: 17 Column: a

Allocated on a corporate overhead ratio basis.

Schedule Page: 262.1 Line No.: 23 Column: a

Allocated on a corporate overhead ratio basis.

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (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)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6							
7		813,836			420	46,505	
8	TOTAL	813,836				46,505	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	GAS UTILITY						
11	4%						
12	10%						
13	8%						
14	SUBTOTAL						
15							
16	COMMON UTILITY						
17	4%						
18	10%						
19	8%						
20	SUBTOTAL						
21							
22							
23							
24	TOTAL OTHER UTILITY						
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
			6
767,331	20 Year		7
767,331			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
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			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
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			41
			42
			43
			44
			45
			46
			47
			48

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2013	Year/Period of Report End of 2013/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Accrued pension expense	85,108,666		47,595,399	1,830,351	39,343,618
2						
3	Accrued and deferred benefit					
4	compensation plans	8,851,671		1,699,571	1,911,721	9,063,821
5						
6	Intercompany portion of					
7	Supplemental Income					
8	Security Program trust assets	11,476,712			1,430,083	12,906,795
9						
10	Gas affordability tracker	98,454	131	13,520		84,934
11						
12	Fiber optic capacity rights	789,041	E-454	49,315		739,726
13	contract					
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
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31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	106,324,544		49,357,805	5,172,155	62,138,894

Schedule Page: 269 Line No.: 1 Column: c

182.3	$33,841,182
131	10,014,592
186	3,739,625

Schedule Page: 269 Line No.: 4 Column: c

242	$1,405,868
131	293,675
146	23
E-930	3
G-930	2

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2013	Year/Period of Report End of 2013/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent’s accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	140,731,474	37,154,350	20,985,184
3	Gas	35,225,761	16,724,372	10,034,080
4	Utility	12,910,872		
5	TOTAL (Enter Total of lines 2 thru 4)	188,868,107	53,878,722	31,019,264
6	Non-Utility	1,123,706		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	189,991,813	53,878,722	31,019,264
10	Classification of TOTAL			
11	Federal Income Tax	173,836,618	43,171,975	22,091,578
12	State Income Tax	16,155,195	10,706,747	8,927,686
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
				282	8,528,597	165,429,237	2
				282	6,807,079	48,723,132	3
			20,673,756		6,773,324	-989,560	4
			20,673,756		22,109,000	213,162,809	5
86,333	290,083					919,956	6
							7
							8
86,333	290,083		20,673,756		22,109,000	214,082,765	9
							10
77,055	225,105		16,393,254		18,516,129	196,891,840	11
9,278	64,978		4,280,502		3,592,871	17,190,925	12
							13

NOTES (Continued)

Schedule Page: 274 Line No.: 2 Column: i

Includes common plant allocated to Electric, previously included in Other.

Schedule Page: 274 Line No.: 3 Column: i

Includes common plant allocated to Gas, previously included in Other.

Schedule Page: 274 Line No.: 4 Column: a

Utility definition includes Regulatory Matters.

Schedule Page: 274 Line No.: 4 Column: b

Common Plant	$15,031,684
Regulatory Matters - 254	(5,481,114)
Regulatory Matters - 182	3,360,302
	$12,910,872

Schedule Page: 274 Line No.: 4 Column: g

Common Plant	$15,031,684
Regulatory Matters - 254	3,411,328
Regulatory Matters - 182	2,230,744
	$20,673,756

Schedule Page: 274 Line No.: 4 Column: i

Regulatory Matters - 254	1,143,833
Regulatory Matters - 182	5,629,491
	$6,773,324

Schedule Page: 274 Line No.: 4 Column: k

Regulatory Matters - 254	(7,748,609)
Regulatory Matters - 182	6,759,049
	($989,560)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

ACCUMULATED DEFFERED 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. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (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	Account 283			
2	Electric			
3	Fuel & Purch. Power Deferral	366,735	674,937	741,739
4	Margin Sharing Adjustment	1	65	6
5	Rate Case	105,506	99,249	173,367
6	Regulatory Assets Awaiting Re	284,670	1	
7	Unrecovered Plant Costs	1,335,821	30,458	511,303
8	Other - Electric		20,403,794	25,944,386
9	TOTAL Electric (Total of lines 3 thru 8)	2,092,733	21,208,504	27,370,801
10	Gas			
11	Unrecovered Purch. Gas Costs	1,175,918	3,166,141	1,265,708
12	Rate Case	30,070	213,311	8,827
13	Def. Postretirement Benefit	27,936	918	16,144
14	Regulatory Assets Awaiting			
15	Recovery	174,059	2,138	36,582
16	Other - Gas		26,073,222	33,768,834
17	TOTAL Gas (Total of lines 11 thru 16)	1,407,983	29,455,730	35,096,095
18	Other	43,755,949		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	47,256,665	50,664,234	62,466,896
20	Classification of TOTAL			
21	Federal Income Tax	43,297,992	41,628,494	52,288,599
22	State Income Tax	3,958,673	9,035,740	10,178,297
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						299,933	3
						60	4
						31,388	5
						284,671	6
						854,976	7
		283	2,285,333	283	20,593,695	12,767,770	8
			2,285,333		20,593,695	14,238,798	9
							10
						3,076,351	11
						234,554	12
						12,710	13
							14
						139,615	15
		283	76,538	283	23,435,861	15,663,711	16
			76,538		23,435,861	19,126,941	17
1,733	11,042		2,305,114		-37,313,538	4,127,988	18
1,733	11,042		4,666,985		6,716,018	37,493,727	19
							20
1,225	9,604		3,295,826		5,022,898	34,356,580	21
508	1,438		1,371,159		1,693,120	3,137,147	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 8 Column: c

UTILITY: Other - Electric*	
Deferred Pension Expense - Reg Asset	$ 17,946,211
MT PSC/MCC Tax Deferral	102,510
Unamortized Loss on Reaquired Debt	2,355,073
	$ 20,403,794

*Included in line 18 Other in 2012.

Schedule Page: 276 Line No.: 8 Column: d

UTILITY: Other - Electric*	
Deferred Pension Expense - Reg Asset	$ 23,368,496
MT PSC/MCC Tax Deferral	5,801
Unamortized Loss on Reaquired Debt	2,570,089
	$ 25,944,386

*Included in line 18 Other in 2012.

Schedule Page: 276 Line No.: 8 Column: h

UTILITY: Other - Electric*	
Unamortized Loss on Reaquired Debt	$ 144,368
Deferred Pension Expense - Reg Asset	2,140,965
	$ 2,285,333

*Included in line 18 Other in 2012.

Schedule Page: 276 Line No.: 8 Column: j

UTILITY: Other - Electric*	
Unamortized Loss on Reaquired Debt	$ 2,448,949
Deferred Pension Expense - Reg Asset	18,144,746
	$ 20,593,695

*Included in line 18 Other in 2012.

Schedule Page: 276 Line No.: 16 Column: c

UTILITY: Other - Gas*	
Deferred Pension Expense - Reg Asset	$ 25,234,307
MT PSC/MCC Tax Deferral	23,816
Unamortized Loss on Reaquired Debt	815,099
	$ 26,073,222

*Included in line 18 Other in 2012.

Schedule Page: 276 Line No.: 16 Column: d

UTILITY: Other - Gas*	
Deferred Pension Expense - Reg Asset	$ 32,877,768
MT PSC/MCC Tax Deferral	1,348
Unamortized Loss on Reaquired Debt	889,718
	$ 33,768,834

*Included in line 18 Other in 2012.

Schedule Page: 276 Line No.: 16 Column: h

UTILITY: Other - Gas*	
Unamortized Loss on Reaquired Debt	$ 5,124
Deferred Pension Expense - Reg Asset	71,414
	$ 76,538

*Included in line 18 Other in 2012.

Schedule Page: 276 Line No.: 16 Column: j

UTILITY: Other - Gas*	
Unamortized Loss on Reaquired Debt	$ 804,901
Deferred Pension Expense - Reg Asset	22,630,960
	$ 23,435,861

*Included in line 18 Other in 2012.

Schedule Page: 276 Line No.: 18 Column: b

UTILITY: Other	
Unamortized Loss on Reaquired Debt	$ 3,104,357

Defense Pension Expense - Reg Asset	38,563,326
Regulatory Matters - 182	2,085,170
Regulatory Matters - 254	(17,341)
Total Utility	$43,735,512
NON-UTILITY	
Partnership Ordinary Gain/(Loss)	$ 20,437
TOTAL OTHER	$43,755,949

Schedule Page: 276 Line No.: 18 Column: e

NONUTILITY: Other	
AMT Carryforward Federal	$ 285
NOL Carryforward Federal	940
Partnership Ordinary Gain/(Loss)	508
	$ 1,733

Schedule Page: 276 Line No.: 18 Column: f

NONUTILITY: Other	
Partnership Ordinary Gain/(Loss)	$ 11,042

Schedule Page: 276 Line No.: 18 Column: h

UTILITY: Other	
Regulatory Matters - 254	$ 876,988
Regulatory Matters - 182	1,428,126
	$ 2,305,114

Schedule Page: 276 Line No.: 18 Column: j

UTILITY: Other	
Unamortized Loss on Reaquired Debt	$ (3,104,357)*
Deferred Pension Expense - Reg Asset	(38,563,326)*
Regulatory Matters - 254	3,485,676
Regulatory Matters - 182	868,469
	$(37,313,538)

*Reflected in Line 8 Electric - Other and Line 16 Gas - Other as appropriate in 2013.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Regulatory matters - Deferred Tax Related	9,019,727		4,326,368	3,108,969	7,802,328
2						
3	Retired Power Plant; Montana	523,665	405	56,211		467,454
4	amortization over 120 months beginning					
5	9/11 and North Dakota amortization					
6	over 120 months beginning 7/11					
7						
8	Deferred Other Postretirement				8,016,598	8,016,598
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
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26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	9,543,392		4,382,579	11,125,567	16,286,380

Schedule Page: 278 Line No.: 1 Column: c

190	$1,196,731
282	2,705,435
283	424,202
	$4,326,368

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	102,811,836	95,225,168
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	106,840,697	100,635,947
5	Large (or Ind.) (See Instr. 4)	28,251,893	26,944,221
6	(444) Public Street and Highway Lighting	2,373,188	2,391,284
7	(445) Other Sales to Public Authorities	3,336,794	3,263,158
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	576,762	714,382
10	TOTAL Sales to Ultimate Consumers	244,191,170	229,174,160
11	(447) Sales for Resale	102,359	9,048
12	TOTAL Sales of Electricity	244,293,529	229,183,208
13	(Less) (449.1) Provision for Rate Refunds	-400,644	3,635,867
14	TOTAL Revenues Net of Prov. for Refunds	244,694,173	225,547,341
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	101,280	114,274
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	5,417,226	4,908,361
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	2,642,920	2,436,435
22	(456.1) Revenues from Transmission of Electricity of Others	2,540,111	2,510,122
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	10,701,537	9,969,192
27	TOTAL Electric Operating Revenues	255,395,710	235,516,533

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
1,199,429	1,111,571	109,981	106,426	2
				3
1,381,520	1,317,680	21,308	21,135	4
503,506	476,459	255	278	5
30,876	31,427	492	672	6
50,918	50,487	818	850	7
				8
6,837	8,904	208	210	9
3,173,086	2,996,528	133,062	129,571	10
22,796	14,094			11
3,195,882	3,010,622	133,062	129,571	12
				13
3,195,882	3,010,622	133,062	129,571	14

Line 12, column (b) includes $ 2,510,700 of unbilled revenues.

Line 12, column (d) includes 41,307 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 4 Column: b

Basis of classification - Commercial Customers

Schedule Page: 300 Line No.: 4 Column: c

Basis of classification - Commercial Customers

Schedule Page: 300 Line No.: 5 Column: b

Basis of classification - Industrial Customers

Schedule Page: 300 Line No.: 5 Column: c

Basis of classification - Industrial Customers

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential-440					
2	Montana					
3	10-Residential Electric Service	189,447	16,263,393	19,634	9,649	0.0858
4	20-Small General Electric Service	4,795	363,880	319	15,031	0.0759
5	52-Outdoor Lighting Service	665	73,606	867	767	0.1107
6	North Dakota					
7	10-Residential Electric Service	755,559	62,186,069	70,533	10,712	0.0823
8	13-Optional Residential Thermal E	124	6,741	3	41,333	0.0544
9	16-Optional Time-of-Day Service	158	11,225	9	17,556	0.0710
10	20-Small General Electric Service	6,293	644,370	719	8,752	0.1024
11	25-Irrigation Power Service	1	278	1	1,000	0.2780
12	30-General Electric Service	9,621	787,129	98	98,173	0.0818
13	32-General Electric Space Heating	2,112	137,268	26	81,231	0.0650
14	52-Outdoor Lighting Service	1,048	97,342	1,152	910	0.0929
15	95-Occassional Power Purchase Non					
16	South Dakota					
17	10-Residential Electric Service	67,305	6,498,356	6,611	10,181	0.0966
18	20-Small General Electric Service	569	52,782	41	13,878	0.0928
19	24-Private Lighting Service	182	14,606	269	677	0.0803
20	53-Special Residential Dual Fuel	6,084	329,516	322	18,894	0.0542
21	54-Special General Electric Dual	125	6,247	5	25,000	0.0500
22	Wyoming					
23	10-Residential Electric Service	129,279	13,610,978	12,858	10,054	0.1053
24	11-Special Residential Controlled	8,910	453,150	688	12,951	0.0509
25	20-Small General Electric Service	1,262	148,748	214	5,897	0.1179
26	22-Special General Controlled Ele	4	263	1	4,000	0.0658
27	24-Outdoor Lighting Service	463	23,786	657	705	0.0514
28	Unbilled-Net	15,420	1,102,071			0.0715
29	Adjustment for Duplicate Customer			-4,393		
30	Subtotal Residential	1,199,426	102,811,804	110,634	10,841	0.0857
31						
32	Small Commercial-442					
33	Montana					
34	20-Small General Electric Service	113,665	8,813,696	5,186	21,918	0.0775
35	25-Irrigation Power Service	1,988	136,629	74	26,865	0.0687
36	32-General Electric Space Heating	324	21,124	3	108,000	0.0652
37	52-Outdoor Lighting Service	1,904	211,773	871	2,186	0.1112
38	North Dakota					
39	20-Small General Electric Service	119,700	10,780,962	8,887	13,469	0.0901
40						
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SALES OF ELECTRICITY BY RATE SCHEDULES

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4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	25-Irrigation Power Service	1,259	70,103	33	38,152	0.0557
2	26-Optional Time-of Day Small Gen	62	5,204	4	15,500	0.0839
3	30-General Electric Service	388,317	31,978,123	2,734	142,033	0.0824
4	31-Optional Time-of-Day General E	14	1,432	3	4,667	0.1023
5	32-General Electric Space Heating	40,810	2,692,203	414	98,575	0.0660
6	40-Small Municipal Electric Servi		119			
7	52-Outdoor Lighting Service	5,208	483,945	1,364	3,818	0.0929
8	South Dakota					
9	20-Small General Electric Service	31,325	2,954,566	1,912	16,383	0.0943
10	24-Private Lighting Service	448	35,994	289	1,550	0.0803
11	25-Irrigation Power Service	229	16,822	4	57,250	0.0735
12	26-Optional Time-of-Day General E	27	2,206	1	27,000	0.0817
13	41-Street Lighting Service		927	1		
14	50-General Electric Water Heating	62	6,042	8	7,750	0.0975
15	54-Special General Electric Dual	4,265	207,390	95	44,895	0.0486
16	56-General Electric Space Heating	724	55,223	32	22,625	0.0763
17	Wyoming					
18	20-Small General Electric Service	50,837	4,548,594	2,356	21,578	0.0895
19	22-Special General Controlled Ele	289	14,492	18	16,056	0.0501
20	24-Outdoor Lighting Service	969	49,688	353	2,745	0.0513
21	25-Irrigation Power Service	2,284	213,532	48	47,583	0.0935
22	26-Irrigation Power Service Optio	112	13,992	5	22,400	0.1249
23	Unbilled-Net	10,983	644,400			0.0587
24	Adjustment for Duplicate Customer			-4,329		
25	Subtotal Small Commercial	775,805	63,959,181	20,366	38,093	0.0824
26						
27	Large Commercial-442					
28	Montana					
29	25-Irrigation Power Service	951	54,679	9	105,667	0.0575
30	30-Large General Electric Service	123,127	8,317,012	239	515,176	0.0675
31	31-Optional Time-of-Day Large Gen	307	32,738	3	102,333	0.1066
32	52-Outdoor Lighting Service	478	53,246	104	4,596	0.1114
33	North Dakota					
34	20-Small General Electric Service	8	867	1	8,000	0.1084
35	25-Irrigation Power Service	17	1,368	1	17,000	0.0805
36	30-General Electric Service	311,871	23,092,577	535	582,936	0.0740
37	31-Opti0nal Time-of-Day General S	6,393	486,341	25	255,720	0.0761
38	32-General Electric Space Heating	12,420	760,265	35	354,857	0.0612
39	38-Interruptible Large Power Dema	24,920	1,485,418	2	12,460,000	0.0596
40	52-Outdoor Lighting Service	407	37,380	138	2,949	0.0918
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SALES OF ELECTRICITY BY RATE SCHEDULES

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6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

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1	South Dakota					
2	24-Private Lighting Service	148	11,871	40	3,700	0.0802
3	25-Irrigation Power Service					
4	30-Large General Electric Service	28,452	2,151,980	105	270,971	0.0756
5	Wyoming					
6	24-Outdoor Lighting Service	65	3,350	20	3,250	0.0515
7	25-Irrigation Power Service					
8	26-Irrigation Power Service Optio					
9	39-Large General Electric Service	85,614	5,817,037	140	611,529	0.0679
10	Unbilled-Net	10,538	575,421			0.0546
11	Adjustment for Duplicate Customer			-431		
12	Subtotal Large Commercial	605,716	42,881,550	966	627,035	0.0708
13						
14	Small Industrial-422					
15	Montana					
16	20-Small General Electric Service	5,328	397,832	84	63,429	0.0747
17	31-Optional Time-of-Day Large Gen	4,063	308,255	4	1,015,750	0.0759
18	35-Contract Service	728	46,374	4	182,000	0.0637
19	52-Outdoor Lighting Service	3	310	4	750	0.1033
20	North Dakota					
21	20-Small General Electric Service	425	37,430	29	14,655	0.0881
22	30-General Electric Service	3,168	303,716	29	109,241	0.0959
23	32-General Electric Space Heating	843	53,282	4	210,750	0.0632
24	52-Outdoor Lighting Service	32	2,949	11	2,909	0.0922
25	South Dakota					
26	20-Small General Electric Service	26	2,352	1	26,000	0.0905
27	24-Private Lighting Service	10	807	3	3,333	0.0807
28	27-Feed Grinding Service	2	819	2	1,000	0.4095
29	Wyoming					
30	20-Small General Electric Service	441	37,413	12	36,750	0.0848
31	24-Outdoor Lighting Service	2	84	2	1,000	0.0420
32	Unbilled-Net	67	4,263			0.0636
33	Adjustment for Duplicate Customer			-32		
34	Subtotal Small Industrial	15,138	1,195,886	157	96,420	0.0790
35						
36	Large Industrial-422					
37	Montana					
38	30-Large General Electric Service	78,029	4,590,535	29	2,690,655	0.0588
39	31-Optional Time-of-Day Large Gen	7,470	491,341	4	1,867,500	0.0658
40	35-Contract Service	228,555	11,124,489	15	15,237,000	0.0487
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

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1	52-Outdoor Lighting Service	1	162	3	333	0.1620
2	North Dakota					
3	30-General Electic Service	151,800	9,442,852	51	2,976,471	0.0622
4	31-Optional Time-of-Day General E	4,015	307,640	9	446,111	0.0766
5	32-General Electric Space Heating	32	2,978	1	32,000	0.0931
6	38-Interruptible Large Power Dema	4,911	238,125	1	4,911,000	0.0485
7	52-Outdoor Lighting Service	19	1,803	5	3,800	0.0949
8	South Dakota					
9	24-Private Lighting Service	12	924	2	6,000	0.0770
10	30-Large General Electric Service	7,727	506,783	6	1,287,833	0.0656
11	Wyoming					
12	39-Large General Electric Service	2,202	181,764	7	314,571	0.0825
13	Ubilled-Net	3,594	166,610			0.0464
14	Adjustment for Duplicate Customer			-43		
15	Subtotal Large Industrial	488,367	27,056,006	90	5,426,300	0.0554
16						
17	Public Street and Highway Lightin					
18	Montana					
19	20-Small General Electric Service	76	5,945	5	15,200	0.0782
20	41-Municipal Lighting Service	6,807	522,356	151	45,079	0.0767
21	52-Outdoor Lighting Service	146	16,291	36	4,056	0.1116
22	North Dakota					
23	20-Small general Electric Service	143	24,335	48	2,979	0.1702
24	40-Small Municipal Electric Servi	29	1,953	1	29,000	0.0673
25	41-Municipal Lighting Service	19,530	1,473,464	671	29,106	0.0754
26	52-Outdoor Lighting Service	193	17,975	69	2,797	0.0931
27	South Dakota					
28	20-Small General Electric Service		24	1		
29	24-Private Lighting Service	10	820	9	1,111	0.0820
30	41-Municipal Lighting Service	2,651	229,287	85	31,188	0.0865
31	Wyoming					
32	20-Small General Electric Service	15	2,483	5	3,000	0.1655
33	24-Outdoor Lighting Service	7	344	3	2,333	0.0491
34	41-Municipal Lighting Service	1,114	88,210	10	111,400	0.0792
35	Unbilled-Net	156	-10,299			-0.0660
36	Adjustment for Duplicate Customer			-620		
37	Subtotal Public Street and Highwa	30,877	2,373,188	474	65,141	0.0769
38						
39	Other Sales to Public Authorities					
40	Montana					
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

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1	48-Municipal Pumping Service	7,202	442,533	109	66,073	0.0614
2	North Dakota					
3	20-Small General Electric Service	437	49,728	66	6,621	0.1138
4	30-General Electric Service	1,624	129,818	7	232,000	0.0799
5	32-General Electric Space Heating	281	17,701	5	56,200	0.0630
6	40-Small Municipal Electric Servi	4,246	341,026	327	12,985	0.0803
7	48-Municipal Pumping Service	35,069	2,220,959	323	108,573	0.0633
8	52-Outdoor Lighting Service		12	2		
9	South Dakota					
10	48-Municipal Pumpling Service	1,508	107,143	52	29,000	0.0710
11	Unbilled-Net	551	27,873			0.0506
12	Adjustment for Duplicate Customer			-83		
13	Subtotal Other Sales	50,918	3,336,793	808	63,017	0.0655
14						
15	Interdepartmental-448					
16	Montana					
17	Billed	541	53,333	96	5,635	0.0986
18	North Dakota					
19	Billed	5,751	465,232	185	31,086	0.0809
20	South Dakota					
21	Billed	357	33,668	15	23,800	0.0943
22	Wyoming					
23	Billed	193	24,168	30	6,433	0.1252
24	Unbilled-Net	-3	361			-0.1203
25	Adjustment for Duplicate Customer			-36		
26	Subtotal Interdepartmental Sales	6,839	576,762	290	23,583	0.0843
27						
28	Total	3,173,086	244,191,170	133,785	23,718	0.0770
29						
30	Fuel Clause Adjustment					
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

Schedule Page: 304.4 Line No.: 30 Column: a

Revenue Billed Pursuant to Fuel Clause Adjustment (FCA) (Included in revenue amounts on pages 304-304.4)

Residential-440	
Montana	
10-Residential Electric Service	4,650,117
20-Small General Electric Service	118,223
52-Outdoor Lighting Service	16,415
North Dakota	
10-Residential Electric Service	19,464,529
13-Optional Residential Thermal Energy Storage	3,258
16-Optional Time-of-Day Residential Electric Service	4,120
20-Small General Electric Service	163,127
25-Irrigation Power Service	16
30-General Electric Service	250,113
32-General Electric Space Heating Service	55,782
52-Outdoor Lighting Service	26,947
South Dakota	
10-Residential Electric Service	482,296
20-Small General Electric Service	4,149
24-Private Lighting Service	1,310
53-Special Residential Electric Dual Fuel Space Heating Service	46,188
54-Special General Electric Dual Fuel Space Heating Service	928
Wyoming	
10-Residential Electric Service	888,540
11-Special Residential Controlled Electric Service	58,138
20-Small General Electric Service	8,539
22-Special General Controlled Electric Service	26
24-Outdoor Lighting Service	3,241
Unbilled-net	577,106
Subtotal Residential	26,823,108
Small Commercial-442	
Montana	
20-Small General Electric Service	2,793,783
25-Irrigation Power Service	46,804
32-General Electric Space Heating Service	8,345
52-Outdoor Lighting Service	46,847
North Dakota	
20-Small General Electric Service	3,118,902
25-Irrigation Power Service	31,056
26-Optional Time-of-Day Small General Electric Service	1,729
30-General Electric Service	10,076,262
31-Time-of-Day General Electric Service	377
32-General Electric Space Heating Service	1,069,754
40-Small Municipal Electric Service	0
52-Outdoor Lighting Service	134,479
South Dakota	
20-Small General Electric Service	224,223
24-Private Lighting Service	3,218
25-Irrigation Power Service	1,334
26-Optional Time-of-Day Small General Electric Service	189
41-Street Lighting Service Service	0
50-General Electric Water Heating Service	466
54-Special General Electric Dual Fuel Space Heating Service	32,459

56-General Electric Space Heating Service	5,220
Wyoming	
20-Small General Electric Service	352,991
22-Special General Controlled Electric Service	1,802
24-Outdoor Lighting Service	6,726
25-Irrigation Power Service	17,251
26-Irrigation Power Service Optional Time-of-Day	847
Unbilled-net	342,688
Subtotal Small Commercial	18,317,752
Large Commercial-442	
Montana	
25-Irrigation Power Service	22,360
30-Large General Electric Service	3,031,532
31-Optional Time-of-Day Large General Electric Service	7,664
52-Outdoor Lighting Service	11,790
North Dakota	
20-Small General Electric Service	213
25-Irrigation Power Service	414
30-General Electric Service	7,952,761
31-Time-of-Day General Electric Service	163,231
32-General Electric Space Heating Service	325,356
38-Interruptible Large Power Demand Response	618,577
52-Outdoor Lighting Service	10,760
South Dakota	
24-Private Lighting Service	1,057
30-Large General Electric Service	208,376
Wyoming	
24-Outdoor Lighting Service	459
39-Large General Electric Service	612,626
Unbilled-net	266,706
Subtotal Large Commercial	13,233,882
Small Industrial-442	
Montana	
20-Small General Electric Service	131,622
31-Optional Time-of-Day Large General Electric Service	94,893
35-Contract Service	15,881
52-Outdoor Lighting Service	69
North Dakota	
20-Small General Electric Service	11,213
30-General Electric Service	81,399
32-General Electric Space Heating Service	21,897
52-Outdoor Lighting Service	816
South Dakota	
20-Small General Electric Service	187
24-Private Lighting Service	72
27-Feed Grinding Service	12
Wyoming	
20-Small General Electric Service	3,028
24-Outdoor Lighting Service	12
Unbilled-net	2,329
Subtotal Small Industrial	363,430
Large Industrial-442	

Montana	
30-General Electric Service	1,922,984
31-Optional Time-of-Day Large General Electric Service	183,175
35-Contract Service	4,988,038
52-Outdoor Lighting Service	36
North Dakota	
30-General Electric Service	3,803,290
31-Optional Time-of-Day General Electric Service	102,853
32-General Electric Space Heating Service	812
38-Interruptible Large Power Demand Response	123,450
52-Outdoor Lighting Service	499
South Dakota	
24-Private Lighting Service	82
30-Large General Electric Service	54,247
Wyoming	
39-Large General Service	15,061
Unbilled-net	100,830
Subtotal Large Industrial	11,295,357
Public Street and Highway Lighting-444	
Montana	
20-Small General Service	1,852
41-Municipal Lighting Service	167,469
52-Outdoor Lighting Service	3,657
North Dakota	
20-Small General Service	3,725
40-Small Municipal Electric Service	750
41-Municipal Lighting Service	501,998
52-Outdoor Lighting Service	5,101
South Dakota	
20-Small General Service	0
24-Private Lighting Service	74
41-Street Lighting Service	19,136
Wyoming	
20-Small General Electric Service	108
24-Outdoor Lighting Service	47
41-Municipal Lighting Service	7,818
Unbilled-net	5,241
Subtotal Public Street and Highway Lighting	716,976
Other Sales to Public Authorities-446	
Montana	
48-Municipal Pumping Service	176,183
North Dakota	
20-Small General Electric Service	11,300
30-General Electric Service	41,740
32-General Electric Space Heating Service	7,493
40-Small Municipal Electric Service	109,350
48-Municipal Pumping Service	888,391
52-Outdoor Lighting Service	3
South Dakota	
48-Municipal Pumping Service	10,693
Unbilled-net	17,324
Subtotal Other Sales	1,262,477

Interdepartmental Sales-448	
Montana	13,275
North Dakota	147,614
South Dakota	2,665
Wyoming	1,293
Unbilled-Net	556
Subtotal Interdepartmental	165,403
Total Fuel Clause Adjustment	72,178,385

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW) Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Midwest Independent Transmission					
2	System Operator (MISO)	OS	MISO	NA	NA	NA
3	Sales for Resale Fuel Cost					
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2013	Year/Period of Report End of 2013/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
22,796		569,325		569,325	2
		-466,966		-466,966	3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
22,796	0	102,359	0	102,359	
22,796	**0**	**102,359**	**0**	**102,359**	

Schedule Page: 310 Line No.: 2 Column: b

Respondent began participation in the Midwest Independent System Operator (MISO) RTO in April 2005.

Schedule Page: 310 Line No.: 3 Column: i

Per Docket No. RM04-12-000; Order No. 668: Sales for Resale Revenue offset by Sales for Resale fuel and purchased power costs of $466,966.

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	2,538,353	2,478,056
5	(501) Fuel	46,215,107	42,511,003
6	(502) Steam Expenses	5,018,064	4,860,529
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,912,911	1,879,451
10	(506) Miscellaneous Steam Power Expenses	2,728,953	2,513,427
11	(507) Rents	685,686	720,465
12	(509) Allowances	70	139
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	59,099,144	54,963,070
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	823,594	1,001,149
16	(511) Maintenance of Structures	665,784	662,502
17	(512) Maintenance of Boiler Plant	5,064,784	5,314,196
18	(513) Maintenance of Electric Plant	1,861,875	2,137,184
19	(514) Maintenance of Miscellaneous Steam Plant	1,416,544	1,330,200
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	9,832,581	10,445,231
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	68,931,725	65,408,301
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	78,524	150,285
63	(547) Fuel	582,335	1,035,030
64	(548) Generation Expenses	637,057	731,915
65	(549) Miscellaneous Other Power Generation Expenses	380,118	428,999
66	(550) Rents	6,000	378,193
67	TOTAL Operation (Enter Total of lines 62 thru 66)	1,684,034	2,724,422
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	51,323	56,672
70	(552) Maintenance of Structures	8,176	797
71	(553) Maintenance of Generating and Electric Plant	663,822	566,201
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,620	3,759
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	724,941	627,429
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	2,408,975	3,351,851
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	36,263,298	28,548,384
77	(556) System Control and Load Dispatching	1,710,975	1,519,664
78	(557) Other Expenses		
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	37,974,273	30,068,048
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	109,314,973	98,828,200
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,209,996	1,248,286
84			
85	(561.1) Load Dispatch-Reliability	470,478	492,861
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,007,190	870,060
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	456,561	470,873
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	33,259	34,301
93	(562) Station Expenses	687,089	447,250
94	(563) Overhead Lines Expenses	256,146	116,840
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	1,705,765	1,306,926
97	(566) Miscellaneous Transmission Expenses	58,556	96,615
98	(567) Rents	1,653,919	1,568,551
99	TOTAL Operation (Enter Total of lines 83 thru 98)	7,538,959	6,652,563
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	59,186	41,324
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	686,418	589,962
108	(571) Maintenance of Overhead Lines	2,444,097	853,310
109	(572) Maintenance of Underground Lines		502
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,189,701	1,485,098
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	10,728,660	8,137,661

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	508,974	453,027
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	508,974	453,027
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	508,974	453,027
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,547,278	1,530,388
135	(581) Load Dispatching		
136	(582) Station Expenses	661,436	679,219
137	(583) Overhead Line Expenses	550,394	533,930
138	(584) Underground Line Expenses	1,520,155	1,267,945
139	(585) Street Lighting and Signal System Expenses	103,624	62,227
140	(586) Meter Expenses	788,936	420,318
141	(587) Customer Installations Expenses	303,250	278,922
142	(588) Miscellaneous Expenses	3,502,100	2,753,663
143	(589) Rents	244,940	190,117
144	TOTAL Operation (Enter Total of lines 134 thru 143)	9,222,113	7,716,729
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	344,471	425,460
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	175,711	290,736
149	(593) Maintenance of Overhead Lines	3,758,520	2,829,039
150	(594) Maintenance of Underground Lines	951,571	886,599
151	(595) Maintenance of Line Transformers	165,118	195,745
152	(596) Maintenance of Street Lighting and Signal Systems	173,282	146,201
153	(597) Maintenance of Meters	28,098	26,451
154	(598) Maintenance of Miscellaneous Distribution Plant	762,227	642,364
155	TOTAL Maintenance (Total of lines 146 thru 154)	6,358,998	5,442,595
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	15,581,111	13,159,324
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	79,607	157,091
160	(902) Meter Reading Expenses	543,855	717,825
161	(903) Customer Records and Collection Expenses	2,417,062	1,935,096
162	(904) Uncollectible Accounts	700,101	424,969
163	(905) Miscellaneous Customer Accounts Expenses	159,835	177,601
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	3,900,460	3,412,582

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	44,676	39,380
168	(908) Customer Assistance Expenses	91,816	115,866
169	(909) Informational and Instructional Expenses	116,917	50,904
170	(910) Miscellaneous Customer Service and Informational Expenses	1,637	1,852
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	255,046	208,002
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	20,600	4,836
175	(912) Demonstrating and Selling Expenses	79,861	145,826
176	(913) Advertising Expenses	28,129	10,890
177	(916) Miscellaneous Sales Expenses	10,786	26,003
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	139,376	187,555
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	5,194,296	4,790,414
182	(921) Office Supplies and Expenses	3,181,729	2,951,409
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	421,551	532,101
185	(924) Property Insurance	945,683	874,024
186	(925) Injuries and Damages	1,184,621	1,376,701
187	(926) Employee Pensions and Benefits	6,833,142	6,670,399
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	850,795	612,420
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	51,607	60,448
192	(930.2) Miscellaneous General Expenses	565,073	397,889
193	(931) Rents	388,031	307,708
194	TOTAL Operation (Enter Total of lines 181 thru 193)	19,616,528	18,573,513
195	Maintenance		
196	(935) Maintenance of General Plant	676,406	572,796
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	20,292,934	19,146,309
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	160,721,534	143,532,660

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Black Hills Power & Light Co.	RQ	BHPL #42	49	49	49
2	Wisconsin Energy	OS		115	115	115
3	Western Area Power Administration	OS	19			
4	Western Area Power Admin - Ft. Peck	LF	19			
5	Western Area Power Administration	EX	19			
6	Midwest Independent Transmission	EX	MISO			
7	System Operator (MISO)					
8	State of North Dakota (Generator)	OS				
9	Deferral per tariff					
10	Constellation NEnergy Inc	OS				
11						
12						
13						
14						
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
88,570			4,449,082	2,231,578		6,680,660	1
			3,929,500			3,929,500	2
							3
14,301				476,844		476,844	4
	71,374	73,152	25,000		-116,104	-91,104	5
870,168				24,028,151		24,028,151	6
							7
			162,450			162,450	8
					982,353	982,353	9
			94,444			94,444	10
							11
							12
							13
							14
973,039	71,374	73,152	8,660,476	26,736,573	866,249	36,263,298	

FOOTNOTE DATA

Schedule Page: 326 Line No.: 2 Column: b

Other Service classification includes purchases for scheduled outages, operational control, general purpose, emergencies, interruptible load replacement and economical reasons.

Schedule Page: 326 Line No.: 5 Column: l

Amounts recorded to reflect power exchanges and do not constitute monetary settlements

Schedule Page: 326 Line No.: 8 Column: b

Other Service classification includes purchases during periods of generation and economical reasons.

Schedule Page: 326 Line No.: 9 Column: l

Reflects amount of fuel and purchased power deferred in accordance with respective state tariffs

Schedule Page: 326 Line No.: 10 Column: b

Other Service classification includes purchases during periods of generation and economical reasons.

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Western Area Power Administration (WAPA)	WAPA	WAPA	OLF
2	Basin Electric Power Cooperative	Basin Electric Power Cooperative	Basin Electric Power Cooperative	OLF
3	Powder River Energy Corp.	Powder River Energy Corp.	Powder River Energy Corp.	OLF
4	Midwest Independent Transmission			
5	System Operator (MISO)	MISO participants	MISO participants	OS
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				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
19	Various	Various		407,651	390,671	1
#30	Various	Various		1,352,253	1,263,788	2
5	Sheridan	Various		42,418	39,643	3
						4
MISO	Various	Various				5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
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						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**1,802,322**	**1,694,102**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	231,631		231,631	1
		105,678	105,678	2
	31,814		31,814	3
				4
	2,170,988		2,170,988	5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
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				30
				31
				32
				33
				34
0	**2,434,433**	**105,678**	**2,540,111**	

Schedule Page: 328 Line No.: 1 Column: d

WAPA contract termination 12/31/2015

Schedule Page: 328 Line No.: 2 Column: m

Fixed monthly wheeling fee

Schedule Page: 328 Line No.: 3 Column: d

Sheridan-Johnson REA contract is perpetual

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	DELIVERED POWER TO AND							
2	RECEIVED POWER FROM							
3	WHEELER							
4	Western Area Power Admn	FNS	730,576	781,716		1,059,748		1,059,748
5	Mor Gran Sou Elec Coop	LFP	1,497	1,631				
6	Grand Elec Coop	LFP	617	680		4,256		4,256
7	Midwest Independent							
8	Transmission System							
9	Operator (MISO)	OS					641,761	641,761
10								
11								
12								
13								
14								
15								
16								
	TOTAL		732,690	784,027		1,064,004	641,761	1,705,765

Schedule Page: 332 Line No.: 9 Column: g

MISO Schedule 26-RECB charges. Effective January 1, 2012, North Dakota's share of the MISO net transmission costs are recoverable.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	299,593
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Directors Fees and Expenses	265,480
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
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32		
33		
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37		
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39		
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41		
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43		
44		
45		
46	TOTAL	565,073

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			312,631		312,631
2	Steam Production Plant	9,869,022				9,869,022
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	6,693,746			-56,210	6,637,536
7	Transmission Plant	3,397,044				3,397,044
8	Distribution Plant	7,956,792				7,956,792
9	Regional Transmission and Market Operation					
10	General Plant	715,855				715,855
11	Common Plant-Electric	1,262,123		995,699		2,257,822
12	TOTAL	29,894,582		1,308,330	-56,210	31,146,702

B. Basis for Amortization Charges

Range from five year, 20% to ten year, 10% Straight Line Amortization for computer software.

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	STEAM PRODUCTION						
13							
14	311	71,453					
15	312	209,219					
16	314	83,906					
17	315	19,534					
18	316	17,109					
19	317.0	854					
20	Subtotal	402,075					
21							
22	OTHER PRODUCTION						
23							
24	341	6,830					
25	342	2,720					
26	344	128,116					
27	345	15,760					
28	346	276					
29	347.0	3,143					
30	Subtotal	156,845					
31	TRANSMISSION PLANT						
32							
33	350.2	2,886					
34	352	2					
35	353	100,734					
36	354	4,993					
37	355	46,872					
38	356	34,935					
39	357	1,942					
40	358	3,102					
41	359.1	1					
42	Subtotal	195,467					
43	DISTRIBUTION PLANT						
44							
45	360.2	860					
46	362	49,444					
47	364	34,060					
48	365	24,889					
49	366	218					
50	367	78,912					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	368	60,385					
13	369	30,461					
14	370	17,589					
15	371	2,691					
16	373	6,840					
17	374.0	40					
18	Subtotal	306,389					
19							
20	GENERAL PLANT						
21							
22	303	9,141					
23	390	687					
24	391.1	153					
25	391.2						
26	391.3	52					
27	391.4	275					
28	391.5	22					
29	392.1	978					
30	392.2	6,307					
31	393	15					
32	394.1	2,701					
33	395	516					
34	396.1	445					
35	396.2	10,418					
36	397.1	126					
37	397.2	59					
38	397.3	152					
39	397.4	211					
40	397.5	121					
41	397.6	992					
42	397.8	1,079					
43	397.9	218					
44	398	57					
45	Subtotal	34,725					
46							
47	Total	1,095,501					
48							
49							
50	FOOTNOTE						

Schedule Page: 336 Line No.: 19 Column: a

Asset Retirement Obligation (ARO) depreciated over the estimated remaining life to removal of the asset, with legal obligations

Schedule Page: 336 Line No.: 29 Column: a

Asset Retirement Oblication (ARO) depreciated over the estimated remaining life to removal of the asset, with legal obligations

Schedule Page: 336 Line No.: 41 Column: a

Asset Retiremnet Obligation (ARO) depreciated over the estimated remaining life to removal of the asset, with legal obligations.

Schedule Page: 336.1 Line No.: 17 Column: a

Asset Retirement Obligation (ARO) depreciated over the estimated remaining life to removal of the asset, with legal obligations

Schedule Page: 336.1 Line No.: 50 Column: a

Column (b) - 12/31/13 depreciable sub-plant account balances

Other depreciation provisions include:
Provision for deferred AFUDC, interest and depreciation of Coyote I Station which had been disallowed in Montana rate base $168,451 in 2013.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	State Commission Regulatory Expense Amortized				
2	Over Various 12 Month Periods				
3					
4	MONTANA				
5	Electric				74,648
6					
7	Gas				76,330
8					
9					
10	NORTH DAKOTA				
11	Electric				81,935
12					
13	Gas				
14					
15					
16	SOUTH DAKOTA				
17	Electric				
18					
19	Gas				
20					
21					
22	SOUTH DAKOTA - EAST RIVER				
23	Gas				
24					
25					
26	WYOMING				
27	Electric				127,638
28					
29	Gas				
30					
31					
32	MINNESOTA				
33	Gas				
34					
35					
36	NORTH DAKOTA - WAHPETON				
37	Gas				
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				360,551

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
							2
							3
							4
	928	53,849		928	74,648		5
							6
	928	18,945	230,026	928	4,256	302,100	7
							8
							9
							10
	928	463,020	80,393	928	80,590	81,738	11
							12
	928	21,724	219,218			219,218	13
							14
							15
							16
	928	13,801					17
							18
	928	63,042	94,091	928	1,568	92,523	19
							20
							21
							22
		277		928			23
							24
							25
							26
	928	37,249		928	127,638		27
							28
	928	32,460					29
							30
							31
							32
	928	161,800					33
							34
							35
							36
	928	33					37
							38
							39
							40
							41
							42
							43
							44
							45
		866,200	623,728		288,700	695,579	46

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. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	5,971,554		
4	Transmission	2,575,546		
5	Regional Market			
6	Distribution	5,820,746		
7	Customer Accounts	1,988,953		
8	Customer Service and Informational	111,630		
9	Sales	79,618		
10	Administrative and General	3,931,896		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	20,479,943		
12	Maintenance			
13	Production	2,028,521		
14	Transmission	883,461		
15	Regional Market			
16	Distribution	3,126,435		
17	Administrative and General	243,477		
18	TOTAL Maintenance (Total of lines 13 thru 17)	6,281,894		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	8,000,075		
21	Transmission (Enter Total of lines 4 and 14)	3,459,007		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	8,947,181		
24	Customer Accounts (Transcribe from line 7)	1,988,953		
25	Customer Service and Informational (Transcribe from line 8)	111,630		
26	Sales (Transcribe from line 9)	79,618		
27	Administrative and General (Enter Total of lines 10 and 17)	4,175,373		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	26,761,837	172,071	26,933,908
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	328,399		
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution	10,716,090		
37	Customer Accounts	4,088,636		
38	Customer Service and Informational	338,358		
39	Sales	211,388		
40	Administrative and General	3,409,698		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	19,092,569		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply	15,395		
46	Storage, LNG Terminaling and Processing			
47	Transmission	290		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	3,114,436		
49	Administrative and General	189,178		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	3,319,299		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	343,794		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru 47)			
56	Transmission (Lines 35 and 47)	290		
57	Distribution (Lines 36 and 48)	13,830,526		
58	Customer Accounts (Line 37)	4,088,636		
59	Customer Service and Informational (Line 38)	338,358		
60	Sales (Line 39)	211,388		
61	Administrative and General (Lines 40 and 49)	3,598,876		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	22,411,868	146,261	22,558,129
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	49,173,705	318,332	49,492,037
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	9,027,101	55,923	9,083,024
69	Gas Plant	7,689,753	47,319	7,737,072
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	16,716,854	103,242	16,820,096
72	Plant Removal (By Utility Departments)			
73	Electric Plant	341,397	4,302	345,699
74	Gas Plant	290,820	4,302	295,122
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	632,217	8,604	640,821
77	Other Accounts (Specify, provide details in footnote):			
78	(183) Preliminary Survey Investigation	1,737		1,737
79	(184) Clearing Accounts	304,155		304,155
80	(416) Cost / Expense of Mech(Job) & Const. Work	755,495		755,495
81	(417) Expense for Non-Utility Operations	302,818		302,818
82	(426) Miscellaneous Income Deductions	12,544		12,544
83	(121) Non-Utility	21,994		21,994
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	1,398,743		1,398,743
96	TOTAL SALARIES AND WAGES	67,921,519	430,178	68,351,697

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Account No.		Utility Plant	Accumulated Depreciation	Depreciation Expense
	PLANT IN SERVICE			
303	Misc. Intangible Plant	54,544,108	22,181,053	2,366,487
389	Land and Land Rights	3,136,091	0	0
390	Structures and Improvements	35,646,694	14,730,001	776,829
391	Office Furniture & Equipment	7,033,354	3,347,689	954,339
392	Transportation Equipment	10,209,035	5,486,660	396,205
393	Stores Equipment	55,573	33,318	1,839
394	Miscellaneous Tools	725,551	378,463	43,645
396	Power Operated Equipment	0	0	0
397	Communication Equipment	3,059,870	788,291	208,793
398	Miscellaneous Equipment	1,331,301	565,996	67,258
3991	Asset Retirement Obligations	7,270	4,723	0
		115,748,847	47,516,194	4,815,395
	WORK IN PROGRESS	8,273,438	17,619	
		124,022,285	47,533,813	4,815,395
Allocation of Common Utility Plant				
	Electric Department	65,344,088	27,785,815	2,257,822
	Natural Gas Department	58,678,197	19,747,998	2,323,847
	Clearing Accounts			233,726
		124,022,285	47,533,813	4,815,395

Basis of Allocation

(1) General Office common plant and depreciation are allocated based on net plant and employee ratios.

(2) Other common plant and depreciation are directly assigned or allocated based on the ratio of electric transmission and distribution and gas distribution gross plant investment by state or employee ratios.

(3) Expenses other than depreciation are not shown above but are allocated on net plant in service and number of employee ratios.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: INTERCONNECTED SYSTEM

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	874	31	1000	516	358				
2	February	773	20	1000	482	291				
3	March	718	18	1000	451	267				
4	Total for Quarter 1	2,365			1,449	916				
5	April	664	9	1000	425	239				
6	May	571	13	1800	398	173				
7	June	640	25	1600	456	184				
8	Total for Quarter 2	1,875			1,279	596				
9	July	765	11	1800	539	226				
10	August	780	28	1800	549	231				
11	September	766	6	1800	541	225				
12	Total for Quarter 3	2,311			1,629	682				
13	October	653	28	2000	431	222				
14	November	770	21	1900	496	274				
15	December	855	9	1900	560	295				
16	Total for Quarter 4	2,278			1,487	791				
17	Total Year to Date/Year	8,829			5,844	2,985				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: SHERDIAN

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	61	11	1900	53	7				
2	February	54	19	900	48	7				
3	March	52	4	2000	46	6				
4	Total for Quarter 1	167			147	20				
5	April	48	8	2200	43	5				
6	May	48	13	1900	43	5				
7	June	54	28	1800	49	5				
8	Total for Quarter 2	150			135	15				
9	July	64	15	1800	58	6				
10	August	65	28	1800	60	5				
11	September	63	4	1800	58	5				
12	Total for Quarter 3	192			176	16				
13	October	47	28	2000	42	5				
14	November	53	20	1900	48	5				
15	December	64	7	1900	59	5				
16	Total for Quarter 4	164			149	15				
17	Total Year to Date/Year	673			607	66				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	3,173,086
3	Steam	2,242,180			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional				
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	22,796
7	Other	187,821			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	2,430,001	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	973,039	27	Total Energy Losses	262,263
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	3,458,145
12	Received	71,374			
13	Delivered	73,152			
14	Net Exchanges (Line 12 minus line 13)	-1,778			
15	Transmission For Other (Wheeling)				
16	Received	1,802,322			
17	Delivered	1,694,102			
18	Net Transmission for Other (Line 16 minus line 17)	108,220			
19	Transmission By Others Losses	-51,337			
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	3,458,145			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM: INTEGRATED SYSTEM

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	310,718		516	31	1000
30	February	254,665	779	482	20	1000
31	March	268,669	6,626	451	18	1000
32	April	234,130	136	425	9	1000
33	May	217,750	161	398	13	1800
34	June	240,544	8,440	456	25	1600
35	July	301,549	446	539	11	1800
36	August	257,418	97	549	28	1800
37	September	215,808	4,838	541	6	1800
38	October	249,497	927	431	28	2000
39	November	276,707	307	496	21	1900
40	December	330,813	39	560	9	1900
41	TOTAL	3,158,268	22,796			

Schedule Page: 401 Line No.: 29 Column: b

MONTHLY PEAKS AND OUTPUTS
Name of System: SHERIDAN SYSTEM

Line #	Month (a)	Total Mo. Energy (b)	Megawatts (d)	Day (e)	Hour (f)
29	Jan	29,119	61	11	1900
30	Feb	25,014	54	19	900
31	Mar	25,063	52	4	2000
32	Apr	22,737	48	8	2200
33	May	20,860	48	13	1900
34	Jun	21,485	54	28	1800
35	Jul	27,770	64	15	1800
36	Aug	27,171	65	28	1800
37	Sep	22,212	63	4	1800
38	Oct	22,625	47	28	2000
39	Nov	24,683	53	20	1900
40	Dec	31,138	64	7	1900
41	Total	299,877	673		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *R.M. Heskett* (b)			Plant Name: *Lewis & Clark* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor Boiler			Outdoor Boiler		
3	Year Originally Constructed	1954			1958		
4	Year Last Unit was Installed	1963			1958		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	86.00			44.00		
6	Net Peak Demand on Plant - MW (60 minutes)	104			52		
7	Plant Hours Connected to Load	8151			8066		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	101			52		
10	When Limited by Condenser Water	91			52		
11	Average Number of Employees	46			28		
12	Net Generation, Exclusive of Plant Use - KWh	444867100			298969282		
13	Cost of Plant: Land and Land Rights	242583			80862		
14	Structures and Improvements	27993471			4529429		
15	Equipment Costs	78467331			36118517		
16	Asset Retirement Costs	699329			30969		
17	Total Cost	107402714			40759777		
18	Cost per KW of Installed Capacity (line 17/5) Including	1248.8688			926.3586		
19	Production Expenses: Oper, Supv, & Engr	861217			322392		
20	Fuel	11735403			7277888		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	2061000			1321316		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	768973			164100		
26	Misc Steam (or Nuclear) Power Expenses	837166			637902		
27	Rents	0			7540		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	260717			211159		
30	Maintenance of Structures	132312			55613		
31	Maintenance of Boiler (or reactor) Plant	1527628			815947		
32	Maintenance of Electric Plant	1222278			111582		
33	Maintenance of Misc Steam (or Nuclear) Plant	672987			369752		
34	Total Production Expenses	20079681			11295191		
35	Expenses per Net KWh	0.0451			0.0378		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal-Lignite	Coal-Sub Bit	Gas	Coal-Lignite	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Tons	Mcf	Tons	Mcf	
38	Quantity (Units) of Fuel Burned	423001	0	5957	292261	9686	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	7028	0	1100	6543	1208	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	26.087	0.000	3.349	23.978	4.814	0.000
41	Average Cost of Fuel per Unit Burned	27.694	0.000	3.349	24.742	4.814	0.000
42	Average Cost of Fuel Burned per Million BTU	1.970	0.000	3.044	1.891	3.985	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.026	0.000	0.000	0.024	0.000	0.000
44	Average BTU per KWh Net Generation	13379.848	0.000	0.000	12831.511	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Miles City* (d)	Plant Name: *Big Stone* (e)	Plant Name: *WY Gen III* (f)	Line No.
Gas Turbine	Steam	Steam	1
Conventional	Conventional	Conventional	2
1972	1975	2010	3
1972	1975	2010	4
23.15	94.11	28.00	5
21	113	27	6
8	7758	8411	7
0	0	0	8
22	108	27	9
20	103	27	10
0	16	5	11
-60	623380087	208533000	12
609	150559	0	13
206731	9397446	3130169	14
3212436	51619065	61051885	15
0	4060	0	16
3419776	61171130	64182054	17
147.7225	649.9961	2292.2162	18
15355	288547	617394	19
24738	13423654	2205991	20
0	0	0	21
71584	248680	360051	22
0	0	0	23
0	0	0	24
43378	379784	139385	25
0	639260	260625	26
0	40	677793	27
0	0	70	28
9866	153412	41742	29
1853	138216	123183	30
29540	1000821	350519	31
0	225481	36454	32
0	157416	1321	33
196314	16655311	4814528	34
-3271.9000	0.0267	0.0231	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Gas	Fuel Oil		Coal-Sub Bit	Fuel Oil		Coal-Sub Bit			36
Mcf	Bbl		Tons	Bbl		Tons			37
1265	30	0	388896	2109	0	146529	0	0	38
1092	140000	0	8324	140000	0	8061	0	0	39
17.155	101.535	0.000	33.434	139.937	0.000	15.055	0.000	0.000	40
17.155	101.535	0.000	33.780	135.900	0.000	15.055	0.000	0.000	41
15.710	17.546	0.000	2.029	23.108	0.000	0.934	0.000	0.000	42
0.000	0.000	0.000	0.022	0.000	0.000	0.011	0.000	0.000	43
0.000	0.000	0.000	10405.785	0.000	0.000	11328.377	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Glendive* (b)			Plant Name: *Coyote* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1979			1981		
4	Year Last Unit was Installed	2003			1981		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	75.50			103.65		
6	Net Peak Demand on Plant - MW (60 minutes)	77			108		
7	Plant Hours Connected to Load	109			7064		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	75			107		
10	When Limited by Condenser Water	73			102		
11	Average Number of Employees	3			20		
12	Net Generation, Exclusive of Plant Use - KWh	1782420			666430500		
13	Cost of Plant: Land and Land Rights	37924			522773		
14	Structures and Improvements	293723			26402993		
15	Equipment Costs	27769065			102510659		
16	Asset Retirement Costs	0			119872		
17	Total Cost	28100712			129556297		
18	Cost per KW of Installed Capacity (line 17/5) Including	372.1949			1249.9402		
19	Production Expenses: Oper, Supv, & Engr	26692			448803		
20	Fuel	258082			12039137		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	97078			1027017		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	88994			460669		
26	Misc Steam (or Nuclear) Power Expenses	0			354000		
27	Rents	0			313		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	19484			156564		
30	Maintenance of Structures	5664			216460		
31	Maintenance of Boiler (or reactor) Plant	335280			1369869		
32	Maintenance of Electric Plant	82			266080		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			215068		
34	Total Production Expenses	831356			16553980		
35	Expenses per Net KWh	0.4664			0.0248		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas			Coal-Lignite	Fuel Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Mcf			Tons	Bbl	
38	Quantity (Units) of Fuel Burned	32222	0	0	529355	2124	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1108	0	0	6991	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	8.009	0.000	0.000	22.253	134.145	0.000
41	Average Cost of Fuel per Unit Burned	8.009	0.000	0.000	22.198	135.806	0.000
42	Average Cost of Fuel Burned per Million BTU	7.229	0.000	0.000	1.588	23.095	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.145	0.000	0.000	0.018	0.000	0.000
44	Average BTU per KWh Net Generation	20030.058	0.000	0.000	11124.838	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0			0			0			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *R.M. Heskett* (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
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0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
		0.00			0.00			0.00	5
		0			0			0	6
		0			0			0	7
		0			0			0	8
		0			0			0	9
		0			0			0	10
		0			0			0	11
		0			0			0	12
		0			0			0	13
		0			0			0	14
		0			0			0	15
		0			0			0	16
		0			0			0	17
		0			0			0	18
		0			0			0	19
		0			0			0	20
		0			0			0	21
		0			0			0	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		0			0			0	26
		0			0			0	27
		0			0			0	28
		0			0			0	29
		0			0			0	30
		0			0			0	31
		0			0			0	32
		0			0			0	33
		0			0			0	34
		0.0000			0.0000			0.0000	35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 403 Line No.: -1 Column: d
Plant is designed for peak load service

Schedule Page: 403 Line No.: -1 Column: e
Plant is 22.7% owned by Respondent. Statistics represent Respondent's share of plant costs, production expenses and other data.

Schedule Page: 403 Line No.: -1 Column: f
Plant is 25.0% owned by Respondent. Statistics represent Respondent's share of plant cost, prodution expenses and other data.

Schedule Page: 402 Line No.: 5 Column: b
Maximum Turbine Name Plate Rating

Schedule Page: 402 Line No.: 5 Column: c
Maximum Turbine Name Plate Rating

Schedule Page: 403 Line No.: 5 Column: d
Maximum Turbine Name Plate Rating

Schedule Page: 403 Line No.: 5 Column: e
Statistics reflect 22.7% of Maximum Turbine Name Plate Rating of 414.6

Schedule Page: 403 Line No.: 5 Column: f
Statistics reflect 25% of Maximum Turbine Name Plate Rating of 112

Schedule Page: 403 Line No.: 10 Column: d
Limited by ambient air temperature

Schedule Page: 402 Line No.: 20 Column: b
Total fuel costs for all generating plants include sales for resale fuel costs of $466,966.

Schedule Page: 402.1 Line No.: -1 Column: b
Plant is designed for peak load service.

Schedule Page: 402.1 Line No.: -1 Column: c
Plant is 25% owned by Respondent. Statistics represent Respondent's share of plant costs, production expenses and other data.

Schedule Page: 402.1 Line No.: 5 Column: b
Maximum Turbine Name Plate Rating

Schedule Page: 402.1 Line No.: 5 Column: c
Statistics reflect 25% of Maximum Turbine Name Plate Rating of 414.6

Schedule Page: 402.1 Line No.: 10 Column: b
Limited by ambient air temperature

Schedule Page: 402 Line No.: 43 Column: b1
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: c1
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: d1
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: e1
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 43 Column: f1
Average cost of all fuels burned per net kWh generated.

Schedule Page: 402 Line No.: 44 Column: b1
Average Btu per net kWh generated for all fuels.

Schedule Page: 402 Line No.: 44 Column: c1
Average Btu per net kWh generated for all fuels.

Schedule Page: 402 Line No.: 44 Column: d1
Average Btu per net kWh generated for all fuels.

Schedule Page: 402 Line No.: 44 Column: e1
Average Btu per net kWh generated for all fuels.

Schedule Page: 402 Line No.: 44 Column: f1
Average Btu per net kWh generated for all fuels.

Schedule Page: 402.1 Line No.: 43 Column: b1

Average cost of all fuels burned per net kWh generated.

Schedule Page: 402.1 Line No.: 43 Column: c1

Average cost of all fuels burned per net kWh generated.

Schedule Page: 402.1 Line No.: 44 Column: b1

Average Btu per net kWh generated for all fuels.

Schedule Page: 402.1 Line No.: 44 Column: c1

Average Btu per net kWh generated for all fuels.

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	OIL					
2	Portable Generators	2012	5.50	6.0	5,609	2,292,531
3						
4	WIND					
5	Diamond Willow	2007	30.00	31.4	93,175,000	62,365,604
6	Cedar Hills	2010	19.50	20.1	54,805,180	45,076,782
7						
8	WASTE HEAT					
9	Ormat Facility	2009	7.50	6.5	38,052,831	15,628,927
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46						

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2013	Year/Period of Report End of 2013/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
	77,039	33,459	22,216	Oil		2
						3
						4
	232,032		163,489	Wind		5
	188,813		116,249	Wind		6
						7
						8
	254,734	266,056	27,218	Waste Heat		9
						10
						11
						12
						13
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						17
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						20
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						45
						46

Schedule Page: 410 Line No.: 2 Column: c

Maximum Turbine Name Plate Rating

Schedule Page: 410 Line No.: 5 Column: b

7 turbines added in 2010

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	AVS	Charlie Creek	345.00	345.00	3	26.57		1
2	Coyote	Center	345.00	345.00	2	11.43		1
3	Coyote Switch Yard		345.00	345.00	2	1.04		1
4	Center	Jamestown	345.00	345.00	2	10.69		1
5	Big Stone Plant	Sisseton	230.00	230.00	2	47.55		1
6	Heskett Station	East Bismarck	230.00	230.00	2	10.49		1
7	Bismarck	Wishek	230.00	230.00	2	67.41		1
8	Wishek	Ellendale	230.00	230.00	2	54.99		1
9	Heskett Station	WAPA Tie	230.00	230.00	2	1.15		1
10	Montana Border	South Dakota Border	230.00	230.00	2	86.19		1
11	Merricourt Windfarm	Ellendale	230.00	230.00	2	29.69		1
12								
13	Lines Below 132 Kilovolts		115.00	115.00	2	580.01	4.12	
14			69.00	69.00	Various	85.24	1.33	1
15			41.60	69.00	2	86.44	17.19	1
16			57.00	69.00	2	3.34		1
17			57.00	60.00	Various	868.12	0.89	1
18			33.00	60.00	1	17.77		1
19			57.00	57.00	1	2.61		2
20			41.60		Various	1,045.00	17.86	
21			33.00	35.00	1	28.99		1
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	3,064.72	41.39	19

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
2306.2 KcMIL								1
2-954 MCM								2
2-954 MCM								3
2-1272 MCM								4
954 MCM								5
795 MCM								6
795 MCM								7
795 MCM								8
954 MCM								9
954 MCM								10
954 MCM								11
								12
Various								13
Various								14
4/0 ACSR								15
4/0 ACSR								16
Various								17
4/0 ACSR								18
4/0 ACSR								19
Various								20
Various								21
								22
	2,942,671	91,693,433	94,636,104	3,492,186	2,503,283	1,653,919	7,649,388	23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	2,942,671	91,693,433	94,636,104	3,492,186	2,503,283	1,653,919	7,649,388	36

Schedule Page: 422 Line No.: 4 Column: b

Respondent, Otter Tail Power Company, Northern Municipal Power Agency and Northwestern Public Service (NMPA) share ownership of 10.69 miles of transmission line. Respondent's ownership share is 6.25%. NMPA pays all operating and maintenance expenses and they are shared based on mileage percentage. Respondent's expenses are reflected in accounts 562 and 570.

Schedule Page: 422 Line No.: 13 Column: h

Various

Schedule Page: 422 Line No.: 20 Column: d

Various

Schedule Page: 422 Line No.: 20 Column: h

Various

Schedule Page: 422 Line No.: 23 Column: j

Cost by transmission line not available. Total costs for all transmission lines.

Schedule Page: 422 Line No.: 23 Column: k

Cost by transmission line not available. Total costs for all transmission lines.

Schedule Page: 422 Line No.: 23 Column: l

Cost by transmission line not available. Total costs for all transmission lines.

Schedule Page: 422 Line No.: 23 Column: m

Cost by transmission line not available. Total costs for all transmission lines.

Schedule Page: 422 Line No.: 23 Column: n

Cost by transmission line not available. Total costs for all transmission lines.

Schedule Page: 422 Line No.: 23 Column: o

Cost by transmission line not available. Total costs for all transmission lines.

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	KRCM Gas coyne	Spur Line	-2.75	Retired			
2							
3	Midway Substation	Tap Line	-0.21	Retired			
4							
5	Matheson	Tap Line	2.63	SP	20.00	1	1
6							
7	Tioga-Spur	Spur Line	0.19	SP	24.00	1	1
8			-0.18	Retired			
9	Harvest Hills	Tap Line	1.53	SP	18.00	1	1
10							
11	Dakota Prairie Refining	Tap Line	0.44	SP	21.00	1	1
12							
13	Air Liquide	Tap Line	0.19	H-Frame	32.00	1	1
14							
15	Heskett III	Tie Line	0.09	H-Frame	34.00	1	1
16							
17	Heskett	Devaul	0.13	H-Frame	31.00	1	1
18			-0.03	Retired			
19	Heskett	Mandan Junction	0.85	H-Frame	12.00	1	1
20							
21	Beulah	Bismarck	0.14	H-Frame	22.00	1	1
22			-0.85	Retired			
23							
24	Mandan Junction Sub	Mandan Sub	-1.01	Retired			
25							
26	Mandan Junction	South Mandan	0.74	H-Frame	15.00	1	1
27			-0.24	Retired			
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		1.66		229.00	10	10

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
			42		4,338		51,157	55,495	1
									2
			42				8,640	8,640	3
									4
336.4	ACSR	T-115-P	115		398,684	598,027		996,711	5
									6
210	ACSR	T-60-HA	57		97,337	44,539		141,876	7
							24,307	24,307	8
4/0	ACSR	T-60-A	57		477,967	33,097		511,064	9
									10
4/0	ACSR	T-46-A1	42		97,809	97,809		195,618	11
							-7,473	-7,473	12
4/0	ACSR	T-60-H	57		50,237	33,629		83,866	13
									14
954	ACSR	T-115-A	115		45,027	11,257		56,284	15
									16
336.4	ACSR	T-69-H	69		45,430	26,565		71,995	17
							5,170	5,170	18
954	ACSR	T-230-A	115		151,100	100,734		251,834	19
									20
T2 4/0	ACSR	T-115-A	115		75,884	49,875		125,759	21
							5,146	5,146	22
									23
			230				55,927	55,927	24
									25
954	ACSR	T-115-A	115		279,565	181,271		460,836	26
							22,964	22,964	27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
					1,723,378	1,176,803	165,838	3,066,019	44

Schedule Page: 424 Line No.: 1 Column: k
46 KV Design

Schedule Page: 424 Line No.: 3 Column: k
46 KV Design

Schedule Page: 424 Line No.: 5 Column: j
11' x 11' x 10' Vertical

Schedule Page: 424 Line No.: 7 Column: j
7' x 7' x 10' Vertical

Schedule Page: 424 Line No.: 7 Column: k
60 KV Design

Schedule Page: 424 Line No.: 9 Column: j
86" x 86" x 86" Triangular

Schedule Page: 424 Line No.: 9 Column: k
60 KV Design

Schedule Page: 424 Line No.: 11 Column: j
86" x 61" x 95" Triangular

Schedule Page: 424 Line No.: 11 Column: k
46 KV Design

Schedule Page: 424 Line No.: 13 Column: j
7'6" x 7'6" Horizontal

Schedule Page: 424 Line No.: 13 Column: k
60 KV Design

Schedule Page: 424 Line No.: 15 Column: j
14'6" x 14'6" Horizontal

Schedule Page: 424 Line No.: 17 Column: j
7'6" x 7'6" Horizontal

Schedule Page: 424 Line No.: 19 Column: j
19'6" x 19'6" Horizontal

Schedule Page: 424 Line No.: 19 Column: k
115 & 230 KV Design

Schedule Page: 424 Line No.: 21 Column: j
14'6" x 14'6" Horizontal

Schedule Page: 424 Line No.: 26 Column: j
14'6" x 14'6" Horizontal

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Big Stone, SD (22.7% Interest)	Trans at Plant	230.00	22.90	
2	Big Stone, SD (22.7% Interest)	Trans at Plant	230.00	118.00	13.80
3	Cedar Hills, ND	Trans at Plant	58.20	34.50	
4	Coyote Station, ND (25% Interest)	Trans at Plant	345.00	22.90	
5	Coyote Station, ND (25% Interest)	Trans at Plant	115.00	13.80	
6	Coyote Station, ND	Trans at Plant	345.00	115.00	13.80
7	Diamond Willow, MT	Trans at Plant	57.20	34.50	
8	Glen Ullin, ND (Ormat)	Trans at Plant	41.60	12.47	
9	Glendive, MT (Turbine)	Trans at Plant	115.00	60.00	
10	Glendive, MT (Turbine)	Trans at Plant	115.00	13.20	
11	Glendive, MT (Turbine)	Trans at Plant	115.00	60.00	
12	Heskett Station, ND	Trans at Plant	230.00	115.00	13.80
13	Heskett Station, ND	Trans at Plant	116.00	13.20	
14	Heskett Station, ND	Trans at Plant	115.00	13.20	
15	Heskett Station, ND	Trans at Plant	115.00	41.60	
16	Heskett Station, ND	Trans at Plant	115.00	69.00	
17	Lewis & Clark Station, MT	Trans at Plant	115.00	13.80	
18	Lewis & Clark Station, MT	Trans at Plant	57.00	13.80	
19	Lewis & Clark Station, MT	Trans at Plant	115.00	60.00	
20	Miles City, MT (Turbine)	Trans at Plant	57.00	13.80	
21	Substations under 10,000 KVA (1)				
22	SUBTOTAL		2802.00	860.67	41.40
23					
24	Baker, MT	Trans Unattended	115.00	57.00	
25	Baker, MT	Trans Unattended	230.00	115.00	14.10
26	Baker, MT Cabin Creek Jct	Trans Unattended	115.00	57.20	
27	Beulah Jct., ND	Trans Unattended	115.00	41.60	
28	Bismarck Jct., ND (E. Bismarck)	Trans Unattended	115.00	41.60	
29	Bismarck, ND NW	Trans Unattended	115.00	41.60	
30	Bismarck, ND Sweet Ave.	Trans Unattended	115.00	41.60	
31	Bowdle Jct., SD	Trans Unattended	115.00	41.60	
32	Dickinson, ND	Trans Unattended	115.00	41.60	
33	Dunning, ND	Trans Unattended	115.00	57.00	
34	Ellendale Jct., ND	Trans Unattended	230.00	115.00	13.80
35	Ellendale Jct., ND	Trans Unattended	115.00	41.60	
36	Elgin, ND	Trans Unattended	69.00	41.60	
37	Gascoyne Jct., ND	Trans Unattended	115.00	41.60	
38	Glenham Jct., SD	Trans Unattended	230.00	115.00	41.60
39	Glenham Jct., SD	Trans Unattended	230.00	115.00	41.60
40	Halliday, ND	Trans Unattended	115.00	41.60	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
104	1					1
52	1					2
28	2					3
120	1					4
21	1					5
168	1					6
28	2					7
11	1					8
50	1					9
40	1					10
37	1					11
112	1					12
94	1	1				13
28	1					14
34	1					15
45	1			1	4	16
53	1					17
20	1					18
47	1					19
31	1					20
8	1					21
1131	23	1		1	4	22
						23
40	1			1	4	24
112	1					25
83	1					26
45	1					27
80	2			2	8	28
47	1			1	4	29
56	1					30
20	1			1	2	31
75	1					32
20	1			1	2	33
100	1					34
37	1					35
15	1					36
11	1			1	1	37
30	1			1	3	38
56	1					39
20	1			1	2	40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Hettinger Jct., ND	Trans Unattended	115.00	41.60	
2	Hettinger Jct., ND	Trans Unattended	230.00	115.00	14.10
3	Kenmare Jct., ND	Trans Unattended	115.00	57.00	
4	Linton Jct., ND	Trans Unattended	115.00	41.60	
5	Mandan, ND 230	Trans Unattended	230.00	115.00	13.80
6	McIntosh Jct., SD	Trans Unattended	115.00	41.60	
7	Miles City, MT	Trans Unattended	230.00	115.00	13.80
8	Miles City, MT	Trans Unattended	115.00	57.00	13.80
9	New England, ND	Trans Unattended	115.00	41.60	
10	Plentywood Jct., MT	Trans Unattended	115.00	57.00	
11	Poplar Jct., MT	Trans Unattended	115.00	57.00	
12	Ray, ND Jct.	Trans Unattended	115.00	57.00	
13	Rosebud Creek, MT	Trans Unattended	230.00	60.00	13.80
14	Sheridan, WY (PP&L)	Trans Unattended	230.00	41.60	
15	Sheridan, WY (PP&L)	Trans Unattended	230.00	41.60	
16	Stanley Jct., ND	Trans Unattended	115.00	69.00	12.47
17	Tioga, ND	Trans Unattended	230.00	115.00	
18	Tioga Jct., ND	Trans Unattended	115.00	57.00	
19	Wishek Jct., ND	Trans Unattended	115.00	41.60	
20	Wishek Jct., ND	Trans Unattended	230.00	115.00	13.80
21	Substations under 10,000 KVA (7)				
22	SUBTOTAL		5589.00	2384.40	206.67
23					
24	Substations under 10,000 KVA Distrib at Plant (2)				
25	SUBTOTAL				
26					
27	Beulah, ND W. M. Port 1	Distrib Unattended	115.00	6.90	
28	Beulah, ND W. M. Port 2	Distrib Unattended	115.00	6.90	
29	Baker, MT Lookout Butte	Distrib Unattended	57.20	12.47	
30	Bismarck, ND Kirkwood	Distrib Unattended	115.00	12.47	
31	Bismarck, ND SE Expressway	Distrib Unattended	115.00	12.47	
32	Bismarck, ND NW (Century)	Distrib Unattended	115.00	12.47	
33	Bismarck, ND NE	Distrib Unattended	115.00	12.47	
34	Bismarck, ND Front Ave	Distrib Unattended	115.00	12.47	
35	Bismarck, ND Front Ave	Distrib Unattended	115.00	12.47	
36	Bismarck, ND Turnpike	Distrib Unattended	115.00	12.47	
37	Bismarck, ND South 9th St.	Distrib Unattended	41.60	12.47	
38	Bismarck, ND Sunrise	Distrib Unattended	115.00	12.47	
39	Bismarck, ND 26th & D	Distrib Unattended	41.60	12.47	
40	Bismarck, ND 26th & D	Distrib Unattended	115.00	12.47	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
25	1			1	2	1
112	1					2
30	1			1	3	3
15	1			1	2	4
224	1					5
13	1			1	1	6
100	1					7
56	1					8
22	1			1	2	9
47	1					10
37	1					11
75	1					12
40	1					13
37	1					14
20	1					15
22	1			1	2	16
112	1					17
75	1					18
30	1			1	3	19
112	1					20
15	15	1				21
2066	53	1		16	41	22
						23
	1			1	1	24
	1			1	1	25
						26
10	1					27
11	1					28
11	1					29
28	1			6	2	30
53	2			9	4	31
22	1			3	2	32
28	1			6	2	33
47	1			15	3	34
47	1			12	4	35
28	1			9	3	36
11	1			3	1	37
28	1			3	1	38
14	1			3	1	39
28	1					40

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Dickinson, ND NW	Distrib Unattended	41.60	12.47	
2	Dickinson, ND East Broadway	Distrib Unattended	41.60	12.47	
3	Dickinson, ND NE	Distrib Unattended	41.60	12.47	
4	Dickinson, ND	Distrib Unattended	41.60	12.47	
5	Glendive, MT	Distrib Unattended	57.00	12.47	
6	Glendive, MT West	Distrib Unattended	57.00	12.47	
7	Glendive, MT	Distrib Unattended	57.00	12.47	
8	Lignite, ND	Distib Unattended	57.00	2.40	
9	Mandan, ND Collins Ave	Distrib Unattended	41.60	12.47	
10	Mandan, ND Midway (New)	Distrib Unattended	41.60	12.47	
11	Mandan, ND Amoco Refinery	Distrib Unattended	41.60	4.16	
12	Mandan, ND	Distrib Unattended	115.00	12.47	
13	Miles City, MT-East	Distrib Unattended	57.00	12.47	
14	Miles City, MT	Distrib Unattended	57.00	12.47	
15	Mobridge, SD	Distrib Unattended	115.00	12.47	
16	Sheridan, WY Broadway	Distrib Unattended	41.60	12.47	
17	Sheridan, WY Broadway	Distrib Unattended	41.60	12.47	
18	Sheridan, WY SW	Distrib Unattended	230.00	41.60	
19	Sheridan, WY Highview	Distrib Unattended	41.60	12.47	
20	Sheridan, WY Sugarland	Distrib Unattended	41.60	12.47	
21	Sheridan, WY West	Distrib Unattended	41.60	12.47	
22	Sidney, MT	Distrib Unattended	57.00	12.47	
23	Sidney, MT	Distrib Unattended	57.00	12.47	
24	Stanley, ND	Distrib Unattended	69.00	12.47	
25	Williston, ND East Broadway	Distrib Unattended	57.00	12.47	
26	Williston, ND NE	Distrib Unattended	57.00	12.47	
27	Williston, ND NW North	Distrib Unattended	57.00	12.47	
28	Williston, ND NW South	Distrib Unattended	57.00	12.47	
29	Williston, ND Sabin Metals	Distrib Unattended	57.00	13.80	
30	Substations Under 10,000 KVA (236)				
31	SUBTOTAL		3174.60	537.15	
32					
33	GRAND TOTAL		11565.60	3782.22	248.07
34					
35					
36	FOOTNOTES				
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
14	1			3	1	1
14	1			3	1	2
14	1			3	1	3
11	1			3	1	4
14	1			3	1	5
11	1			3	1	6
11	1			3	1	7
12	4			3	1	8
14	1			3	1	9
28	1			6	2	10
11	1					11
50	2			9	3	12
10	1			6	2	13
11	1			3	1	14
22	1			9	2	15
11	1			3	2	16
13	1			3	2	17
74	1					18
11	1			3	1	19
11	1			3	2	20
11	1			3	1	21
11	1			3	1	22
14	1			3	1	23
14	1			3	1	24
11	1			3	1	25
10	1			3	1	26
				3	1	27
14	1			3	1	28
10	1					29
553	401			425	47	30
1381	448			590	104	31
						32
4578	525	2		608	150	33
						34
						35
						36
						37
						38
						39
						40

FOOTNOTE DATA

Schedule Page: 426 Line No.: 28 Column: a

See (A) and (B) of footnotes

Schedule Page: 426 Line No.: 29 Column: a

See (B) and (C) of footnotes

Schedule Page: 426 Line No.: 33 Column: a

See (J) and (K) of footnotes

Schedule Page: 426 Line No.: 36 Column: a

See (N) and (O) of footnotes

Schedule Page: 426 Line No.: 40 Column: a

See (H) and (I) of footnotes

Schedule Page: 426.1 Line No.: 7 Column: a

See (P) of footnotes

Schedule Page: 426.1 Line No.: 8 Column: a

See (L) and (M) of footnotes

Schedule Page: 426.1 Line No.: 13 Column: a

See (D) and (E) of footnotes

Schedule Page: 426.1 Line No.: 20 Column: a

See (F) and (G) of footnotes

Schedule Page: 426.2 Line No.: 36 Column: a

FOOTNOTES:

(A) Capital Electric Cooperative, Inc. has a 25 MVA capacity interest.

(B) Capital Electric Cooperative, Inc. pays for all expenses relating to equipment owned by them and is not an associated company.

(C) Capital Electric Cooperative, Inc. has a 10 MVA capacity interest.

(D) Mid-Yellowstone Electric Cooperative, Inc. has a 14,911 KVA capacity interest.

(E) Respondent and Mid-Yellowstone Electric Cooperative, Inc. shared the facilities construction cost and available capacity in the respective percentages of 63% and 37%. All maintenance and operating expenses are shared in the same percentage. The Respondent's expenses are reflected in accounts 570 and 562. Mid-Yellowstone Electric Cooperative, Inc. is not an associated company.

(F) KEM Electric Cooperative, Inc. has a 59,136 KVA capacity interest.

(G) KEM Electric Cooperative, Inc. pays for all expenses relating to equipment owned by them and is not an associated company.

(H) Upper Missouri G&T Electric Cooperative, Inc. has a 15,300 KVA capacity interest.

(I) Upper Missouri G&T Electric Cooperative, Inc. pays for all expenses relating to equipment owned by them and is not an associated company.

(J) Central Power and Upper Missouri G&T Electric Cooperative, Inc. have a 9,420 KVA capacity interest.

(K) Central Power pays for all expenses relating to equipment owned by them and is not an associated company. Respondent pays for all expenses relating to transformer and regulator equipment owned by Respondent.

(L) Western Area Power Administration (WAPA) has a 9,500 KVA capacity interest.

(M) WAPA does routine maintenance at their expense and major repairs are allocated 19% WAPA and 81% Respondent.

(N) Mor-Gran-Sou Electric Cooperative has a 4,560 KVA capacity interest.

(O) Mor-Gran-Sou Electric Cooperative pays for all expenses relating to equipment owned by them and is not an associated company.

(P) WAPA has a 25,000 KVA capacity interest.

Name of Respondent MDU Resources Group, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2013	Year/Period of Report End of 2013/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Insurance	CHCC	401,165,184,228	3,115,104
3	Cost of Service	CHCC	401	1,038,487
4	Corporate Air	CHCC	401,402,107,146	295,820
5	Subcontract	WBIH		282,070
6	Cost of Service and Utility Group Projects	MDU EC	401	47,677
7	Contract Services	KRC	107	637,020
8	Contract Services	MDU CSG	401,402,107	10,030,552
9				
10	Total			15,446,730
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Cost of Service for Facilities Used	KRC	454,493	537,193
22	Cost of Service for Facilities Used	MDU CSG	454,493	117,038
23	Cost of Service for Facilities Used	MDU EC	454,493	1,413,219
24	Cost of Service for Facilities Used	WBIH	454,493	267,061
25				
26	Total			2,334,511
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2				

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
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20	**Non-power Goods or Services Provided for Affiliate**			
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39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
MDU Resources Group, Inc.	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
5				
6				
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12				
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15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
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42				

Schedule Page: 429 Line No.: 2 Column: b

Company Abbreviations used in Column (b)

CHCC	Centennial Holdings Capital LLC
KRC	Knife River Corporation
MDU CSG	MDU Construction Services Group, Inc.
MDU EC	MDU Energy Capital, LLC
WBIH	WBI Holdings, Inc.

Schedule Page: 429 Line No.: 5 Column: c

107,146,184,401,402,417