YEAR ENDING 2018

ANNUAL REPORT
OF

MONTANA-DAKOTA UTILITIES CO.

GAS UTILITY

TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 202601
HELENA, MT 59620-2601

REVISED 2005

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 1**

IDENTIFICATION

Year: 2018

1.	Legal Name of Respondent:	MDU Resources Group, Inc.
2.	Name Under Which Respondent Does Business:	Montana-Dakota Utilities Co.
3.	Date Utility Service First Offered in Montana	1920
4.	Address to send Correspondence Concerning Report:	Montana-Dakota Utilities Co. 400 North Fourth Street Bismarck, ND 58501
5.	Person Responsible for This Report:	Tamie A. Aberle
5a.	Telephone Number:	(701) 222-7856

Control Over Respondent

1. If direct control over the respondent was held by another entity at the end of year provide the following:

   1a. Name and address of the controlling organization or person:

   1b. Means by which control was held:

   1c. Percent Ownership:

SCHEDULE 2

Board of Directors 1/ 2/

Line No.	Name of Director and Address (City, State) (a)	Remuneration (b)
1	David L. Goodin (Chairman), Bismarck, ND	-
2	Daniel S. Kuntz, Bismarck, ND	-
3	Nicole A. Kivisto, Bismarck, ND	-
4	Jason L. Vollmer, Bismarck, ND	-
5		
6		
7		
8	1/ At December 31, 2018, Montana-Dakota Utilities Co. was a Division of MDU	
9	Resources Group, Inc., and had no Board of Directors. The affairs of the	
10	Company were managed by a Managing Committee, the members of which	
11	are proved herein rather than the directors of MDU Resources Group, Inc.	
12		
13	2/ On January 1, 2019, Montana-Dakota Utilities Co. became a subsidiary of	
14	MDU Resources Group, Inc. with its own Board of Directors, the names of	
15	which are provided above.	
16		
17		

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 3**

Officers

Year: 2018

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	President & Chief Executive Officer	Executive	Nicole A. Kivisto
2			
3	Vice President	Electric Supply	Jay W. Skabo
4			
5	Vice President	Operations	Patrick C. Darras
6			
7	Executive Vice President	Business Development & Gas Supply	Scott W. Madison
8			
9	Executive Vice President	Regulatory Affairs, Customer Service, &	Garret Senger
10		Administration	
11			
12	Vice President	Regulatory Affairs & Customer Service	Mark A. Chiles
13			
14	Vice President	Safety Process Improvement &	Hart Gilchrist
15		Operations Systems	
16			
17	Vice President	Field Operations	Eric P. Martuscelli
18			
19	Controller	Accounting	Tammy J. Nygaard
20			
21			
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Company Name: Montana-Dakota Utilities Co. **SCHEDULE 4**

CORPORATE STRUCTURE

Year: 2018

Subsidiary/Company Name	Line of Business	Earnings (000's)	Percent of Total
Montana-Dakota Utilities Co./ Great Plains Natural Gas Co. (Divisions of MDU Resources Group, Inc.)/Cascade Natural Gas Corp. and Intermountain Gas Company	Electric and Natural Gas Distribution	$84,732	31.12%
WBI Holdings, Inc.	Pipeline and Midstream	29,993	11.01%
Knife River Corporation	Construction Materials and Contracting	92,647	34.02%
MDU Construction Services Group, Inc.	Construction Services	64,309	23.62%
Centennial Energy Resources LLC/ Centennial Holdings Capital LLC	Other	637	0.23%
TOTAL		$272,318	100.00%

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 5**

CORPORATE ALLOCATIONS - GAS

Year: 2018

Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
Audit Costs	Administrative & General	Various Corporate Overhead Allocation Factors	$11,055	3.33%	$320,856
Advertising	Administrative & General	Various Corporate Overhead Allocation Factors, and/or Actual Costs Incurred	5,423	3.33%	157,261
Air Service	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,925	2.74%	68,249
Automobile	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	546	3.08%	17,176
Bank Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	8,254	3.33%	239,660
Computer Rental	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	75	3.18%	2,285
Consultant Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	26,539	2.75%	937,011
Contract Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	47,809	2.14%	2,184,604
Corporate Aircraft	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	2,952	3.22%	88,603
Directors Expenses	Administrative & General	Corporate Overhead Allocation Factor	81,015	3.32%	2,355,588
Employee Benefits	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	2,041	3.35%	58,809

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 5**

CORPORATE ALLOCATIONS - GAS

Year: 2018

Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
Employee Meetings	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	9	3.53%	246
Employee Reimbursable Expenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	4,333	2.94%	143,155
Entertainment	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	9	3.46%	251
Legal Retainers & Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	8,678	3.34%	251,411
Meal Allowance	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	18	3.08%	567
Meals	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	3,942	3.21%	118,766
Industry Dues & Licenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	3,440	3.16%	105,517
Office Expenses	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	2,984	2.51%	116,018
Prepaid Insurance	Administrative & General	Various Corporate Overhead Allocation Factors and Allocation Factors Based on Actual Experience	3,015	1.05%	283,319
Permits and Filing Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	1,212	3.32%	35,281

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 5**

CORPORATE ALLOCATIONS - GAS

Year: 2018

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Postage & Express Mail	Administrative & General	Various Corporate Overhead Allocation Factors and/or	(152)	3.33%	(4,411)
2			Actual Costs Incurred			
3						
4	Payroll	Administrative & General	Various Corporate Overhead Allocation Factors, Time	907,031	3.23%	27,207,134
5			Studies, and/or Actual Costs Incurred			
6						
7	Reimbursements	Administrative & General	Various Corporate Overhead Allocation Factors and/or	(30)	1.56%	(1,898)
8			Actual Costs Incurred			
9						
10	Rental	Administrative & General	Various Corporate Overhead Allocation Factors and/or	60	3.91%	1,473
11			Actual Costs Incurred			
12						
13	Reference Materials	Administrative & General	Various Corporate Overhead Allocation Factors and/or	6,109	3.36%	175,582
14			Actual Costs Incurred			
15						
16	Seminars & Meeting	Administrative & General	Various Corporate Overhead Allocation Factors, Time	5,138	3.17%	156,714
17	Registrations		Studies, and/or Actual Costs Incurred			
18						
19	Software Maintenance	Administrative & General	Various Corporate Overhead Allocation Factors, Time	63,244	3.05%	2,007,195
20			Studies, and/or Actual Costs Incurred			
21						
22	Telephone & Cell Phones	Administrative & General	Various Corporate Overhead Allocation Factors and/or	12,199	2.97%	397,912
23			Actual Costs Incurred			
24						
25	Training Material	Administrative & General	Various Corporate Overhead Allocation Factors, Time	2,447	4.02%	58,416
26			Studies, and/or Actual Costs Incurred			
27						
28	Uniforms	Administrative & General	Various Corporate Overhead Allocation Factors, Time	43	6.15%	656
29			Studies, and/or Actual Costs Incurred			
30						
31	**TOTAL**			$1,211,363	3.13%	$37,483,406

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 6**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**KNIFE RIVER CORPORATION**	Expense	Actual Costs Incurred			
2		Contract Services		$242		$242
3		Materials		478		478
4						
5		Capital	Actual Costs Incurred			
6		Contract Services		36,929		36,929
7		Materials		2,580		2,267
8						
9						
10		Other				
11		Balance Sheet Accts		1,010,994		0
12		Resources Cost Centers		11,842		0
13						
14						
15		Total Knife River Corporation Operating Revenues for the Year 2018			$1,925,854,000	
16		Excludes Intersegment Eliminations				
17	**TOTAL**	**Grand Total Affiliate Transactions**		$1,063,065	0.0552%	$39,916
18	**WBI HOLDINGS, INC.**	Natural Gas	Actual Costs Incurred			
19		Purchases/Transportation		$50,675,860		$14,954,647
20						
21		Expense	Actual Costs Incurred			
22		Contract Services		85,694		25,544
23		Materials		3,791		486
24		Miscellaneous		8,931		2,510
25		Employee Benefits		4,893		1,169
26						
27		Capital	Actual Costs Incurred			
28		Contract Services		126,617		85,706
29		Materials		152,127		49,009
30		Miscellaneous		283		40
31						
32		Other				
33		Balance Sheet Accounts		1,056,890		0
34		Resources Cost Centers		23,849		0
35						
36						
37		Total WBI Operating Revenues for the Year 2018			$128,923,000	
38		Excludes Intersegment Eliminations				
39	**TOTAL**	**Grand Total Affiliate Transactions**		$52,138,935	40.4419%	$15,119,111

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 6**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**MDU CONSTRUCTION**					
2	**SERVICES GROUP, INC.**	Expense	Actual Costs Incurred			
3		Contract Services		$410		$410
4		Miscellaneous		1,265		302
5						
6		Capital	Actual Costs Incurred			
7		Contract Services		527,894		527,894
8						
9		Other				
10		Resources Cost Centers		16,887		0
11		Balance Sheet Accounts		7,709		0
12						
13						
14		Total MDU Construction Services Group, Inc Operating Revenues for the Year 2018			$1,371,453,000	
15		Excludes Intersegment Eliminations				
16	**TOTAL**	**Grand Total Affiliate Transactions**		$554,165	0.0404%	$528,606

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 6**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**CENTENNIAL HOLDINGS**	Expense	1/ Various Corporate Overhead			
2	**CAPITAL, LLC**	Contract Services	Allocation Factors and/or	$187,644		$44,825
3		Corporate Aircraft	Actual Costs Incurred	35,254		12,430
4		Office Expense		336,947		80,492
5		Miscellaneous		472,190		112,800
6						
7		Capital				
8		Corporate Aircraft	Actual Costs Incurred	8,365		1,889
9		Future Source Shares (Plane)		0		0
10						
11		Other				
12		Resources Cost Centers		138,263		0
13		Balance Sheet Accounts		4,521,213		0
14						
15		Total Centennial Holdings Capital, LLC Operating Revenues for the Year 2018			$11,259,000	
16		Excludes Intersegment Eliminations				
17	**TOTAL**	**Grand Total Affiliate Transactions**		$5,699,876	50.6251%	$252,436

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 6**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**MDU ENERGY CAPITAL**	Expense	Actual Costs Incurred			
2		Cost of Service		$325,110		$79,215
3		Office Expenses		18,455		5,321
4		Payroll		289,989		149,224
5		Miscellaneous		78,585		19,000
6						
7		Capital	Actual Costs Incurred			
8		Contract Services		26,261		5,418
9		Payroll		59,468		14,471
10		Material		60,325		60,011
11		Miscellaneous		4,193		917
12						
13		Other Transactions/Reimbursements	Actual Costs Incurred			
14		Clearing		(2,546)		0
15		Balance Sheet Accounts		2,185		0
16						
17						
18						
19		Total MDU Energy Capital Operating Revenues for the Year 2018			$530,038,000	
20						
21	**TOTAL**	**Grand Total Affiliate Transactions**		$862,025	0.1626%	$333,577

1/Corporate overhead allocation factors are derived from the invested capital balance as a percentage of the total corporate invested capital. Montana-Dakota Utilities Co. cost of service amounts are calculated for the general office complex, the printing department, and the budget and forecast system. The general office complex amounts are payroll and floor space costs for employees that perform services for MDU Resources. These include accounts payable, general accounting, fixed asset accounting, and miscellaneous other services. The charges are based on the percentage of system users that are MDU Resources employees. Both the general office complex and amounts for MDU Resources are allocated to affiliated companies based on corporate overhead allocation factors. The printing department amount is allocated to affiliated companies based on the direct printing images processed for them and their percentage of the corporate overhead allocation for the corporate printed image amount.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER	MDU RESOURCES GROUP, INC.				
2	CORPORATION	Corporate Overhead	1/ Various Corporate Overhead Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$70,189		
4		Advertising	Costs Incurred	36,029		
5		Air Service		13,818		
6		Automobile		4,965		
7		Bank Services		54,945		
8		Corporate Aircraft		18,708		
9		Consultant Fees		201,762		
10		Contract Services		928,329		
11		Computer Rental		537		
12		Directors Expenses		540,476		
13		Employee Benefits		13,112		
14		Employee Meeting		52		
15		Employee Reimbursable Expense		31,136		
16		Entertainment		57		
17		Non-Qualified Defined Contributions		23,914		
18		Legal Retainers & Fees		57,098		
19		Meal Allowance		140		
20		Cash Donations		9,118		
21		Meals		25,246		
22		Industry Dues & Licenses		23,805		
23		Office Expenses		30,969		
24		Supplemental Insurance		482,514		
25		Permits & Filing Fees		8,005		
26		Postage		(1,013)		
27		Payroll		5,642,276		
28		Reimbursements		(537)		
29		Reference Materials		39,840		
30		Rental		315		
31		Seminars & Meeting Registrations		31,072		
32		Software Maintenance		517,098		
33		Telephone/Cell Expenses		122,167		
34		Training		11,699		
35		Uniforms		88		
36		**Total MDU Resources Group, Inc.**		$8,937,929	0.5009%	

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER	MONTANA-DAKOTA UTILITIES CO.				
2	CORPORATION	Other Direct Charges	Actual Costs Incurred			
3		Contract Services		$88,313		
4		Communications		344,720		
5		Employee Discounts		17,418		
6		Dues, Permits, and Filing Fees		22,410		
7		Legal		26,160		
8		Sponsorship		44,200		
9		Electric Consumption		167,884		
10		Gas Consumption		166,258		$61,419
11		Bank Fees		32,653		
12		Computer/Software Support		987,338		
13		Office Expense		29,772		
14		Cost of Service		653,742		145,061
15		Audit Costs		752,914		
16		Auto		265		
17		Travel		9,908		
18		Employee Benefits		12,011		
19		Marketing		1,000		
20		Training Registration		2,000		
21		Balance Sheet		1,314,059		
22						
23		**Total Montana-Dakota Utilities Co.**		$4,673,025	0.2619%	$206,480
24						
25		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual Costs Incurred			
26						
27		Federal & State Tax Liability Payments		$3,101,274		
28		Miscellaneous Reimbursements		(876,867)		
29						
30		**Total Other Transactions/Reimbursements**		$2,224,407	0.1247%	
31						
32		**Grand Total Affiliate Transactions**		$15,835,361	0.8874%	$206,480
33						
34		**Total Knife River Corporation Operating Expenses for 2018-Excludes Intersegment Eliminations**			$1,784,428,000	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

KNIFE RIVER CORPORATION

1/Corporate overhead allocation factors are derived from the invested capital balance as a percentage of the total corporate invested capital. Montana-Dakota Utilities Co. cost of service amounts are calculated for the general office complex, the printing department, and the budget and forecast system. The general office complex amounts are payroll and floor space costs for employees that perform services for MDU Resources. These include accounts payable, general accounting, fixed asset accounting, and miscellaneous other services. The charges are based on the percentage of system users that are MDU Resources employees. Both the general office complex and amounts for MDU Resources are allocated to affiliated companies based on corporate overhead allocation factors. The printing department amount is allocated to affiliated companies based on the direct printing images processed for them and their percentage of the corporate overhead allocation for the corporate printed image amount.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI ENERGY, INC.	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead	1/ Various Corporate Overhead			
3		Audit Costs	Allocation Factors, Time	$27,509		
4		Advertising	Studies and/or Actual Costs	14,044		
5		Air Service	Incurred	9,666		
6		Automobile		1,498		
7		Bank Services		21,605		
8		Corporate Aircraft		9,968		
9		Consultant Fees		119,702		
10		Contract Services		190,296		
11		Computer Rental		216		
12		Directors Expenses		214,609		
13		Employee Benefits		6,167		
14		Employee Meeting		33		
15		Employee Reimbursable Expense		16,790		
16		Entertainment		22		
17		Non-Qualified Defined Contributions		9,094		
18		Legal Retainers & Fees		22,236		
19		Meal Allowance		81		
20		Cash Donations		3,470		
21		Meals		13,314		
22		Industry Dues & Licenses		9,845		
23		Office Expenses		10,517		
24		Supplemental Insurance		182,625		
25		Permits & Filing Fees		3,256		
26		Postage		(406)		
27		Payroll		3,196,805		
28		Reimbursements		(115)		
29		Reference Materials		15,979		
30		Rental		133		
31		Seminars & Meeting Registrations		19,461		
32		Software Maintenance		208,478		
33		Telephone/Cell Expenses		51,389		
34		Training		5,645		
35		Uniforms		55		
36		**Total MDU Resources Group, Inc.**		$4,383,987	4.7202%	

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI ENERGY, INC.	MONTANA-DAKOTA UTILITIES CO.				
2		Other Direct Charges	Actual Costs Incurred			
3		Audit Costs		$210,939		
4		Auto		1,726		
5		Bank Fees		9,687		
6		Communication Services		44,978		
7		Computer/Software Support		315,575		
8		Contract Services		393,896		
9		Utility/Merchandise Discounts		26,080		
10		Dues, Permits, and Filing Fees		13,845		
11		Interest		12,382		
12		Misc Employee Benefits		305,612		
13		Electric Consumption		699,220		$487,893
14		Gas Consumption		40,450		27,392
15		Cost of Service		84,776		18,811
16		Legal Fees		2,151		
17		Office Expense		101,088		
18		Sponsorship		18,000		
19		Training Registration		7,868		
20		Travel		21,546		
21		Payroll		184,450		
22		Balance Sheet		297,779		
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33		**Total Montana-Dakota Utilities Co.**		$2,792,048	3.0061%	$534,096

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI ENERGY, INC.					
2						
3		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual Costs Incurred			
4						
5		Federal & State Tax Liability Payments		$12,578,096		
6		Miscellaneous Reimbursements		(131,280)		
7		**Total Other Transactions/Reimbursements**		$12,446,816	13.4013%	
8						
9		**Grand Total Affiliate Transactions**		$19,622,851	21.1276%	$534,096
10						
11						
12						
13		**Total WBI Energy Operating Expenses for 2018 - Excludes Intersegment Eliminations**			$92,878,000	

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Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	MDU CONSTRUCTION	MDU RESOURCES GROUP, INC.				
2	SERVICES GROUP INC	Corporate Overhead	1/ Various Corporate Overhead			
3		Audit Costs	Allocation Factors, Time	$37,921		
4		Advertising	Studies and/or Actual Costs	14,902		
5		Air Service	Incurred	10,805		
6		Automobile		1,920		
7		Bank Services		22,588		
8		Corporate Aircraft		8,622		
9		Consultant Fees		91,615		
10		Contract Services		210,789		
11		Computer Rental		219		
12		Directors Expenses		220,644		
13		Employee Benefits		6,358		
14		Employee Meeting		33		
15		Employee Reimbursable Expense		19,457		
16		Entertainment		24		
17		Non-Qualified Defined Contributions		10,060		
18		Legal Retainers & Fees		23,636		
19		Meal Allowance		65		
20		Cash Donations		3,833		
21		Meals		12,051		
22		Industry Dues & Licenses		10,296		
23		Office Expenses		19,242		
24		Supplemental Insurance		203,622		
25		Permits & Filing Fees		3,264		
26		Postage		(411)		
27		Payroll		2,776,643		
28		Reimbursements		(419)		
29		Reference Materials		16,911		
30		Rent		140		
31		Seminars & Meeting Registrations		15,092		
32		Software Maintenance		248,483		
33		Telephone/Cell Expenses		50,477		
34		Training		5,021		
35		Uniforms		27		
36		**Total MDU Resources Group, Inc.**		$4,043,930	0.3148%	

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	MDU CONSTRUCTION	Intercompany Settlements	Actual Costs Incurred			
2	SERVICES GROUP INC	Audit Costs		$512,778		
3		Bank Fees		76,977		
4		Communication Services		171,696		
5		Computer/Software Support		1,001,109		
6		Contract Services		141,192		
7		Cost of Service		251,759		$55,863
8		Dues, Permits, and Filing Fees		51,146		
9		Gas Consumption		5,119		5,119
10		Legal		5,876		
11		Marketing		642		
12		Misc Employee Benefits		22,863		
13		Office Expense		26,433		
14		Payflex		(872)		
15		Payroll		3,022		
16		Sponsorship		17,800		
17		Travel		9,786		
18		Training Registration		21,773		
19		Balance Sheet		815,145		
20		**Total Montana-Dakota Utilities Co.**		$3,134,244	0.2440%	$60,982
21						
22		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual Costs Incurred			
23		Federal & State Tax Liability Payments		$15,266,074		
24		Miscellaneous Reimbursements		(571,508)		
25						
26		**Total Other Transactions/Reimbursements**		$14,694,566	1.1438%	
27						
28		**Grand Total Affiliate Transactions**		$21,872,740	1.7026%	$60,982
29						
30		**Total MDU Construction Services Group, Inc. Operating Expenses for 2018**			$1,284,689,000	
31		**Excludes Intersegment Eliminations**				

1/Corporate overhead allocation factors are derived from the invested capital balance as a percentage of the total corporate invested capital. Montana-Dakota Utilities Co. cost of service amounts are calculated for the general office complex, the printing department, and the budget and forecast system. The general office complex amounts are payroll and floor space costs for employees that perform services for MDU Resources. These include accounts payable, general accounting, fixed asset accounting, and miscellaneous other services. The charges are based on the percentage of system users that are MDU Resources employees. Both the general office complex and amounts for MDU Resources are allocated to affiliated companies based on corporate overhead allocation factors. The printing department amount is allocated to affiliated companies based on the direct printing images processed for them and their percentage of the corporate overhead allocation for the corporate printed image amount.

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	CENTENNIAL ENERGY	MONTANA-DAKOTA UTILITIES CO.				
2	RESOURCES INT					
3		Other Direct Charges	Actual costs incurred			
4		Dues, Permits, and Filing Fees		$550		
5		Bank Fees		2,604		
6						
8						
9		Intercompany Settlements	Actual costs incurred			
10		Dues, Permits, and Filing Fees		300		
11						
12		**Total Montana-Dakota Utilities Co.**		$3,454	4.0635%	$0
13						
14		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual costs incurred			
15		Federal & State Tax Liability Payments		($66,722)		
16						
17		**Total Other Transactions/Reimbursements**		($66,722)	-78.4965%	$0
18						
19		**Grand Total Affiliate Transactions**		($63,268)	-74.4329%	$0
20						
21		**Total Centennial Energy Resources International Operating Expenses for 2018**			$85,000	
22		**Excludes Intersegment Eliminations**				

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	CENTENNIAL HOLDINGS	MONTANA-DAKOTA UTILITIES CO.				
2	CAPITAL CORP. AND	Direct and Intercompany charges	Actual costs incurred			
3	FUTURESOURCE	Auto		$1,404		
4		Bank Fees		1,311		
5		Contract Services		769,582		
6		Materials		332,923		
7		Office Expense		156,702		
8		Travel		2,410		
9		Electric Consumption		188,578		
10		Gas Consumption		14,016		
11		Payroll		517,412		
12		Legal		135		
13		Dues, Permits, and Filing Fees		408		
14		Other		245		
15		Rent		139,382		
16		**Total Montana-Dakota Utilities Co.**		$2,124,508	19.0198%	$0
17		OTHER TRANSACTIONS/REIMBURSEMENTS				
18		Miscellaneous Reimbursements		($58,821)		
19		Federal & State Tax Liability Payments		8,516,485		
20		**Total Other Transactions/Reimbursements**		$8,457,664	75.7177%	$0
21						
22		**Grand Total Affiliate Transactions**		$10,582,172	94.7374%	$0
23						
24		**Total CHCC Operating Expenses for 2018**			$11,170,000	
25		**Excludes Intersegment Eliminations**				

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	MDU ENERGY	MDU RESOURCES GROUP, INC.				
2	CAPITAL 2/	Corporate Overhead	1/ Various Corporate Overhead			
3		Audit Costs	Allocation Factors, Time	$80,845		
4		Advertising	Studies and/or Actual Costs	41,083		
5		Air Service	Incurred	15,785		
6		Automobile		3,634		
7		Bank Services		62,566		
8		Corporate Aircraft		23,434		
9		Consultant Fees		161,434		
10		Contract Services		403,659		
11		Computer Rental		606		
12		Directors Expenses		614,474		
13		Employee Benefits		13,903		
14		Employee Meeting		43		
15		Employee Reimbursable Expense		34,865		
16		Entertainment		66		
17		Non-Qualified Defined Contributions		27,374		
18		Legal Retainers & Fees		66,513		
19		Meal Allowance		113		
20		Cash Donations		10,436		
21		Meals		30,940		
22		Industry Dues & Licenses		27,231		
23		Office Expenses		27,120		
24		Supplemental Insurance		552,740		
25		Permits & Filing Fees		9,300		
26		Postage		(1,150)		
27		Payroll		7,028,066		
28		Reimbursements		(539)		
29		Reference Materials		45,187		
30		Rental		318		
31		Seminars & Meeting Registrations		42,590		
32		Software Maintenance		435,834		
33		Telephone/Cell Expenses		58,700		
34		Training		12,942		
35		Uniforms		76		
36		**Total MDU Resources Group, Inc.**		$9,830,188	2.0447%	

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	MDU ENERGY	MONTANA-DAKOTA UTILITIES CO.				
2	CAPITAL 2/	Other Direct Charges	Actual costs incurred			
3		Bank Fees		$3,422		
4		Computer Equip/Software		13,700		
5		Contract Services		557,399		
6		Employee Benefits		6,791		
7		Filing Fees		42,059		
8		Training		11,700		
9		Legal		1,779		
10		Balance Sheet		674,432		
11						
12						
13						
14						
15		Intercompany Settlements				
16		O&M	Actual costs incurred			
17		Auto		$79		
18		Bank Fees		27,521		
19		Communications		336,148		
20		Contract Services		542,708		
21		Cost of Service		2,025,240		$449,386
22		Employee Benefits		84,539		
23		Marketing		15,400		
24		Marterial		16,877		
25		Miscellaneous		318,700		
26		Office Expenses		179,301		
27		Payroll		10,491,410		
28		SISP		119,708		
29		Software Maintenance		2,208,877		
30		Sponsorship		50,000		
31		Travel		251,538		
32						
33						
34						
35						
36						
37						
38						
39						

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	MDU ENERGY	MONTANA-DAKOTA UTILITIES CO.				
2	CAPITAL 2/	Other	Actual costs incurred			
3		Audit		$441,737		
4		LTIP		640,924		
5		MII		4,211		
6		Payflex		(14,702)		
7		Prepaid		255,718		
8		Miscellaneous		139,106		
9						
10		Capital	Actual costs incurred			
11		Auto		$136		
12		Company Consumption-Electric		476		
13		Company Consumption-Gas		311		
14		Contract Services		5,451		
15		Material		391,884		
16		Misc Employee Benefit		1,923		
17		Misc Other		148,119		
18		Office Expenses		544		
19		Payroll		1,591,784		
20		Travel		27,090		
21		Utility Group Project Allocation		1,882,356		
22		**Total Montana-Dakota Utilities Co.**		$23,496,396	4.8873%	$449,386
23						
24		OTHER TRANSACTIONS/REIMBURSEMENTS				
25		Federal & State Tax Liability Payments		$11,407,633		
26		Miscellaneous Reimbursements		(916,490)		
27						
28		**Total Other Transactions/Reimbursements**		$10,491,143	2.1822%	$0
29						
30		**Grand Total Affiliate Transactions**		$43,817,727	9.1143%	$449,386
31						
32		**Total MDU Energy Capital Operating Expenses for 2018**			$480,760,000	
33		**Excludes Intersegment Eliminations**				

1/Corporate overhead allocation factors are derived from the invested capital balance as a percentage of the total corporate invested capital. Montana-Dakota Utilities Co. cost of service amounts are calculated for the general office complex, the printing department, and the budget and forecast system. The general office complex amounts are payroll and floor space costs for employees that perform services for MDU Resources. These include accounts payable, general accounting, fixed asset accounting, and miscellaneous other services. The charges are based on the percentage of system users that are MDU Resources employees. Both the general office complex and amounts for MDU Resources are allocated to affiliated companies based on corporate overhead allocation factors. The printing department amount is allocated to affiliated companies based on the direct printing images processed for them and their percentage of the corporate overhead allocation for the corporate printed image amount.

2/ MDU Energy Capital is the parent company for Cascade Natural Gas Company and Intermountain Gas Company.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 7**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY Year: 2018

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	CENTENNIAL ENERGY	MONTANA-DAKOTA UTILITIES CO.				
2	HOLDING INC					
3		Other Direct Charges	Actual costs incurred			
4		Audit Costs		$138,616		
5		Bank Fees		2,797		
6		Contract Services		220,228		
7		Dues, Permits, and Filing Fees		250		
8		Legal		4,378		
9		Miscellaneous		713		
10		**Total Montana-Dakota Utilities Co.**		$366,982		
11						
12		**Grand Total Affiliate Transactions**		$366,982		
13						
14						
15						

MONTANA UTILITY INCOME STATEMENT

Year: 2018

	Account Number & Title		Last Year	This Year	% Change
1	400	Operating Revenues	$69,468,925	$72,073,248	3.75%
2					
3		Operating Expenses			
4	401	Operation Expenses	$54,143,474	$55,967,079	3.37%
5	402	Maintenance Expense	1,205,440	1,314,579	9.05%
6		Total O& M Expenses	55,348,914	57,281,658	3.49%
7					
8	403	Depreciation Expense	4,427,802	4,572,237	3.26%
9	404-405	Amort. & Depl. of Gas Plant	598,565	633,823	5.89%
10	406	Amort. of Gas Plant Acquisition Adjustments			
11	407.1	Amort. of Property Losses, Unrecovered Plant			
12		& Regulatory Study Costs			
13	407.2	Amort. of Conversion Expense			
14	408.1	Taxes Other Than Income Taxes	5,209,297	5,903,741	13.33%
15	409.1	Income Taxes - Federal	(240,195)	327,257	236.25%
16		- Other	(11,066)	155,378	1504.10%
17	410.1	Provision for Deferred Income Taxes	31,643,725	8,470,170	-73.23%
18	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	30,404,292	8,576,519	-71.79%
19	411.4	Investment Tax Credit Adjustments			
20	411.6	(Less) Gains from Disposition of Utility Plant			
21	411.7	Losses from Disposition of Utility Plant			
22					
23		**TOTAL Utility Operating Expenses**	$66,572,750	$68,767,745	3.30%
24		**NET UTILITY OPERATING INCOME**	$2,896,175	$3,305,503	14.13%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title		Last Year	This Year	% Change
1		Sales of Gas			
2					
3	480	Residential	$41,001,283	$43,025,501	4.94%
4	481	Commercial & Industrial - Small	25,893,772	27,406,091	5.84%
5		Commercial & Industrial - Large	223,082	238,762	7.03%
6	482	Other Sales to Public Authorities			
7	484	Interdepartmental Sales			
8	485	Intracompany Transfers			
9		Net Unbilled Revenue	431,385	(496,597)	-215.12%
10					
11		**TOTAL Sales to Ultimate Consumers**	$67,549,522	$70,173,757	3.88%
12	483	Sales for Resale			
13					
14		**TOTAL Sales of Gas**	$67,549,522	$70,173,757	3.88%
15		Other Operating Revenues			
16	487	Forfeited Discounts & Late Payment Revenues	$78,900	$79,515	0.78%
17	488	Miscellaneous Service Revenues	216,873	40,391	-81.38%
18	489	Revenues from Transp. of Gas for Others 1/	1,247,486	1,213,031	-2.76%
19	490	Sales of Products Extracted from Natural Gas			
20	491	Revenues from Nat. Gas Processed by Others			
21	492	Incidental Gasoline & Oil Sales			
22	493	Rent From Gas Property	321,139	340,796	6.12%
23	494	Interdepartmental Rents			
24	495	Other Gas Revenues	55,005	225,758	310.43%
25					
26		**TOTAL Other Operating Revenues**	1,919,403	1,899,491	-1.04%
27		**Total Gas Operating Revenues**	$69,468,925	$72,073,248	3.75%
28	496	(Less) Provision for Rate Refunds			
29					
30		**TOTAL Oper. Revs. Net of Pro. for Refunds**	$69,468,925	$72,073,248	3.75%

1/ Includes unbilled revenue.

MONTANA OPERATION & MAINTENANCE EXPENSES

	Account Number & Title		Last Year	This Year	% Change
1		**Production Expenses**			
2					
3	Production & Gathering - Operation				
4	750	Operation Supervision & Engineering			
5	751	Production Maps & Records			
6	752	Gas Wells Expenses			
7	753	Field Lines Expenses	NOT	NOT	
8	754	Field Compressor Station Expenses	APPLICABLE	APPLICABLE	
9	755	Field Compressor Station Fuel & Power			
10	756	Field Measuring & Regulating Station Expense			
11	757	Purification Expenses			
12	758	Gas Well Royalties			
13	759	Other Expenses			
14	760	Rents			
15					
16		**Total Operation - Natural Gas Production**			
17	Production & Gathering - Maintenance				
18					
19	761	Maintenance Supervision & Engineering			
20	762	Maintenance of Structures & Improvements			
21	763	Maintenance of Producing Gas Wells			
22	764	Maintenance of Field Lines	NOT	NOT	
23	765	Maintenance of Field Compressor Sta. Equip.	APPLICABLE	APPLICABLE	
24	766	Maintenance of Field Meas. & Reg. Sta. Equip.			
25	767	Maintenance of Purification Equipment			
26	768	Maintenance of Drilling & Cleaning Equip.			
27	769	Maintenance of Other Equipment			
28					
29		**Total Maintenance- Natural Gas Prod.**			
30		**TOTAL Natural Gas Production & Gathering**			
31	Products Extraction - Operation				
32					
33	770	Operation Supervision & Engineering			
34	771	Operation Labor			
35	772	Gas Shrinkage			
36	773	Fuel			
37	774	Power			
38	775	Materials			
39	776	Operation Supplies & Expenses	NOT	NOT	
40	777	Gas Processed by Others	APPLICABLE	APPLICABLE	
41	778	Royalties on Products Extracted			
42	779	Marketing Expenses			
43	780	Products Purchased for Resale			
44	781	Variation in Products Inventory			
45	782	(Less) Extracted Products Used by Utility - Cr.			
46	783	Rents			
47					
48		**Total Operation - Products Extraction**			
49	Products Extraction - Maintenance				
50					
51	784	Maintenance Supervision & Engineering			
52	785	Maintenance of Structures & Improvements			
53	786	Maintenance of Extraction & Refining Equip.			
54	787	Maintenance of Pipe Lines	NOT	NOT	
55	788	Maintenance of Extracted Prod. Storage Equip.	APPLICABLE	APPLICABLE	
56	789	Maintenance of Compressor Equipment			
57	790	Maintenance of Gas Meas. & Reg. Equip.			
58	791	Maintenance of Other Equipment			
59					
60		**Total Maintenance - Products Extraction**			
61		**TOTAL Products Extraction**			

MONTANA OPERATION & MAINTENANCE EXPENSES Year: 2018

	Account Number & Title	Last Year	This Year	% Change
1	**Production Expenses - continued**			
2				
3	Exploration & Development - Operation			
4	795 Delay Rentals			
5	796 Nonproductive Well Drilling	NOT	NOT	
6	797 Abandoned Leases	APPLICABLE	APPLICABLE	
7	798 Other Exploration			
8				
9	**TOTAL Exploration & Development**			
10				
11	Other Gas Supply Expenses - Operation			
12	800 Natural Gas Wellhead Purchases			
13	800.1 Nat. Gas Wellhead Purch., Intracomp. Trans.			
14	801 Natural Gas Field Line Purchases			
15	802 Natural Gas Gasoline Plant Outlet Purchases			
16	803 Natural Gas Transmission Line Purchases			
17	804 Natural Gas City Gate Purchases	$40,925,809	$42,783,707	4.54%
18	805 Other Gas Purchases			
19	805.1 Purchased Gas Cost Adjustments	816,111	601,641	-26.28%
20	805.2 Incremental Gas Cost Adjustments			
21	806 Exchange Gas			
22	807.1 Well Expenses - Purchased Gas			
23	807.2 Operation of Purch. Gas Measuring Stations			
24	807.3 Maintenance of Purch. Gas Measuring Stations			
25	807.4 Purchased Gas Calculations Expenses			
26	807.5 Other Purchased Gas Expenses			
27	808.1 Gas Withdrawn from Storage -Dr.	823,568	(184,685)	-122.42%
28	809.2 (Less) Deliveries of Nat. Gas for Processing-Cr.			
29	810 (Less) Gas Used for Compressor Sta. Fuel-Cr.			
30	811 (Less) Gas Used for Products Extraction-Cr.			
31	812 (Less) Gas Used for Other Utility Operations-Cr.			
32	813 Other Gas Supply Expenses	183,555	159,095	-13.33%
33				
34	**TOTAL Other Gas Supply Expenses**	$42,749,043	$43,359,758	1.43%
35	**TOTAL PRODUCTION EXPENSES**	$42,749,043	$43,359,758	1.43%

MONTANA OPERATION & MAINTENANCE EXPENSES
Year: 2018

	Account Number & Title		Last Year	This Year	% Change
1	**Storage, Terminaling & Processing Expenses**				
2					
3	Underground Storage Expenses - Operation				
4	814	Operation Supervision & Engineering			
5	815	Maps & Records			
6	816	Wells Expenses			
7	817	Lines Expenses			
8	818	Compressor Station Expenses			
9	819	Compressor Station Fuel & Power	NOT	NOT	
10	820	Measuring & Reg. Station Expenses	APPLICABLE	APPLICABLE	
11	821	Purification Expenses			
12	822	Exploration & Development			
13	823	Gas Losses			
14	824	Other Expenses			
15	825	Storage Well Royalties			
16	826	Rents			
17					
18		**Total Operation - Underground Strg. Exp.**			
19					
20	Underground Storage Expenses - Maintenance				
21	830	Maintenance Supervision & Engineering			
22	831	Maintenance of Structures & Improvements			
23	832	Maintenance of Reservoirs & Wells			
24	833	Maintenance of Lines			
25	834	Maintenance of Compressor Station Equip.	NOT	NOT	
26	835	Maintenance of Meas. & Reg. Sta. Equip.	APPLICABLE	APPLICABLE	
27	836	Maintenance of Purification Equipment			
28	837	Maintenance of Other Equipment			
29					
30		**Total Maintenance - Underground Storage**			
31		**TOTAL Underground Storage Expenses**			
32					
33	Other Storage Expenses - Operation				
34	840	Operation Supervision & Engineering			
35	841	Operation Labor and Expenses			
36	842	Rents	NOT	NOT	
37	842.1	Fuel	APPLICABLE	APPLICABLE	
38	842.2	Power			
39	842.3	Gas Losses			
40					
41		**Total Operation - Other Storage Expenses**			
42					
43	Other Storage Expenses - Maintenance				
44	843.1	Maintenance Supervision & Engineering			
45	843.2	Maintenance of Structures & Improvements			
46	843.3	Maintenance of Gas Holders			
47	843.4	Maintenance of Purification Equipment	NOT	NOT	
48	843.6	Maintenance of Vaporizing Equipment	APPLICABLE	APPLICABLE	
49	843.7	Maintenance of Compressor Equipment			
50	843.8	Maintenance of Measuring & Reg. Equipment			
51	843.9	Maintenance of Other Equipment			
52		**Total Maintenance - Other Storage Exp.**			
53		**TOTAL - Other Storage Expenses**			
54	**TOTAL - STORAGE, TERMINALING & PROC.**				

MONTANA OPERATION & MAINTENANCE EXPENSES Year: 2018

	Account Number & Title		Last Year	This Year	% Change
1		**Transmission Expenses**			
2					
3	Operation				
4	850	Operation Supervision & Engineering			
5	851	System Control & Load Dispatching			
6	852	Communications System Expenses			
7	853	Compressor Station Labor & Expenses			
8	854	Gas for Compressor Station Fuel	NOT	NOT	
9	855	Other Fuel & Power for Compressor Stations	APPLICABLE	APPLICABLE	
10	856	Mains Expenses			
11	857	Measuring & Regulating Station Expenses			
12	858	Transmission & Compression of Gas by Others			
13	859	Other Expenses			
14	860	Rents			
15					
16		**Total Operation - Transmission**			
17					
18	Maintenance				
19	861	Maintenance Supervision & Engineering			
20	862	Maintenance of Structures & Improvements			
21	863	Maintenance of Mains			
22	864	Maintenance of Compressor Station Equip.	NOT	NOT	
23	865	Maintenance of Measuring & Reg. Sta. Equip.	APPLICABLE	APPLICABLE	
24	866	Maintenance of Communication Equipment			
25	867	Maintenance of Other Equipment			
26		**Total Maintenance - Transmission**			
27		**TOTAL Transmission Expenses**			
28		**Distribution Expenses**			
29					
30	Operation				
31	870	Operation Supervision & Engineering	$828,007	$974,246	17.66%
32	871	Distribution Load Dispatching	7,420	8,268	11.43%
33	872	Compressor Station Labor and Expenses			
34	873	Compressor Station Fuel and Power			
35	874	Mains and Services Expenses	1,322,994	1,526,031	15.35%
36	875	Measuring & Reg. Station Exp.-General	36,877	46,923	27.24%
37	876	Measuring & Reg. Station Exp.-Industrial	24,062	8,959	-62.77%
38	877	Meas. & Reg. Station Exp.-City Gate Ck. Sta.			
39	878	Meter & House Regulator Expenses	508,347	733,392	44.27%
40	879	Customer Installations Expenses	479,643	486,141	1.35%
41	880	Other Expenses	1,111,698	1,134,313	2.03%
42	881	Rents	35,811	39,118	9.23%
43					
44		**Total Operation - Distribution**	$4,354,859	$4,957,391	13.84%
45					
46	Maintenance				
47	885	Maintenance Supervision & Engineering	$297,054	$290,639	-2.16%
48	886	Maintenance of Structures & Improvements	8,506	3,469	-59.22%
49	887	Maintenance of Mains	114,739	104,118	-9.26%
50	888	Maint. of Compressor Station Equipment			
51	889	Maint. of Meas. & Reg. Station Exp.-General	57,004	90,232	58.29%
52	890	Maint. of Meas. & Reg. Sta. Exp.-Industrial	43,720	43,092	-1.44%
53	891	Maint. of Meas. & Reg. Sta. Equip.-City Gate	0	25	2500.00%
54	892	Maintenance of Services	159,657	171,689	7.54%
55	893	Maintenance of Meters & House Regulators	240,989	304,459	26.34%
56	894	Maintenance of Other Equipment	190,996	210,489	10.21%
57					
58		**Total Maintenance - Distribution**	$1,112,665	$1,218,212	9.49%
52		**TOTAL Distribution Expenses**	$5,467,524	$6,175,603	12.95%

MONTANA OPERATION & MAINTENANCE EXPENSES Year: 2018

	Account Number & Title	Last Year	This Year	% Change
1	**Customer Accounts Expenses**			
2				
3	Operation			
4	901 Supervision	$77,796	$56,219	-27.74%
5	902 Meter Reading Expenses	189,308	211,380	11.66%
6	903 Customer Records & Collection Expenses	1,459,741	1,347,720	-7.67%
7	904 Uncollectible Accounts Expenses	258,342	291,978	13.02%
8	905 Miscellaneous Customer Accounts Expenses	65,566	90,130	37.46%
9				
10	**TOTAL Customer Accounts Expenses**	$2,050,753	$1,997,427	-2.60%
11	**Customer Service & Informational Expenses**			
12				
13	Operation			
14	907 Supervision	$28,986	$16,723	-42.31%
15	908 Customer Assistance Expenses	10,969	134,179	1123.26%
16	909 Informational & Instructional Advertising Exp.	36,469	41,818	14.67%
17	910 Miscellaneous Customer Service & Info. Exp.	116	0	-100.00%
18				
19	**TOTAL Customer Service & Info. Expenses**	$76,540	$192,720	151.79%
20	**Sales Expenses**			
21				
22	Operation			
23	911 Supervision	$679	($1,140)	-267.89%
24	912 Demonstrating & Selling Expenses	61,637	66,227	7.45%
25	913 Advertising Expenses	36,191	34,934	-3.47%
26	916 Miscellaneous Sales Expenses	2,256	1,930	-14.45%
27				
28	**TOTAL Sales Expenses**	$100,763	$101,951	1.18%
29	**Administrative & General Expenses**			
30				
31	Operation			
32	920 Administrative & General Salaries	$1,303,511	$1,466,420	12.50%
33	921 Office Supplies & Expenses	837,947	947,917	13.12%
34	922 (Less) Administrative Expenses Transferred - Cr.			
35	923 Outside Services Employed	118,439	452,853	282.35%
36	924 Property Insurance	112,311	119,673	6.56%
37	925 Injuries & Damages	360,375	372,408	3.34%
38	926 Employee Pensions & Benefits	1,689,122	1,599,107	-5.33%
39	927 Franchise Requirements			
40	928 Regulatory Commission Expenses	40,489	64,691	59.77%
41	929 (Less) Duplicate Charges - Cr.			
42	930 Miscellaneous General Expenses	115,721	145,093	25.38%
43	931 Rents	233,601	189,670	-18.81%
44				
45	**TOTAL Operation - Admin. & General**	$4,811,516	$5,357,832	11.35%
46				
47	Maintenance			
48	935 Maintenance of General Plant	$92,775	$96,367	3.87%
49				
50	**TOTAL Administrative & General Expenses**	$4,904,291	$5,454,199	11.21%
51	**TOTAL OPERATION & MAINTENANCE EXP.**	$55,348,914	$57,281,658	3.49%

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 11**

MONTANA TAXES OTHER THAN INCOME Year: 2018

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes	$488,139	$499,315	2.29%
2	Secretary of State	246	239	-2.85%
3	Highway Use Tax	385	456	18.44%
4	Montana Consumer Counsel	39,616	70,251	77.33%
5	Montana PSC	187,381	286,822	53.07%
6	Delaware Franchise Taxes	23,325	23,476	0.65%
7	Property Taxes	4,470,205	5,023,182	12.37%
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50	**TOTAL MT Taxes other than Income**	$5,209,297	$5,903,741	13.33%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2018

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	AGRI INDUSTRIES, INC.	Pipeline Install, Underground Construction	$220,365	$82,791	37.57%
2					
3	ALLIANCE PIPELINE LP	Contract Service - Milnor-Gwinner Pipeline	1,502,073	0	0.00%
4					
5	AMERICAN GAS ASSOCIATION	Industrial Membership	295,040	25,013	8.48%
6					
7	ANCHOR QEA	Erosion Control	97,014	0	0.00%
8					
9	APPLIED CONTROL (MT & WY)	Automation and Control Solutions	81,488	0	0.00%
10					
11	APPTIO INC	IT Planning, Budgeting and Forecasting	183,461	6,446	3.51%
12					
13	ARBOR SOLUTIONS TREE SERVICE LLC	Vegetation Removal	198,810	0	0.00%
14					
15	ARVIG CONSTRUCTION	Construction Services	1,848,128	0	0.00%
16					
17	ASSOCIATED BUILDERS	Service Center Roof Reinforcement	485,129	6,846	1.41%
18					
19	AUTOMOTIVE RENTALS, INC	Contract Services	322,657	0	0.00%
20					
21	AVERY TECHNICAL RESOURCES	Contract Services	83,556	0	0.00%
22					
23	B & B EXCAVATING INC	Contract Services	130,424	0	0.00%
24					
25	B&H UTILITY SERVICES, INC	Contract Services	320,511	0	0.00%
26					
27	BARR ENGINEERING COMPANY	Engineering Services - Power Plants	947,659	0	0.00%
28					
29	BARTLETT & WEST INC	Contract Services	423,390	0	0.00%
30					
31	BESLER INC	Contract Services - Equipment	316,854	0	0.00%
32					
33	BIG HORN ASPHALT & MORE	Contract Services	112,551	0	0.00%
34					
35	BLUE HERON CONSULTING CORPORATION	Consulting Services	106,640	9,258	8.68%
36					
37	BOWERS EXCAVATING LLC	Contract Services - Service Center	139,700	3,549	2.54%
38					
39	BOYCE LAW FIRM LLP	Legal Services	97,767	0	0.00%
40					
41	BRAHMA INDUSTRIAL SERVICES INC (BISI)	Subcontract Labor - Power Plants	167,307	0	0.00%
42					
43	BROADRIDGE ICS	Investing Services	166,913	5,542	3.32%
44					
45	BULLINGER TREE SERVICE	Vegetation Removal	260,708	0	0.00%
46					
47	BURNS & MCDONNELL ENGINEERING CO, INC	Engineering Services	726,463	0	0.00%
48					
49	CA CONTRACTING INC	Contract Services	137,275	0	0.00%
50					

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 12**

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS Year: 2018

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	CA INC	Construction Services	$84,656	$5,472	6.46%
2					
3	CBB COLLECTIONS INC	Collection Services	81,768	57,699	70.56%
4					
5	CENTRAL MECHANICAL INC	Underground Construction	115,650	2,970	2.57%
6					
7	CENTRAL TRENCHING INC.	Contract Services	347,057	0	0.00%
8					
9	CGI TECHNOLOGIES AND SOLUTIONS INC	Consulting Services	282,355	18,636	6.60%
10					
11	CHAPMAN AND CUTLER LLP	Contract Services	141,660	0	0.00%
12					
13	CHIEF CONSTRUCTION INC	Contract Services	1,091,067	0	0.00%
14					
15	CISCO SYSTEMS CAPITAL CORP	Software Maintenance	230,795	31,398	13.60%
16					
17	CITRIX SYSTEMS, INC	Software Maintenance	76,857	2,211	2.88%
18					
19	CITY OF BILLINGS	Multiple Permits	82,657	75,519	91.36%
20					
21	COFFMAN ENGINEERS	Contract Services	174,252	0	0.00%
22					
23	COMPLETE CONTRACTING SOLUTIONS	Contract Services	514,431	0	0.00%
24					
25	CONCENTRIC ENERGY ADVISORS INC	Consulting Services	305,530	0	0.00%
26					
27	CONDUCTOR POWER LLC	Contract Services - Power Plants	3,161,932	0	0.00%
28					
29	COP CONSTRUCTION LLC	Construction Services	264,529	264,529	100.00%
30					
31	CROWLEY FLECK PLLP	Legal Services	371,915	272,258	73.20%
32					
33	CYBER ADVISORS, INC	Software Maintenance	94,413	0	0.00%
34					
35	DAKOTA FENCE COMPANY	Fence Maintenance & Installation	81,355	602	0.74%
36					
37	DAVEY RESOURCE GROUP INC	Consulting Services	662,206	0	0.00%
38					
39	DELOITTE & TOUCHE LLP	Auditing & Consulting Services	2,205,484	31,715	1.44%
40					
41	DIS TECHNOLOGIES	GIS Data Conversion	82,030	7,122	8.68%
42					
43	DNV-GL	SL Essentials	227,953	14,209	6.23%
44					
45	E ON ENERGY SERVICES LLC	Energy Services & Maintenance	88,425	0	0.00%
46					
47	EDISON ELECTRIC INSTITUTE	Industrial Membership	136,513	463	0.34%
48					
49	EDLING ELECTRIC INC	Contract Services - Fiber-Interduct Work	143,999	1,948	1.35%
50					

Company Name: Montana-Dakota Utilities Co. SCHEDULE 12

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2018

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	ELECTRIC COMPANY OF SOUTH DAKOTA	Underground Construction	$507,095	$0	0.00%
2					
3	EMERSON PROCESS MGMT POWER & WATER	Contract Services - Power Plants	846,266	0	0.00%
4					
5	ENVIRONMENTAL CONSULTING & TECH INC	Consulting Services	80,054	0	0.00%
6					
7	ENVIROSYSTEMS USA INC-FORMERLY VISTEC	Contract Services - Power Plants	67,858	0	0.00%
8					
9	EQUINITI TRUST COMPANY	Bank Services Fees	173,843	5,788	3.33%
10					
11	ESRI	Consulting Services	191,458	11,567	6.04%
12					
13	ETSYSTEMS, INC	Engineering Services	211,259	397	0.19%
14					
15	EVERIST, THOMAS S	Director Fees	80,000	2,666	3.33%
16					
17	EXTREME UNDERGROUND HDD LLC	Underground Construction	606,789	0	0.00%
18					
19	FAGG, KAREN B	Director Fees	83,061	2,768	3.33%
20					
21	FIS ENERGY SYSTEMS, INC	Software Maintenance	87,775	6,710	7.64%
22					
23	FISCHER CONTRACTING	Construction Services	300,689	0	0.00%
24					
25	FITCH RATINGS	Credit Rating Services	176,500	4,629	2.62%
26					
27	FORRESTER, GARY	Lobbying & Promotion	119,986	4,000	3.33%
28					
29	FOSTER CONTRUCTION SERVICES LLC	Contract Services	135,981	0	0.00%
30					
31	FRANZ CONSTRUCTION INC	Contract Services - Power Plants	4,305,088	0	0.00%
32					
33	GARTNER INC	Consulting Services	75,409	2,522	3.34%
34					
35	GE ENERGY - BRETT HANSON	Subcontract Labor - Heskett	173,911	0	0.00%
36					
37	GE PACKAGED POWER LLC	Subcontract Labor	85,296	0	0.00%
38					
39	GE PROLEC TRANSFORMERS INC	Constract Services	100,600	0	0.00%
40					
41	HDR INC	Engineering Services	702,317	0	0.00%
42					
43	HEITKAMP CONSTRUCTION COMPANY, INC	Contract Services	157,742	0	0.00%
44					
45	HIGH VOLTAGE, INC	Contract Services-Preventative Maintenance	2,075,380	0	0.00%
46					
47	HIGHMARK ERECTORS INC	Contract Services	3,657,478	0	0.00%
48					
49	HONEYWELL	SE & SP Support Renewal	90,324	0	0.00%
50					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2018

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	HPI LLC	Contract Services - Miles City Turbine	$218,772	$0	0.00%
2					
3	IBA DRILLING CO INC	Contract Services	89,540	0	0.00%
4					
5	INDOOR SERVICES, INC	Janitorial Services	125,579	11,747	9.35%
6					
7	INDUSTRIAL CONTRACTORS, INC	Contract Services - Maintenance	682,923	0	0.00%
8					
9	INFRASOURCE	Construction Services	1,258,245	1,193,518	94.86%
10					
11	INFRASOURCE CONST LLC	Contract Services	3,983,366	0	0.00%
12					
13	INSIGHT	Software Maintenance	621,816	18,468	2.97%
14					
15	ITRON INC	Software Maintenance	363,775	28,613	7.87%
16					
17	J.B. CONSTRUCTION INC	Construction Services	484,499	0	0.00%
18					
19	J2 STUDIO ARCHITECT & DESIGN	Architectural Services	264,246	22,941	8.68%
20					
21	JACKSON UTILITIES LLC	Gas & Electric Line Installation	1,862,027	271,443	14.58%
22					
23	JACOBSEN TREE EXPERTS	Vegetation Removal	927,540	0	0.00%
24					
25	JOHN HANCOCK LIFE INSURANCE CO USA	Retirement Plan Services	21,457,128	927	0.00%
26					
27	JOHNSON, DENNIS	Director Fees	86,632	2,887	3.33%
28					
29	KADRMAS LEE & JACKSON	Engineering Services	345,899	2,965	0.86%
30					
31	KEY CONTRACTING INC	Contract Services - Transmission Line	1,670,487	0	0.00%
32					
33	L & S ELECTRIC INC	Lewis & Clark Rep Exiter System	336,492	0	0.00%
34					
35	LANDWORKS INC	Data Entry & Mapping	1,236,580	0	0.00%
36					
37	LIGNITE ENERGY COUNCIL	Membership Dues	106,992	0	0.00%
38					
39	MANAGED DESIGN, INC	Software Design	101,823	0	0.00%
40					
41	MARCO INC	Software Maintenance	221,093	4,929	2.23%
42					
43	MARCO TECHNOLOGIES LLC	Software Maintenance	350,565	11,253	3.21%
44					
45	MAULER CONTRACTING LLC	Contract Services - Cable Installation	110,862	0	0.00%
46					
47	MAVIRO INC	Pur Payment Processing Software	52,064	0	0.00%
48					
49	MCCRACKEN, WILLIAM E	Director Fees	75,034	2,501	3.33%
50					

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 12

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2018

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	MCM GENERAL CONTRACTORS, INC	Construction Services	$462,353	$0	0.00%
2					
3	MERIDIAN COMPENSATION PARTNERS LLC	Consulting Services	108,272	3,620	3.34%
4					
5	MG MEDIA STRATEGIES	Radio Advertising	101,145	6,651	6.58%
6					
7	MICROSOFT CORPORATION	Software Maintenance	1,738,981	50,284	2.89%
8					
9	MINNESOTA DEPARTMENT OF COMMERCE	Permits & Filing Fees	127,151	0	0.00%
10					
11	MINNESOTA VALLEY TESTING	Fuel Sampling & Testing	122,657	0	0.00%
12					
13	MOBILE SOLUTIONS SERVICES INC	Phone Services	260,310	0	0.00%
14					
15	MOORHEAD ELECTRIC INC (MEI)	Equipment Rental	431,587	0	0.00%
16					
17	NERC	Contract Services - Quarterly Assessment	123,417	0	0.00%
18					
19	NORDEX USA INC	Thunder Spirit - Service Contract	911,370	0	0.00%
20					
21	NYSE MARKET INC	Financial Services	211,511	7,023	3.32%
22					
23	ONE CALL LOCATORS LTD (ELM)	Line Locating Services	2,423,435	448,227	18.50%
24					
25	ONSHARP	Software Maintenance	94,057	3,140	3.34%
26					
27	OPEN SYSTEMS INTERNATIONAL, INC	Software Maintenance	411,266	0	0.00%
28					
29	OPTIV SECURITY, INC	Software Maintenance	248,761	7,696	3.09%
30					
31	ORACLE AMERICA, INC	Software Maintenance	1,103,886	47,425	4.30%
32					
33	ORACLE CORP	Software Maintenance	222,432	11,424	5.14%
34					
35	ORMAT NEVEDA INC	Energy Converter Maintenance	492,259	0	0.00%
36					
37	OSMOSE UTILITIES SERVICES, INC	Contract Services	354,698	0	0.00%
38					
39	PEARCE, HARRY J	Director Fees	160,000	5,332	3.33%
40					
41	PEARL MEYER & PARTNERS	Consulting Services	91,162	6,279	6.89%
42					
43	PERKINS COIE LLP	Legal Services	266,902	8,609	3.23%
44					
45	PHIFER OILFIELD CONSTRUCTION	Contract Services	309,074	0	0.00%
46					
47	PINKE LUMBER COMPANY	Contract Services	86,253	0	0.00%
48					
49	PLURALSIGHT	Software Maintenance	97,167	2,678	2.76%
50					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2018

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	POWERCOSTS INC	Software Maintenance	$194,154	$0	0.00%
2					
3	POWERPLAN, INC	Consulting Services - Software	888,031	52,527	5.92%
4					
5	POWERTECH LABS INC	Software License	76,123	0	0.00%
6					
7	PPI GROUP	Professional Organization Dues	390,800	13,895	3.56%
8					
9	PRESORT PLUS LLC	Mail Delivery & Pickup	79,009	10,719	13.57%
10					
11	PRICEWATERHOUSE COOPERS LLP	Consulting Services	263,934	1,908	0.72%
12					
13	PROSOURCE TECHNOLOGIES LLC	Consulting Services	96,228	3,661	3.80%
14					
15	Q3 CONTRACTING	Contract Services	3,965,103	0	0.00%
16					
17	R & L CONTRACTING INC	Contract Services	106,925	0	0.00%
18					
19	REMOTE ADMIN INC	Software Maintenance	79,800	2,669	3.34%
20					
21	ROCKY MOUNTAIN CONTACTORS, INC	Construction Services	1,472,585	528,305	35.88%
22					
23	ROCKY MOUNTAIN LINE SYSTEMS, INC	Construction Services	1,512,516	1,510,006	99.83%
24					
25	SCHERBENSKE INC	Contract Services	333,912	0	0.00%
26					
27	SCHULTE TA INC	Contract Services	374,351	0	0.00%
28					
29	SEAWAY PAINTING LLC	Subcontract Labor	153,306	0	0.00%
30					
31	SIBLEY ELECTRIC	Contract Services	91,755	0	0.00%
32					
33	SOUTHERN CROSS CORP	Contract Services-Preventative Maintenance	726,221	120,307	16.57%
34					
35	SPERION STAFFING LLC	Temp Services	172,707	13,769	7.97%
36					
37	STATE-LINE CONTRACTORS INC	Underground Construction	145,480	141,220	97.07%
38					
39	STINSON LEONARD STREET LLP	Legal Services	179,251	10,725	5.98%
40					
41	SUBURBAN CONSULTING ENGINEERS INC	Consulting Services	699,982	107,882	15.41%
42					
43	SWANSON & YOUNGDALE INC.	Subcontract Labor - Heskett	184,806	0	0.00%
44					
45	TRC ENVIRONMENTAL CORPORATION	Testing Pollution Control Equipment	282,138	0	0.00%
46					
47	TREASURY MANAGEMENT SERVICES	Banking Services	117,030	18,716	15.99%
48					
49	TRU PIPE INC	Underground Maintenance	146,447	96,364	65.80%
50					

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2018

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	TRU NORTH CONTRACTING LLC	Construction Services	$173,437	$162,247	93.55%
2					
3	TURBINEPROS	Subcontract Labor - Heskett	762,740	0	0.00%
4					
5	UBISENSE, INC	Underground GPS Based Leak Survey	80,750	17,483	21.65%
6					
7	UNITED ACCOUNTS INC	Credit Collections	84,842	0	0.00%
8					
9	UPPER MISSOURI POWER COOP	Construction Services	278,873	0	0.00%
10					
11	US DEPARTMENT ENERGY	Transmission Charges	1,314,427	0	0.00%
12					
13	USIC LOCATING SERVICES, INC	Line Locating Services	141,038	0	0.00%
14					
15	UTILITY SHAREHOLDERS OF NORTH DAKOTA	Organizational Dues	84,481	50	0.06%
16					
17	VERIZON WIRELESS	Phone Services	131,111	1	0.00%
18					
19	WEED WARRIORS	Subcontract Labor	99,211	0	0.00%
20					
21	WELLS FARGO BANK AGENCY SERVICES	Banking Services	553,903	0	0.00%
22					
23	WESTERN HORIZON	Vegetation Removal	109,988	3,550	3.23%
24					
25	WESTMORELAND SAVAGE CORPORATION	Equipment Rental	154,549	0	0.00%
26					
27	WINN CONSTRUCTION INC	Contract Services	90,885	0	0.00%
28					
29	WOOD MACKENZIE INC	Contract Services	80,500	0	0.00%
30					
31	WORKFORCE SERVICES, INC	Vehicle Maintenance	292,197	3,920	1.34%
32					
33	WORKIVA INC	Cloud Based Subscription for FCC Filing	62,631	7,502	11.98%
34					
35	XEROX CORPORATION	Copier Leases	126,299	13,750	10.89%
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44					
45					
46					
47					
48					
49					
50					
	Total Payments for Services		$100,862,072	$5,988,999	5.94%

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 13**

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2018

	Description	Total Company	Montana	% Montana
1	Contributions to Candidates by PAC	$125,675	$9,000	7.16%
2				
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39				
40	**TOTAL Contributions**	$125,675	$9,000	7.16%

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 14**

PENSION COSTS Year: 2018

1	Plan Name MDU Resources Group, Inc. Master Pension Plan Trust			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Traditional Unit Credit	IRS Code: 1A		
4	Annual Contribution by Employer: 0	Is the Plan Over Funded? No		
5				
6	Item	Current Year	Last Year	% Change
7	**Change in Benefit Obligation**	(000's)	(000's)	
8	Benefit obligation at beginning of year	$250,888	$245,858	2.05%
9	Service cost	-	-	0.00%
10	Interest cost	8,183	9,090	-9.98%
11	Plan participants' contributions	-	-	0.00%
12	Amendments	-	-	0.00%
13	Actuarial (Gain) Loss	(17,943)	10,543	-270.19%
14	Curtailment gain	-	-	0.00%
15	Benefits paid	(21,159)	(14,603)	-44.89%
16	Benefit obligation at end of year	$219,969	$250,888	-12.32%
17	**Change in Plan Assets**			
18	Fair value of plan assets at beginning of year	$192,712	$182,213	5.76%
19	Actual return on plan assets	(11,423)	24,679	-146.29%
20	Employer contribution	7,201	423	1602.36%
21	Plan participants' contributions	-	-	0.00%
22	Benefits paid	(21,159)	(14,603)	-44.89%
23	Fair value of plan assets at end of year	$167,331	$192,712	-13.17%
24	**Funded Status**	($52,638)	($58,176)	9.52%
25	Unrecognized net actuarial loss	103,455	102,514	0.92%
26	Unrecognized prior service cost	-	-	0.00%
27	Unrecognized net transition obligation	-	-	0.00%
28	Accrued benefit cost	$50,817	$44,338	14.61%
29	**Weighted-Average Assumptions as of Year End**			
30	Discount rate	4.03	3.38	19.23%
31	Expected return on plan assets	6.75	6.75	0.00%
32	Rate of compensation increase	-	-	0.00%
33	**Components of Net Periodic Benefit Costs**			
34	Service cost	-	-	0.00%
35	Interest cost	$8,182	$9,090	-9.99%
36	Expected return on plan assets	(11,352)	(11,222)	-1.16%
37	Amortization of prior service cost	-	-	0.00%
38	Recognized net actuarial loss	3,890	3,554	9.45%
39	Curtailment loss	-	-	0.00%
40	Net periodic benefit cost	$720	$1,422	-49.37%
41	**Montana Intrastate Costs:**			
42	Pension costs	$720	$1,422	-49.37%
43	Pension costs capitalized	-	249	-100.00%
44	Accumulated pension asset (liability) at year end	($52,638)	($57,927)	9.13%
45	**Number of Company Employees:**			
46	Covered by the plan	1,460	1,503	-2.86%
47	Not covered by the plan	809	708	14.27%
48	Active	411	440	-6.59%
49	Retired	931	941	-1.06%
50	Deferred vested terminated	118	122	-3.28%

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 15**

OTHER POST EMPLOYMENT BENEFITS (OPEBS) Year: 2018

	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number:			
4	Order numbers:			
5	Amount recovered through rates -			
6	**Weighted-Average Assumptions as of Year End**			
7	Discount rate	4.03	3.38	19.23%
8	Expected return on plan assets	5.75	5.75	0.00%
9	Medical cost inflation rate	4.50	4.50	0.00%
10	Actuarial cost method	Projected unit credit	Projected unit credit	
11	Rate of compensation increase	N/A	N/A	
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	**VEBA**			
14	**Describe any Changes to the Benefit Plan:**			
15	**TOTAL COMPANY**			
16	**Change in Benefit Obligation**	(000's)	(000's)	
17	Benefit obligation at beginning of year	$40,128	$40,267	-0.35%
18	Service cost	621	616	0.81%
19	Interest cost	1,257	1,443	-12.89%
20	Plan participants' contributions	731	804	-9.08%
21	Amendments	-	-	0.00%
22	Actuarial (Gain) Loss	(4,389)	260	1788.08%
23	Acquisition	-	-	0.00%
24	Benefits paid	(2,749)	(3,262)	-15.73%
25	Benefit obligation at end of year	$35,599	$40,128	-11.29%
26	**Change in Plan Assets**			
27	Fair value of plan assets at beginning of year	$50,531	$47,253	6.94%
28	Actual return on plan assets	(1,551)	5,645	-127.48%
29	Acquisition	-	-	0.00%
30	Employer contribution	70	91	-23.08%
31	Plan participants' contributions	731	804	-9.08%
32	Benefits paid	(2,749)	(3,262)	-15.73%
33	Fair value of plan assets at end of year	$47,032	$50,531	-6.92%
34	**Funded Status**	$11,433	$10,403	9.90%
35	Unrecognized net actuarial loss	-	-	0.00%
36	Unrecognized prior service cost	-	-	0.00%
37	Unrecognized transition obligation	-	-	0.00%
38	Accrued benefit cost	$11,433	$10,403	9.90%
39	**Components of Net Periodic Benefit Costs**			
40	Service cost	$621	$616	0.81%
41	Interest cost	1,257	1,443	-12.89%
42	Expected return on plan assets	(2,754)	(2,651)	-3.89%
43	Amortization of prior service cost	(976)	(976)	0.00%
44	Recognized net acturial gain	-	-	0.00%
45	Transition amount amortization	-	-	0.00%
46	Net periodic benefit cost	($1,852)	($1,568)	18.11%
47	**Accumulated Post Retirement Benefit Obligation**			
48	Amount funded through VEBA	$801	$895	-10.50%
49	Amount funded through 401(h)	-	-	0.00%
50	Amount funded through Other ___________________	-	-	0.00%
51	TOTAL	$801	$895	-10.50%
52	Amount that was tax deductible - VEBA (1)	$70	$91	-23.08%
53	Amount that was tax deductible - 401(h)	-	-	0.00%
54	Amount that was tax deductible - Other ___________	-	-	0.00%
55	TOTAL	$70	$91	-23.08%

(1) Estimated

Other Post Employment Benefits (OPEBS) Continued Year: 2018

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the plan	1,231	1,271	-3.15%
3	Not covered by the plan	39	39	0.00%
4	Active	535	557	-3.95%
5	Retired	517	544	-4.96%
6	Spouses/dependants covered by the plan	179	170	5.29%
7	**Montana**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year			
10	Service cost	NOT APPLICABLE		
11	Interest cost			
12	Plan participants' contributions			
13	Amendments			
14	Actuarial gain			
15	Acquisition			
16	Benefits paid			
17	Benefit obligation at end of year			
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year			
20	Actual return on plan assets			
21	Acquisition	NOT APPLICABLE		
22	Employer contribution			
23	Plan participants' contributions			
24	Benefits paid			
25	Fair value of plan assets at end of year			
26	**Funded Status**			
27	Unrecognized net actuarial loss	NOT APPLICABLE		
28	Unrecognized prior service cost			
29	Prepaid (accrued) benefit cost			
30	**Components of Net Periodic Benefit Costs**			
31	Service cost			
32	Interest cost	NOT APPLICABLE		
33	Expected return on plan assets			
34	Amortization of prior service cost			
35	Recognized net actuarial loss			
36	Net periodic benefit cost			
37	**Accumulated Post Retirement Benefit Obligation**			
38	Amount funded through VEBA			
39	Amount funded through 401(h)	NOT APPLICABLE		
40	Amount funded through other _______________			
41	TOTAL			
42	Amount that was tax deductible - VEBA			
43	Amount that was tax deductible - 401(h)			
44	Amount that was tax deductible - Other			
45	TOTAL			
46	**Montana Intrastate Costs:**			
47	Pension costs	($1,852)	($1,568)	18.11%
48	Pension costs capitalized	119	0	100.00%
49	Accumulated pension asset (liability) at year end	11,433	10,403	9.90%
50	**Number of Montana Employees:**			
51	Covered by the plan			
52	Not covered by the plan	NOT APPLICABLE		
53	Active			
54	Retired			
55	Spouses/dependants covered by the plan			

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 16
Year: 2018

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1							
2							
3							
4							
5	The requested information will be provided after the entry of a protective order which maintains the confidentiality of the information being provided. Montana-Dakota, submitted a Motion for Protective Order on April 21, 2015 in Docket No. N2015.2.17.						
6							
7							
8							
9							
10							

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 17**

Year: 2018

COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION 1/

Line No.	Name/Title	Base Salary	Bonuses	Other 2/	Total Compensation	Total Compensation Last Year 2/	% Increase Total Compensation
1	David L. Goodin President & CEO	$824,460	$807,971	$2,491,636	$4,124,067	$4,058,001	2%
2	Jason L. Vollmer Vice President, CFO & Treasurer	$350,000	$222,950	$559,075	$1,132,025	$634,551	78%
3	David C. Barney President & CEO of Knife River Corporation	$455,000	$384,589	$1,192,325	$2,031,914	$1,502,240	35%
4	Jeffrey S. Thiede President & CEO of MDU Construction Services Group	$455,000	$437,141	$1,081,995	$1,974,136	$1,636,860	21%
5	Nicole A. Kivisto President & CEO of Montanan-Dakota Utilities Co.	$430,000	$225,277	$643,901	$1,299,178	$1,228,841	6%

1/ See Schedule 17A for Total Compensation detail.

2/ Amounts represent the aggregate grant date fair value of the performance share awards calculated in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 718 - Share Based Payment.

EXECUTIVE COMPENSATION TABLES

Summary Compensation Table for 2018

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Stock Awards ($) (e)[1]	Non-Equity Incentive Plan Compensation ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)[2]	All Other Compensation ($) (i)[3]	Total ($) (j)
David L. Goodin	2018	824,460	2,433,437	807,971	16,503	41,696	4,124,067
President and CEO	2017	792,750	1,504,546	1,377,007	342,727	40,971	4,058,001
	2016	755,000	1,441,954	1,055,490	218,301	40,246	3,510,991
Jason L. Vollmer[4]	2018	350,000	495,840	222,950	—	63,235	1,132,025
Vice President, CFO and Treasurer	2017	256,625	95,101	230,988	3,681	48,156	634,551
David C. Barney	2018	455,000	958,410	384,589	—	233,915	2,031,914
President and CEO of	2017	427,140	324,247	483,736	93,786	173,331	1,502,240
Knife River Corporation	2016	406,800	276,232	593,114	77,565	22,905	1,376,616
Jeffrey S. Thiede	2018	455,000	958,410	437,141	—	123,585	1,974,136
President and CEO of	2017	437,750	332,318	743,629	—	123,163	1,636,860
MDU Construction Services Group, Inc.	2016	425,000	288,598	489,600	—	122,708	1,325,906
Nicole A. Kivisto[5]	2018	430,000	609,197	225,277	210	34,494	1,299,178
President and CEO of Montana-Dakota Utilities Co.	2017	378,000	286,955	433,906	96,931	33,049	1,228,841

1 Amounts in this column represent the aggregate grant date fair value of performance share award opportunities at target calculated in accordance with Financial Accounting Standards Board (FASB) generally accepted accounting principles for stock-based compensation in FASB Accounting Standards Codification Topic 718. This column was prepared assuming none of the awards were or will be forfeited. The amounts were calculated as described in Note 12 of our audited financial statements in our Annual Report on Form 10-K for the year ended December 31, 2018. For 2018, the total aggregate grant date fair value of performance share award opportunities assuming the highest level of payout would be as follows:

Name	Aggregate grant date fair value at highest payout ($)
David L. Goodin	4,866,874
Jason L. Vollmer	991,681
David C. Barney	1,603,026
Jeffrey S. Thiede	1,603,026
Nicole A. Kivisto	1,218,393

[2] Amounts shown for 2018 represent the change in the actuarial present value for the named executive officers' accumulated benefits under the pension plan, SISP, and Excess SISP, collectively referred to as the "accumulated pension change," plus above-market earnings on deferred annual incentives as of December 31, 2018.

Name	Accumulated Pension Change ($)	Above Market Interest ($)
David L. Goodin	(230,602)	16,503
Jason L. Vollmer	(3,594)	—
David C. Barney	(28,196)	—
Jeffrey S. Thiede	—	—
Nicole A. Kivisto	(98,726)	210

[3] All Other Compensation is comprised of:

Name	401(k) ($)[a]	Nonqualified Defined Contribution Plan ($)	Life Insurance Premium ($)	Matching Charitable Contributions ($)	Moving Stipend ($)[b]	Total ($)
David L. Goodin	39,875	—	621	1,200	—	41,696
Jason L. Vollmer	27,500	35,000	435	300	—	63,235
David C. Barney	22,000	150,000	565	1,200	60,150	233,915
Jeffrey S. Thiede	22,000	100,000	565	1,020	—	123,585
Nicole A. Kivisto	33,000	—	534	960	—	34,494

[a] Represents company contributions to the 401(k) plan, which includes matching contributions and retirement contributions made after the pension plans were frozen at December 31, 2009.

[b] Represents stipend for moving household goods as approved in Mr. Barney's 2012 relocation proposal.

[4] Mr. Vollmer was promoted to vice president, chief financial officer and treasurer effective September 30, 2017. He appeared as a named executive officer for the first time in 2017.

[5] Ms. Kivisto was promoted to president and chief executive officer of the electric and natural gas distribution segments effective January 9, 2015. She appeared as a named executive officer for the first time in 2017.

Grants of Plan-Based Awards in 2018

Name (a)	Grant Date (b)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All other stock awards: Number of shares of stock or units # (i)	Grant Date Fair Value of Stock and Option Awards ($) (l)
David L. Goodin	2/15/2018 [1]	303,707	824,460	1,648,920					
	2/15/2018 [2]				15,692	78,460	156,920		2,433,437
Jason L. Vollmer	2/15/2018 [1]	83,804	227,500	455,000					
	2/15/2018 [2]				3,197	15,987	31,974		495,840
David C. Barney	2/15/2018 [1]	85,313	341,250	819,000					
	2/15/2018 [2]				4,156	20,784	41,568		644,616
	2/15/2018 [3]							11,419	313,794
Jeffrey S. Thiede	2/15/2018 [1]	85,313	341,250	819,000					
	2/15/2018 [2]				4,156	20,784	41,568		644,616
	2/15/2018 [3]							11,419	313,794
Nicole A. Kivisto	2/15/2018 [1]	125,775	279,500	559,000					
	2/15/2018 [2]				3,928	19,642	39,284		609,197

[1] Annual incentive for 2018 granted pursuant to the MDU Resources Group, Inc. Executive Incentive Compensation Plan.

[2] Performance shares for the 2018-2020 performance period granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

[3] Time-vesting restricted stock units granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

Narrative Discussion Relating to the Summary Compensation Table and Grants of Plan-Based Awards Table

Annual Incentive

The compensation committee recommended the 2018 annual incentive award opportunities for our named executive officers and the board approved these opportunities at its meeting on February 15, 2018. The award opportunities at threshold, target, and maximum are reflected in columns (c), (d), and (e), respectively, of the Grants of Plan-Based Awards Table. The actual amount paid with respect to 2018 performance is reflected in column (g) of the Summary Compensation Table.

As described in the "Annual Incentives" section of the "Compensation Discussion and Analysis," payment of annual award opportunities is dependent upon achievement of performance measures; actual payout may range from 0% to 200% of the target except for the construction materials and contracting and construction services segments which may range from 0% to 240%.

All our named executive officers were awarded their annual incentive opportunities pursuant to the MDU Resources Group, Inc. Executive Incentive Compensation Plan. Under the Executive Incentive Compensation Plan, executives who retire during the year at or after age 65 remain eligible to receive an award, but executives who terminate employment for other reasons are not eligible for an award. The compensation committee generally does not modify the performance measures; however, if major unforeseen changes in economic and environmental conditions or other significant factors beyond the control of management substantially affected management's ability to achieve the specified performance measures, the compensation committee, in consultation with the CEO, may modify the performance measures. The compensation committee has full discretion to determine the extent to which goals have been achieved, the payment level, and whether to adjust payment of awards downward based upon individual performance. For further discussion of the specific 2018 incentive plan performance measures and results, see the "Annual Incentives" section in the "Compensation Discussion and Analysis."

Long-Term Incentive

The compensation committee recommended long-term incentive award opportunities for the named executive officers in the form of performance shares, and the board approved the award opportunities at its meeting on February 15, 2018. The long-term incentive opportunities are presented as the number of performance shares at threshold, target, and maximum in columns (f), (g), and (h) of the

Grants of Plan-Based Awards Table. The value of the long-term performance-based incentive opportunities is based on the aggregate grant date fair value and is reflected in column (e) of the Summary Compensation Table and column (l) of the Grant of Plan-Based Awards Table.

Depending on the achievement of the performance measures associated with our 2018-2020 performance period, executives will receive from 0% to 200% of the target awards in February 2021. We also will pay dividend equivalents in cash on the number of shares actually vested for the performance period. The dividend equivalents will be paid in 2021 at the same time as the performance share awards are issued.

The compensation committee also awarded Messrs. Barney and Thiede each 11,419 restricted stock units on February 15, 2018, which will vest on December 31, 2020 if the officers remain employees of the company through the vesting date as reflected in column (i) of the Grants of Plan-Based Awards Table. The compensation committee believes the restricted stock unit awards will incentivize Messrs. Barney and Thiede to continue their employment with the company for the next three years and grow their respective business segments during that time. For further discussion of the specific long-term incentive plan, see the "Long-Term Incentives" section in the "Compensation Discussion and Analysis."

Nonqualified Defined Contribution Plan

The CEO recommends participants and contribution amounts to the Nonqualified Defined Contribution Plan which are approved by the compensation committee of the board of directors. The purpose of the plan is to recognize outstanding performance coupled with enhanced retention as the Nonqualified Defined Contribution Plan requires a vesting period. The amount shown in column (i) - All Other Compensation of the Summary Compensation Table includes contributions of $35,000 to Mr. Vollmer, $150,000 to Mr. Barney, and $100,000 to Mr. Thiede. For further information, see the section entitled "Nonqualified Deferred Compensation for 2018."

Salary and Bonus in Proportion to Total Compensation

The following table shows the proportion of salary and bonus to total compensation:

Name	Salary ($)	Bonus ($)	Total Compensation ($)	Salary and Bonus as a % of Total Compensation
David L. Goodin	824,460	—	4,124,067	20.0%
Jason L. Vollmer	350,000	—	1,132,025	30.9%
David C. Barney	455,000	—	2,031,914	22.4%
Jeffrey S. Thiede	455,000	—	1,974,136	23.0%
Nicole A. Kivisto	430,000	—	1,299,178	33.1%

Outstanding Equity Awards at Fiscal Year-End 2018

Name (a)	Stock Awards: Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (i)[1]	Stock Awards: Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)[2]
David L. Goodin	337,878	8,055,012
Jason L. Vollmer	29,433	701,683
David C. Barney	83,381	1,987,803
Jeffrey S. Thiede	85,407	2,036,103
Nicole A. Kivisto	64,934	1,548,027

[1] Below is a breakdown by year of the outstanding performance share plan awards:

Performance Period End	2016 Award 12/31/2018	2017 Award 12/31/2019	2018 Award 12/31/2020	Total
David L. Goodin	197,528	61,890	78,460	337,878
Jason L. Vollmer	9,534	3,912	15,987	29,433
David C. Barney	37,840	13,338	32,203	83,381
Jeffrey S. Thiede	39,534	13,670	32,203	85,407
Nicole A. Kivisto	33,488	11,804	19,642	64,934

Shares for the 2016 award are shown at the maximum level (200%) based on results for the 2016-2018 performance cycle above target.

Shares for the 2017 award are shown at the target level (100%) based on results for the first two years of the 2017-2019 performance cycle between threshold and target.

Shares for the 2018 award are shown at the target level (100%) based on results for the first year of the 2018-2020 performance cycle between threshold and target. The number of shares under the 2018 award also includes 11,419 time-vesting restricted stock units granted to Messrs. Barney and Thiede.

[2] Value based on the number of performance shares and restricted stock units reflected in column (i) multiplied by $23.84, the year-end per share closing stock price for 2018.

While for purposes of the Outstanding Equity Awards at Fiscal Year-End 2018 Table, the number of shares and value shown for the 2016-2018 performance cycle is at 200% of target, the actual results for the performance period certified by the compensation committee and settled on February 14, 2019, was 140% of target. For further information, see the "Long-Term Incentives" section of the "Compensation Discussion and Analysis."

Option Exercises and Stock Vested During 2018

	Stock Awards	
Name (a)	Number of Shares Acquired on Vesting (#) (d)[1]	Value Realized on Vesting ($) (e)[2]
David L. Goodin	103,916	3,090,981
Jason L. Vollmer	2,751	81,829
David C. Barney	16,912	503,047
Jeffrey S. Thiede	18,198	541,300
Nicole A. Kivisto	17,616	523,988

1 Reflects performance shares for the 2015-2017 performance period ended December 31, 2017, which were settled February 15, 2018.

2 Reflects the value of vested performance shares based on the closing stock price of $27.48 per share on February 15, 2018, and the dividend equivalents paid on the vested shares.

Pension Benefits for 2018

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)[1]	Present Value of Accumulated Benefit ($) (d)
David L. Goodin	Pension	26	1,146,362
	Basic SISP [2]	10	2,343,866
	Excess SISP [3]	26	38,870
Jason L. Vollmer	Pension	4	20,857
	Basic SISP [3]	n/a	—
	Excess SISP [3]	n/a	—
David C. Barney	Pension [3]	n/a	—
	Basic SISP [2]	10	1,449,287
	Excess SISP [3]	n/a	—
Jeffrey S. Thiede	Pension [3]	n/a	—
	Basic SISP [3]	n/a	—
	Excess SISP [3]	n/a	—
Nicole A. Kivisto	Pension	14	220,945
	Basic SISP [2]	8	424,883
	Excess SISP [3]	n/a	—

1 Years of credited service related to the pension plan reflects the years of participation in the plan as of December 31, 2009, when the pension plan was frozen. Years of credited service related to the Basic SISP reflects the years toward full vesting of the benefit which is 10 years. Years of credited service related to Excess SISP reflects the same number of credited years of services as the pension plan.

2 The present value of accumulated benefits for the Basic SISP assumes the named executive officer would be fully vested in the benefit on the benefit commencement date; therefore, no reduction was made to reflect actual vesting levels.

3 Messrs. Barney and Thiede are not eligible to participate in the pension plans. Messrs. Vollmer and Thiede do not participate in the SISP. Mr. Goodin is the only named executive officer eligible to participate in the Excess SISP.

The amounts shown for the pension plan, Basic SISP, and Excess SISP represent the actuarial present values of the executives' accumulated benefits accrued as of December 31, 2018, calculated using:

- a 3.85% discount rate for the Basic SISP and Excess SISP;
- a 4.01% discount rate for the pension plan;
- the Society of Actuaries RP-2014 Mortality Table with scale MP-2018 for post-retirement mortality; and
- no recognition of future salary increases or pre-retirement mortality.

The actuary assumed a retirement age of 60 for the pension, Basic SISP, and Excess SISP benefits and assumed retirement benefits commence at age 60 for the pension and Excess SISP and age 65 for Basic SISP benefits.

Pension Plan

The MDU Resources Group, Inc. Pension Plan for Non-Bargaining Unit Employees (pension plan) applies to employees hired before 2006 and was amended to cease benefit accruals as of December 31, 2009. The benefits under the pension plan are based on a participant's average annual salary over the 60 consecutive month period where the participant received the highest annual salary between 1999 and 2009. Benefits are paid as straight life annuities for single participants and as actuarially reduced annuities with a survivor benefit for married participants unless they choose otherwise.

Supplemental Income Security Plan

The Supplemental Income Security Plan (SISP), a defined benefit nonqualified retirement plan, is offered to select key managers and executives. SISP benefits are determined by reference to levels defined within the plan. Our compensation committee, after receiving recommendations from our CEO, determined each participant's level within the plan. On February 11, 2016, the SISP was amended to exclude new participants to the plan and freeze current benefit levels for existing participants.

Basic SISP Benefits

Basic SISP is a supplemental retirement benefit intended to augment the retirement income provided under the pension plans. The Basic SISP benefits are subject to the following ten-year vesting schedule:

- 0% vesting for less than three years of participation;
- 20% vesting for three years of participation;
- 40% vesting for four years of participation; and
- an additional 10% vesting for each additional year of participation up to 100% vesting for ten years of participation.

Participants can elect to receive the Basic SISP as:

- monthly retirement benefits only;
- monthly death benefits paid to a beneficiary only; or
- a combination of retirement and death benefits, where each benefit is reduced proportionately.

Regardless of the election, if the participant dies before the SISP retirement benefit commences, only the SISP death benefit is provided.

Excess SISP Benefits

Excess SISP is an additional retirement benefit relating to Internal Revenue Code limitations on retirement benefits provided under the pension plans. Excess SISP benefits are equal to the difference between the monthly retirement benefits that would have been payable to the participant under the pension plans absent the limitations under the Internal Revenue Code and the actual benefits payable to the participant under the pension plans. Participants are only eligible for the Excess SISP benefits if the participant is fully vested under the pension plan, their employment terminates prior to age 65, and benefits under the pension plan are reduced due to limitations under the Internal Revenue Code on plan compensation.

In 2009, the SISP was amended to limit eligibility for the Excess SISP benefit. Mr. Goodin is the only named executive officer eligible for the Excess SISP benefit and must remain employed with the company until age 60 in order to receive the benefit. Benefits generally commence six months after the participant's employment terminates and continue to age 65 or until the death of the participant, if prior to age 65.

Both Basic and Excess SISP benefits are forfeited if the participant's employment is terminated for cause.

Nonqualified Deferred Compensation for 2018

Deferred Annual Incentive Compensation

Executives participating in the annual incentive compensation plans may elect to defer up to 100% of their annual incentive awards. Deferred amounts accrue interest at a rate determined annually by the compensation committee. The interest rate in effect for 2018 was 4.28% based on an average of the Moody's U.S. Long-Term Corporate Bond Yield Average for "A" and "Baa" rated companies. The deferred amount will be paid in accordance with the participant's election, following termination of employment or beginning in the fifth year following the year the award was earned. The amounts are paid in accordance with the participant's election in either a lump sum or in monthly installments not to exceed 120 months. In the event of a change of control, all amounts deferred would immediately become payable. For purposes of deferred annual incentive compensation, a change of control is defined as:

- an acquisition during a 12-month period of 30% or more of the total voting power of our stock;
- an acquisition of our stock that, together with stock already held by the acquirer, constitutes more than 50% of the total fair market value or total voting power of our stock;
- replacement of a majority of the members of our board of directors during any 12-month period by directors whose appointment or election is not endorsed by a majority of the members of our board of directors; or
- acquisition of our assets having a gross fair market value at least equal to 40% of the gross fair market value of all of our assets.

Nonqualified Defined Contribution Plan

The company adopted the Nonqualified Defined Contribution Plan, effective January 1, 2012, to provide deferred compensation for a select group of employees. The compensation committee approves the amount of employer contributions under the Nonqualified Defined Contribution Plan and the obligations under the plan constitute an unsecured promise of the company to make such payments. The company credits contributions to plan accounts which capture the hypothetical investment experience based on the participant's elections. Contributions made prior to 2017 vest four years after each contribution in accordance with the terms of the plan. Contributions made in 2017 vest rateably over a three-year period with 1/3 vesting after the first year, an additional 1/3 after the second year, and the final 1/3 after the third year. Amounts shown as aggregate earnings in the table below for Messrs. Vollmer, Barney, and Thiede reflect the change in investment value at market rates for the hypothetical investments selected by the participants. Participants may elect to receive their vested contributions and investment earnings either in a lump sum upon separation from service with the company or in annual installments over a period of years upon the later of (i) separation from service and (ii) age 65. Plan benefits become fully vested if the participant dies while actively employed. Benefits are forfeited if the participant's employment is terminated for cause.

The table below includes individual contributions from deferrals of annual incentive compensation and company contributions under the Nonqualified Defined Contribution Plan:

Name (a)	Executive Contributions in Last FY ($) (b)	Registrant Contributions in Last FY ($) (c)	Aggregate Earnings in Last FY ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE ($) (f)
David L. Goodin	688,504	—	58,102	—	1,498,658 [1]
Jason L. Vollmer	—	35,000	(6,425)	—	56,250 [2]
David C. Barney	—	150,000	(19,556)	—	303,785 [3]
Jeffrey S. Thiede	—	100,000	(52,812)	—	627,169 [4]
Nicole A. Kivisto	—	—	740	—	17,685

[1] Mr. Goodin deferred 50% of his 2017 annual incentive compensation which was $1,377,007 as reported in the Summary Compensation Table for 2017.

[2] Mr. Vollmer received $35,000 under the Nonqualified Defined Contribution Plan for 2018. Mr. Vollmer's balance also includes a contribution of $22,550 for 2017. Each of these amounts are reported in column (i) of the Summary Compensation Table for its respective year, where applicable.

[3] Mr. Barney received $150,000 under the Nonqualified Defined Contribution Plan for 2018. Mr. Barney's balance also includes a contribution of $150,000 for 2017. Each of these amounts are reported in column (i) of the Summary Compensation Table for its respective year.

[4] Mr. Thiede received $100,000 under the Nonqualified Defined Contribution Plan for 2018. Mr. Thiede's balance also includes contributions of $100,000 for 2017, $100,000 for 2016, $150,000 for 2015, $75,000 for 2014, and $33,000 for 2013. Each of these amounts is reported in column (i) of the Summary Compensation Table in the Proxy Statement for its respective year, where applicable.

Potential Payments upon Termination or Change of Control

The Potential Payments upon Termination or Change of Control Table shows the payments and benefits our named executive officers would receive in connection with a variety of employment termination scenarios or upon a change of control. The scenarios include:

- Voluntary Termination
- Not for Cause Termination
- Death
- Disability
- Change of Control with Termination
- Change of Control without Termination.

For the named executive officers, the information assumes the terminations or the change of control occurred on December 31, 2018.

The table excludes compensation and benefits our named executive officers would earn during their employment with us whether or not a termination or change of control event had occurred. The tables also do not include benefits under plans or arrangements generally available to all salaried employees and that do not discriminate in favor of the named executive officers, such as benefits under our qualified defined benefit pension plan (for employees hired before 2006), accrued vacation pay, continuation of health care benefits, and life insurance benefits. The tables also do not include Nonqualified Defined Contribution Plan or deferred annual compensation amounts which are shown and explained in the Nonqualified Deferred Compensation for 2018 Table.

Compensation

None of our named executive officers have employment or severance agreements entitling them to their base salary, some multiple of base salary or severance upon termination or change of control. Our compensation committee generally considers providing severance benefits on a case-by-case basis. Because severance payments are discretionary, no amounts are presented in the tables.

All our named executive officers were granted their 2018 annual incentive award under the Executive Incentive Compensation Plan (EICP) which has no change of control provision in regards to annual incentive compensation other than for deferred compensation. The EICP requires participants to remain employed with the company through the service year to be eligible for a payout unless otherwise determined by the compensation committee for named executive officers, or employment termination after age 65. As all our scenarios assume a termination or change in control event on December 31st, the named executives officers would be considered employed for the entire performance period; therefore, no amounts are shown for annual incentives in the tables for our named executive officers, as they would be eligible to receive their annual incentive award based on the level that performance measures were achieved for the performance period regardless of termination or change of control occurring on December 31, 2018.

All named executive officers received their performance share awards under the Long-Term Performance-Based Incentive Plan (LTIP). Upon a change of control (with or without termination), performance share awards would be deemed fully earned and vest at their target levels for the named executive officers. For this purpose, the term "change of control" is defined in the LTIP as:

- the acquisition by an individual, entity, or group of 20% or more of our outstanding common stock;
- a majority of our board of directors whose election or nomination was not approved by a majority of the incumbent board members;
- consummation of a merger or similar transaction or sale of all or substantially all of our assets, unless our stockholders immediately prior to the transaction beneficially own more than 60% of the outstanding common stock and voting power of the resulting corporation in substantially the same proportions as before the merger, no person owns 20% or more of the resulting corporation's outstanding common stock or voting power except for any such ownership that existed before the merger and at least a majority of the board of the resulting corporation is comprised of our directors; or
- stockholder approval of our liquidation or dissolution.

For termination scenarios other than a change of control, our award agreements provide that performance share awards are forfeited if the participant's employment terminates before the participant has reached age 55 and completed 10 years of service. If a participant's employment is terminated other than for cause after reaching age 55 and completing 10 years of service, performance shares are prorated as follows:

- termination of employment during the first year of the performance period = shares are forfeited;
- termination of employment during the second year of the performance period = performance shares earned are prorated based on the number of months employed during the performance period; and
- termination of employment during the third year of the performance period = full amount of any performance shares earned are received.

Under the termination scenarios, Messrs. Goodin, Barney, and Thiede would receive performance shares as they have each reached age 55 and have 10 or more years of service. The number of performance shares received would be based on the following:

- 2016-2018 performance shares would vest based on the achievement of the performance measure for the period ended December 31, 2018, which was 140%;
- 2017-2019 performance shares would be prorated at 24 out of 36 months (2/3) of the performance period and vest based on the achievement of the performance measure for the period ended December 31, 2019. For purposes of the Potential Payments upon Termination or Change of Control Table, the vesting is shown at 100%; and
- 2018-2020 performance shares would be forfeited.

For purposes of calculating the performance share value shown in the Potential Payments upon Termination or Change of Control Table, the number of vesting shares was multiplied by the average of the high and low stock price for the last market day of the year, which was December 31, 2018. Dividend equivalents based on the number of vesting shares are also included in the amounts presented.

Neither Ms. Kivisto nor Mr. Vollmer have reached age 55; therefore, they are not eligible for vesting of performance shares in the event of their termination.

Messrs. Barney and Thiede were granted 11,419 restricted stock units in February 2018. The restricted stock units will vest on December 31, 2020 provided that Messrs. Barney and Thiede remain continuously employed by the company through December 31, 2020, except for termination due to death or disability or a change in control as defined in the LTIP. In the case of a voluntary or not for cause termination on December 31, 2018, Messrs Barney and Thiede would forfeit the restricted stock units. In the case of death or disability, the restricted stock units would vest based on the number of full months of employment completed during the grant period to the date of death or disability divided by the total number of months in the grant period. In the case of death or disability occurring on December 31, 2018, one-third of Messrs. Barney and Thiede's restricted stock units plus dividend equivalents would vest. In the case of a change of control (with or without termination) occurring on December 31, 2018, the restricted stock units plus dividend equivalents would fully vest.

Benefits and Perquisites

Supplemental Income Security Plan

As described in the "Pension Benefits for 2018" section, the Basis SISP provides a benefit of payments commencing at age 65 and payable for 15 years. Of the named executive officers, only Messrs. Goodin, Barney, and Ms. Kivisto participate in the Basic SISP benefits. While Messrs. Goodin and Barney are 100% vested in their SISP benefit, Ms. Kivisto entered the plan in 2011 and is only 80% vested in her SISP benefit at December 31, 2018. Ms. Kivisto received a benefit level upgrade in 2014, which cliff vests on January 1, 2021. This means that if her employment terminates for any reason other than death before January 1, 2021, her benefit upgrade is forfeited.

Under all scenarios except death and change of control without termination, the payment represents the present value of the vested Basic SISP benefit as of December 31, 2018 using the monthly retirement benefit shown in the table below and a discount rate of 3.85%. In the event of death, Messrs. Goodin, Barney, and Ms. Kivisto's beneficiaries would receive monthly death benefit payments for 15 years. The Potential Payments upon Termination or Change of Control Tableshows the present value calculations of the monthly death benefit using the 3.85% discount rate.

	Monthly SISP Retirement Payment ($)	Monthly SISP Death Payment ($)
David L. Goodin	23,040	46,080
David C. Barney	10,936	21,872
Nicole A. Kivisto	5,000 *	10,000 *

* Ms. Kivisto's calculations are based on 80% of the value shown above for voluntary, not for cause and change of control with termination scenarios. The disability scenario allows for two additional years of vesting and is calculated using 100% of the value shown above. Ms. Kivisto's death benefit scenario is calculated using her 2014 benefit upgrade level with a monthly death benefit of $13,144.

Because the plan requires a participant to be no longer actively employed by the company in order to be eligible for payments, we do not show benefits for the change of control without termination scenario.

Disability

We provide disability benefits to some of our salaried employees equal to 60% of their base salary, subject to a salary limit of $200,000 for officers and $100,000 for other salaried employees when calculating benefits. For all eligible employees, disability payments continue until age 65 if disability occurs at or before age 60 and for five years if disability occurs between the ages of 60 and 65. Disability benefits are reduced for amounts paid as retirement benefits. The disability payments in the Potential Payments upon Termination or Change of Control Table reflect the present value of the disability benefits attributable to the additional $100,000 of base salary recognized for executives under our disability program, subject to the 60% limitation, after reduction for amounts that would be paid as retirement benefits. For Messrs. Goodin and Vollmer and Ms. Kivisto, who participate in the pension plan, the amount represents the present value of the disability benefit after reduction for retirement benefits using a discount rate of 4.01%. Because Mr. Goodin's retirement benefit is greater than the disability benefit, the amount shown is zero. For Messrs. Barney and Thiede, who do not participate in the pension plan, the amount represents the present value of the disability benefit without reduction for retirement benefits using the discount rate of 3.85%, which is considered a reasonable rate for purposes of the calculation.

Potential Payments upon Termination or Change of Control Table

Executive Benefits and Payments upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	Death ($)	Disability ($)	Change of Control (With Termination) ($)	Change of Control (Without Termination) ($)
David L. Goodin						
Compensation:						
Performance Shares	4,615,957	4,615,957	4,615,957	4,615,957	6,067,414	6,067,414
Benefits and Perquisites:						
Basic SISP	2,343,541	2,343,541	—	2,343,541	2,343,541	—
SISP Death Benefits	—	—	6,313,609	—	—	—
Disability Benefits	—	—	—	—	—	—
Total	**6,959,498**	**6,959,498**	**10,929,566**	**6,959,498**	**8,410,955**	**6,067,414**
Jason L. Vollmer						
Compensation:						
Performance Shares	—	—	—	—	611,066	611,066
Benefits and Perquisites:						
Disability Benefits	—	—	—	893,360	—	—
Total	**—**	**—**	**—**	**893,360**	**611,066**	**611,066**
David C. Barney						
Compensation:						
Performance Shares	909,098	909,098	909,098	909,098	1,333,967	1,333,967
Restricted Stock Units	—	—	92,695	92,695	278,110	278,110
Benefits and Perquisites:						
Basic SISP	1,432,676	1,432,676	—	1,432,676	1,432,676	—
SISP Death Benefits	—	—	2,996,772	—	—	—
Disability Benefits	—	—	—	273,370	—	—
Total	**2,341,774**	**2,341,774**	**3,998,565**	**2,707,839**	**3,044,753**	**1,612,077**
Jeffrey S. Thiede						
Compensation:						
Performance Shares	945,326	945,326	945,326	945,326	1,361,390	1,361,390
Restricted Stock Units	—	—	92,695	92,695	278,110	278,110
Benefits and Perquisites:						
Disability Benefits	—	—	—	413,878	—	—
Total	**945,326**	**945,326**	**1,038,021**	**1,451,899**	**1,639,500**	**1,639,500**
Nicole A. Kivisto						
Compensation:						
Performance Shares	—	—	—	—	1,209,958	1,209,958
Benefits and Perquisites:						
Basic SISP	258,172	258,172	—	322,715	258,172	—
SISP Death Benefits	—	—	1,800,913	—	—	—
Disability Benefits	—	—	—	708,366	—	—
Total	**258,172**	**258,172**	**1,800,913**	**1,031,081**	**1,468,130**	**1,209,958**

CEO Pay Ratio Disclosure

As required by Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 402(u) of Regulation S-K, we are providing information regarding the relationship of the annual total compensation of David L. Goodin, our president and chief executive officer, to the annual total compensation of our median employee.

Our employee workforce fluctuates during the year largely depending on the seasonality, number, and size of construction project activity conducted by our businesses. Approximately 49.6% of our employee workforce is employed under union bargained labor contracts which define compensation and benefits for participants which may include payments made by the company associated with employee participation in union benefit and pension plans.

We identified the median employee by examining the 2018 taxable wage information for all individuals on the company's payroll records as of December 31, 2018, excluding Mr. Goodin and the employees of Sweetman Construction Company which was acquired by our Construction Materials and Contracting segment during the fourth quarter. Because of the timing of this acquisition and its integration, payroll records were not available to include in the pay ratio analysis. Sweetman Construction Company reported 232 employees which represents less than 2% of the company's employee population. All of the company's employees are located in the United States. We made no adjustments to annualize compensation for individuals employed for only part of the year. We selected taxable wages as reported to the Internal Revenue Service on Form W-2 for 2018 to identify the median employee as it includes substantially all of the compensation for our median employee and provided a reasonably efficient and economic manner for the identification of the median employee. Our median employee works for our corporate office with annual compensation consisting of wages, annual incentive and company matching, retirement replacement and profit sharing 401(k) contributions. Our median employee does not participate in the company's pension plan since our median employee joined the company in 2017, after the plan was frozen. Our median employee receives an additional 5% company match to his 401(k) plan in lieu of pension contributions.

Once identified, we categorized the median employee's compensation to correspond to the compensation components as reported in the Summary Compensation Table. For 2018, the total annual compensation of Mr. Goodin as reported in the Summary Compensation Table included in this Proxy Statement was $4,124,067, and the total annual compensation of our median employee was $77,268. Based on this information, the 2018 ratio of annual total compensation of Mr. Goodin to the median employee was 53 to 1.

BALANCE SHEET Year: 2018

	Account Number & Title		Last Year	This Year	% Change
1		**Assets and Other Debits**			
2					
3	**Utility Plant**				
4	101	Gas Plant in Service	$552,389,410	$612,400,623	10.86%
5	101.1	Property Under Capital Leases			
6	102	Gas Plant Purchased or Sold			
7	104	Gas Plant Leased to Others			
8	105	Gas Plant Held for Future Use			
9	105.1	Production Properties Held for Future Use			
10	106	Completed Constr. Not Classified - Gas	18,189,485	9,554,360	-47.47%
11	107	Construction Work in Progress - Gas	5,874,134	1,666,554	-71.63%
12	108	(Less) Accumulated Depreciation	(255,268,098)	(268,305,998)	5.11%
13	111	(Less) Accumulated Amortization & Depletion	(2,462,462)	(3,012,458)	22.34%
14	114	Gas Plant Acquisition Adjustments	97,266	97,266	0.00%
15	115	(Less) Accum. Amort. Gas Plant Acq. Adj.	(69,309)	(72,131)	4.07%
16	116	Other Gas Plant Adjustments			
17	117	Gas Stored Underground - Noncurrent	2,514,929	1,718,566	-31.67%
18	118	Other Utility Plant	2,038,161,040	2,206,065,220	8.24%
19	119	Accum. Depr. and Amort. - Other Utl. Plant	(664,061,045)	(696,242,281)	4.85%
20					
21		**Total Utility Plant**	$1,695,365,350	$1,863,869,721	9.94%
22					
23	**Other Property & Investments**				
24	121	Nonutility Property	$16,449,813	$16,931,362	2.93%
25	122	(Less) Accum. Depr. & Amort. of Nonutil. Prop.	(5,380,673)	(6,199,490)	15.22%
26	123	Investments in Associated Companies			
27	123.1	Investments in Subsidiary Companies	1,704,908,136	1,790,885,738	5.04%
28	124	Other Investments	76,779,282	76,201,921	-0.75%
29	125	Sinking Funds			
30					
31		**Total Other Property & Investments**	$1,792,756,558	$1,877,819,531	4.74%
32					
33	**Current & Accrued Assets**				
34	131	Cash	$619,085	($273,799)	-144.23%
35	132-134	Special Deposits	4,603,012	617,411	-86.59%
36	135	Working Funds	150,750	312,522	107.31%
37	136	Temporary Cash Investments		1,178,164	100.00%
38	141	Notes Receivable			
39	142	Customer Accounts Receivable	25,259,589	27,283,245	8.01%
40	143	Other Accounts Receivable	4,110,686	14,756,480	258.98%
41	144	(Less) Accum. Provision for Uncollectible Accts.	(561,438)	(779,796)	38.89%
42	145	Notes Receivable - Associated Companies			
43	146	Accounts Receivable - Associated Companies	34,029,187	36,014,729	5.83%
44	151	Fuel Stock	4,684,911	4,784,694	2.13%
45	152	Fuel Stock Expenses Undistributed			
46	153	Residuals and Extracted Products			
47	154	Plant Materials and Operating Supplies	16,837,763	21,026,434	24.88%
48	155	Merchandise			
49	156	Other Material & Supplies			
50	163	Stores Expense Undistributed			
51	164.1	Gas Stored Underground - Current	9,179,608	8,508,246	-7.31%
52	165	Prepayments	5,865,158	5,480,655	-6.56%
53	166	Advances for Gas Explor., Devl. & Production			
54	171	Interest & Dividends Receivable			
55	172	Rents Receivable			
56	173	Accrued Utility Revenues	50,091,799	47,151,553	-5.87%
57	174	Miscellaneous Current & Accrued Assets			
58					
59		**Total Current & Accrued Assets**	$154,870,110	$166,060,538	7.23%

BALANCE SHEET Year: 2018

	Account Number & Title	Last Year	This Year	% Change
1	**Assets and Other Debits (cont.)**			
2				
3	**Deferred Debits**			
4	181 Unamortized Debt Expense	$2,353,114	$2,581,364	9.70%
5	182.1 Extraordinary Property Losses			
6	182.2 Unrecovered Plant & Regulatory Study Costs	2,959,651	2,508,004	-15.26%
7	182.3 Other Regulatory Assets	206,776,202	214,409,347	3.69%
8	183 Prelim. Electric Survey & Investigation Chrg.	1,678,581	1,112,510	-33.72%
9	183.1 Prelim. Nat. Gas Survey & Investigation Chrg.	7,900	11,624	47.14%
10	183.2 Other Prelim. Nat. Gas Survey & Invtg. Chrgs.	24,835	57,531	100.00%
11	184 Clearing Accounts	(52,274)	(31,304)	-40.12%
12	185 Temporary Facilities			
13	186 Miscellaneous Deferred Debits	29,033,605	28,836,015	-0.68%
14	187 Deferred Losses from Disposition of Util. Plant			
15	188 Research, Devel. & Demonstration Expend.			
16	189 Unamortized Loss on Reacquired Debt	4,726,100	4,154,385	-12.10%
17	190 Accumulated Deferred Income Taxes	59,350,651	51,529,326	-13.18%
18	191 Unrecovered Purchased Gas Costs	2,175,012	(2,576,502)	-218.46%
19	192.1 Unrecovered Incremental Gas Costs			
20	192.2 Unrecovered Incremental Surcharges			
21				
22	**Total Deferred Debits**	$309,033,377	$302,592,300	-2.08%
23				
24	**TOTAL ASSETS & OTHER DEBITS**	$3,952,025,395	$4,210,342,090	6.54%
25				
26	Account Number & Title	Last Year	This Year	% Change
27	**Liabilities and Other Credits**			
28				
29	**Proprietary Capital**			
30	201 Common Stock Issued	$195,843,297	$196,564,907	0.37%
31	202 Common Stock Subscribed			
32	204 Preferred Stock Issued			
33	205 Preferred Stock Subscribed			
34	207 Premium on Capital Stock	1,239,981,494	1,255,155,546	1.22%
35	211 Miscellaneous Paid-In Capital			
36	213 (Less) Discount on Capital Stock			
37	214 (Less) Capital Stock Expense	(6,569,697)	(6,579,697)	0.15%
38	216 Appropriated Retained Earnings	620,946,628	642,942,878	3.54%
39	216.1 Unappropriated Retained Earnings	419,801,251	520,659,042	24.03%
40	217 (Less) Reacquired Capital Stock	(3,625,813)	(3,625,813)	0.00%
41	219 Accumulated Other Comprehensive Income	(37,333,718)	(38,342,046)	-2.70%
42				
43	**Total Proprietary Capital**	$2,429,043,442	$2,566,774,817	5.67%
44				
45	**Long Term Debt**			
46	221 Bonds			
47	222 (Less) Reacquired Bonds			
48	223 Advances from Associated Companies			
49	224 Other Long Term Debt	714,686,250	788,725,495	10.36%
50	225 Unamortized Premium on Long Term Debt			
51	226 (Less) Unamort. Discount on Long Term Debt-Dr.			
52				
53	**Total Long Term Debt**	$714,686,250	$788,725,495	10.36%

BALANCE SHEET

	Account Number & Title		Last Year	This Year	% Change
1	**Total Liabilities and Other Credits (cont.)**				
2					
3	**Other Noncurrent Liabilities**				
4	227	Obligations Under Cap. Leases - Noncurrent			
5	228.1	Accumulated Provision for Property Insurance			
6	228.2	Accumulated Provision for Injuries & Damages	$283,024	$190,410	-32.72%
7	228.3	Accumulated Provision for Pensions & Benefits	45,731,295	41,383,945	-9.51%
8	228.4	Accumulated Misc. Operating Provisions			
9	229	Accumulated Provision for Rate Refunds	0	15,514,270	100.00%
10	230	Asset Retirement Obligations	127,809,107	142,922,575	11.83%
11					
12	**Total Other Noncurrent Liabilities**		$173,823,426	$200,011,200	15.07%
13					
14	**Current & Accrued Liabilities**				
15	231	Notes Payable			
16	232	Accounts Payable	$45,904,554	$48,869,177	6.46%
17	233	Notes Payable to Associated Companies			
18	234	Accounts Payable to Associated Companies	7,233,715	12,438,043	71.95%
19	235	Customer Deposits	1,361,897	1,443,059	5.96%
20	236	Taxes Accrued	3,296,066	24,703,900	649.50%
21	237	Interest Accrued	8,191,173	6,739,759	-17.72%
22	238	Dividends Declared	38,572,614	39,695,262	2.91%
23	239	Matured Long Term Debt			
24	240	Matured Interest			
25	241	Tax Collections Payable	1,095,165	1,181,720	7.90%
26	242	Miscellaneous Current & Accrued Liabilities	35,763,020	31,208,839	-12.73%
27	243	Obligations Under Capital Leases - Current			
28					
29	**Total Current & Accrued Liabilities**		$141,418,204	$166,279,759	17.58%
30					
31	**Deferred Credits**				
32	252	Customer Advances for Construction	$23,674,715	$20,525,735	-13.30%
33	253	Other Deferred Credits	87,716,626	83,378,564	-4.95%
34	254	Other Regulatory Liabilities	172,633,655	164,617,567	-4.64%
35	255	Accumulated Deferred Investment Tax Credits	1,830,976	3,377,889	84.49%
36	256	Deferred Gains from Disposition Of Util. Plant			
37	257	Unamortized Gain on Reacquired Debt			
38	281-283	Accumulated Deferred Income Taxes	207,198,101	216,651,064	4.56%
39					
40	**Total Deferred Credits**		$493,054,073	$488,550,819	-0.91%
41					
42	**TOTAL LIABILITIES & OTHER CREDITS**		$3,952,025,395	$4,210,342,090	6.54%

Definitions

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

AFUDC	Allowance for funds used during construction
ARAM	Average Rate Assumption Method
ASC	FASB Accounting Standards Codification
ASU	Accounting Standards Update
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Company	MDU Resources Group, Inc. (formerly known as MDUR Newco), which, as the context requires, refers to the previous MDU Resources Group, Inc. prior to January 1, 2019, and the new holding company of the same name after January 1, 2019.
Coyote 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
Holding Company Reorganization	The internal holding company reorganization completed on January 1, 2019, pursuant to the agreement and plan of merger, dated as of December 31, 2018, by and among Montana-Dakota, the Company and MDUR Newco Sub, which resulted in the Company becoming a holding company and owning all of the outstanding capital stock on Montana-Dakota
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
MDUR Newco	MDUR Newco, Inc., a public holding company created by implementing the Holding Company Reorganization, now known as the Company
MDUR Newco Sub	MDUR Newco Sub, Inc., a direct, wholly owned subsidiary of MDUR Newco, which was merged with and into Montana-Dakota in the Holding Company Reorganization
MISO	Midcontinent Independent System Operator, Inc.

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
SEC	United States Securities and Exchange Commission
SDPUC	South Dakota Public Utilities Commission
SSIP	System Safety and Integrity Program
TCJA	Tax Cuts and Jobs Act
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 approximately 143,000 electric and 299,000 natural gas residential, commercial, industrial and municipal customers in 285 communities and adjacent rural areas as of December 31, 2018.

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 $975.6 million; current and accrued assets would increase by $1.0 billion; deferred debits would increase by $784.1 million; long-term debt would increase by $1.1 billion; other noncurrent liabilities and current and accrued liabilities would increase by $619.8 million; and deferred credits would increase by $1.1 billion as of December 31, 2018. Furthermore, operating revenues would increase by $3.9 billion and operating expenses, excluding income taxes, would increase by $3.6 billion for the twelve months ended December 31, 2018. In addition, net cash provided by operating activities would increase by $202.4 million; net cash used in investing activities would increase by $498.1 million; net cash used in financing activities would decrease by $314.6 million; the effect of exchange rate changes on cash would decrease by $1,000; and the net change in cash and cash equivalents would be an increase of $18.9 million for the twelve months ended December 31, 2018. 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 5 for more information regarding the nature and amounts of these regulatory deferrals.

On January 2, 2019, the Company announced the completion of the Holding Company Reorganization, which resulted in Montana-Dakota and Great Plains becoming a subsidiary of the Company. The purpose of the reorganization was to make the public utility divisions into a subsidiary of the holding company, just as the other operating companies are wholly owned subsidiaries. Unless otherwise indicated, the amounts presented in the accompanying notes to the consolidated financial statements relate to the Company's corporate structure prior to the Holding Company Reorganization.

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

Due to the enactment of the TCJA, the jurisdictions in which the Company provides service requested the Company furnish plans for the effect of the reduced corporate tax rate, which impacted the Company’s rates to customers. Therefore, the Company reserved for such impacts as an offset to revenue or passed back to customers through lower rates in certain jurisdictions. For more information on the details and statuses of the open requests, see Note 16.

Management has also evaluated the impact of events occurring after December 31, 2018, up to the date of issuance of these 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 $640,000 and $690,000 at December 31, 2018 and 2017, respectively.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts at December 31, 2018 and 2017 was $780,000 and $561,000, respectively.

Accounts receivable also consists of accrued unbilled revenue representing revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota was $47.2 million and $50.1 million at December 31, 2018 and 2017, respectively.

Inventories and natural gas in storage

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

	2018	2017
	(In thousands)	
Plant materials and operating supplies	**$ 21,026**	$ 16,838
Gas stored underground-current	**8,508**	9,179
Fuel stock	**4,785**	4,685
Total	**$ 34,319**	$ 30,702

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was $1.7 million and $2.5 million at December 31, 2018 and 2017, 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 6 and 14.

Property, plant and equipment

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

	2018	2017
	(In thousands)	
AFUDC - borrowed	**$ 1,283**	$ 503
AFUDC - equity	**$ 1,027**	$ 401

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
MDU Resources Group, Inc.	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 12/31/2018	2018/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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:

		2018		2017	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)				
Electric:					
Generation	$	**1,131,484**	$	1,034,765	49
Distribution		**430,750**		415,543	46
Transmission		**302,315**		296,941	64
Construction in progress		**161,742**		117,922	-
Other		**117,133**		112,301	13
Natural gas distribution:					
Distribution		**547,788**		506,539	46
Construction in progress		**4,122**		6,998	-
Other		**134,450**		123,702	12
Less accumulated depreciation, depletion and amortization		**967,633**		921,861	
Net utility plant	$	**1,862,151**	$	1,692,850	
Nonutility property	$	**16,931**	$	16,450	
Less accumulated depreciation, depletion and amortization		**6,199**		5,381	
Net nonutility property	$	**10,732**	$	11,069	

Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. No impairment losses were recorded in 2018 and 2017. Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Goodwill

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

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 impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2018 and 2017, there were no impairment losses recorded. At December 31, 2018, the fair value of the natural gas distribution reporting unit substantially exceeded its carrying value. For more information on goodwill, see Note 4.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the Company's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, risk adjusted cost of capital, operational plans, and current and future economic conditions, among others. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach. Under the income approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the risk adjusted cost of capital at each reporting unit. The risk adjusted cost of capital of 5.0 percent, and a long-term growth rate projection of 3.5 percent were utilized in the goodwill impairment test performed in the fourth quarter of 2018. Under the market approach, the Company estimates fair value using multiples derived from enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information.

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

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

The Company recognizes all other revenues when services are rendered or goods are delivered. For more information on revenue from contracts with customers, see Note 2.

Asset retirement obligations
The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company either settles the obligation for the recorded amount or incurs a regulatory asset or liability. For more information on asset retirement obligations, see Note 8.

Legal costs
The Company expenses external legal fees as they are incurred.

Natural gas costs recoverable or refundable through rate adjustments
Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments which are filed annually. Natural gas costs recoverable (refundable) through rate adjustments were ($2.6) million and $2.2 million at December 31, 2018 and 2017, respectively, and included in unrecovered purchased gas costs.

Stock-based compensation
The Company determines compensation expense for stock-based awards based on the estimated fair values at the grant date and recognizes the related compensation expense over the vesting period. The Company uses the straight-line amortization method to recognize compensation expense related to restricted stock, which only has a service condition. This method recognizes stock compensation expense on a straight-line basis over the requisite service period for the entire award. The Company recognizes compensation expense related to performance awards that vest based on performance metrics and service conditions on a straight-line basis over the service period. Inception-to-date expense is adjusted based upon the determination of the potential achievement of the performance target at each reporting date. The Company recognizes compensation expense related to performance awards with market-based performance metrics on a straight-line basis over the requisite service period.

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

Income taxes
The Company and its subsidiaries file consolidated 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 by using enacted tax rates in effect for

the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. 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.

The Company records uncertain tax positions in accordance with accounting guidance on accounting for income taxes on the basis of a two-step process in which (1) the Company determines whether it is more-likely-than-not that the tax position will be sustained on the basis of the technical merits of the position and (2) for those tax positions that meet the more-likely-than-not recognition threshold, the Company recognizes the largest amount of the tax benefit that is more than 50 percent likely to be realized upon ultimate settlement with the related tax authority. Tax positions that do not meet the more-likely-than-not criteria are reflected as a tax liability. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in 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 long-lived assets and goodwill; fair values of acquired assets and liabilities under the acquisition method of accounting; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; 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.

New accounting standards

Recently adopted accounting standards

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

The Company adopted the guidance on January 1, 2018, using the modified retrospective approach. The Company elected the practical expedient to not disclose the aggregate amount of the transaction price allocated to the performance obligations that are unsatisfied (or partially unsatisfied) as of the end of the reporting period, along with an explanation of when such revenue would be expected to be recognized. This practical expedient was used since the performance obligations are part of contracts with an original duration of one year or less. The Company also elected the practical expedient to recognize the incremental costs of obtaining a contract as an expense when incurred if the amortization period of the asset that the Company otherwise would have recognized is one year or less. Upon completion of the Company's evaluation of contracts and methods of revenue recognition under the previous accounting guidance, the Company did not identify any material cumulative effect adjustments to be made to retained earnings. In addition, the Company has expanded revenue disclosures, both quantitatively and qualitatively, related to the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers, as discussed in Note 2. The Company reviewed its revenue streams to evaluate the impact of this guidance and did not identify a significant change in the timing of revenue recognition, results of operations, financial position or cash flows. The Company reviewed its internal controls related to revenue recognition and disclosures and concluded that the guidance impacted certain business processes and controls. As such, the Company developed modifications to its internal controls for certain topics under the guidance as they apply to the Company and such modifications were not deemed to be significant. Results for reporting periods beginning after December 31, 2017, are presented under the new guidance, while prior period amounts are not adjusted and continue to be reported in accordance with historic accounting for revenue recognition.

For the twelve months ended December 31, 2018, there were no material impacts to the financial statements as a result of applying the guidance.

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

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

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

In December 2017, the FERC issued guidance to provide clarification of whether and how to apply this ASU for purposes of regulatory accounting and reporting. The FERC concluded that pension and postretirement benefit cost, in its entirety without separation of the various components, be recorded in operating expenses. Regarding capitalization, companies may continue to capitalize the service cost component and non-service cost component or elect to capitalize only the service cost component as prescribed by ASU No. 2017-07.

The Company has elected to capitalize only the service cost component as prescribed by ASU No. 2017-07 as of January 1, 2018. This change in accounting practice will not have a material effect on the Company’s results of operations, cash flows or disclosures, nor will it have a material effect on rates, rate base or current period expenses.

ASU 2018-02 - Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income In February 2018, the FASB issued guidance that allows an entity to reclassify the stranded tax effects resulting from the newly enacted federal corporate income tax rate from accumulated other comprehensive income (loss) to retained earnings. The guidance is effective for the Company on January 1, 2019, including interim periods, with early adoption permitted. The guidance can be applied using one of two methods. One method is to record the reclassification of the stranded income taxes at the beginning of the period of adoption. The other method is to apply the guidance retrospectively to each period in which the income tax effects of the TCJA are recognized in accumulated other comprehensive income (loss).

In November 2018, the FERC issued an Order granting blanket approval for certain public utilities to reclassify the stranded tax effects caused by the reduction in corporate tax rate by the TCJA, from Account 219 to Account 439, in keeping with FASB’s guidance for public utilities that include both accumulated other comprehensive income and retained earnings in their capital structures for ratemaking purposes. The approval was granted provided the transfer from accumulated other comprehensive income to retained earnings will not affect rates.

The Company early adopted the guidance on January 1, 2018, for its GAAP financial statements and elected to reclassify the stranded income taxes at the beginning of the period. During the first quarter of 2018, the Company reclassified $7.9 million of stranded tax expense from accumulated other comprehensive loss to retained earnings, including $6.9 million related to the stranded tax expense of subsidiaries. As the Company’s capital structure for ratemaking purposes would not be impacted, following the FERC’s Order, the Company reclassified the stranded income taxes in its FERC financial statements from Account 219 to Account 439 as of December 31, 2018. The guidance did not have a material effect on the Company's results of operations, cash flows or disclosures.

Recently issued accounting standards not yet adopted
ASU 2016-02 - Leases In February 2016, the FASB issued guidance regarding leases. The guidance requires lessees to recognize a lease liability and a right-of-use asset on the balance sheet for operating and financing leases. The guidance remains largely the same for lessors, although some changes were made to better align lessor accounting with the new lessee accounting and to align with the revenue recognition standard. The guidance also requires additional disclosures, both quantitative and qualitative, related to operating and finance leases for the lessee and sales-type, direct financing and operating leases for the lessor. The Company adopted the standard for its GAAP financial statements on January 1, 2019.

In December 2018, the FERC issued guidance to provide clarity on how regulated entities can implement the lease accounting guidance within the framework and regulatory intent of the FERC’s existing requirements for lease accounting. The FERC guidance permits entities to record operating leases that may be capitalized under ASU No. 2016-02 in the FERC balance sheet accounts that have already been established for capital lease assets and liabilities. All other provisions of lease accounting are not affected by this accounting guidance, and the accounting guidance is intended to have no impact on the existing ratemaking treatment or practices. For entities that elect this option, additional disclosures would be required within their FERC filings. The Company has elected to not record operating leases on its FERC financial statements. Therefore, this standard will not have an impact on the Company's FERC financial statements or disclosures.

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

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

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

ASU 2018-15 - Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract In August 2018, the FASB issued guidance on the accounting for implementation costs of a hosting arrangement that is a service contract. The guidance aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract similar to the costs incurred to develop or obtain internal-use software and such capitalized costs to be expensed over the term of the hosting arrangement. Costs incurred during the preliminary and postimplementation stages should continue to be expensed as activities are performed. The capitalized costs are required to be presented on the balance sheet in the same line the prepayment for the fees associated with the hosting arrangement would be presented. In addition, the expense related to the capitalized implementation costs should be presented in the same line on the income statement as the fees associated with the hosting element of the arrangements. The guidance will be effective for the Company on January 1, 2020, including interim periods, and may be applied on a retrospective or a prospective basis with early adoption permitted. The Company adopted the guidance for its GAAP financial statements effective January 1, 2019, on a prospective basis. For FERC financial statements, the Company will functionalize these costs within the FERC plant accounts or in miscellaneous intangible plant, if appropriate. Additionally, the amortization of these costs will be reported as depreciation and amortization. The adoption of the guidance will not have a material impact on its results of operations, financial position, cash flows and disclosures.

Comprehensive income (loss)

Comprehensive income (loss) is the sum of net income (loss) as reported and other comprehensive income (loss). The Company's other comprehensive income (loss) resulted from postretirement liability adjustments and other comprehensive income (loss) recorded by its subsidiaries.

The postretirement liability adjustment in other comprehensive income was $1.0 million and $(517,000), net of tax of $(323,000) and $315,000, for the years ended December 31, 2018 and 2017, respectively.

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

Twelve Months Ended December 31, 2018	Postretirement Liability Adjustment	Subsidiary Other Comprehensive Loss	Total Accumulated Other Comprehensive Loss
		(In thousands)	
Balance at December 31, 2017	$ (4,803)	$ (32,531)	$ (37,334)
Other comprehensive income before reclassifications	903	3,333	4,236
Amounts reclassified from accumulated other comprehensive loss	99	2,616	2,715
Net current-period other comprehensive income	1,002	5,949	6,951
Reclassification adjustment of prior period tax effects related to TCJA included in accumulated other comprehensive loss	(1,045)	(6,914)	(7,959)
Balance at December 31, 2018	**$ (4,846)**	**$ (33,496)**	**$ (38,342)**

Twelve Months Ended December 31, 2017	Postretirement Liability Adjustment	Subsidiary Other Comprehensive Loss	Total Accumulated Other Comprehensive Loss
		(In thousands)	
Balance at December 31, 2016	$ (4,287)	$ (31,446)	$ (35,733)
Other comprehensive loss before reclassifications	(599)	(1,358)	(1,957)
Amounts reclassified from accumulated other comprehensive loss	83	1,416	1,499
Amounts reclassified to accumulated other comprehensive loss from a regulatory asset	---	(1,143)	(1,143)
Net current-period other comprehensive income loss	(516)	(1,085)	(1,601)
Balance at December 31, 2017	**$ (4,803)**	**$ (32,531)**	**$ (37,334)**

The following amounts were reclassified out of accumulated other comprehensive loss into net income. The amounts presented in parenthesis indicate a decrease to net income on the Statement of Income. The reclassifications were as follows:

Twelve Months Ended December 31,	**2018**	2017	Location on Statement of Income
	(In thousands)		
Amortization of postretirement liability losses included in net periodic benefit cost (credit)	**$ (131)**	$ (133)	(a)
	32	50	Income taxes
	(99)	(83)	
Subsidiary reclassifications out of accumulated other comprehensive loss	**(2,616)**	(1,416)	Equity in earnings of Subsidiary Companies
Total reclassifications	**$ (2,715)**	$ (1,499)	

(a) Included in net periodic benefit cost (credit). For more information, see Note 14.

Note 2 – Revenue from contracts with customers

Disaggregation

In the following table, revenue is disaggregated by the type of customer or service provided. The Company believes this level of disaggregation best depicts how the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors. The table also includes a reconciliation of the disaggregated revenue by reportable segments.

Year Ended December 31, 2018	Electric	Natural Gas Distribution	Total
		(In thousands)	
Residential utility sales	$ 121,477	$ 160,022	$ 281,499
Commercial utility sales	136,236	109,631	245,867
Industrial utility sales	34,353	5,672	40,025
Other utility sales	7,556	---	7,556
Natural gas transportation	---	6,423	6,423
Other	31,568	9,431	40,999
Revenues from contracts with customers	331,190	291,179	622,369
Revenues out of scope	3,933	1,475	5,408
Total external operating revenues	$ 335,123	$ 292,654	$ 627,777

Note 3 - Acquisitions

During 2018, a subsidiary of the Company completed four acquisitions of construction materials and contracting businesses in Oregon, Minnesota, and South Dakota. As of December 31, 2018, the gross aggregate consideration for these acquisitions, which were all accounted for as business combinations was $168.1 million in cash, subject to certain adjustments, and 721,610 shares of common stock with a market value of $20.3 million as of the respective acquisition date. Due to the holding period restriction on the common stock, the share consideration has been discounted to a fair value of approximately $18.2 million, as reflected in the Company's financial statements. The acquisitions are subject to customary adjustments based on, among other things, the amount of cash, debt and working capital in the businesses as of the closing dates.

The discount rate used in calculating the fair value of the common stock issued was determined by a Black-Scholes-Merton model. The model used Level 2 inputs including risk-free interest rate, volatility range and dividend yield.

Note 4 - 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, 2018 and 2017. This amount is included in miscellaneous deferred debits. No impairments have been recorded in any periods.

Note 5 - Regulatory Assets and Liabilities

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

	Estimated Recovery Period*	2018	2017
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(h)	**$ 96,595**	$ 95,806
Asset retirement obligations (a) (b)	Over plant lives	**13,763**	12,036
Taxes recoverable from customers (a)	Over plant lives	**8,179**	8,253
Unamortized loss on required debt	Up to 8 years	**4,154**	4,726
Costs related to identifying generation development (c)	Up to 8 years	**2,508**	2,960
Unrecovered purchased gas costs	Up to 1 year	**(2,577)**	2,175
Other (a) (d) (e)	Up to 20 years	**13,832**	14,283
Total regulatory assets		**136,454**	140,239
Regulatory liabilities:			
Taxes refundable to customers (f)		**148,015**	155,329
Plant removal and decommissioning costs (b) (f)		**56,095**	55,519
Accumulated provision for rate refunds		**15,514**	---
Pension and postretirement benefits (f)		**10,309**	11,056
Other (f) (g)		**6,209**	3,214
Total regulatory liabilities		**236,142**	225,118
Net regulatory position		**$ (99,688)**	$ (84,879)

* Estimated recovery period for regulatory assets currently being recovered in rates charged to customers.
(a) Included in other regulatory assets on the Comparative Balance Sheet.
(b) Included in accumulated provision for depreciation, amortization and depletion on the Comparative Balance Sheet.
(c) Included in unrecovered plant and regulatory study costs on the Comparative Balance Sheet.

(d) Included in prepayments on the Comparative Balance Sheet.
(e) Included in miscellaneous deferred debits on the Comparative Balance Sheet.
(f) Included in other regulatory liabilities on the Comparative Balance Sheet.
(g) Included in accumulated deferred investment tax credits on the Comparative Balance Sheet.
(h) Recovered as expense is incurred.

The regulatory assets are expected to be recovered in rates charged to customers. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates. As of December 31, 2018 and 2017, approximately $119.4 million and $118.5 million respectively, of regulatory assets were not earning a rate of return.

In the fourth quarter of 2017, the Company performed a one-time revaluation of the Company's regulated deferred tax assets and liabilities for the reduction of the corporate tax rate from 35 percent to 21 percent effective January 1, 2018, as identified in the TCJA. In the fourth quarter of 2017, the revaluation of the deferred tax assets and liabilities resulted in a decrease of $7.4 million in taxes recoverable from customers and an increase of $149.8 million in taxes refundable to customers. The revaluation of the Company’s regulatory deferred tax assets and liabilities were deferred as the Company worked with the various regulators to plan for amounts expected to be returned to customers. All amounts related to the TCJA are reserved or passed back to customers. The Company has tax settlements in place in most jurisdictions, with new rates in place in 2018 or expected to be in place in the first half of 2019, TCJA filings are pending in Wyoming. For more information on the various rate cases, see Note 16. There were no significant changes between the preliminary estimate and final determination of taxes refundable to or recoverable from customers. These regulatory amounts will largely be refunded over the remaining life of the related assets.

If, for any reason, the Company's regulated 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 or accumulated other comprehensive income (loss) in the period in which the discontinuance of regulatory accounting occurs.

Note 6 - 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 $49.2 million and $51.6 million as of December 31, 2018 and 2017, respectively, are classified as Other Investments on the Comparative Balance Sheet. The net unrealized loss on these investments for the year ended December 31, 2018, was $2.4 million. The net unrealized gain on these investments for the year ended December 31, 2017, was $6.5 million. 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.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs. The estimated fair values of the Company's assets and liabilities measured on a recurring basis are determined using the market approach. The Company’s Level 2 money market funds are valued at the net asset value of shares held at the end of the period, based on published market quotations on active markets, or using other known sources including pricing from outside sources. The estimated fair value of the Company's Level 2 insurance contract is based on contractual cash surrender values that are determined primarily by investments in managed separate accounts of the insurer. These amounts approximate fair value. The managed separate accounts are valued based on other observable inputs or corroborated market data.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2018 and 2017, there were no transfers between Levels 1 and 2.

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

	Fair Value Measurements at December 31, 2018, Using			
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2018
	(In thousands)			
Assets:				
Money market funds	$ —	$ 5,045	$ —	$ 5,045
Insurance contract*	—	49,213	—	49,213
Total assets measured at fair value	$ —	$ 54,258	$ —	$ 54,258

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

	Fair Value Measurements at December 31, 2017, Using			
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2017
	(In thousands)			
Assets:				
Money market funds	$ —	$ 3,762	$ —	$ 3,762
Insurance contract*	—	51,578	—	51,578
Total assets measured at fair value	$ —	$ 55,340	$ —	$ 55,340

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

The Company'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:

	2018		2017	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	**$ 788,725**	**$ 795,113**	$ 714,686	$ 752,311

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

Note 7 - Debt

Certain debt instruments of the Company, including those discussed later, contain restrictive covenants and provisions. In order to borrow under the respective credit agreement, the Company must be in compliance with the applicable covenants and certain other conditions. At December 31, 2018, the Company complied with all applicable financial covenants and restrictions. In the event the Company 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, 2018	Amount Outstanding at December 31, 2017	Letters of Credit at December 31, 2018	Expiration Date
				(Dollars in millions)			
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement	(a)	$ 175.0	$ 48.5 (b)	$ 73.8 (b)	$ —	6/8/23

(a) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $225.0 million). The amount outstanding under the revolving credit agreement was $48.5 million.
(b) Amount outstanding under commercial paper program 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. The Company's ratio of funded debt to total capitalization at December 31, 2018, was 45 percent. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

There are no credit facilities that contain cross-default provisions between the Company and any of its subsidiaries.

On January 1, 2019, the Company's revolving credit agreement and commercial paper program became Montana-Dakota's revolving credit agreement and commercial paper program as a result of the Holding Company Reorganization. The outstanding balance of the revolving credit agreement was also transferred to Montana-Dakota. All of the related terms and covenants of the credit agreements remained the same. For more information on the reorganization, see Note 1.

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

	2018	2017
	(In thousands)	
Senior Notes at a weighted average rate of 4.12%, due on dates ranging from October 17, 2019 to November 21, 2046	**$ 739,800**	$ 640,500
Commercial paper at an interest rate of 2.83%, supported by revolving credit agreement	**48,500**	73,750
Other note at a rate of 6.0%, due on November 30, 2038	**425**	436
Total long-term debt	**$ 788,725**	$ 714,686

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

	2019	2020	2021	2022	2023	Thereafter
			(In thousands)			
Long-term debt maturities	$200,711	$712	$713	$714	$49,214	$536,661

Note 8 - Asset Retirement Obligations

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

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

	2018	2017
	(In thousands)	
Balance at beginning of year	**$ 127,809**	$ 119,521
Liabilities incurred	**6,293**	4,559
Liabilities settled	**(1,006)**	(2,509)
Accretion expense *	**6,690**	6,277
Revisions in estimates	**3,137**	(39)
Balance at end of year	**$ 142,923**	$ 127,809

* Includes $6.7 million and $6.3 million in 2018 and 2017, respectively, related to regulatory assets.

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

Note 9 - Preferred Stocks

The Company currently has 500,000 shares of preferred stock authorized to be issued with a $100 par value; 1,000,000 shares of preferred stock A authorized to be issued with no par value; and 500,000 shares of preference stock authorized to be issued with no par value. At December 31, 2018, there were no shares outstanding. At December 31, 2017, there were no shares outstanding. On April 1, 2017, the Company redeemed all outstanding 4.50% Series and 4.70% Series preferred stocks at $105 per share and $102 per share, respectively, for a repurchase price of approximately $15.6 million and $300,000 of redeemable preferred stock classified as long-term debt.

Note 10 - Common Stock

For the years 2018 and 2017, dividends declared on common stock were $.7950 and $.7750 per common share, respectively.

The K-Plan provides participants the option to invest in the Company's common stock. For the years ended December 31, 2018 and 2017, the K-Plan purchased shares of common stock on the open market. At December 31, 2018, there were 7.8 million shares of common stock reserved for original issuance under the K-Plan.

The Company depends on earnings and dividends from its subsidiaries to pay dividends on common stock. The Company has paid quarterly dividends for more than 80 consecutive years with an increase in the payout amount for the last 28 consecutive years. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. In addition, the Company and Centennial are generally restricted to paying dividends out of capital accounts or net assets. The following discusses the most restrictive limitations.

Pursuant to a covenant under a credit agreement, Centennial may only declare or pay distributions if as of the last day of any fiscal quarter, the ratio of Centennial’s average consolidated indebtedness as of the last day of such fiscal quarter and each of the preceding three fiscal quarters to Centennial’s Consolidated EBITDA does not exceed 3 to 1. Intermountain has regulatory limitations on the amount of dividends it can pay. Based on these limitations, approximately $1.1 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2018. In addition, the Company's credit agreement also contains restrictions on dividend payments. The most restrictive limitation requires the Company not to permit the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Based on this limitation, approximately $424 million of the Company's (excluding its subsidiaries) net assets, which represents common stockholders’ equity including retained earnings, would be restricted from use for dividend payments at December 31, 2018. In addition, state regulatory commissions may require the Company to maintain certain capitalization ratios. These requirements are not expected to affect the Company's ability to pay dividends in the near term.

Note 11 - Stock-Based Compensation

The Company has stock-based compensation plans under which it is currently authorized to grant restricted stock and other stock awards. As of December 31, 2018, there were 5.0 million remaining shares available to grant under these plans. The Company either purchases shares on the open market or issues new shares of common stock to satisfy the vesting of stock based awards.

Total stock-based compensation expense (after tax), excluding the amount recognized by the Company’s subsidiaries, was $1.2 million and $805,000 in 2018 and 2017, respectively.

As of December 31, 2018, total remaining unrecognized compensation expense, excluding the amount to be recognized by the Company’s subsidiaries, related to stock-based compensation was approximately $2.0 million (before income taxes) which will be amortized over a weighted average period of 1.6 years.

Stock awards

Non-employee directors receive shares of common stock in addition to and in lieu of cash payment for directors' fees. Shares of common stock were issued under the non-employee director stock compensation plan or the non-employee director long-term incentive compensation plan. There were 38,605 shares with a fair value of $1.0 million and 40,572 shares with a fair value of $1.1 million issued to non-employee directors during the years ended December 31, 2018 and 2017, respectively.

Restricted stock awards

In February 2018, the Company began granting restricted stock awards under the long-term performance-based incentive plan to certain key employees. The restricted stock awards granted will vest after three years. The grant-date fair value is the market price of the Company's stock on the grant date. At December 31, 2018, the total nonvested shares were 22,838 with a weighted average grant-date fair value of $27.48 per share.

Performance share awards

Since 2003, key employees of the Company and its subsidiaries have been granted performance share awards each year under the long-term performance-based incentive plan. Entitlement to performance shares is established by either the market condition or the performance metrics and service condition relative to the designated award.

Target grants of performance shares outstanding at December 31, 2018, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2016	2016-2018	255,773
March 2016	2016-2018	2,151
February 2017	2017-2019	164,558
February 2018	2018-2020	246,309

Under the market condition for these performance share awards, participants may earn from zero to 200 percent of the apportioned target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value as determined by Monte Carlo simulation. The blended volatility term structure ranges are comprised of 50 percent historical volatility and 50 percent implied volatility. Risk-free interest rates were based on U.S. Treasury security rates in effect as of the grant date. Assumptions used for grants applicable to the market condition for certain performance shares issued in 2018 and 2017 were:

	2018	2017	2016
Weighted average grant-date fair value	**$34.55**	$24.31	$14.60
Blended volatility range	**17.87 % – 22.14 %**	22.70% – 25.56%	29.25 % – 32.51 %
Risk-free interest rate range	**1.86 % – 2.46 %**	.69% – 1.61%	.47 % – .92 %
Weighted average discounted dividends per share	**$2.46**	$1.70	$1.56

Under the performance conditions for these performance share awards, participants may earn from zero to 200 percent of the apportioned target grant of shares. The performance conditions are based on the Company's compound annual growth rate in earnings from continuing operations before interest, taxes, depreciation, depletion and amortization and the Company's compound annual growth rate in earnings from continuing operations. The performance shares applicable to these performance conditions have a weighted average grant-date fair value of $27.48 per share.

There were no performance shares that vested in 2018. The fair value of the performance shares that vested during the year ended December 31, 2017, was $9.6 million.

A summary of the status of the performance share awards for the year ended December 31, 2018, was as follows:

	Number of Shares		Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	425,534	$	18.35
Granted	246,309		31.02
Less:			
Forfeited	3,052		14.60
Nonvested at end of period	668,791	$	23.03

Note 12 - Income Taxes

Income before income taxes for the years ended December 31, 2018 and 2017, respectively was $57.0 million and $76.5 million.

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

		2018		2017
		(In thousands)		
Current:				
Federal	**$**	**(15,223)**	$	(19,922)
State		**(295)**		(1,380)
		(15,518)		(21,302)
Deferred:				
Income taxes:				
Federal		**8,835**		32,335
State		**877**		2,590
Investment tax credit - net		**1,547**		191
		11,259		35,116
Total income tax expense (benefit)	**$**	**(4,259)**	$	13,814

In accordance with the accounting guidance on accounting for income taxes, the tax effects of the change in tax laws or rates are to be recorded in the period of enactment. The TCJA was enacted on December 22, 2017, as discussed in Note 1. Therefore, the reduction in the corporate tax rate from 35 percent to 21 percent required the Company to prepare a one-time revaluation of the Company's deferred tax assets and liabilities in the fourth quarter of 2017, the period of enactment. The deferred taxes associated with the non-regulated operations were revalued at the new tax rate because deferred taxes should reflect what the Company expects to pay or receive in future periods under the applicable tax rate. As a result of the revaluation, the Company reduced the value of these assets and liabilities and recorded a tax expense of $2.9 million for the year ended December 31, 2017. Included in the tax expense was $1.0 million related to amounts in accumulated other comprehensive loss.

The Company's regulated operations prepared a one-time revaluation of the Company's regulatory deferred tax assets and liabilities in the fourth quarter of 2017 related to the enactment of the TCJA. The revaluation is being deferred under regulatory accounting as the Company works with the various regulators to plan for amounts expected to be returned to customers, as discussed in Notes 5 and 16. The revaluation of the deferred tax assets and liabilities resulted in a net decrease of $157.2 million in the fourth quarter of 2017. There were no significant changes between the preliminary estimate and final determination of taxes refundable to or recoverable from customers. These regulatory amounts will largely be refunded over the remaining life of the related assets.

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

Based on the Company’s estimate of the amount of excess deferred income taxes that would be used to reduce future customer rates, the Company recorded an increase in regulatory liabilities of approximately $149.8 million and a reduction in regulatory assets of $7.4 million, including gross ups, to reflect the future revenue reduction required to return previously collected income taxes to customers.

The accounts that increased and (decreased) in the 2017 remeasurement of deferred income taxes are reflected below (in millions):

FERC Account	**254**	**182.3**	**190**	**281**	**282**	**283**
Excess Deferred Income Taxes:						
Electric*	$122.5		$(1.7)	$(0.5)	$(120.3)	$(3.4)
Gas	27.3		(3.1)		(26.3)	(4.1)
Regulatory Asset and Deferred Taxes associated with AFUDC:						
Electric*		$(6.8)			(3.2)	(3.6)
Gas		(0.6)			(0.3)	(0.3)
Total	$149.8	$(7.4)	$(4.8)	$(0.5)	$(150.1)	$(11.4)

*Deferred income taxes for the Company’s electric integrated system, including excess deferred income taxes and those associated with AFUDC, are included in the MISO attachment O formula rate template based on an allocation percentage of transmission-related assets to total integrated system-related assets for each given year. For the years ended

December 31, 2018 and 2017, the allocation percentage for transmission-related assets to total integrated-system related assets was 18.92% and 15.83%, respectively.

Total plant-related excess deferred taxes, those originating in FERC accounts 281 or 282, as of December 31, 2017, were $147.1 million, and were largely considered protected. The Company has proposed in all of its state jurisdictions to amortize both protected and non-protected plant-related excess deferred taxes on an ARAM basis which is based on plant lives. See Note 1 for more information on the Company's weighted average depreciable lives. All state jurisdictions which have approved rates related to TCJA have approved this treatment and the Company is awaiting final orders in the remaining jurisdictions.

Net non-plant-related excess deferred taxes, those originating in FERC accounts 190 and 283, as of December 31, 2017 were $2.7 million. These excess deferred taxes are being amortized on a straight-line basis over periods ranging from 1-10 years as approved by the respective state jurisdictions which have approved rates related to TCJA.

Deferred taxes associated with AFUDC, recorded in FERC account 282 and 283, and the related regulatory asset, recorded in FERC account 182.3 were reduced by $7.4 million as of December 31, 2017 reflecting the reduction in future revenue requirement required to be collected from customers.

Amortization of the excess deferred taxes are being recorded to FERC Accounts 410.1 and 411.1 as appropriate. For the year ended December 31, 2018, the amortization of excess deferred taxes, including gross ups, has reduced the related regulatory liabilities by $7.3 million.

In November 2018, MISO submitted revisions to the generic rate template in attachment O of its Open Access Transmission, Energy and Operating Reserve Markets Tariff and to company-specific formula rate templates of several MISO transmission owners, including the Company's (FERC Docket No. ER19-249-000). The revisions add two income tax items to the generic rate template and the company-specific formula rates regarding the allowance for funds used during construction and a provision to return (or recover) excess (or deficient) accumulated deferred income taxes resulting from tax law or rate changes. In December 2018, the submittal was approved by the FERC for filing effective January 1, 2019.

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

	2018	2017
	(In thousands)	
Deferred tax assets:		
Postretirement	**$ 23,695**	$ 26,021
Production Tax Credits	**8,015**	19,367
Compensation-related	**7,903**	5,294
Customer advances	**4,988**	5,762
Other	**6,928**	2,907
Total deferred tax assets	**51,529**	59,351
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	**183,229**	173,782
Postretirement	**26,206**	25,745
Cost recovery mechanisms	**1,688**	2,285
Other	**5,528**	5,386
Total deferred tax liabilities	**216,651**	207,198
Net deferred income tax liability	**$ (165,122)**	$ (147,847)

As of December 31, 2018 and 2017, the Company had a federal income tax credit carryforward of $8.0 million and $19.4 million, respectively. The federal income tax credit carryforwards will expire in 2037 and 2038 if not utilized. As of December 31, 2018 and 2017, no valuation allowances have been recorded associated with previously identified deferred tax assets. Changes in tax regulations or assumptions regarding current and future taxable income could require valuation allowances in the future.

The following table reconciles the change in the net deferred income tax liability from December 31, 2017, to December 31, 2018, to deferred income tax expense:

	2018
	(In thousands)
Change in net deferred income tax liability from the preceding table	**$ 17,275**
Deferred taxes associated with TCJA enactment for regulated activities	**(5,364)**
Deferred taxes associated with other comprehensive income (loss)	**(323)**
Other	**(329)**
Deferred income tax expense for the period	**$ 11,259**

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

Years ended December 31,	2018		2017	
	Amount	%	Amount	%
	(Dollars in thousands)			
Computed tax at federal statutory rate	**$ 11,959**	**21.0**	$ 26,781	35.0
Increases (reductions) resulting from:				
Production tax credit	**(11,759)**	**(20.6)**	(13,958)	(18.2)
Excess deferred income tax amortization	**(5,364)**	**(9.4)**	---	---
Amortization and deferral of investment tax credit	**(120)**	**(0.2)**	(171)	(0.2)
R&D tax credit	**(669)**	**(1.2)**	---	---
Deductible K-Plan dividends	**(644)**	**(1.1)**	(1,092)	(1.4)
AFUDC equity	**(215)**	**(0.4)**	(140)	(0.2)
State income taxes, net of federal income tax	**2,163**	**3.8**	1,923	2.5
Nonqualified benefit plan TCJA	**182**	**0.3**	(2,342)	(3.1)
revaluation	---	---	1,890	2.5
TCJA revaluation related to accumulated other comprehensive income	---	---	1,045	1.4
Other	**208**	**0.3**	(122)	(0.2)
Total income tax expense (benefit)	**$ (4,259)**	**(7.5)**	$ 13,814	18.1

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

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

	2018	2017
	(In thousands)	
Balance at beginning of year	**$ ---**	$ ---
Additions based on tax positions related to current year	**39**	---
Additions for tax positions of prior years	**100**	---
Balance at end of year	**$ 139**	---

For the years ended December 31, 2018 and 2017, the Company recognized approximately $59,000 and $14,000, respectively, of interest income, related to income taxes. At December 31, 2018 and 2017, the Company had no accrued receivables for interest.

Note 13 – Cash Flow Information

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

		2018		2017
		(In thousands)		
Interest, net of AFUDC – borrowed of $1,283 and $503 in 2018 and 2017, respectively	**$**	**32,841**	$	30,101
Income taxes refunded, net	**$**	**(36,926)**	$	(7,885)

Noncash investing transactions at December 31 were as follows:

		2018		2017
		(In thousands)		
Property, plant and equipment additions in accounts payable	**$**	**12,907**	$	12,324
Issuance of common stock in connection with acquisition by a subsidiary	**$**	**18,186**	$	---

Note 14 - Employee Benefit Plans

Pension and other postretirement benefit plans

The Company has noncontributory qualified defined benefit pension plans and other postretirement benefit plans for certain eligible employees. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans. Other postretirement plans presented here include certain of the Company’s subsidiaries.

Prior to 2017, all of the Company’s defined benefit pension plans were frozen. These employees were eligible to receive additional defined contribution plan benefits. In October 2018, the Company transferred the liability of certain participants in the defined benefit pension plan, who are currently receiving benefits to an annuity company. The transfer of the benefit payments for these participants reduces the Company’s liability and future premiums.

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

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

Changes in benefit obligation and plan assets for the years ended December 31, 2018 and 2017, and amounts recognized in the Comparative Balance Sheet at December 31, 2018 and 2017, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	**2018**	2017
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 250,889**	$ 245,858	**$ 40,128**	$ 40,267
Service cost	**---**	---	**621**	616
Interest cost	**8,183**	9,090	**1,257**	1,443
Plan participants' contributions	**---**	---	**731**	804
Actuarial (gain) loss	**(17,944)**	10,543	**(4,389)**	260
Benefits paid	**(21,159)**	(14,602)	**(2,749)**	(3,262)
Benefit obligation at end of year	**219,969**	250,889	**35,599**	40,128
Change in net plan assets:				
Fair value of plan assets at beginning of year	**192,712**	182,213	**50,531**	47,253
Actual gain (loss) on plan assets	**(11,422)**	24,679	**(1,551)**	5,645
Employer contribution	**7,200**	422	**70**	91
Plan participants' contributions	**---**	---	**731**	804
Benefits paid	**(21,159)**	(14,602)	**(2,749)**	(3,262)
Fair value of net plan assets at end of year	**167,331**	192,712	**47,032**	50,531
Funded status – over (under)	**$ (52,638)**	$ (58,177)	**$ 11,433**	$ 10,403
Amounts recognized in the Comparative Balance Sheet at December 31:				
Other deferred debits (credits)	**$ (52,638)**	$ (58,177)	**$ 11,433**	$ 10,403
Net amount recognized	**$ (52,638)**	$ (58,177)	**$ 11,433**	$ 10,403
Amounts recognized in accumulated other comprehensive (income) loss/regulatory assets (liabilities) consist of:				
Actuarial loss	**$ 103,455**	$ 102,514	**$ 599**	$ 683
Prior service credit	**---**	---	**(7,253)**	(8,228)
Total	**$ 103,455**	$ 102,514	**$ (6,654)**	$ (7,545)

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. The table above includes amounts related to regulated operations, which are recorded as regulatory assets (liabilities) and are expected to be reflected in rates charged to customers over time. For more information on regulatory assets (liabilities), see Note 5.

Unrecognized pension actuarial losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets are amortized over the average life expectancy of plan participants for frozen plans. The market-related value of assets is determined using a five-year average of assets.

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

	2018	2017
	(In thousands)	
Projected benefit obligation	$ **219,969**	$ 250,889
Accumulated benefit obligation	$ **219,969**	$ 250,889
Fair value of plan assets	$ **167,331**	$ 192,712

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

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	**2018**	2017
	(In thousands)			
Components of net periodic benefit cost (credit):				
Service cost	**$ ---**	$ ---	**$ 621**	$ 616
Interest cost	**8,183**	9,090	**1,257**	1,443
Expected return on assets	**(11,352)**	(11,222)	**(2,754)**	(2,651)
Amortization of prior service credit	**---**	---	**(976)**	(976)
Recognized net actuarial loss	**3,890**	3,554	**---**	---
Net periodic benefit cost (credit), including amount capitalized	**721**	1,422	**(1,852)**	(1,568)
Less amount capitalized	**---**	294	**119**	(360)
Net periodic benefit cost (credit)	**721**	1,128	**(1,971)**	(1,208)
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss/regulatory assets (liabilities):				
Net (gain) loss	**4,831**	(2,915)	**(84)**	(2,733)
Amortization of actuarial loss	**(3,890)**	(3,554)	**---**	---
Amortization of prior service credit	**---**	---	**976**	976
Total recognized in accumulated other comprehensive (income) loss and regulatory assets (liabilities)	**941**	(6,469)	**892**	(1,757)
Total recognized in net periodic benefit cost (credit) and accumulated other comprehensive (income) loss and regulatory assets (liabilities)	**$ 1,662**	$ (5,341)	**$ (1,079)**	$ (2,965)

The estimated net loss for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss and regulatory assets into net periodic benefit cost in 2019 is $3.0 million. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss and regulatory assets into net periodic benefit cost (credit) in 2019 are $0 and $976,000, respectively. Prior service cost is amortized on a straight-line basis over the average remaining service period of active participants.

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

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	**2018**	2017
Discount rate	**4.02%**	3.37%	**4.03%**	3.38%
Expected return on plan assets	**6.75%**	6.75%	**5.75%**	5.75%

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

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	**2018**	2017
Discount rate	**3.38 %**	3.82%	**3.38%**	3.83%
Expected return on plan assets	**6.75 %**	6.75%	**5.75%**	5.75%

The expected rate of return on pension plan assets is based on a targeted asset allocation range determined by the funded ratio of the plan. As of December 31, 2018, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 40 percent to 50 percent equity securities and 50 percent to 60 percent fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets is based on the targeted asset allocation range of 25 percent to 30 percent equity securities and 70 percent to 75 percent fixed-income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

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

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

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

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2018:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 42	$ (36)
Effect on postretirement benefit obligation	$ 925	$ (806)

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

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The fair value ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs. The estimated fair values of the Company's pension plans’ assets are determined using the market approach.

The carrying value of the pension plans' Level 2 cash equivalents approximates fair value and is determined using observable inputs in active markets or the net asset value of shares held at year end, which is determined using other observable inputs including pricing from outside sources.

The estimated fair value of the pension plans' Level 1 equity securities is based on the closing price reported on the active market on which the individual securities are traded. The estimated fair value of the pension plans' Level 1 and Level 2 collective and mutual funds are based on the net asset value of shares held at year end, based on either published market quotations on active markets or other known sources including pricing from outside sources. The estimated fair value of the pension plans' Level 2 corporate and municipal bonds is determined using other observable inputs, including benchmark yields, reported trades, broker/dealer quotes, bids, offers, future cash flows and other reference data. The estimated fair value of the pension plans' Level 1 U.S. Government securities are valued based on quoted prices on an active market.

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

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2018 and 2017, there were no transfers between Levels 1 and 2.

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

	Fair Value Measurements at December 31, 2018, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2018
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 2,680	$ —	$ 2,680
Equity securities:				
U.S. companies	6,000	—	—	6,000
International companies	---	526	—	526
Collective and mutual funds *	79,347	28,051	—	107,398
Corporate bonds	—	39,744	—	39,744
Municipal bonds	—	5,775	—	5,775
U.S. Government securities	261	3,205	—	3,466
Total assets measured at fair value	$ 85,608	$ 79,981	$ —	$ 165,589

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

	Fair Value Measurements at December 31, 2017, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2017
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 2,074	$ —	$ 2,074
Equity securities:				
U.S. companies	7,257	—	—	7,257
International companies	960	—	—	960
Collective and mutual funds *	93,436	36,842	—	130,278
Corporate bonds	—	40,761	—	40,761
Municipal bonds	—	4,647	—	4,647
U.S. Government securities	564	4,510	—	5,074
Total assets measured at fair value	$ 102,217	$ 88,834	$ —	$ 191,051

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

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

The estimated fair value of the other postretirement benefit plans' Level 2 cash equivalents is valued at the net asset value of shares held at year end, based on published market quotations on active markets, or using other known sources including pricing from outside sources.

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

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

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2018 and 2017, there were no transfers between Levels 1 and 2.

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

	Fair Value Measurements at December 31, 2018, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2018
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 2,187	$ —	$ 2,187
Equity securities:				
U.S. companies	841	—	—	841
Insurance contract*	—	44,004	—	44,004
Total assets measured at fair value	$ 841	$ 46,191	$ —	$ 47,032

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

	Fair Value Measurements at December 31, 2017, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2017
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 2,738	$ —	$ 2,738
Equity securities:				
U.S. companies	1,074	—	—	1,074
Insurance contract*	—	46,719	—	46,719
Total assets measured at fair value	$ 1,074	$ 49,457	$ —	$ 50,531

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

The Company expects to contribute approximately $2.8 million to its defined benefit pension plans in 2019. The Company does not expect to contribute to its postretirement benefit plans in 2019.

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

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
	(In thousands)		
2019	$ 13,893	$ 2,653	$ 91
2020	13,992	2,544	87
2021	14,138	2,486	82
2022	14,305	2,476	76
2023	14,377	2,445	70
2024– 2028	70,899	11,592	249

Nonqualified benefit plans

In addition to the qualified defined benefit pension plans reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or, upon death, to their beneficiaries for a 15-year period. In February 2016, the Company froze the unfunded, nonqualified defined benefit plans to new participants and eliminated benefit increases. Vesting for participants not fully vested was retained.

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

	2018	2017
	(In thousands)	
Projected benefit obligation	**$ 47,176**	$ 51,388
Accumulated benefit obligation	**$ 47,176**	$ 51,388

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

	2018	2017
	(In thousands)	
Components of net periodic benefit cost:		
Service cost	**$ 185**	$ 221
Interest cost	**1,586**	1,769
Recognized net actuarial loss	**290**	214
Net periodic benefit cost	**$ 2,061**	$ 2,204

Weighted average assumptions used at December 31 were as follows:

	2018	2017
Benefit obligation discount rate	**3.85%**	3.18%
Benefit obligation rate of compensation increase	**N/A**	N/A
Net periodic benefit cost discount rate	**3.18%**	3.54%
Net periodic benefit cost rate of compensation increase	**N/A**	N/A

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

	2019	2020	2021	2022	2023	Thereafter
			(In thousands)			
Nonqualified benefits	$ 4,263	$ 4,525	$ 4,620	$ 3,914	$ 4,035	$ 18,272

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Expenses incurred under this plan for 2018 and 2017 were $96,000 and $167,000, respectively.

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

	2018	2017
	(In thousands)	
Investments		
Insurance contract*	$ 49,213	$ 51,578
Life insurance**	19,122	19,399
Other	5,054	3,765
Total investments	$ 73,389	$ 74,742

* For more information on the insurance contract, see Note 6.
**Investments of life insurance are carried on plan participants (payable upon the employee's death).

Defined contribution plans
The Company sponsors various defined contribution plans for eligible employees, and costs incurred under these plans were $10.6 million in 2018 and $11.1 million in 2017.

Note 15 - Jointly Owned Facilities
The financial statements include the Company's ownership interests in the assets, liabilities and expenses of Big Stone Station, Coyote Station and Wygen III. Each owner of the stations is responsible for financing its investment in the jointly owned facilities. The Company has an ownership interest of 22.7 percent in Big Stone Station, 25 percent in Coyote Station, and 25 percent in Wygen III.

The Company's share of the stations’ operating expenses was reflected in the appropriate categories of operating expenses (electric fuel and purchased power, operation and maintenance, and taxes, other than income) in the 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:

		2018		2017
		(In thousands)		
Big Stone Station:				
Utility plant in service	**$**	**156,534**	$	158,084
Less accumulated depreciation		**49,345**		51,740
	$	**107,189**	$	106,344
Coyote Station:				
Utility plant in service	**$**	**155,236**	$	155,287
Less accumulated depreciation		**105,565**		103,897
	$	**49,671**	$	51,390
Wygen III:				
Utility plant in service	**$**	**65,382**	$	65,065
Less accumulated depreciation		**9,174**		7,652
	$	**56,208**	$	57,413

Note 16 - Regulatory Matters

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

MNPUC

On December 29, 2017, the MNPUC issued a notice of investigation related to tax changes with the enactment of the TCJA. On January 19, 2018, the MNPUC issued a notice of request for information, commission planning meeting and subsequent comment period. Pursuant to the notice, Great Plains provided preliminary impacts of the TCJA on January 30, 2018. On March 2, 2018, Great Plains submitted its initial filing addressing the impacts of the TCJA advocating existing rates are reasonable and a reduction in rates is not warranted. On August 9, 2018, the MNPUC ruled that Great Plains reduce rates to reflect TCJA impacts and to also provide a one-time refund that captures the TCJA impacts from January 1, 2018 through the implementation date of new rates. On December 5, 2018, the MNPUC issued an order requiring Great Plains reduce its rates by $400,000 on an annual basis and provide a one-time refund of approximately $400,000, as previously mentioned, within 90 days after the rates are implemented through credits to customers' bills. The required compliance filing was submitted to the MNPUC on January 4, 2019. The MNPUC is scheduled to address the compliance filing on April 18, 2019.

MTPSC

On December 27, 2017, the MTPSC requested Montana-Dakota identify a plan for the impacts of the TCJA and to file a proposal for the impacts on the electric segment by March 31, 2018. On April 2, 2018, Montana-Dakota submitted its plan requesting the MTPSC recognize the identified need for additional rate relief and to consider the effects of the TCJA in a general electric rate case to be submitted by September 30, 2018. Montana-Dakota submitted the general electric rate case on September 28, 2018, as discussed below. On November 30, 2018, Montana-Dakota and interveners of the case submitted a stipulation and settlement agreement reflecting a one-time refund of approximately $1.5 million to account for all TCJA related impacts from January 1, 2018 through the date new rates are effective in the rate case noted below. A hearing was held on December 4, 2018, and the MTPSC issued an order accepting the stipulation and settlement agreement on December 21, 2018, requiring a one-time bill credit to occur in April 2019. The TCJA refund was issued to customers on March 29, 2019.

On September 28, 2018, Montana-Dakota filed an application with the MTPSC for an electric rate increase of approximately $11.9 million annually or approximately 18.9 percent above current rates. The requested increase is primarily to recover investments in facilities to enhance safety and reliability and the depreciation and taxes associated with the increase in investment. The increase was offset by tax savings related to the TCJA. On March 7, 2019, the MTPSC issued an interim order authorizing an interim increase of $7.9 million or 12.8% to be effective April 1, 2019. The interim increase is subject to refund depending on the final outcome of the rate case. This matter is pending before the MTPSC.

NDPSC

On July 21, 2017, Montana-Dakota filed an application with the NDPSC for a natural gas rate increase of approximately $5.9 million annually or approximately 5.4 percent above current rates. The requested increase is primarily to recover the increased investment in distribution facilities to enhance system safety and reliability and the depreciation and taxes associated with the increase in investment. Montana-Dakota also introduced a SSIP and the proposed adjustment mechanism required to fund the SSIP. Montana-Dakota requested an interim increase of approximately $4.6 million or approximately 4.2 percent, subject to refund. On September 6, 2017, the NDPSC approved the request for interim rates effective with service rendered on or after September 19, 2017. On February 14, 2018, Montana-Dakota filed a revised interim increase request of approximately $2.7 million, subject to refund, incorporating the estimated impacts of the TCJA reduction in the federal corporate income tax rate. On March 1, 2018, the updated interim rates were implemented. The impact of the TCJA was submitted as part of a rebuttal testimony identifying a reduction of the adjusted revenue requirement to approximately $3.6 million. On July 19, 2018, a settlement was filed reflecting a revised annual revenue increase of approximately $2.5 million or approximately 2.3 percent. The proposed adjustment mechanism to fund the SSIP was not included in the settlement and will be decided on separately by the NDPSC. On September 26, 2018, the NDPSC issued an order approving the settlement as filed but did not approve the SSIP recovery mechanism. On October 5, 2018, Montana-Dakota submitted a compliance filing, which included a plan for the one-time refund to be available March 1, 2019, for the interim amount to be refunded to customers. The NDPSC approved the compliance rates and were effective with service rendered on and after December 1, 2018. The interim refund was issued to customers on March 1, 2019.

On January 10, 2018, the NDPSC issued a general order initiating the investigation into the effects of the TCJA. The order required regulatory deferral accounting on the impacts of the TCJA and for companies to file comments and the expected impacts. On February 15, 2018, Montana-Dakota filed a summary of the primary impacts of the TCJA on the electric and natural gas utilities. On March 9, 2018, Montana-Dakota submitted a request to decrease its electric rates by $7.2 million or 3.9 percent annually. On August 10, 2018, a settlement agreement was filed requesting a decrease in rates of approximately $8.4 million. On September 26, 2018, the NDPSC issued an order approving the settlement along with requiring an additional adjustment to the rates to return 100 percent of the tax-effective 2018 excess deferred income taxes. On October 10, 2018, Montana-Dakota submitted a compliance filing, which included a refund plan for the interim amount to be refunded to customers. On November 20, 2018, the NDPSC approved the compliance rates which were effective with service rendered on and after December 1, 2018. The NDPSC also approved a one-time refund of approximately $7.9 million to be credited to customers' bills by March 15, 2019, based on 4.7 percent of the revenues collected between January 1, 2018, through November 30, 2018. The TCJA refund was issued to customers on March 12, 2019.

On October 19, 2018, Great Plains and the NDPSC advocacy staff filed a settlement agreement to resolve all outstanding issues in the NDPSC's investigation into the TCJA and a revenue neutral tariff filing submitted by Great Plains. The settlement agreement provides for miscellaneous tariff changes and a reduction in annual revenues of $168,000. On January 9, 2019, the NDPSC issued an order approving the settlement agreement and a refund requirement for the period from January 1, 2018 through the month preceding the effective date of the rate change. On January 23, 2019, the NDPSC approved the compliance rates to be effective February 1, 2019, along with the refund plan that provides for approximately $200,000 in refunds to be credited to customers' bills by April 15, 2019. New rates were implemented on February 1, 2019. The refund is scheduled to be issued to customers on April 12, 2019.

SDPUC

On December 29, 2017, the SDPUC issued an order initiating the investigation into the effects of the TCJA. The order required Montana-Dakota to provide comments by February 1, 2018, regarding the general effects of the TCJA on the cost of service in South Dakota and possible mechanisms for adjusting rates. The order also stated that all rates impacted by the federal income tax shall be adjusted effective January 1, 2018, subject to refund. On May 4, 2018 and June 2, 2018, Montana-Dakota submitted detailed plans to address the TCJA impacts on the natural gas and electric utilities, respectively, to the SDPUC staff. On September 28, 2018, a settlement agreement was submitted to the SDPUC reflecting a proposal to refund approximately $600,000 to electric customers and approximately $1.3 million to natural gas customers. These refunds reflect the impact of the TCJA on 2018. On October 23, 2018, an order was issued by the SDPUC approving the settlement agreement with the refunds being credited to customers' bills beginning on February 15, 2019. On December 3, 2018, Montana-Dakota submitted proposed rate changes to reflect 2018 pro forma results and the TCJA impacts. On December 28, 2018, the SDPUC approved an annual decrease in revenues of approximately $300,000 for the natural gas operations and approximately $100,000 for the electric operations. The decrease in revenues was effective January 1, 2019. The TCJA refund was issued to customers on February 15, 2019.

WYPSC

On December 29, 2017, the WYPSC issued a general order requiring regulatory deferral accounting on the impacts of the TCJA. A technical conference was held on February 6, 2018, to discuss the implications of the TCJA. On March 23, 2018, the WYPSC issued an order requiring all public utilities to submit an initial assessment of the overall effects on the TCJA on their rates by March 30, 2018. On March 30, 2018, Montana-Dakota submitted its initial assessment indicating a rate reduction for its electric rates in the amount of approximately $1.1 million annually or approximately 4.2 percent. Revised electric rates reflecting this reduction were submitted to the WYPSC on June 13, 2018. Montana-Dakota reported its natural gas earnings do not support a decrease in rates and requested the WYPSC allow the impacts of the TCJA be addressed in a natural gas rate case to be submitted by June 1, 2019. On March 19, 2019, the WYPSC ruled to approve Montana-Dakota’s requested decrease in electric rates and required a refund to customers for the period of January 1, 2018, through the date prior to the implementation of rates within 90 days of the effective date of new rates. Compliance electric rates were submitted to the WYPSC on April 4, 2019. Both matters are pending before the WYPSC.

FERC

Montana-Dakota and certain MISO Transmission Owners with projected rates submitted a filing to the FERC on February 1, 2018, requesting the FERC to waive certain provisions of the MISO tariff in order for Montana-Dakota and certain MISO Transmission Owners with projected rates to revise their rates to reflect the reduction in the corporate tax rate. Under the MISO tariff, rates are to be changed only on an annual basis with any changes reflected in subsequent true-ups. On March 15, 2018, the FERC approved the waiver request and new rates reflecting the effects of the TCJA were implemented by MISO on March 1, 2018. MISO also retroactively re-billed the January and February 2018 services to reflect the new rates. On September 4, 2018, Montana-Dakota filed an update to its transmission formula rate under the MISO tariff for the multivalue project for $12.5 million, which is effective January 1, 2019.

Note 17 - Commitments and Contingencies

Claims and Litigation

The Company is party to claims and lawsuits arising out of its business, which may include, but are not limited to, matters involving property damage, personal injury, and environmental, contractual, statutory and regulatory obligations. The Company accrues a liability for those contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, in some circumstances, an estimate of the possible loss. Accruals are based on the best information available, but in certain situations management is unable to estimate an amount or range of a reasonably possible loss including, but not limited to when: (1) the damages are unsubstantiated or indeterminate, (2) the proceedings are in the early stages, (3) numerous parties are involved, or (4) the matter involves novel or unsettled legal theories. The Company accrued liabilities of $190,000 and $283,000 which have not been discounted, for contingencies related to litigation as of December 31, 2018 and 2017, respectively. The Company will continue to monitor each matter and adjust accruals as might be warranted based on new information and further developments. Management believes that the outcomes with respect to probable and reasonably possible losses in excess of the amounts accrued, net of insurance recoveries, while uncertain, either cannot be estimated or will not have a material effect upon the Company’s financial position, results of operations or cash flows. Legal costs are expensed as they are incurred.

Operating leases

The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2018, were:

	2019	2020	2021	2022	2023	Thereafter
				(In thousands)		
Operating leases	$1,802	$1,738	$1,610	$1,386	$1,340	$27,122

Rent expense was $1.9 million and $2.7 million for the years ended December 31, 2018 and 2017, 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 22 years. The commitments under these contracts as of December 31, 2018, were:

	2019	2020	2021	2022	2023	Thereafter
				(In thousands)		
Purchase commitments	$167,413	$89,378	$61,099	$20,883	$18,401	$22,298

These commitments were not reflected in the Company's financial statements. Amounts purchased under various commitments for the years ended December 31, 2018 and 2017, were $292.6 million and $256.7 million, respectively.

Note 18 - Subsequent Event

On February 19, 2019, the Company announced that it intends to retire three aging coal-fired electric generation units within the next three years due to the fact that the plants are no longer expected to be cost competitive. The retirements are expected to be in late 2020 in Sidney, Montana, and in late 2021 in Mandan, North Dakota. A plan is in place to maintain staff until the plant retirements. In addition, the Company announced that it intends to construct a new simple-cycle natural gas combustion turbine peaking unit at the existing plant site in Mandan, North Dakota.

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2018

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Intangible Plant**			
3	301	Organization			
4	302	Franchises & Consents			
5	303	Miscellaneous Intangible Plant	$9,830,158	$9,727,894	-1.04%
6					
7	**Total Intangible Plant**		$9,830,158	$9,727,894	-1.04%
8					
9		**Production Plant**			
10					
11	**Production & Gathering Plant**				
12	325.1	Producing Lands			
13	325.2	Producing Leaseholds			
14	325.3	Gas Rights			
15	325.4	Rights-of-Way			
16	325.5	Other Land & Land Rights			
17	326	Gas Well Structures	NOT	NOT	
18	327	Field Compressor Station Structures	APPLICABLE	APPLICABLE	
19	328	Field Meas. & Reg. Station Structures			
20	329	Other Structures			
21	330	Producing Gas Wells-Well Construction			
22	331	Producing Gas Wells-Well Equipment			
23	332	Field Lines			
24	333	Field Compressor Station Equipment			
25	334	Field Meas. & Reg. Station Equipment			
26	335	Drilling & Cleaning Equipment			
27	336	Purification Equipment			
28	337	Other Equipment			
29	338	Unsuccessful Exploration & Dev. Costs			
30					
31	**Total Production & Gathering Plant**				
32					
33	**Products Extraction Plant**				
34					
35	340	Land & Land Rights			
36	341	Structures & Improvements			
37	342	Extraction & Refining Equipment			
38	343	Pipe Lines	NOT	NOT	
39	344	Extracted Products Storage Equipment	APPLICABLE	APPLICABLE	
40	345	Compressor Equipment			
41	346	Gas Measuring & Regulating Equipment			
42	347	Other Equipment			
43					
44	**Total Products Extraction Plant**				
45					
46	**Total Production Plant**				

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED) Year: 2018

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Natural Gas Storage and Processing Plant**			
3					
4	**Underground Storage Plant**				
5	350.1	Land			
6	350.2	Rights-of-Way			
7	351	Structures & Improvements			
8	352	Wells			
9	352.1	Storage Leaseholds & Rights			
10	352.2	Reservoirs	NOT	NOT	
11	352.3	Non-Recoverable Natural Gas	APPLICABLE	APPLICABLE	
12	353	Lines			
13	354	Compressor Station Equipment			
14	355	Measuring & Regulating Equipment			
15	356	Purification Equipment			
16	357	Other Equipment			
17					
18		**Total Underground Storage Plant**			
19					
20	**Other Storage Plant**				
21	360	Land & Land Rights			
22	361	Structures & Improvements			
23	362	Gas Holders			
24	363	Purification Equipment			
25	363.1	Liquification Equipment	NOT	NOT	
26	363.2	Vaporizing Equipment	APPLICABLE	APPLICABLE	
27	363.3	Compressor Equipment			
28	363.4	Measuring & Regulating Equipment			
29	363.5	Other Equipment			
30					
31		**Total Other Storage Plant**			
32					
33	**Total Natural Gas Storage and Processing Plant**				
34					
35		**Transmission Plant**			
36	365.1	Land & Land Rights			
37	365.2	Rights-of-Way			
38	366	Structures & Improvements			
39	367	Mains	NOT	NOT	
40	368	Compressor Station Equipment	APPLICABLE	APPLICABLE	
41	369	Measuring & Reg. Station Equipment			
42	370	Communication Equipment			
43	371	Other Equipment			
44					
45		**Total Transmission Plant**			

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2018

	Account Number & Title		Last Year	This Year	% Change
1		**Distribution Plant**			
2	374	Land & Land Rights	$38,480	$42,899	11.48%
3	375	Structures & Improvements	243,878	248,297	1.81%
4	376	Mains	39,368,794	43,625,856	10.81%
5	377	Compressor Station Equipment			
6	378	Meas. & Reg. Station Equipment-General	707,671	797,907	12.75%
7	379	Meas. & Reg. Station Equipment-City Gate	125,755	161,108	28.11%
8	380	Services	33,737,648	37,534,211	11.25%
9	381	Meters	22,868,443	23,862,474	4.35%
10	382	Meter Installations			
11	383	House Regulators	3,148,233	3,320,047	5.46%
12	384	House Regulator Installations			
13	385	Industrial Meas. & Reg. Station Equipment	431,100	431,100	0.00%
14	386	Other Prop. on Customers' Premises			0.00%
15	387	Other Equipment	1,962,010	2,220,437	13.17%
16					
17		**Total Distribution Plant**	$102,632,012	$112,244,336	9.37%
18					
19		**General Plant**			
20	389	Land & Land Rights	$852,812	$859,196	0.75%
21	390	Structures & Improvements	4,710,666	4,734,016	0.50%
22	391	Office Furniture & Equipment	240,753	185,730	-22.85%
23	392	Transportation Equipment	3,453,329	3,561,946	3.15%
24	393	Stores Equipment	14,253	14,253	0.00%
25	394	Tools, Shop & Garage Equipment	1,522,693	1,546,866	1.59%
26	395	Laboratory Equipment	27,161	37,448	37.87%
27	396	Power Operated Equipment	2,377,649	2,573,555	8.24%
28	397	Communication Equipment	455,406	540,537	18.69%
29	398	Miscellaneous Equipment	44,004	42,353	-3.75%
30	399	Other Tangible Property			
31					
32		**Total General Plant**	$13,698,726	$14,095,900	2.90%
33					
34		**Common Plant**			
35	389	Land & Land Rights	$157,968	$241,247	52.72%
36	390	Structures & Improvements	3,294,472	3,422,466	3.89%
37	391	Office Furniture & Equipment	442,249	473,090	6.97%
38	392	Transportation Equipment	1,230,296	1,247,809	1.42%
39	393	Stores Equipment	20,755	27,288	31.48%
40	394	Tools, Shop & Garage Equipment	91,184	88,920	-2.48%
41	396	Power Operated Equipment			
42	397	Communication Equipment	405,582	376,721	-7.12%
43	398	Miscellaneous Equipment	104,802	106,824	1.93%
44					
45		**Total Common Plant**	$5,747,308	$5,984,365	4.12%
46		**Total Gas Plant in Service**	$131,908,204	$142,052,495	7.69%

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 20**

MONTANA DEPRECIATION SUMMARY Year: 2018

	Functional Plant Classification	Plant Cost	Accumulated Depreciation Last Year Bal.	Accumulated Depreciation This Year Bal.	Current Avg. Rate
1	Production & Gathering				
2	Products Extraction				
3	Underground Storage				
4	Other Storage				
5	Transmission				
6	Distribution	112,244,336	58,375,473	61,674,987	3.68%
7	General	14,708,358	3,524,964	3,694,689	2.18%
8	Common	15,099,801	5,988,258	6,601,807	5.01%
9	**Total**	$142,052,495	$67,888,695	$71,971,483	3.66%

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED) **SCHEDULE 21**

	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock			
3	152 Fuel Stock Expenses - Undistributed			
4	153 Residuals & Extracted Products			
5	154 Plant Materials & Operating Supplies:			
6	Assigned to Construction (Estimated)			
7	Assigned to Operations & Maintenance			
8	Production Plant (Estimated)			
9	Transmission Plant (Estimated)			
10	Distribution Plant (Estimated)	$1,055,933	$943,252	-10.67%
11	Assigned to Other			
12	155 Merchandise			
13	156 Other Materials & Supplies			
14	163 Stores Expense Undistributed			
15	**Total Materials & Supplies**	$1,055,933	$943,252	-10.67%

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS **SCHEDULE 22**

	Commission Accepted - Most Recent 1/		% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number	D2017.9.79			
2	Order Number	7573f			
3					
4	Common Equity			9.400%	
5	Preferred Stock				
6	Long Term Debt				
7					
8	**Total**				
9					
10	Actual at Year End				
11					
12	Common Equity		49.258%	9.400%	4.630%
13	Long Term Debt		46.371%	4.921%	2.282%
14	Short Term Debt		4.371%	2.906%	0.127%
15	**Total**		100.000%		7.039%

1/ Order No. 7573f only addressed return on equity. Cost of capital, capital structure, and cost of service items were not individually identified.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 23**

STATEMENT OF CASH FLOWS Year: 2018

	Description	Last Year	This Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2				
3	**Cash Flows from Operating Activities:**			
4	Net Income	$281,202,988	$272,318,357	-3.16%
5	Depreciation	67,700,375	72,312,708	6.81%
6	Amortization	495,300	343,465	-30.66%
7	Deferred Income Taxes - Net	34,925,280	9,711,851	-72.19%
8	Investment Tax Credit Adjustments - Net	190,592	1,546,913	711.64%
9	Change in Operating Receivables - Net	(426,114)	(14,436,634)	-3287.97%
10	Change in Materials, Supplies & Inventories - Net	4,163,158	(2,820,729)	-167.75%
11	Change in Operating Payables & Accrued Liabilities - Net	2,207,920	23,281,803	954.47%
12	Change in Other Regulatory Assets	5,923,937	8,688,521	46.67%
13	Change in Other Regulatory Liabilities	(1,212,357)	563	100.05%
14	Allowance for Other Funds Used During Construction (AFUDC)	(400,908)	(1,026,572)	-156.06%
15	Change in Other Assets & Liabilities - Net	(15,841,825)	22,778,222	243.79%
16	Less Undistributed Earnings from Subsidiary Companies	(102,928,921)	(95,210,157)	7.50%
17	Other Operating Activities (explained on attached page)			
18	**Net Cash Provided by/(Used in) Operating Activities**	$275,999,425	$297,488,311	7.79%
19				
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment			
22	(net of AFUDC & Capital Lease Related Acquisitions)	($145,516,664)	($243,141,453)	-67.09%
23	Acquisition of Other Noncurrent Assets	(468,090)	(527,466)	-12.68%
24	Proceeds from Disposal of Noncurrent Assets			
25	Investments In and Advances to Affiliates	(40,000,000)	30,000,000	175.00%
26	Contributions and Advances from Affiliates	40,000,000	0	-100.00%
27	Disposition of Investments in and Advances to Affiliates			
28	Other Investing Activities: Depreciation & RWIP on Nonutility Plant	1,064,862	811,995	-23.75%
29	**Net Cash Provided by/(Used in) Investing Activities**	($144,919,892)	($212,856,924)	-46.88%
30				
31	**Cash Flows from Financing Activities:**			
32	Proceeds from Issuance of:			
33	Long-Term Debt	$70,500,000	$200,000,000	183.69%
34	Preferred Stock			
35	Common Stock	0	(10,000)	100.00%
36	Other:			
37	Net Increase in Short-Term Debt			
38	Other: Repurchase of Common Stock	(564,642)	(1,920,095)	-240.06%
39	Other: Tax Withholding on Stock-Based Compensation	(508,519)	(1,720,999)	-238.43%
40	Payment for Retirement of:			
41	Long-Term Debt	(37,568,736)	(125,960,755)	-235.28%
42	Preferred Stock	(15,600,000)	0	100.00%
43	Common Stock			
44	Other: Adjustment to Retained Earnings			
45	Net Decrease in Short-Term Debt			
46	Dividends on Preferred Stock	(342,501)	0	100.00%
47	Dividends on Common Stock	(150,384,383)	(154,572,486)	-2.78%
48	Other Financing Activities (related to IGC acquisition)			
49	**Net Cash Provided by (Used in) Financing Activities**	($134,468,781)	($84,184,335)	37.39%
50				
51	**Net Increase/(Decrease) in Cash and Cash Equivalents**	($3,389,248)	$447,052	113.19%
52	**Cash and Cash Equivalents at Beginning of Year**	$4,159,083	$769,835	-81.49%
53	**Cash and Cash Equivalents at End of Year**	$769,835	$1,216,887	58.07%

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 24**

LONG TERM DEBT Year: 2018

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost % 1/
1	5.98% Senior Notes	12/03	12/33	$30,000,000	$29,375,535	$30,000,000	5.98%	$1,863,000	6.21%
2	6.33% Senior Notes	08/06	08/26	100,000,000	89,123,930	100,000,000	6.33%	7,514,000	7.51%
3	5.18% Senior Notes	04/14	04/44	50,000,000	49,760,822	50,000,000	5.18%	2,640,000	5.28%
4	4.24% Senior Notes	07/14	07/24	60,000,000	59,708,737	60,000,000	4.24%	2,607,600	4.35%
5	4.34% Senior Notes	07/14	07/26	40,000,000	39,802,958	40,000,000	4.34%	1,776,800	4.44%
6	3.78% Senior Notes	10/15	10/25	87,000,000	86,528,003	87,000,000	3.78%	3,378,210	3.88%
7	4.03% Senior Notes	12/15	12/30	52,000,000	51,713,645	52,000,000	4.03%	2,143,440	4.12%
8	4.87% Senior Notes	10/15	10/45	11,000,000	10,940,539	11,000,000	4.87%	546,040	4.96%
9	4.15% Senior Notes	11/16	11/46	40,000,000	39,773,916	40,000,000	4.15%	1,691,200	4.23%
10	3.73% Senior Notes	03/17	03/37	40,000,000	39,826,363	40,000,000	3.73%	1,518,800	3.80%
11	3.36% Senior Notes	03/17	03/32	20,000,000	19,913,929	20,000,000	3.36%	685,000	3.43%
12	2.00% Senior Notes	09/17	09/32	10,500,000	10,500,000	9,800,000	2.00%	196,000	2.00%
13	Minot Air Force Base Payable	09/08	11/38	509,197		425,495	6.00%	25,530	6.00%
14	LIBOR Floating Rate Note	09/18	10/19	100,000,000	99,600,000	100,000,000	Variable	4,755,000	4.76%
15	LIBOR Floating Rate Note	10/18	11/19	100,000,000	99,600,000	100,000,000	Variable	4,755,000	4.76%
16	Revolving Credit Facility	06/18	06/23			48,500,000	Variable		
17	Amortization of Loss on Reacquired Debt							43,469	
18									
19									
20									
21									
22									
23									
24									
25									
26	**TOTAL**			$741,009,197	$726,168,377	$788,725,495		$36,139,089	4.58%

1/ Yield to maturity based upon the life, net proceeds and semiannual compounding of stated interest rate.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 25**

PREFERRED STOCK

Year: 2018

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1										
2	Not applicable									
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
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21										
22										
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25										
26										
27										
28										
29										
30										
31										
32	**TOTAL**					$0		$0	$0	0.00%

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 26**

COMMON STOCK

Year: 2018

		Avg. Number of Shares Outstanding 1/	Book Value Per Share	Earnings Per Share 2/	Dividends Per Share	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio 3/
1	January								
2									
3	February								
4									
5	March	195,304,376	$12.42	$0.22	$0.1975	10.23%	$28.23	$24.29	18.9
6									
7	April								
8									
9	May								
10									
11	June	195,524,052	12.50	0.22	0.1975	10.23%	29.28	27.05	19.2
12									
13	July								
14									
15	August								
16									
17	September	196,018,324	12.86	0.55	0.1975	64.09%	29.62	25.33	16.3
18									
19	October								
20									
21	November								
22									
23	December	196,022,905	13.09	0.40	0.2025	49.38%	26.96	22.73	17.3
24									
25	TOTAL Year End	196,022,905	$13.09	$1.39	$0.7950	42.81%			

1/ Basic shares
2/ Basic earnings per share.
3/ Calculated on 12 months ended using closing stock price.

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 27**

MONTANA EARNED RATE OF RETURN Year: 2018

		Description	Last Year	This Year	% Change
		Rate Base			
1					
2	101	Plant in Service	$131,908,204	$142,052,495	7.69%
3	108	(Less) Accumulated Depreciation	67,888,695	71,971,483	6.01%
4					
5		**Net Plant in Service**	$64,019,509	$70,081,012	9.47%
6					
7		Additions			
8	154, 156	Materials & Supplies	$1,055,933	$943,252	-10.67%
9	165	Prepayments	31,304	24,264	-22.49%
10		Prepaid Demand/Commodity Charges	1,132,504	1,144,393	1.05%
11		Gas in Underground Storage	3,147,873	3,086,252	-1.96%
12	189	Unamortized Loss on Debt	179,538	163,574	-8.89%
13	182	Other Regulatory Assets	0	19,296	0.00%
14		Provision for Pension & Benefits	6,638,051	7,690,465	15.85%
15		Provision for Injuries & Damages	(13,675)	(10,279)	24.83%
16					
17		**Total Additions**	$12,171,528	$13,061,217	7.31%
18		Deductions			
19	282	Accumulated Deferred Income Taxes	$13,863,503	$14,572,090	5.11%
20		DIT Related to Pension & Benefits	2,560,366	1,900,537	-25.77%
21		DIT Related to Injuries & Damages	(5,182)	(2,507)	51.62%
22	252	Customer Advances for Construction	2,121,992	2,384,217	12.36%
23					
24		**Total Deductions**	$18,540,679	$18,854,337	1.69%
25		**Total Rate Base**	$57,650,358	$64,287,892	11.51%
26					
27		**Net Earnings**	$2,896,175	$3,305,503	14.13%
28					
29		**Rate of Return on Average Rate Base**	5.17%	5.42%	4.84%
30					
31		**Rate of Return on Average Equity**	5.34%	6.00%	12.36%
32		Major Normalizing Adjustments & Commission			
33		Ratemaking Adjustments to Utility Operations			
34		Adjustments to Operating Revenues 1/			
35		Weather Normalization	($312,284)	($1,378,513)	-341.43%
36		Gain (Loss) from Disposition of Utility Plant 2/	(7,227)	(8,264)	-14.35%
37		Penalty Revenue 3/	(9,651)	3,388	135.11%
38					
39		Adjustments to Operating Expenses 1/			
40		Elimination of Promotional & Institutional Advertising	(31,558)	(36,848)	-16.76%
41					
42		Other Adjustments to Federal & State Income Taxes			
43		Federal & State Out of Period & Closing/Filing	202,590	(221,973)	-209.57%
44		Deferred Federal & State Out of Period & Closing/Filing	(186,107)	215,621	215.86%
45					
46		Total Adjustments to Operating Income	($314,087)	($1,340,189)	-326.69%
47					
48		**Adjusted Rate of Return on Average Rate Base**	4.61%	3.22%	-30.15%
49					
50		**Adjusted Rate of Return on Average Equity**	4.26%	1.60%	-62.44%

1/ Updated amounts, net of taxes.
2/ Amortized over five years.
3/ Adjusted to reflect a three year average.

MONTANA COMPOSITE STATISTICS

Year: 2018

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	$135,400
5	107	Construction Work in Progress	487
6	114	Plant Acquisition Adjustments	
7	104	Plant Leased to Others	
8	105	Plant Held for Future Use	
9	154, 156	Materials & Supplies	943
10		(Less):	
11	108, 111	Depreciation & Amortization Reserves	71,971
12	252	Contributions in Aid of Construction	2,384
13			
14		**NET BOOK COSTS**	$62,475
15			
16		Revenues & Expenses (000 Omitted)	
17			
18	400	Operating Revenues	$72,073
19			
20	403 - 407	Depreciation & Amortization Expenses	$5,206
21		Federal & State Income Taxes	376
22		Other Taxes	5,904
23		Other Operating Expenses	57,282
24		Total Operating Expenses	$68,768
25			
26		Net Operating Income	$3,305
27			
28		Other Income	551
29		Other Deductions	1,306
30			
31		**NET INCOME**	$2,550
32			
33		Customers (Intrastate Only)	
34			
35		Year End Average:	
36		Residential	74,919
37		Firm General	9,628
38		Small Interruptible	44
39		Large Interruptible	5
40			
41		**TOTAL NUMBER OF CUSTOMERS**	84,596
42			
43		Other Statistics (Intrastate Only)	
44			
45		Average Annual Residential Use (Dkt)	89
46		Average Annual Residential Cost per (Dkt) ($) *	$6.62
		* Avg annual cost = [(cost per Dkt x annual use) +	
47		(monthly service charge x 12)]/annual use	
48		Average Residential Monthly Bill	$49.10
49		Gross Plant per Customer	$1,601

MONTANA CUSTOMER INFORMATION Year: 2018

	City/Town	Population (Includes Rural) 1/	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Belfry	218	129	17		146
2	Billings	104,170	49,508	5,267	9	54,784
3	Bridger	708	423	63		486
4	Crow Agency	1,616	272	72		344
5	Edgar	114	106	12		118
6	Fromberg	438	284	20		304
7	Hardin	3,505	1,226	210	1	1,437
8	Joliet	595	377	49		426
9	Laurel	6,718	4,161	344		4,505
10	Park City	983	725	27		752
11	Pryor	618	78	13		91
12	Rockvale	Not Available	69	4		73
13	Silesia	96	34	1		35
14	Warren	Not Available		2		2
15	Alzada	29	10	10	1	21
16	Baker	1,741	804	201	2	1,007
17	Carlyle	Not Available	8	1		9
18	Fort Peck	233	142	13		155
19	Fairview	840	400	64	1	465
20	Forsyth	1,777	849	151	1	1,001
21	Frazer	362	94	14		108
22	Glasgow	3,250	1,616	358	3	1,977
23	Glendive	4,935	3,144	467	7	3,618
24	Hinsdale	217	114	22		136
25	Ismay	19	11	4		15
26	Malta	1,997	986	211	2	1,199
27	Miles City	8,410	3,961	634	6	4,601
28	Nashua	290	175	20		195
29	Poplar	810	840	122	6	968
30	Richey	177	132	27		159
31	Rosebud	111	42	7		49
32	Saco	197	36	4		40
33	Savage	Not Available	158	25		183
34	Sidney	5,191	2,671	499	4	3,174
35	Terry	605	320	67		387
36	St. Marie	264	254	12		266
37	Wibaux	589	215	57		272
38	Whitewater	64	28	10		38
39	Wolf Point	2,621	1,348	215	2	1,565
40	MT Oil Fields	Not Available	1	3		4
41	**TOTAL Montana Customers**	154,508	75,751	9,319	45	85,115

1/ 2010 Census

MONTANA EMPLOYEE COUNTS Year: 2018

	Department	Year Beginning	Year End	Average
1	Electric	26	24	25
2	Gas	38	36	37
3	Accounting	4	4	4
4	Management	4	6	5
5	Service	36	39	38
6	Training	0	0	0
7	Power Production	38	38	38
8				
9				
10				
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31				
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34				
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36				
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38				
39				
40				
41				
42				
43				
44	**TOTAL Montana Employees**	146	147	147

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 31**

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) **Year: 2018**

	Project Description	Total Company	Total Montana	
1	**Projects>$1,000,000**			
2				
3	**Common-General**			
4	Renovate purchased Substation and Communications building in Bismarck	$4,031,935	$884,357	1/
5				
6	**Common-Intangible**			
7	Purchase Workforce Asset Management software for the Company	2,841,596	623,270	1/
8				
9	**Total Common**	$6,873,531	$1,507,627	
10				
11	**Electric-Distribution**			
12	Construct 115/6.9kV substation for Keystone Pipeline	$2,852,640	$2,852,640	2/
13	Replace street lighting with LED lighting in ND	2,497,695	0	
14				
15	**Electric-Steam Production**			
16	Install bank erosion improvements at Lewis & Clark Station	3,792,881	901,129	1/
17	Construct ash disposal cells at Heskett Station	1,705,513	405,203	1/
18	Install slag pond liner for Coal Combustion Residuals Compliance at Coyote	1,286,420	305,633	1/
19				
20	**Electric-Other Production**			
21	Replace gearboxes at Diamond Willow wind farm	1,288,213	337,391	1/
22				
23	**Electric-Transmission**			
24	Install 115kV breakers in N junction substation in Dickinson, ND	3,587,124	0	
25	Construct 115kV line from Ellendale, ND to Leola, SD (ND portion)	3,429,178	814,719	1/
26	Construct 115kV line from Ellendale, ND to Leola, SD (SD portion)	3,113,764	739,782	1/
27	Construct 345kV line-Big Stone to Ellendale, ND	2,458,796	0	
28	Construct 115kV loop line in Dickinson, ND	2,381,173	0	
29	Construct 34.5KV line from WAPA sub to NW Watford City, ND	2,305,965	0	
30	Install 115kV oilfield line tap from Glendive to Baker, MT	2,157,920	2,157,920	2/
31	Rebuild 60kV line from Glendive to Baker, MT	2,099,156	2,099,156	2/
32	Install 60kV loop line from Rosebud to Forsyth, MT	1,907,446	1,907,446	2/
33	Reconductor 115kV double circuit from Lewis & Clark to Richland substations	1,370,723	325,662	1/
34	Add 115kV bay for junction substation in Ellendale, ND	1,058,924	225,614	1/
35				
36	**Total Electric**	$39,293,531	$13,072,295	
37				
38	**Gas-Distribution**			
39	Construct main to serve new facilities in Menoken, ND	$1,002,668	0	
40				
41	**Gas-General**			
42	Construct office/shop in Glasgow, MT	1,013,953	$1,013,953	2/
43				
44	**Total Gas**	$2,016,621	$1,013,953	
45	**Total Projects >$1,000,000**	$48,183,683	$15,593,875	

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 31**

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) **Year: 2018**

	Project Description	Total Company	Total Montana	
1	**Other Projects<$1,000,000**			
2				
3	**Electric**			
4	Production	$13,003,490	$2,554,243	1/
5	Integrated Transmission	2,507,053	449,508	1/
6	Direct Transmission	4,873,996	686,712	2/
7	Distribution	27,678,021	5,684,346	3/
8	General	6,222,682	1,200,805	3/
9	Intangible	2,021,622	451,707	1/
10	Common:			
11	General Office	4,475,932	923,828	1/
12	Other Direct	744,460	180,491	3/
13				
14	**Total Other Electric**	$61,527,256	$12,131,640	
15				
16	**Gas**			
17	Distribution	$35,428,428	$10,984,748	3/
18	General	4,787,178	1,199,735	3/
19	Intangible	439,718	82,752	1/
20	Common:			
21	General Office	2,730,019	657,494	1/
22	Other Direct	391,711	133,545	3/
23				
24	**Total Other Gas**	$43,777,054	$13,058,274	
25	**Total Other Projects <$1,000,000**	$105,304,310	$25,189,914	
26				
27	**Total Projects**	$153,487,993	$40,783,789	

1/ Allocated to Montana.
2/ Directly assigned to Montana.
3/ Combination of allocated and directly assigned to Montana.

TRANSMISSION SYSTEM - TOTAL COMPANY & MONTANA

Year: 2018

	Total Company			
		Peak Day of Month	Peak Day Volumes Mcf or Dkt	Total Monthly Volumes Mcf or Dkt
1	January			
2	February			
3	March			
4	April			
5	May			
6	June	**NOT APPLICABLE**		
7	July			
8	August			
9	September			
10	October			
11	November			
12	December			
13	**TOTAL**			

	Montana			
		Peak Day of Month	Peak Day Volumes Mcf or Dkt	Total Monthly Volumes Mcf or Dkt
14	January			
15	February			
16	March			
17	April			
18	May			
19	June	**NOT APPLICABLE**		
20	July			
21	August			
22	September			
23	October			
24	November			
25	December			
26	**TOTAL**			

DISTRIBUTION SYSTEM - TOTAL COMPANY & MONTANA Year: 2018

	Total Company			
		Peak Day of Month	Peak Day Volumes Dkt	Total Monthly Volumes Dkt
1	January	15	367,413	8,153,169
2	February	9	346,447	8,062,740
3	March	31	254,571	6,050,121
4	April	6	246,020	4,460,800
5	May	11	103,264	2,128,437
6	June	11	67,323	1,794,621
7	July	16	60,706	1,613,648
8	August	27	64,172	1,660,194
9	September	30	142,115	2,376,666
10	October	14	201,399	4,327,730
11	November	8	264,586	6,244,714
12	December	31	326,234	7,025,166
13	**TOTAL**			53,898,006

	Montana			
		Peak Day of Month	Peak Day Volumes Dkt	Total Monthly Volumes Dkt
1	January	1	105,075	2,300,691
2	February	9	98,034	2,282,366
3	March	31	70,325	1,646,348
4	April	2	66,113	1,118,941
5	May	19	27,906	591,258
6	June	11	22,493	577,428
7	July	2	18,725	429,397
8	August	27	19,333	452,193
9	September	30	43,377	698,702
10	October	13	52,420	1,077,538
11	November	8	67,816	1,558,488
12	December	31	84,352	1,844,869
13	**TOTAL**			14,578,219

Company Name: Montana-Dakota Utilities Co.

STORAGE SYSTEM - TOTAL COMPANY & MONTANA

Year: 2018

		Total Company						
		Peak Day of Month		Peak Day Volumes (Dkt)		Total Monthly Volumes (Dkt)		
		Injection	Withdrawal	Injection	Withdrawal	Injection	Withdrawal	Losses
1	January	19	1	13,273	220,549	97,418	3,593,709	
2	February	28	9	37,230	178,444	144,403	3,214,682	
3	March	8	31	47,878	113,106	387,936	1,654,831	
4	April	28	2	65,781	136,048	1,278,669	1,324,047	
5	May	25	11	74,441	34,604	2,078,893	235,523	
6	June	9	15	84,479	7,248	2,299,629	101,643	
7	July	6	27	90,472	5,734	2,683,389	55,904	
8	August	11	21	91,472	7,535	2,660,424	75,231	
9	September	7	27	72,975	26,419	1,797,453	193,741	
10	October	18	14	46,630	54,111	914,903	592,120	
11	November	15	17	6,597	105,572	66,128	1,670,432	
12	December	2	31	6,625	169,676	27,894	2,158,984	
13	**TOTAL**					14,437,139	14,870,847	

		Montana						
		Peak Day of Month		Peak Day Volumes (Dkt)		Total Monthly Volumes (Dkt)		
		Injection	Withdrawal	Injection	Withdrawal	Injection	Withdrawal	Losses
14	January							
15	February							
16	March							
17	April							
18	May							
19	June	NOT AVAILABLE						
20	July							
21	August							
22	September							
23	October							
24	November							
25	December							
26	**TOTAL**							

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 33**

SOURCES OF GAS SUPPLY

Year: 2018

	Name of Supplier 1/	Last Year Volumes Dkt	This Year Volumes Dkt	Last Year Avg. Commodity Cost	This Year Avg. Commodity Cost
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
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24					
25					
26					
27					
28					
29					
30					
31	1/ Supplier information is proprietary and confidential.				
32					
33	**Total Gas Supply Volumes**	35,317,621	40,679,444	$2.530	$2.304

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 34**

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2018

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings **(Mcf or Dkt)**	Achieved Savings **(Mcf or Dkt)**	Difference
1							
2	MT Conservation & DSM Program	$134,402	$139,153	-3.41%	7,727	8,170	443
3	(As Detailed on Schedule 36B)						
4							
5							
6							
7							
8							
9							
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26							
27							
28							
29							
30							
31							
32	**TOTAL**	$134,402	$139,153	-3.41%	7,727	8,170	443

MONTANA CONSUMPTION AND REVENUES Year: 2018

	Sales of Gas	Operating Revenues Current Year	Operating Revenues Previous Year	DK Sold Current Year	DK Sold Previous Year	Avg. No. of Customers Current Year	Avg. No. of Customers Previous Year
1	Residential	$43,025,501	$41,001,283	6,634,584	6,038,139	74,919	74,363
2	Firm General	26,877,601	25,259,797	4,367,144	3,928,571	9,628	9,512
3	Small Interruptible	528,490	633,975	130,754	155,466	17	14
4	Large Interruptible	238,762	223,082	68,905	59,547	1	1
5							
6							
7							
8							
9							
10							
11	**TOTAL**	$70,670,354	$67,118,137	11,201,387	10,181,723	84,565	83,890
12							
13							
14		**Operating Revenues**		**BCF Transported**		**Avg. No. of Customers**	
15							
16		Current	Previous	Current	Previous	Current	Previous
17	**Transportation of Gas**	Year	Year	Year	Year	Year	Year
18							
19	Small Interruptible	$578,572	$559,706	0.7	0.6	27	30
20	Large Interruptible	665,376	632,600	3.2	3.0	4	4
21							
22							
23							
24	**TOTAL**	$1,243,948	$1,192,306	3.9	3.6	31	34

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 36A**

NATURAL GAS UNIVERSAL SYSTEM BENEFITS PROGRAMS

Year: 2018

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (Mcf or Dkt)	Most recent program evaluation
1	Local Conservation					
2						
3						
4						
5						
6						
7						
8	Market Transformation					
9						
10						
11						
12						
13						
14						
15	Research & Development					
16						
17						
18						
19						
20						
21						
22	Low Income					
23	Discounts	$414,550	$0	$414,550		2018
24	Furnace Safety/Repair	0	50,000	50,000		2018
25	Bill Assistance	0	65,000	65,000		2018
26	Weatherization	0	107,000	107,000		2018
27						
28						
29	Other					
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42	Total	$414,550	$222,000	$636,550		2018
43	Number of customers that received low income rate discounts			(Average)	3,062	
44	Average monthly bill discount amount ($/mo)				$11.28	
45	Average LIEAP-eligible household income				N/A	
46	Number of customers that received weatherization assistance				N/A	
47	Expected average annual bill savings from weatherization				N/A	
48	Number of residential audits performed				N/A	

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 36B**

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2018

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (Mcf or Dkt)	Most recent program evaluation
1	Local Conservation					
2	High Efficiency Furnace	$113,313	$0	$113,313	6,143	2017
3	Programmable Thermostat	13,800	0	13,800	690	2017
4	High Efficiency Boiler	0	0	0	394	2017
5	Custom Efficiency	0	0	0	500	2017
6	Residential Energy Assessment	7,289	0	7,289	N/A	2017
7						
8						
9	Demand Response					
10						
11						
12						
13						
14						
15						
16	Market Transformation					
17						
18						
19						
20						
21						
22						
23	Research & Development					
24						
25						
26						
27						
28						
29						
30	Low Income					
31						
32						
33						
34						
35						
36	Other					
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Total	$134,402	$0	$134,402	7,727	2017