GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
DOCKET NO. G004/GR-19-511
INDEX OF STATEMENTS

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
CALCULATION OF REVENUE DEFICIENCY
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

		Projected		
	Per Books	2019	2020	Reference
Rate Base	$25,477,480	$29,263,477	$31,686,174	Statement B, page 1
Required Rate of Return	7.522%	7.383%	7.460%	Statement D, page 1
Required Income	$1,916,416	$2,160,523	$2,363,789	
Operating Income	604,015	530,441	(229,888)	Statement C, page 1
Income Deficiency	$1,312,401	$1,630,082	$2,593,677	
Gross Revenue Conversion Factor	1.403351	1.403351	1.403351	Schedule F-2, page 1
Total Revenue Deficiency	$1,841,759	$2,287,577	$3,639,839	
GUIC in current rates, excluding out-of-period true up			$790,153	
Net increase in required recovery			$2,849,686	

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
AVERAGE RATE BASE
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

		Projected		
	2018	2019	2020	Reference
Gas Plant in Service	$55,571,667	$60,892,941	$64,948,541	Schedule B-1, page 1
Accumulated Reserve for Depreciation	27,768,448	29,325,511	31,052,110	Schedule B-2, page 1
Net Gas Plant in Service	$27,803,219	$31,567,430	$33,896,431	
Additions				
Materials and Supplies	$423,681	$486,504	$486,504	Schedule B-3, page 1
Gas in Underground Storage	504,327	306,530	306,530	Schedule B-3, page 1
Prepayments	94,018	127,086	141,544	Schedule B-3, page 1
Unamortized Loss on Debt	64,857	62,664	56,258	Schedule B-3, page 1
Unamort. Redemption Cost-Pref. Stk.	5,600	10,811	10,034	Schedule B-3, page 1
Total Additions	$1,092,483	$993,595	$1,000,870	
Total Before Deductions	$28,895,702	$32,561,025	$34,897,301	
Deductions				
Accumulated Deferred Income Taxes	$2,643,559	$2,534,787	$2,448,366	Schedule B-4, page 1
Customer Advances	774,663	762,761	762,761	Schedule B-3, page 1
Total Deductions	$3,418,222	$3,297,548	$3,211,127	
Total Rate Base	$25,477,480	$29,263,477	$31,686,174	

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
AVERAGE RATE BASE
TWELVE MONTHS ENDING DECEMBER 31, 2018

	Total Company	Minnesota	Other	Reference
Gas Plant in Service	$62,356,043	$55,571,667	$6,784,376	Schedule B-1, page 3
Accumulated Reserve for Depreciation	31,119,478	27,768,448	3,351,030	Schedule B-2, page 2
Net Gas Plant in Service	$31,236,565	$27,803,219	$3,433,346	
Additions				
Materials and Supplies	$488,613	$423,681	$64,932	Schedule B-3, page 1
Gas in Underground Storage	528,844	504,327	24,517	Schedule B-3, page 1
Prepayments	98,735	94,018	4,717	Schedule B-3, page 1
Unamortized Loss on Debt	72,798	64,857	7,941	Schedule B-3, page 1
Unamort. Redemption Cost-Pref. Stk.	6,078	5,600	478	Schedule B-3, page 1
Total Additions	$1,195,068	$1,092,483	$102,585	
Total Before Deductions	$32,431,633	$28,895,702	$3,535,931	
Deductions				
Accumulated Deferred Income Taxes	$3,079,338	$2,643,559	$435,779	Schedule B-4, page 2
Customer Advances	1,047,704	774,663	273,041	Schedule B-3, page 1
Total Deductions	$4,127,042	$3,418,222	$708,820	
Total Rate Base	$28,304,591	$25,477,480	$2,827,111	

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SCHEUDLE OF RATE BASE ADJUSTMENTS
PROJECTED 2019

	Average Per Books 2018	Plant 1/ Additions	Materials & Supplies 2/	Gas in Storage 3/	Prepayments 4/	Unamort. 5/ Loss on Debt	Unamort. 6/ Redemption Cost Pref. Stk.	Customer Advances 7/	Subtotal	Projected 2019
Gas Plant in Service	$55,571,667	$5,321,274							$5,321,274	$60,892,941
Accumulated Reserve for Depreciation	27,768,448	1,557,063							1,557,063	29,325,511
Net Gas Plant in Service	$27,803,219	$3,764,211	$0	$0	$0	$0	$0	$0	$3,764,211	$31,567,430
Additions										
Materials and Supplies	$423,681		$62,823						$62,823	$486,504
Gas in Underground Storage	504,327			($197,797)					(197,797)	306,530
Prepayments	94,018				$33,068				33,068	127,086
Unamortized Loss on Debt	64,857					($2,193)			(2,193)	62,664
Unamort. Redemption Cost-Pref. Stk.	5,600						$5,211		5,211	10,811
Total Additions	$1,092,483	$0	$62,823	($197,797)	$33,068	($2,193)	$5,211	$0	($98,888)	$993,595
Total Before Deductions	$28,895,702	$3,764,211	$62,823	($197,797)	$33,068	($2,193)	$5,211	$0	$3,665,323	$32,561,025
Deductions										
Accumulated Deferred Income Taxes	$2,643,559	($111,927) 8/				($496)		$3,651	($108,772)	$2,534,787
Customer Advances	774,663							(11,902)	(11,902)	762,761
Total Deductions	$3,418,222	($111,927)	$0	$0	$0	($496)	$0	($8,251)	($120,674)	$3,297,548
Total Rate Base	$25,477,480	$3,876,138	$62,823	($197,797)	$33,068	($1,697)	$5,211	$8,251	$3,785,997	$29,263,477

1/ Schedule B-1, page 6.
2/ Schedule B-3, page 2.
3/ Schedule B-3, page 3.
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5/ Schedule B-3, page 6.
6/ Schedule B-3, page 7.
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8/ Schedule B-4, page 1-2.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SCHEUDLE OF RATE BASE ADJUSTMENTS
PROJECTED 2020

	Projected 2019	Plant 1/ Additions	Materials & Supplies 2/	Gas in Storage 3/	Prepayments 4/	Unamort. 5/ Loss on Debt	Unamort. 6/ Redemption Cost Pref. Stk.	Customer Advances 7/	Subtotal	Projected 2020
Gas Plant in Service	$60,892,941	$4,055,600							$4,055,600	$64,948,541
Accumulated Reserve for Depreciation	29,325,511	1,726,599							1,726,599	31,052,110
Net Gas Plant in Service	$31,567,430	$2,329,001	$0	$0	$0	$0	$0	$0	$2,329,001	$33,896,431
Additions										
Materials and Supplies	$486,504		$0						$0	$486,504
Gas in Underground Storage	306,530			$0					0	306,530
Prepayments	127,086				$14,458				14,458	141,544
Unamortized Loss on Debt	62,664					($6,406)			(6,406)	56,258
Unamort. Redemption Cost-Pref. Stk.	10,811						($777)		(777)	10,034
Total Additions	$993,595	$0	$0	$0	$14,458	($6,406)	($777)	$0	$7,275	$1,000,870
Total Before Deductions	$32,561,025	$2,329,001	$0	$0	$14,458	($6,406)	($777)	$0	$2,336,276	$34,897,301
Deductions 3/										
Accumulated Deferred Income Taxes	$2,534,787	($84,762) 8/				($1,429)		($230)	($86,421)	$2,448,366
Customer Advances	762,761							0	0	762,761
Total Deductions	$3,297,548	($84,762)	$0	$0	$0	($1,429)	$0	($230)	($86,421)	$3,211,127
Total Rate Base	$29,263,477	$2,413,763	$0	$0	$14,458	($4,977)	($777)	$230	$2,422,697	$31,686,174

1/ Schedule B-1, page 6.
2/ Schedule B-3, page 2.
3/ Schedule B-3, page 3.
4/ Schedule B-3, page 4-5.
5/ Schedule B-3, page 6.
6/ Schedule B-3, page 7.
7/ Schedule B-3, page 8.
8/ Schedule B-4, page 1.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
AVERAGE RATE BASE
TWELVE MONTHS ENDING DECEMBER 31, 2018

	Total Company			Minnesota		
	2017	2018	Average	2017	2018	Average
Gas Plant in Service	$58,057,519	$66,654,567	$62,356,043	$51,983,102	$59,160,231	$55,571,667
Accumulated Reserve for Depreciation	30,252,327	31,986,628	31,119,478	27,013,971	28,522,925	27,768,448
Net Gas Plant in Service	$27,805,192	$34,667,939	$31,236,565	$24,969,131	$30,637,306	$27,803,219
Additions						
Materials and Supplies	$465,768	$511,457	$488,613	$403,593	$443,769	$423,681
Gas in Underground Storage	534,090	523,598	528,844	534,090	474,564	504,327
Prepayments	92,488	104,981	98,735	90,713	97,321	94,018
Unamortized Loss on Debt	74,135	71,460	72,798	65,521	64,193	64,857
Unamort. Redemption Cost-Pref. Stk.	0	12,156	6,078	0	11,199	5,600
Total Additions	$1,166,481	$1,223,652	$1,195,068	$1,093,917	$1,091,046	$1,092,483
Total Before Deductions	$28,971,673	$35,891,591	$32,431,633	$26,063,048	$31,728,352	$28,895,702
Deductions						
Accumulated Deferred Income Taxes	$3,131,832	$3,026,844	$3,079,338	$2,701,365	$2,585,753	$2,643,559
Customer Advances	1,119,951	975,457	1,047,704	788,170	761,156	774,663
Total Deductions	$4,251,783	$4,002,301	$4,127,042	$3,489,535	$3,346,909	$3,418,222
Total Rate Base	$24,719,890	$31,889,290	$28,304,591	$22,573,513	$28,381,443	$25,477,480

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY
AVERAGE RATE BASE
PROJECTED 2019 - 2020

	Projected 2019			Projected 2020		
	Total	MN	ND	Total	MN	ND
Gas Plant in Service	$68,505,008	$60,892,941	$7,612,067	$72,871,714	$64,948,541	$7,923,173
Accumulated Reserve for Depreciation	32,909,656	29,325,511	3,584,145	34,883,978	31,052,110	3,831,868
Net Gas Plant in Service	$35,595,352	$31,567,430	$4,027,922	$37,987,736	$33,896,431	$4,091,305
Additions						
Materials and Supplies	$563,609	$486,504	$77,105	$563,609	$486,504	$77,105
Gas in Underground Storage	337,353	306,530	30,823	337,353	306,530	30,823
Prepayments	140,345	127,086	13,259	154,803	141,544	13,259
Unamortized Loss on Debt	69,768	62,664	7,104	62,699	56,258	6,441
Unamort. Redemption Cost-Pref. Stk.	11,755	10,811	944	10,893	10,034	859
Total Additions	$1,122,830	$993,595	$129,235	$1,129,357	$1,000,870	$128,487
Total Before Deductions	$36,718,182	$32,561,025	$4,157,157	$39,117,093	$34,897,301	$4,219,792
Deductions						
Accumulated Deferred Income Taxes	$2,983,116	2,534,787	448,329	$2,908,855	$2,448,366	$460,489
Customer Advances	988,743	762,761	225,982	990,873	762,761	228,112
Total Deductions	$3,971,859	$3,297,548	$674,311	$3,899,728	$3,211,127	$688,601
Total Rate Base	$32,746,323	$29,263,477	$3,482,846	$35,217,365	$31,686,174	$3,531,191

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
AVERAGE PLANT IN SERVICE
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

		Projected	
	2018	2019	2020
Intangible	$2,851,819	$2,883,294	$2,910,862
Transmission	3,421,971	5,150,191	5,151,592
Distribution	40,880,113	43,933,900	47,546,452
General	6,391,087	6,665,291	6,705,525
Common	1,204,074	1,317,956	1,480,188
Common - Intangible	822,603	942,309	1,153,922
Plant in Service	$55,571,667	$60,892,941	$64,948,541

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
PLANT IN SERVICE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2018

Acct. No.	Account	Balance @ 12/31/17	Balance @ 12/31/18	Average
	Intangible Plant			
301	Organization	$4,453	$4,483	$4,468
302	Franchises & Consents	66,894	66,900	66,897
303	Misc.	2,765,333	2,795,575	2,780,454
	Total Intangible	$2,836,680	$2,866,958	$2,851,819
	Transmission Plant			
365.1	Land	$4,194	$4,186	$4,190
365.2	Land Rights	118,778	118,533	118,656
366	Structures	0	16,682	8,341
367.1	Mains	1,157,477	4,569,780	2,863,629
369.1	Meas. & Reg. Station Equip.	414,703	439,609	427,155
	Total Transmission Plant	$1,695,152	$5,148,790	$3,421,971
	Distribution Plant			
374.1	Land	$2,978	$2,978	$2,978
374.2	Rights of Way	17,615	17,615	17,615
375	Structures	32,251	34,860	33,556
376	Mains	17,113,479	18,429,187	17,771,333
378	Meas. & Reg. Equip.-General	467,484	460,915	464,199
379	Meas. & Reg. Equip.-City Gate	484,623	489,390	487,006
380	Services	14,568,953	15,556,608	15,062,780
381	Positive Meters	5,843,340	6,544,073	6,193,707
383	Service Regulators	703,113	873,749	788,431
385	Ind. Meas. & Reg. Station Eqpt.	37,775	37,775	37,775
387.1	Cathodic Protection Equip.	9,235	9,235	9,235
387.2	Other Distribution Equip.	11,498	11,498	11,498
	Total Distribution Plant	$39,292,344	$42,467,883	$40,880,113
	General Plant			
389	Land & Land Rights	$48,028	$48,062	$48,045
390	Structures and Improvements	2,390,677	2,374,168	2,382,423
391.1	Furniture and Fixtures	88,421	83,428	85,925
391.3	Computer Equip. - PC	62,019	100,124	81,072
391.5	Computer Equip. - Other	0	0	0
392.1	Trans. Equip., Non-Unitized	32,539	23,776	28,158
392.2	Trans. Equip., Unitized	1,384,847	1,486,940	1,435,894
394.1	Tools,Shop&Gar. Eq.-Non-Un.	598,097	728,235	663,166
395	Laboratory Equipment	333	346	339
396.1	Work Equipment Trailers	153,803	163,495	158,649
396.2	Power Operated Equipment	1,098,833	1,175,583	1,137,208
397.1	Radio Comm. Equip.-Fixed	114,665	134,065	124,365
397.2	Radio Comm. Equip.-Mobile	57,925	68,658	63,292
397.3	General Tele. Comm. Equip.	25,818	50,701	38,259
397.8	Network Equipment	96,648	96,648	96,647
398	Miscellaneous Equipment	46,350	48,941	47,645
	Total General Plant	$6,199,003	$6,583,170	$6,391,087

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
PLANT IN SERVICE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2018

Acct. No.	Account	Balance @ 12/31/17	Balance @ 12/31/18	Average
	Common Plant			
389	Land & Land Rights	$40,770	$61,170	$50,970
390	Structures and Improvements	701,507	690,003	695,755
391.1	Furniture and Fixtures	37,981	35,080	36,531
391.3	Computer Equip. - PC	51,008	64,784	57,896
391.5	Computer Equip. - Other	39,153	47,302	43,228
392.1	Trans. Equip., Non-Unitized	86	90	88
392.2	Trans. Equip., Unitized	54,747	59,402	57,075
392.3	Aircraft	177,229	185,205	181,217
393	Stores Equipment	344	359	351
394.1	Tools,Shop&Gar. Eq.-Non-Un.	3,030	3,765	3,397
394.3	Vehicle Maintenance Equipment	2,154	2,081	2,117
394.4	Vehicle Refueling Equip.	372	389	381
397.1	Radio Comm. Equip.-Fixed	3,228	3,374	3,301
397.2	Radio Comm. Equip.-Mobile	9,292	7,379	8,336
397.3	General Tele. Comm. Equip.	21,455	16,422	18,938
397.5	Supervisory & Telemetering	527	551	539
397.8	Network Equipment	3,493	4,819	4,156
398	Miscellaneous Equipment	38,686	40,911	39,798
	Total Common Plant	$1,185,062	$1,223,086	$1,204,074
303	Intangible Plant - Common	$774,861	$870,344	$822,603
	Total Gas Plant in Service	$51,983,102	$59,160,231	$55,571,667

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY
DETAILED COST OF PLANT
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2018

Acct. No.	Account	Balance @ 12/31/17	Additions	Retirements	Transfers	Balance @ 12/31/18
	Intangible Plant					
301	Organization	$5,006	$0	$0	$0	$5,006
302	Franchises & Consents	73,680	0	0	0	73,680
303	Misc.	2,783,783	969	0	0	2,784,752
	Total Intangible Plant	$2,862,469	$969	$0	$0	$2,863,438
	Transmission Plant					
365.1	Land	$5,585	$0	$0	$0	$5,585
365.2	Land Rights	158,152	0	0	0	158,152
366	Structures	0	16,683	0	0	16,683
367.1	Mains	1,541,179	4,556,013	0	0	6,097,192
369.1	Measuring & Regulating Station Equip.	855,908	31,570	0	(10,808)	876,670
	Total Transmission Plant	$2,560,824	$4,604,266	$0	($10,808)	$7,154,282
	Distribution Plant					
374.1	Land	$2,978	$0	$0	$0	$2,978
374.2	Land Rights	17,654	0	0	0	17,654
375	Structures & Improvements	32,251	2,609	0	0	34,860
376	Mains	19,426,616	1,589,216	(171,571)	0	20,844,261
378	Measuring & Regulating Equip. - Gen.	511,305	5,508	(12,082)	10,808	515,539
379	Measuring & Regulating Equip. - City Gate	484,883	4,766	0	0	489,649
380	Services	15,937,760	1,305,373	(252,541)	0	16,990,592
381	Meters	6,438,022	331,131	(65,745)	525,026	7,228,434
383	Service Regulators	774,939	91,920	(68,559)	167,129	965,429
385	Industrial Measuring & Regulating Equip.	162,784	0	0	0	162,784
387.1	Cathodic Protection Equipment	9,235	0	0	0	9,235
387.2	Other Distribution Equipment	11,499	0	0	0	11,499
	Total Distribution Plant	$43,809,926	$3,330,523	($570,498)	$702,963	$47,272,914
	General Plant					
389	Land & Land Rights	$48,659	$0	$0	$0	$48,659
390	Structures & Improvements	2,528,697	78,333	(102,323)	0	2,504,707

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY
DETAILED COST OF PLANT
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2018

Acct. No.	Account	Balance @ 12/31/17	Additions	Retirements	Transfers	Balance @ 12/31/18
391.1	Office Furniture & Equipment	95,317	1,629	(7,641)	0	89,305
391.3	Computer Equip.-PC	61,617	3,179	(18,589)	58,860	105,067
392.1	Transportation Equipment - Non-Unitized	31,167	0	(8,818)	0	22,349
392.2	Transportation Equipment - Unitized	1,380,893	238,714	(151,579)	0	1,468,028
394.1	Miscellaneous Tools	628,270	129,526	0	0	757,796
396.1	Work Equipment Trailers	151,442	12,916	(6,331)	0	158,027
396.2	Power Operated Equipment	1,101,925	376,050	(314,068)	0	1,163,907
397.1	Radio Communication Equip. - Fixed	116,257	22,858	(3,457)	0	135,658
397.2	Radio Communication Equip. - Mobile	59,341	0	0	10,733	70,074
397.3	General Tele. Comm. Equip.	27,484	0	(1,719)	25,685	51,450
397.8	Network Equipment	100,501	0	0	0	100,501
398	Miscellaneous Equipment	51,339	0	0	2,321	53,660
	Total General Plant	$6,382,909	$863,205	($614,525)	$97,599	$6,729,188
	Total Gas Plant in Service	$55,616,128	$8,798,963	($1,185,023)	$789,754	$64,019,822

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
PLANT IN SERVICE
PROJECTED 2019 - 2020

Plant in Service	Plant in Service @ 12/31/18 1/	Projected 2019 Plant Additions 2/	Projected 2019 Plant Retirements 3/	Projected 2019 Balance @ 12/31/19	Average 2019 Plant	Projected 2020 Plant Additions 2/	Projected 2020 Plant Retirements 3/	Projected 2020 Balance @ 12/31/20	Average 2020 Plant
Intangible	$2,866,958	$32,672	$0	$2,899,630	$2,883,294	$22,464	$0	$2,922,094	$2,910,862
Transmission	$5,148,790	$2,802	$0	$5,151,592	$5,150,191	$0	$0	$5,151,592	$5,151,592
Distribution	$42,467,883	$3,509,596	($577,563)	$45,399,916	$43,933,900	$4,910,510	($617,439)	$49,692,987	$47,546,452
General									
Other General	$1,259,084	$229,369	($115,836)	$1,372,617	$1,315,851	$253,152	($126,281)	$1,499,488	$1,436,053
Structures & Improvements	2,374,168	266,105	(218,423)	2,421,850	2,398,009	8,068	(222,810)	2,207,108	2,314,479
Computer Equipment	100,124	6,797	(9,211)	97,710	98,917	13,367	(8,989)	102,088	99,899
Transportation Eqpt.	1,510,716	218,015	(138,986)	1,589,745	1,550,231	230,000	(146,257)	1,673,488	1,631,617
Tools & Work Eqpt.	1,339,078	49,606	(123,195)	1,265,489	1,302,283	32,400	(116,425)	1,181,464	1,223,477
Total General	$6,583,170	$769,892	($605,651)	$6,747,411	$6,665,291	$536,987	($620,762)	$6,663,636	$6,705,525
Common									
Other Common	$361,505	$35,995	($14,713)	$382,787	$372,146	$111,929	($15,579)	$479,137	$430,962
Structures & Improvements	690,003	143,516	(28,083)	805,436	747,720	44,267	(32,781)	816,922	811,179
Computer Equipment	112,086	60,005	(4,562)	167,529	139,808	36,034	(6,818)	196,745	182,137
Transportation Eqpt.	59,492	0	(2,421)	57,071	58,282	0	(2,323)	54,748	55,910
Total Common	$1,223,086	$239,516	($49,779)	$1,412,823	$1,317,956	$192,230	($57,501)	$1,547,552	$1,480,188
Intangible	$870,344	$143,930	$0	$1,014,274	$942,309	$279,296	$0	$1,293,570	$1,153,922
Total Plant in Service	$59,160,231	$4,698,408	($1,232,993)	$62,625,646	$60,892,941	$5,941,487	($1,295,702)	$67,271,431	$64,948,541

1/ Schedule B-1, pages 2-3.
2/ Schedule B-1, pages 7-12.
3/ Based on 2016-2018 average ratio of retirements to plant.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
PLANT ADDITIONS
PROJECTED 2019

Project No.	Account	Description	Region	Amount
		Transmission		
312381	367	Replace 6" Transmission Line	Great Plains	$2,802
		Total Transmission		$2,802
		Distribution		
100854	376	Mains - Replace	Great Plains	$108,332
100855	376	Mains - Growth	Great Plains	117,496
200800	376	Mains - System Safety and Integrity	Great Plains	1,412,140
		Total Account 376		$1,637,968
100864	378	Measuring & Regulating Equipment	Great Plains	$4,456
316080	378	Measuring & Regulating Equipment	Great Plains	20,859
		Total Account 378		$25,315
316907	379	Measuring & Regulating - City Gate	Great Plains	$47,330
100909	380	Service lines - Growth	Great Plains	$62,832
311094	380	Service lines - Replacement	Great Plains	66,628
200823	380	Service lines - System Safety and Integrity	Great Plains	1,176,785
		Total Account 380		$1,306,245
100910	381	Meters	Great Plains	$316,252
100912	383	Regulators	Great Plains	$118,011
316070	387	Cathodic Protection	Great Plains	$58,475
		Total Distribution		$3,509,596
		General		
316860	390	Blacktop Parking Lot	Great Plains	$76,920
316861	390	Install LED Lights	Great Plains	2,021
316862	390	Shop Insulation	Great Plains	187,164
		Total Account 390		$266,105
100929	391.1	Office Equipment	Great Plains	$2,051
100958	391.3	Personal Computers	Great Plains	$6,797
100959	392.2	Vehicles	Great Plains	$218,015
316075	394.1	Minor Work Equipment	Great Plains	$27,230
316951	394.1	Sensit PMDs	Great Plains	61,550
316955	394.1	Corrosion Detector	Great Plains	5,799
316956	394.1	Update Mueller Equipment	Great Plains	4,259
316957	394.1	Test Guage	Great Plains	7,451
316974	394.1	Core Drills	Great Plains	10,590
317122	394.1	Training Props	Great Plains	8,800
		Total Account 394.1		$125,679

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
PLANT ADDITIONS
PROJECTED 2019

Project No.	Account	Description	Region	Amount
		General (Cont.)		
100979	396.2	Power Operated Equipment	Great Plains	$49,606
316754	397.1	Fixed Network Expansion	Great Plains	$74,973
317139	397.1	Upgrade Gas Collectors to 4G	Great Plains	26,666
		Total Account 397.1		$101,639
		Total General		$769,892
		General Intangible		
316450	303	PCAD Annual Enhancements	General Office	$9,589
317045	303	SCADA DR System	General Office	2,878
317411	303	Synergi Model Development	General Office	18,730
317615	303	Migrate Aligne Database	General Office	1,475
		Total Acct. 303		$32,672
		Common		
302486	390	Purchase Carpet	General Office	$17,849
315957	390	Remodel Control Center	General Office	9,049
316404	390	Renovate New Building - Communications	General Office	116,014
316464	390	New Building - Communications	General Office	604
		Total Acct. 390		$143,516
100755	391.1	Office Equipment	General Office	$10,001
100014	391.3	Replace Toughbooks	General Office	$24,043
100756	391.3	Replace Computer Peripherals	General Office	6,752
307540	391.3	Replace Network Equipment	General Office	18,275
311597	391.3	Itron Mobile Radio	General Office	6,053
315424	391.3	Replace UPS Batteries	General Office	571
		Total Acct. 391.3		$55,694
317563	391.5	Work Asset Management Hardware	General Office	$4,311
100744	397.1	Communication Equipment	General Office	$12,612
300071	397.2	Replace Mobile Collectors	General Office	$8,431
316128	397.2	Replace Mobile Radio System	General Office	4,951
		Total Acct. 397.2		$13,382
		Total Common		$239,516
		Common - Intangible		
100336	303	PIM Installation	General Office	$846
100575	303	Purchase IVR - Web	General Office	8,234
200714	303	GIS System Upgrade	General Office	6,718
301563	303	GIS Data Conversion	General Office	91,583
315864	303	ThoughtSpot Implementation	General Office	6,381
315942	303	PragmaFIELD Implementation	General Office	9,831

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
PLANT ADDITIONS
PROJECTED 2019

Project No.	Account	Description	Region	Amount
		Common - Intangible (Cont.)		
316262	303	JDE Weblogic	General Office	$2,408
316282	303	PowerPlan Lease Module	General Office	5,579
317093	303	PowerPlan Upgrade	General Office	8,587
318236	303	HVAC & Security System Software	General Office	3,763
		Total Common Intangible		$143,930
		Total 2019 Additions		$4,698,408
		Transmission		$2,802
		Distribution		$3,509,596
		General		
		Other		$229,369
		Structures & Improvements		266,105
		Computer Equipment		6,797
		Vehicles		218,015
		Work Equipment		49,606
		Total General		$769,892
		General Intangible		$32,672
		Common		
		Other		$35,995
		Structures & Improvements		143,516
		Computer Equipment		60,005
		Vehicles		0
		Total Common		$239,516
		Common Intangible		$143,930
		Total 2019 Additions		$4,698,408

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
PLANT ADDITIONS
PROJECTED 2020

Project No.	Account	Description	Region	Amount
		Distribution		
100854	376	Mains - Replace	Great Plains	$152,490
100855	376	Mains - Growth	Great Plains	91,493
200800	376	Mains - System Safety and Integrity	Great Plains	1,800,573
		Total Account 376		$2,044,556
318100	378	Measuring & Regulating Equipment - Growth	Great Plains	$100,000
319042	378	Measuring & Regulating Equipment	Great Plains	349,308
		Total Account 378		$449,308
316911	379	Measuring & Regulating - City Gate	Great Plains	$91,493
318802	379	Measuring & Regulating - Line Heater	Great Plains	170,786
		Total Account 379		$262,279
100909	380	Service lines - Growth	Great Plains	$341,572
311094	380	Service lines - Replacement	Great Plains	140,289
200823	380	Service lines - System Safety and Integrity	Great Plains	1,195,502
		Total Account 380		$1,677,363
100910	381	Meters	Great Plains	$314,776
100912	383	Regulators	Great Plains	$99,403
316070	387	Cathodic Protection	Great Plains	$62,825
		Total Distribution		$4,910,510
		General		
318600	390	Replace 2 Doors	Great Plains	$8,068
100929	391.1	Office Equipment	Great Plains	$3,026
318578	391.1	Conference Room Tables	Great Plains	3,132
318594	391.1	Ice Machine	Great Plains	3,132
		Total Account 391.1		$9,290
100958	391.3	Personal Computers	Great Plains	$13,367
100959	392.2	Vehicles	Great Plains	$230,000
100976	394.1	Minor Work Equipment	Great Plains	$7,060
318013	394.1	Tools & Minor Work Equipment	Great Plains	20,170
318596	394.1	Air Compressor	Great Plains	2,017
318597	394.1	Portable Pipe Threader	Great Plains	6,051
318598	394.1	Yard Gate	Great Plains	3,227
318605	394.1	Remote Methane Detector	Great Plains	12,102
318753	394.1	Shoring Box	Great Plains	6,555
318754	394.1	Shoring Box	Great Plains	6,555
		Total Account 394.1		$63,737
100979	396.2	Power Operated Equipment	Great Plains	$32,400

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
PLANT ADDITIONS
PROJECTED 2020

Project No.	Account	Description	Region	Amount
		General (Cont.)		
316754	397.1	Fixed Network Expansion	Great Plains	$10,085
316489	397.2	Replace Mobile Radio System	Great Plains	$152,142
318118	397.8	Fixed Network Equipment	Great Plains	$17,898
		Total General		$536,987
		General - Intangible		
316359	303	SCADA System Enhancements	General Office	$5,532
316450	303	PCAD Enhancements	General Office	12,159
318453	303	SCADA Autosol	General Office	4,773
		Total General Intangible		$22,464
		Common		
318332	390	Remodel Restrooms	General Office	$27,874
318336	390	Remodel Restrooms	General Office	16,393
		Total Acct. 390		$44,267
100755	391.1	Office Equipment	General Office	$21,294
100014	391.3	Replace Toughbooks	General Office	$10,551
100756	391.3	Replace Computer Peripherals	General Office	4,917
311597	391.3	Itron Mobile Radio	General Office	6,843
316892	391.3	Replace UPS Batteries	General Office	935
316917	391.3	Replace Display Devices	General Office	5,307
		Total Acct. 391.3		$28,553
317563	391.5	Work Asset Management - Hardware	General Office	$7,481
318216	394.1	Communications Tools	General Office	$2,337
100744	397.1	Communication Equipment	General Office	$7,848
316128	397.2	Replace Mobile Radio System	General Office	$69,166
300071	397.2	Replace Mobile Collectors	General Office	1,588
		Total Acct. 397.2		$70,754
318970	397.3	Replace Cisco VoIP	General Office	$8,138
318189	397.8	Fixed Network Equipment	General Office	$1,558
		Total Common		$192,230
		Common - Intangible		
100550	303	Work Asset Management - Software	General Office	$187,764
100575	303	Customer Self Service Web/IVR	General Office	9,938
200714	303	GIS Enhancements	General Office	9,844

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
PLANT ADDITIONS
PROJECTED 2020

Project No.	Account	Description	Region	Amount
		Common - Intangible (Cont.)		
315864	303	ThoughtSpot Implementation	General Office	$12,015
316021	303	GIS ESRI System Upgrade	General Office	42,020
316104	303	GIS Pipeline Inspection System	General Office	6,232
317095	303	JDEdwards AS400 to Oracle	General Office	3,732
318360	303	Sierra AirLink Manager	General Office	2,337
318407	303	Upgrade FDM Software	General Office	2,142
318844	303	2Ring Dashboard	General Office	1,675
318890	303	GIS Offline Mobile Maps	General Office	1,597
		Total Common Intangible		$279,296
		Total 2020 Additions		$5,941,487
		Transmission		$0
		Distribution		$4,910,510
		General		
		Other		$253,152
		Structures & Improvements		8,068
		Computer Equipment		13,367
		Vehicles		230,000
		Work Equipment		32,400
		Total General		$536,987
		General Intangible		$22,464
		Common		
		Other		$111,929
		Structures & Improvements		44,267
		Computer Equipment		36,034
		Vehicles		0
		Total Common		$192,230
		Common Intangible		$279,296
		Total 2020 Additions		$5,941,487

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SUMMARY OF ACCUMULATED RESERVE FOR DEPRECIATION
PROJECTED 2019 - 2020

	2018 1/	Projected 2019 2/	Average 2019 2/	Projected 2020 3/	Average 2020 3/
Intangible	$806,414	$988,975	$897,695	$1,175,659	$1,082,317
Transmission	1,300,558	1,406,522	1,353,540	1,512,504	1,459,513
Distribution	22,790,089	24,281,166	23,535,628	25,904,268	25,092,717
General	2,548,073	2,282,192	2,415,132	2,083,337	2,182,764
Common	547,747	561,497	554,624	586,399	573,949
Common Intangible	530,045	607,741	568,892	713,960	660,850
Total	$28,522,926	$30,128,093	$29,325,511	$31,976,127	$31,052,110

1/ Schedule B-2, page 2.
2/ Schedule B-2, page 4.
3/ Schedule B-2, page 5.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SUMMARY OF ACCUMULATED RESERVE FOR DEPRECIATION
TWELVE MONTHS ENDING DECEMBER 31, 2018

	Total Company			Minnesota		
	Balance 12/31/17	Balance 12/31/18	Average Balance	Balance 12/31/17	Balance 12/31/18	Average Balance
Intangible	$677,070	$875,306	$776,188	$624,162	$806,414	$715,288
Transmission	1,779,577	1,796,682	1,788,130	1,295,647	1,300,558	1,298,103
Distribution	24,059,619	25,497,377	24,778,498	21,538,392	22,790,089	22,164,241
General	2,675,306	2,613,547	2,644,427	2,612,386	2,548,073	2,580,229
Common	560,658	611,809	586,234	498,554	547,747	523,151
Intangible Plant - Common	500,098	591,908	546,003	444,829	530,045	487,436
Total	$30,252,328	$31,986,629	$31,119,480	$27,013,970	$28,522,926	$27,768,448

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY
BOOK CHANGES IN ACCUMULATED PROVISION FOR
DEPRECIATION AND AMORTIZATION
TWELVE MONTHS ENDING DECEMBER 31, 2018

Gas Utility	Beginning Balance 1/1/18	Annual Provision	Retirements (Original Cost)	Salvage	Removal Costs	Adjustments	Ending Balance 12/31/18
Intangible	$606,972	$175,685					$782,657
Transmission	1,779,577	39,391			($16,705)	($5,581)	1,796,682
Distribution	25,450,454	2,062,863	($683,066)	$124	(165,615)	188,201	26,852,961
General	2,635,305	262,933	(614,525)	282,712	(92)	53,528	2,619,861
Total	$30,472,308	$2,540,872	($1,297,591)	$282,836	($182,412)	$236,148	$32,052,161

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
ACCUMULATED RESERVE FOR DEPRECIATION
PROJECTED 2019

	2018 Acc. Reserve for Depr.	2019 Average Plant In Service 1/	Depreciation/ Amortization Rate 2/	2019 Depreciation/ Amortization Expense	2019 Retirements/ Removal	2019 Ending Balance	2019 Average Balance
Intangible	$806,414	$2,883,294	3/	$182,561	$0	$988,975	$897,695
Transmission	$1,300,558	$5,150,191	2.06%	$106,094	($130)	$1,406,522	$1,353,540
Distribution	$22,790,089	$43,933,900	4.67%	$2,051,713	($560,636)	$24,281,166	$23,535,628
General							
Other General	$533,972	$1,315,851	5.03%	$66,187	($116,086)	$484,073	$509,023
Structures & Improvements	770,994	2,398,009	1.92%	46,042	(167,614)	649,422	710,208
Computer Equipment	83,813	98,917	14.87%	14,709	(18,221)	80,301	82,057
Transportation Eqpt.	664,655	1,550,231	8.21%	127,274	(144,496)	647,433	656,044
Work Eqpt.	494,639	1,302,283	2.60%	33,859	(107,535)	420,963	457,800
Total General	$2,548,073	$6,665,291		$288,071	($553,952)	$2,282,192	$2,415,132
Common							
Other Common	$184,537	$372,146	4.44%	$16,523	($16,830)	$184,230	$184,384
Structures & Improvements	312,312	747,720	2.25%	16,824	(28,483)	300,653	306,483
Computer Equipment	42,209	139,808	20.00%	27,962	(3,849)	66,322	54,266
Transportation Eqpt.	8,689	58,282	4.11%	2,395	(792)	10,292	9,491
Total Common	$547,747	$1,317,956		$63,704	($49,954)	$561,497	$554,624
Common Intangible	$530,045	$942,309	3/	$77,696	$0 3/	$607,741	$568,892
Total Gas Plant in Service	$28,522,926	$60,892,941		$2,769,839	($1,164,672)	$30,128,093	$29,325,511
Depreciation Expense				$2,606,311			

1/ Schedule B-1, page 6.
2/ Composite depreciation rates by function, rates per Depreciation Study as submitted in Docket No. D-19-376.
3/ Amortization based on the life of each item.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
ACCUMULATED RESERVE FOR DEPRECIATION
PROJECTED 2020

				2020			
	2019 Acc. Reserve for Depr.	2020 Average Plant In Service 1/	Depreciation/ Amortization Rate 2/	Depreciation/ Amortization Expense	Retirements/ Removal	Ending Balance	2020 Average Balance
Intangible	$988,975	$2,910,862	3/	$186,684	$0	$1,175,659	$1,082,317
Transmission	$1,406,522	$5,151,592	2.06%	$106,123	($141)	$1,512,504	$1,459,513
Distribution	$24,281,166	$47,546,452	4.67%	$2,220,419	($597,317)	$25,904,268	$25,092,717
General							
Other General	$484,073	$1,436,053	5.03%	$72,233	($105,237)	$451,069	$467,571
Structures & Improvements	649,422	2,314,479	1.92%	44,438	(141,184)	552,676	601,049
Computer Equipment	80,301	99,899	14.87%	14,855	(17,457)	77,699	78,999
Transportation Eqpt.	647,433	1,631,617	8.21%	133,956	(140,752)	640,637	644,035
Work Eqpt.	420,963	1,223,477	2.60%	31,810	(91,517)	361,256	391,110
Total General	$2,282,192	$6,705,525		$297,292	($496,147)	$2,083,337	$2,182,764
Common							
Other Common	$184,230	$430,962	4.44%	$19,135	($16,802)	$186,563	$185,397
Structures & Improvements	300,653	811,179	2.25%	18,252	(27,420)	291,485	296,069
Computer Equipment	66,322	182,137	20.00%	36,427	(6,049)	96,700	81,511
Transportation Eqpt.	10,292	55,910	4.11%	2,298	(939)	11,651	10,972
Total Common	$561,497	$1,480,188		$76,112	($51,210)	$586,399	$573,949
Common Intangible	$607,741	$1,153,922	3/	$106,219	$0	$713,960	$660,850
Total Gas Plant in Service	$30,128,093	$64,948,541		$2,992,849	($1,144,815)	$31,976,127	$31,052,110
Depreciation Expense				$2,824,785			

1/ Schedule B-1, page 6.
2/ Composite depreciation rates by function, rates per Depreciation Study as submitted in Docket No. D-19-376.
3/ Amortization based on the life of each item.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SUMMARY OF WORKING CAPITAL AND
CUSTOMER ADVANCES FOR CONSTRUCTION
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

Working Capital	Average Balance @ 12/31/18	Projected 2019	Projected 2020	Reference
Materials and Supplies	$423,681	$486,504	$486,504	Schedule B-3, page 2
Gas In Underground Storage	$504,327	$306,530	$306,530	Schedule B-3, page 3
Prepayments				
Prepaid Insurance	$12,621	$71,709	$86,167	Schedule B-3, page 4
Prepaid Commodity	81,397	55,377	55,377	Schedule B-3, page 5
Total Prepayments	$94,018	$127,086	$141,544	
Unamortized Loss on Debt	$64,857	$62,664	$56,258	Schedule B-3, page 6
Preferred Stock Redemption Cost Amort.	5,600	10,811	10,034	Schedule B-3, page 7
Total Working Capital	$1,092,483	$993,595	$1,000,870	
Customer Advances for Construction	$774,663	$762,761	$762,761	Schedule B-3, page 8

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
MATERIALS AND SUPPLIES
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

		Projected	
	Per Books	2019 1/	2020
December 2017	$403,593	$443,769	
January 2018	410,363	436,003	
February	417,677	437,458	
March	413,677	452,618	
April	458,381	460,428	
May	473,410	527,072	
June	558,011	609,814	
July	567,478	567,478	
August	551,043	551,043	
September	483,982	483,982	
October	457,719	457,719	
November	453,393	453,393	
December	443,769	443,769	
Average Balance	$423,681		
Thirteen Month Average		$486,504	$486,504

1/ Reflects actual data for January through June 2019. Remainder of 2019 months to remain at 2018 level.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
GAS IN UNDERGROUND STORAGE
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

		Projected	
	Per Books	2019 1/	2020
December 2017	$534,090	$474,564	
January 2018	326,635	268,622	
February	165,433	132,481	
March	47,496	42,409	
April	0	0	
May	0	0	
June	127,963	104,436	
July	248,334	248,334	
August	371,148	371,148	
September	577,624	577,624	
October	645,357	645,357	
November	645,357	645,357	
December	474,564	474,564	
Average Balance	$504,327		
Thirteen Month Average		$306,530	$306,530

1/ Reflects actual data for January through June 2019. Remainder of 2019 months to remain at 2018 level.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
PREPAID INSURANCE
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

		Projected	
	Per Books	2019 1/	2020 1/
December 2017	$14,596	$10,645	$6,263
January 2018	130,694	150,247	184,395
February	118,220	136,545	167,521
March	106,616	127,186	150,648
April	94,731	109,438	133,774
May	82,769	96,667	116,901
June	70,611	82,810	100,027
July	58,452	68,888	83,154
August	46,293	54,966	66,280
September	34,135	41,043	49,406
October	23,569	27,120	32,538
November	25,996	20,393	23,070
December	10,645	6,263	6,191
Average Balance	$12,621		
Thirteen Month Average		$71,709	$86,167

1/ Reflects actual data through June 2019 and reflects reallocation of corporate cost. Projected based on projected insurance expense.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
PREPAID COMMODITY CHARGES
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

		Projected	
	Per Books	2019 1/	2020
December 2017	$76,117	$86,676	
January 2018	45,732	48,707	
February	22,466	24,727	
March	6,434	7,932	
April	0	0	
May	0	0	
June	25,074	22,618	
July	47,299	47,299	
August	69,591	69,591	
September	95,253	95,253	
October	115,209	115,209	
November	115,210	115,210	
December	86,676	86,676	
Average Balance	$81,397		
Thirteen Month Average		$55,377	$55,377

1/ Reflects actual data for January through June 2019. Remainder of 2019 months to remain at 2018 level.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
UNAMORTIZED GAIN(LOSS) ON DEBT
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

	Unamortized Loss on Debt	Acc. Deferred Inc. Tax
Balance at December 31, 2017	$65,521	($14,630)
Balance at December 31, 2018	$64,193	($14,320)
Average Balance	$64,857	($14,475)
2019 Amortization 1/	(3,057)	682
Balance at December 31, 2019	$61,136	($13,638)
Average Balance	$62,664	($13,979)
2020 Amortization	(9,756)	2,176
Balance at December 31, 2020	$51,380	($11,462)
Average Balance	$56,258	($12,550)

1/ Includes annual amortization and reallocation.

January 2019 amortization:	$5,886
February amortization:	(813)
Reallocation entry:	$6,699
Monthly amortization:	($813)
months:	12
	($9,756)

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
UNAMORTIZED REDEMPTION COST OF PREFERRED STOCK
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

	Net	Unamort. Redemption Cost	
Balance at December 31, 2017	$0	$0	1/
Balance at December 31, 2018	$11,199	$11,199	
Average Balance	$5,600	$5,600	
2019 Amortization 2/	(777)	(777)	
Balance at December 31, 2019	$10,422	$10,422	
Average Balance	$10,811	$10,811	
2020 Amortization	(777)	(777)	
Balance at December 31, 2020	$9,645	$9,645	
Average Balance	$10,034	$10,034	

1/ Included in rate base beginning 1/1/2018.
2/ Amortized over fifteen years.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
CUSTOMER ADVANCES FOR CONSTRUCTION
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

		Projected	
	Per Books	2019 1/	2020
December 2017	$788,170	$761,156	
January 2018	788,170	763,556	
February	787,892	762,756	
March	811,396	763,197	
April	811,396	763,197	
May	822,146	763,197	
June	715,296	762,690	
July	708,385	762,690	
August	708,385	762,690	
September	741,990	762,690	
October	741,990	762,690	
November	748,215	762,690	
December	761,156	762,690	
Average Balance	$774,663		
Thirteen Month Average		$762,761	$762,761

1/ Reflects actual data through June 2019. Remainder of months to remain at 2019 level.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
ACCUMULATED DEFERRED INCOME TAXES
PROJECTED 2019 - 2020

		Projected 2019			Projected 2020		
	2018 1/	Changes	Balance	Average	Changes	Balance	Average
Accumulated Deferred Income Taxes							
Liberalized Depreciation	$3,366,268	($109,825) 2/	$3,256,443	$3,311,356	($77,771) 2/	$3,178,672	$3,217,558
Contribution in Aid of Construction	(494,741)		(494,741)	(494,741)		(494,741)	(494,741)
Customer Advances	(218,772)	(461) 3/	(219,233)	(219,003)	0 3/	(219,233)	(219,233)
Unamortized Loss on Debt	14,320	(682) 4/	13,638	13,979	(2,176) 4/	11,462	12,550
Excess Deferred - Non-Plant in Rate Base	(81,322)	9,036 5/	(72,286)	(76,804)	9,036 5/	(63,250)	(67,768)
Balance	$2,585,753	($101,932)	$2,483,821	$2,534,787	($70,911)	$2,412,910	$2,448,366

1/ Schedule B-4, page 2.
2/ Schedule B-4, page 3.
3/ Change in customer advances multiplied by 28.742 percent.
4/ Schedule B-3, page 6.
5/ Annual amortization of Non-Plant Excess Deferred Income Taxes in Rate Base, 10 year amortization of $9,036 per year.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
ANALYSIS OF ACCUMULATED DEFERRED INCOME TAXES
TWELVE MONTHS ENDING DECEMBER 31, 2018

	Total Company			Minnesota		
	Balance 12/31/17	Balance 12/31/18	Average Balance	Balance 12/31/17	Balance 12/31/18	Average Balance
Gas Utility - Rate Base Deductions:						
Depreciation, Retirements and Other Timing Differences Required to be Normalized	$4,167,382	$3,953,435	$4,060,409	$3,554,369	$3,366,268	$3,460,319
Contributions In Aid of Construction	(608,638)	(552,445)	(580,542)	(547,547)	(494,741)	(521,144)
Customer Advances	(307,507)	(271,072)	(289,290)	(226,536)	(218,772)	(222,654)
Unamortized Loss on Debt	18,083	17,431	17,757	14,630	14,320	14,475
Excess Deferred - Non-Plant in Rate Base	(137,488)	(120,506)	(128,997)	(93,552)	(81,322)	(87,437)
Total	$3,131,832	$3,026,843	$3,079,338	$2,701,364	$2,585,753	$2,643,559

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
CHANGES IN ACCUMULATED DEFERRED INCOME TAXES
RELATED TO PLANT IN SERVICE
PROJECTED 2019 - 2020

	Projected	
	2019	2020
DIT on 2018 and prior plant:		
Book depreciation - 2018 and prior plant 1/	($2,677,917)	($2,677,917)
Tax Depreciation - 2018 and prior plant	2,212,455	2,171,263
Net tax deductions	($465,462)	($506,654)
Accumulated deferred income taxes on historical plant @ 28.742%	($133,783)	($145,622)
DIT on plant additions 2/	$23,958	$67,851
Changes in Accumulated Deferred income taxes @ 28.742%	($109,825)	($77,771)

1/ Includes depreciation on accounts charged to clearing accounts.
2/ See Schedule B-4, page 4.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
LIBERALIZED DEPRECIATION
PROJECTED 2019 - 2020

Month	Weighting For Projection	Monthly Increments	Balance/ Increments
December 2018	100.00%		
January 2019	91.78%	$4,310	$3,956
February	84.11%	4,310	3,625
March	75.62%	4,310	3,259
April	67.40%	4,310	2,905
May	58.90%	4,310	2,539
June	50.68%	4,310	2,184
July	42.19%	4,310	1,818
August	33.70%	4,310	1,452
September	25.48%	4,310	1,098
October	16.99%	4,310	732
November	8.77%	4,310	378
December	0.27%	4,312	12
Total		$51,722	$23,958
December 2019	100.00%		
January 2020	91.78%	$12,206	$11,203
February	84.11%	12,206	10,266
March	75.62%	12,206	9,230
April	67.40%	12,206	8,227
May	58.90%	12,206	7,189
June	50.68%	12,206	6,186
July	42.19%	12,206	5,150
August	33.70%	12,206	4,113
September	25.48%	12,206	3,110
October	16.99%	12,206	2,074
November	8.77%	12,206	1,070
December	0.27%	12,210	33
Total		$146,476	$67,851

	Projected 2019	Projected 2020
Projected Deferred Income Taxes on Plant Additions 1/	$51,722	$146,476
Monthly Increment	$4,310	$12,206

1/ See Schedule B-4, pages 5-6.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
TAX DEPRECIATION ON 2019 PLANT ADDITIONS
PROJECTED 2019 - 2020

	2019 Plant Additions	Annual Depreciation	Book Depr. 1/ for 2019	2019 Deferred Tax Calculation: Tax 2/ Depreciation	2019: Book/Tax Difference	2019: Deferred Income Taxes	2020 Deferred Tax Calculation: Tax 2/ Depreciation	2020: Book/Tax 3/ Difference	2020: Deferred Income Taxes
Transmission	$2,802	$57	$29	$105	$76	$22	$202	$145	$42
Distribution	$3,509,596	$150,526	$75,263	$131,610	$56,347	$16,195	$253,358	$102,832	$29,556
General									
Other	$229,369	$12,069	$6,035	$32,777	$26,742	$7,686	$56,172	$44,103	$12,676
Structures & Improvement	266,105	5,109	2,555	3,702	1,147	330	6,823	1,714	493
Computer Equip.	6,797	1,011	506	1,359	853	245	2,175	1,164	335
Vehicles	218,015	18,248	9,124	43,603	34,479	9,910	69,765	51,517	14,807
Work Eqpt.	49,606	1,285	642	7,089	6,447	1,853	12,149	10,864	3,123
Total General	$769,892	$37,722	$18,862	$88,530	$69,668	$20,024	$147,084	$109,362	$31,434
General Intangible	$32,672	$5,651	$2,826	$10,890	$8,064	$2,318	$14,523	$8,872	$2,550
Common									
Other	$35,995	$2,401	$1,201	$5,144	$3,943	$1,133	$8,815	$6,414	$1,844
Structures & Improvement	143,516	3,229	1,615	1,996	381	110	3,680	451	130
Computer Equip.	60,005	12,001	6,001	12,001	6,000	1,725	19,202	7,201	2,070
Vehicles	0	0	0	0	0	0	0	0	0
Total Common	$239,516	$17,631	$8,817	$19,141	$10,324	$2,968	$31,697	$14,066	$4,044
Intangible Common	$143,930	$24,999	$12,500	$47,972	$35,472	$10,195	$63,977	$38,978	$11,203
Total Additions	$4,698,408	$236,586	$118,297	$298,248	$179,951	$51,722	$510,841	$274,255	$78,829

1/ Annual depreciation divided by 2 to reflect half year convention for 2019 deferred taxes.

2/ Tax depreciation rates are:

	Year 1	Year 2
Transmission/Distribution	3.750%	7.219%
General & Common	14.290%	24.490%
Structures & Improvements	1.391%	2.564%
Transportation & Computer	20.000%	32.000%
Intangible	33.330%	44.450%
Tax Rate	28.742%	

3/ Full year book depreciation net to 2020 tax depreciation.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
TAX DEPRECIATION ON 2020 PLANT ADDITIONS
PROJECTED 2020

	2020 Plant Additions	Annual Depreciation	Book Depr. 1/ for Taxes	Tax 2/ Depreciation	Book/Tax Difference	Deferred Income Taxes
Distribution	$4,910,510	$238,951	$119,476	$184,144	$64,668	$18,587
General						
Other	$253,152	$13,593	$6,797	$36,175	$29,378	$8,444
Structures & Improvement	8,068	155	78	112	34	10
Computer Equip.	13,367	1,988	994	2,673	1,679	483
Vehicles	230,000	19,251	9,626	46,000	36,374	10,455
Work Eqpt.	32,400	839	419	4,630	4,211	1,210
Total General	$536,987	$35,826	$17,914	$89,590	$71,676	$20,602
General Intangible	$22,464	$2,596	$1,298	$7,487	$6,189	$1,779
Common						
Other	$111,929	$7,918	$3,959	$15,995	$12,036	$3,459
Structures & Improvement	44,267	996	498	616	118	34
Computer Equip.	36,034	7,207	3,604	7,207	3,603	1,036
Vehicles	0	0	0	0	0	0
	$192,230	$16,121	$8,061	$23,818	$15,757	$4,529
Intangible Common	$279,296	$32,048	$16,024	$93,089	$77,065	$22,150
Total Additions	$5,941,487	$325,542	$162,773	$398,128	$235,355	$67,647

1/ Annual depreciation divided by 2 to reflect half year convention for 2020 deferred taxes.

2/ Tax depreciation rates are:	Year 1
Transmission/Distribution	3.750%
General & Common	14.290%
Structures & Improvements	1.391%
Transportation & Computer	20.000%
Intangible	33.330%
Tax Rate	28.742%

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
INCOME STATEMENT
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

	Per Books 2018 1/	Projected 2019		Projected 2020	Projected 2019 & 2020 Reference
Operating Revenues					
Sales	$26,128,502	$22,499,641		$21,952,876	Schedule C-1, page 1
Transportation	1,592,291	1,866,273		1,915,879	Schedule C-1, page 1
Other	817,345	239,165		237,773	Schedule C-1, page 1
Total Revenues	$28,538,138	$24,605,079		$24,106,528	
Operating Expenses					
Operation and Maintenance					
Cost of Gas	$18,175,295	$13,751,669		$13,869,562	Schedule C-2, pages 1-4
Other O&M	6,731,406	6,799,490		7,002,825	Schedule C-2, pages 1-4
Total O&M	$24,906,701	$20,551,159		$20,872,387	
Depreciation/Amortization	2,311,083	2,607,088		2,825,562	Schedule C-3, page 1
Taxes Other Than Income	1,081,692	1,150,824		1,229,308	Schedule C-4, page 1
Current Income Taxes	402,026	(234,433)	2/	(590,841)	Schedule C-5, page 1
Deferred Income Taxes	(767,379)		2/		
Total Expenses	$27,934,123	$24,074,638		$24,336,416	
Operating Income	$604,015	$530,441		($229,888)	
Rate Base	$25,477,480	$29,263,477		$31,686,174	Statement B, page 1
Rate of Return	2.371%	1.813%		-0.726%	

1/ See Statement C, page 2.
2/ Projected 2019 - 2020 current and deferred income taxes, including the amortization of excess deferred income taxes, are combined and shown in Current Income Taxes. See Statement C, Schedule C-5.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
INCOME STATEMENT
TWELVE MONTHS ENDING DECEMBER 31, 2018

	Total Company	Minnesota	Other
Operating Revenues			
Sales	$31,280,215	$26,128,502	$5,151,713
Transportation	1,939,049	1,592,291	346,758
Other	849,827	817,345	32,482
Total Revenues	$34,069,091	$28,538,138	$5,530,953
Operating Expenses			
Operation and Maintenance			
Cost of Gas	$22,406,132	$18,175,295	$4,230,837
Other O&M	7,444,397	6,731,406	712,991
Total O&M	$29,850,529	$24,906,701	$4,943,828
Depreciation	2,567,164	2,311,083	256,081
Taxes Other Than Income	1,152,350	1,081,692	70,658
Current Income Taxes	533,588	402,026	131,562
Deferred Income Taxes	(835,236)	(767,379)	(67,857)
Total Expenses	$33,268,395	$27,934,123	$5,334,272
Operating Income	$800,696	$604,015	$196,681
Rate Base	$28,304,591	$25,477,480	$2,827,111
Rate of Return	2.829%	2.371%	6.957%

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SUMMARY OF OPERATING INCOME
2019 ADJUSTMENTS

	2018 Per Books	Sales/Trans Revenue 1/	Other Revenue 1/	Labor 2/	Benefits 3/	Subcontract Labor 4/	Vehicles & Work Equip. 5/	Uncollectible Accounts 6/
Operating Revenues								
Sales	$26,128,502	($3,628,861)						
Transportation	1,592,291	273,982						
Other	817,345		($578,180)					
Total Revenues	$28,538,138	($3,354,879)	($578,180)					
Operating Expenses								
Operation & Maintenance								
Cost of Gas	$18,175,295	($4,423,626)						
Other O&M	6,731,406			$4,543	$111,273	$51,376	$29,142	($70,023)
Total O&M	$24,906,701	($4,423,626)	$0	$4,543	$111,273	$51,376	$29,142	($70,023)
Depreciation	2,311,083							
Taxes Other Than Income	1,081,692							
Current Income Taxes	402,026	307,179	(166,180)	(1,306)	(31,982)	(14,766)	(8,376)	20,126
Deferred Income Taxes	(767,379)							
Total Expenses	$27,934,123	($4,116,447)	($166,180)	$3,237	$79,291	$36,610	$20,766	($49,897)
Operating Income	$604,015	$761,568	($412,000)	($3,237)	($79,291)	($36,610)	($20,766)	$49,897

1/ Schedule C-1, page 1 and C-2, pages 1-2.
2/ Schedule C-2, page 10.
3/ Schedule C-2, page 13.
4/ Schedule C-2, page 14.
5/ Schedule C-2, page 15.
6/ Schedule C-2, page 16.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SUMMARY OF OPERATING INCOME
2019 ADJUSTMENTS

	CIP 7/	Software 8/ Maintenance	9/ Advertising	Industry Dues 10/	11/ Insurance	Reg. Comm. Expense 12/	All Other O&M 13/	Depreciation 14/
Operating Revenues								
Sales								
Transportation								
Other								
Total Revenues								
Operating Expenses								
Operation & Maintenance								
Cost of Gas								
Other O&M	$0	$18,972	($29,078)	$7,283	$24,519	($13,151)	($66,772)	
Total O&M	$0	$18,972	($29,078)	$7,283	$24,519	($13,151)	($66,772)	$0
Depreciation								296,005
Taxes Other Than Income								
Current Income Taxes	0	(5,453)	8,356	(2,093)	(7,047)	3,780	19,192	(85,078)
Deferred Income Taxes								
Total Expenses	$0	$13,519	($20,722)	$5,190	$17,472	($9,371)	($47,580)	$210,927
Operating Income	$0	($13,519)	$20,722	($5,190)	($17,472)	$9,371	$47,580	($210,927)

7/ Schedule C-2, page 17.
8/ Schedule C-2, page 18.
9/ Schedule C-2, page 19.
10/ Schedule C-2, page 20.
11/ Schedule C-2, page 21.
12/ Schedule C-2, page 22.
13/ Schedule C-2, page 23.
14/ Schedule C-3, page 1.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SUMMARY OF OPERATING INCOME
2019 ADJUSTMENTS

	Ad Valorem Taxes 15/	Payroll Taxes 16/	Income Tax Deductions & Adj. 17/	Deferred Income Taxes 18/	Subtotal	Projected 2019
Operating Revenues						
Sales					($3,628,861)	$22,499,641
Transportation					273,982	1,866,273
Other					(578,180)	239,165
Total Revenues					($3,933,059)	$24,605,079
Operating Expenses						
Operation & Maintenance						
Cost of Gas					($4,423,626)	$13,751,669
Other O&M					68,084	6,799,490
Total O&M	$0	$0	$0	$0	($4,355,542)	$20,551,159
Depreciation					296,005	2,607,088
Taxes Other Than Income	68,891	241			69,132	1,150,824
Current Income Taxes	(19,801)	(69)	(652,941)		(636,459)	(234,433)
Deferred Income Taxes				767,379	767,379	0
Total Expenses	$49,090	$172	($652,941)	$767,379	($3,859,485)	$24,074,638
Operating Income	($49,090)	($172)	$652,941	($767,379)	($73,574)	$530,441

15/ Schedule C-4, page 2.
16/ Schedule C-4, page 3.
17/ Schedule C-5, page 1.
18/ Schedule C-5, page 5.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SUMMARY OF OPERATING INCOME
2020 ADJUSTMENTS

	Projected 2019	Sales/Trans Revenue 1/	Other Revenue 1/	Labor 2/	Benefits 3/	Subcontract Labor 4/	Vehicles & Work Equip. 5/	Uncollectible 6/ Accounts
Operating Revenues								
Sales	$22,499,641	($546,765)						
Transportation	1,866,273	49,606						
Other	239,165		($1,392)					
Total Revenues	$24,605,079	($497,159)	($1,392)					
Operating Expenses								
Operation & Maintenance								
Cost of Gas	$13,751,669	$117,893						
Other O&M	6,799,490			$108,469	($7,618)	$10,001	$2,529	($2,635)
Total O&M	$20,551,159	$117,893	$0	$108,469	($7,618)	$10,001	$2,529	($2,635)
Depreciation	2,607,088							
Taxes Other Than Income	1,150,824							
Current Income Taxes	(234,433)	(176,778)	(400)	(31,176)	2,190	(2,875)	(727)	757
Deferred Income Taxes	0							
Total Expenses	$24,074,638	($58,885)	($400)	$77,293	($5,428)	$7,126	$1,802	($1,878)
Operating Income	$530,441	($438,274)	($992)	($77,293)	$5,428	($7,126)	($1,802)	$1,878

1/ Schedule C-1, page 1 and C-2, pages 3-4.
2/ Schedule C-2, page 10.
3/ Schedule C-2, page 13.
4/ Schedule C-2, page 14.
5/ Schedule C-2, page 15.
6/ Schedule C-2, page 16.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SUMMARY OF OPERATING INCOME
2020 ADJUSTMENTS

	CIP 7/	Software 8/ Maintenance	9/ Advertising	Industry Dues 10/	11/ Insurance	Reg. Comm. Expense 12/	All Other O&M 13/	Depreciation 14/
Operating Revenues								
Sales								
Transportation								
Other								
Total Revenues								
Operating Expenses								
Operation & Maintenance								
Cost of Gas								
Other O&M	$0	$50,474	$0	$0	$10,446	$16,889	$14,780	
Total O&M	$0	$50,474	$0	$0	$10,446	$16,889	$14,780	$0
Depreciation								218,474
Taxes Other Than Income								
Current Income Taxes	0	(14,507)	0	0	(3,004)	(4,854)	(4,248)	(62,794)
Deferred Income Taxes								
Total Expenses	$0	$35,967	$0	$0	$7,442	$12,035	$10,532	$155,680
Operating Income	$0	($35,967)	$0	$0	($7,442)	($12,035)	($10,532)	($155,680)

7/ Schedule C-2, page 17.
8/ Schedule C-2, page 18.
9/ Schedule C-2, page 19.
10/ Schedule C-2, page 20.
11/ Schedule C-2, page 21.
12/ Schedule C-2, page 22.
13/ Schedule C-2, page 23.
14/ Schedule C-3, page 1.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SUMMARY OF OPERATING INCOME
2020 ADJUSTMENTS

	Ad Valorem Taxes 15/	Payroll Taxes 16/	Income Tax Deductions & Adj. 17/	Subtotal	Projected 2020
Operating Revenues					
Sales				($546,765)	$21,952,876
Transportation				49,606	1,915,879
Other				(1,392)	237,773
Total Revenues				($498,551)	$24,106,528
Operating Expenses					
Operation & Maintenance					
Cost of Gas				$117,893	$13,869,562
Other O&M				203,335	7,002,825
Total O&M	$0	$0	$0	$321,228	$20,872,387
Depreciation				218,474	2,825,562
Taxes Other Than Income	71,032	7,452		78,484	1,229,308
Current Income Taxes	(20,416)	(2,142)	($35,435)	(356,409)	(590,842)
Deferred Income Taxes				0	0
Total Expenses	$50,616	$5,310	($35,435)	$261,777	$24,336,415
Operating Income	($50,616)	($5,310)	$35,435	($760,328)	($229,887)

15/ Schedule C-4, page 2.
16/ Schedule C-4, page 3.
17/ Schedule C-5, page 1.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY
INCOME STATEMENT
PROJECTED 2019 - 2020

	Projected 2019			Projected 2020		
	Total	MN	ND	Total	MN	ND
Operating Revenues						
Sales	$27,046,469	$22,499,641	$4,546,828	$26,554,419	$21,952,876	$4,601,543
Transportation	2,251,202	1,866,273	384,929	2,312,876	1,915,879	396,997
Other	271,647	239,165	32,482	270,255	237,773	32,482
Total Operating Revenues	$29,569,318	$24,605,079	$4,964,239	$29,137,550	$24,106,528	$5,031,022
Operating Expenses						
Operation and Maintenance						
Cost of Gas	$17,356,393	$13,751,669	$3,604,724	$17,516,616	$13,869,562	$3,647,054
Other O&M	7,523,151	6,799,490	723,661	7,737,312	7,002,825	734,487
Total O&M	$24,879,544	$20,551,159	$4,328,385	$25,253,928	$20,872,387	$4,381,541
Depreciation	2,884,188	2,607,088	277,100	3,116,304	2,825,562	290,742
Taxes Other Than Income	1,224,117	1,150,824	73,293	1,306,452	1,229,308	77,144
Income Taxes	(198,330)	(234,433)	36,103	(557,506)	(590,841)	33,335
Total Operating Expenses	$28,789,519	$24,074,638	$4,714,881	$29,119,178	$24,336,416	$4,782,762
Operating Income	$779,799	$530,441	$249,358	$18,372	($229,888)	$248,260
Average Rate Base	$32,746,323	$29,263,477	$3,482,846	$35,217,365	$31,686,174	$3,531,191
Rate of Return	2.381%	1.813%	7.160%	0.052%	-0.726%	7.030%

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SUMMARY OF CURRENT AND PROJECTED REVENUES
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

		Projected	
	2018	2019	2020
Sales 1/			
Residential	$12,590,027	$10,476,655	$10,145,514
Firm General	9,479,538	7,991,610	7,896,682
Small Interruptible	3,653,514	2,509,725	2,431,168
Large Interruptible	1,313,578	1,521,651	1,479,512
Unbilled Revenue	(508,155)		
Reserved Revenue	(400,000)		
Total Sales	$26,128,502	$22,499,641	$21,952,876
Transportation 1/			
Small Interruptible	$147,996	$121,904	$114,039
Large Interruptible	1,223,571	1,744,369	1,801,840
Unbilled Revenue	220,724		
Total Transportation	$1,592,291	$1,866,273	$1,915,879
Total Sales and Transportation	$27,720,793	$24,365,914	$23,868,755
Other Revenue 2/			
Miscellaneous Service Revenue	$46,148	$39,031	$39,031
Rent from Property	118,503	123,809	123,809
Other Revenue	652,694	76,325	74,933
Total Other Revenue	$817,345	$239,165	$237,773
Total Operating Revenue	$28,538,138	$24,605,079	$24,106,528

1/ Schedule C-1, pages 2-3.
2/ Schedule C-1, page 18.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SUMMARY OF REVENUES
TWELVE MONTHS ENDING DECEMBER 31, 2018

	Per Books		Per Books @ Current Rates		Weather Normalized	
	Dk	Revenue	Dk	Revenue 1/	Dk	Revenue 1/
Total Minnesota						
Sales						
Residential	1,597,215	$12,590,027	1,597,215	$10,868,865	1,514,897	$10,434,933
Firm General Service	1,345,854	9,479,538	1,430,080	8,541,120	1,293,901	7,846,340
Small Interruptible	700,567	3,653,514	535,091	2,484,537	537,690	2,509,725
Large Interruptible	299,507	1,313,578	417,590	1,553,553	405,970	1,521,651
Unbilled Revenue	0	(508,155)	0	0	0	0
Reserved Revenue	0	(400,000)	0	0	0	0
Total Sales	3,943,143	$26,128,502	3,979,976	$23,448,075	3,752,458	$22,312,649
Transportation						
Small Interruptible	98,986	$147,996	65,480	$95,386	85,118	$121,904
Large Interruptible	4,888,159	1,223,571	4,813,230	1,729,286	4,589,882	1,744,369
Unbilled Revenue		220,724				
Total Transportation	4,987,145	$1,592,291	4,878,710	$1,824,672	4,675,000	$1,866,273
Total Throughput	8,930,288	$27,720,793	8,858,686	$25,272,747	8,427,458	$24,178,922

1/ Rates effective May 1, 2019 and new base cost of gas.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SALES AND TRANSPORTATION REVENUE
PROJECTED 2019 - 2020

	Per Books @ Current Rates		Projected 2019		Projected 2020	
	Dk	Revenue 1/	Dk	Revenue 1/	Dk	Revenue 1/
Total Minnesota						
Sales						
Residential	1,597,215	$10,868,865	1,520,948	$10,476,655	1,527,457	$10,145,514
Firm General	1,430,080	8,541,120	1,317,966	7,991,610	1,342,053	7,896,682
Small Interruptible	535,091	2,484,537	537,690	2,509,725	537,690	2,431,168
Large Interruptible	417,590	1,553,553	405,970	1,521,651	405,970	1,479,512
Total Sales	3,979,976	$23,448,075	3,782,574	$22,499,641	3,813,170	$21,952,876
Transportation						
Small Interruptible	65,480	$95,386	85,118	$121,904	85,118	$114,039
Large Interruptible	4,813,230	1,729,286	4,589,882	1,744,369	4,589,882	1,801,840
Total Transportation	4,878,710	$1,824,672	4,675,000	$1,866,273	4,675,000	$1,915,879
Total Minnesota	8,858,686	$25,272,747	8,457,574	$24,365,914	8,488,170	$23,868,755

1/ Rates effective May 1, 2019 and new base cost of gas.

GREAT PLAINS NATURAL GAS CO.
MINNESOTA GAS UTILITY
Summary of Sales and Transportation Revenue
Projected Revenue for the
Twelve Months Ended December 31, 2020

				Projected 2020 Revenue				Cost of Gas				
	Rate	Billing Units	Dk	Basic Service Charge	Distribution Excl. CIP	CIP Base	GUIC	Demand	Commodity	Total	Total	Total Excl CIP Base
Residential	60	18,808.0	1,527,457	$1,692,720	$2,442,251	$124,946	$0	$1,860,137	$4,025,460	$5,885,597	$10,145,514	$10,020,568
Firm General												
Small Firm General	70	2,014.0	286,401	555,864	361,925	23,428	0	348,779	754,781	1,103,560	2,044,777	2,021,349
Large Firm General	70	1,064.0	1,055,652	363,888	1,334,027	86,352	0	1,285,573	2,782,065	4,067,638	5,851,905	5,765,553
Total Firm General		3,078.0	1,342,053	919,752	1,695,952	109,780	0	1,634,352	3,536,846	5,171,198	7,896,682	7,786,902
Total Firm		21,886.0	2,869,510	$2,612,472	$4,138,203	$234,726	$0	$3,494,489	$7,562,306	$11,056,795	$18,042,196	$17,807,470
Small Interruptible												
Sales	71	92.5	392,421	160,950	427,268	32,100	0	135,503	1,034,186	1,169,689	1,790,007	1,757,907
Sales - Grain Drying	71	21.9	145,269	38,106	158,169	11,883	0	50,161	382,842	433,003	641,161	629,278
Transportation	81	6.0	85,118	14,400	92,676	6,963	0				114,039	107,076
Total Small Interruptible		120.4	622,808	213,456	678,113	50,946	0	185,664	1,417,028	1,602,692	2,545,207	2,494,261
Large Interruptible												
Sales	85	7.0	359,600	19,320	187,244	29,415	0	124,170	947,690	1,071,860	1,307,839	1,278,424
Sales - Grain Drying	85	2.0	46,370	5,520	24,145	3,793	0	16,012	122,203	138,215	171,673	167,880
Transportation	82	10.0	2,328,400	31,200	1,212,398	62,487	0				1,306,085	1,243,598
Transportation-Flex		3.0	2,261,482	9,360	301,406	184,989					495,755	310,766
Total Large Interruptible		22.0	4,995,852	65,400	1,725,193	280,684	0	140,182	1,069,893	1,210,075	3,281,352	3,000,668
Total Interruptible		142.4	5,618,660	$278,856	$2,403,306	$331,630	$0	$325,846	$2,486,921	$2,812,767	$5,826,559	$5,494,929
Total Minnesota		22,028.4	8,488,170	$2,891,328	$6,541,509	$566,356	$0	$3,820,335	$10,049,227	$13,869,562	$23,868,755	$23,302,399
Total Sales		22,009.4	3,813,170	2,836,368	4,935,029	311,917	0	3,820,335	10,049,227	13,869,562	21,952,876	21,640,959
Total Transportation		19.0	4,675,000	54,960	1,606,480	254,439	0				1,915,879	1,661,440

GREAT PLAINS NATURAL GAS CO.
MINNESOTA GAS UTILITY
Summary of Sales and Transportation Revenue
Projected Revenue for the
Twelve Months Ended December 31, 2019

				Projected 2019 Revenue								
		Billing		Basic Service	Distribution	CIP		Cost of Gas				Total Excl
	Rate	Units	Dk	Charge	Excl. CIP	Base	GUIC	Demand	Commodity	Total	Total	CIP Base
Residential	60	18,732.0	1,520,948	$1,685,880	$2,431,844	$124,414	$374,001	$1,852,210	$4,008,306	$5,860,516	$10,476,655	$10,352,241
Firm General												
Small Firm General	70	1,986.0	282,421	548,136	356,895	23,102	50,384	343,932	744,292	1,088,224	2,066,741	2,043,639
Large Firm General	70	1,042.0	1,035,545	356,364	1,308,618	84,708	184,741	1,261,087	2,729,075	3,990,162	5,924,593	5,839,885
Total Firm General		3,028.0	1,317,966	904,500	1,665,513	107,810	235,125	1,605,019	3,473,367	5,078,386	7,991,334	7,883,524
Total Firm		21,760.0	2,838,914	$2,590,380	$4,097,357	$232,224	$609,126	$3,457,229	$7,481,673	$10,938,902	$18,467,989	$18,235,765
Small Interruptible												
Sales	71	92.5	392,421	160,950	427,268	32,100	57,333	135,503	1,034,186	1,169,689	1,847,340	1,815,240
Sales - Grain Drying	71	21.9	145,269	38,106	158,169	11,883	21,224	50,161	382,842	433,003	662,385	650,502
Transportation	81	6.0	85,118	14,400	92,676	6,963	7,865				121,904	114,941
Total Small Interruptible		120.4	622,808	213,456	678,113	50,946	86,422	185,664	1,417,028	1,602,692	2,631,629	2,580,683
Large Interruptible												
Sales	85	7.0	359,600	19,320	187,244	29,415	37,326	124,170	947,690	1,071,860	1,345,165	1,315,750
Sales - Grain Drying	85	2.0	46,370	5,520	24,145	3,793	4,813	16,012	122,203	138,215	176,486	172,693
Transportation	82	8.0	763,905	24,960	397,765	62,487	15,278				500,490	438,003
Transportation-Flex		5.0	3,825,977	15,600	1,043,290	184,989					1,243,879	1,058,890
Total Large Interruptible		22.0	4,995,852	65,400	1,652,444	280,684	57,417	140,182	1,069,893	1,210,075	3,266,020	2,985,336
Total Interruptible		142.4	5,618,660	$278,856	$2,330,557	$331,630	$143,839	$325,846	$2,486,921	$2,812,767	$5,897,649	$5,566,019
Total Minnesota		21,902.4	8,457,574	$2,869,236	$6,427,914	$563,854	$752,965	$3,783,075	$9,968,594	$13,751,669	$24,365,638	$23,801,784
Total Sales		21,883.4	3,782,574	2,814,276	4,894,183	309,415	729,822	3,783,075	9,968,594	13,751,669	22,499,365	22,189,950
Total Transportation		19.0	4,675,000	54,960	1,533,731	254,439	23,143				1,866,273	1,611,834

GREAT PLAINS NATURAL GAS CO.
MINNESOTA GAS UTILITY
Summary of Sales and Transportation Revenue
Per Books Normalized for the
Twelve Months Ended December 31, 2018

				Normalized Revenue									
								Cost of Gas					
	Rate	Billing Units	Dk	Basic Service Charge	Distribution Excl. CIP	CIP Base	GUIC	Demand	Commodity	Total	Total	Total Excl CIP Base
Residential	60	18,657.0	1,514,897	$1,679,130	$2,422,169	$123,919	$372,513	$1,844,842	$3,992,360	$5,837,202	$10,434,933	$10,311,014
Firm General												
Small Firm General	70	1,959.0	278,463	540,684	351,894	22,778	49,678	339,112	733,861	1,072,973	2,038,007	2,015,229
Large Firm General	70	1,019.0	1,015,438	348,498	1,283,209	83,063	181,154	1,236,600	2,676,085	3,912,685	5,808,609	5,725,546
Total Firm General		2,978.0	1,293,901	889,182	1,635,103	105,841	230,832	1,575,712	3,409,946	4,985,658	7,846,616	7,740,775
Total Firm		21,635.0	2,808,798	$2,568,312	$4,057,272	$229,760	$603,345	$3,420,554	$7,402,306	$10,822,860	$18,281,549	$18,051,789
Small Interruptible												
Sales	71	92.5	392,421	160,950	427,268	32,100	57,333	135,503	1,034,186	1,169,689	1,847,340	1,815,240
Sales - Grain Drying	71	21.9	145,269	38,106	158,169	11,883	21,224	50,161	382,842	433,003	662,385	650,502
Transportation	81	6.0	85,118	14,400	92,676	6,963	7,865				121,904	114,941
Total Small Interruptible		120.4	622,808	213,456	678,113	50,946	86,422	185,664	1,417,028	1,602,692	2,631,629	2,580,683
Large Interruptible												
Sales	85	7.0	359,600	19,320	187,244	29,415	37,326	124,170	947,690	1,071,860	1,345,165	1,315,750
Sales - Grain Drying	85	2.0	46,370	5,520	24,145	3,793	4,813	16,012	122,203	138,215	176,486	172,693
Transportation	82	8.0	763,905	24,960	397,765	62,487	15,278				500,490	438,003
Transportation-Flex		5.0	3,825,977	15,600	1,043,290	184,989					1,243,879	1,058,890
Total Large Interruptible		22.0	4,995,852	65,400	1,652,444	280,684	57,417	140,182	1,069,893	1,210,075	3,266,020	2,985,336
Total Interruptible		142.4	5,618,660	$278,856	$2,330,557	$331,630	$143,839	$325,846	$2,486,921	$2,812,767	$5,897,649	$5,566,019
Total Minnesota		21,777.4	8,427,458	$2,847,168	$6,387,829	$561,390	$747,184	$3,746,400	$9,889,227	$13,635,627	$24,179,198	$23,617,808
Total Sales		21,758.4	3,752,458	2,792,208	4,854,098	306,951	724,041	3,746,400	9,889,227	13,635,627	22,312,925	22,005,974
Total Transportation		19.0	4,675,000	54,960	1,533,731	254,439	23,143				1,866,273	1,611,834

Great Plains Natural Gas Co.
Gas Utility - Minnesota
Summary of Sales and Transportation Revenue
Per Books at Current Rates for the
Twelve Months Ended December 31, 2018

				Revenue @ Current Rates								
								Cost of Gas				
	Rate	Billing Units	Dk	Basic Service Charge	Distribution Excl. CIP	CIP Base	GUIC	Demand	Commodity	Total	Total	Total Excl CIP Base
Residential	60	18,657.0	1,597,215	$1,679,130	$2,553,787	$88,805	$392,755	$1,945,088	$4,209,300	$6,154,388	$10,868,865	$10,780,060
Firm General												
Small Firm General	70	1,959.0	313,208	540,684	395,801	17,414	55,876	381,425	825,428	1,206,853	2,216,628	2,199,214
Large Firm General	70	1,019.0	1,116,872	348,498	1,411,391	62,098	199,250	1,360,127	2,943,404	4,303,531	6,324,768	6,262,670
Total Firm General		2,978.0	1,430,080	889,182	1,807,192	79,512	255,126	1,741,552	3,768,832	5,510,384	8,541,396	8,461,884
Total Firm		21,635.0	3,027,295	$2,568,312	$4,360,979	$168,317	$647,881	$3,686,640	$7,978,132	$11,664,772	$19,410,261	$19,241,944
Small Interruptible												
Sales	71	92.5	395,237	160,950	430,334	21,975	57,744	136,475	1,041,608	1,178,083	1,849,086	1,827,111
Sales - Grain Drying	71	21.9	139,854	38,106	152,273	7,776	20,433	48,292	368,571	416,863	635,451	627,675
Transportation	81	6.0	65,480	14,400	71,295	3,641	6,050				95,386	91,745
Total Small Interruptible		120.4	600,571	213,456	653,902	33,392	84,227	184,767	1,410,179	1,594,946	2,579,923	2,546,531
Large Interruptible												
Sales	85	7.0	358,162	19,320	186,495	19,914	37,177	123,673	943,900	1,067,573	1,330,479	1,310,565
Sales - Grain Drying	85	2.0	59,428	5,520	30,944	3,304	6,169	20,520	156,617	177,137	223,074	219,770
Transportation	82	8.0	777,872	24,960	405,038	43,250	15,557				488,805	445,555
Transportation-Flex		5.0	4,035,358	15,600	1,090,985	133,896					1,240,481	1,106,585
Total Large Interruptible		22.0	5,230,820	65,400	1,713,462	200,364	58,903	144,193	1,100,517	1,244,710	3,282,839	3,082,475
Total Interruptible		142.4	5,831,391	$278,856	$2,367,364	$233,756	$143,130	$328,960	$2,510,696	$2,839,656	$5,862,762	$5,629,006
Total Minnesota		21,777.4	8,858,686	$2,847,168	$6,728,343	$402,073	$791,011	$4,015,600	$10,488,828	$14,504,428	$25,273,023	$24,870,950
Total Sales		21,758.4	3,979,976	2,792,208	5,161,025	221,286	769,404	4,015,600	10,488,828	14,504,428	23,448,351	23,227,065
Total Transportation		19.0	4,878,710	54,960	1,567,318	180,787	21,607				1,824,672	1,643,885

Great Plains Natural Gas Co.
Gas Utility - Minnesota
Summary of Sales and Transportation Revenue
Per Books for the
Twelve Months Ended December 31, 2018

				Per Books Revenue						
					Distribution Charge					
Rate Class	Rate	Billing Units	Dk	Basic Service Charge	Distribution Excl. CIP Base & Riders	Revenue Decoupling	GUIC	Total Distribution	Cost of Gas	Total
Sales										
Residential										
North	N60	8,448.0	749,383	$756,995	$1,299,398	$184,037	$218,958	$1,702,393	$3,564,641	$6,024,029
South	S60	10,209.0	847,832	913,563	1,228,243	147,760	248,966	1,624,969	4,027,466	6,565,998
Total Residential		18,657.0	1,597,215	1,670,558	2,527,641	331,797	467,924	3,327,362	7,592,107	12,590,027
Small Firm General										
North	N70	817.0	134,129	224,159	177,617	28,469	36,342	242,428	639,562	1,106,149
South	S70	1,141.0	176,714	313,823	196,629	31,005	47,443	275,077	842,053	1,430,953
Total Small Firm General		1,958.0	310,843	537,982	374,246	59,474	83,785	517,505	1,481,615	2,537,102
Large Firm General										
North	N70	434.0	418,065	148,171	560,022	92,293	105,196	757,511	1,973,213	2,878,895
South	S70	585.0	616,946	199,762	700,292	109,298	152,281	961,871	2,901,908	4,063,541
Total Large Firm General		1,019.0	1,035,011	347,933	1,260,314	201,591	257,477	1,719,382	4,875,121	6,942,436
Total Firm		2,977.0	1,345,854	885,915	1,634,560	261,065	341,262	2,236,887	6,356,736	9,479,538
Small Interruptible										
North	N71		336,871	99,460	360,404	32,547	61,378	454,329	1,240,137	1,793,926
South	S71		363,696	104,072	389,369	16,032	59,298	464,699	1,290,817	1,859,588
Total Small Interruptible		119.8	700,567	203,532	749,773	48,579	120,676	919,028	2,530,954	3,653,514
Large Interruptible										
North	N85	4.0	230,002	11,040	187,332	25,586	28,482	241,400	795,991	1,048,431
South	S85	1.0	69,505	2,760	25,365	(9,815)	10,710	26,260	236,127	265,147
Total Large Interruptible		5.0	299,507	13,800	212,697	15,771	39,192	267,660	1,032,118	1,313,578
Total Interruptible		124.8	1,000,074	217,332	962,470	64,350	159,868	1,186,688	3,563,072	4,967,092
Total Sales		21,758.8	3,943,143	2,773,805	5,124,671	657,212	969,054	6,750,937	17,511,915	27,036,657

Great Plains Natural Gas Co.
Gas Utility - Minnesota
Summary of Sales and Transportation Revenue
Per Books for the
Twelve Months Ended December 31, 2018

				Per Books Revenue						
					Distribution Charge					
Rate Class	Rate	Billing Units	Dk	Basic Service Charge	Distribution Excl. CIP Base & Riders	Revenue Decoupling	GUIC	Total Distribution	Cost of Gas	Total
Transportation										
Small Interruptible										
North	N81	5.0	77,164	11,200	80,429	7,176	14,633	102,238		113,438
South	S81	3.0	21,822	7,200	21,854	895	4,609	27,358		34,558
Total Small Interruptible		8.0	98,986	18,400	102,283	8,071	19,242	129,596		147,996
Large Interruptible										
North	N82	1.0	81,861	3,120	64,521	8,982	10,017	83,520		86,640
South	S82	5.0	703,122	15,600	241,701	(99,087)	100,843	243,457		259,057
North Flex		4.0	2,348,013	12,480	756,728			756,728		769,208
South Flex		2.0	1,755,163	6,240	254,479	(152,053)		102,426		108,666
Total Large Interruptible		12.0	4,888,159	37,440	1,317,429	(242,158)	110,860	1,186,131		1,223,571
Total Transportation		20.0	4,987,145	$55,840	$1,419,712	($234,087)	$130,102	$1,315,727		$1,371,567
Total Minnesota		21,778.8	8,930,288	$2,829,645	$6,544,383	$423,125	$1,099,156	$8,066,664	$17,511,915	$28,408,224

Great Plains Natural Gas Co.
Gas Utility - Minnesota
Rate Schedules Effective with Service Rendered on and after July 1, 2019
New Base Cost of Gas - Projected 2019 and 2020

	Rate	Basic Service	Distribution Charge per Tariff 1/					Proposed Cost of Gas				GUIC
				CIP Base 4/		Total Charge						Excl
	Designation	Charge 1/	Margin	Current	*Proposed*	Current	*Proposed*	Demand	Commodity	Total 2/	GUIC 3/	Deferred
North District												
Residential Gas Service	N60	$7.50	$1.5989	$0.0556	0.0818	1.6545	1.6807	$1.2178	2.6354	$3.8532	$0.2494	$0.2459
Firm General Service (meters < 500 cubic feet/hr)	N70	23.00	1.2637	0.0556	0.0818	1.3193	1.3455	1.2178	2.6354	3.8532	0.1792	0.1784
Firm General Service (meters > 500 cubic feet/hr)	N70	28.50	1.2637	0.0556	0.0818	1.3193	1.3455	1.2178	2.6354	3.8532	0.1792	0.1784
Small Int Gas Sales Service	N71	145.00	1.0888	0.0556	0.0818	1.1444	1.1706	0.3453	2.6354	2.9807	0.1519	0.1461
Small Int General Gas Trans Service	N81	200.00	1.0888	0.0556	0.0818	1.1444	1.1706				0.0791	0.0924
Large Int General Gas Trans Service	N82	260.00	0.5207	0.0556	0.0818	0.5763	0.6025				0.0105	0.0200
Large Int Gas Sales Service	N85	230.00	0.5207	0.0556	0.0818	0.5763	0.6025	0.3453	2.6354	2.9807	0.1103	0.1038
South District												
Residential Gas Service	S60	$7.50	$1.5989	$0.0556	0.0818	1.6545	1.6807	$1.2178	2.6354	$3.8532	$0.2494	$0.2459
Firm General Service (meters < 500 cubic feet/hr)	S70	23.00	1.2637	0.0556	0.0818	1.3193	1.3455	1.2178	2.6354	3.8532	0.1792	0.1784
Firm General Service (meters > 500 cubic feet/hr)	S70	28.50	1.2637	0.0556	0.0818	1.3193	1.3455	1.2178	2.6354	3.8532	0.1792	0.1784
Small Int Gas Sales Service	S71	145.00	1.0888	0.0556	0.0818	1.1444	1.1706	0.3453	2.6354	2.9807	0.1519	0.1461
Small Int General Gas Trans Service	S81	200.00	1.0888	0.0556	0.0818	1.1444	1.1706				0.0791	0.0924
Large Int General Gas Trans Service	S82	260.00	0.5207	0.0556	0.0818	0.5763	0.6025				0.0105	0.0200
Large Int Gas Sales Service	S85	230.00	0.5207	0.0556	0.0818	0.5763	0.6025	0.3453	2.6354	2.9807	0.1103	0.1038
Large Int Flexible Trans	TF1	260.00	0.6944	0.0556	0.0818	0.7500	$0.7762					
Large Int Flexible Trans	TF2	260.00	0.0900	0.0556	0.0818	0.1456	$0.1718					
Large Int Flexible Trans	TF3	260.00	0.1700	0.0556	0.0818	0.2256	$0.2518					
Large Int Flexible Trans	TF4	260.00	0.4742	0.0000	0.0000	0.4742	$0.4742					
Large Int Flexible Trans	TF5	260.00	0.1350	0.0556	0.0818	0.1906	$0.2168					

1/ Effective with service rendered on and after May 1, 2019 - Docket No. E,G-999/CI-17-895.
2/ Proposed base cost of gas from Schedule C-2, page 9.
3/ Effective with service rendered on and after March 1, 2019 - Docket No. G004/M-18-282.
4/ Proposed CIP Base Rate calculation:

		$566,621	CIP O&M from Schedule C-2, page16
Projected 2020 Dk	8,488,170		
Less CIP exempt Dk	1,564,495	6,923,675	Divided by Projected 2020 CIP Dk
		$0.0818	Proposed CIP Base Rate

Great Plains Natural Gas Co.
Gas Utility - Minnesota
Twelve Months Ended December 31, 2018 and Projected 2019 and 2020
RESIDENTIAL GAS SERVICE

			Per Books @ Current Rates		Normalized		Projected 2019		Projected 2020	
Residential Rates N60 and S60	Rates 1/ 2/		Billing Units	Revenue	Billing Units	Revenue	Billing Units	Revenue	Billing Units	Revenue
Basic Service Charge	$7.50	per month	18,657	$1,679,130	18,657	$1,679,130	18,732	$1,685,880	18,808	$1,692,720
Distribution-Excl. CIP	1.5989	per dk	1,597,215	2,553,787	1,514,897	2,422,169	1,520,948	2,431,844	1,527,457	2,442,251
CIP Base	0.0556	per dk	1,597,215	88,805						
Projected - CIP Base	0.0818	per dk			1,514,897	123,919	1,520,948	124,414	1,527,457	124,946
Projected Cost of Gas - Demand	1.2178	per dk	1,597,215	1,945,088	1,514,897	1,844,842	1,520,948	1,852,210	1,527,457	1,860,137
Projected Cost of Gas - Commodity	2.6354	per dk	1,597,215	4,209,300	1,514,897	3,992,360	1,520,948	4,008,306	1,527,457	4,025,460
GUIC 3/	0.2459	per dk	1,597,215	392,755	1,514,897	372,513	1,520,948	374,001		
Total Revenue - Residential			1,597,215	$10,868,865	1,514,897	$10,434,933	1,520,948	$10,476,655	1,527,457	$10,145,514

1/ Basic Service Charges and Distribution Charges effective with service rendered on and after May 1, 2019. New base cost of gas reflective of Projected 2020 gas costs.
2/ GUIC rate effective March 1, 2019, excluding the surcharge.
3/ To coincide with projected implementation of interim rates, the projected 2020 GUIC rate is set to zero. All GUIC projects will be included in interim revenue requirement.

GREAT PLAINS NATURAL GAS CO.
MINNESOTA GAS UTILITY
Twelve Months Ended December 31, 2018 and Projected 2019 and 2020
SMALL AND LARGE FIRM GENERAL GAS SERVICE

Firm General Rates		Per Books @ Current Rates		Normalized		Projected 2019		Projected 2020	
N70 and S70	Rates 1/ 2/	Billing Units	Revenue	Billing Units	Revenue	Billing Units	Revenue	Billing Units	Revenue
Basic Service Charge< 500	$23.00 per month	1,959	$540,684	1,959	$540,684	1,986	$548,136	2,014	$555,864
Basic Service Charge > 500	$28.50 per month	1,019	348,498	1,019	348,498	1,042	356,364	1,064	363,888
Total Basic Service Charge		2,978	889,182	2,978	889,182	3,028	904,500	3,078	919,752
Distribution-Excl. CIP < 500		313,208	395,801	278,463	351,894	282,421	356,895	286,401	361,925
Distribution-Excl. CIP > 500		1,116,872	1,411,391	1,015,438	1,283,209	1,035,545	1,308,618	1,055,652	1,334,027
Distribution-Excl. CIP	1.2637 per dk	1,430,080	1,807,192	1,293,901	1,635,103	1,317,966	1,665,513	1,342,053	1,695,952
CIP Base < 500		313,208	17,414						
CIP Base > 500		1,116,872	62,098						
CIP Base	0.0556 per dk	1,430,080	79,512						
Projected - CIP Base < 500				278,463	22,778	282,421	23,102	286,401	23,428
Projected - CIP Base > 500				1,015,438	83,063	1,035,545	84,708	1,055,652	86,352
Projected - CIP Base	0.0818 per dk			1,293,901	105,841	1,317,966	107,810	1,342,053	109,780
Projected - Cost of Gas - Demand < 500		313,208	381,425	278,463	339,112	282,421	343,932	286,401	348,779
Projected - Cost of Gas - Demand > 500		1,116,872	1,360,127	1,015,438	1,236,600	1,035,545	1,261,087	1,055,652	1,285,573
Projected Cost of Gas - Demand	1.2178 per dk	1,430,080	1,741,552	1,293,901	1,575,712	1,317,966	1,605,019	1,342,053	1,634,352
Projected - Cost of Gas - Commodity < 500		313,208	825,428	278,463	733,861	282,421	744,292	286,401	754,781
Projected - Cost of Gas - Commodity > 500		1,116,872	2,943,404	1,015,438	2,676,085	1,035,545	2,729,075	1,055,652	2,782,065
Projected Cost of Gas - Commodity	2.6354 per dk	1,430,080	3,768,832	1,293,901	3,409,946	1,317,966	3,473,367	1,342,053	3,536,846
GUIC < 500 3/		313,208	55,876	278,463	49,678	282,421	50,384		
GUIC > 500 3/		1,116,872	199,250	1,015,438	181,154	1,035,545	184,741		
GUIC 3/	0.1784 per dk	1,430,080	255,126	1,293,901	230,832	1,317,966	235,125		
Total Small Meters		313,208	$2,216,628	278,463	$2,038,007	282,421	$2,066,741	286,401	$2,044,777
Total Large Meters		1,116,872	6,324,768	1,015,438	5,808,609	1,035,545	5,924,593	1,055,652	5,851,905
Total Firm General Service		1,430,080	$8,541,396	1,293,901	$7,846,616	1,317,966	$7,991,334	1,342,053	$7,896,682

1/ Basic Service Charges and Distribution Charges effective with service rendered on and after May 1, 2019. New base cost of gas reflective of Projected 2020 gas costs.
2/ GUIC rate effective March 1, 2019, excluding the surcharge.
3/ To coincide with projected implementation of interim rates, the projected 2020 GUIC rate is set to zero. All GUIC projects will be included in interim revenue requirement.

GREAT PLAINS NATURAL GAS CO.
MINNESOTA GAS UTILITY
Twelve Months Ended December 31, 2018 and Projected 2019 and 2020
SMALL INTERRUPTIBLE SALES AND TRANSPORTATION GAS SERVICE

Small Interruptible Rates N71, S71, N81, and S81	Rates 1/ 2/		Per Books @ Current Rates Billing Units	Per Books @ Current Rates Revenue	Normalized Billing Units	Normalized Revenue	Projected 2019 Billing Units	Projected 2019 Revenue	Projected 2020 Billing Units	Projected 2020 Revenue
Small Interruptible										
Basic Service Charge - Sales	$145.00	per month	92.5	$160,950	92.5	$160,950	92.5	$160,950	92.5	$160,950
Basic Service Charge - Transport	200.00	per month	6.0	14,400	6.0	14,400	6.0	14,400	6.0	14,400
Total Basic Service Charge			98.5	175,350	98.5	175,350	98.5	175,350	98.5	175,350
Distribution-Excl. CIP - Sales	1.0888	per dk	395,237	430,334	392,421	427,268	392,421	427,268	392,421	427,268
Distribution-Excl. CIP - Transport	1.0888	per dk	65,480	71,295	85,118	92,676	85,118	92,676	85,118	92,676
Total Distribution-Excl. CIP			460,717	501,629	477,539	519,944	477,539	519,944	477,539	519,944
CIP Base - Sales	0.0556	per dk	395,237	21,975						
CIP Base - Transport	0.0556	per dk	65,480	3,641						
Total CIP Base			460,717	25,616						
Projected CIP Base - Sales	0.0818	per dk			392,421	32,100	392,421	32,100	392,421	32,100
Projected CIP Base - Transport	0.0818	per dk			85,118	6,963	85,118	6,963	85,118	6,963
Total Projected - CIP Base					477,539	39,063	477,539	39,063	477,539	39,063
Projected Cost of Gas - Demand	0.3453	per dk	395,237	136,475	392,421	135,503	392,421	135,503	392,421	135,503
Projected Cost of Gas - Commodity	2.6354	per dk	395,237	1,041,608	392,421	1,034,186	392,421	1,034,186	392,421	1,034,186
GUIC - Sales 3/	0.1461	per dk	395,237	57,744	392,421	57,333	392,421	57,333		
GUIC - Transport 3/	0.0924	per dk	65,480	6,050	85,118	7,865	85,118	7,865		
Total GUIC 3/			460,717	63,794	477,539	65,198	477,539	65,198		
Total Sales			395,237	$1,849,086	392,421	$1,847,340	392,421	$1,847,340	392,421	$1,790,007
Total Transport			65,480	95,386	85,118	121,904	85,118	121,904	85,118	114,039
Total Small Interruptible			460,717	$1,944,472	477,539	$1,969,244	477,539	$1,969,244	477,539	$1,904,046

1/ Basic Service Charges and Distribution Charges effective with service rendered on and after May 1, 2019. New base cost of gas reflective of Projected 2020 gas costs.
2/ GUIC rate effective March 1, 2019, excluding the surcharge.
3/ To coincide with projected implementation of interim rates, the projected 2020 GUIC rate is set to zero. All GUIC projects will be included in interim revenue requirement.

GREAT PLAINS NATURAL GAS CO.
MINNESOTA GAS UTILITY
Twelve Months Ended December 31, 2018 and Projected 2019 and 2020
SMALL INTERRUPTIBLE - GRAIN DRYING SALES

Small Interruptible Rates - Grain Drying N71 and S71	Rates 1/ 2/		Per Books @ Current Rates Billing Units	Per Books @ Current Rates Revenue	Normalized Billing Units	Normalized Revenue	Projected 2019 Billing Units	Projected 2019 Revenue	Projected 2020 Billing Units	Projected 2020 Revenue
Small Interruptible										
Basic Service Charge - Sales	$145.00	per month	21.9	$38,106	21.9	$38,106	21.9	$38,106	21.9	$38,106
Distribution-Excl. CIP - Sales	1.0888	per dk	139,854	152,273	145,269	158,169	145,269	158,169	145,269	158,169
CIP Base - Sales	0.0556	per dk	139,854	7,776						
Projected CIP Base - Sales	0.0818	per dk			145,269	11,883	145,269	11,883	145,269	11,883
Projected Cost of Gas - Demand	0.3453	per dk	139,854	48,292	145,269	50,161	145,269	50,161	145,269	50,161
Projected Cost of Gas - Commodity	2.6354	per dk	139,854	368,571	145,269	382,842	145,269	382,842	145,269	382,842
GUIC - Sales 3/	0.1461	per dk	139,854	20,433	145,269	21,224	145,269	21,224		
Total Small Interruptible - Grain Drying			139,854	$635,451	145,269	$662,385	145,269	$662,385	145,269	$641,161

1/ Basic Service Charges and Distribution Charges effective with service rendered on and after May 1, 2019. New base cost of gas reflective of Projected 2020 gas costs.
2/ GUIC rate effective March 1, 2019, excluding the surcharge.
3/ To coincide with projected implementation of interim rates, the projected 2020 GUIC rate is set to zero. All GUIC projects will be included in interim revenue requirement.

Great Plains Natural Gas Co.
Gas Utility - Minnesota
Twelve Months Ended December 31, 2018 and Projected 2019 and 2020
LARGE INTERRUPTIBLE SALES AND TRANSPORTATION GAS SERVICE

			Per Books @ Current Rates		Normalized		Projected 2019		Projected 2020		
Large Interruptible Rates N82, S82, N85, and S85	Rates 1/ 2/		Billing Units	Revenue	Billing Units	Revenue	Billing Units	Revenue	Billing Units		Revenue
Large IT @ Maximum Rate											
Basic Service Charge - Sales	$230.00	per month	7	$19,320	7	$19,320	7	$19,320	7		$19,320
Basic Service Charge - Transport	260.00	per month	8	24,960	8	24,960	8	24,960	10	3/	31,200
Total Basic Service Charge			15	44,280	15	44,280	15	44,280	17		50,520
Distribution-Excl. CIP - Sales	0.5207	per dk	358,162	186,495	359,600	187,244	359,600	187,244	359,600		187,244
Distribution-Excl. CIP - Transport	0.5207	per dk	777,872	405,038	763,905	397,765	763,905	397,765	2,328,400	3/	1,212,398
Total Distribution-Excl. CIP			1,136,034	591,533	1,123,505	585,009	1,123,505	585,009	2,688,000		1,399,642
CIP Base - Sales	0.0556	per dk	358,162	19,914							
CIP Base - Transport	0.0556	per dk	777,872	43,250							
Total CIP Base			1,136,034	63,164							
Projected CIP Base - Sales	0.0818	per dk			359,600	29,415	359,600	29,415	359,600		29,415
Projected CIP Base - Transport	0.0818	per dk			763,905	62,487	763,905	62,487	763,905	4/	62,487
Total Projected - CIP Base					1,123,505	91,902	1,123,505	91,902	1,123,505		91,902
Projected Cost of Gas - Demand	0.3453	per dk	358,162	123,673	359,600	124,170	359,600	124,170	359,600		124,170
Projected Cost of Gas - Commodity	2.6354	per dk	358,162	943,900	359,600	947,690	359,600	947,690	359,600		947,690
GUIC - Sales 5/	0.1038	per dk	358,162	37,177	359,600	37,326	359,600	37,326			
GUIC - Transport 5/	0.0200	per dk	777,872	15,557	763,905	15,278	763,905	15,278			
Total GUIC 5/			1,136,034	52,734	1,123,505	52,604	1,123,505	52,604			
Total Sales			358,162	$1,330,479	359,600	$1,345,165	359,600	$1,345,165	359,600		$1,307,839
Total Transport			777,872	488,805	763,905	500,490	763,905	500,490	2,328,400		1,306,085
Total Large IT @ Maximum Rate			1,136,034	$1,819,284	1,123,505	$1,845,655	1,123,505	$1,845,655	2,688,000		$2,613,924

Great Plains Natural Gas Co.
Gas Utility - Minnesota
Twelve Months Ended December 31, 2018 and Projected 2019 and 2020
LARGE INTERRUPTIBLE SALES AND TRANSPORTATION GAS SERVICE

Large Interruptible Rates		Per Books @ Current Rates		Normalized		Projected 2019		Projected 2020	
N82, S82, N85, and S85	Rates 1/ 2/	Billing Units	Revenue	Billing Units	Revenue	Billing Units	Revenue	Billing Units	Revenue
Large IT - Flex Rate Contracts									
Basic Service Charge - Transport	260.00 per month	5	$15,600	5	$15,600	5	$15,600	3 3/	$9,360
Distribution-Excl. CIP - Transport									
TF-2	0.0900 per dk	653,043	58,774	596,861	53,717	596,861	53,717	596,861	53,717
TF-3	0.1700 per dk	676,278	114,967	656,155	111,546	656,155	111,546	656,155	111,546
TF-4	0.4742 per dk	1,627,152	771,595	1,564,495	741,884	1,564,495	741,884	3/	
TF-5	0.1350 per dk	1,078,885	145,649	1,008,466	136,143	1,008,466	136,143	1,008,466	136,143
Total Distribution-Excl. CIP		4,035,358	1,090,985	3,825,977	1,043,290	3,825,977	1,043,290	2,261,482	301,406
CIP Base - Transport 4/	0.0556 per dk	2,408,206	133,896						
Projected CIP Base - Transport 4/	0.0818 per dk			2,261,482	184,989	2,261,482	184,989	2,261,482	184,989
Total Large IT @ Flex Rate Contracts		4,035,358	$1,240,481	3,825,977	$1,243,879	3,825,977	$1,243,879	2,261,482	$495,755
Total Sales		358,162	$1,330,479	359,600	$1,345,165	359,600	$1,345,165	359,600	$1,307,839
Total Transport		4,813,230	1,729,286	4,589,882	1,744,369	4,589,882	1,744,369	4,589,882	1,801,840
Total Large IT		5,171,392	$3,059,765	4,949,482	$3,089,534	4,949,482	$3,089,534	4,949,482	$3,109,679

1/ Basic Service Charges and Distribution Charges effective with service rendered on and after May 1, 2019. New base cost of gas reflective of Projected 2020 gas costs.
2/ GUIC rate effective March 1, 2019, excluding the surcharge.
3/ Per contract, July 1, 2020 customer TF-4 will be at N82 Maximum Tariff Rate less CIP Base.
4/ Customer TF-4 is CIP Exempt.
5/ To coincide with projected implementation of interim rates, the projected 2020 GUIC rate is set to zero. All GUIC projects will be included in interim revenue requirement.

Great Plains Natural Gas Co.
Gas Utility - Minnesota
Twelve Months Ended December 31, 2018 and Projected 2019 and 2020
LARGE INTERRUPTIBLE-GRAIN DRYING SALES

Large IT Rates - Grain Drying N85 and S85	Rates 1/ 2/		Per Books @ Current Rates Billing Units	Per Books @ Current Rates Revenue	Normalized Billing Units	Normalized Revenue	Projected 2019 Billing Units	Projected 2019 Revenue	Projected 2020 Billing Units	Projected 2020 Revenue
Large IT - Grain Drying										
Basic Service Charge - Sales	$230.00	per month	2	$5,520	2	$5,520	2	$5,520	2	$5,520
Distribution-Excl. CIP - Sales	0.5207	per dk	59,428	30,944	46,370	24,145	46,370	24,145	46,370	24,145
CIP Base - Sales	0.0556	per dk	59,428	3,304						
Projected CIP Base - Sales	0.0818	per dk			46,370	3,793	46,370	3,793	46,370	3,793
Projected Cost of Gas - Demand	0.3453	per dk	59,428	20,520	46,370	16,012	46,370	16,012	46,370	16,012
Projected Cost of Gas - Commodity	2.6354	per dk	59,428	156,617	46,370	122,203	46,370	122,203	46,370	122,203
GUIC - Sales 3/	0.1038	per dk	59,428	6,169	46,370	4,813	46,370	4,813		
Total Large IT - Grain Drying			59,428	$223,074	46,370	$176,486	46,370	$176,486	46,370	$171,673

1/ Basic Service Charges and Distribution Charges effective with service rendered on and after May 1, 2019. New base cost of gas reflective of Projected 2020 gas costs.
2/ GUIC rate effective March 1, 2019, excluding the surcharge.
3/ To coincide with projected implementation of interim rates, the projected 2020 GUIC rate is set to zero. All GUIC projects will be included in interim revenue requirement.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
MISCELLANEOUS REVENUES
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

		Projected	
	2018	2019	2020
Misc. Service Revenue 1/			
Reconnect Fee	$34,889	$29,815	$29,815
NSF Check Fees	6,588	4,455	4,455
Energy Diversion	171	503	503
Natural Gas Distribution Material	4,500	4,258	4,258
Total Misc. Service Revenue	$46,148	$39,031	$39,031
Rent from Property			
Building and Parking Lot Rent 1/	$991	$397	$397
Cost of Service - Corporate 2/	117,512	123,412	123,412
Total Rent from Property	$118,503	$123,809	$123,809
Other Operating Revenue			
Curtailment Revenue 3/	$0	$0	$0
Late Payment Revenue 4/	78,234	68,225	66,833
CIP Revenue 5/	566,584		
Miscellaneous 1/	7,876	8,100	8,100
Total Other Revenue	$652,694	$76,325	$74,933
Total Other Operating Revenue	$817,345	$239,165	$237,773

1/ Based on a three year average (2016-2018) of actual revenues received.
2/ Based on year-to-date June 2019 actuals and estimated July - December revenue.
3/ Great Plains has not received curtailment revenue from January 2015 - June 2019.
4/ Projection based on the ratio of 2018 late payments to sales and transportation revenue of 0.28 percent applied to projected revenue.
5/ Per books CIP revenue is recorded as Other Operating Revenue. Projected 2019 - 2020 CIP Revenue is included in Sales and Transportation Revenue. See Schedule C-1, Pages 4-5.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
OPERATION & MAINTENANCE EXPENSE
PROJECTED 2019

Function	Total	1/ Cost of Gas	2/ Labor	3/ Benefits	Subcontract Labor 4/	Vehicles & 5/ Work Equip.	Uncollectible Accounts 6/
Cost of Gas	$13,751,669	$13,751,669					
Other Gas Supply	63,670		$57,659			$2	
Other Production	80						
Transmission	18,653		1,875		$939	515	
Distribution	2,851,326		2,079,100		398,680	196,175	$2,688
Customer Accounting	749,002		428,400		23,503	29,834	129,139
Customer Service	597,326		30,515			2,366	
Sales	9,235		5,470		1,615	141	
Administrative & General	2,510,198		500,501	$735,232	90,826	4,362	
Total Other O&M	$6,799,490	$0	$3,103,520	$735,232	$515,563	$233,395	$131,827
Total O&M	$20,551,159	$13,751,669	$3,103,520	$735,232	$515,563	$233,395	$131,827

1/ Schedule C-2, page 9.
2/ Schedule C-2, page 10.
3/ Schedule C-2, page 13.
4/ Schedule C-2, page 14.
5/ Schedule C-2, page 15.
6/ Schedule C-2, page 16.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
OPERATION & MAINTENANCE EXPENSE
PROJECTED 2019

Function	CIP 7/	Software 8/ Maintenance	9/ Advertising	Industry Dues 10/	11/ Insurance	Reg. Comm. Expense 12/	All 13/ Other O&M
Cost of Gas							
Other Gas Supply		$2,422					$3,587
Other Production							80
Transmission							15,324
Distribution		11,729					162,954
Customer Accounting		6,686					131,440
Customer Service	$533,261		$27,453				3,731
Sales							2,009
Administrative & General	25,725	167,069		$41,872	$208,905	$292,960	442,746
Total Other O&M	$558,986	$187,906	$27,453	$41,872	$208,905	$292,960	$761,871
Total O&M	$558,986	$187,906	$27,453	$41,872	$208,905	$292,960	$761,871

7/ Schedule C-2, page 17.
8/ Schedule C-2, page 18.
9/ Schedule C-2, page 19.
10/ Schedule C-2, page 20.
11/ Schedule C-2, page 21.
12/ Schedule C-2, page 22.
13/ Schedule C-2, page 23.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
OPERATION & MAINTENANCE EXPENSE
PROJECTED 2020

Function	Total	1/ Cost of Gas	2/ Labor	3/ Benefits	Subcontract Labor 4/	Vehicles & 5/ Work Equip.	Uncollectible Accounts 6/
Cost of Gas	$13,869,562	$13,869,562					
Other Gas Supply	66,210		$59,674			$2	
Other Production	82						
Transmission	19,040		1,941		$957	521	
Distribution	2,939,214		2,151,764		406,414	198,300	$2,688
Customer Accounting	765,925		443,373		23,959	30,157	126,504
Customer Service	598,490		31,582			2,391	
Sales	9,498		5,661		1,646	143	
Administrative & General	2,604,366		517,994	$727,614	92,588	4,410	
Total Other O&M	$7,002,825	$0	$3,211,989	$727,614	$525,564	$235,924	$129,192
Total O&M	$20,872,387	$13,869,562	$3,211,989	$727,614	$525,564	$235,924	$129,192

1/ Schedule C-2, page 9.
2/ Schedule C-2, page 10.
3/ Schedule C-2, page 13.
4/ Schedule C-2, page 14.
5/ Schedule C-2, page 15.
6/ Schedule C-2, page 16.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
OPERATION & MAINTENANCE EXPENSE
PROJECTED 2020

Function	CIP 7/	Software 8/ Maintenance	9/ Advertising	Industry Dues 10/	11/ Insurance	Reg. Comm. Expense 12/	All 13/ Other O&M
Cost of Gas							
Other Gas Supply		$2,877					$3,657
Other Production							82
Transmission							15,621
Distribution		13,933					166,115
Customer Accounting		7,942					133,990
Customer Service	$533,261		$27,453				3,803
Sales							2,048
Administrative & General	25,725	213,628		$41,872	$219,351	$309,849	451,335
Total Other O&M	$558,986	$238,380	$27,453	$41,872	$219,351	$309,849	$776,651
Total O&M	$558,986	$238,380	$27,453	$41,872	$219,351	$309,849	$776,651

7/ Schedule C-2, page 17.
8/ Schedule C-2, page 18.
9/ Schedule C-2, page 19.
10/ Schedule C-2, page 20.
11/ Schedule C-2, page 21.
12/ Schedule C-2, page 22.
13/ Schedule C-2, page 23.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
TWELVE MONTHS ENDING DECEMBER 31, 2018

Function	Total Company 1/	Minnesota 1/
Manufactured Gas Production	$78	$78
Cost of Gas	22,406,133	18,175,295
Other Gas Supply	75,601	58,534
Transmission	26,728	20,033
Distribution	2,957,018	2,631,814
Customer Accounts	852,126	776,868
Customer Service & Info.	602,363	594,974
Sales	37,416	30,739
Administrative and General	2,893,066	2,618,366
Total Operation and Maintenance Expense	$29,850,529	$24,906,701

1/ Schedule C-2, pages 6-8.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
TWELVE MONTHS ENDING DECEMBER 31, 2018

Acct. No.		Total Company	Minnesota
	Manufactured Gas Production Expenses		
733	Gas Mixing Expense	$78	$78
741	Maintenance of Structures and Improvements	0	0
	Total Manufactured Gas Production Expenses	$78	$78
	Other Gas Supply Expenses		
804	Natural Gas City Gate Purch.	$21,122,246	$16,973,709
805.1	Purchased Gas Cost Adj.	1,273,394	1,021,918
808.1	Gas Withdrawn from Storage	722,530	686,304
808.2	Gas Delivered to Storage	(712,037)	(506,636)
813	Other Gas Supply Expenses	75,601	58,534
	Total Other Gas Supply Expenses	$22,481,734	$18,233,829
	Transmission Expenses		
	Operation		
850	Operation & Super-Transmission	$0	$0
	Maintenance		
856	Mains Expense	$24,592	$18,432
857	Measuring and Regulating Station Expenses	194	145
863	Maintenance of Mains	465	349
865	Maint of Measure & Reg Stat Eq.	946	709
866	Maint of Communication Equip	531	398
	Total Maintenance	$26,728	$20,033
	Total Transmission Expenses	$26,728	$20,033
	Distribution Expenses		
	Operation		
870	Supervision & Engineering	$487,911	$437,559
871	Distribution Load Dispatching	2,012	1,800
874	Mains and Service	651,248	573,508
875	Measuring & Reg. Station Exp.-General	9,614	8,906
876	Measuring & Reg. Station Exp.-Ind.	25,530	23,423
877	Measuring & Reg. Station Exp. - CG	74,236	58,554
878	Meters & House Regulators	172,876	150,994
879	Customer Installations	141,490	125,436
880	Other Expenses	496,099	445,979
881	Rents	27,964	24,013
	Total Operation Expenses	$2,088,980	$1,850,172

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
TWELVE MONTHS ENDING DECEMBER 31, 2018

Acct. No.		Total Company	Minnesota
	Maintenance		
885	Supervision & Engineering	$139,918	$122,882
886	Structures & Imp.	24,816	22,947
887	Mains	155,035	140,062
889	Measuring & Reg. Station Exp.-General	14,242	12,037
890	Mtc of Meas & Reg Stn Eq -Ind.	17,812	15,593
891	Mtc of Meas & Reg Stn Eq - CG	31,619	27,940
892	Services	135,117	123,467
893	Meters & House Regulators	97,074	85,427
894	Other Equipment	252,405	231,287
	Total Maintenance Expenses	$868,038	$781,642
	Total Distribution Expenses	$2,957,018	$2,631,814
	Customer Accounts Expenses		
901	Supervision	$13,033	$11,780
902	Meter Reading Expenses	131,328	118,199
903	Customer Records and Collection Exp.	429,108	391,863
904	Uncollectible Accounts	215,111	199,162
905	Misc. Customer Accounts Expenses	63,546	55,864
	Total Customer Accounts Expenses	$852,126	$776,868
	Customer Service & Information Expense		
907	Supervision	$4,776	$4,323
908	Customer Assistance Expenses	560,227	560,151
909	Informational & Instructional Advertising Expenses	37,294	30,434
910	Misc. Customer Serv. & Inform.	66	66
	Total Customer Service & Info. Expenses	$602,363	$594,974
	Sales Expenses		
	Operation		
911	Supervision	($114)	($103)
912	Demonstrating & Selling Expenses	7,527	6,812
913	Advertising Expenses	27,816	22,070
916	Miscellaneous Sales Expenses	2,187	1,960
	Total Sales Expenses	$37,416	$30,739

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SUMMARY OF OPERATION AND MAINTENANCE EXPENSES
TWELVE MONTHS ENDING DECEMBER 31, 2018

Acct. No.		Total Company	Minnesota
	Administrative & General Expenses		
	Operation		
920	Administrative & General Salaries	$740,352	$659,194
921	Office Supplies & Expenses	498,575	443,381
923	Outside Services Employed	115,947	103,678
924	Property Insurance	60,419	53,796
925	Injuries & Damages	180,901	161,205
926	Employee Pensions & Benefits	734,886	659,498
927	Franchise Requirements	966	762
928	Regulatory Commission Expenses	306,711	306,111
930.1	General Advertising Expense	82,108	75,055
930.2	Miscellaneous General Expenses	8,076	7,087
931	Rents	99,225	88,188
	Total Operation Expenses	$2,828,166	$2,557,955
	Maintenance		
935	Maintenance of General Plant	$64,900	$60,411
	Total Maintenance Expenses	$64,900	$60,411
	Total Administrative & General Expenses	$2,893,066	$2,618,366
	Total Operation & Maintenance Expenses	$29,850,529	$24,906,701

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
COST OF GAS
PROJECTED 2019 - 2020

	Projected	Demand	Commodity	Total Cost	Projected Cost of Gas		
	Dk Sales 1/	Charge 2/	Charge 2/	of Gas 2/	Demand	Commodity	Total
Projected 2019							
Total Minnesota							
Residential	1,520,948	$1.2178	$2.6354	$3.8532	$1,852,210	$4,008,306	$5,860,516
Firm General Service	1,317,966	1.2178	2.6354	3.8532	1,605,019	3,473,368	5,078,387
Small Interruptible	537,690	0.3453	2.6354	2.9807	185,664	1,417,028	1,602,692
Large Interruptible	405,970	0.3453	2.6354	2.9807	140,181	1,069,893	1,210,074
Total	3,782,574				$3,783,074	$9,968,595	$13,751,669
Projected 2020							
Total Minnesota							
Residential	1,527,457	$1.2178	$2.6354	$3.8532	$1,860,137	$4,025,461	$5,885,598
Firm General Service	1,342,053	1.2178	2.6354	3.8532	1,634,352	3,536,846	5,171,198
Small Interruptible	537,690	0.3453	2.6354	2.9807	185,664	1,417,028	1,602,692
Large Interruptible	405,970	0.3453	2.6354	2.9807	140,181	1,069,893	1,210,074
Total	3,813,170				$3,820,334	$10,049,228	$13,869,562

1/ Schedule C-1, page 3.
2/ Base cost of gas in Docket No. G004/MR-19-512.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
LABOR EXPENSE
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

	Per Books		Projected		
	Total Company	Minnesota	2019		2020
Other Gas Supply	$69,150	$53,540	$57,659		$59,674
Transmission	2,377	1,781	1,875		1,941
Distribution	2,179,778	1,940,897	2,079,100		2,151,764
Customer Accounting	440,025	398,198	428,400		443,373
Customer Service	29,013	28,607	30,515		31,582
Sales	5,607	5,075	5,470		5,661
A&G	752,785	670,879	500,501	1/	517,994
Total	$3,478,735	$3,098,977	$3,103,520		$3,211,989

	Per Books		Projected	
	Total Company	Minnesota	2019 5/	2020
Straight time 2/	$2,954,308	$2,630,732	$2,633,081	$2,725,239
Premium time 2/	186,569	167,569	173,349	179,416
Bonuses & Commissions 3/	105,278	93,645	9,187	9,509
Incentive Compensation 4/	193,092	171,887	253,036	261,892
Meals	5,017	4,414	4,414	4,414
Vacation 2/	34,471	30,730	30,453	31,519
Total	$3,478,735	$3,098,977	$3,103,520	$3,211,989

1/ Reflects elimination of corporate allocation factor adjustment. Schedule C-2, page 25.
2/ Reflects a 3.46% increase effective December 10, 2018 and a projected 3.50% increase for 2020.
3/ Projected 2019 excludes all stock compensation. Projected 2020 is increased by the projected increase in labor.
4/ Reflects an average incentive level of 9.50% of straight time and vacation.
5/ Schedule C-2, pages 11-12.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
LABOR EXPENSE SUPPORT WORKPAPER

	Total Per Books	CIP 1/ Adjustment	Adjusted Per Books	Corporate 2/ Elimination	Stock Comp Elimination	Adjusted Total	Projected 2019
Other Gas Supply							
Straight Time	$49,728		$49,728			$49,728	$51,449
Premium Time	22		22			22	23
Bonuses & Commissions	659		659			659	659
Incentive Compensation	2,565		2,565			2,565	4,943
Vacation/Other Non-Prod.	565		565			565	585
Other Gas Supply Total	**$53,539**		**$53,539**			**$53,539**	**$57,659**
Transmission							
Straight Time	$1,515		$1,515			$1,515	$1,567
Incentive Compensation	108		108			108	150
Taxable Meals	145		145			145	145
Vacation/Other Non-Prod.	13		13			13	13
Transmission Total	**$1,781**		**$1,781**			**$1,781**	**$1,875**
Distribution							
Straight Time	$1,669,919		$1,669,919			$1,669,919	$1,727,698
Premium Time	156,293		156,293			156,293	161,701
Bonuses & Commissions	126		126			126	126
Incentive Compensation	91,631		91,631			91,631	165,992
Taxable Meals	3,996		3,996			3,996	3,996
Vacation/Other Non-Prod.	18,932		18,932			18,932	19,587
Distribution Total	**$1,940,897**		**$1,940,897**			**$1,940,897**	**$2,079,100**
Cust Acct							
Straight Time	$365,747		$365,747			$365,747	$378,402
Premium Time	8,433		8,433			8,433	8,725
Bonuses & Commissions	369		369			369	369
Incentive Compensation	19,249		19,249			19,249	36,359
Taxable Meals	217		217			217	217
Vacation/Other Non-Prod.	4,183		4,183			4,183	4,328
Cust Acct Total	**$398,198**		**$398,198**			**$398,198**	**$428,400**

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
LABOR EXPENSE SUPPORT WORKPAPER

	Total Per Books	CIP 1/ Adjustment	Adjusted Per Books	Corporate 2/ Elimination	Stock Comp Elimination	Adjusted Total	Projected 2019
Cust Svc							
Straight Time	$122,753	$96,112	$26,641			$26,641	$27,563
Incentive Compensation	8,832	7,164	1,668			1,668	2,644
Taxable Meals	41		41			41	41
Vacation/Other Non-Prod.	1,039	781	258			258	267
Cust Svc Total	**$132,665**	**$104,057**	**$28,608**			**$28,608**	**$30,515**
Sales							
Straight Time	$4,774		$4,774			$4,774	$4,939
Incentive Compensation	247		247			247	475
Vacation/Other Non-Prod.	54		54			54	56
Sales Total	**$5,075**	**$0**	**$5,075**			**$5,075**	**$5,470**
A&G							
Straight Time	$512,408		$512,408	$85,709		$426,699	$441,463
Premium Time	2,821		2,821	18		2,803	2,900
Incentive Compensation	92,491		92,491	53,011	$31,447	8,033	8,033
Incentive Compensation	56,419		56,419	7,467		48,952	42,473
Taxable Meals	15		15			15	15
Vacation/Other Non-Prod.	6,725		6,725	1,296		5,429	5,617
A&G Total	**$670,879**		**$670,879**	**$147,501**	**$31,447**	**$491,931**	**$500,501**
	$3,203,034	**$104,057**	**$3,098,977**	**$147,501**	**$31,447**	**$2,920,029**	**$3,103,520**
Straight Time	$2,726,844	$96,112	$2,630,732	$85,709	$0	$2,545,023	$2,633,081
Premium Time	167,569	0	167,569	18	0	167,551	173,349
Bonuses & Commissions	93,645	0	93,645	53,011	31,447	9,187	9,187
Incentive Compensation	179,051	7,164	171,887	7,467	0	164,420	253,036
Taxable Meals	4,414	0	4,414	0	0	4,414	4,414
Vacation/Other Non-Prod.	31,511	781	30,730	1,296	0	29,434	30,453
	$3,203,034	**$104,057**	**$3,098,977**	**$147,501**	**$31,447**	**$2,920,029**	**$3,103,520**

3.46% 2019 Labor Increase   9.50% Average Incentive

1/ Schedule C-2, page 17.
2/ Schedule C-2, page 25.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
BENEFITS EXPENSE
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

	Per Books		Projected	
	Total Company	Minnesota	2019	2020
Medical/Dental 1/	$444,158	$398,409	$475,686	$504,227
Pension 2/	21,766	19,375	59,881	13,156
Post-Retirement 3/	(76,426)	(68,048)	(93,637)	(93,337)
401-K 4/	283,214	252,111	270,201	279,658
Workers Compensation 4/	21,173	18,913	19,627	20,314
Other Benefits 4/	3,590	3,199	3,474	3,596
Total	$697,475	$623,959	$735,232	$727,614

1/ Projected 2019 reflects the corporate allocation adjustment of $6,737 and an increase in medical/dental expense of 21.45% based on the annualization of medical/dental expense through June 2019. Projected 2020 reflects an increase in premium expense of 6%.

2/ Pension expense for 2019 based on the annualization of actual pension expense through June 2019. Pension expense for 2020 based on most current actuarial estimate.

	Minnesota		Actuarial Estimate	
	2018	2019	2019	2020
Bargaining			$655,346	$230,000
Non-Bargaining			723,770	73,000
Total	$19,375	$61,658	$1,379,116	$303,000
		218.23%		-78.03%
Corporate Allocation Adjustment		$558		

3/ Post-retirement expense for 2019 based on the annualization of actual post-retirement expense through June 2019. Post-retirement expense for 2020 based on most current actuarial estimate.

	Minnesota		Actuarial Estimate	
	2018	2019	2019	2020
Total	($68,048)	($91,590)	($1,858,990)	($1,853,000)
		34.60%		-0.32%
Corporate Allocation Adjustment		($1,519)		

4/ Projected 2019 reflects the applicable corporate allocation adjustment and the straight time labor increase of 3.46%. Projected 2020 is based on the straight time labor increase of 3.50%

Corporate Allocation Adjustment	
401K	$9,054
Workers Comp	58
Other Benefits	159

Total Corporate Adjusment $15,047 Schedule C-2, page 25.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SUBCONTRACT LABOR
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

	Per Books		Projected		
	Total Company	Minnesota	2019 1/		2020 3/
Other Gas Supply	$0	$0	$0		$0
Transmission	1,091	817	939		957
Distribution	374,780	346,829	398,680		406,414
Customer Accounting	22,263	20,446	23,503		23,959
Customer Service	0	0	0		0
Sales	1,558	1,405	1,615		1,646
A&G	104,141	94,690	90,826	2/	92,588
Total	$503,833	$464,187	$515,563		$525,564

1/ Minnesota per books expense increased 5% based on the percentage of change between January - June 2018 and January - June 2019 subcontract costs.

2/ 2019 excludes portion of MDU Resources due to reallocation of corporate costs.

2018 A&G per books	$94,690	
Corporate cost adjustment	(8,189)	Schedule C-2, page 25
Adjusted total	$86,501	
2019 inflator	5.00%	
2019 projected A&G	$90,826	

3/ Reflects an increase at the average inflation rate of 1.94%.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
VEHICLES AND WORK EQUIPMENT
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

	Per Books		Projected 1/		
	Total Company	Minnesota	2019		2020
Other Gas Supply	$1	$1	$2		$2
Transmission	602	451	515		521
Distribution	192,449	171,641	196,175		198,300
Customer Accounting	28,640	26,103	29,834		30,157
Customer Service & Info	2,097	2,070	2,366		2,391
Sales	158	124	141		143
A&G	4,379	3,863	4,362	2/	4,410
Total Company Vehicles	$228,326	$204,253	$233,395		$235,924

1/ Based on projected plant and depreciation rates from Docket No. G004/D-19-376.
2/ Excludes portion of MDU Resources of $53 due to reallocation of corporate costs. Schedule C-2, page 25.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
UNCOLLECTIBLE ACCOUNTS
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

	Per Books		Projected 1/	
	Total Company	Minnesota	2019	2020
Distribution	$2,688	$2,688	$2,688	$2,688
Customer Accounting	215,111	199,162	129,139	126,504
	$217,799	$201,850	$131,827	$129,192

1/ Based on five year average ratio of write-offs to revenues applied to projected revenues:

Total Projected Sales Revenue	$24,365,914	$23,868,755
Five-Year Average Write-Offs	0.53%	0.53%
	$129,139	$126,504

Twelve months ending	Net Write-Offs	Sales and Trans. Rev	%
12/31/2014	$217,364	$36,287,842	0.60%
12/31/2015	157,228	24,912,203	0.63%
12/31/2016	57,475	20,636,771	0.28%
12/31/2017	108,728	24,034,297	0.45%
12/31/2018	172,757	28,408,224	0.61%
	$713,552	$134,279,337	0.53%

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
CONSERVATION IMPROVEMENT PROGRAM (CIP)
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

	Per Books		Projected 1/	
	Total Company	Minnesota	2019	2020
Customer Service	$533,261	$533,261	$533,261	$533,261
A&G	25,725	25,725	25,725	25,725
CIP O&M	$558,986	$558,986	$558,986	$558,986
Payroll Tax	7,635	7,635	7,635	7,635
Total CIP	$566,621	$566,621	$566,621	$566,621

1/ Projected CIP expense to remain at current level.

Customer Service	
Labor	$104,057
Subcontract Labor	4,039
Advertising	4,259
Incentives	408,494
Other	12,412
Total Cust Service	$533,261
A&G	
Benefits	$21,625
Dues	4,100
Total A&G	$25,725
Payroll Tax	$7,635
Total	$566,621

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SOFTWARE MAINTENANCE
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

	Per Books		Projected 1/		
	Total Company	Minnesota	2019		2020
Other Gas Supply	$1,838	$1,422	$2,422		$2,877
Distribution	11,049	9,906	11,729		13,933
Customer Accounting	4,302	4,018	6,686		7,942
A&G	172,497	153,588	167,069	2/	213,628
Total Software Maintenance	$189,686	$168,934	$187,906		$238,380

1/ An increase of 18.79% per year related to contract increases and additional cyber security software.

2/ Excludes portion of MDU Resources of $12,768 due to reallocation of corporate costs. Schedule C-2, page 25.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
ADVERTISING
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

	Per Books		Projected 1/	
	Total Company	Minnesota	2019	2020
Customer Accounting	$2	$2	$0	$0
Customer Service	34,235	27,376	27,453	27,453
Sales	27,816	22,069	0	0
A&G 2/	8,076	7,084	0	0
Total Advertising	$70,129	$56,531	$27,453	$27,453

1/ Promotional and institutional advertising eliminated, along with informational advertising not applicable to Minnesota.
2/ Includes all Corporate charges - Schedule C-2, page 25.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
INDUSTRY DUES
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

		Projected		
	Per Books	2019		2020
American Gas Association	$11,244	$12,603	1/	$12,603
Chamber of Commerce - Crookston Area	0	722	1/	722
Chamber of Commerce - Fergus Falls Area	552	552		552
Chamber of Commerce - Marshall	1,020	1,020		1,020
Chamber of Commerce - Minnesota	0	546	1/	546
Chamber of Commerce - Montevideo	0	815	1/	815
Chamber of Commerce - Pelican Rapids	0	153	1/	153
Chamber of Commerce - Wahpeton/Breckenridge	0	764	1/	764
Common Ground Alliance	55	102	1/	102
Consortium for Energy Efficiency, Inc.	4,100	4,100		4,100
Economic Development Association of Minnesota	295	295		295
Edison Electric Institute	208	464	1/	464
Energy Solutions Center	865	1,029	1/	1,029
MEA Energy Association	1,559	1,559		1,559
Midwest Energy Association	884	884		884
Midwest Region Task Force	0	898	1/	898
Minnesota Blue Flame	1,945	1,945	1/	1,945
Minnesota Utility Investors	9,750	11,500	1/	11,500
Redwood Area Chamber & Tourism	0	437	1/	437
South West Utility Coordinating Committee	0	500	1/	500
West Associates	0	54	1/	54
Western Energy Institute	930	930		930
Other 2/	1,182	-		-
Total	$34,589	$41,872		$41,872

1/ Updated to reflect 2019 actuals.
2/ Corporate crosscharges removed.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
INSURANCE EXPENSE
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

	Per Books		Projected	
	Total Company	Minnesota	2019 1/	2020 3/
Directors & Officer's Liability	$15,154	$13,493	$2,749 4/	$2,886
General Liability				
Fiduciary Liability	3,485	3,103	3,435	3,607
Employment Liability	1,356	1,207	1,357	1,425
Excess Liability	104,325	92,889	112,591	118,221
Property - All Risk	59,469	52,950	71,771	75,360
Blanket Crime	875	779	868	911
Special Contingency	76	68	92	97
Self Insurance 2/	22,347	19,897	16,042	16,844
Total Insurance Expense	$207,087	$184,386	$208,905	$219,351

1/ Adjusted to reflect insurance expense at current levels.
2/ Adjustment based on 5 year average.
3/ Reflects an increase of 5.0%.
4/ Excludes portion of MDU Resources due to reallocation of corporate costs.

Corporate Cost Adjustment	($11,057)	Schedule C-2, page 25
2019 % Change in Premium	12.86%	
2019 Corporate Adjustment	($12,479)	
2019 Premium	15,228	
	$2,749	

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
REGULATORY COMMISSION EXPENSE
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

		Projected	
	Per Books	2019	2020
Ongoing Regulatory Comm. Exp. 1/	$174,861	$142,754	$142,754
Midwest Region Gas Task Force 2/	0	18,956	18,956
Rate Case Expense Amortization 3/	131,250	131,250	148,139
Total	$306,111	$292,960	$309,849

1/ Reflects three year average of ongoing assessments and legal expense.
2/ Assessment of fees to cover the legal costs associated with litigating natural gas transportation rate cases.
3/ Rate case expense for 2019 reflects the four year amortization of rate case expense approved in Docket No. G-004/GR-15-879. Rate case expense for 2020 is a four year amortization of the rate case expense projected in Docket No. G004/GR-19-511.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
OTHER O&M ADJUSTED FOR INFLATION
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

		Projected 2/	
	Per Books 1/	2019 3/	2020
Other Gas Supply	$3,571	$3,587	$3,657
Other Production	78	80	82
Transmission	16,984	15,324	15,621
Distribution	159,853	162,954	166,115
Customer Accounting	128,939	131,440	133,990
Customer Service	3,660	3,731	3,803
Sales	2,066	2,009	2,048
A&G	513,492	442,746	451,335
Total Other O&M	$828,643	$761,871	$776,651

1/ Schedule C-2, page 27.
2/ Increase of 1.94 percent annually after elimination of corporate and other expenses noted below.
3/ Reflects eliminations to account for the Corporate Allocation and Board of Directors, Travels, Meals, & Entertainment and Other Adjustments:

	Corporate 4/	Other 5/	Total
Other Gas Supply	$0	($53)	($53)
Distribution	0	(1,952)	(1,952)
Customer Accounting	0	(469)	(469)
Customer Service	0	(95)	(95)
A&G	(70,120)	(9,052)	(79,172)
Total Other O&M	($70,120)	($11,620)	($81,740)

4/ Schedule C-2, page 25.
5/ Schedule C-2, page 24.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
BOARD OF DIRECTORS, TRAVEL, MEALS & ENTERTAINMENT, AND OTHER
ADJUSTMENT TO EXPENSES
TWELVE MONTHS ENDING DECEMBER 31, 2018

	Total 1/	Board of Directors	Travel	Meals & Entertainment	Other Reimbursable	Professional Dues
Other Gas Supply	($53)		($31)	($12)	($9)	$0
Transmission	0		0	0		0
Distribution	(1,952)		(462)	(379)	(1,111)	0
Customer Accounting	(469)		(87)	(238)	(143)	0
Customer Service	(95)		(34)	(8)	(54)	0
Sales	0		0	0	0	0
A&G	(9,052)	($4,064)	(1,829)	(1,963)	(1,183)	(14)
Total	($11,620)	($4,064)	($2,443)	($2,599)	($2,500)	($14)

1/ Reflects elimination of amounts that are not applicable to Minnesota gas operations or do not meet the standards for inclusion in expense.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
CORPORATE ALLOCATION
TWELVE MONTHS ENDING DECEMBER 31, 2018

	Per Books	Reallocated 1/	Adjustment	Adjustment
Labor	$180,004	$32,503	($147,501)	2/
Benefits	18,362	3,315	(15,047)	2/
Subcontract labor	9,994	1,805	(8,189)	2/
Vehicles and Work Equipment	65	12	(53)	2/
Advertising	2,438	440	(1,998)	2/ 3/
Industry Dues	1,132	204	(928)	2/ 3/
Insurance Expense	13,493	2,436	(11,057)	2/
Software maintenance	15,582	2,814	(12,768)	2/
All Other	85,574	15,454	(70,120)	(70,120)
	$326,644	$58,983	($267,661)	($70,120)

1/ Original allocation based on average capitalization and reallocated based on Minnesota method (Minnesota allocation from 1.498029 percent to 0.270504 percent).
2/ Included in the applicable O&M item.
3/ Total amount is eliminated in the applicable O&M adjustment.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
O&M ITEMS ADJUSTED INDIVIDUALLY
TWELVE MONTHS ENDING DECEMBER 31, 2018

Function	Per Books	1/ Cost of Gas	2/ Labor	3/ Benefits	Subcontract Labor 4/	Vehicles & 5/ Work Equip.	Uncollectible Accounts 6/
Cost of Gas	$18,175,295	$18,175,295					
Other Gas Supply	58,534		$53,540			$1	
Other Production	78						
Transmission	20,033		1,781		$817	451	
Distribution	2,631,814		1,940,897		346,829	171,641	$2,688
Customer Accounting	776,868		398,198		20,446	26,103	199,162
Customer Service	594,974		28,607			2,070	
Sales	30,739		5,075		1,405	124	
Administrative & General	2,618,366		670,879	$623,959	94,690	3,863	
Total Other O&M	$6,731,406	$0	$3,098,977	$623,959	$464,187	$204,253	$201,850
Total O&M	$24,906,701	$18,175,295	$3,098,977	$623,959	$464,187	$204,253	$201,850

1/ Schedule C-2, pages 5-6.
2/ Schedule C-2, page 10.
3/ Schedule C-2, page 13.
4/ Schedule C-2, page 14.
5/ Schedule C-2, page 15.
6/ Schedule C-2, page 16.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
O&M ITEMS ADJUSTED INDIVIDUALLY
TWELVE MONTHS ENDING DECEMBER 31, 2018

Function	CIP 7/	Software 8/ Maintenance	9/ Advertising	Industry Dues 10/	11/ Insurance	Reg. Comm. Expense 12/	All 13/ Other O&M
Cost of Gas							
Other Gas Supply		$1,422					$3,571
Other Production							78
Transmission							16,984
Distribution		9,906					159,853
Customer Accounting		4,018	$2				128,939
Customer Service	$533,261		27,376				3,660
Sales			22,069				2,066
Administrative & General	25,725	153,588	7,084	$34,589	$184,386	$306,111	513,492
Total Other O&M	$558,986	$168,934	$56,531	$34,589	$184,386	$306,111	$828,643
Total O&M	$558,986	$168,934	$56,531	$34,589	$184,386	$306,111	$828,643

7/ Schedule C-2, page 17.
8/ Schedule C-2, page 18.
9/ Schedule C-2, page 19.
10/ Schedule C-2, page 20.
11/ Schedule C-2, page 21.
12/ Schedule C-2, page 22.
13/ Schedule C-2, page 23.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SUMMARY OF DEPRECATION EXPENSE AND AMORTIZATION
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

		Projected 1/	
	Per Books	2019	2020
Intangible	$179,735	$182,561	$186,684
Transmission	23,961	106,094	106,123
Distribution	1,858,403	2,051,713	2,220,419
General	133,978	126,938	131,526
Common	49,357	61,309	73,814
Common - Intangible	65,196	77,696	106,219
Total Depreciation:	$2,310,630	$2,606,311	$2,824,785
Pref. Stock Redemption - Gas 2/	$453	$777	$777
Total Depreciation and Amortization	$2,311,083	$2,607,088	$2,825,562

1/ See Schedule B-2, pages 4-5 for the calculation of depreciation expense.
2/ See Schedule B-3, page 7.

GREAT PLAINS NATURAL GAS CO.

TABLE 1. REVISED SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT AS OF DECEMBER 31, 2018

- TOTAL -

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2018	CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	REMAINING LIFE
TRANSMISSION PLANT									
365.2	RIGHTS OF WAY	50-R2.5	0	158,152	101,961	125,291	1,199	0.76	17.8
366.0	TRANSMISSION STRUCTURES	85-S1	-5	16,683	309	39	600	3.60	29.1
367.0	TRANSMISSION MAINS	50-R3	-20	6,097,192	1,238,506	1,448,992	125,012	2.05	41.5
369.0	MEAS & REG STATION EQUIPMENT	40-R0.5	-10	876,671	169,310	222,360	21,831	2.49	33.0
TOTAL TRANSMISSION PLANT				7,148,697	1,510,086	1,796,682	148,642	2.08	
DISTRIBUTION PLANT									
374.2	RIGHTS OF WAY	50-R2.5	0	17,654	9,420	9,164	367	2.08	23.3
375.0	DISTR. MEAS & REG STATION STRUCTURES	N/A	-5	34,860	N/A	28,001	990 [1]	2.84	N/A
376.0	MAINS	46-R3	-55	20,844,261	9,725,081	10,215,541	663,973	3.19	32.2
378.0	MEAS & REG STATION EQUIP-GENERAL	N/A	-25	515,539	N/A	401,406	64,700 [2]	12.55	N/A
379.0	MEAS & REG STATION EQUIP-CITY GATE	28-R3	-5	489,650	149,186	132,883	20,089	4.10	19.9
380.0	SERVICES	39-R3	-75	16,990,592	8,662,388	9,676,121	669,027	3.94	27.6
381.0	METERS & METER INSTALLATIONS	N/A	-25	7,228,434	N/A	4,575,990	716,338 [3]	9.91	N/A
383.0	HOUSE REGULATORS	N/A	-5	965,429	N/A	443,088	63,911 [3]	6.62	N/A
385.0	INDUSTRIAL MEAS. & REG. STATION EQUIPMENT	40-S4	0	162,784	18,270	17,890	4,087	2.51	35.5
387.1	CATHODIC PROTECTION EQUIPMENT	25-R3	0	9,235	3,962	3,659	401	4.34	14.3
387.2	OTHER EQUIPMENT	30-R3	0	11,498	9,738	11,498	-	-	4.6
TOTAL DISTRIBUTION PLANT				47,269,936	18,578,045	25,515,241	2,203,883	4.66	
GENERAL PLANT									
390.0	GENERAL STRUCTURES & IMPROVEMENTS	45-R4	0	2,504,707	663,003	812,380	48,189	1.92	33.1
391.1	OFFICE FURNITURE & EQUIPMENT	16-SQ	0	89,305	57,385	56,978	5,446	6.10	5.7
391.3	COMPUTER & ELECTRONIC EQUIPMENT	4-SQ	0	105,067	95,378	88,199	15,622	14.87	0.4
392.1	TRANSPORTATION EQUIPMENT - TRAILERS	12-R1	10	22,349	12,533	23,335	-	-	4.5
392.2	TRANSPORTATION EQUIPMENT	7-L2	20	1,468,028	500,274	639,362	122,821	8.37	4.0
394.0	TOOLS, SHOP, & GARAGE EQUIPMENT	20-SQ	0	757,796	262,445	258,887	38,801	5.12	13.1
396.1	POWER OPERATED EQUIPMENT - TRAILERS	6-L0	65	158,027	17,575	35,215	4,217	2.67	4.1
396.2	POWER OPERATED EQUIPMENT	6-L0	65	1,163,907	101,201	243,640	30,164	2.59	4.5
397.0	COMMUNICATION EQUIPMENT	18-SQ	0	357,683	214,610	215,486	19,404	5.42	7.2
398.0	MISCELLANEOUS EQUIPMENT	25-SQ	0	53,659	22,275	20,516	2,271	4.23	14.6
TOTAL GENERAL PLANT				6,680,528	1,946,679	2,393,999	286,935	4.30	
TOTAL GAS PLANT STUDIED				61,099,161	22,034,810	29,705,922	2,639,460	4.32	
PLANT NOT STUDIED									
301.0	ORGANIZATION COSTS			5,006					
302.0	FRANCHISE COSTS			73,680					
303.0	INTANGIABLE ASSETS			2,784,752					
365.0	LAND			5,585					
374.0	LAND			2,978					
389.0	LAND & LAND RIGHTS GENERAL			48,659					
TOTAL PLANT				64,019,822					

Notes:

[1] Interim Retirement Rate. Service lives vary.

[2] Based upon anticipated district regulator change out / eliminations.

[3] Based upon 20 ERT battery life and remaining PVC program term 2016 - 2026.

All currently approved rates include salvage portion.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
TAXES OTHER THAN INCOME
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

Type of Tax	Total Company	Minnesota	Projected 1/ 2019	2020
Ad Valorem				
Intangible	$51			
Transmission	20,406	$14,960	$22,517	$22,523
Distribution	798,377	764,353	821,432	888,976
General	58,433	56,445	58,868	59,223
Common	3,897	3,490	3,819	4,290
Common - Intangible	11,533	10,328	11,831	14,487
Total Ad Valorem Taxes	$892,697	$849,576	$918,467	$989,499
O&M Related Taxes - Other				
Payroll Taxes	$246,725	$220,606	$220,847	$228,299
Delaware Franchise	12,605	11,221	11,221	11,221
Total O&M Related Taxes	$259,330	$231,827	$232,068	$239,520
Other				
Highway Use Tax	$195	$175	$175	$175
Secretary of State	128	114	114	114
Total Other	$323	$289	$289	$289
Total Taxes Other Than Income	$1,152,350	$1,081,692	$1,150,824	$1,229,308

1/ Schedule C-4, pages 2-3.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
AD VALOREM TAXES
PROJECTED 2019 - 2020

Function	Average Plant Balance @ 12/31/18 1/	Ad Valorem Tax @ 12/31/18	Effective Tax Rate	Projected 2019 Plant Balance 1/	Projected 2019 Ad Valorem Tax	Projected 2020 Plant Balance 1/	Projected 2020 Ad Valorem Tax
Intangible	$2,851,819	$0	0.0000%	$2,883,294	$0	$2,910,862	$0
Transmission	3,421,971	14,960	0.4372%	5,150,191	22,517	5,151,592	22,523
Distribution	40,880,113	764,353	1.8697%	43,933,900	821,432	47,546,452	888,976
General	6,391,087	56,445	0.8832%	6,665,291	58,868	6,705,525	59,223
Common	1,204,074	3,490	0.2898%	1,317,956	3,819	1,480,188	4,290
Common - Intangible	822,603	10,328	1.2555%	942,309	11,831	1,153,922	14,487
Total	$55,571,667	$849,576		$60,892,941	$918,467	$64,948,541	$989,499

1/ Schedule B-1, page 1.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
PAYROLL TAXES
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

		Projected 1/	
	2018	2019	2020
Payroll Taxes	$212,971	$213,212	$220,664
Payroll Taxes - CIP	7,635	7,635	7,635
Total Payroll Taxes	$220,606	$220,847	$228,299

1/ Calculated based on 2018 ratio of payroll taxes to labor:

	2018	
Payroll Taxes	$220,606	
Less: CIP	7,635	See Schedule C-2, page 17
Net Payroll Tax	$212,971	

	2018	2019	2020
Gas Labor - MN	$3,098,977	$3,103,520	$3,211,989
% Net Payroll Tax to Labor	6.87%		

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
CALCULATION OF CURRENT INCOME TAXES
PROJECTED 2019 - 2020

	Projected 2019	Projected 2020	Reference
Operating Revenues			
Sales Revenues	$22,499,641	$21,952,876	Schedule C-1, page 1
Transportation Revenues	1,866,273	1,915,879	Schedule C-1, page 1
Other Revenues	239,165	237,773	Schedule C-1, page 1
Total Operating Revenues	$24,605,079	$24,106,528	
Operating Expenses			
Operation and Maintenance			
Cost of Gas	$13,751,669	$13,869,562	Schedule C-2, pages 1-4
Other O&M	6,799,490	7,002,825	Schedule C-2, pages 1-4
Total O&M	$20,551,159	$20,872,387	
Depreciation Expense	2,607,088	2,825,562	Schedule C-3, page 1
Taxes other Than Income	1,150,824	1,229,308	Schedule C-4, page 1
Total Operating Expenses	$24,309,071	$24,927,257	
Operating Income before Income Taxes	$296,008	($820,729)	
Deductions and Adjustments to Book Income:			
Interest Expense	$690,618	$721,494	Schedule C-5, page 2
Other Additions / Deductions	(35,819)	(35,819)	Schedule C-5, page 4
Total Adjustments to Taxable Income	$654,799	$685,675	
Taxable Income	($358,791)	($1,506,404)	
Federal & State Income Taxes @ 28.742%	($103,124)	($432,971)	
Amortization of Excess Deferred Income Taxes			
Plant Related - ARAM Method	($113,882)	($140,443)	
Excess Non-Plant - Other - 10-Year	(26,463)	(26,463)	
Excess Non-Plant - Rate Base - 10-Year	9,036	9,036	
Total Current & Deferred Income Taxes	($234,433)	($590,841)	

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
INTEREST EXPENSE ANNUALIZATION
PROJECTED 2019 - 2020

	Projected	
	2019	2020
Rate Base 1/	$29,263,477	$31,686,174
Weighted Cost of Debt	2.360%	2.277%
Interest Expense	$690,618	$721,494

1/ Statement B, page 1.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
CALCULATION OF RECORDED STATE AND FEDERAL INCOME TAXES
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2018

	Total Company	Minnesota
Operating Revenue	$34,069,091	$28,538,138
Operating Expense:		
O&M Expense	$29,850,529	$24,906,701
Depreciation Expense	2,567,164	2,311,083
Taxes Other than Income	1,152,350	1,081,692
Total Operating Expense	$33,570,043	$28,299,476
Operating Income	$499,048	$238,662
Interest Expense	766,998	706,226
Book Taxable Income before Adjustments	($267,950)	($467,564)
Deductions and Adjustments to Book Income:		
Tax Deductions 1/	($2,038,300)	($1,897,018)
Taxable Income - Before State Income Tax	$1,770,350	$1,429,454
Less: State Income Taxes	(52,718)	(102,294)
Federal Taxable Income	$1,823,068	$1,531,748
Federal Income Taxes	$382,844	$321,667
Credits and Adjustments	(15,147)	(13,537)
State Income Taxes	(52,718)	(102,294)
Federal and State Income Taxes	$314,979	$205,836
Rounding and Prior Year's Adjustment	$218,609	$196,190
Total Federal and State Income Taxes	$533,588	$402,026

1/ See Schedule C-5, page 4.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
CALCULATION OF RECORDED STATE AND FEDERAL INCOME TAXES
INCOME TAX DEDUCTIONS
TWELVE MONTHS ENDING DECEMBER 31, 2018

	Total Company	Minnesota
Timing Differences		
CWIP	($54,075)	($58,156)
Liberalized Depreciation and Other Property	297,484	266,697
Property Timing Differences-Common	(13,115)	(11,745)
Contributions In Aid of Construction	143,802	136,740
Bad Debt Expense	($27,794)	(25,958)
Board of Directors Retirement Benefit	966	860
Bonus & 401k Profit Sharing	(332,018)	(295,574)
Customer Advances	144,494	27,014
Deferred Compensation - Directors	(21,789)	(19,397)
Deferred Medicare Part D	17,912	16,362
Deferred Postretirement Benefit Costs (FAS 106)	52,510	46,746
Management Incentive	(21,513)	(19,152)
MN Decoupling Reg Asset	(545,857)	(545,857)
MN Infrastructure Rider	296,533	296,533
Performance Share Program	(166,539)	(146,621)
Postretirement Benefits Cost (FAS 158)	82,389	69,261
Pref Stk Redemption Amort - Reg Asset	(492)	(453)
Prepaid Expenses	3,435	2,932
Property Insurance	1,687	1,511
Purchased Gas Adjustment	(1,269,272)	(1,021,918)
Regulatory Commission Expense	(131,250)	(131,250)
Reserved Revenues	(400,000)	(400,000)
Sundry Reserves	(14,532)	(13,013)
Unamortized Loss on Reacquired Debt	(9,834)	(8,834)
Uniform Capitalization	(8,412)	(7,489)
Vacation Pay	(22,958)	(20,438)
Subtotal - Timing Differences	($1,998,238)	($1,861,199)
Permanent Additions/Deductions		
AFUDC CWIP	($73,332)	($65,743)
AFUDC Equity	48,365	43,362
50% Meals and Entertainment	(11,721)	(10,434)
Dividend Received Deduction	722	643
Penalties	(10)	(9)
Qualified Transportation Fringe - Parking	(5,076)	(4,519)
Fuel Tax Credit	(1,017)	(905)
Performance Share Program - Perm	2,007	1,786
Subtotal - Permanent Additions/Deductions	($40,062)	($35,819)
Total Deductions	($2,038,300)	($1,897,018)

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
DEFERRED INCOME TAXES
TWELVE MONTHS ENDING DECEMBER 31, 2018

	Total Company	Minnesota
Deferred Income Taxes - Timing		
Liberalized Depreciation and Other Property Timing Differences	$61,145	$58,209
Contributions In Aid of Construction	33,916	30,528
Customer Advances	45,863	7,764
Unamortized Loss on Reacquired Debt	(2,399)	(1,971)
AFUDC Debt - Capitalized	($22,305)	($18,290)
AFUDC Debt - Capitalized - Common	(35)	(29)
AFUDC Debt - Incurred	17,641	12,433
Bad Debt Expense	(7,909)	(7,461)
Board of Directors Retirement Benefits	236	192
Bonus & 401k Profit Sharing	(80,989)	(65,972)
CPI - Capitalized	20,673	16,951
CPI - Capitalized - Common	(174)	(142)
CPI - Incurred	(28,896)	(23,694)
CPI - Incurred - Common	(95)	(78)
Deferred Compensation - Directors	(5,314)	(4,329)
Deferred Medicare Part D	4,370	3,647
Deferred Postretirement Benefit Costs (FAS 106)	12,809	10,434
Management Incentive	(5,248)	(4,275)
MN Decoupling Reg Asset	(156,890)	(156,890)
MN Infrastructure Rider	85,230	85,230
Performance Share Program	(40,623)	(32,747)
Postretirement Benefit Costs (FAS 158)	20,097	15,513
Pref Stk Redemption Amort - Reg Asset	(139)	(130)
Prepaid Expenses	838	656
Property Insurance	413	338
Purchased Gas Adjustment	(354,087)	(293,720)
Regulatory Commission Expense	(37,724)	(37,724)
Reserved Revenues	(114,968)	(114,968)
Sundry Reserves	(3,545)	(2,904)
Uniform Capitalization	(2,051)	(1,671)
Vacation Pay	(5,600)	(4,562)
Amortization of Excess ADITs		
TCJA Excess Plant - ARAM	($91,065)	($81,634)
Excess Non-Plant - Other	(30,447)	(26,463)
Excess Non-Plant - Rate Base	13,390	9,036
Other Deferred Income Tax Adjustments		
R&D Tax Credit Carryforward	$3,593	$3,194
Closing/Filing and Out of Period	(164,947)	(141,850)
Total Deferred Income Taxes	($835,236)	($767,379)

Montana-Dakota Utilities Co.
Great Plains Natural Gas Co.

Cost Allocation Manual

2019

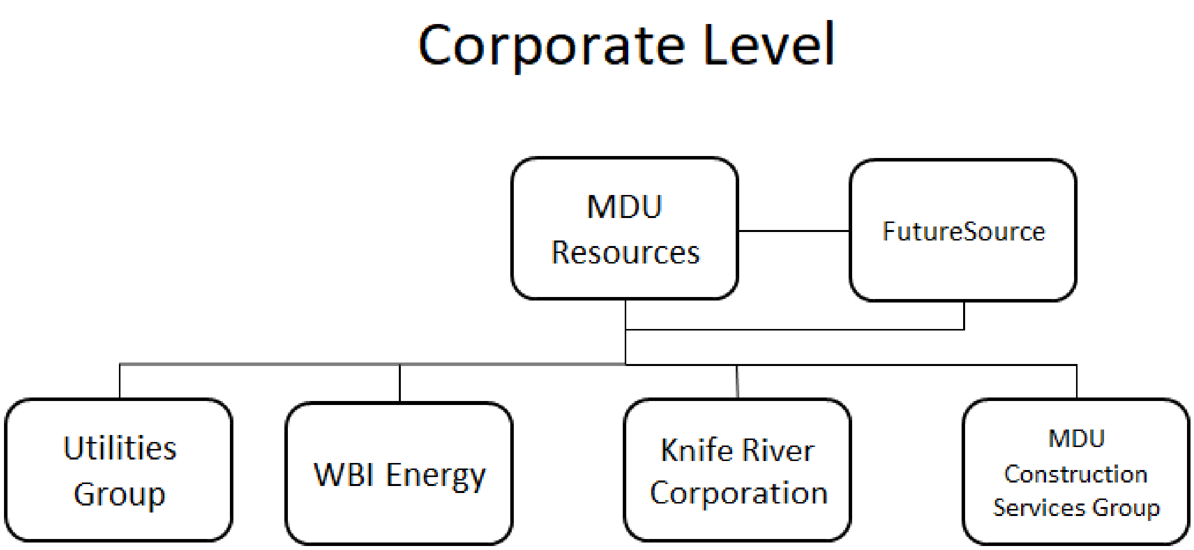
Table of Contents

Overview

Montana-Dakota Utilities Co. (Montana-Dakota), a subsidiary of MDU Resources Group, Inc. (MDUR), and Great Plains Natural Gas Company (Great Plains), a division of Montana-Dakota, conduct business in five states with two regulated utility segments 1) electric operations (comprised of generation, transmission and distribution operations) and 2) gas distribution operations. Montana-Dakota and Great Plains are one legal entity and have one set of financial records. However, utility related rate base and income statement items, whether directly assigned or allocated, are captured in a unique financial ledger to provide for regulatory reporting. The operations of both Montana-Dakota and Great Plains are under the direction of one Utility Group (UG) executive leadership team.

FutureSource Capital Corporation (FutureSource) is a separate legal entity that owns the corporate campus facilities that house the MDUR corporate staff and other property utilized in providing services to the operating companies within MDUR.

Below is an overview of the operational structure for the purpose of assigning costs. The diagram presented is intended to provide an overview for cost allocation only and is not intended to represent the legal structure of the Corporation. Note that costs from MDUR and FutureSource are directly assigned or allocated and charged to the operating companies (i.e. Utilities Group, WBI Energy, etc.)



This document is intended to provide an overview of the different types of allocations and the processes employed to direct costs to the proper utility or business segment (electric or gas) and state jurisdiction for Montana-Dakota and Great Plains.

This document will discuss the allocations to/from:

- MDUR and FutureSource to Montana-Dakota/Great Plains
- Montana-Dakota to other companies within MDUR
- Montana-Dakota/Great Plains to Cascade Natural Gas Company (CNGC) and Intermountain Gas Corporation (IGC)
- Montana-Dakota to a utility segment (electric or gas)
- Utility segment to state jurisdictions

Overall, the approach to allocating costs at each level is to directly assign costs when applicable and to allocate costs based on the function or driver of the cost.

MDU Resources Group, Inc. (MDUR) Allocations

The MDUR corporate staff consists of shared services departments (payroll, human resources, business services and enterprise information technology), and administrative and general departments.

Shared Services

MDU Resources Group, Inc. has several departments that provide specific services to the operating companies. These departments have developed a pricing methodology which is updated annually for the allocation of costs to the MDUR operating companies that utilize their services. (See Exhibit IV) These departments include:

Payroll Shared Services

Payroll Shared Services department provides comprehensive payroll services for MDUR companies and employees. It processes payroll in compliance with appropriate federal, state and local tax laws and regulations. Payroll Shared Services is also responsible for preparation, filing and payment of all payroll related federal, state and local tax returns. It also maintains and facilitates payments and accurate reporting to payroll vendors for employee benefits and other payroll deductions. For Montana-Dakota and Great Plains, the payroll shared services department is also responsible for the accumulation of time entry records and maintenance of employee records. Montana-Dakota and Great Plains do not have any departments that provide these payroll related services.

Human Resources

Human Resources operates as “One HR” across the regulated business units of MDU Resources Group including Montana-Dakota, Great Plains, Cascade Natural Gas, Intermountain Gas, and WBI Energy. There are employees in the HR departments at each of the business units that focus on the operational function of human resources: employee relations, labor relations, staffing, and leave management, all for their specific location. At MDU Resources, shared HR functions are performed for all of the regulated businesses: compensation management, benefits administration, policy development, human resource information systems, organizational development, as well as providing support and backup for the business unit functions.

Business Services

Business Services provides support services for facilities and administrative services (including bill printing), supply chain (purchasing and inventory), fleet, travel, and accounts payable (including unclaimed property). Business Services also creates and maintains the Corporation’s national accounts for the purchase of products, goods and services. National accounts take advantage of the combined purchasing power of all the Corporation’s operating companies. Business Services is committed to serving its customers by providing timely, standardized, cost-effective goods and services that support business strategies and goals.

Enterprise Information Technology

Enterprise Information Technology (EIT) provides policy guidance, infrastructure related IT functions and security-focused governance. EIT seeks to increase the return on investment in technology through consolidation of common IT systems and services, while eliminating waste and duplication. EIT works to increase the quality and consistency of technology, increase functionality and service to the enterprise, provide governance for managing and controlling risk and reduce costs through economies of scale.

The EIT services get allocated to Montana Dakota using agreed upon formulas based on utilization of the services.

General and Administrative Services

Administrative and general functions performed by MDUR for the benefit of the operating companies include the following departments:

- Corporate governance, accounting & planning
- Communications & public affairs
- Human resources
- Internal audit
- Investor relations
- Legal
- Risk management
- Tax and compliance
- Treasury services

Montana-Dakota and Great Plains receive an allocation of these corporate costs. Corporate Policy No. 50.10 states "*It is the policy of the Company to allocate MDU Resources Group, Inc.'s (MDU) administrative costs and general expenses to the MDU's business units*". Business units described in the policy have been referred to as operating companies in this document. The policy states that costs that directly relate to a business unit will be directly assigned to the applicable business unit and only the remaining unassigned expenses will be allocated to the operating companies using the corporate allocation methodology. The allocation factor developed to apportion MDUR's unassigned administrative costs is a capitalization factor which is based on 12 month average capitalization at March 31, effective July 1 and at September 30, effective January 1 each year. MDUR has a mix of regulated and non-regulated companies.

The non-regulated companies are cyclical in nature and could be impacted significantly with a downturn in the economy. It is unlikely during that same downturn their share of corporate costs would be materially different. Due to the volatility of non-regulated companies, and inconsistency between periods of other potential allocation factors, capitalization is the most appropriate allocation factor for MDUR. Capitalization includes total equity and current and non-current long-term debt (including capital lease obligations). The computation of the Corporate Overhead Allocation Factors is shown in Exhibit I.

Montana-Dakota's gas (including Great Plains) and electric business segments are reflected in the Corporate Overhead Allocation Factors in Exhibit I. Operating companies that receive allocated costs on a monthly basis from MDUR include:

- Montana Dakota – Electric utility segment
- Montana Dakota/Great Plains – Gas utility segment
- Cascade Natural Gas Corporation (CNGC)
- Intermountain Gas Company (IGC)
- WBI Energy Transmission
- WBI Midstream
- Knife River (KR)
- MDU Construction Services Group, Inc. (CSG)

The corporate costs allocated to the electric and gas segments at Montana-Dakota/Great Plains are subsequently allocated to the state jurisdictions Montana Dakota and Great Plains serve. Corporate costs are recorded in the administrative and general (A&G) function for Montana-Dakota/Great Plains. (See state jurisdictional allocation discussion on page 11.)

FutureSource

FutureSource, a separate legal entity, owns the facilities at the corporate campus that house the MDUR corporate staff and other property utilized in providing services to all the operating companies within MDUR. These include the corporate office, computers, telephones, furniture, fixtures and aircraft. Montana-Dakota/Great Plains acquired an interest in a portion of the land, building, hangar and aircraft with a cash contribution to FutureSource and placed these assets into rate base. The purchase of a portion of the assets (based on the net book value) was determined to be beneficial to the rate payer rather than paying a higher rate of return for the investment in the cost of service calculation billed by FutureSource. The investment in these assets is fluid in nature and does change over time depending on the total investment held by FutureSource. This investment is monitored annually and compared to its proximity to the Corporate Overhead Allocation Factor. The level of investment is targeted to remain relatively close to the Utility Group's Corporate Overhead Allocation Factor. Montana-Dakota/Great Plains receives a cost of service return from IGC and CNGC for their proportionate share of the contribution made by Montana-Dakota. The revenue received by Montana-Dakota for this cost of service is recorded in miscellaneous revenue.

Annually FutureSource calculates a cost of service for any unfunded portion of these corporate assets and bills the operating companies monthly. Components included in the cost of service for these facilities and other property include operation and maintenance expense, depreciation, property taxes, income taxes and a pretax return on the investment. The annual calculation is maintained by FutureSource and the most recent copy may be requested from the MDU Resources Corporate Planning Department. Each month Montana-Dakota /Great Plains allocates these costs to the electric and gas utility segment based on the Montana-Dakota corporate overhead factor, Exhibit II.

FutureSource also owns and operates a corporate aircraft and a hangar. Fixed costs for the aircraft are allocated to the MDUR operating companies on the MDUR corporate overhead factor referenced above (Exhibit I). The variable costs are charged to the appropriate business unit as a direct charge on an hourly flight rate. These charges will at times exceed or be below the actual variable cost. A year-end true-up includes an adjustment to the excess or shortfall in such hourly billing. Flights for employees of Montana-Dakota/Great Plains are directly assigned to the appropriate utility segment and state jurisdiction based on the purpose of the trip. For trips that are not directly applicable to a utility segment/jurisdiction, costs are allocated on the employee's standard payroll allocation and subsequently allocated to the jurisdictions. Standard labor distribution allocations are discussed on page 9.

Montana-Dakota / Great Plains Allocation of Cost to / from Others

Allocations to / from other MDUR Companies

Certain Montana-Dakota/Great Plains owned assets, such as the General Office/Annex facility, located at the utility headquarters in Bismarck, and the assets associated with the contribution made for FutureSource assets, are also used for the benefit of other MDUR operating companies. To cover the cost of ownership and operating costs associated with these owned assets, a revenue requirement (asset return plus annual operating expenses) is computed for the shared assets. The expense component included in the return is composed of operating and maintenance costs, depreciation, income tax and property tax expenses. The resulting revenue requirement is billed to the other MDUR operating companies, including CNGC and IGC, as a monthly fee.

Intermountain Gas owns the customer care center located in Meridian, ID. To cover the cost of ownership associated with that owned asset, a revenue requirement (asset return) is computed similarly to Montana-Dakota owned assets. The expense component included in the return is composed of depreciation, income tax and property tax expenses. The resulting revenue requirement is billed to the Montana-Dakota/Great Plains and Cascade as a monthly fee. The costs are allocated based on the number of customers served by each utility.

Allocations to other Utility Companies

Montana-Dakota/Great Plains has several departments that provide services to all four utility operating companies (Montana-Dakota, Great Plains, Cascade Natural Gas Co. and Intermountain Gas Company). These departments include:

- Leadership Group - composed of the Executive Group and Directors that oversee shared utility specific functions
- Customer Services - (Call Center, Scheduling and Online Services)
- Operations & Engineering Services Group – composed of shared utility group operations department functions
- Information Technology and Communications- (Enterprise Network & Telecommunications, Enterprise Management, Enterprise Development and Integration, Field Automation, Enterprise GIS)
- Environmental

- Safety & Technical Training
- Business Development
- Gas Supply & Control
- Utility Group Controller

These operational groups have calculated the proper allocation to use to allocate the costs to the utility companies based on services performed for each utility company. The allocation methodology is included in Exhibit V.

Montana-Dakota/Great Plains Allocations to Utility Segment

Revenues

All sales and transportation revenues are directly assigned to the utility segment and state jurisdiction. Miscellaneous service revenue, rent and other revenue is directly assigned to the utility segment where possible and common derived revenue is allocated to the utility segment based on the reason for which the revenue was received. As an example, revenue derived from the cost of service billed to other MDUR operating companies is allocated between the electric and gas segments based on the Montana-Dakota corporate overhead factor which is a composite of plant and employees as shown in Exhibit II, whereas miscellaneous revenue derived from patronage dividends received in a combination district would be split based on the customer count percentage for the applicable district where the dividend was received. These allocations between segments are computed manually. Customer Allocation factors are found in Exhibit III.

O&M Expense

As operation and maintenance costs are incurred, the expense is directly assigned to a utility segment in the general ledger where possible. Expenses incurred that are common to both segments, such as administrative and general costs, are split between utility segments based on the function and/or driver of the cost. Common facility expenses and labor/reimbursable expenses are discussed below.

Facility Expense Allocations

Costs for operations and maintenance of facilities are charged directly to the applicable utility segment when the facility is for the benefit of one utility segment. For example, costs applicable to the maintenance of gas mains are charged directly to the gas segment, whereas costs for maintenance at an electric generation or transmission facility are charged directly to the electric utility segment.

For expenses associated with distribution operation facilities, such as a region office that serves more than one utility segment, the costs are allocated to the utility segment based on the number of customers served by that facility. See the list of Customer Allocation factors in Exhibit III. General office facility costs are allocated to the electric and gas utility segments based on the Montana-Dakota corporate overhead factor percentage which is based on an average of the Employee and Plant factors and shown on Exhibit II.

Labor / Reimbursable expense allocations

The development of standard labor distributions for Montana-Dakota/Great Plains employees is described below based on the type of employee. Standard labor distributions are used for all employees to account for certain expenses as detailed below.

Labor, benefit costs and reimbursable expenses are directly assigned to a utility segment where possible. If the expense is not direct, the appropriate utility segment is charged as follows:

Union Employees

Time tickets are required for productive time. The employee specifies the proper utility segment, location and FERC account based on work performed. To account for non-productive time, standard payroll labor distributions are established for all employees. These standard labor distributions are calculated for union employees based on the historical actual charges by utility segment for the last 12 months.

Non-Union Employees

Non-union employees are not required to submit detailed time tickets with applicable general ledger accounts specified. Rather each employee has a “standard” set of general ledger accounts that split the labor costs to utility segment based on an expected ratio of work between segments. This split can be unique and is based on the employee’s position. Costs are distributed based on this standard labor distribution for each employee, and the allocations are reviewed annually. Time studies are completed at least every five years.

- Payroll allocations for operations supervisors are a function of their direct reports or may be determined by time studies conducted.
- Payroll allocations for staff engineers are determined by time studies.
- Payroll allocations for General Office support staff are reviewed by the applicable department head based on the type of work performed.

Reimbursable employee expenses are directly assigned to a utility segment and FERC account when possible. For employee expenses that are applicable to more than one utility segment, such as training that is not specific to a utility segment, the employee's standard labor distribution percentages for each segment are used.

Taxes Other than Income

Ad valorem taxes are reviewed by function and all functions are directly assigned except for common ad valorem taxes, which follow plant. Payroll related taxes follow the allocation of labor and revenue and electric production taxes are directly assigned. Common taxes other than income, such as the Highway Use tax or Secretary of State filing tax are allocated on the appropriate factor to the segments.

Income Taxes

Income taxes, both current and deferred, are allocated to the utility segment based on the underlying revenue or expense that generated the deferred taxes.

If the underlying income item is specific to a particular segment, the related taxes are assigned directly to that segment. If the underlying income item is common to both segments, the related taxes are allocated with factors used to allocate the underlying revenue or expense.

Plant in service / work in progress / reserve / depreciation

Plant in service, work in progress, reserve and depreciation expense accounts are assigned to a utility segment based on the function of property.

For property that benefits both utility segments an allocation process is used.

The allocation process is based on the combination of the location of the asset and the FERC account (function) that is used to allocate the project, asset, reserve and depreciation. See Exhibit VI for a list of the allocation factors.

Prepayments

Prepaid demand and commodity charges are directly assigned to the applicable utility segment. Prepaid insurance is directly assigned where possible and common policies are allocated based on the type of policy.

Customer Advances

Customer advances are directly assigned to the applicable segment.

Other rate base items

Where possible, these items are directly assigned to the applicable utility segment. Common items are allocated based on the cost driver for each item.

Montana-Dakota / Great Plains Allocations to State Jurisdictions

Montana-Dakota utilizes an automated allocation process each month to record the income statement and rate base account activity to the financial ledger (state jurisdiction) to facilitate regulatory reporting. This process is based on the general ledger account structure used in the financial software (JD Edwards). As with other items, costs are directly assigned to a jurisdiction when possible. Costs common to more than one state jurisdiction are allocated between jurisdictions. The primary driver of the allocation is the Business Unit component of the general ledger account; however, the FERC account associated with the charge is also used to determine the proper allocation method. Since operation and maintenance costs are assigned to the utility segment as incurred, this process only allocates costs between state jurisdictions. The allocation process creates a Journal Entry to the JD Edwards jurisdictional ledgers established by state and utility segment.

The allocation methodology is as follows:

The JD Edwards (JDE) software is used by Montana-Dakota/Great Plains for recording financial transactions as well as the jurisdictional allocation process for all accounts except those related to fixed assets.

The account structure within JDE consists of the following components:

Business Unit **-** The Business Unit is one of the primary components used for identifying the regulatory allocation of costs. It usually defines a location such as an operating region, operating district or facility (i.e. power generating facility, substation, gas regulator station), or department (i.e. human resources, engineering).

Object **–** The object for operations and maintenance (O&M) expense accounts represents the resource consumed (i.e. payroll or materials). For balance sheet accounts, the object represents the FERC account.

Subsidiary **–** The subsidiary portion of the account for O&M accounts identifies the utility segment and the FERC account. For balance sheet accounts the subsidiary represents a further breakdown of the account such as which bank for a cash account.

Revenue Accounts – Revenues are directly assigned to the jurisdiction when possible. The applicable FERC account is part of the account structure and in the case of utility billed revenue the utility segment is included. It is the combination of the business unit, utility segment and FERC that drive the allocation factor used. An example of revenue that is allocated to the jurisdictions is revenue from the cost of service calculation which is assigned an allocable location (Business Unit).

Operation and Maintenance (O&M) accounts – As costs are incurred, the approver of the expense assigns the general ledger account structure.

It is the combination of the location (Business Unit), utility segment and FERC that drive the allocation factor utilized. Locations are assigned a factor based on the geographic area for which they serve and the FERC function assigned. For example, location (Business Unit) 230 represents the geographic location of the Sheridan, WY District. The Sheridan District serves both electric and gas and is therefore directly assigned to Wyoming for all FERC accounts. Another example is location 12900, representing the Credit and Collections Department. The Credit and Collections Department services both the electric and gas customers. The allocation of costs is based on the FERC range of accounts. The location may also be a responsibility, or department.

Location	Location Description	Sub 1	Sub 2	Utility Segment	Utility Alloc Code	Utility Allocation Description	Utility Allocation Rate	Juris Alloc Code	Juris Allocation Description	Juris Allocation Rate	Combined Effective Rate
230	Wyoming District	1560	15709999	1 Electric	00001	ELECTRIC ONLY	100.0000%	00005	WYOMING ONLY	100.000000%	100.000000%
230	Wyoming District	1580	19359999	1 Electric	00001	ELECTRIC ONLY	100.0000%	00005	WYOMING ONLY	100.000000%	100.000000%
12900	Credit & Collections	1920	19359999	1 Electric	00001	ELECTRIC ONLY	100.0000%	00026	O&M EXCLUDING FUEL & PURCHASED POWER & A&G	8.336614%	8.336614%
12900	Credit & Collections	1901	19169999	1 Electric	00001	ELECTRIC ONLY	100.0000%	00085	TOTAL COMPANY ELECTRIC CUSTOMER COUNT	11.315965%	11.315965%
12900	Credit & Collections	1580	15989999	1 Electric	00001	ELECTRIC ONLY	100.0000%	00118	ELECTRIC DISTRIBUTION PLANT	14.798583%	14.798583%

*Co	*Location	*Obj Acct	*FERC Sub 1	*FERC Sub 2	*Start Date	Stop Date	Description	Utility Alloc Code	Utility 01	Allocation Code 01
00001	230		1560	15709999	199703	203512	Wyoming District	00001	1	00005
00001	230		1580	19359999	199501	203512	Wyoming District	00001	1	00005
00001	230		28120	28120	199703	203512	Wyoming District	00002	2	00005
00001	230		2870	29359999	199501	203512	Wyoming District	00002	2	00005

00001 code = 100 % Electric

00002 code = 100 % Gas

Code 00005 = 100% allocated to WY

*Co	*Location	*Obj Acct	*FERC Sub 1	*FERC Sub 2	*Start Date	Stop Date	Description	Utility Alloc Code	Utility 01	Allocation Code 01
00001	12900		1580	15989999	200910	203512	Credit & Collections	00001	1	00118
00001	12900		1901	19169999	200501	203512	Credit & Collections	00001	1	00085
00001	12900		1920	19359999	200501	203512	Credit & Collections	00001	1	00026
00001	12900		2870	28949999	200910	203512	Credit & Collections	00002	2	00119
00001	12900		2901	29169999	200501	201508	Credit & Collections	00002	2	00086
00001	12900		2901	29169999	201509	203512	Credit & Collections	00002	2	00087
00001	12900		2920	29359999	200501	203512	Credit & Collections	00002	2	00027

Utility Allocation Code
Represents the code used to allocate costs to a business segment
00001 = Electric segment
00002 = Gas segment

Allocation code 01
Represents the code used to allocate costs to a Jurisdiction
00118 = Electric distribution plant
00085 = Total company electric customer count
00026 = O&M excluding fuel & purchased power and A&G
00119 = Gas distribution plant
00087 = Total company gas sales customer count
00027 = O&M excluding cost of gas and A&G

Taxes Other Than Income

Taxes other than income taxes are directly assigned when possible. Ad valorem taxes are allocated based on the subsidiary, which indicates the jurisdiction and function. Payroll related taxes follow the allocation of labor, revenue taxes are directly assigned and generation and other taxes are allocated on the applicable factor.

Income Taxes

Federal taxes that are allocated or directly assigned to the utility segment are allocated to the segment's jurisdictions based on the factors used to allocate the underlying revenue or expense among the jurisdictions within that segment.

State taxes that are allocated or directly assigned to a utility segment, are allocated to the jurisdictions that have state income tax based on their respective state apportionments.

Plant in Service/Work in Progress/Reserve/Depreciation Accounts

Plant in service, work in progress, reserve and depreciation expense accounts are allocated in through a similar process in the PowerPlan software based on attributes associated with the work order and asset.

It is the combination of the utility segment, location of the asset and the FERC account that is used to allocate the project, asset, reserve and depreciation. The tables that are maintained in JDE for jurisdictional allocations are interfaced into PowerPlan and are used to allocate these accounts.

Allocation Factors
The allocation factors are computed annually by the Regulatory Affairs and General Accounting departments and assigned to the proper Business Unit (location) effective in January each year. See Exhibit VI for a list of the allocation factors.

Exhibit I- MDUR Corporate Overhead factor

MDU Resources Group, Inc.
Corporate Overhead Allocation Factor
January - June 2019

	MDU Electric	MDU/GP Gas	CNGC	IGC	WBI Energy Transmission	WBI Energy Midstream	KR	CSG
MDUR Corporate Factor	20.4%	14.0%	14.9%	10.0%	8.3%	0.3%	22.9%	9.2%

MDU RESOURCES GROUP, INC.
12 Month Average Consolidating Balance Sheet
September 2018

	WBI Energy	Knife River	Construction Services	Utilities Group	Consolidated
Debt and Equity					
Short-term borrowings					---
LTD due within one year	1,000,000.00	28,809,524.50	71,239.98	97,035,948.02	126,916,712.50
Long-term debt	184,897,919.53	341,354,594.53	89,118,439.42	1,118,067,733.43	1,733,438,686.91
Total Debt	**185,897,919.53**	**370,164,119.03**	**89,189,679.40**	**1,215,103,681.45**	**1,860,355,399.41**
Stockholders' equity:					
Preferred stocks		---	---	---	---
Common stock	1,000.00	800,000.00	1,000.00	196,082,279.67	196,884,279.67
Other paid-in capital	803,182,762.05	495,748,408.91	134,859,038.50	1,739,022,954.79	3,172,813,164.25
Retained earnings	(586,466,247.50)	123,448,294.30	162,271,164.51	1,081,619,915.31	780,873,126.62
Accumulated other comprehensive income (loss)	(3,158,615.65)	(29,585,480.00)	(2,627,163.98)	(43,006,431.98)	(78,377,691.61)
Treasury stock	---	(3,625,812.59)	---	(3,625,812.59)	(7,251,625.18)
Total common stockholders' equity	**213,558,898.90**	**586,785,410.62**	**294,504,039.03**	**2,970,092,905.20**	**4,064,941,253.75**
Total stockholders' equity	**213,558,898.90**	**586,785,410.62**	**294,504,039.03**	**2,970,092,905.20**	**4,064,941,253.75**
Total liabilities and stockholders' equity	**399,456,818.43**	**956,949,529.65**	**383,693,718.43**	**4,185,196,586.65**	**5,925,296,653.16**
IC Investment in Subsidiaries	---	---	---	1,706,288,626.51	1,706,288,626.51
Fidelity E&P 12 Mth Avg Capitalization	(40,471,854.42)	---	---	---	(40,471,854.42)
Capitalization	**358,984,964.01**	**956,949,529.65**	**383,693,718.43**	**2,478,907,960.14**	**4,178,536,172.23**

	WBI Energy	Knife River	CSG	Utilities Group	Total
MDUR Corporate OH Factor	8.6%	22.9%	9.2%	59.3%	100.0%

	2018 Capitalization (In thousands)	Share of Corp. Allocation	Corporate Allocation	Electric	Gas
Montana-Dakota 1/	$1,465,385	58.0%	34.4%	20.4%	14.0%
Cascade	635,833	25.2%	14.9%		14.9%
Intermountain	425,565	16.8%	10.0%		10.0%
Total Utilities Group	$2,526,783	100.0%	59.3%	20.4%	38.9%

1/ Electric and gas segments allocated on Montana-Dakota's Corporate Overhead Factor

Exhibit II- Montana-Dakota/Great Plains Overhead factor

Montana-Dakota Utilities Co.
Corporate Overhead Allocation Factors
January - June 2019

	Electric	Gas
Montana-Dakota corporate factor	59.2	40.8
Employee factor	42.9	57.1
Plant factor	75.5	24.5
Customer factor	32.6	67.4

Exhibit III- Montana-Dakota/Great Plains Customer Allocation Factors

Montana-Dakota Utilities Co
2019 Customer Allocation Factors

	Customers	% Factor	State % Factor
Montana			
Gas	84,565	0.77	0.20
Electric	25,707	0.23	0.06
	110,272	1.00	0.26
North Dakota			
Gas	109,365	0.54	0.26
Electric	92,817	0.46	0.22
	202,182	1.00	0.49
South Dakota			
Gas	60,402	0.88	0.15
Electric	8,547	0.12	0.02
	68,949	1.00	0.17
Wyoming			
Gas	18,782	0.54	0.05
Electric	15,976	0.46	0.04
	34,758	1.00	0.08
Total Customers	416,161		

Great Plains
Jurisdictional Customer Allocation Factor

North Dakota GPNG	2,275	0.10
Minnesota - GPNG	21,668	0.90
	23,943	1.00

Montana-Dakota Utilities Co
Customer Count Splits for Regions and Districts

Rocky Mountain Region		**Badlands Region**	
MT Gas	65%	ND Elec	36%
WY Elec	16%	ND Gas	23%
WY Gas	19%	MT Elec	22%
		MT Gas	18%
Billings District		SD Elec	1%
All Gas	100%		
Sheridan Dist (#63)		**Reg split (#65)**	
Electric	46%	Electric	59%
Gas	54%	Gas	41%
		Dickinson Dist	
		Electric	58%
Dakota Heartland Region		Gas	42%
ND Elec	34%	***Glendive Dist***	
ND Gas	55%	Electric	56%
SD Elec	5%	Gas	44%
SD Gas	6%	***Williston Dist (#69)***	
		Electric	65%
Region Split (#64)		Gas	35%
Electric	39%	***Wolf Point Dist (#68)***	
Gas	61%	Electric	50%
Bismarck Dist (#86)		Gas	50%
Electric	51%		
Gas	49%		
Mobridge Dist (#14)		**Black Hills Region**	
Electric	58%	SD Gas	100%
Gas	42%		
Jamestown District		***Rapid City District***	
All Gas	100%	All Gas	100%
Minot District		***Spearfish District***	
All Gas	100%	Gas	100%

Customer Allocations by State

GAS		
MT Gas	84,565	31.0%
ND Gas	109,365	40.0%
SD Gas	60,402	22.1%
WY Gas	18,782	6.9%
	273,114	
ELECTRIC		
MT Elec	25,707	18.0%
ND Elec	92,817	64.9%
SD Elec	8,547	6.0%
WY Elec	15,976	11.1%
	143,047	

Exhibit IV- MDUR Shared Services Pricing Methodology

MDU Resources Shared Services
Pricing Methodology - Effective for 2019

Note: Any shared services amount allocated to MDU Resources are charges out to the business units on the corporate allocation factor.

761 – Payroll Shared Services:

Payroll Shared Services costs are invoiced based on the number of employees paid and stated as a cost per check. The word check, for this purpose, generically refers to paper paychecks, direct deposits and pay card transactions.

Checks are charged on a tiered structure, intended to recognize the fixed or baseline effort associated with maintaining a payroll cycle and associated reporting, regardless of number of people paid. It is also intended to reward consolidation of multiple pay groups and companies where possible and to align charges with the additional effort required to maintain multiple pay groups and pay cycles.

The monthly volume for this step pricing is accumulated individually for each pay cycle processed.

Checks for weekly pay cycles, cost per check based on the number of checks written per month:
- $ 4.25 per check for the first 500 checks
- $ 0.25 per check for the next 500 checks
- $ 0.10 per check for each additional check

Checks for non-weekly pay cycles, cost per check based on the number of checks written per month:
- $ 4.25 per check for the first 1500 checks
- $ 0.25 per check for the next 500 checks
- $ 0.10 per check for each additional check

Additionally, there will be a $4.00 charge for each tax payment and $250.00 charge for each quarterly tax filing and $2 charge for each W2

There is a $500 per month minimum charge for each operating company.

There is a premium charge of $50 per transaction for specific off cycle checks and back-pay calculations. Examples of transactions included in the premium charge schedule are missing hours, refunded deductions, length of service awards submitted too late for inclusion in a scheduled payroll process, and back pay calculation because an increase was submitted after the pay period that includes the effective date. Examples of transactions excluded from the premium charge calculation are bonus payments, final paychecks, certified wage settlements, or any payment required as a result of a Shared Service or system error.

766 –Time Entry Shared Services:

Time entry service is provided for the Utility Group and MDU Resources employees based on the average number of employees at each location.

	MDUR	MDU/GP	CNG	IGC	WBIE	KRC	CSG*	Total
Average Number of Employees	205	1,050	365	245				1,865
Total weighted allocation factor	10.99%	56.30%	19.57%	13.14%				100%

* Time Entry Shared Services manually keys time entry for Desert Fire. Payroll Shared Services and Desert Fire agree to use two times the amount of the cost per check rather than a separate time entry charge. The two methods are comparable.

970 – Human Resources:

Human Resources costs for the MDU Resources HR team are based on employees served. The average number of employees at each company for 12 months ending June 30 is calculated, then further broken down to whether they are on the Corporate-held benefit plans and/or retirement plans.

An allocation for each individual HR team member is calculated based on which group(s) of employees they serve. For example, an HR Generalist whose functions serve the Regulated companies would have an allocation to MDUR, MDUG, and WBI. A Benefits Analyst who is responsible for the Health & Welfare plans would have an allocation to the regulated companies as well as KRC and CSG companies who participate in the Corporate plans.

These individual allocations are all combined into one aggregate allocation to be used by all MDUR shared HR employees. The reason for this method is that the same work would need to be absorbed should a vacancy occur. Human Resources has three individuals that are not considered shared services and are allocated on the corporate overhead allocation factor.

	MDUR	MDU/GP	CNG	IGC	WBIE-T	WBIE-M	KRC	CSG	Total
Allocation	4.34%	25.15%	7.60%	5.25%	13.72%	2.61%	22.49%	18.84%	100%

762 –Business Services:
This allocation factor is derived from the results of the following four responsibilities. After allocating the projected (budget) costs for the following four responsibilities to each business unit, based on the weighted allocation factor of each of these four responsibilities, each business unit total is summed and divided by the total cost resulting in the following allocation percentages. Individuals in this responsibility provide oversite and support for the following four responsibilities.

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Allocation %	17.66%	32.71%	11.66%	9.55%	0.64%	6.06%	1.48%	12.28%	7.96%	100%

763 –Fleet and Travel:
Fleet and Travel Departments costs are invoiced based on five weighted factors from the previous year:

- Travel – based on corporate factor
- Managed Units
- National Account Spend
- Construction Equipment Acquisitions
- Fleet Acquisitions

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
% of Travel Corporate		34.30%	14.40%	12.50%		8.00%	0.40%	21.70%	8.70%	100%
# Managed Units		36	319	223						578
% of Managed Units		6.23%	55.19%	38.58%						100%
National Account Spend	$1,322,570	$18,679,456	$7,681,820	$4,895,822		$6,196,219	$992,764	$132,526,463	$51,797,911	$224,093,025
% of National Account Spend	0.59%	8.34%	3.43%	2.18%		2.77%	0.44%	59.14%	23.11%	100%
# Construction Equip Acquisitions		69	18	9		7	4	108	107	322
% of Construction Equip Acquisitions		21.43%	5.59%	2.80%		2.17%	1.24%	33.54%	33.23%	100%
# Fleet Acquisitions		29	25	29		40	7	166	127	423
% of Fleet Acquisitions		6.86%	5.91%	6.86%		9.46%	1.65%	39.24%	30.02%	100%
Weighted Allocation Factors:										
Travel Corporate	21.70%	The percent of time spent on corporate travel.								
# Managed Units	15.66%	The percent of time spent on managed units.								
National Acct Spend	15.66%	The percent of time spent on national accounts.								
Construction Equip Acquisition	23.49%	The percent of time spent on the acquisition of construction equipment assets.								
Fleet Acquisition	23.49%	The percent of time spent on the acquisition of vehicle assets.								
	MDUR	**MDU/GP**	**CNG**	**IGC**	**WBIE**	**WBIT**	**WBIM**	**KRC**	**CSG**	**Total**
Total weighted allocation factor	0.09%	16.37%	15.00%	11.36%		4.90%	0.84%	31.07%	20.37%	100%

764 –Supply Chain:
There are several individuals that are primarily focused on the Utility Group and some that have multiple business unit responsibilities.

Allocations are based on two weighted factors from previous year:

- Purchase Order Count
- Purchase Order Line Count

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Purchase Order Count	29	4413	908	971		835	252			7,408
% of Purchase Orders	0.39%	59.57%	12.26%	13.11%		11.27%	3.40%			100%
Purchase Order Line Count	44	26,707	2,770	2,858		4,876	1,479			38,734
% of Purchase Order Line Count	0.11%	68.95%	7.15%	7.38%		12.59%	3.82%			100%
Weighted Allocation Factors:										
PO Count	1.00%	The percent of purchase orders processed by Company.								
PO Line Count	99.00%	The percent of lines on purchase orders processed by Company.								
	MDUR	**MDU/GP**	**CNG**	**IGC**	**WBIE**	**WBIT**	**WBIM**	**KRC**	**CSG**	**Total**
Total weighted allocation factor	0.12%	68.86%	7.20%	7.44%		12.57%	3.81%			100%

767 –Accounts Payable:
Costs are invoiced based on four weighted factors from previous year:

- Number of Payments
- Number of Vouchers
- Number of Unclaimed Property reports
- Number of PNC payments

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
# of Payments - 8/1/2017 through 8/1/2018	2,133	32,726	20,778	18,433		6,686	2,044		739	83,539
% of Payments	2.55%	39.17%	24.87%	22.07%		8.00%	2.45%		0.89%	100%
# of Vouchers - 8/1/2017 through 8/1/2018	2,497	49,487	32,806	23,596		11,911	3,312		1,525	125,134
% of Vouchers	1.99%	39.55%	26.22%	18.85%		9.52%	2.65%		1.22%	100%
# of States Filed In - as of 5/26/2018		34	17	28		23	3	10	4	119
% of Unclaimed Property		28.57%	14.29%	23.53%		19.33%	2.52%	8.40%	3.36%	100%
# of Companies Implemented - as of 8/1/2018	3	1	1	1		1	1	19	16	43
% of PNC	6.98%	2.32%	2.33%	2.33%		2.32%	2.32%	44.19%	37.21%	100%
Weighted Allocation Factors:										
# of Payments	15.00%	The percent of time spent on processing payments, setting up address book records, 1099s, etc.								
# of Vouchers	65.00%	The percent of time spent on vouchering and reviewing invoices								
# of Unclaimed Property	15.00%	The percent of time spent filing unclaimed property reports, sending due diligence letters, defending audits.								
# of PNC	5.00%	The percent of time spent with companies that are using PNC to make vendor payments.								
	MDUR	**MDU/GP**	**CNG**	**IGC**	**WBIE**	**WBIT**	**WBIM**	**KRC**	**CSG**	**Total**
Total weighted allocation factor	2.00%	36.00%	23.00%	19.20%		10.40%	2.60%	3.50%	3.30%	100%

770 –Buildings and Grounds:
This allocation is based on labor hours spent by location from the previous year

	MDUR	MDU/GP	CNG	IGC	WBIE	KRC	CSG	Total
Allocation %	43.00%	50.00%			4.00%	3.00%		100%

Enterprise Information Technology (EIT):

There are several EIT departments, and each is billed out based on its own criteria. They are as follows:

Application Services (765) – The allocations will be based on time tracked history for the 12 months of the prior year. The MDUG portion is further divided by meter count and the WBI portion is further divided by the WBI corporate factor.

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
12-month work load	3,977	2,955	1,944	2,347		970	103	1,234	237	13,767
% of 12 mon work load	28.89%	21.46%	14.12%	17.05%		7.05%	0.75%	8.96%	1.72%	100%

Definition of 765: This team is made up of software developers providing integrations to systems and software changes.

Operational Technology (768) –The allocations are based on projected work load. This department is 100% direct allocated based on the projects assigned.

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Projected Hours	661	5.579								6,240
% of 12 mon work load	10.60%	89.40%								100%

Definition of 768: This team is made up of security and infrastructure technicians.

Customer Relations (965) – Enterprise charges for the customer relations group are invoiced using three weighted allocation factors. The factors are as follows:

1. Direct charge for employees working for a specific business
2. Number of computing devices supported by the help desk (90%)
3. Number of mobile devices supported by the help desk (10%)

The metric used to determine device counts is devices that have checked into active directory during a 60-day period in the summer of 2018 and active devices in MobileIron.

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Direct Charges			53.53%	46.47%						100%
Factor- 13.49%			7.22%	6.27%						13.49%
Computing Device Counts	313	1,266	509	653	54	309	46	1,885	1,798	6,833
% of Device Count	4.58%	18.53%	7.45%	9.56%	0.79%	4.52%	0.67%	27.59%	26.31%	100%
% of Device Factor- 77.86% (86.51% x 90%)	3.57%	14.42%	5.80%	7.44%	0.62%	3.52%	0.53%	21.48%	20.48%	77.86%
Mobile Device Counts	159	561	277	195	207			1,866	2,410	5,675
% of Device Count	2.80%	9.89%	4.88%	3.43%	3.65%			32.88%	42.47%	100%
% of Device Factor- 8.65% (86.51% x 10%)	0.24%	0.86%	0.42%	0.30%	0.32%			2.84%	3.67%	8.65%
Total weighted allocation factor	3.81%	15.28%	13.44%	14.01%	0.94%	3.52%	0.53%	24.32%	24.15%	100%

Definition of 965: This team is made up of help desk agents who support company owned devices and software.

Communications (971)

Enterprise charges for the communications group are invoiced using four weighted allocation factors. The factors are as follows:

1. Direct charge for employee hours working for a specific business (10.53%) (MDUG portion is split by meter count).
2. Wide Area Network/Local Area Network/Metropolitan Area Network- Number of business unit locations (35.79%)
3. Internet/Firewall Access – Number of computing devices (35.79%)
4. IP Telephony (17.89%)

The costs are invoiced based on the following percentages:

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Direct Charges		40.78%	26.83%	32.39%						100%
Factor- 10.53%		4.29%	2.83%	3.41%						10.53%
WAN/LAN/MAN	7	61	19	13	1	144	3	222	78	548
% of Business Unit Locations	1.28%	11.13%	3.47%	2.37%	0.18%	26.28%	0.55%	40.51%	14.23%	100%
Factor- 35.79%	0.46%	3.98%	1.24%	0.85%	0.06%	9.41%	0.20%	14.50%	5.09%	35.79%
Internet Access/Firewall	313	1,266	509	653	54	309	46	1,885	1,798	6,833
% of User Accounts	4.58%	18.53%	7.45%	9.56%	0.79%	4.52%	0.67%	27.59%	26.31%	100%
Factor- 35.79%	1.64%	6.63%	2.67%	3.42%	0.28%	1.62%	0.24%	9.87%	9.42%	35.79%
IP Telephone	256	822	435	389		269	35	1,747	177	4,130
% of Handsets	6.20%	19.90%	10.53%	9.42%		6.51%	0.85%	42.30%	4.29%	100%
Factor- 17.89%	1.11%	3.56%	1.88%	1.69%		1.16%	0.15%	7.57%	0.77%	17.90%
Total weighted allocation factor	3.21%	18.46%	8.62%	9.37%	0.34%	12.19%	0.59%	31.94%	15.28%	100%

Definition of 971: This team supports the wide area network and phones. This includes switches, routers and firewalls.

Operations (972) – Enterprise charges for the operations group are invoiced using three separate factors

(1) 18.12% are direct charges that are costs directly related to the AS/400 computer and are invoiced upon the AS/400 allocation as agreed to by MDU and WBI.

The remaining 81.88% of the costs are based upon the number of servers that are supported for each business unit. These servers are then broken out between full service servers and shared service servers. Full service servers have a greater weighting factor since they require more dedicated time and cost more.
(2) Full Service Servers - 61.41% (81.88% x 75%)
(3) Shared Service Servers 20.47% (81.88% x 25%).

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Direct Charges	4.93%	39.76%	22.80%	23.85%	8.34%				0.32%	100%
Factor- 18.12%	0.90%	7.20%	4.13%	4.32%	1.51%				0.06%	18.12%
Full Service Servers	240	84	1	2	32	5		133	36	533
% of Full Service Servers	45.03%	15.76%	0.19%	0.38%	6.00%	0.94%		24.95%	6.75%	100%
Factor- 61.41%	27.65%	9.68%	0.12%	0.23%	3.69%	0.58%		15.32%	4.14%	61.41%
Shared Service Servers		131	38	92		31	3	49	105	449
% of Full Service Servers		29.18%	8.46%	20.49%		6.90%	0.67%	10.91%	23.39%	100%
Factor- 20.47%		5.97%	1.73%	4.19%		1.41%	0.14%	2.24%	4.79%	20.47%
Total weight allocation factor	28.55%	22.85%	5.98%	8.74%	5.20%	1.99%	0.14%	17.56%	8.99%	100%

Definition of 972: This team is responsible for administration of the enterprise servers.

Security (977) – Enterprise charges for the security group are distributed via the number of computing devices (90.00%) and mobile devices (10.00%). Costs are invoiced based on the following percentages:

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Computing Device Counts	313	1,266	509	653	54	309	46	1,885	1,798	6,833
% of Device Factor- 90%	4.12%	16.67%	6.70%	8.60%	0.72%	4.07%	0.61%	24.83%	23.68%	90.0%
Mobile Device Counts	159	561	277	195	207			1,866	2,410	5,675
% of Device Factor- 10%	0.28%	0.99%	0.49%	0.34%	0.36%			3.29%	4.25%	10.0%
Total weighted allocation factor	4.40%	17.66%	7.19%	8.94%	1.08%	4.07%	0.61%	28.12%	27.93%	100%

Definition of 977: This team supports the cyber security initiatives.

ERP (956) – Enterprise charges for the ERP group are being allocated based on 12 months of the prior year hours worked in JIRA. The costs are invoiced based on the following percentages:

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
12-month work load	927	885	362	196	1,064			277		3,711
% of 12 mon work load	24.98%	23.84%	9.76%	5.29%	28.67%			7.46%		100%

Definition of 956: This team supports the accounting software.

Scada (968) – Enterprise charges for the SCADA group are being allocated based on 12 months of the prior year of hours worked in JIRA. The costs are invoiced based on the following percentages:

	MDUR	MDU/GP	CNG	IMG	WBIE	WBIT	WBIM	KRC	CSG	Total
12-month work load		444	438	528		2,707				4117
% of 12 mon work load		10.78%	10.64%	12.83%		65.75%				100%

Definition of 968: This team supports the gas SCADA systems.

Governance (982) –. Costs for the governance and administration group are invoiced based on a weighting of the combined methodologies of the eight previous EIT responsibilities.

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
2019 % of Total Governance & Administration	15.73%	22.88%	9.23%	10.66%	3.24%	7.76%	0.44%	18.66%	11.40%	100%

Exhibit V- Utility Operations Support Allocation Methodology

Leadership Group:

President & CEO (985) – The payroll allocations will be based on average Utility Group customer and employee counts for the President & CEO and Executive Assistant.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Customer Counts	118,169	245,530	293,376	365,744	1,022,819
% of Factor – 50%	5.75%	12.03%	14.34%	17.88%	50%
Utility Group Employee Counts	431	573	338	242	1,584
% of Factor – 50%	13.60%	18.10%	10.65%	7.65%	50%
Total weighted allocation factor	19.4%	30.1%	25.0%	25.5%	100%

Executive Vice President of Business Development & Gas Supply (701) – The payroll allocations will be based on Utility Group customer counts.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Customer Counts	11.5%	24.0%	28.7%	35.8%	100%

Vice President of Safety, Process Improvement & Operations Systems (707) – The payroll allocations will be based on Utility Group meter counts.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Meter Counts	13.4%	27.1%	26.5%	33.0%	100%

Executive Vice President of Regulatory Affairs, Customer Service & Administration (919) – The payroll allocations will be based on meter counts.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Meter Counts	13.4%	27.1%	26.5%	33.0%	100%

Vice President of Operations & Engineering Service (960) – The payroll allocations will be based on Utility Group customer counts.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Customer Counts	11.5%	24.0%	28.7%	35.8%	100%

Customer Service Group:

The Customer Service group is made up of four distinct areas and provides service to all four brands within the MDU Utility Group. Those areas are Credit and Collections, Scheduling, Customer Service, and Customer Programs and Support. In addition to these departments, the Customer Service group has a management team, Consumer Specialists, and other administrative positions. Customer Service payroll costs are allocated using five (5) different methodologies: Customer Count, Customer Call Time, Cleared Order Count, Credit To-Dos, and Emails and Web Requests. Costs other than payroll will be allocated based on customer count if they provide benefit for all brands. Costs specific to a brand will be charged directly to that brand and will not go through an allocation process.

Customer Count

- Based on the average customer count of each utility brand from December to November.
- Uses a customer weighting of 1 for each natural gas or electric only customer and 1.25 for each electric/natural gas combination customer.
- The following positions will be allocated based on customer count ***with nonutility***:
    - Customer Service Director
    - Manager, Customer Service
    - Supervisor, Customer Service
    - Customer Service Trainer
    - Customer Service Team Lead (Support)
- The following positions will be allocated based on customer count ***without nonutility***:
    - Administrative Assistant
    - Customer Service Team Lead (Credit)
    - Customer Project Analyst I and II
    - Supervisor, Scheduling & Customer Support
    - Manager, Customer Service & Credit
    - Customer Communications Coordinator
    - Supervisor, Credit & Collections
    - Manager, Scheduling, Support, Prgm
    - Scheduling Analyst
    - Scheduling Lead

Customer Call Time

- Based on the total time that Customer Service Agents are handling a call.
    - Includes total talk time and after call work
    - Does not include idle time or auxiliary time
- Uses data for the preceding December to November of each year.
- The following positions will be allocated based on customer call time:
    - Customer Service Rep I, II, III, IV, and IV PT

- ***Cleared Order Count***
    - Based on the number or work orders cleared through the work assignment management system for each brand.
    - Uses data for the preceding December to November of each year.
    - The following positions will be allocated based on cleared order count:
        - Scheduler

- ***Credit To-Do's***
    - Based on three types of completed To-Do's;
        - accounts up for severance

        - closed accounts pending write-off
        - broken payment plans
    - Uses data for the preceding December to November of each year.
    - The following positions will be allocated based on credit to-do's:
        - Credit & Collections Rep I, II, and III
        - Credit Support Rep

- ***E-mails and web requests***
    - Based on e-mails that include direct inquiries from customers, follow up requests from a CSR phone call, or e-mails generated by the web applications requiring account maintenance.
    - Uses data for the preceding December to November of each year.
    - The following positions will be allocated based on e-mails
        - Customer Support Rep I, II, and III

	MDU Elect	MDU/GP Gas	MDU Nonutility	CNG	IGC	Total
Customer Counts	11.82%	24.51%	.74%	28.1%	34.83%	100%
Customer Counts	12.06%	25.01%	-	28.1%	34.83%	100%
Customer Call Time	12.49%	25.9%	-	27.9%	33.71%	100%
Cleared Order Count	10.48%	21.91%	-	35.88%	31.73%	100%
Credit To-Dos	15.53%	32.21%	-	19.63%	32.63%	100%
Emails	10.05%	20.85%	-	30.92%	38.18%	100%

<u>Operations & Engineering Services Group:</u>

Process Improvement & Operations Tech (Dept 703)
The payroll allocations will be based on the Utility Group employee counts.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Employee Counts	27.2%	36.2%	21.3%	15.3%	100%

Quality Control (Dept 730)
The Quality Control department provides oversight and post work review of both maintenance and construction work that is performed by both utility group employees and our contractors. The payroll allocations will be based on time studies.

Engineering Services (Dept 769)
The Engineering Services department duties include gas modeling, working with district personnel, engineering design of capital projects, creation of cost estimates, creation of design and work plans, budget planning, etc. The payroll allocations will be based on time studies.

Construction Services (Dept 863)
The Construction Services (CS) department provides construction management and inspection for large and high-pressure projects, as well as for projects generated by TIMP, DIMP, and MAOP Validation Plans. CS creates and manages programs and procedures for welding and fusion programs. Fabrication standards and a majority of fabrication are done by CS. The payroll allocations will be based on time studies.

Operation Systems (Dept 864)
This department supports Operations compliance systems as well as supporting other systems that Operations and Engineering utilize. The group not only supports these efforts but also works as a liaison group between the business and enterprise information technology (EIT). The payroll allocations will be based on time studies. Costs specific to a brand will be charged directly to that brand and will not go through an allocation process.

System Integrity (Dept 865)
The System Integrity department is responsible for the Utilities Distribution and Transmission Integrity Management Programs, Integrity Projects, Cascade's MAOP Validation Project, and Corrosion Control. The payroll allocations will be based on time studies.

Safety Management System & Quality Assurance (Dept 866)
The Safety Management System and Quality Assurance (SMS/QA) department is responsible for the implementation of the utility group's safety management system. The team is responsible for reviewing, documenting, and developing processes to ensure compliance with the industry recommend practice 1173. Key objectives of our current plan include the development of an operational risk management program, SMS/QA program oversight and metrics, and completion of risk-based process audits. The payroll allocations will be based on Utility Group gas customer count.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Gas Customer Counts	-	31.2%	30.6%	38.2%	100%

Operations Policies & Procedures (Dept 923)
This department is responsible for aligning new Utility Group procedures as well as maintaining all previous company specific procedures. Each company was and is required to have and maintain these procedures per federal code 192. The payroll allocations will be based on an equal share across the gas segments.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Allocation %	-	34.0%	33.0%	33.0%	100%

Operation Services (Dept 958)
The Operation Services department provides compliance, damage prevention, and public awareness across the Utility Group. The payroll allocations will be based on time studies.

Information Technology and Communications Group:

Enterprise Network & Telecommunications (Dept 721)
This department processes bill payment files, provides scheduled and Ad Hoc reporting, and monitors nightly batch file updates. The payroll allocations will be based on Utility Group Capitalization Factor.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Capitalization Factor	34.3%	23.7%	25.2%	16.8%	100%

Enterprise Management, Enterprise Development and Integration, Field Automation (Dept 723, 926, 964)
These teams support business and technical functions that are common to all brands. Provides support to the business through data requests and augments the system by developing programs and technical solutions to accommodate business and field needs as well as regulatory requirements. The payroll allocations will be based on Utility Group meter counts.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Meter Counts	13.4%	27.1%	26.5%	33.0%	100%

Enterprise GIS (Dept 951)
This department provides gas, electric and fiber pipeline and facilities mapping services for the Utility Group The payroll allocations will be based on Utility Group meter counts or time studies.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Meter Counts	13.4%	27.1%	26.5%	33.0%	100%

Environmental (Dept 889)
The Environmental Department provides environmental regulatory compliance guidance and assistance to MDU Utilities Group facilities and operations in accordance with the company environmental policy: The Company will operate efficiently to meet the needs of the present without compromising the ability of future generations to meet their own needs. Our environmental goals are:

- To minimize waste and maximize resources.
- To support environmental laws and regulations that are based on sound science and cost-effective technology; and
- To comply with or exceed all applicable environmental laws, regulations and permit requirements.

The payroll allocations will be based on time studies.

Safety & Technical Training (Dept 720, 901)
The Safety and Technical Training department provides oversight for all things safety and technical training for the entire utility group. The payroll allocations will be based on Utility Group or Montana-Dakota employee counts or time studies, depending on the employee's job functions.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Employee Counts	27.2%	36.2%	21.3%	15.3%	100%
Montana-Dakota Utilities Employee Counts	42.9%	57.1%	-	-	100%

Business Development (Dept 918)
The payroll allocations will be based on time studies.

Gas Supply (Dept 931, 933)
The payroll allocations will be based on two methodologies: Utility Group meter count and time studies. There are employees focused on Montana-Dakota Utilities functions, which will be allocated 100% to Montana-Dakota Utilities gas segment.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Meter Counts	-	40.5%	26.5%	33.0%	100%

Utility Group Controller (Dept 941)
The Controller Department provides various accounting services to the Utility Group: Fixed Assets Accounting, Revenue Accounting, Internal Controls Coordination, and Management. The payroll allocations are based on these methodologies: Utility Group customer count, Utility Group meter count, number of employees, Montana-Dakota customer factor, Utility Group corporate factor, Montana-Dakota corporate factor, and specific shared services methodologies.

- ***Utility Group customer count***
  - The following positions will be allocated based on Utility Group customer count based on job duties/functions:
    - Business Analyst I and II (Revenue Accounting)
- ***Utility Group meter count***
  - The following positions will be allocated based on Utility Group meter count based on job duties/functions:
    - Business Analyst II and Sr. (Customer Accounting)
- ***Number of employees***
  - The following positions will be allocated based on number of employees under their supervision:
    - Controller – Utility Group
    - Director, Finance
    - Manager, Revenue Administration
- ***Montana-Dakota customer factor***
  - The following positions will be allocated based on MDU customer factor
    - Financial Analyst I, II (Revenue Accounting)
    - Financial Specialist (Revenue Accounting)
    - Financial Technician (Revenue Accounting)
    - Manager, Revenue Accounting

- ***Utility Group corporate factor***
  - The following position will be allocated based on Utility Group corporate factor
    - Internal Controls Coordinator
- ***Montana-Dakota corporate factor***
  - The following positions will be allocated based on MDU corporate factor
    - Financial Analyst I, II, III, IV (Gen Acctg, Reporting & Planning)
    - Financial Systems Analyst (Gen Acctg)
    - Financial Technician (Gen Acctg)
    - Manager, Accounting & Finance
    - Manager, Financial Reporting & Planning
      Manager, General Accounting

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Customer Counts	11.5%	24.1%	28.7%	35.7%	100%
Utility Group Meter Counts	13.4%	27.1%	26.5%	33.0%	100%
Number of Employees: Controller*	34.75%	24.0%	22.5%	18.75%	100%
Number of Employees: Director, Finance*	32.4%	22.4%	25.8%	19.4%	100%
Number of Employees: Manager, Revenue Administration**	19.1%	39.4%	22.0%	19.5%	100%
Montana-Dakota Customer Factor	32.6%	67.4%	-	-	100%
Utility Group Corporate Factor	34.4%	23.6%	25.1%	16.9%	100%
Montana-Dakota Corporate Factor	59.2%	40.8%	-	-	100%

* MDU electric/gas split is based on the MDU Corporate Factor.
** MDU electric/gas split is based on the MDU Customer Factor.

- ***Utility Group Fixed Assets Accounting methodology***
  - The following positions will be allocated based on time study:
    - Financial Analyst I, II, III, IV (Fixed Assets Accounting)
    - Supervisor, Fixed Assets Accounting
    - Manager, Fixed Assets Accounting

Costs for the Financial Analysts in the MDU Utility Group Fixed Asset Accounting group are invoiced based upon three separate methodologies based on the three major types of work performed in the department. The three major work types of work are:

1. Capital Expenditure Support (21.5% of workload)-Allocated to capital overhead (ES/GA) accounts based on 3-year average of capital expenditures.
2. Fixed Asset Life Cycle Support (63.5% of workload)-Allocated to capital overhead (ES/GA) accounts based on 3-year average of capital work orders weighted by a difficulty factor.
3. All Other Fixed Asset Accounting (15.0% of workload)-Allocated to expense (O&M) accounts based on estimate of time spent on non-project related tasks (Depreciation, ARO, Data Requests, etc.).

	MDUR*	MDU	WBIE**	KRC**	CSG**	CNG	IGC	Total
3-Year Average Capital Expenditures (Millions)		249.4				50.6	38.6	338.6
% of 3-Year Average Capital Expenditures		73.66%				14.94%	11.40%	100.00%
Capital Expenditure Support-21.5% Weight		15.84%				3.21%	2.45%	21.50%
3-Year Average Capital Work Orders		1,930				1,949	862	4,741
Difficulty Factor		68.29%				25.00%	25.00%	
Weighted % of 3-Year Average Capital WO's		65.22%				24.11%	10.67%	100.00%
Fixed Asset Life Cycle Support-63.5% Weight		41.41%				15.31%	6.78%	63.50%
% of Non-Project Related Task Time		62.64%				18.68%	18.68%	100.00%
All Other Fixed Asset Accounting-15% Weight		9.40%				2.80%	2.80%	15.00%
Totals		**66.65%**				**21.32%**	**12.03%**	**100.00%**
Total Allocated to ES/GA		57.25%				18.52%	9.23%	85.00%
Total Allocated to O&M		9.40%				2.80%	2.80%	15.00%

* Time devoted to CHCC companies deemed immaterial and is included in MDU amounts.
** No service provided to WBIE, CSG or CSG

Costs for the Manager of the Utility Group Fixed Asset Accounting group are invoiced based upon the company workload split of the "Other Fixed Asset Accounting" time spent by the Lead Financial Analyst in charge of depreciation, ARO's, data requests, etc. No portion of these costs is allocated to capital overhead (ES/GA) as they are deemed to be non-direct construction support costs.

	MDUR*	MDU	WBIE**	KRC**	CSG**	CNG	IGC	Total
Other Fixed Asset Acct. Workload of Lead Non-Project Support F/A		50.00%				10.00%	10.00%	70.00%
% Allocation of UGFA Manager Costs to O&M		71.42%				14.29%	14.29%	100.00%
Totals		**71.42%**				**14.29%**	**14.29%**	**100.00%**

* Time devoted to CHCC companies deemed immaterial and is included in MDU amounts.
** No service provided to WBIE, CSG or CSG

- ***Utility Group Payment Processing methodology***
    - Payment Processer (Revenue Accounting)
    - Payment Processer, Lead (Revenue Accounting)

Payment Processing has been allocated by utility brand based on the number of customer payments posted to utility accounts in the 12 month period ending June 30, 2018.

	CNG	IGC	MDU/GPNG	Total
# of Payments Processed	957,174	1,057,909	1,876,189	3,891,272
% of Payments Processed by Brand	24.6%	27.2%	48.2%	100%

Exhibit VI- Allocation Factors

- Plant in service allocation factors
- Income statement allocation factors
- Other rate base and income statement allocation factors

Minnesota Gas
Plant in Service Allocations
2019

Location	Location Description	Object Account	Account Description	Sub 1	Sub 2	Bus Segment	Utility Alloc Code	Utility Allocaiton Description	Utility Alloc Rate	Juris Allocation Code	Juris Allocation Description	Juris Allocation Rate	Combined Effective Rate
40	Great Plains Region	1010	Great Plains Region	303	30399999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00235	Great Plains Net Plant in Service	88.359885%	88.359885%
40	Great Plains Region	1010	Great Plains Region	391	3919	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00235	Great Plains Net Plant in Service	88.359885%	88.359885%
101500	Fergus Falls-General O	1010	Fergus Falls-General Office	389	39899999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00229	Great Plains Plt Excl Fergus Falls GO	88.734484%	88.734484%
327500	Bismarck Service Cent	1010	Bismarck Service Center	303	39999999	2 Natural Gas	00279	Bismarck Service Center Split - Region/GO	35.060659%	00279	Bismarck Service Center Gas - Region/GO	3.284556%	1.151587%
327503	Communicatn Dep-Bis	1010	Communicatn Dep-Bis Service Cr	391	39899999	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
498500	Mandan Office-G.O. A	1010	Mandan Office-G.O. Allocation	391	39899999	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900000	General Office	1010	General Office	303	30399999	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900000	General Office-Utility I	1010	General Office-Utility Main	389	39999999	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900001	General Office-Utility /	1010	General Office-Utility Annex	303	30399999	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900001	General Office-Utility /	1010	General Office-Utility Annex	389	39999999	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900002	General Office-Vehicle	1010	General Office-Vehicle Maint.	303	30399999	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900002	General Office-Vehicle	1010	General Office-Vehicle Maint.	389	39899999	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900003	General Office-Airport	1010	General Office-Airport	390	39099999	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900003	General Office-Airport	1010	General Office-Airport	391	39119999	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900003	General Office-Airport	1010	General Office-Airport	392	39239999	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900003	General Office-Airport	1010	General Office-Airport	398	398	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900005	Call Centr/Mobile Serv	1010	Call Centr/Mobile Services	303	30399999	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900005	Call Centr/Mobile Serv	1010	Call Centr/Mobile Services	389	39999999	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900007	Gen Off-MDU Joint Ov	1010	Gen Off-MDU Joint Own Cor Camp	389	39899999	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900008	Gen Off-MDU Owned	1010	Gen Off-MDU Owned at Corp Camp	303	303	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900008	Gen Off-MDU Owned	1010	Gen Off-MDU Owned at Corp Camp	389	39899999	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900009	G.O. EMS Integrated S	1010	G.O. EMS Integrated System	3972	39729999	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900010	MDU Utility Group	1010	MDU Utility Group	303	30399999	2 Natural Gas	00275	Total Customers	65.798448%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	4.826189%
900010	MDU Utility Group	1010	MDU Utility Group	389	39899999	2 Natural Gas	00028	Total Customers	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900011	G.O. Utility Group - Bo	1010	G.O. Utility Group - Boise, ID	389	39899999	2 Natural Gas	00028	Total Customers	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900012	G.O. Utility Group - Ke	1010	G.O. Utility Group - Kennewick	391	39899999	2 Natural Gas	00028	Total Customers	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900013	G.O. Utility Group - M	1010	G.O. Utility Group - Meridian	391	39899999	2 Natural Gas	00028	Total Customers	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900015	Gen Off - Vault Bldg	1010	Gen Off - Vault Bldg	389	39899999	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900016	Gen Off - West Fargo	1010	Gen Off - West Fargo	389	39899999	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900017	Bismarck Communicat	1010	Bismarck Communications & Substation Shop	303	39999999	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
40	Great Plains Region	1012	Great Plains Region	303	30399999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00235	Great Plains Net Plant in Service	88.359885%	88.359885%
40	Great Plains Region	1012	Great Plains Region	374	38099999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00235	Great Plains Net Plant in Service	88.359885%	88.359885%
40	Great Plains Region	1012	Great Plains Region	381	38399999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00241	Great Plains Sales & Transp Meters	90.538423%	90.538423%
40	Great Plains Region	1012	Great Plains Region	387	38899999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00235	Great Plains Net Plant in Service	88.359885%	88.359885%
40	Great Plains Region	1012	Great Plains Region	389	39899999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00235	Great Plains Net Plant in Service	88.359885%	88.359885%
90	MDU General Office	1012	MDU General Office	378	37899999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00037	Gas Gross Plant in Service	9.125997%	9.125997%
410	Great Plains North Dis	1012	Great Plains North District	374	39899999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00238	Great Plains Fergus Falls Composite	76.678757%	76.678757%
420	Great Plains South Dis	1012	Great Plains South District	374	39899999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
101000	Fergus Falls	1012	Fergus Falls	302	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
101001	Fergus Falls Peak Shav	1012	Fergus Falls Peak Shaving Plt	304	32099999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00239	North 5 Peak Day	75.256211%	75.256211%
101500	Fergus Falls-General O	1012	Fergus Falls-General Office	301	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00229	Great Plains Plt Excl Fergus Falls GO	88.734484%	88.734484%
102000	Pelican Rapids	1012	Pelican Rapids	302	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
103000	Breckenridge	1012	Breckenridge	302	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
103001	Breckenridge Peak Sha	1012	Breckenridge Peak Shaving Plt	304	32099999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
105000	Belview	1012	Belview	302	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
106000	Boyd	1012	Boyd	302	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
107000	Clarkfield	1012	Clarkfield	302	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
108000	Danube	1012	Danube	302	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
109000	Dawson MN	1012	Dawson MN	302	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
110000	Echo	1012	Echo	302	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
111000	Granite Falls	1012	Granite Falls	302	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
112000	Marshall	1012	Marshall	302	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
112001	Marshall Peak Shaving	1012	Marshall Peak Shaving Plt	304	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
113000	Montevideo	1012	Montevideo	302	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
113001	Montevideo Peak Shav	1012	Montevideo Peak Shaving Plt	304	32099999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
114000	Redwood Falls	1012	Redwood Falls	302	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
114001	Redwood Falls Peak Sh	1012	Redwood Falls Peak Shaving Pl	304	32099999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
115000	Renville	1012	Renville	302	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
116000	Sacred Heart	1012	Sacred Heart	302	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
117000	Wood Lake	1012	Wood Lake	302	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
118000	Crookston	1012	Crookston	302	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
119000	Vergas	1012	Vergas	302	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
900000	General Office-Utility I	1012	General Office-Utility Main	303	38899999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00040	Gas Plant Excl Common GO	9.465580%	9.465580%
900000	General Office-Utility I	1012	General Office-Utility Main	389	39899999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00040	Gas Plant Excl Common GO	9.465580%	9.465580%
900001	General Office-Utility /	1012	General Office-Utility Annex	303	303	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00123	Total Co Normalized Gas Sales Vols	8.794904%	8.794904%
900001	General Office-Utility /	1012	General Office-Utility Annex	3912	3912	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00040	Gas Plant Excl Common GO	9.465580%	9.465580%

Minnesota Gas
Plant in Service Allocations
2019

Location	Location Description	Object Account	Account Description	Sub 1	Sub 2	Bus Segment	Utility Alloc Code	Utility Allocaiton Description	Utility Alloc Rate	Juris Allocation Code	Juris Allocation Description	Juris Allocation Rate	Combined Effective Rate
900001	General Office-Utility A	1012	General Office-Utility Annex	398	398	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00040	Gas Plant Excl Common GO	9.465580%	9.465580%
900002	General Office-Vehicle	1012	General Office-Vehicle Maint.	389	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00040	Gas Plant Excl Common GO	9.465580%	9.465580%
900011	G.O. Utility Group - Bo	1012	G.O. Utility Group - Boise, ID	389	39899999	2 Natural Gas	00002	Total Customers	100.000000%	00040	Gas Plant Excl Common GO	9.465580%	9.465580%
900012	G.O. Utility Group - Ke	1012	G.O. Utility Group - Kennewick	3922	39229999	2 Natural Gas	00002	Total Customers	100.000000%	00040	Gas Plant Excl Common GO	9.465580%	9.465580%
900040	Gen Off - GPNG CC&B	1012	Gen Off - GPNG CC&B & PCAD	303	30399999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00227	Great Plains Sales & Transport Cust	90.538423%	90.538423%
40MN	Great Plains Region - M	1012	Great Plains Region - MN	3741	39899999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
41MN	Great Plains North - M	1012	Great Plains North - MN	303	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
41MN	Great Plains North - M	1012	Great Plains North - MN	374	38799999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
42MN	Great Plains South - M	1012	Great Plains South - MN	374	38719999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
111D3	Granite Falls Dist Statr	1012	Granite Falls Dist Statn No 3	378	37899999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
113D5	Montevideo Station N	1012	Montevideo Station No. 5	378	37899999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
118D1	Crookston City Gate St	1012	Crookston City Gate Statn	379	37999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
101D01	Ottertail Ag Eth Plt Sta	1012	Ottertail Ag Eth Plt Sta-South	374	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
101D02	Ottertail Ag Eth Plt Sta	1012	Ottertail Ag Eth Plt Sta-North	371	38599999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
101D03	Fergus Falls DR-Mt Fai	1012	Fergus Falls DR-Mt Faith	371	38599999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
101D06	Union Str. Sta. - Fergus	1012	Union Str. Sta. - Fergus Falls	378	37899999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
101D12	Fergus Falls TBS Sta	1012	Fergus Falls TBS Sta	366	36699999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
101D12	Fergus Falls TBS Sta	1012	Fergus Falls TBS Sta	369	37999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
101D13	Fergus Falls US Grain M	1012	Fergus Falls US Grain Mtr Sta	385	38599999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
101D14	Fergus Falls TBS By-Pa	1012	Fergus Falls TBS By-Pass Sta	378	37899999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
102D01	Pelican Rapids Reg. Sta	1012	Pelican Rapids Reg. Sta. #1	385	38599999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
103D04	Breckenridge/Waphet	1012	Breckenridge/Wapheton TBS	303	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00274	TBS Wahp-Breck	24.530298%	24.530298%
105D01	Belview TBS - Hwy 273	1012	Belview TBS - Hwy 273	303	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
109D01	Dawson MN Ag Proces	1012	Dawson MN Ag Processing	385	38599999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
112D01	Marshall TBS	1012	Marshall TBS	303	30399999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
112D03	Marshall Reg. Sta. #3	1012	Marshall Reg. Sta. #3	378	37899999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
114D01	Redwood Falls Reg Str	1012	Redwood Falls Reg Stn-Meadwlnd	385	38599999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
114D03	Redwood Falls Reg. Sta	1012	Redwood Falls Reg. Sta. #3	378	37899999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
115D01	Renville Beet Plant TB	1012	Renville Beet Plant TBS	379	37999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
116D01	Sacred Heart Regulato	1012	Sacred Heart Regulator Statn	385	38599999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
117D01	Wood Lake Regulator	1012	Wood Lake Regulator Station	378	37899999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
118D09	Crookston Station 9	1012	Crookston Station 9	303	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
119D01	Vergas Viking Takeoff	1012	Vergas Viking Takeoff	369	36999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
119D01	Vergas Viking Takeoff	1012	Vergas Viking Takeoff	379	37999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
GL410-1	GPNG Transmn Line-N	1012	GPNG Transmn Line-North Towns	3651	36999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00239	North 5 Peak Day	75.256211%	75.256211%
40MNGU	MN Gas Utility Infrastr	1012	MN Gas Utility Infrastructure Cost	370	39999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
101001	Fergus Falls Peak Shav	1082	Fergus Falls Peak Shaving Plt	3111	31119999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00239	North 5 Peak Day	75.256211%	75.256211%
103001	Breckenridge Peak Sha	1082	Breckenridge Peak Shaving Plt	3111	3111	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
112001	Marshall Peak Shaving	1082	Marshall Peak Shaving Plt	3111	3111	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
113001	Montevideo Peak Shav	1082	Montevideo Peak Shaving Plt	3111	3111	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
114001	Redwood Falls Peak Sh	1082	Redwood Falls Peak Shaving Pl	3111	3111	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
101001	Fergus Falls Peak Shav	1087	Fergus Falls Peak Shaving Plt	3111	31119999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00239	North 5 Peak Day	75.256211%	75.256211%
112001	Marshall Peak Shaving	1087	Marshall Peak Shaving Plt	3111	31119999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
113001	Montevideo Peak Shav	1087	Montevideo Peak Shaving Plt	3111	31119999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
114001	Redwood Falls Peak Sh	1087	Redwood Falls Peak Shaving Pl	3111	31119999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%

Minnesota Gas
Operations and Expense Allocations
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Location	Location Description	Object Account	Account Description	Sub 1	Sub 2	Bus Segment	Utility Alloc Code	Utility Allocaiton Description	Utility Alloc Rate	Juris Allocation Code	Juris Allocation Description	Juris Allocation Rate	Combined Effective Rate
40	Great Plains Region		Great Plains Region	2870	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00228	Great Plains Distribution Plant	89.844371%	89.844371%
410	Great Plains North Dis		Great Plains North District	2710	27439999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
410	Great Plains North Dis		Great Plains North District	2870	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00237	Great Plains Fergus Falls Distrib Plant	76.436758%	76.436758%
420	Great Plains South Dis		Great Plains South District	2710	27439999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
420	Great Plains South Dis		Great Plains South District	2870	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
12900	Credit & Collections		Credit & Collections	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
12900	Credit & Collections		Credit & Collections	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
12900	Credit & Collections		Credit & Collections	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
12906	Credit & Collections -N		Customer Services-MN	2901	2916999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
70100	EVP Bus. Devel./Gas Su		EVP Bus. Devel./Gas Supply	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
70100	EVP Bus. Devel./Gas Su		EVP Bus. Devel./Gas Supply	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
70100	EVP Bus. Devel./Gas Su		EVP Bus. Devel./Gas Supply	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
70300	Process Improv & Ope		Process Improv & Oper Tech	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
70700	V.P. Safety, Proc Impro		V.P. Safety, Proc Improv & Ops Systems	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
70800	Customer Service (cro		Customer Service (cross charge)	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
70900	Bus Development (cro		Bus Development (cross charge)	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
71000	Energy Programs		Energy Programs	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
71000	Energy Programs		Energy Programs	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
71000	Energy Programs		Energy Programs	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
71006	Energy Programs - MN		Energy Programs - MN	2901	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
71100	Customer Services, Dir		Customer Services, Dir	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
71100	Customer Services, Dir		Customer Services, Dir	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
71106	Customer Services, Dir		Customer Services, Dir MN	2901	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
71200	Meridian – Cust Servic		Meridian – Cust Service Center	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
71200	Meridian – Cust Servic		Meridian – Cust Service Center	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
71206	Meridian – CSC - GPNG		Meridian – CSC - GPNG MN	290100	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
71300	Customer Developmer		Customer Development/Programs	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
71300	Customer Developmer		Customer Development/Programs	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
71306	Customer Developmer		Customer Development/Prog-MN	2901	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
71400	Customer Scheduling		Customer Scheduling	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
71400	Customer Scheduling		Customer Scheduling	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
72000	Technical Training		Technical Training	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
72100	Compliance Systems &		Compliance Systems & Telecom	2813	28139999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00123	Total Co Normalized Gas Sales Vols	8.794904%	8.794904%
72100	Compliance Systems &		Compliance Systems & Telecom	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
72100	Compliance Systems &		Compliance Systems & Telecom	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
72100	Compliance Systems &		Compliance Systems & Telecom	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
72300	Director of Distributio		Director of Distribution Eng.	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
72300	Information Tech, Dir		Information Tech, Dir	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
72500	VP Field Operations		VP Field Operations	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
73000	Dir. Quality Control		Dir. Quality Control	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
73000	Dir. Quality Control		Dir. Quality Control	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
73000	Dir. Quality Control		Dir. Quality Control	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
73106	Energy Programs -MN		Energy Programs -MN	2901	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
75100	Legal Montana-Dakota		Legal Montana-Dakota Only	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
75106	Legal Montana-Dakota		Legal Montana-Dakota Only-MN	2804	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
75200	Treas Serv Montana-D		Treas Serv Montana-Dakota Only	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
75200	Treas Serv Montana-D		Treas Serv Montana-Dakota Only	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
76900	Dir. Engineering Servic		Dir. Engineering Services	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
76900	Dir. Engineering Servic		Dir. Engineering Services	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
76900	Dir. Engineering Servic		Dir. Engineering Services	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
86300	Dir. Construction Servi		Dir. Construction Services	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
86300	Dir. Construction Servi		Dir. Construction Services	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
86300	Dir. Construction Servi		Dir. Construction Services	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
86400	Mgr. Operations Syste		Mgr. Operations Systems	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
86400	Mgr. Operations Syste		Mgr. Operations Systems	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
86500	Dir. System Integrity		Dir. System Integrity	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
86500	Dir. System Integrity		Dir. System Integrity	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
86500	Dir. System Integrity		Dir. System Integrity	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
86600	Safety Mgmt Syst & Q		Safety Mgmt Syst & Qlty Assur.	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
86600	Safety Mgmt Syst & Q		Safety Mgmt Syst & Qlty Assur.	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
86600	Safety Mgmt Syst & Q		Safety Mgmt Syst & Qlty Assur.	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
88100	Power Production		Power Production	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
88100	Power Production		Power Production	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
88300	Electric System Manag		Electric System Manager	2813	28139999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00123	Total Co Normalized Gas Sales Vols	8.794904%	8.794904%
88300	Electric System Manag		Electric System Manager	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
88400	Electric Transmission E		Electric Transmission Engineer	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%

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Location	Location Description	Object Account	Account Description	Sub 1	Sub 2	Bus Segment	Utility Alloc Code	Utility Allocaiton Description	Utility Alloc Rate	Juris Allocation Code	Juris Allocation Description	Juris Allocation Rate	Combined Effective Rate
88400	Electric Transmission E		Electric Transmission Engineer	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
88500	Supv. Engineering Serv		Supv. Engineering Services	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
88500	Supv. Engineering Serv		Supv. Engineering Services	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
88500	Supv. Engineering Serv		Supv. Engineering Services	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
88600	Mgr. Elec. Measureme		Mgr. Elec. Measurement	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
88600	Mgr. Elec. Measureme		Mgr. Elec. Measurement	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
88600	Mgr. Elec. Measureme		Mgr. Elec. Measurement	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
88700	Director of Distributio		Director of Distribution Eng.	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
88700	Director of Distributio		Distribution Engineering -Elec	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
88700	Director of Distributio		Director of Distribution Eng.	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
88706	Director of Distributio		Director of Distribution Eng.	2804	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
88800	Communications		Communications	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
88800	Communications		Communications- Gas Cust Acct	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
88800	Communications		Communications	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
88806	Communications -MN		Communications-Minnesota	2804	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
88900	Environmental		Environmental	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
88900	Environmental		Environmental	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
89000	V.P. Energy Supply		V.P. Energy Supply	2813	28139999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00123	Total Co Normalized Gas Sales Vols	8.794904%	8.794904%
89000	V.P. Energy Supply		V.P. Energy Supply	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
89000	V.P. Energy Supply		V.P. Energy Supply	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
90100	MDU Safety & Training		MDU Safety & Training	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
90106	MDU Safety-MN		MDU Safety-MN	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
91800	Business Development		Business Development	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
91806	Business Development		Business Development MN	2901	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
91900	EVP Reg Affairs, Cust S		EVP Reg Affairs, Cust Serv and Gas Supply	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
91900	V.P Utility Group		V.P Utility Group	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
91906	V.P Utility Group - MN		V.P Utility Group - MN	2901	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
92000	Office Services		Office Services	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
92000	Office Services		Office Services	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
92300	Dir. Oper. Policies & Pr		Dir. Oper. Policies & Proc	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
92300	Dir. Oper. Policies & Pr		Dir. Oper. Policies & Proc	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
92300	Dir. Oper. Policies & Pr		Dir. Oper. Policies & Proc	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
92500	Regulatory Affairs		Regulatory Affairs	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
92506	Regulatory Affairs-MN		Regulatory Affairs-MN	2804	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
92600	Information Systems		Information Systems	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
92600	Information Systems		Information Systems	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
92600	Information Systems		Information Systems	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
92606	Information Systems-		Information Systems- MN	2804	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
92800	Gas Control		Gas Control (cross charge)	2813	28139999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00123	Total Co Normalized Gas Sales Vols	8.794904%	8.794904%
92800	Gas Control		Gas Supply (cross charges)	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
92800	Gas Control		Gas Supply (cross charges)	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
92800	Gas Control		Gas Supply (cross charges)	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
93100	Gas Supply		Gas Supply	2813	28139999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00123	Total Co Normalized Gas Sales Vols	8.794904%	8.794904%
93100	Gas Supply		Gas Supply	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
93100	Gas Supply		Gas Supply	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
93100	Gas Supply		Gas Supply	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
93106	Gas Supply - MN		Gas Supply - MN	2804	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
93300	Mgr.Gas Supply -Midw		Mgr.Gas Supply -Midwest	2813	28139999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00123	Total Co Normalized Gas Sales Vols	8.794904%	8.794904%
93300	Mgr.Gas Supply -Midw		Mgr.Gas Supply -Midwest	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
93300	Mgr.Gas Supply -Midw		Mgr.Gas Supply -Midwest	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
93300	Mgr.Gas Supply -Midw		Mgr.Gas Supply -Midwest	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
94000	Accounting (cross char		Accounting (cross charge)	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
94100	Accounting - Gas Oper		Accounting - Gas Operations	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
94100	EVP Reg Affairs and CA		EVP Reg Affairs and CAO	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
94100	EVP Reg Affairs and CA		EVP Reg Affairs and CAO	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
94106	EVP Reg Affairs and CA		EVP Reg Affairs and CAO - MN	2804	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
95100	Enterprise GIS Departr		Enterprise GIS Department	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
95100	Enterprise GIS Departr		Enterprise GIS Department	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
95300	Gas Operations		Gas Operations	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
95300	Gas Opeations		Gas Opeations	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
95300	Gas Operations		Gas Operations	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
95306	Gas Operations - MN		Gas Operations - MN	2804	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
95400	Mgr. Corrosion Contro		Mgr. Corrosion Control	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
95400	Mgr. Corrosion Contro		Mgr. Corrosion Control	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
95400	Mgr. Corrosion Contro		Mgr. Corrosion Control	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
95500	Mgr. Gas Measuremer		Mgr. Gas Measurement	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%

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Location	Location Description	Object Account	Account Description	Sub 1	Sub 2	Bus Segment	Utility Alloc Code	Utility Allocaiton Description	Utility Alloc Rate	Juris Allocation Code	Juris Allocation Description	Juris Allocation Rate	Combined Effective Rate
95500	Mgr. Gas Measuremer		Mgr. Gas Measurement	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
95500	Mgr. Gas Measuremer		Mgr. Gas Measurement	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
95800	Dir. Operations Service		Dir. Operations Services	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
95800	Dir. Operations Service		Dir. Operations Services	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
95800	Dir. Operations Service		Dir. Operations Services	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
96000	V.P. Division Operatior		V.P. Division Operations	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
96000	V.P. Division Operatior		V.P. Division Operations	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
96006	V.P. Division Operatior		V.P. Division Operations-MN	2804	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
96100	Transportation & Proc		Transportation & Procurement	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
96100	Transportation & Proc		Transportation & Procurement	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
96200	Buildings & Grounds		Buildings & Grounds	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
96300	VP HR, Cust Serv. & Sa		VP HR, Cust Serv. & Safety	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
96300	VP HR, Cust Serv. & Sa		VP HR, Cust Serv. & Safety	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
96400	Mobile Services Mana		Mobile Services Manager	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
96400	Mobile Services Mana		Mobile Services Manager	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
96400	Mobile Services Mana		Mobile Services Manager	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
96406	Mobile Services Mana		Mobile Services Manager-MN	2804	2935999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
98500	Montana-Dakota Presi		Montana-Dakota President & CEO	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
98506	Montana-Dakota Presi		Montana-Dakota President & CEO-MN	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
98800	Corporate Airplane		Corporate Airplane	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
99400	MDU Resources Cross		MDU Resources Cross Charge	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
99700	Year End Adjustments		Year End Adjustments	2813	28139999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00123	Total Co Normalized Gas Sales Vols	8.794904%	8.794904%
99700	Year End Adjustments		Year End Adjustments	2870	28949999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
99700	Year End Adjustments		Year End Adjustments	2901	29169999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00087	Total Co. Gas Sales & Transportation Customers	7.334807%	7.334807%
99700	Year End Adjustments		Year End Adjustments	2920	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	11.953225%
99706	Year End Adjustments		Year End Adjustments-MN	2901	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
327500	Bismarck Service Cent		Bismarck Service Center - GO/Region	2870	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00279	Bismarck Service Center Gas - Region/GO	3.284556%	3.284556%
40MN	Great Plains Region - N		Great Plains Region - MN	2804	29359999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
41MN	Great Plains North - M		Great Plains North - MN	2804	28059999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
42MN	Great Plains South - M		Great Plains South - MN	2804	28059999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
42MN	Great Plains South - M		Great Plains South - MN	2806	28089999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
GL410-1	GPNG Transmn Line-N		GPNG Transmn Line-North Towns	2850	28689999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00239	North 5 Peak Day	75.256211%	75.256211%

Minnesota Gas
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Location	Location Description	Object Account	Account Description	Sub 1	Sub 2	Bus Segment	Utility Alloc Code	Utility Allocaiton Description	Utility Alloc Rate	Juris Allocation Code	Juris Allocation Description	Juris Allocation Rate	Combined Effective Rate
40MN	Great Plains Region - N	1142	Great Plains Region - MN	37	37	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
40	Great Plains Region	1510	Fuel	3	3	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
41000	Fergus Falls Disct War	1540	Plant Mat. & Oper. Supplies	2	2	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00237	Great Plains Fergus Falls Distrib Plant	76.436758%	76.436758%
42001	Marshall Warehouse	1540	Plant Mat. & Oper. Supplies	2	2	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
90	MDU General Office	1541	Gas Inventory Manual Stores	2	2	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00119	Gas Distribution Plant	8.602604%	8.602604%
90	MDU General Office	1541	Communication Equip	45	45	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
41000	Fergus Falls Disct War	1542	Allow. for Inventory Shrink.	2000	2499	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00237	Great Plains Fergus Falls Distrib Plant	76.436758%	76.436758%
42001	Marshall Warehouse	1542	Allow. for Inventory Shrink.	2000	2499	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
41000	Fergus Falls Disct War	1543	Plant Mat. & Oper. Supplies	2	2	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00237	Great Plains Fergus Falls Distrib Plant	76.436758%	76.436758%
42001	Marshall Warehouse	1543	Plant Mat. & Oper. Supplies	2	29999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
41000	Fergus Falls Disct War	1544	Plant Mat. & Oper. Supplies	2	2	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00237	Great Plains Fergus Falls Distrib Plant	76.436758%	76.436758%
42001	Marshall Warehouse	1544	Plant Mat. & Oper. Supplies	2	2	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	1641	Gas Strd UG - Cur GP	02	02	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00139	MDDQ-GP	90.535287%	90.535287%
1	Balance Sheet	1641	Gas Strd UG - Cur GP WBI	04	04	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00139	MDDQ-GP	90.535287%	90.535287%
1	Balance Sheet	1655	Prepayments-D & O	01	01	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	4.876916%
1	Balance Sheet	1655	Prepayments-Fid. & Employee Ben. Liab.	02	02	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00038	Gas Net Plant in Service	8.462643%	3.452758%
1	Balance Sheet	1655	Prepayments- Gen Liab.	03	03	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00027	O&M Excl Cost of Gas & A&G	11.953225%	4.876916%
1	Balance Sheet	1655	Prepayments-Fire, Ext Cov Boiler & Mch	04	04	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00037	Gas Gross Plant in Service	9.125997%	3.723407%
1	Balance Sheet	1655	Prepayments-Blanket Crime	05	05	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00037	Gas Gross Plant in Service	9.125997%	3.723407%
1	Balance Sheet	1655	Prepayments-Special Contingencies	06	06	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00037	Gas Gross Plant in Service	9.125997%	3.723407%
1	Balance Sheet	1659	Fuel & Gathering - GP NN	12	12	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00139	MDDQ-GP	90.535287%	90.535287%
1	Balance Sheet	1659	Fuel & Gathering - GP NW	13	14	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00139	MDDQ-GP	90.535287%	90.535287%
1	Balance Sheet	1823	Other Regulatory Assets	26201	26201	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	1823	G MN Conservation Program	526001	526999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	1823	MN Misc Regulatory Assets	926	92699999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
900000	Preliminary Survey	1830	Preliminary Survey	303	303	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
900000	Preliminary Survey	1830	Preliminary Survey	3030	3030	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
1	Balance Sheet	1869	Misc. Deferred Debits	040	040	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	1890	Unamort. Loss on Reacq. De	952	999	2 Natural Gas	00025	Net Plant in Service including Total CWIP	20.164312%	00038	Gas Net Plant in Service	8.462643%	1.706434%
1	Balance Sheet	1900	GMN Customer Advances	86301206	86301206	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	1900	GMN-Excess Deferreds State	86309206	86309206	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	1900	GMN Customer Advances	96301206	96301206	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	1900	GMN-R&D Tax Credit Carryforward	96308206	96308206	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	1900	GMN-Excess Deferreds Federal	96309206	96309206	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	2540	Other Regulatory Liabilities	26100	26100	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	2820	Acc. Def. Inc. Tx-Oth. Prop.-GMN Gas Plant	86301206	86301206	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	2820	Acc. Def. Inc. Tx-Oth. Prop.-GMN CIAC	86305206	86305206	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	2820	Acc. Def. Inc. Tx-Oth. Prop.-GMN Gas Plant	96301206	96301206	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	2820	Acc. Def. Inc. Tx-Oth. Prop.-GMN CIAC	96305206	96305206	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	2830	GMN Unamort Loss Reaqui	86301206	86301206	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	2830	GMN Pref Stk Redemption	86304206	86304206	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	2830	GMN-Excess Deferreds State	86309206	86309206	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	2830	GMN Unamort Loss Reaqui	96301206	96301206	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	2830	GMN Pref Stk Redemption	96304206	96304206	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
40MN	Great Plains Region - N	4002	Natural Gas Billed Revenues-MN	4800	4899	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
40MN	Great Plains Region - N	4005	Unbilled Revenue Gas-MN Tariff	4800	4840	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
40MN	Great Plains Region - N	4009	Natural Gas Unbilled Revenues-MN	4800	4899	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	4073	Regulatory Debits-MN	262	262	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	4074	...	262	262	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	4081	Taxes Other Than Income	1MN21	1MN21	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00242	Minnesota Gas General plant	97.107314%	97.107314%
1	Balance Sheet	4081	Taxes Other Than Income	1MN22	1MN22	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	4081	Taxes Other Than Income	1MN27	1MN27	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00239	North 5 Peak Day	75.256211%	75.256211%
1	Balance Sheet	4081	Taxes Other Than Income	1MN28	1MN28	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	4081	Taxes Other Than Income	1MN29	1MN29	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00242	Minnesota Gas General plant	97.107314%	97.107314%
1	Balance Sheet	4081	Taxes Other Than Income	1ND01	1ND01	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00040	Gas Plant Excl Common GO	9.465580%	3.861957%
1	Balance Sheet	4081	Taxes Other Than Income	1ND09	1ND09	2 Natural Gas	00180	North Dakota Common Plant	35.272092%	00068	North Dakota Common Gas Plant	4.657387%	1.642758%
1	Balance Sheet	4081	Taxes Other Than Income	299	299	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00025	O&M Excl Cost of Gas	11.950279%	4.875714%
1	Balance Sheet	4081	Taxes Other Than Income	63	63	2 Natural Gas	00024	Gross Plant in Service	24.910550%	00119	Gas Distribution Plant	8.602604%	2.142956%
1	Balance Sheet	4081	Taxes Other Than Income	9	9	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00025	O&M Excl Cost of Gas	11.950279%	4.875714%
GMN	Gas -Minnesota	4091	Income Taxes- Utility Operations	0	99999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
GMN	Gas -Minnesota	4092	Income Taxes, Other Inc & Deductions	0	99999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
GMN	Gas -Minnesota	4101	DEFERRED INCOME TAXES	0	99999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
GMN	Gas -Minnesota	4102	Prov for DIT- Other Inc & Deductions	0	99999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
GMN	Gas -Minnesota	4111	DEFERRED INCOME TAXES	0	99999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
GMN	Gas -Minnesota	4112	Prov for DIT (CR) - Other Inc & Deductions	0	99999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	4192	Interest on Debt and Dividends - Jan	1	2	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	22.922386%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.424627%	2.389573%

Minnesota Gas
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Location	Location Description	Object Account	Account Description	Sub 1	Sub 2	Bus Segment	Utility Alloc Code	Utility Allocaiton Description	Utility Alloc Rate	Juris Allocation Code	Juris Allocation Description	Juris Allocation Rate	Combined Effective Rate
1	Balance Sheet	4192	Interest on Debt and Dividends - Feb	1	2	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	23.269669%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	9.975181%	2.321192%
1	Balance Sheet	4192	Interest on Debt and Dividends - Mar	1	2	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	22.726951%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.197614%	2.317607%
1	Balance Sheet	4192	Interest on Debt and Dividends - Apr	1	2	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	22.613323%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.252256%	2.318376%
1	Balance Sheet	4192	Interest on Debt and Dividends - May	1	2	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	22.706190%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.153084%	2.305379%
1	Balance Sheet	4192	Interest on Debt and Dividends - Jun	1	2	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	23.043287%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.012983%	2.307320%
GMN	Gas -Minnesota	4200	INVESTMENT TAX CREDIT	0	99999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	4265	Loss on Corp Dev Investments	4265	42659999	2 Natural Gas	00028	CORPORATE OVERHEAD	40.800000%	00038	Gas Net Plant in Service	8.462643%	3.452758%
1	Balance Sheet	4271	First Mortgage Bonds - Jan			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.073354%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.424627%	2.196819%
1	Balance Sheet	4271	First Mortgage Bonds - Feb			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.429630%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	9.975181%	2.137644%
1	Balance Sheet	4271	First Mortgage Bonds -Mar			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.910597%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.197614%	2.132382%
1	Balance Sheet	4271	First Mortgage Bonds - Apr			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.840756%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.252256%	2.136648%
1	Balance Sheet	4271	First Mortgage Bonds - May			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.927453%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.153084%	2.124782%
1	Balance Sheet	4271	First Mortgage Bonds - Jun			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.245634%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.012983%	2.127322%
1	Balance Sheet	4279	Other Long Term Interest - Jan		99999999	2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.073354%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.424627%	2.196819%
1	Balance Sheet	4279	Other Long Term Interest - Feb		99999999	2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.429630%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	9.975181%	2.137644%
1	Balance Sheet	4279	Other Long Term Interest -Mar		99999999	2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.910597%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.197614%	2.132382%
1	Balance Sheet	4279	Other Long Term Interest - Apr		99999999	2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.840756%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.252256%	2.136648%
1	Balance Sheet	4279	Other Long Term Interest - May		99999999	2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.927453%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.153084%	2.124782%
1	Balance Sheet	4279	Other Long Term Interest - Jun		99999999	2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.245634%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.012983%	2.127322%
1	Balance Sheet	4280	Amort. of Debt Discount & Exp. - Jan			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.073354%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.424627%	2.196819%
1	Balance Sheet	4280	Amort. of Debt Discount & Exp. - Feb			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.429630%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	9.975181%	2.137644%
1	Balance Sheet	4280	Amort. of Debt Discount & Exp. -Mar			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.910597%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.197614%	2.132382%
1	Balance Sheet	4280	Amort. of Debt Discount & Exp. - Apr			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.840756%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.252256%	2.136648%
1	Balance Sheet	4280	Amort. of Debt Discount & Exp. - May			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.927453%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.153084%	2.124782%
1	Balance Sheet	4280	Amort. of Debt Discount & Exp. - Jun			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.245634%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.012983%	2.127322%
1	Balance Sheet	4281	Amort. of Loss on Reacq. Debt - Jan			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.073354%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.424627%	2.196819%
1	Balance Sheet	4281	Amort. of Loss on Reacq. Debt - Feb			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.429630%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	9.975181%	2.137644%
1	Balance Sheet	4281	Amort. of Loss on Reacq. Debt -Mar			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.910597%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.197614%	2.132382%
1	Balance Sheet	4281	Amort. of Loss on Reacq. Debt - Apr			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.840756%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.252256%	2.136648%
1	Balance Sheet	4281	Amort. of Loss on Reacq. Debt - May			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.927453%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.153084%	2.124782%
1	Balance Sheet	4281	Amort. of Loss on Reacq. Debt - Jun			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.245634%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.012983%	2.127322%
90	MDU General Office	4310	Other Interest Expense - Jan	0	010	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	22.922386%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.424627%	2.389573%
90	MDU General Office	4310	Accrued Tax Interest - Jan	011	011	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	22.922386%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.424627%	2.389573%
90	MDU General Office	4310	Other Interest Expense - Jan	012	019	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	22.922386%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.424627%	2.389573%
90	MDU General Office	4310	Other Interest Expense - Feb	0	010	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	23.269669%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	9.975181%	2.321192%
90	MDU General Office	4310	Accrued Tax Interest - Feb	011	011	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	23.269669%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	9.975181%	2.321192%
90	MDU General Office	4310	Other Interest Expense - Feb	012	019	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	23.269669%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	9.975181%	2.321192%
90	MDU General Office	4310	Other Interest Expense - Mar	0	010	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	22.726951%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.197614%	2.317607%
90	MDU General Office	4310	Accrued Tax Interest - Mar	011	011	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	22.726951%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.197614%	2.317607%
90	MDU General Office	4310	Other Interest Expense - Mar	012	019	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	22.726951%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.197614%	2.317607%
90	MDU General Office	4310	Other Interest Expense - Apr	0	010	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	22.613323%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.252256%	2.318376%
90	MDU General Office	4310	Accrued Tax Interest - Apr	011	011	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	22.613323%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.252256%	2.318376%
90	MDU General Office	4310	Other Interest Expense - Apr	012	019	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	22.613323%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.252256%	2.318376%
90	MDU General Office	4310	Other Interest Expense - May	0	010	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	22.706190%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.153084%	2.305379%
90	MDU General Office	4310	Accrued Tax Interest - May	011	011	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	22.706190%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.153084%	2.305379%
90	MDU General Office	4310	Other Interest Expense - May	012	019	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	22.706190%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.153084%	2.305379%
90	MDU General Office	4310	Other Interest Expense - Jun	0	010	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	23.043287%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.012983%	2.307320%
90	MDU General Office	4310	Accrued Tax Interest - Jun	011	011	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	23.043287%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.012983%	2.307320%
90	MDU General Office	4310	Other Interest Expense - Jun	012	019	2 Natural Gas	00100	AVERAGE RATE BASE - CHANGES MONTHLY	23.043287%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.012983%	2.307320%
40MN	Great Plains Region - M	4310	Other Interest Expense-MN	200	299	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
1	Balance Sheet	4370	4.5% Preferred Stock - Jan			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.073354%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.424627%	2.196819%
1	Balance Sheet	4370	4.5% Preferred Stock - Feb			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.429630%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	9.975181%	2.137644%
1	Balance Sheet	4370	4.5% Preferred Stock -Mar			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.910597%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.197614%	2.132382%
1	Balance Sheet	4370	4.5% Preferred Stock - Apr			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.840756%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.252256%	2.136648%
1	Balance Sheet	4370	4.5% Preferred Stock - May			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.927453%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.153084%	2.124782%
1	Balance Sheet	4370	4.5% Preferred Stock - Jun			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.245634%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.012983%	2.127322%
1	Balance Sheet	4371	4.7% Preferred Stock - Jan			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.073354%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.424627%	2.196819%
1	Balance Sheet	4371	4.7% Preferred Stock - Feb			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.429630%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	9.975181%	2.137644%
1	Balance Sheet	4371	4.7% Preferred Stock -Mar			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.910597%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.197614%	2.132382%
1	Balance Sheet	4371	4.7% Preferred Stock - Apr			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.840756%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.252256%	2.136648%
1	Balance Sheet	4371	4.7% Preferred Stock - May			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.927453%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.153084%	2.124782%
1	Balance Sheet	4371	4.7% Preferred Stock - Jun			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.245634%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.012983%	2.127322%
1	Balance Sheet	4372	5.10% Preferred Stock - Jan			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.073354%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.424627%	2.196819%
1	Balance Sheet	4372	5.10% Preferred Stock - Feb			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.429630%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	9.975181%	2.137644%
1	Balance Sheet	4372	5.10% Preferred Stock -Mar			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.910597%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.197614%	2.132382%
1	Balance Sheet	4372	5.10% Preferred Stock - Apr			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.840756%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.252256%	2.136648%

Minnesota Gas
Other Rate Base and Income Statement Allocations
2019

Location	Location Description	Object Account	Account Description	Sub 1	Sub 2	Bus Segment	Utility Alloc Code	Utility Allocaiton Description	Utility Alloc Rate	Juris Allocation Code	Juris Allocation Description	Juris Allocation Rate	Combined Effective Rate
1	Balance Sheet	4372	5.10% Preferred Stock - May			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.927453%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.153084%	2.124782%
1	Balance Sheet	4372	5.10% Preferred Stock - Jun			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.245634%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.012983%	2.127322%
1	Balance Sheet	4390	Loss on Redemption of Preferred Stock - Jan			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.073354%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.424627%	2.196819%
1	Balance Sheet	4390	Loss on Redemption of Preferred Stock - Feb			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.429630%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	9.975181%	2.137644%
1	Balance Sheet	4390	Loss on Redemption of Preferred Stock -Mar			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.910597%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.197614%	2.132382%
1	Balance Sheet	4390	Loss on Redemption of Preferred Stock - Apr			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.840756%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.252256%	2.136648%
1	Balance Sheet	4390	Loss on Redemption of Preferred Stock - May			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	20.927453%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.153084%	2.124782%
1	Balance Sheet	4390	Loss on Redemption of Preferred Stock - Jun			2 Natural Gas	00101	AVERAGE RATE BASE - CHANGES MONTHLY	21.245634%	00117	AVERAGE GAS RATE BASE - INCLUDING ADJUSTMENTS	10.012983%	2.127322%
40MN	Great Plains Region - M	4870	Late Payment Revenue	0	99999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
90	MDU General Office	4880	Misc. Service Revenue	020	029	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00034	Gas Sales & Trans. Rev.	9.963020%	9.963020%
40MN	Great Plains Region - M	4880	Misc. Service Revenue-MN		99999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
40MN	Great Plains Region - M	4890	GPNG - MN	4800	4899	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
40MN	Great Plains Region - M	4891	Unbilled Trans Gas Revenue	4800	48999999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
40MN	Great Plains Region - M	4895	Unbilled Rev Trans Gas-MN Tariff	4800	4899	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
90	MDU General Office	4930	Rent from Gas Property	001	0039	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00034	Gas Sales & Trans. Rev.	9.963020%	9.963020%
40MN	Great Plains Region - M	4930	Rent from Gas Property	001	009	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
90	MDU General Office	4950	Other Gas Revenues	010	017	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00034	Gas Sales & Trans. Rev.	9.963020%	9.963020%
40MN	Great Plains Region - M	4950	Other Gas revenues		99999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%
40MN	Great Plains Region - M	4962	Prov-Gas Rate Refund		99999	2 Natural Gas	00002	NATURAL GAS ONLY	100.000000%	00006	MINNESOTA- ONLY	100.000000%	100.000000%

Montana-Dakota Utilities Co.
811-Call Before You Dig Radio Ad Copy

30 second radio ad:

Hey new guy, shovel right?

Yeah right and I'm not exactly new. I've seen some action.

Yeah what's your story?

Hey my last gig, I nearly got electrocuted almost drilled. That guy never called 811 to see if it was safe to dig.

Our guy calls every time he digs.

It's quick and easy, any tool can do it. Calling 811 gets your underground utility lines marked for free.

Hey safe digging is no accident. Always call 811 before you dig.

This message brought to you by Montana-Dakota Utilities Company – In the Community to Serve.


Bill Pay
—the—
Easy Way
montana-dakota.com
In the Community
to Serve®
MONTANA-DAKOTA
UTILITIES CO.
Online Account Services
Welcome to the Montana-Dakota Utilities
Online Account Services Website
Not Registered?
Login


Know what's below.
Call before you dig.
811®
www.call811.com
MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.
In the Community to Serve®

Protect Our Energy Lines. Protect The Community.

Please share this safety information with students and their families.

Call Before You Dig

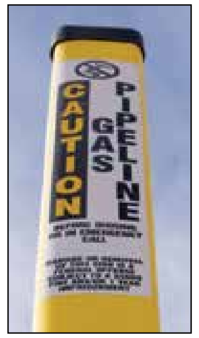
Call 811 if you plan to dig or move earth in any way—even just planting a tree or shrub. This free service marks the location of underground utility lines so you can dig a safe distance away from them. After you call, wait three business days and until the marks have been made before digging. Respect the marks and dig with care!

811 Know what's below. Call before you dig.

Be Alert for Gas Leaks

Use your eyes and ears, as well as your nose, to detect a natural gas leak. Gas leaks usually have a distinctive, sulfur-like odor—but not always. So be alert for additional warning signs, such as dirt spraying or blowing into the air, a hissing or roaring sound, continual bubbling in water, or plants or grass dead or dying for no apparent reason.

If You Suspect a Gas Leak



- **Leave your home or the outside area immediately** and move to a safe location.
- **Call 911 and Montana-Dakota Utilities Company's at 1-800-638-3278.**
- **Warn others to stay away.**
- **Even a tiny spark could ignite the gas:**
  - **Never use a phone or cell** until you are safely away.
  - **Never operate electric appliances or switches,** such as lights, doorbells, radios, televisions or TV controllers, and garage door openers.
  - **Do not strike a match.**
- **Never try to extinguish a gas fire or turn a valve on pipeline equipment.**

Order Your Teaching Resources Today!

Three ways to order your FREE teaching materials!

1) **Online:** Order online at montana-dakota.e-smartonline.net/educator and submit.

2) **Mail:** Complete the attached order card, and mail it.

3) **Fax:** Fax the card to 978-463-1715.

Orders are filled on a first-come, first-served basis. If inventories are depleted, you will be notified by mail. Your materials will arrive in two to four weeks.

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In the Community to Serve®

Educational Materials Distribution
104 Bridge Road
Salisbury, MA 01952

Power Up Your Curriculum

Order FREE Energy Education Resources that meet National and State Academic Standards

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.
In the Community to Serve®

ELECTRICAL AND GAS SAFETY

ENERGY Efficiency Education

Program resources include student booklets, teacher's guides, and interactive online resources.

- **Conserve your budget—order FREE classroom materials**
- **Meet national and state academic standards**
- **Save prep time**
- **Address learning styles and engage students**

Visit montana-dakota.e-smartonline.net/educator to learn more.

FREE ELECTRICAL AND NATURAL GAS SAFETY MATERIALS SUPPORT MT, ND, SD, WY STATE STANDARDS

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.
In the Community to Serve®

Montana-Dakota Utilities Co. is glad to help you meet your teaching objectives with our complimentary materials that:

Align with National and State Academic Standards

We all have a responsibility to support student achievement and to prepare our students for the future. That's why we've incorporated state academic standards into our materials. You can be sure you're addressing critical subject matter and meeting your teaching objectives.

Save Prep Time

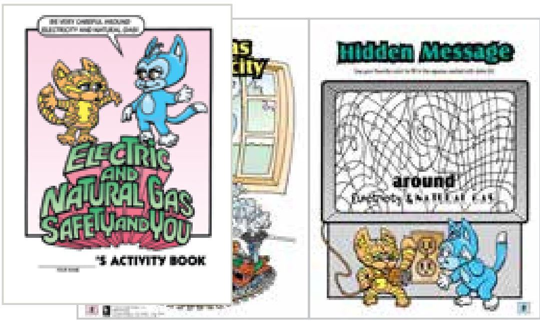
Because you face so many demands on your time, each of our kits includes a teacher's guide to save you planning time, help you easily implement our materials, and reinforce learning.

Address Learning Styles & Engage Students

Our materials offer many tools, including scientific inquiry-based experiments, informative stories, thought-provoking discussion exercises, interactive games, and challenging quizzes. Whether used for group or individualized learning, there's something to appeal to all interests and learning styles.

Conserve Your Budget—Order at No Charge

During a time when budgets are squeezed and teachers often spend their own money to supplement classroom materials, we're proud to provide you with educational materials free of charge. No cost to order, no cost for materials, and no fee for shipping!



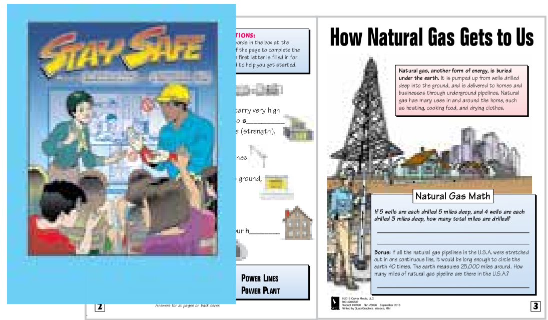
Electric and Natural Gas Safety and You

Grades K–2, #35807

- Meet Zap and Sniff, two comical cats, who guide kids through the fundamentals of electrical and natural gas science and safety
- Contains learning activities including coloring, decoding, matching and sequencing
- Includes a quiz to help reinforce lessons to improve comprehension and recall

Subjects covered include:

- Safety around electricity and natural gas
- Substations and utility towers
- Safety around outlets, switches and appliances
- Electric-water hazards
- Electrical fires
- Underground pipelines and safe digging
- Gas leak recognition and response
- Proper home evacuation steps



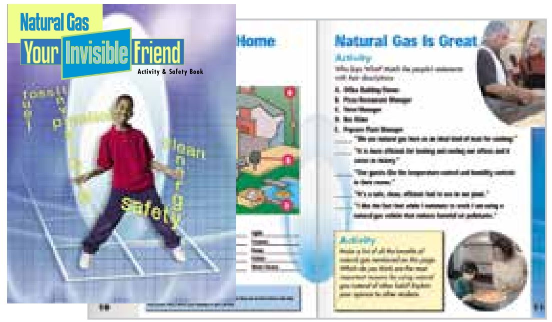
Stay Safe Around Electricity and Natural Gas

Grades 3–6, #37990

- Packs 16 pages of age-appropriate lessons and activities essential to electrical and natural gas safety
- Uses vocabulary, math, crossword and decoding activities to entertain and engage students
- Presents situational exercises that challenge kids to find "hidden" electrical dangers

Subjects covered include:

- Natural gas deposits, drilling and distribution
- The uses of electricity and natural gas
- Electrical flow, paths and grounding
- Conductors and insulators
- Safety around downed power lines
- The dangers of water and electricity
- Safety around natural gas appliances
- Natural gas leak recognition, response and prevention



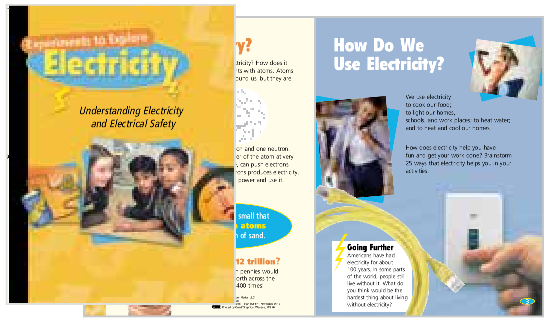
Natural Gas: Your Invisible Friend

Grades 3–6, #37620

- Addresses academic standards for science and health
- Uses word jumbles, crossword puzzles, math exercises and decoding activities
- Nearly every page features a "Going Further" element that challenges students to further research, discuss, write about or act upon the page content

Subjects covered include:

- The qualities of natural gas
- The uses of natural gas
- Fuel cleanliness and efficiency
- The history of natural gas
- Safe digging around buried utilities
- The importance of energy in our life
- Natural gas-powered vehicles



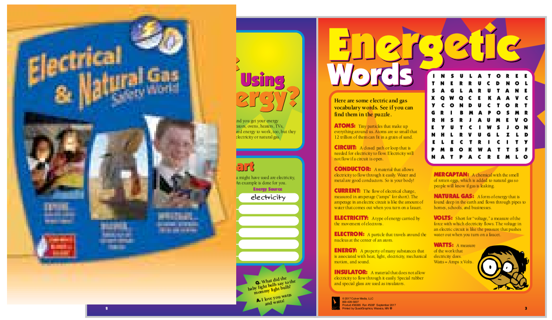
Experiments to Explore Electricity

Grades 3–6, #36690

- Addresses key electrical science principals
- Hands-on experiments, like building circuits and making a wet-cell battery
- Word puzzles and quizzes reinforce learning
- A home safety checklist encourages family discussions

Subjects covered include:

- What is electricity
- Where does electricity come from
- Atoms, protons, neutrons and electrons
- How we use electricity in our society
- Electrical circuits—opened and closed



Electrical & Natural Gas Safety World

Grades 4–6, #36385

- Packs 16 pages full of activities and experiments that address both the science and safety of electricity and natural gas
- Utilizes various stories including a lightning strike survivor story to enhance the lessons of indoor and outdoor safety
- Features "What Do You Think?" questions to challenge students to think beyond the page lesson

Subjects covered include:

- Energy in our daily lives
- Energy vocabulary
- Electricity, currents and circuits
- Fossil fuels and nuclear power
- Renewable forms of energy
- The electrical distribution system
- Lightning safety
- Natural gas drilling, processing, storage and distribution
- Electrical and natural gas home safety

Visit e-SMARTkids Website at montana-dakota.e-smartonline.net/educator

The e-SMARTkids website contains the tools you need to help students take positive action when it comes to electrical and natural gas safety.

FREE resources include:

✓ Educational booklets
✓ Downloadable teachers' guides
✓ Multimedia online games and experiments
✓ Fascinating stories, fun facts, and more

TO ORDER: Fill out this card and mail it, or fax it to 978-463-1715 or order online at **montana-dakota.e-smartonline.net/educator.**

Order FREE Safety Training Materials from Montana-Dakota Utilities Co.

Name: ____________________

Role (e.g., teacher, principal, librarian): ____________________

School name: ____________________

Is this a homeschool? ❑ Yes ❑ No

Address: ____________________

City: __________ **State:** ______ **Zip:** ______

Phone: __________ **Email:** __________

Which subject(s) do you teach? ____________________

Which grade(s) are you ordering for? ____________________

How many teachers will be using these materials? __________

Comments: ____________________

Title	# of Booklets
Electric and Natural Gas Safety and You, *Gr. K–2, #35807*	
Stay Safe Around Electricity and Natural Gas, *Gr. 3–6, #37990*	
Natural Gas: Your Invisible Friend, *Gr.3-6, #367620*	
Experiments to Explore Electricity, *Gr. 3–6, #36690*	
Electrical & Natural Gas Safety World, *Gr. 4–6, #36385*	

Docket No. G004/GR-19-511
Rule 7825.4100
Statement C
Schedule C-7
Page 5 of 5

Thank you for your order. Materials will arrive in two to four weeks.

#11241

GREAT PLAINS NATURAL GAS CO.
AVERAGE UTILITY CAPITAL STRUCTURE
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019-2020

	Balance	Ratio	Cost	Required Return
2018				
Long Term Debt 1/	$680,430,873	45.383%	5.038%	2.286%
Short Term Debt 2/	68,849,896	4.592%	2.906%	0.133%
Common Equity 3/	750,012,192	50.025%	10.200%	5.103%
Total	$1,499,292,961	100.000%		7.522%
Projected 2019				
Long Term Debt 1/	$730,419,315	45.611%	4.819%	2.198%
Short Term Debt 2/	82,352,265	5.142%	3.147%	0.162%
Common Equity 3/	788,652,539	49.247%	10.200%	5.023%
Total	$1,601,424,119	100.000%		7.383%
Projected 2020				
Long Term Debt 1/	$767,907,043	45.132%	4.712%	2.127%
Short Term Debt 2/	68,954,808	4.053%	3.693%	0.150%
Common Equity 3/	864,618,203	50.815%	10.200%	5.183%
Total	$1,701,480,054	100.000%		7.460%

1/ Schedule D-1, page 1.
2/ Schedule D-2, page 1.
3/ Schedule D-3, page 1.

GREAT PLAINS NATURAL GAS CO.
AVERAGE LONG-TERM DEBT

	Balance Outstanding	Annual Cost		Adjusted Embedded Cost
Balance at 12/31/2017	$630,436,250	$32,614,734		5.173%
Balance at 12/31/2018	$730,000,000	$35,874,090		4.914%
Minot Air Force Base Payable	425,495	25,530		6.000%
Amortization of Gain/Loss		43,469	1/	
Total @ 12/31/2018	$730,425,495	$35,943,089		4.921%
Average @ 12/31/2018	$680,430,873	$34,278,912		5.038%
Balance at 12/31/2019	$730,000,000	$34,389,090		4.711%
Minot Air Force Base Payable	413,134	24,788		6.000%
Amortization of Gain/Loss		43,469	1/	
Total @ 12/31/2019	$730,413,134	$34,457,347		4.718%
Average @ 12/31/2019	$730,419,315	$35,200,218		4.819%
Balance at 12/31/2020	805,000,000	37,848,090		4.702%
Minot Air Force Base Payable	400,952	24,057		6.000%
Amortization of Gain/Loss		43,469	1/	
Total @ 12/31/20	$805,400,952	$37,915,616		4.708%
Average @ 12/31/2020	$767,907,043	$36,186,482		4.712%

1/ Schedule D-4, page 1.

GREAT PLAINS NATURAL GAS CO.
LONG-TERM DEBT CAPITAL
DECEMBER 31, 2018

Description	Date of Issuance	Date of Maturity	Interest Rate	Principal Amount of Issue	Gross Proceeds	Underwriters' Commission Amount	Underwriters' Commission % Gross Proceeds	Loss on Reacquirement Redemption and Issuance Expense Amount	Loss on Reacquirement Redemption and Issuance Expense % Gross Proceeds
Unsecured Long-Term Debt:									
5.98% - Senior Note	12/15/03	12/15/33	5.980%	$30,000,000	$30,000,000	$624,465	2.082%	$0	0.000%
6.33% - Senior Note	08/24/06	08/24/26	6.330%	100,000,000	100,000,000	344,061	0.344%	10,532,009	10.532%
5.18% - Senior Note	04/15/14	04/15/44	5.180%	50,000,000	50,000,000	239,178	0.478%	0	0.000%
4.24% - Senior Note	07/15/14	07/15/24	4.240%	60,000,000	60,000,000	291,263	0.485%	0	0.000%
4.34% - Senior Note	07/15/14	07/15/26	4.340%	40,000,000	40,000,000	197,042	0.493%	0	0.000%
3.78% - Senior Note	10/29/15	10/30/25	3.780%	87,000,000	87,000,000	471,997	0.543%	0	0.000%
4.87% - Senior Note	10/29/15	10/30/45	4.870%	11,000,000	11,000,000	59,461	0.541%	0	0.000%
4.03% - Senior Note	12/10/15	12/10/30	4.030%	52,000,000	52,000,000	286,355	0.551%	0	0.000%
4.15% - Senior Note	11/21/16	11/21/46	4.150%	40,000,000	40,000,000	226,084	0.565%	0	0.000%
3.73% - Senior Note	03/21/17	03/31/37	3.730%	40,000,000	40,000,000	173,637	0.434%	0	0.000%
3.36% - Senior Note	03/21/17	03/31/32	3.360%	20,000,000	20,000,000	86,071	0.430%	0	0.000%
LIBOR Floating Rate Note Sep 2018			4.650%	200,000,000	200,000,000	800,000	0.400%	0	0.000%
Total Long-Term Debt Capital				$730,000,000	$730,000,000	$3,799,614		$10,532,009	

Description	Net Proceeds Amount	Net Proceeds Per Unit	Cost of Money 1/	Principal Outstanding	Annual Cost	Embedded Cost
Unsecured Long-Term Debt:						
5.98% - Senior Note	$29,375,535	97.918%	6.210%	$30,000,000	$1,863,000	
6.33% - Senior Note	89,123,930	89.124%	7.514%	100,000,000	7,514,000	
5.18% - Senior Note	49,760,822	99.522%	5.280%	50,000,000	2,640,000	
4.24% - Senior Note	59,708,737	99.515%	4.346%	60,000,000	2,607,600	
4.34% - Senior Note	39,802,958	99.507%	4.442%	40,000,000	1,776,800	
3.78% - Senior Note	86,528,003	99.457%	3.883%	87,000,000	3,378,210	
4.87% - Senior Note	10,940,539	99.459%	4.964%	11,000,000	546,040	
4.03% - Senior Note	51,713,645	99.449%	4.122%	52,000,000	2,143,440	
4.15% - Senior Note	39,773,916	99.435%	4.228%	40,000,000	1,691,200	
3.73% - Senior Note	39,826,363	99.566%	3.797%	40,000,000	1,518,800	
3.36% - Senior Note	19,913,929	99.570%	3.425%	20,000,000	685,000	
LIBOR Floating Rate Note Sep 2018	199,200,000	99.600%	4.755%	200,000,000	9,510,000	
Total Long-Term Debt Capital	$715,668,377			$730,000,000	$35,874,090	4.914%

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

GREAT PLAINS NATURAL GAS CO.
LONG-TERM DEBT CAPITAL
PROJECTED DECEMBER 31, 2019

Description	Date of Issuance	Date of Maturity	Interest Rate	Principal Amount of Issue	Gross Proceeds	Underwriters' Commission Amount	Underwriters' Commission % Gross Proceeds	Loss on Reacquirement Redemption and Issuance Expense Amount	Loss on Reacquirement Redemption and Issuance Expense % Gross Proceeds
Unsecured Long-Term Debt:									
5.98% - Senior Note	12/15/03	12/15/33	5.980%	$30,000,000	$30,000,000	$624,465	2.082%	$0	0.000%
6.33% - Senior Note	08/24/06	08/24/26	6.330%	100,000,000	100,000,000	344,061	0.344%	10,532,009	10.532%
5.18% - Senior Note	04/15/14	04/15/44	5.180%	50,000,000	50,000,000	239,178	0.478%	0	0.000%
4.24% - Senior Note	07/15/14	07/15/24	4.240%	60,000,000	60,000,000	291,263	0.485%	0	0.000%
4.34% - Senior Note	07/15/14	07/15/26	4.340%	40,000,000	40,000,000	197,042	0.493%	0	0.000%
3.78% - Senior Note	10/29/15	10/30/25	3.780%	87,000,000	87,000,000	471,997	0.543%	0	0.000%
4.87% - Senior Note	10/29/15	10/30/45	4.870%	11,000,000	11,000,000	59,461	0.541%	0	0.000%
4.03% - Senior Note	12/10/15	12/10/30	4.030%	52,000,000	52,000,000	286,355	0.551%	0	0.000%
4.15% - Senior Note	11/21/16	11/21/46	4.150%	40,000,000	40,000,000	226,084	0.565%	0	0.000%
3.73% - Senior Note	03/21/17	03/31/37	3.730%	40,000,000	40,000,000	173,637	0.434%	0	0.000%
3.36% - Senior Note	03/21/17	03/31/32	3.360%	20,000,000	20,000,000	86,071	0.430%	0	0.000%
3.66% - Senior Note	10/17/19	10/17/39	3.660%	50,000,000	50,000,000	200,000	0.400%	0	0.000%
3.98% - Senior Note	10/17/19	10/17/49	3.980%	50,000,000	50,000,000	200,000	0.400%	0	0.000%
4.08% - Senior Note	11/18/19	11/18/59	4.080%	100,000,000	100,000,000	400,000	0.400%	0	0.000%
Total Long-Term Debt Capital				$730,000,000	$730,000,000	$3,799,614		$10,532,009	

Description	Net Proceeds Amount	Net Proceeds Per Unit	Cost of Money 1/	Principal Outstanding	Annual Cost	Embedded Cost
Unsecured Long-Term Debt:						
5.98% - Senior Note	$29,375,535	97.918%	6.210%	$30,000,000	$1,863,000	
6.33% - Senior Note	89,123,930	89.124%	7.514%	100,000,000	7,514,000	
5.18% - Senior Note	49,760,822	99.522%	5.280%	50,000,000	2,640,000	
4.24% - Senior Note	59,708,737	99.515%	4.346%	60,000,000	2,607,600	
4.34% - Senior Note	39,802,958	99.507%	4.442%	40,000,000	1,776,800	
3.78% - Senior Note	86,528,003	99.457%	3.883%	87,000,000	3,378,210	
4.87% - Senior Note	10,940,539	99.459%	4.964%	11,000,000	546,040	
4.03% - Senior Note	51,713,645	99.449%	4.122%	52,000,000	2,143,440	
4.15% - Senior Note	39,773,916	99.435%	4.228%	40,000,000	1,691,200	
3.73% - Senior Note	39,826,363	99.566%	3.797%	40,000,000	1,518,800	
3.36% - Senior Note	19,913,929	99.570%	3.425%	20,000,000	685,000	
3.66% - Senior Note	49,800,000	99.600%	3.722%	50,000,000	1,861,000	
3.98% - Senior Note	49,800,000	99.600%	4.044%	50,000,000	2,022,000	
4.08% - Senior Note	99,600,000	99.600%	4.142%	100,000,000	4,142,000	
Total Long-Term Debt Capital	$715,668,377			$730,000,000	$34,389,090	4.711%

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

GREAT PLAINS NATURAL GAS CO.
LONG-TERM DEBT CAPITAL
PROJECTED DECEMBER 31, 2020

Description	Date of Issuance	Date of Maturity	Interest Rate	Principal Amount of Issue	Gross Proceeds	Underwriters' Commission Amount	Underwriters' Commission % Gross Proceeds	Loss on Reacquirement Redemption and Issuance Expense Amount	Loss on Reacquirement Redemption and Issuance Expense % Gross Proceeds
Unsecured Long-Term Debt:									
5.98% - Senior Note	12/15/03	12/15/33	5.980%	$30,000,000	$30,000,000	$624,465	2.082%	$0	0.000%
6.33% - Senior Note	08/24/06	08/24/26	6.330%	100,000,000	100,000,000	344,061	0.344%	10,532,009	10.532%
5.18% - Senior Note	04/15/14	04/15/44	5.180%	50,000,000	50,000,000	239,178	0.478%	0	0.000%
4.24% - Senior Note	07/15/14	07/15/24	4.240%	60,000,000	60,000,000	291,263	0.485%	0	0.000%
4.34% - Senior Note	07/15/14	07/15/26	4.340%	40,000,000	40,000,000	197,042	0.493%	0	0.000%
3.78% - Senior Note	10/29/15	10/30/25	3.780%	87,000,000	87,000,000	471,997	0.543%	0	0.000%
4.87% - Senior Note	10/29/15	10/30/45	4.870%	11,000,000	11,000,000	59,461	0.541%	0	0.000%
4.03% - Senior Note	12/10/15	12/10/30	4.030%	52,000,000	52,000,000	286,355	0.551%	0	0.000%
4.15% - Senior Note	11/21/16	11/21/46	4.150%	40,000,000	40,000,000	226,084	0.565%	0	0.000%
3.73% - Senior Note	03/21/17	03/31/37	3.730%	40,000,000	40,000,000	173,637	0.434%	0	0.000%
3.36% - Senior Note	03/21/17	03/31/32	3.360%	20,000,000	20,000,000	86,071	0.430%	0	0.000%
3.66% - Senior Note	10/17/19	10/17/39	3.660%	50,000,000	50,000,000	200,000	0.400%	0	0.000%
3.98% - Senior Note	10/17/19	10/17/49	3.980%	50,000,000	50,000,000	200,000	0.400%	0	0.000%
4.08% - Senior Note	11/18/19	11/18/59	4.080%	100,000,000	100,000,000	400,000	0.400%	0	0.000%
4.51% - Senior Note	06/15/20	06/15/30	4.510%	75,000,000	75,000,000	300,000	0.400%	0	0.000%
Total Long-Term Debt Capital				$805,000,000	$805,000,000	$4,099,614		$10,532,009	

Description	Net Proceeds Amount	Net Proceeds Per Unit	Cost of Money 1/	Principal Outstanding	Annual Cost	Embedded Cost
Unsecured Long-Term Debt:						
5.98% - Senior Note	$29,375,535	97.918%	6.210%	$30,000,000	$1,863,000	
6.33% - Senior Note	89,123,930	89.124%	7.514%	100,000,000	7,514,000	
5.18% - Senior Note	49,760,822	99.522%	5.280%	50,000,000	2,640,000	
4.24% - Senior Note	59,708,737	99.515%	4.346%	60,000,000	2,607,600	
4.34% - Senior Note	39,802,958	99.507%	4.442%	40,000,000	1,776,800	
3.78% - Senior Note	86,528,003	99.457%	3.883%	87,000,000	3,378,210	
4.87% - Senior Note	10,940,539	99.459%	4.964%	11,000,000	546,040	
4.03% - Senior Note	51,713,645	99.449%	4.122%	52,000,000	2,143,440	
4.15% - Senior Note	39,773,916	99.435%	4.228%	40,000,000	1,691,200	
3.73% - Senior Note	39,826,363	99.566%	3.797%	40,000,000	1,518,800	
3.36% - Senior Note	19,913,929	99.570%	3.425%	20,000,000	685,000	
3.66% - Senior Note	49,800,000	99.600%	3.722%	50,000,000	1,861,000	
3.98% - Senior Note	49,800,000	99.600%	4.044%	50,000,000	2,022,000	
4.08% - Senior Note	99,600,000	99.600%	4.142%	100,000,000	4,142,000	
4.51% - Senior Note	74,700,000	99.600%	4.612%	75,000,000	3,459,000	
Total Long-Term Debt Capital	$790,368,377			$805,000,000	$37,848,090	4.702%

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

GREAT PLAINS NATURAL GAS CO.
AVERAGE SHORT-TERM DEBT

	Balance Outstanding	Annual Cost	Average Cost
2018			
Average Balance 1/	$68,849,896	$1,649,614	2.396%
Amortization of Fees 2/		351,065	
Total	$68,849,896	$2,000,679	2.906%
Projected 2019			
Average Balance 1/	$82,352,265	$2,238,639	2.718%
Amortization of Fees 2/		352,863	
Total	$82,352,265	$2,591,502	3.147%
Projected 2020			
Average Balance 1/	$68,954,808	$2,193,833	3.182%
Amortization of Fees 2/		352,863	
Total	$68,954,808	$2,546,696	3.693%

1/ Twelve month average balance.
2/ Negotiation and commitment fees.

GREAT PLAINS NATURAL GAS CO.
AVERAGE UTILITY COMMON EQUITY

Description	Amount
Common Equity - 12/31/2017	$724,135,306
Common Equity - 12/31/2018	$2,566,774,816
Investment in Subsidiaries	1,790,885,738
Utility Common Equity - 12/31/2018	$775,889,078
Average @ 12/31/2018	$750,012,192
Common Equity - 12/31/2019	$801,416,000
Investment in Subsidiaries	0
Utility Common Equity - 12/31/2019	$801,416,000
Average @ 12/31/2019	$788,652,539
Common Equity - 12/31/2020	$927,820,405
Investment in Subsidiaries	0
Utility Common Equity - 12/31/2020	$927,820,405
Average @ 12/31/2020	$864,618,203

GREAT PLAINS NATURAL GAS CO.
AMORTIZATION OF LOSS ON REACQUIRED DEBT

	Amortization
Acct. 1890 - Unamortized Loss	
PCN Notes Loss/Unamortized Expense - 2018	$43,469
PCN Notes Loss/Unamortized Expense - 2019	43,469
PCN Notes Loss/Unamortized Expense - 2020	43,469

GREAT PLAINS NATURAL GAS CO.
REVENUES UNDER CURRENT AND PROPOSED RATES
GAS UTILITY - MINNESOTA
Projected 2020 - Docket No. G004/GR-19-511

Customer Class/Rate	Revenues Before Increase Bills	Dk	Revenue	Total Proposed Revenue 1/	Proposed Revenue Increase	GUIC 2/	Effective Rate Case Increase 3/	Net Percent Increase
Residential - Rate 60	18,808.0	1,527,457	$10,145,514	$12,120,411	$1,974,897	$380,948	$1,593,949	15.7%
Firm General - Rate 70	3,078.0	1,342,053	7,896,682	9,126,415	1,229,733	240,496	989,237	12.5%
Interruptible - Grain Drying Rate 73	23.9	191,639	812,834	939,405	126,571	27,181	99,390	12.2%
Small Interruptible								
Sales - Rate 71	92.5	392,421	1,790,007	1,894,918	104,911	59,609	45,302	2.5%
Transport - Rate 81	6.0	85,118	114,039	139,191	25,152	6,733	18,419	16.2%
Total Small Interruptible	98.5	477,539	1,904,046	2,034,109	130,063	66,342	63,721	3.3%
Large Interruptible								
Sales - Rate 85	7.0	359,600	1,307,839	1,353,246	45,407	39,664	5,743	0.4%
Transport - Rate 82	8.0	763,905	485,212	562,291	77,079	24,448	52,631	10.8%
Margin Sharing Customer	2.0	1,564,495	820,873	877,041	56,168	0	56,168	6.8%
Transport - Flex	3.0	2,261,482	495,755	495,755	0	0	0	0.0%
Total Large Interruptible	20.0	4,949,482	3,109,679	3,288,333	178,654	64,112	114,542	3.7%
Total Minnesota	22,028.4	8,488,170	$23,868,755	$27,508,673	$3,639,918	$779,079	$2,860,839	12.0%

1/ Includes margin sharing credit.
2/ GUIC revenue at current rates.
3/ GUIC revenue was excluded in the revenue analysis and was therefore built into the revenue requirement as part of the rate case. However, the dollars do not represent an increase to retail rates as part of the rate case as customers would pay this amount if no rate case had been filed. The Company is separating the dollars here to show the effective increase resulting from the rate case.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
ALLOCATION OF REVENUES
Projected 2020 - Docket No. G004/GR-19-511

	Cost of Gas			Distribution Including CIP		Increase		Total Revenue		Increase	
	Demand	Commodity	Total	Present	Proposed 1/	(Decrease)	%	Present	Proposed 1/	(Decrease)	%
Sales											
Residential	$1,860,137	$4,025,460	$5,885,597	$4,259,917	$6,234,814	$1,974,897	46.4%	$10,145,514	$12,120,411	$1,974,897	19.5%
Firm General	1,634,352	3,536,846	5,171,198	2,725,484	3,955,217	1,229,733	45.1%	7,896,682	9,126,415	1,229,733	15.6%
Interruptible - Grain Drying	66,173	505,045	571,218	241,616	368,187	126,571	52.4%	812,834	939,405	126,571	15.6%
Small Interruptible	135,503	1,034,186	1,169,689	620,318	725,229	104,911	16.9%	1,790,007	1,894,918	104,911	5.9%
Large Interruptible	124,170	947,690	1,071,860	235,979	281,386	45,407	19.2%	1,307,839	1,353,246	45,407	3.5%
Total Sales	3,820,335	10,049,227	13,869,562	8,083,314	11,564,833	3,481,519	43.1%	21,952,876	25,434,395	3,481,519	15.9%
Transportation											
Small Interruptible				114,039	139,191	25,152	22.1%	114,039	139,191	25,152	22.1%
Large Interruptible				485,212	562,291	77,079	15.9%	485,212	562,291	77,079	15.9%
Margin Sharing Customer				820,873	877,041	56,168	6.8%	820,873	877,041	56,168	6.8%
Flex Contracts				495,755	495,755	0	0.0%	495,755	495,755	0	0.0%
Total Transportation				1,915,879	2,074,278	158,399	8.3%	1,915,879	2,074,278	158,399	8.3%
Total	$3,820,335	$10,049,227	$13,869,562	$9,999,193	$13,639,111	$3,639,918	36.4%	$23,868,755	$27,508,673	$3,639,918	15.2%

1/ Includes margin sharing credit.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
Comparison of Revenues - Current & Projected
Projected 2020 - Docket No. G004/GR-19-511

	Projected 2020		Current Rates						Current Revenues						
	Bills	Dk	Basic Service Chg	Distribution Delivery 1/	Margin Sharing	Demand	Cost of Gas Commodity	Total	Basic Service Chg	Distribution Delivery	Margin Sharing	Demand	Cost of Gas Commodity	Total	Total
Current															
Residential	18,808.0	1,527,457	$7.50	$1.6807	$0.0000	$1.2178	$2.6354	$3.8532	$1,692,720	$2,567,197	$0	$1,860,137	$4,025,460	$5,885,597	$10,145,514
Firm General Gas < 500	2,014.0	286,401	23.00	1.3455	$0.0000	1.2178	2.6354	3.8532	555,864	385,353	0	348,779	754,781	1,103,560	2,044,777
Firm General Gas > 500	1,064.0	1,055,652	28.50	1.3455	$0.0000	1.2178	2.6354	3.8532	363,888	1,420,379	0	1,285,573	2,782,065	4,067,638	5,851,905
Interruptible Grain Drying 2/	21.9	145,269	145.00	1.1706	$0.0000	0.3453	2.6354	2.9807	38,106	170,052	0	50,161	382,842	433,003	641,161
Interruptible Grain Drying 3/	2.0	46,370	230.00	0.6025	$0.0000	0.3453	2.6354	2.9807	5,520	27,938	0	16,012	122,203	138,215	171,673
Small Int. Gas Sales	92.5	392,421	145.00	1.1706	$0.0000	0.3453	2.6354	2.9807	160,950	459,368	0	135,503	1,034,186	1,169,689	1,790,007
Small Int. General Gas Trans.	6.0	85,118	200.00	1.1706	$0.0000				14,400	99,639	0	0	0	0	114,039
Large Int. General Gas Trans.	8.0	763,905	260.00	0.6025	$0.0000				24,960	460,252	0	0	0	0	485,212
Margin Sharing Customer	2.0	1,564,495	260.00	0.5207	$0.0000				6,240	814,633	0	0	0	0	820,873
Large Int. Gas Sales	7.0	359,600	230.00	0.6025	$0.0000	0.3453	2.6354	2.9807	19,320	216,659	0	124,170	947,690	1,071,860	1,307,839
Large Int. Flex Trans.	3.0	2,261,482	260.00		$0.0000				9,360	486,395	0	0	0	0	495,755
Total - Current Rates	22,028.4	8,488,170							2,891,328	7,107,865	0	3,820,335	10,049,227	13,869,562	23,868,755

	Projected 2020		Proposed Rates						Proposed Revenues						
	Bills	Dk	Basic Service Chg	Distribution Delivery 1/	Margin Sharing	Demand	Cost of Gas Commodity	Total	Basic Service Chg	Distribution Delivery	Margin Sharing	Demand	Cost of Gas Commodity	Total	Total
Proposed															
Residential	18,808.0	1,527,457	$0.296	$3.0375	($0.2860)	$1.2178	$2.6354	$3.8532	$2,032,016	$4,639,651	($436,853)	$1,860,137	$4,025,460	$5,885,597	$12,120,411
Firm General Gas < 500	2,014.0	286,401	0.904	2.3248	(0.2059)	1.2178	2.6354	3.8532	664,539	665,825	(58,970)	348,779	754,781	1,103,560	2,374,954
Firm General Gas > 500	1,064.0	1,055,652	1.151	2.3248	(0.2059)	1.2178	2.6354	3.8532	447,002	2,454,180	(217,359)	1,285,573	2,782,065	4,067,638	6,751,461
Interruptible Grain Drying	23.9	191,639.0	450.00	1.3723	(0.1245)	0.3453	2.6354	2.9807	129,060	262,986	(23,859)	66,173	505,045	571,218	939,405
Small Int. Gas Sales	92.5	392,421	150.00	1.5777	(0.1539)	0.3453	2.6354	2.9807	166,500	619,123	(60,394)	135,503	1,034,186	1,169,689	1,894,918
Small Int. General Gas Trans.	6.0	85,118	250.00	1.5777	(0.1539)				18,000	134,291	(13,100)	0	0	0	139,191
Large Int. General Gas Trans.	8.0	763,905	560.00	0.7249	(0.0592)				53,760	553,755	(45,223)	0	0	0	562,292
Margin Sharing Customer	2.0	1,564,495	560.00	0.5520	0.0000				13,440	863,601	0	0	0	0	877,041
Large Int. Gas Sales	7.0	359,600	500.00	0.7249	(0.0592)	0.3453	2.6354	2.9807	42,000	260,674	(21,288)	124,170	947,690	1,071,860	1,353,246
Large Int. Flex Trans.	3.0	2,261,482	260.00	0	0.0000				9,360	486,395	0	0	0	0	495,755
Total - Proposed Rates	22,028.4	8,488,170							3,575,677	10,940,481	(877,046)	3,820,335	10,049,227	13,869,562	27,508,674
								Increase	$684,349	$3,832,616	($877,046)	$0	$0	$0	$3,639,919

1/ Includes CIP.
2/ Grain drying customers currently served under Rate 71.
3/ Grain drying customers currently served under Rate 85.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
ALLOCATION OF REVENUES
Projected 2020 - Docket No. G004/GR-19-511

	Embedded COS Before Increase			Cost Based Increase Required				Rate Design Results		
Rate Class	Operating Income	Rate Base	Rate Of Return	Operating Income	Revenues	% Increase	Cost Based Apportionment	Revenue Increase	Rate Of Return	Increase Apportionment
Residential	($1,109,418)	$19,498,024	-5.69%	$2,563,970	$3,598,150	35.47%	98.85%	$1,974,897	1.53%	54.26%
Firm General	112,739	8,998,312	1.25%	558,535	783,821	9.93%	21.53%	1,229,733	10.99%	33.78%
Interruptible - Grain Drying	65,307	412,595	15.83%	(34,527)	(48,454)	-5.96%	-1.33%	126,571	37.69%	3.48%
Small Interruptible Sales	255,024	497,593	51.25%	(217,903)	(305,794)	-17.08%	-8.40%	104,911	66.28%	2.88%
Small Interruptible Transport	57,996	120,065	48.30%	(49,039)	(68,820)	-60.35%	-1.89%	25,152	63.23%	0.69%
Large Interruptible Sales	58,307	540,724	10.78%	(17,969)	(25,217)	-1.93%	-0.69%	45,407	16.77%	1.25%
Large Interruptible Transport	330,157	1,618,861	20.39%	(209,390)	(293,848)	-60.56%	-8.07%	133,247	26.26%	3.66%
Total Minnesota	($229,888)	$31,686,174	-0.73%	$2,593,677	$3,639,838	15.25%	100.00%	$3,639,918	7.46%	100.0%

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
ALLOCATION OF REVENUES
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Rate Class	Target Rate Design: Target Increase 1/	Target Margin Sharing Increase	Current Distribution Revenue	Distr Rev Reflecting Increase 2/	Gas Costs: Demand	Gas Costs: Commodity	Gas Costs: Total	Total Design Revenues	Total Current Revenues	Total Design Increase	Resulting % Design Increase
Residential	$1,974,930	436,854	$4,259,917	$6,234,814	$1,860,137	$4,025,460	$5,885,597	$12,120,411	$10,145,514	$1,974,897	19.47%
Firm General	1,229,737	276,356	2,725,484	3,955,217	1,634,352	3,536,846	5,171,198	9,126,415	7,896,682	1,229,733	15.57%
Interruptible - Grain Drying	126,581	23,856	241,616	368,187	66,173	505,045	571,218	939,405	812,834	126,571	15.57%
Small Interruptible Sales	122,263	62,182	620,318	725,229	135,503	1,034,186	1,169,689	1,894,918	1,790,007	104,911	5.86%
Small Interruptible Transport	7,789	11,314	114,039	139,191	0	0	0	139,191	114,039	25,152	22.06%
Large Interruptible Sales	89,330	21,838	235,979	281,386	124,170	947,690	1,071,860	1,353,246	1,307,839	45,407	3.47%
Large Interruptible Transport	33,141	44,641	485,212	562,291	0	0	0	562,291	485,212	77,079	15.89%
Margin Sharing Customer	56,068	0	820,873	877,041				877,041	820,873	56,168	6.84%
Large IT Transport Flex	0	0	495,755	495,755	0	0	0	495,755	495,755	0	0.00%
Total Minnesota	$3,639,839	$877,041	$9,999,193	$13,639,111	$3,820,335	$10,049,227	$13,869,562	$27,508,673	$23,868,755	$3,639,918	15.25%

1/ Allocation of Revenues		
Residential @ 1.25 x Overall	19.47%	
Firm General @ Overall	15.57%	
IT - Grain Drying	15.57%	
Small IT Sales	6.83%	
Small IT Transport	6.83%	
Large IT Sales	6.83%	
Large IT Transport	6.83%	(Excluding Flex)
Overall	15.57%	
Design Increase	$3,639,839	
Residential/Firm/Grain Drying Target	$3,331,248	
Remainder Equally	$308,591	6.83%
Inverse of Tax Rate	71.2580%	

2/ Includes margin sharing credit.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
ALLOCATION OF REVENUES
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	Rate Design Summary of Results							
	Distribution Revenue Summary				Total Effective Increase Summary			
Rate Class	Current Dist. Revenue 1/	% Share of Distribution Revenue	Distr Rev Reflecting Increase 2/	% Share of Distribution Revenue	Total Design Increase	(Less) GUIC Revenue	Total Effective Increase 3/	Total % Increase
Residential	$4,259,917	42.5%	$6,234,814	45.8%	$1,974,897	$380,948	$1,593,949	15.7%
Firm General	2,725,484	27.3%	3,955,217	29.0%	1,229,733	240,496	989,237	12.5%
Interruptible - Grain Drying	241,616	2.4%	368,187	2.7%	126,571	27,181	99,390	12.2%
Small Interruptible Sales	620,318	6.2%	725,229	5.3%	104,911	59,609	45,302	2.5%
Small Interruptible Transport	114,039	1.1%	139,191	1.0%	25,152	6,733	18,419	16.2%
Large Interruptible Sales	235,979	2.4%	281,386	2.1%	45,407	39,664	5,743	0.4%
Large Interruptible Transport	485,212	4.9%	562,291	4.1%	77,079	24,448	52,631	10.8%
Margin Sharing Customer	820,873	8.2%	877,041	6.4%	56,168	0	56,168	6.8%
Large IT Transport Flex	495,755	5.0%	495,755	3.6%	0	0	0	0.0%
Total Minnesota	$9,999,193	100.0%	$13,639,111	100.0%	$3,639,918	$779,079	$2,860,839	12.0%

1/ Including CIP Base.
2/ Including CIP Base and Margin Sharing credit.
3/ Total increase expected as a direct result of the rate case.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
ALLOCATION OF REVENUES
Projected 2020 - Docket No. G004/GR-19-511

Margin Sharing Allocation 1/			
Rate Class	Distribution Revenues 2/	Share of Dist. Revs	Margin Sharing Allocation
Residential	$4,134,971	49.81%	$436,854
Small Firm	917,789		
Large Firm	1,697,915		
Total Firm General	2,615,704	31.51%	276,356
IT - Grain Drying	225,940	2.72%	23,856
Small IT Sales	588,218	7.09%	62,182
Small IT Transport	107,076	1.29%	11,314
Small IT Total	695,294	8.38%	73,496
Large IT Sales	206,564	2.49%	21,838
Large IT Transport 1/	422,725	5.09%	44,641
Large IT Total	629,289	7.58%	66,479
Total Minnesota	$8,301,198	100.00%	$877,041

1/ Excludes revenues associated with proposed Margin Sharing customer and flexible rate customers.
2/ Projected 2020 distribution revenues Excluding CIP.
Projected 2020 Margin Sharing customer revenue. $877,041

GUIC Revenue @ Current Rates			
Rate Class	Projected Volumes	GUIC Rate	GUIC Revenue
Residential	1,527,457	$0.2494	$380,948
Small Firm	286,401	0.1792	51,323
Large Firm	1,055,652	0.1792	189,173
Total Firm General	1,342,053		240,496
IT - Grain Drying	145,269	0.1519	22,066
IT - Grain Drying	46,370	0.1103	5,115
Small IT Sales	392,421	0.1519	59,609
Small IT Transport	85,118	0.0791	6,733
Small IT Total	477,539		66,342
Large IT Sales	359,600	0.1103	39,664
Large IT Transport 1/	2,328,400	0.0105	24,448
Large IT Total	2,688,000		64,112
Total Minnesota	6,226,688		$779,079

1/ Excludes transportation flexible rate customer volumes.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
RATE RECONCILIATION
RESIDENTIAL GAS SERVICE
Projected 2020 - Docket No. G004/GR-19-511

	Billing Units		Current Rate	Current Amount	Proposed Rate		Proposed Amount	Revenue Change
Residential Rate 60								
Basic Service Charge	18,808	Billing Units	$7.50	$1,692,720	$0.296	1/	$2,032,016	339,296
Distribution Charge	1,527,457	Dk	1.5989	2,442,251	2.9557		4,514,705	2,072,454
Margin Sharing Credit	1,527,457	Dk	0.0000	0	(0.2860)		(436,853)	(436,853)
CIP Base	1,527,457	Dk	0.0818	124,946	0.0818		124,946	0
Cost of Gas - Commodity	1,527,457	Dk	2.6354	4,025,460	2.6354		4,025,460	0
Cost of Gas - Demand	1,527,457	Dk	1.2178	1,860,137	1.2178		1,860,137	0
Total Revenue				10,145,514			12,120,411	1,974,897

Total Distribution Revenues Per Design	$6,671,667
Target Distribution Revenues	6,671,701
Difference	($34)

1/ Basic Service Charge applied on a daily basis under Proposed Rates. $9.00 effective monthly rate.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
RESIDENTIAL GAS SERVICE
Derivation of Rates
Projected 2020 - Docket No. G004/GR-19-511

Current Non-Gas Revenues	$4,259,917
Proposed Revenue Increase	2,411,784
Total Revenue Requirement	$6,671,701

	Total
Current Non-Gas Revenue	$4,259,917
Proposed Rev Req Inc.	1,974,930
Proposed Margin Sharing Inc.	436,854
	6,671,701
Proposed Base Rate	2,032,016
Net Commodity	4,639,685
Proposed Distribution Charge	
Per Dk	$3.0375
Less: CIP Base/Dk	0.0818
	2.9557
Margin Sharing Credit	($436,854)
Per Dk	($0.2860)
Projected 2020 Dk	1,527,457
Proposed CIP Base	$0.0818

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
RATE RECONCILIATION
FIRM GENERAL GAS SERVICE
Projected 2020 - Docket No. G004/GR-19-511

	Billing Units		Current Rate	Current Amount	Proposed Rate		Amount	Revenue Change
Firm General Rate 70								
Basic Service Charge < 500	2,014	Billing Units	$23.00	$555,864	$0.904	1/	$664,539	108,675
Basic Service Charge > 500	1,064	Billing Units	28.50	363,888	$1.151	1/	447,002	83,114
Distribution Charge	1,342,053	Dk	1.2637	1,695,952	2.2430		3,010,225	1,314,273
Margin Sharing Credit	1,342,053	Dk	0.0000	0	(0.2059)		(276,329)	(276,329)
CIP Base	1,342,053	Dk	0.0818	109,780	0.0818		109,780	0
Cost of Gas - Commodity	1,342,053	Dk	2.6354	3,536,846	2.6354		3,536,846	0
Cost of Gas - Demand	1,342,053	Dk	1.2178	1,634,352	1.2178		1,634,352	0
Total Revenue Rate				7,896,682			9,126,415	1,229,733

Total Distribution Revenues Per Design	$4,231,546
Target Distribution Revenues	4,231,577
Difference	($31)

1/ Basic Service Charge applied on a daily basis under Proposed Rates. Effective monthly rates of $27.50 and $35.00 for Small Large, respectively.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
FIRM GENERAL GAS SERVICE
Derivation of Rates
Projected 2020 - Docket No. G004/GR-19-511

Current Non-Gas Revenues	$2,725,484
Proposed Revenue Increase	1,506,093
Total Revenue Requirement	$4,231,577

	Total
Current Non-Gas Revenue	$2,725,484
Proposed Rev Req Inc.	1,229,737
Proposed Margin Sharing Inc.	276,356
	4,231,577
Proposed Base Rate	1,111,541
Net Commodity	3,120,036
Proposed Distribution Charge	
Per Dk	$2.3248
Less: CIP Base/Dk	0.0818
	2.2430
Margin Sharing Credit	($276,356)
Per Dk	($0.2059)
Projected 2020 Dk	1,342,053
Proposed CIP Base	$0.0818

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
RATE RECONCILIATION
INTERRUPTIBLE GRAIN DRYING GAS SERVICE
Projected 2020 - Docket No. G004/GR-19-511

	Billing Units		Current Rate	Current Amount	Proposed Rate	Proposed Amount	Revenue Change
Interruptible - Grain Drying Rate 73							
Basic Service Charge	21.9	Billing Units	$145.00	$38,106	450.00	$118,260	80,154
Basic Service Charge	2.0	Billing Units	230.00	$5,520	450.00	10,800	5,280
Distribution Charge	145,269	Dk	1.0888	158,169	1.2905	187,470	29,301
Distribution Charge	46,370	Dk	0.5207	24,145	1.2905	59,840	35,695
Margin Sharing Credit	191,639	Dk	0.0000	0	(0.1245)	(23,859)	(23,859)
CIP Base	191,639	Dk	0.0818	15,676	0.0818	15,676	0
Cost of Gas - Commodity	191,639	Dk	2.6354	505,045	2.6354	505,045	0
Cost of Gas - Demand	191,639	Dk	0.3453	66,173	0.3453	66,173	0
Total Revenue				812,834		939,405	126,571

Total Distribution Revenues Per Design	$392,046
Target Distribution Revenues	392,053
Difference	($7)

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
INTERRUPTIBLE GRAIN DRYING GAS SERVICE
Derivation of Rates
Projected 2020 - Docket No. G004/GR-19-511

Current Non-Gas Revenues	$241,616
Proposed Revenue Increase	150,437
Total Revenue Requirement	$392,053

	Total
Current Non-Gas Revenue	$241,616
Proposed Rev Req Inc.	126,581
Proposed Margin Sharing Inc.	23,856
	392,053
Proposed Base Rate	129,060
Net Commodity	262,993
Proposed Distribution Charge	
Per Dk	$1.3723
Less: CIP Base/Dk	0.0818
	1.2905
Margin Sharing Credit	($23,856)
Per Dk	($0.1245)
Projected 2020 Dk	191,639
Proposed CIP Base	$0.0818

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
RATE RECONCILIATION
SMALL INTERRUPTIBLE GAS SERVICE
Projected 2020 - Docket No. G004/GR-19-511

	Billing Units		Current Rate	Current Amount	Proposed Rate	Proposed Amount	Revenue Change
Small Interruptible Rates 71 & 81							
Basic Service Charge - Sales	92.5	Billing Units	$145.00	$160,950	$150.00	166,500	5,550
Basic Service Charge - Transport	6.0	Billing Units	200.00	14,400	250.00	18,000	3,600
Distribution Chg - Sales	392,421	Dk	1.0888	427,268	1.4959	587,023	159,755
Distribution Chg - Transport	85,118	Dk	1.0888	92,676	1.4959	127,328	34,652
Margin Sharing Credit - Sales	392,421	Dk	0.0000	0	(0.1539)	(60,394)	(60,394)
Margin Sharing Credit - Transport	85,118	Dk	0.0000	0	(0.1539)	(13,100)	(13,100)
CIP Base - Int. Sales	392,421	Dk	0.0818	32,100	0.0818	32,100	0
CIP Base - Transport	85,118	Dk	0.0818	6,963	0.0818	6,963	0
Cost of Gas - Commodity	392,421	Dk	2.6354	1,034,186	2.6354	1,034,186	0
Cost of Gas - Demand	392,421	Dk	0.3453	135,503	0.3453	135,503	0
Total Revenue				1,904,046		2,034,109	130,063

Total Distribution Revenues Per Design	937,914
Target Distribution Revenues	937,905
Difference	$9

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
SMALL INTERRUPTIBLE GAS SERVICE
Derivation of Rates
Projected 2020 - Docket No. G004/GR-19-511

Current Non-Gas Revenues	$734,357
Proposed Revenue Increase	203,548
Total Revenue Requirement	$937,905

	Total
Current Non-Gas Revenue	$734,357
Proposed Rev Req Inc.	130,052
Proposed Margin Sharing Inc.	73,496
	937,905
Proposed Base Rate	184,500
Net Commodity	753,405
Proposed Distribution Charge	
Per Dk	$1.5777
Less: CIP Base/Dk	0.0818
	1.4959
Margin Sharing Credit - Sales	($73,496)
Per Dk	($0.1539)
Projected 2020 Sales Dk	392,421
Projected 2020 Transport Dk	85,118
Total Dk	477,539
Proposed CIP Base	0.0818

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
RATE RECONCILIATION
LARGE INTERRUPTIBLE GAS SERVICE
Projected 2020 - Docket No. G004/GR-19-511

	Billing Units		Current Rate	Current Amount	Proposed Rate	Proposed Amount	Revenue Change
Large Interruptible							
Basic Service Charge - Sales	7	Billing Units	$230.00	$19,320	$500.00	42,000	22,680
Basic Service Charge - Transport	8	Billing Units	260.00	24,960	560.00	53,760	28,800
Distribution Charge - Sales	359,600	Dk	0.5207	187,244	0.6431	231,259	44,015
Distribution Charge - Transport	763,905	Dk	0.5207	397,765	0.6431	491,267	93,502
Margin Sharing Credit - Sales	359,600	Dk	0.0000	0	(0.0592)	(21,288)	(21,288)
Margin Sharing Credit - Transport	763,905	Dk	0.0000	0	(0.0592)	(45,223)	(45,223)
CIP Base - Sales	359,600	Dk	0.0818	29,415	0.0818	29,415	0
CIP Base - Transport	763,905	Dk	0.0818	62,487	0.0818	62,487	0
Cost of Gas - Commodity	359,600	Dk	2.6354	947,690	2.6354	947,690	0
Cost of Gas - Demand	359,600	Dk	0.3453	124,170	0.3453	124,170	0
Margin Sharing Customer							
Basic Service Charge	2	Billing Units	260.00	6,240	560.00	13,440	7,200
Distribution Charge	1,564,495	Dk	0.5207	814,633	0.5520	863,601	48,968
Flexible Contracts							
Basic Service Charge	3	Billing Units	260.00	9,360	260.00	9,360	0
Distribution Charge	2,261,482	Dk		301,406		301,406	0
CIP Base	2,261,482	Dk	0.0818	184,989	0.0818	184,989	0
Total Revenue Rate				3,109,679		3,288,333	178,654

Total Distribution Revenues Per Design @ Ceiling	$910,188
Target Distribution Revenues @ Ceiling	910,141
Difference	$47

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
LARGE INTERRUPTIBLE GAS SERVICE
Derivation of Rates
Projected 2020 - Docket No. G004/GR-19-511

Current Non-Gas Revenues	$1,216,946
Less: Flexed Contracts 1/	($495,755)
Proposed Revenue Increase	$188,950
Total Revenue Requirement for Non-Flex and Non-Margin Sharing Customer	910,141

	Total	Margin Sharing Customer
Current Non-Gas Revenue @ Ceiling	$721,191	$820,873
Proposed Rev Req Inc.	122,471	56,068
Proposed Margin Sharing Inc.	66,479	0
	910,141	876,941
Proposed Base Rate	95,760	13,440
Net Commodity	814,381	863,501
Less Proposed CIP	91,902	0
	722,479	863,501
Proposed Distribution Charge	$0.6431	$0.5520
Margin Sharing Credit - Sales	($66,479)	
Per Dk	($0.0592)	
Projected 2020 Sales Dk	359,600	
Projected 2020 Transport Dk	763,905	1,564,495
Total Dk	1,123,505	
Proposed CIP Base	0.0818	

1/ Flexed Contracts

Customer ID	Basic Service Charge	Dk	CIP Base	Distribution Revenue	Total Rev
TF-2	3,120	596,861	48,823	53,717	105,660
TF-3	3,120	656,155	53,673	111,546	168,339
TF-5	3,120	1,008,466	82,493	136,143	221,756
Total	$9,360	2,261,482	$184,989	$301,406	$495,755

Great Plains Natural Gas Company
Gas Utility - Minnesota
Flexible Distribution Rates

Large Interruptible Fixed Rate 85

Distribution Rate including CIP	$ 0.7249

Flexible Rate 85

Minimum Margin	$ 0.0810
Mid Point (Margin per rate design)	$ 0.7249
Minimum	0.0810
Difference	$ 0.6439
Mid Point	$ 0.7249
Plus Difference	0.6439
Maximum Margin	$ 1.3688

Interruptible Transport Flex - Rate 82

Minimum Margin	$ 0.0530
Mid Point (Margin per rate design)	$ 0.7249
Minimum	0.0530
Difference	$ 0.6719
Mid Point	$ 0.7249
Plus Difference	0.6719
Maximum Margin	$ 1.3968

Note: CIP shall be added to the above rates where applicable.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
Embedded Class Cost of Service Study
Cost of Service by Component
Projected 2020

	Total Minnesota	Residential			Total Residential
		Demand	Energy	Customer	
Projected Rate Base	31,686,174	8,511,047	0	10,986,977	19,498,024
Operating Income for Proposed Return	2,363,789	634,924	0	819,628	1,454,552
Projected Operating Income	(229,888)	(1,341,342)	2,032,756	(1,800,832)	(1,109,418)
Increase in Operating Income	2,593,677	1,976,266	(2,032,756)	2,620,460	2,563,970
Related Taxes for Increase					
Federal Income	1,046,162	797,128	(819,915)	1,056,966	1,034,179
Total Increase in Revenue	3,639,839	2,773,394	(2,852,671)	3,677,426	3,598,149
Projected Revenue Before Increase	24,106,528	1,895,886	7,001,535	1,826,715	10,724,136
Total Cost of Service Required from Rates:	27,746,367	4,669,280	4,148,864	5,504,141	14,322,285
Less Projected Cost of Gas	13,869,562	1,860,137	4,025,460	0	5,885,597
Net Distribution Cost of Service	13,876,805	2,809,143	123,404	5,504,141	8,436,688
Return on Rate Base Before Increase	-0.726%				-5.690%
Projected Billing Units	22,003			18,808	
Bills	264,030			225,696	
Dk	8,488,170	1,527,457	1,527,457		
Unit Cost of Service					
Energy cost per Dk			$0.081		
Demand cost per Dk		$1.839			
Customer Cost Per Month				$24.39	
Cust and Demand cost per month				$36.83	

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
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Cost of Service by Component
Projected 2020

	Small Firm General			Total	Large Firm General			Total
	Demand	Energy	Customer	Small Firm General	Demand	Energy	Customer	Large Firm General
Projected Rate Base	1,718,355	0	1,350,156	3,068,511	4,714,052	0	1,215,749	5,929,801
Operating Income for Proposed Return	128,189	0	100,722	228,911	351,668	0	90,695	442,363
Projected Operating Income	(269,871)	322,779	31,949	84,857	(742,309)	1,071,006	(300,815)	27,882
Increase in Operating Income	398,060	(322,779)	68,773	144,054	1,093,977	(1,071,006)	391,510	414,481
Related Taxes for Increase								
Federal Income	160,558	(130,193)	27,740	58,105	441,257	(431,992)	157,916	167,181
Total Increase in Revenue	558,618	(452,972)	96,513	202,159	1,535,234	(1,502,998)	549,426	581,662
Projected Revenue Before Increase	355,972	1,230,891	571,015	2,157,878	1,305,357	4,370,344	374,422	6,050,123
Total Cost of Service Required from Rates:	914,590	777,919	667,528	2,360,037	2,840,591	2,867,346	923,848	6,631,785
Less Projected Cost of Gas	348,779	754,781	0	1,103,560	1,285,573	2,782,065	0	4,067,638
Net Distribution Cost of Service	565,811	23,138	667,528	1,256,477	1,555,018	85,281	923,848	2,564,147
Return on Rate Base Before Increase				2.765%				0.470%
Projected Billing Units			2,014				1,064	
Bills			24,168				12,768	
Dk	286,401	286,401			1,055,652	1,055,652		
Unit Cost of Service								
Energy cost per Dk		$0.081				$0.081		
Demand cost per Dk	$1.976				$1.473			
Customer Cost Per Month			$27.62				$72.36	
Cust and Demand cost per month			$51.03				$194.15	

GREAT PLAINS NATURAL GAS CO.
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Cost of Service by Component
Projected 2020

	Interruptible Sales - Grain Drying			Total Interruptible Sales - Grain Drying
	Demand	Energy	Customer	
Projected Rate Base	261,778	0	150,817	412,595
Operating Income for Proposed Return	19,529	0	11,251	30,780
Projected Operating Income	(41,081)	145,963	(39,575)	65,307
Increase in Operating Income	60,610	(145,963)	50,826	(34,527)
Related Taxes for Increase				
Federal Income	24,447	(58,874)	20,501	(13,926)
Total Increase in Revenue	85,057	(204,837)	71,327	(48,453)
Projected Revenue Before Increase	67,268	725,363	44,262	836,893
Total Cost of Service Required from Rates:	152,325	520,526	115,589	788,440
Less Projected Cost of Gas	66,173	505,045	0	571,218
Net Distribution Cost of Service	86,152	15,481	115,589	217,222
Return on Rate Base Before Increase				15.828%
Projected Billing Units			23.9	
Bills			287	
Dk	191,639	191,639		
Unit Cost of Service				
Energy cost per Dk		$0.081		
Demand cost per Dk	$0.450			
Customer Cost Per Month			$402.75	
Cust and Demand cost per month			$702.93	

GREAT PLAINS NATURAL GAS CO.
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Cost of Service by Component
Projected 2020

	Small Interruptible Sales			Total Small Interruptible Sales	Small Interruptible Transporation			Total Small Interruptible Transporation
	Demand	Energy	Customer		Demand	Energy	Customer	
Projected Rate Base	531,849	0	(34,256)	497,593	113,963	0	6,102	120,065
Operating Income for Proposed Return	39,676	0	(2,555)	37,121	8,502	0	455	8,957
Projected Operating Income	(84,116)	346,219	(7,079)	255,024	(18,227)	73,649	2,574	57,996
Increase in Operating Income	123,792	(346,219)	4,524	(217,903)	26,729	(73,649)	(2,119)	(49,039)
Related Taxes for Increase								
Federal Income	49,932	(139,648)	1,825	(87,891)	10,781	(29,706)	(855)	(19,780)
Total Increase in Revenue	173,724	(485,867)	6,349	(305,794)	37,510	(103,355)	(2,974)	(68,819)
Projected Revenue Before Increase	137,745	1,551,754	162,024	1,851,523	486	110,228	14,467	125,181
Total Cost of Service Required from Rates:	311,469	1,065,887	168,373	1,545,729	37,996	6,873	11,493	56,362
Less Projected Cost of Gas	135,503	1,034,186	0	1,169,689	0	0	0	0
Net Distribution Cost of Service	175,966	31,701	168,373	376,040	37,996	6,873	11,493	56,362
Return on Rate Base Before Increase				51.252%				48.304%
Projected Billing Units			92.5				6	
Bills			1,110				72	
Dk	392,421	392,421			85,118	85,118		
Unit Cost of Service								
Energy cost per Dk		$0.081				$0.081		
Demand cost per Dk	$0.448				$0.446			
Customer Cost Per Month			$151.69				$159.63	
Cust and Demand cost per month			$310.22				$687.35	

GREAT PLAINS NATURAL GAS CO.
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Cost of Service by Component
Projected 2020

	Large Interruptible Sales			Total Large Interruptible Sales	Large Interruptible Transportation			Total Large Interruptible Transportation
	Demand	Energy	Customer		Demand	Energy	Customer	
Projected Rate Base	491,150	0	49,574	540,724	1,672,708	0	(53,847)	1,618,861
Operating Income for Proposed Return	36,640	0	3,698	40,338	124,784	0	(4,017)	120,767
Projected Operating Income	(77,071)	148,254	(12,876)	58,307	(182,808)	530,274	(17,309)	330,157
Increase in Operating Income	113,711	(148,254)	16,574	(17,969)	307,592	(530,274)	13,292	(209,390)
Related Taxes for Increase								
Federal Income	45,865	(59,798)	6,685	(7,248)	124,068	(213,887)	5,361	(84,458)
Total Increase in Revenue	159,576	(208,052)	23,259	(25,217)	431,660	(744,161)	18,653	(293,848)
Projected Revenue Before Increase	126,224	1,184,788	19,529	1,330,541	7,177	988,429	34,647	1,030,253
Total Cost of Service Required from Rates:	285,800	976,736	42,788	1,305,324	438,837	244,268	53,300	736,405
Less Projected Cost of Gas	124,170	947,690	0	1,071,860	0	0	0	0
Net Distribution Cost of Service	161,630	29,046	42,788	233,464	438,837	244,268	53,300	736,405
Return on Rate Base Before Increase				10.783%				20.394%
Projected Billing Units			7				11	
Bills			84				132	
Dk	359,600	359,600			4,589,882	4,589,882		
Unit Cost of Service								
Energy cost per Dk		$0.081				$0.053		
Demand cost per Dk	$0.449				$0.096			
Customer Cost Per Month			$509.38				$403.79	
Cust and Demand cost per month			$2,433.55				$3,728.31	

GREAT PLAINS NATURAL GAS CO.
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Twelve Months Ended December 31, 2018
Projected 2020

Description	Allocation Factor	Total Minnesota	Residential Demand	Residential Energy	Residential Customer	Total Residential
Rate Base-Projected						
Gas Plant in Service						
Transmission Plant	3	5,151,592	2,144,317	0	0	2,144,317
Distribution Plant						
Land	13	2,917	1,417	0	0	1,417
Rights of Way	13	17,257	8,376	0	0	8,376
Structures & Improvements	13	34,152	16,575	0	0	16,575
Mains						
Demand Related 100%	2	20,704,043	10,048,111	0	0	10,048,111
Customer Related 0%	4	0	0	0	0	0
Meas. & Reg. Equip. - General	13	701,353	340,382	0	0	340,382
Meas. & Reg. Equip. - City Gate	13	657,599	319,147	0	0	319,147
Services	9	17,376,736	0	0	14,231,914	14,231,914
Meters	5	6,882,669	0	0	4,207,678	4,207,678
Service Regulators	5	1,022,916	0	0	625,353	625,353
Ind. Meas. & Reg. Station Equipment	13	37,008	17,960	0	0	17,960
Cathodic Protection & Other Equipment	13	109,802	53,290	0	0	53,290
Distribution Plant		47,546,452	10,805,258	0	19,064,945	29,870,203
Distribution Plant Excluding Direct Assignments		47,546,452	10,805,258	0	19,064,945	29,870,203
General Plant	38	6,705,525	1,523,877	0	2,688,746	4,212,623
Intangible Plant - General excluding CC&B	15	889,075	202,048	0	356,498	558,546
Intangible Plant -CC&B	4	2,021,787	0	0	1,725,698	1,725,698
Common Plant	15	1,480,188	336,383	0	593,518	929,901
Intangible Common	15	1,153,922	262,237	0	462,693	724,930
Total Gas Plant in Service		64,948,541	15,274,120	0	24,892,098	40,166,218

GREAT PLAINS NATURAL GAS CO.
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Twelve Months Ended December 31, 2018
Projected 2020

Description	Allocation Factor	Total Minnesota	Residential Demand	Residential Energy	Residential Customer	Total Residential
Less: Accumulated Depreciation						
Transmission Plant	3	1,459,513	607,513	0	0	607,513
Distribution Plant						
Land Rights	13	9,347	4,536	0	0	4,536
Structures & Improvements	23	28,432	13,799	0	0	13,799
Mains	13	9,529,057	4,624,653	0	0	4,624,653
Meas. & Reg. Equip. - General	18	421,826	204,722	0	0	204,722
Meas. & Reg. Equip. - City Gate	19	161,846	78,546	0	0	78,546
Services	9	9,449,867	0	0	7,739,640	7,739,640
Meters	5	4,983,055	0	0	3,046,361	3,046,361
Service Regulators	5	480,784	0	0	293,925	293,925
Ind. Meas. & Reg. Station Equipment	21	10,118	4,910	0	0	4,910
Property on Customer Premise	13	7,310	3,548	0	0	3,548
Cathodic Protection & Other Equipment	13	11,075	5,374	0	0	5,374
Distribution Plant		25,092,717	4,940,088	0	11,079,926	16,020,014
General Plant	38	2,182,764	496,048	0	875,234	1,371,282
Intangible Plant - General excluding CC&B	15	367,519	83,521	0	147,365	230,886
Intangible Plant -CC&B	4	714,798	0	0	610,116	610,116
Common Plant	15	573,950	130,434	0	230,140	360,574
Intangible Plant - Common	15	660,849	150,182	0	264,985	415,167
Less: Total Accumulated Reserve for Depreciation		31,052,110	6,407,786	0	13,207,766	19,615,552
Net Gas Plant in Service		33,896,431	8,866,334	0	11,684,332	20,550,666
Additions						
Materials & Supplies	15	486,504	110,561	0	195,076	305,637
Gas in Underground Storage	36	306,530	160,875	0	0	160,875
Prepayments	25	141,544	33,286	0	54,249	87,535
Unamortized Loss on Debt	24	56,258	14,715	0	19,390	34,105
Unamortized Redemption Cost - Pref. Stock	24	10,034	2,625	0	3,459	6,084
Total Additions		1,000,870	322,062	0	272,174	594,236

GREAT PLAINS NATURAL GAS CO.
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Twelve Months Ended December 31, 2018
Projected 2020

			Residential			
Description	Allocation Factor	Total Minnesota	Demand	Energy	Customer	Total Residential
Total Before Deductions		34,897,301	9,188,396	0	11,956,506	21,144,902
Deductions						
Accumulated Deferred Income Tax	24	(2,448,366)	(640,422)	0	(843,969)	(1,484,391)
Customer Advances For Construction	Direct	(762,761)	(36,927)		(125,560)	(162,487)
Total Deductions		(3,211,127)	(677,349)	0	(969,529)	(1,646,878)
Total Rate Base		31,686,174	8,511,047	0	10,986,977	19,498,024
Income Statement						
Gas Operating Revenues						
Retail Sales & Transportation						
Residential	Direct	10,554,392	1,860,137	7,001,535	1,692,720	10,554,392
Firm General	Direct	8,155,339	0	0	0	0
Interruptible Sales - Grain Drying	Direct	835,162	0	0	0	0
Small Interruptible Sales	Direct	1,848,207	0	0	0	0
Small Interruptible Transportation	Direct	124,628	0	0	0	0
Large Interruptible Sales	Direct	1,328,278				
Large Interruptible Transporation	Direct	1,022,749	0	0	0	0
Total Sales & Transportation Revenues		23,868,755	1,860,137	7,001,535	1,692,720	10,554,392
Other Operating Revenue						
Miscellaneous						
Reconnect Fees	6	29,815	0	0	25,622	25,622
NSF Check Fees	6	4,455	0	0	3,828	3,828
Work for Construction of Others	24	0	0	0	0	0
Miscellaneous	24	12,861	3,364	0	4,433	7,797
Rent From Gas Property	24	123,809	32,385	0	42,678	75,063
Late Payment Revenue	6	66,833	0	0	57,434	57,434
Total Other Operating Revenue		237,773	35,749	0	133,995	169,744
Total Operating Revenues		24,106,528	1,895,886	7,001,535	1,826,715	10,724,136

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
Embedded Class Cost of Service Study
Twelve Months Ended December 31, 2018
Projected 2020

Description	Allocation Factor	Total Minnesota	Residential Demand	Residential Energy	Residential Customer	Total Residential
Operation & Maintenance Expenses						
Cost of Purchased Gas	Direct	13,869,562	1,860,137	4,025,460	0	5,885,597
Other Gas Supply Expenses	2	66,292	32,173	0	0	32,173
Transmission Expense	2	19,040	9,240	0	0	9,240
Distribution Expenses						
Operation						
Load Dispatch	2	2,010	976	0	0	976
Mains and Services	22	640,496	169,002	0	239,372	408,374
Measuring Stations - General	18	9,946	4,827	0	0	4,827
Measuring Stations - Industrial	21	26,159	12,695	0	0	12,695
Measuring Stations - City Gate	19	65,393	31,739	0	0	31,739
Meters & House Regulators	16	168,630	0	0	103,090	103,090
Customer Installations	5	140,087	0	0	85,641	85,641
Other Gas Distribution	27	498,070	103,727	0	202,547	306,274
Rents	27	26,818	5,585	0	10,906	16,491
Supervision & Engineering	27	488,667	101,769	0	198,724	300,493
Total Operation Expense		2,066,276	430,320	0	840,280	1,270,600
Maintenance						
Structures & Improvements	13	25,627	12,437	0	0	12,437
Mains	13	156,421	75,915	0	0	75,915
Measuring Stations - General	18	13,443	6,524	0	0	6,524
Measuring Stations - Industrial	21	17,414	8,450	0	0	8,450
Measuring Stations - City Gate	19	31,204	15,143	0	0	15,143
Services	5	137,888	0	0	84,298	84,298
Meters & House Regulators	16	95,405	0	0	58,324	58,324
Other Equipment	28	258,302	64,099	0	77,164	141,263
Supervision & Engineering	28	137,235	34,055	0	40,998	75,053
Total Maintenance Expense		872,939	216,623	0	260,784	477,407
Total Distribution Expenses		2,939,215	646,943	0	1,101,064	1,748,007

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
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Twelve Months Ended December 31, 2018
Projected 2020

Description	Allocation Factor	Total Minnesota	Residential Demand	Residential Energy	Residential Customer	Total Residential
Customer Accounts	4	11,614	0	0	9,912	9,912
Meter Reading	5	116,534	0	0	71,243	71,243
Customer Records & Collection	4	386,343	0	0	329,763	329,763
Uncollectible Accounts	6	196,357	0	0	168,742	168,742
Miscellaneous Customer Accounts	4	55,077	0	0	47,013	47,013
Customer Service & Information	4	39,504	0	0	33,717	33,717
Sales Expenses	4	9,498	0	0	8,106	8,106
Administration & General Expenses	30	2,604,365	573,241	0	975,625	1,548,866
CIP Base Expense	37	558,986	0	123,320	0	123,320
Total Gas O&M Expenses		20,872,387	3,121,734	4,148,780	2,745,185	10,015,699
O&M Excl. Cost of Gas and A&G		4,398,460	688,356	123,320	1,769,560	2,581,236
O&M Excl. Cost of Gas & CIP Base		6,443,839	1,261,597	0	2,745,185	4,006,782
Depreciation Expense						
Transmission Plant	2	106,123	51,504	0	0	51,504
Distribution Plant						
Land Rights	13	359	175	0	0	175
Structures & Improvements	23	970	469	0	0	469
Mains less Direct	13	664,470	322,482	0	0	322,482
Mains-Direct	Direct	0				
Meas. & Reg. Equip. - General	18	88,020	42,718	0	0	42,718
Meas. & Reg. Equip. - City Gate	19	26,962	13,084	0	0	13,084
Services less Direct	9	684,643	0	0	560,737	560,737
Services Direct	Direct	0				
Meters	5	682,072	0	0	416,982	416,982
Service Regulators	20	67,717	0	0	41,398	41,398
Ind. Meas. & Reg. Station Equipment	21	929	450	0	0	450
Cathodic Protection & Other Equipment	13	4,277	2,075	0	0	2,075
Total Distribution Plant		2,220,419	381,453	0	1,019,117	1,400,570
General Plant	38	131,526	29,890	0	52,741	82,631
Amort. of Intangible Plant - General	15	48,825	11,096	0	19,578	30,674
Amort. of Intangible Plant - CC&B	4	137,859	0	0	117,669	117,669

GREAT PLAINS NATURAL GAS CO.
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Twelve Months Ended December 31, 2018
Projected 2020

Description	Allocation Factor	Total Minnesota	Residential Demand	Residential Energy	Residential Customer	Total Residential
Common Plant	15	73,814	16,775	0	29,597	46,372
Intangible Plant - Common	15	106,219	24,139	0	42,591	66,730
Amort. Of Pref. Stock Redemption	15	777	177	0	311	488
Total Depreciation Expense		2,825,562	515,034	0	1,281,604	1,796,638
Taxes Other Than Income						
Ad Valorem Taxes	15	989,499	224,870	0	396,765	621,635
Other Taxes - Payroll, Franchise, Other	31	239,520	46,893	0	102,042	148,935
Other Taxes - Revenue	26	289	23	85	19	127
Total Taxes Other Than Income Taxes		1,229,308	271,786	85	498,826	770,697
Total Operating Expense		24,927,257	3,908,554	4,148,865	4,525,615	12,583,034
Interest Expense and Other Additions/Deductions	24	685,675	179,353	0	236,356	415,709
Taxable Income		(1,506,404)	(2,192,021)	2,852,670	(2,935,256)	(2,274,607)
Current Income Taxes	28.74%	(432,974)	(630,033)	819,914	(843,651)	(653,770)
Deferred Income Taxes	24	(157,868)	(41,294)	0	(54,417)	(95,711)
Total Income Taxes		(590,842)	(671,327)	819,914	(898,068)	(749,481)
Total Operating Expense		24,336,415	3,237,227	4,968,779	3,627,547	11,833,553
Operating Income:		(229,887)	(1,341,341)	2,032,756	(1,800,832)	(1,109,417)

GREAT PLAINS NATURAL GAS CO.
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Twelve Months Ended December 31, 2018
Projected 2020

			Firm General-Meter < 500 cubic feet				Firm General > 500 cubic feet			
Description	Allocation Factor	Total Minnesota	Demand	Energy	Customer	Total Small Firm General	Demand	Energy	Customer	Total Large Firm General
Rate Base-Projected										
Gas Plant in Service										
Transmission Plant	3	5,151,592	431,415	0	0	431,415	1,186,674	0	0	1,186,674
Distribution Plant										
Land	13	2,917	285	0	0	285	783	0	0	783
Rights of Way	13	17,257	1,685	0	0	1,685	4,635	0	0	4,635
Structures & Improvements	13	34,152	3,335	0	0	3,335	9,172	0	0	9,172
Mains										
Demand Related 100%	2	20,704,043	2,021,579	0	0	2,021,579	5,560,662	0	0	5,560,662
Customer Related 0%	4	0	0	0	0	0	0	0	0	0
Meas. & Reg. Equip. - General	13	701,353	68,481	0	0	68,481	188,368	0	0	188,368
Meas. & Reg. Equip. - City Gate	13	657,599	64,209	0	0	64,209	176,617	0	0	176,617
Services	9	17,376,736	0	0	1,813,797	1,813,797	0	0	1,030,618	1,030,618
Meters	5	6,882,669	0	0	504,707	504,707	0	0	1,411,657	1,411,657
Service Regulators	5	1,022,916	0	0	75,011	75,011	0	0	209,803	209,803
Ind. Meas. & Reg. Station Equipment	13	37,008	3,614	0	0	3,614	9,940	0	0	9,940
Cathodic Protection & Other Equipment	13	109,802	10,721	0	0	10,721	29,490	0	0	29,490
Distribution Plant		47,546,452	2,173,909	0	2,393,515	4,567,424	5,979,667	0	2,652,078	8,631,745
Distribution Plant Excluding Direct Assignments		47,546,452	2,173,909	0	2,393,515	4,567,424	5,979,667	0	2,652,078	8,631,745
General Plant	38	6,705,525	306,589	0	337,560	644,149	843,319	0	374,025	1,217,344
Intangible Plant - General excluding CC&B	15	889,075	40,650	0	44,757	85,407	111,814	0	49,591	161,405
Intangible Plant -CC&B	4	2,021,787	0	0	184,791	184,791	0	0	97,626	97,626
Common Plant	15	1,480,188	67,677	0	74,513	142,190	186,155	0	82,563	268,718
Intangible Common	15	1,153,922	52,759	0	58,089	110,848	145,123	0	64,364	209,487
Total Gas Plant in Service		64,948,541	3,072,999	0	3,093,225	6,166,224	8,452,752	0	3,320,247	11,772,999

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Description	Allocation Factor	Total Minnesota	Firm General-Meter < 500 cubic feet Demand	Energy	Customer	Total Small Firm General	Firm General > 500 cubic feet Demand	Energy	Customer	Total Large Firm General
Less: Accumulated Depreciation										
Transmission Plant	3	1,459,513	122,226	0	0	122,226	336,200	0	0	336,200
Distribution Plant										
Land Rights	13	9,347	913	0	0	913	2,510	0	0	2,510
Structures & Improvements	23	28,432	2,776	0	0	2,776	7,636	0	0	7,636
Mains	13	9,529,057	930,434	0	0	930,434	2,559,300	0	0	2,559,300
Meas. & Reg. Equip. - General	18	421,826	41,188	0	0	41,188	113,293	0	0	113,293
Meas. & Reg. Equip. - City Gate	19	161,846	15,803	0	0	15,803	43,468	0	0	43,468
Services	9	9,449,867	0	0	986,384	986,384	0	0	560,474	560,474
Meters	5	4,983,055	0	0	365,408	365,408	0	0	1,022,041	1,022,041
Service Regulators	5	480,784	0	0	35,256	35,256	0	0	98,610	98,610
Ind. Meas. & Reg. Station Equipment	21	10,118	988	0	0	988	2,718	0	0	2,718
Property on Customer Premise	13	7,310	714	0	0	714	1,963	0	0	1,963
Cathodic Protection & Other Equipment	13	11,075	1,081	0	0	1,081	2,975	0	0	2,975
Distribution Plant		25,092,717	993,897	0	1,387,048	2,380,945	2,733,863	0	1,681,125	4,414,988
General Plant	38	2,182,764	99,800	0	109,882	209,682	274,515	0	121,752	396,267
Intangible Plant - General excluding CC&B	15	367,519	16,804	0	18,501	35,305	46,221	0	20,500	66,721
Intangible Plant -CC&B	4	714,798	0	0	65,333	65,333	0	0	34,515	34,515
Common Plant	15	573,950	26,242	0	28,893	55,135	72,183	0	32,014	104,197
Intangible Plant - Common	15	660,849	30,215	0	33,268	63,483	83,112	0	36,861	119,973
Less: Total Accumulated Reserve for Depreciation		31,052,110	1,289,184	0	1,642,925	2,932,109	3,546,094	0	1,926,767	5,472,861
Net Gas Plant in Service		33,896,431	1,783,815	0	1,450,300	3,234,115	4,906,658	0	1,393,480	6,300,138
Additions										
Materials & Supplies	15	486,504	22,244	0	24,491	46,735	61,185	0	27,137	88,322
Gas in Underground Storage	36	306,530	32,367	0	0	32,367	89,029	0	0	89,029
Prepayments	25	141,544	6,697	0	6,741	13,438	18,421	0	7,236	25,657
Unamortized Loss on Debt	24	56,258	2,961	0	2,407	5,368	8,144	0	2,313	10,457
Unamortized Redemption Cost - Pref. Stock	24	10,034	528	0	429	957	1,452	0	412	1,864
Total Additions		1,000,870	64,797	0	34,068	98,865	178,231	0	37,098	215,329

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			Firm General-Meter < 500 cubic feet				Firm General > 500 cubic feet			
Description	Allocation Factor	Total Minnesota	Demand	Energy	Customer	Total Small Firm General	Demand	Energy	Customer	Total Large Firm General
Total Before Deductions		34,897,301	1,848,612	0	1,484,368	3,332,980	5,084,889	0	1,430,578	6,515,467
Deductions										
Accumulated Deferred Income Tax	24	(2,448,366)	(128,846)	0	(104,756)	(233,602)	(354,412)	0	(100,652)	(455,064)
Customer Advances For Construction	Direct	(762,761)	(1,411)		(29,456)	(30,867)	(16,425)		(114,177)	(130,602)
Total Deductions		(3,211,127)	(130,257)	0	(134,212)	(264,469)	(370,837)	0	(214,829)	(585,666)
Total Rate Base		31,686,174	1,718,355	0	1,350,156	3,068,511	4,714,052	0	1,215,749	5,929,801
Income Statement										
Gas Operating Revenues										
Retail Sales & Transportation										
Residential	Direct	10,554,392	0	0	0	0	0	0	0	0
Firm General	Direct	8,155,339	348,779	1,230,891	555,864	2,135,534	1,285,573	4,370,344	363,888	6,019,805
Interruptible Sales - Grain Drying	Direct	835,162	0	0	0	0	0	0	0	0
Small Interruptible Sales	Direct	1,848,207	0	0	0	0	0	0	0	0
Small Interruptible Transportation	Direct	124,628	0	0	0	0	0	0	0	0
Large Interruptible Sales	Direct	1,328,278								
Large Interruptible Transporation	Direct	1,022,749	0	0	0	0	0	0	0	0
Total Sales & Transportation Revenues		23,868,755	348,779	1,230,891	555,864	2,135,534	1,285,573	4,370,344	363,888	6,019,805
Other Operating Revenue										
Miscellaneous										
Reconnect Fees	6	29,815	0	0	2,744	2,744	0	0	1,449	1,449
NSF Check Fees	6	4,455	0	0	410	410	0	0	217	217
Work for Construction of Others	24	0	0	0	0	0	0	0	0	0
Miscellaneous	24	12,861	677	0	550	1,227	1,862	0	529	2,391
Rent From Gas Property	24	123,809	6,516	0	5,297	11,813	17,922	0	5,090	23,012
Late Payment Revenue	6	66,833	0	0	6,150	6,150	0	0	3,249	3,249
Total Other Operating Revenue		237,773	7,193	0	15,151	22,344	19,784	0	10,534	30,318
Total Operating Revenues		24,106,528	355,972	1,230,891	571,015	2,157,878	1,305,357	4,370,344	374,422	6,050,123

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Description	Allocation Factor	Total Minnesota	Firm General-Meter < 500 cubic feet			Total Small Firm General	Firm General > 500 cubic feet			Total Large Firm General
			Demand	Energy	Customer		Demand	Energy	Customer	
Operation & Maintenance Expenses										
Cost of Purchased Gas	Direct	13,869,562	348,779	754,781	0	1,103,560	1,285,573	2,782,065	0	4,067,638
Other Gas Supply Expenses	2	66,292	6,473	0	0	6,473	17,805	0	0	17,805
Transmission Expense	2	19,040	1,859	0	0	1,859	5,114	0	0	5,114
Distribution Expenses										
Operation										
Load Dispatch	2	2,010	196	0	0	196	540	0	0	540
Mains and Services	22	640,496	34,002	0	30,507	64,509	93,527	0	17,334	110,861
Measuring Stations - General	18	9,946	971	0	0	971	2,671	0	0	2,671
Measuring Stations - Industrial	21	26,159	2,555	0	0	2,555	7,026	0	0	7,026
Measuring Stations - City Gate	19	65,393	6,385	0	0	6,385	17,563	0	0	17,563
Meters & House Regulators	16	168,630	0	0	12,366	12,366	0	0	34,587	34,587
Customer Installations	5	140,087	0	0	10,273	10,273	0	0	28,732	28,732
Other Gas Distribution	27	498,070	20,869	0	25,145	46,014	57,403	0	38,159	95,562
Rents	27	26,818	1,124	0	1,354	2,478	3,091	0	2,055	5,146
Supervision & Engineering	27	488,667	20,475	0	24,670	45,145	56,319	0	37,439	93,758
Total Operation Expense		2,066,276	86,577	0	104,315	190,892	238,140	0	158,306	396,446
Maintenance										
Structures & Improvements	13	25,627	2,502	0	0	2,502	6,883	0	0	6,883
Mains	13	156,421	15,273	0	0	15,273	42,011	0	0	42,011
Measuring Stations - General	18	13,443	1,313	0	0	1,313	3,610	0	0	3,610
Measuring Stations - Industrial	21	17,414	1,701	0	0	1,701	4,677	0	0	4,677
Measuring Stations - City Gate	19	31,204	3,047	0	0	3,047	8,381	0	0	8,381
Services	5	137,888	0	0	10,111	10,111	0	0	28,281	28,281
Meters & House Regulators	16	95,405	0	0	6,996	6,996	0	0	19,568	19,568
Other Equipment	28	258,302	12,897	0	9,256	22,153	35,473	0	25,889	61,362
Supervision & Engineering	28	137,235	6,852	0	4,918	11,770	18,847	0	13,755	32,602
Total Maintenance Expense		872,939	43,585	0	31,281	74,866	119,882	0	87,493	207,375
Total Distribution Expenses		2,939,215	130,162	0	135,596	265,758	358,022	0	245,799	603,821

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			Firm General-Meter < 500 cubic feet				Firm General > 500 cubic feet			
Description	Allocation Factor	Total Minnesota	Demand	Energy	Customer	Total Small Firm General	Demand	Energy	Customer	Total Large Firm General
Customer Accounts	4	11,614	0	0	1,062	1,062	0	0	561	561
Meter Reading	5	116,534	0	0	8,545	8,545	0	0	23,901	23,901
Customer Records & Collection	4	386,343	0	0	35,312	35,312	0	0	18,655	18,655
Uncollectible Accounts	6	196,357	0	0	18,069	18,069	0	0	9,546	9,546
Miscellaneous Customer Accounts	4	55,077	0	0	5,034	5,034	0	0	2,659	2,659
Customer Service & Information	4	39,504	0	0	3,611	3,611	0	0	1,908	1,908
Sales Expenses	4	9,498	0	0	868	868	0	0	459	459
Administration & General Expenses	30	2,604,365	115,333	0	120,148	235,481	317,234	0	217,796	535,030
CIP Base Expense	37	558,986	0	23,123	0	23,123	0	85,229	0	85,229
Total Gas O&M Expenses		20,872,387	602,606	777,904	328,245	1,708,755	1,983,748	2,867,294	521,284	5,372,326
O&M Excl. Cost of Gas and A&G		4,398,460	138,494	23,123	208,097	369,714	380,941	85,229	303,488	769,658
O&M Excl. Cost of Gas & CIP Base		6,443,839	253,827	0	328,245	582,072	698,175	0	521,284	1,219,459
Depreciation Expense										
Transmission Plant	2	106,123	10,362	0	0	10,362	28,502	0	0	28,502
Distribution Plant										
Land Rights	13	359	35	0	0	35	96	0	0	96
Structures & Improvements	23	970	95	0	0	95	261	0	1	262
Mains less Direct	13	664,470	64,880	0	0	64,880	178,462	0	0	178,462
Mains-Direct	Direct	0								
Meas. & Reg. Equip. - General	18	88,020	8,594	0	0	8,594	23,640	0	0	23,640
Meas. & Reg. Equip. - City Gate	19	26,962	2,633	0	0	2,633	7,241	0	0	7,241
Services less Direct	9	684,643	0	0	71,464	71,464	0	0	40,606	40,606
Services Direct	Direct	0								
Meters	5	682,072	0	0	50,016	50,016	0	0	139,895	139,895
Service Regulators	20	67,717	0	0	4,966	4,966	0	0	13,889	13,889
Ind. Meas. & Reg. Station Equipment	21	929	91	0	0	91	250	0	0	250
Cathodic Protection & Other Equipment	13	4,277	418	0	0	418	1,149	0	0	1,149
Total Distribution Plant		2,220,419	76,746	0	126,446	203,192	211,099	0	194,391	405,490
General Plant	38	131,526	6,014	0	6,621	12,635	16,541	0	7,336	23,877
Amort. of Intangible Plant - General	15	48,825	2,232	0	2,458	4,690	6,140	0	2,723	8,863
Amort. of Intangible Plant - CC&B	4	137,859	0	0	12,600	12,600	0	0	6,657	6,657

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Description	Allocation Factor	Total Minnesota	Firm General-Meter < 500 cubic feet Demand	Energy	Customer	Total Small Firm General	Firm General > 500 cubic feet Demand	Energy	Customer	Total Large Firm General
Common Plant	15	73,814	3,375	0	3,716	7,091	9,283	0	4,117	13,400
Intangible Plant - Common	15	106,219	4,857	0	5,347	10,204	13,359	0	5,925	19,284
Amort. Of Pref. Stock Redemption	15	777	36	0	39	75	98	0	43	141
Total Depreciation Expense		2,825,562	103,622	0	157,227	260,849	285,022	0	221,192	506,214
Taxes Other Than Income										
Ad Valorem Taxes	15	989,499	45,242	0	49,812	95,054	124,444	0	55,193	179,637
Other Taxes - Payroll, Franchise, Other	31	239,520	9,435	0	12,201	21,636	25,951	0	19,376	45,327
Other Taxes - Revenue	26	289	4	15	7	26	16	53	4	73
Total Taxes Other Than Income Taxes		1,229,308	54,681	15	62,020	116,716	150,411	53	74,573	225,037
Total Operating Expense		24,927,257	760,909	777,919	547,492	2,086,320	2,419,181	2,867,347	817,049	6,103,577
Interest Expense and Other Additions/Deductions	24	685,675	36,084	0	29,337	65,421	99,254	0	28,188	127,442
Taxable Income		(1,506,404)	(441,021)	452,972	(5,814)	6,137	(1,213,078)	1,502,997	(470,815)	(180,896)
Current Income Taxes	28.74%	(432,974)	(126,758)	130,193	(1,671)	1,764	(348,663)	431,991	(135,322)	(51,994)
Deferred Income Taxes	24	(157,868)	(8,308)	0	(6,755)	(15,063)	(22,852)	0	(6,490)	(29,342)
Total Income Taxes		(590,842)	(135,066)	130,193	(8,426)	(13,299)	(371,515)	431,991	(141,812)	(81,336)
Total Operating Expense		24,336,415	625,843	908,112	539,066	2,073,021	2,047,666	3,299,338	675,237	6,022,241
Operating Income:		(229,887)	(269,871)	322,779	31,949	84,857	(742,309)	1,071,006	(300,815)	27,882

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Description	Allocation Factor	Total Minnesota	Interruptible Sales - Grain Drying: Demand	Interruptible Sales - Grain Drying: Energy	Interruptible Sales - Grain Drying: Customer	Total Interruptible Grain Drying Sales
Rate Base-Projected						
Gas Plant in Service						
Transmission Plant	3	5,151,592	65,669	0	0	65,669
Distribution Plant						
Land	13	2,917	43	0	0	43
Rights of Way	13	17,257	256	0	0	256
Structures & Improvements	13	34,152	508	0	0	508
Mains						
Demand Related 100%	2	20,704,043	307,721	0	0	307,721
Customer Related 0%	4	0	0	0	0	0
Meas. & Reg. Equip. - General	13	701,353	10,424	0	0	10,424
Meas. & Reg. Equip. - City Gate	13	657,599	9,774	0	0	9,774
Services	9	17,376,736	0	0	94,587	94,587
Meters	5	6,882,669	0	0	195,977	195,977
Service Regulators	5	1,022,916	0	0	29,126	29,126
Ind. Meas. & Reg. Station Equipment	13	37,008	550	0	0	550
Cathodic Protection & Other Equipment	13	109,802	1,632	0	0	1,632
Distribution Plant		47,546,452	330,908	0	319,690	650,598
Distribution Plant Excluding Direct Assignments		47,546,452	330,908	0	319,690	650,598
General Plant	38	6,705,525	46,668	0	45,086	91,754
Intangible Plant - General excluding CC&B	15	889,075	6,188	0	5,978	12,166
Intangible Plant -CC&B	4	2,021,787	0	0	2,753	2,753
Common Plant	15	1,480,188	10,302	0	9,952	20,254
Intangible Common	15	1,153,922	8,031	0	7,759	15,790
Total Gas Plant in Service		64,948,541	467,766	0	391,218	858,984

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Description	Allocation Factor	Total Minnesota	Interruptible Sales - Grain Drying: Demand	Interruptible Sales - Grain Drying: Energy	Interruptible Sales - Grain Drying: Customer	Interruptible Grain Drying Sales
Less: Accumulated Depreciation						
Transmission Plant	3	1,459,513	18,605	0	0	18,605
Distribution Plant						
Land Rights	13	9,347	139	0	0	139
Structures & Improvements	23	28,432	423	0	0	423
Mains	13	9,529,057	141,629	0	0	141,629
Meas. & Reg. Equip. - General	18	421,826	6,269	0	0	6,269
Meas. & Reg. Equip. - City Gate	19	161,846	2,406	0	0	2,406
Services	9	9,449,867	0	0	51,438	51,438
Meters	5	4,983,055	0	0	141,887	141,887
Service Regulators	5	480,784	0	0	13,690	13,690
Ind. Meas. & Reg. Station Equipment	21	10,118	150	0	0	150
Property on Customer Premise	13	7,310	109	0	0	109
Cathodic Protection & Other Equipment	13	11,075	165	0	0	165
Distribution Plant		25,092,717	151,290	0	207,015	358,305
General Plant	38	2,182,764	15,191	0	14,676	29,867
Intangible Plant - General excluding CC&B	15	367,519	2,558	0	2,471	5,029
Intangible Plant -CC&B	4	714,798	0	0	973	973
Common Plant	15	573,950	3,995	0	3,859	7,854
Intangible Plant - Common	15	660,849	4,599	0	4,443	9,042
Less: Total Accumulated Reserve for Depreciation		31,052,110	196,238	0	233,437	429,675
Net Gas Plant in Service		33,896,431	271,528	0	157,781	429,309
Additions						
Materials & Supplies	15	486,504	3,386	0	3,271	6,657
Gas in Underground Storage	36	306,530	4,927	0	0	4,927
Prepayments	25	141,544	1,019	0	853	1,872
Unamortized Loss on Debt	24	56,258	451	0	262	713
Unamortized Redemption Cost - Pref. Stock	24	10,034	80	0	47	127
Total Additions		1,000,870	9,863	0	4,433	14,296

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Description	Allocation Factor	Total Minnesota	Interruptible Sales - Grain Drying Demand	Interruptible Sales - Grain Drying Energy	Interruptible Sales - Grain Drying Customer	Interruptible Grain Drying Sales
Total Before Deductions		34,897,301	281,391	0	162,214	443,605
Deductions						
Accumulated Deferred Income Tax	24	(2,448,366)	(19,613)	0	(11,397)	(31,010)
Customer Advances For Construction	Direct	(762,761)	0	0	0	0
Total Deductions		(3,211,127)	(19,613)	0	(11,397)	(31,010)
Total Rate Base		31,686,174	261,778	0	150,817	412,595
Income Statement						
Gas Operating Revenues						
Retail Sales & Transportation						
Residential	Direct	10,554,392	0	0	0	0
Firm General	Direct	8,155,339				0
Interruptible Sales - Grain Drying	Direct	835,162	66,173	725,363	43,626	835,162
Small Interruptible Sales	Direct	1,848,207	0	0	0	0
Small Interruptible Transportation	Direct	124,628	0	0	0	0
Large Interruptible Sales	Direct	1,328,278				
Large Interruptible Transporation	Direct	1,022,749	0	0	0	0
Total Sales & Transportation Revenues		23,868,755	66,173	725,363	43,626	835,162
Other Operating Revenue						
Miscellaneous						
Reconnect Fees	6	29,815	0	0	0	0
NSF Check Fees	6	4,455	0	0	0	0
Work for Construction of Others	24	0	0	0	0	0
Miscellaneous	24	12,861	103	0	60	163
Rent From Gas Property	24	123,809	992	0	576	1,568
Late Payment Revenue	6	66,833	0	0	0	0
Total Other Operating Revenue		237,773	1,095	0	636	1,731
Total Operating Revenues		24,106,528	67,268	725,363	44,262	836,893

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Description	Allocation Factor	Total Minnesota	Interruptible Sales - Grain Drying Demand	Interruptible Sales - Grain Drying Energy	Interruptible Sales - Grain Drying Customer	Interruptible Grain Drying Sales
Operation & Maintenance Expenses						
Cost of Purchased Gas	Direct	13,869,562	66,173	505,045	0	571,218
Other Gas Supply Expenses	2	66,292	985	0	0	985
Transmission Expense	2	19,040	283	0	0	283
Distribution Expenses						
Operation						
Load Dispatch	2	2,010	30	0	0	30
Mains and Services	22	640,496	5,176	0	1,591	6,767
Measuring Stations - General	18	9,946	148	0	0	148
Measuring Stations - Industrial	21	26,159	389	0	0	389
Measuring Stations - City Gate	19	65,393	972	0	0	972
Meters & House Regulators	16	168,630	0	0	4,802	4,802
Customer Installations	5	140,087	0	0	3,989	3,989
Other Gas Distribution	27	498,070	3,177	0	4,912	8,089
Rents	27	26,818	171	0	264	435
Supervision & Engineering	27	488,667	3,117	0	4,819	7,936
Total Operation Expense		2,066,276	13,180	0	20,377	33,557
Maintenance						
Structures & Improvements	13	25,627	381	0	0	381
Mains	13	156,421	2,325	0	0	2,325
Measuring Stations - General	18	13,443	200	0	0	200
Measuring Stations - Industrial	21	17,414	259	0	0	259
Measuring Stations - City Gate	19	31,204	464	0	0	464
Services	5	137,888	0	0	3,926	3,926
Meters & House Regulators	16	95,405	0	0	2,717	2,717
Other Equipment	28	258,302	1,963	0	3,594	5,557
Supervision & Engineering	28	137,235	1,043	0	1,910	2,953
Total Maintenance Expense		872,939	6,635	0	12,147	18,782
Total Distribution Expenses		2,939,215	19,815	0	32,524	52,339

GREAT PLAINS NATURAL GAS CO.
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Description	Allocation Factor	Total Minnesota	Interruptible Sales - Grain Drying: Demand	Interruptible Sales - Grain Drying: Energy	Interruptible Sales - Grain Drying: Customer	Interruptible Grain Drying Sales
Customer Accounts	4	11,614	0	0	16	16
Meter Reading	5	116,534	0	0	3,318	3,318
Customer Records & Collection	4	386,343	0	0	526	526
Uncollectible Accounts	6	196,357	0	0	0	0
Miscellaneous Customer Accounts	4	55,077	0	0	75	75
Customer Service & Information	4	39,504	0	0	54	54
Sales Expenses	4	9,498	0	0	13	13
Administration & General Expenses	30	2,604,365	17,558	0	28,819	46,377
CIP Base Expense	37	558,986	0	15,472	0	15,472
Total Gas O&M Expenses		20,872,387	104,814	520,517	65,345	690,676
O&M Excl. Cost of Gas and A&G		4,398,460	21,083	15,472	36,526	73,081
O&M Excl. Cost of Gas & CIP Base		6,443,839	38,641	0	65,345	103,986
Depreciation Expense						
Transmission Plant	2	106,123	1,577	0	0	1,577
Distribution Plant						
Land Rights	13	359	5	0	0	5
Structures & Improvements	23	970	14	0	0	14
Mains less Direct	13	664,470	9,876	0	0	9,876
Mains-Direct	Direct	0				0
Meas. & Reg. Equip. - General	18	88,020	1,308	0	0	1,308
Meas. & Reg. Equip. - City Gate	19	26,962	401	0	0	401
Services less Direct	9	684,643	0	0	3,727	3,727
Services Direct	Direct	0				0
Meters	5	682,072	0	0	19,421	19,421
Service Regulators	20	67,717	0	0	1,928	1,928
Ind. Meas. & Reg. Station Equipment	21	929	14	0	0	14
Cathodic Protection & Other Equipment	13	4,277	64	0	0	64
Total Distribution Plant		2,220,419	11,682	0	25,076	36,758
General Plant	38	131,526	915	0	884	1,799
Amort. of Intangible Plant - General	15	48,825	340	0	328	668
Amort. of Intangible Plant - CC&B	4	137,859	0	0	188	188

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Description	Allocation Factor	Total Minnesota	Interruptible Sales - Grain Drying Demand	Interruptible Sales - Grain Drying Energy	Interruptible Sales - Grain Drying Customer	Interruptible Grain Drying Sales
Common Plant	15	73,814	514	0	496	1,010
Intangible Plant - Common	15	106,219	739	0	714	1,453
Amort. Of Pref. Stock Redemption	15	777	5	0	5	10
Total Depreciation Expense		2,825,562	15,772	0	27,691	43,463
Taxes Other Than Income						
Ad Valorem Taxes	15	989,499	6,887	0	6,653	13,540
Other Taxes - Payroll, Franchise, Other	31	239,520	1,436	0	2,429	3,865
Other Taxes - Revenue	26	289	1	9	1	11
Total Taxes Other Than Income Taxes		1,229,308	8,324	9	9,083	17,416
Total Operating Expense		24,927,257	128,910	520,526	102,119	751,555
Interest Expense and Other Additions/Deductions	24	685,675	5,493	0	3,192	8,685
Taxable Income		(1,506,404)	(67,135)	204,837	(61,049)	76,653
Current Income Taxes	28.74%	(432,974)	(19,296)	58,874	(17,547)	22,032
Deferred Income Taxes	24	(157,868)	(1,265)	0	(735)	(2,000)
Total Income Taxes		(590,842)	(20,561)	58,874	(18,282)	20,032
Total Operating Expense		24,336,415	108,349	579,400	83,837	771,587
Operating Income:		(229,887)	(41,081)	145,963	(39,575)	65,306

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Description	Allocation Factor	Total Minnesota	Small Interruptible Sales Demand	Small Interruptible Sales Energy	Small Interruptible Sales Customer	Total Small Interruptible Sales	Small Interruptible Transportation Demand	Small Interruptible Transportation Energy	Small Interruptible Transportation Customer	Total Small Interruptible Transportation
Rate Base-Projected										
Gas Plant in Service										
Transmission Plant	3	5,151,592	134,466	0	0	134,466	29,145	0	0	29,145
Distribution Plant										
Land	13	2,917	89	0	0	89	19	0	0	19
Rights of Way	13	17,257	525	0	0	525	114	0	0	114
Structures & Improvements	13	34,152	1,039	0	0	1,039	225	0	0	225
Mains										
Demand Related 100%	2	20,704,043	630,095	0	0	630,095	136,569	0	0	136,569
Customer Related 0%	4	0	0	0	0	0	0	0	0	0
Meas. & Reg. Equip. - General	13	701,353	21,345	0	0	21,345	4,626	0	0	4,626
Meas. & Reg. Equip. - City Gate	13	657,599	20,013	0	0	20,013	4,338	0	0	4,338
Services	9	17,376,736	0	0	148,312	148,312	0	0	9,080	9,080
Meters	5	6,882,669	0	0	338,932	338,932	0	0	21,477	21,477
Service Regulators	5	1,022,916	0	0	50,373	50,373	0	0	3,192	3,192
Ind. Meas. & Reg. Station Equipment	13	37,008	1,126	0	0	1,126	244	0	0	244
Cathodic Protection & Other Equipment	13	109,802	3,342	0	0	3,342	724	0	0	724
Distribution Plant		47,546,452	677,574	0	537,617	1,215,191	146,859	0	33,749	180,608
Distribution Plant Excluding Direct Assignments		47,546,452	677,574	0	537,617	1,215,191	146,859	0	33,749	180,608
General Plant	38	6,705,525	95,559	0	75,821	171,380	20,712	0	4,760	25,472
Intangible Plant - General excluding CC&B	15	889,075	12,670	0	10,053	22,723	2,746	0	631	3,377
Intangible Plant -CC&B	4	2,021,787	0	0	8,717	8,717	0	0	551	551
Common Plant	15	1,480,188	21,094	0	16,737	37,831	4,572	0	1,051	5,623
Intangible Common	15	1,153,922	16,444	0	13,048	29,492	3,564	0	819	4,383
Total Gas Plant in Service		64,948,541	957,807	0	661,993	1,619,800	207,598	0	41,561	249,159

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Description	Allocation Factor	Total Minnesota	Small Interruptible Sales Demand	Small Interruptible Sales Energy	Small Interruptible Sales Customer	Small Interruptible Sales	Small Interruptible Transportation Demand	Small Interruptible Transportation Energy	Small Interruptible Transportation Customer	Small Interruptible Transportation
Less: Accumulated Depreciation										
Transmission Plant	3	1,459,513	38,096	0	0	38,096	8,257	0	0	8,257
Distribution Plant										
Land Rights	13	9,347	284	0	0	284	62	0	0	62
Structures & Improvements	23	28,432	865	0	0	865	187	0	0	187
Mains	13	9,529,057	290,002	0	0	290,002	62,856	0	0	62,856
Meas. & Reg. Equip. - General	18	421,826	12,838	0	0	12,838	2,782	0	0	2,782
Meas. & Reg. Equip. - City Gate	19	161,846	4,926	0	0	4,926	1,068	0	0	1,068
Services	9	9,449,867	0	0	80,656	80,656	0	0	4,938	4,938
Meters	5	4,983,055	0	0	245,387	245,387	0	0	15,549	15,549
Service Regulators	5	480,784	0	0	23,676	23,676	0	0	1,500	1,500
Ind. Meas. & Reg. Station Equipment	21	10,118	308	0	0	308	67	0	0	67
Property on Customer Premise	13	7,310	222	0	0	222	48	0	0	48
Cathodic Protection & Other Equipment	13	11,075	337	0	0	337	73	0	0	73
Distribution Plant		25,092,717	309,782	0	349,719	659,501	67,143	0	21,987	89,130
General Plant	38	2,182,764	31,106	0	24,681	55,787	6,742	0	1,549	8,291
Intangible Plant - General excluding CC&B	15	367,519	5,237	0	4,156	9,393	1,135	0	261	1,396
Intangible Plant -CC&B	4	714,798	0	0	3,082	3,082	0	0	195	195
Common Plant	15	573,950	8,179	0	6,490	14,669	1,773	0	407	2,180
Intangible Plant - Common	15	660,849	9,418	0	7,472	16,890	2,041	0	469	2,510
Less: Total Accumulated Reserve for Depreciation		31,052,110	401,818	0	395,600	797,418	87,091	0	24,868	111,959
Net Gas Plant in Service		33,896,431	555,989	0	266,393	822,382	120,507	0	16,693	137,200
Additions										
Materials & Supplies	15	486,504	6,933	0	5,501	12,434	1,503	0	345	1,848
Gas in Underground Storage	36	306,530	10,088	0	0	10,088	0	0	0	0
Prepayments	25	141,544	2,087	0	1,443	3,530	452	0	91	543
Unamortized Loss on Debt	24	56,258	923	0	442	1,365	200	0	28	228
Unamortized Redemption Cost - Pref. Stock	24	10,034	165	0	79	244	36	0	5	41
Total Additions		1,000,870	20,196	0	7,465	27,661	2,191	0	469	2,660

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Description	Allocation Factor	Total Minnesota	Small Interruptible Sales Demand	Small Interruptible Sales Energy	Small Interruptible Sales Customer	Small Interruptible Sales	Small Interruptible Transportation Demand	Small Interruptible Transportation Energy	Small Interruptible Transportation Customer	Small Interruptible Transportation
Total Before Deductions		34,897,301	576,185	0	273,858	850,043	122,698	0	17,162	139,860
Deductions										
Accumulated Deferred Income Tax	24	(2,448,366)	(40,160)	0	(19,242)	(59,402)	(8,704)	0	(1,206)	(9,910)
Customer Advances For Construction	Direct	(762,761)	(4,176)	0	(288,872)	(293,048)	(31)	0	(9,854)	(9,885)
Total Deductions		(3,211,127)	(44,336)	0	(308,114)	(352,450)	(8,735)	0	(11,060)	(19,795)
Total Rate Base		31,686,174	531,849	0	(34,256)	497,593	113,963	0	6,102	120,065
Income Statement										
Gas Operating Revenues										
Retail Sales & Transportation										
Residential	Direct	10,554,392	0	0	0	0	0	0	0	0
Firm General	Direct	8,155,339				0	0	0	0	0
Interruptible Sales - Grain Drying	Direct	835,162	0	0	0	0				0
Small Interruptible Sales	Direct	1,848,207	135,503	1,551,754	160,950	1,848,207				0
Small Interruptible Transportation	Direct	124,628	0	0	0	0	0	110,228	14,400	124,628
Large Interruptible Sales	Direct	1,328,278								
Large Interruptible Transporation	Direct	1,022,749	0	0	0	0	0	0	0	0
Total Sales & Transportation Revenues		23,868,755	135,503	1,551,754	160,950	1,848,207	0	110,228	14,400	124,628
Other Operating Revenue										
Miscellaneous										
Reconnect Fees	6	29,815	0	0	0	0	0	0	0	0
NSF Check Fees	6	4,455	0	0	0	0	0	0	0	0
Work for Construction of Others	24	0	0	0	0	0	0	0	0	0
Miscellaneous	24	12,861	211	0	101	312	46	0	6	52
Rent From Gas Property	24	123,809	2,031	0	973	3,004	440	0	61	501
Late Payment Revenue	6	66,833	0	0	0	0	0	0	0	0
Total Other Operating Revenue		237,773	2,242	0	1,074	3,316	486	0	67	553
Total Operating Revenues		24,106,528	137,745	1,551,754	162,024	1,851,523	486	110,228	14,467	125,181

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Description	Allocation Factor	Total Minnesota	Small Interruptible Sales Demand	Small Interruptible Sales Energy	Small Interruptible Sales Customer	Small Interruptible Sales	Small Interruptible Transportation Demand	Small Interruptible Transportation Energy	Small Interruptible Transportation Customer	Small Interruptible Transportation
Operation & Maintenance Expenses										
Cost of Purchased Gas	Direct	13,869,562	135,503	1,034,186	0	1,169,689	0	0	0	0
Other Gas Supply Expenses	2	66,292	2,017	0	0	2,017	437	0	0	437
Transmission Expense	2	19,040	579	0	0	579	126	0	0	126
Distribution Expenses										
Operation										
Load Dispatch	2	2,010	61	0	0	61	13	0	0	13
Mains and Services	22	640,496	10,598	0	2,495	13,093	2,297	0	153	2,450
Measuring Stations - General	18	9,946	303	0	0	303	66	0	0	66
Measuring Stations - Industrial	21	26,159	796	0	0	796	172	0	0	172
Measuring Stations - City Gate	19	65,393	1,990	0	0	1,990	430	0	0	430
Meters & House Regulators	16	168,630	0	0	8,304	8,304	0	0	526	526
Customer Installations	5	140,087	0	0	6,898	6,898	0	0	437	437
Other Gas Distribution	27	498,070	6,505	0	8,373	14,878	1,409	0	528	1,937
Rents	27	26,818	350	0	451	801	76	0	28	104
Supervision & Engineering	27	488,667	6,382	0	8,215	14,597	1,382	0	518	1,900
Total Operation Expense		2,066,276	26,985	0	34,736	61,721	5,845	0	2,190	8,035
Maintenance										
Structures & Improvements	13	25,627	780	0	0	780	169	0	0	169
Mains	13	156,421	4,760	0	0	4,760	1,032	0	0	1,032
Measuring Stations - General	18	13,443	409	0	0	409	89	0	0	89
Measuring Stations - Industrial	21	17,414	530	0	0	530	115	0	0	115
Measuring Stations - City Gate	19	31,204	950	0	0	950	206	0	0	206
Services	5	137,888	0	0	6,790	6,790	0	0	430	430
Meters & House Regulators	16	95,405	0	0	4,698	4,698	0	0	298	298
Other Equipment	28	258,302	4,020	0	6,216	10,236	872	0	394	1,266
Supervision & Engineering	28	137,235	2,136	0	3,302	5,438	463	0	209	672
Total Maintenance Expense		872,939	13,585	0	21,006	34,591	2,946	0	1,331	4,277
Total Distribution Expenses		2,939,215	40,570	0	55,742	96,312	8,791	0	3,521	12,312

GREAT PLAINS NATURAL GAS CO.
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Description	Allocation Factor	Total Minnesota	Small Interruptible Sales Demand	Small Interruptible Sales Energy	Small Interruptible Sales Customer	Small Interruptible Sales	Small Interruptible Transportation Demand	Small Interruptible Transportation Energy	Small Interruptible Transportation Customer	Small Interruptible Transportation
Customer Accounts	4	11,614	0	0	50	50	0	0	3	3
Meter Reading	5	116,534	0	0	5,739	5,739	0	0	364	364
Customer Records & Collection	4	386,343	0	0	1,666	1,666	0	0	105	105
Uncollectible Accounts	6	196,357	0	0	0	0	0	0	0	0
Miscellaneous Customer Accounts	4	55,077	0	0	237	237	0	0	15	15
Customer Service & Information	4	39,504	0	0	170	170	0	0	11	11
Sales Expenses	4	9,498	0	0	41	41	0	0	3	3
Administration & General Expenses	30	2,604,365	35,948	0	49,392	85,340	7,789	0	3,120	10,909
CIP Base Expense	37	558,986	0	31,682	0	31,682	0	6,872	0	6,872
Total Gas O&M Expenses		20,872,387	214,617	1,065,868	113,037	1,393,522	17,143	6,872	7,142	31,157
O&M Excl. Cost of Gas and A&G		4,398,460	43,166	31,682	63,645	138,493	9,354	6,872	4,022	20,248
O&M Excl. Cost of Gas & CIP Base		6,443,839	79,114	0	113,037	192,151	17,143	0	7,142	24,285
Depreciation Expense										
Transmission Plant	2	106,123	3,230	0	0	3,230	700	0	0	700
Distribution Plant										
Land Rights	13	359	11	0	0	11	2	0	0	2
Structures & Improvements	23	970	30	0	0	30	6	0	0	6
Mains less Direct	13	664,470	20,222	0	0	20,222	4,383	0	0	4,383
Mains-Direct	Direct	0			0	0				
Meas. & Reg. Equip. - General	18	88,020	2,679	0	0	2,679	581	0	0	581
Meas. & Reg. Equip. - City Gate	19	26,962	821	0	0	821	178	0	0	178
Services less Direct	9	684,643	0	0	5,843	5,843	0	0	358	358
Services Direct	Direct	0			0	0				
Meters	5	682,072	0	0	33,588	33,588	0	0	2,128	2,128
Service Regulators	20	67,717	0	0	3,335	3,335	0	0	211	211
Ind. Meas. & Reg. Station Equipment	21	929	28	0	0	28	6	0	0	6
Cathodic Protection & Other Equipment	13	4,277	130	0	0	130	28	0	0	28
Total Distribution Plant		2,220,419	23,921	0	42,766	66,687	5,184	0	2,697	7,881
General Plant	38	131,526	1,874	0	1,487	3,361	406	0	93	499
Amort. of Intangible Plant - General	15	48,825	696	0	552	1,248	151	0	35	186
Amort. of Intangible Plant - CC&B	4	137,859	0	0	594	594	0	0	38	38

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Description	Allocation Factor	Total Minnesota	Small Interruptible Sales Demand	Small Interruptible Sales Energy	Small Interruptible Sales Customer	Small Interruptible Sales	Small Interruptible Transportation Demand	Small Interruptible Transportation Energy	Small Interruptible Transportation Customer	Small Interruptible Transportation
Common Plant	15	73,814	1,052	0	835	1,887	228	0	52	280
Intangible Plant - Common	15	106,219	1,514	0	1,201	2,715	328	0	75	403
Amort. Of Pref. Stock Redemption	15	777	11	0	9	20	2	0	1	3
Total Depreciation Expense		2,825,562	32,298	0	47,444	79,742	6,999	0	2,991	9,990
Taxes Other Than Income										
Ad Valorem Taxes	15	989,499	14,101	0	11,188	25,289	3,056	0	702	3,758
Other Taxes - Payroll, Franchise, Other	31	239,520	2,941	0	4,202	7,143	637	0	265	902
Other Taxes - Revenue	26	289	2	19	2	23	0	1	0	1
Total Taxes Other Than Income Taxes		1,229,308	17,044	19	15,392	32,455	3,693	1	967	4,661
Total Operating Expense		24,927,257	263,959	1,065,887	175,873	1,505,719	27,835	6,873	11,100	45,808
Interest Expense and Other Additions/Deductions	24	685,675	11,247	0	5,389	16,636	2,438	0	338	2,776
Taxable Income		(1,506,404)	(137,461)	485,867	(19,238)	329,168	(29,787)	103,355	3,029	76,597
Current Income Taxes	28.74%	(432,974)	(39,509)	139,648	(5,529)	94,609	(8,561)	29,706	871	22,016
Deferred Income Taxes	24	(157,868)	(2,589)	0	(1,241)	(3,830)	(561)	0	(78)	(639)
Total Income Taxes		(590,842)	(42,098)	139,648	(6,770)	90,779	(9,122)	29,706	793	21,377
Total Operating Expense		24,336,415	221,861	1,205,535	169,103	1,596,498	18,713	36,579	11,893	67,185
Operating Income:		(229,887)	(84,116)	346,219	(7,079)	255,025	(18,227)	73,649	2,574	57,996

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Description	Allocation Factor	Total Minnesota	Large Interruptible Sales Demand	Large Interruptible Sales Energy	Large Interruptible Sales Customer	Total Large Interruptible Sales	Large Interruptible Transportation Demand	Large Interruptible Transportation Energy	Large Interruptible Transportation Customer	Total Large Interruptible Transportation
Rate Base-Projected										
Gas Plant in Service										
Transmission Plant	3	5,151,592	123,208	0	0	123,208	1,036,698	0	0	1,036,698
Distribution Plant										
Land	13	2,917	81	0	0	81	200	0	0	200
Rights of Way	13	17,257	481	0	0	481	1,185	0	0	1,185
Structures & Improvements	13	34,152	952	0	0	952	2,346	0	0	2,346
Mains										
Demand Related 100%	2	20,704,043	577,343	0	0	577,343	1,421,963	0	0	1,421,963
Customer Related 0%	4	0	0	0	0	0	0	0	0	0
Meas. & Reg. Equip. - General	13	701,353	19,558	0	0	19,558	48,169	0	0	48,169
Meas. & Reg. Equip. - City Gate	13	657,599	18,337	0	0	18,337	45,164	0	0	45,164
Services	9	17,376,736	0	0	18,917	18,917	0	0	29,511	29,511
Meters	5	6,882,669	0	0	78,749	78,749	0	0	123,492	123,492
Service Regulators	5	1,022,916	0	0	11,704	11,704	0	0	18,354	18,354
Ind. Meas. & Reg. Station Equipment	13	37,008	1,032	0	0	1,032	2,542	0	0	2,542
Cathodic Protection & Other Equipment	13	109,802	3,062	0	0	3,062	7,541	0	0	7,541
Distribution Plant		47,546,452	620,846	0	109,370	730,216	1,529,110	0	171,357	1,700,467
Distribution Plant Excluding Direct Assignments		47,546,452	620,846	0	109,370	730,216	1,529,110	0	171,357	1,700,467
General Plant	38	6,705,525	87,559	0	15,425	102,984	215,652	0	24,167	239,819
Intangible Plant - General excluding CC&B	15	889,075	11,609	0	2,045	13,654	28,593	0	3,204	31,797
Intangible Plant -CC&B	4	2,021,787	0	0	642	642	0	0	1,009	1,009
Common Plant	15	1,480,188	19,328	0	3,405	22,733	47,603	0	5,335	52,938
Intangible Common	15	1,153,922	15,068	0	2,654	17,722	37,111	0	4,159	41,270
Total Gas Plant in Service		64,948,541	877,618	0	133,541	1,011,159	2,894,767	0	209,231	3,103,998

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
Embedded Class Cost of Service Study
Twelve Months Ended December 31, 2018
Projected 2020

Description	Allocation Factor	Total Minnesota	Large Interruptible Sales Demand	Large Interruptible Sales Energy	Large Interruptible Sales Customer	Large Interruptible Sales	Large Interruptible Transportation Demand	Large Interruptible Transportation Energy	Large Interruptible Transportation Customer	Large Interruptible Transportation
Less: Accumulated Depreciation										
Transmission Plant	3	1,459,513	34,906	0	0	34,906	293,710	0	0	293,710
Distribution Plant										
Land Rights	13	9,347	261	0	0	261	642	0	0	642
Structures & Improvements	23	28,432	793	0	0	793	1,953	0	0	1,953
Mains	13	9,529,057	265,723	0	0	265,723	654,460	0	0	654,460
Meas. & Reg. Equip. - General	18	421,826	11,763	0	0	11,763	28,971	0	0	28,971
Meas. & Reg. Equip. - City Gate	19	161,846	4,513	0	0	4,513	11,116	0	0	11,116
Services	9	9,449,867	0	0	10,288	10,288	0	0	16,049	16,049
Meters	5	4,983,055	0	0	57,014	57,014	0	0	89,408	89,408
Service Regulators	5	480,784	0	0	5,501	5,501	0	0	8,626	8,626
Ind. Meas. & Reg. Station Equipment	21	10,118	282	0	0	282	695	0	0	695
Property on Customer Premise	13	7,310	204	0	0	204	502	0	0	502
Cathodic Protection & Other Equipment	13	11,075	309	0	0	309	761	0	0	761
Distribution Plant		25,092,717	283,848	0	72,803	356,651	699,100	0	114,083	813,183
General Plant	38	2,182,764	28,502	0	5,021	33,523	70,198	0	7,867	78,065
Intangible Plant - General excluding CC&B	15	367,519	4,799	0	845	5,644	11,820	0	1,325	13,145
Intangible Plant -CC&B	4	714,798	0	0	227	227	0	0	357	357
Common Plant	15	573,950	7,494	0	1,320	8,814	18,458	0	2,069	20,527
Intangible Plant - Common	15	660,849	8,629	0	1,520	10,149	21,253	0	2,382	23,635
Less: Total Accumulated Reserve for Depreciation		31,052,110	368,178	0	81,736	449,914	1,114,539	0	128,083	1,242,622
Net Gas Plant in Service		33,896,431	509,440	0	51,805	561,245	1,780,228	0	81,148	1,861,376
Additions										
Materials & Supplies	15	486,504	6,353	0	1,119	7,472	15,646	0	1,753	17,399
Gas in Underground Storage	36	306,530	9,244	0	0	9,244	0	0	0	0
Prepayments	25	141,544	1,913	0	291	2,204	6,309	0	456	6,765
Unamortized Loss on Debt	24	56,258	846	0	86	932	2,955	0	135	3,090
Unamortized Redemption Cost - Pref. Stock	24	10,034	151	0	15	166	527	0	24	551
Total Additions		1,000,870	18,507	0	1,511	20,018	25,437	0	2,368	27,805

GREAT PLAINS NATURAL GAS CO.
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Description	Allocation Factor	Total Minnesota	Large Interruptible Sales Demand	Large Interruptible Sales Energy	Large Interruptible Sales Customer	Large Interruptible Sales	Large Interruptible Transportation Demand	Large Interruptible Transportation Energy	Large Interruptible Transportation Customer	Large Interruptible Transportation
Total Before Deductions		34,897,301	527,947	0	53,316	581,263	1,805,665	0	83,516	1,889,181
Deductions										
Accumulated Deferred Income Tax	24	(2,448,366)	(36,797)	0	(3,742)	(40,539)	(128,587)	0	(5,861)	(134,448)
Customer Advances For Construction	Direct	(762,761)	0	0	0	0	(4,370)	0	(131,502)	(135,872)
Total Deductions		(3,211,127)	(36,797)	0	(3,742)	(40,539)	(132,957)	0	(137,363)	(270,320)
Total Rate Base		31,686,174	491,150	0	49,574	540,724	1,672,708	0	(53,847)	1,618,861
Income Statement										
Gas Operating Revenues										
Retail Sales & Transportation										
Residential	Direct	10,554,392	0	0	0	0	0	0	0	0
Firm General	Direct	8,155,339	0	0	0	0	0	0	0	0
Interruptible Sales - Grain Drying	Direct	835,162	0	0	0	0	0	0	0	0
Small Interruptible Sales	Direct	1,848,207	0	0	0	0	0	0	0	0
Small Interruptible Transportation	Direct	124,628	0	0	0	0	0	0	0	0
Large Interruptible Sales	Direct	1,328,278	124,170	1,184,788	19,320	1,328,278	0	0	0	0
Large Interruptible Transporation	Direct	1,022,749				0	0	988,429	34,320	1,022,749
Total Sales & Transportation Revenues		23,868,755	124,170	1,184,788	19,320	1,328,278	0	988,429	34,320	1,022,749
Other Operating Revenue										
Miscellaneous										
Reconnect Fees	6	29,815	0	0	0	0	0	0	0	0
NSF Check Fees	6	4,455	0	0	0	0	0	0	0	0
Work for Construction of Others	24	0	0	0	0	0	0	0	0	0
Miscellaneous	24	12,861	193	0	20	213	675	0	31	706
Rent From Gas Property	24	123,809	1,861	0	189	2,050	6,502	0	296	6,798
Late Payment Revenue	6	66,833	0	0	0	0	0	0	0	0
Total Other Operating Revenue		237,773	2,054	0	209	2,263	7,177	0	327	7,504
Total Operating Revenues		24,106,528	126,224	1,184,788	19,529	1,330,541	7,177	988,429	34,647	1,030,253

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
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Twelve Months Ended December 31, 2018
Projected 2020

Description	Allocation Factor	Total Minnesota	Large Interruptible Sales			Large Interruptible Sales	Large Interruptible Transportation			Large Interruptible Transportation
			Demand	Energy	Customer		Demand	Energy	Customer	
Operation & Maintenance Expenses										
Cost of Purchased Gas	Direct	13,869,562	124,170	947,690	0	1,071,860	0	0	0	0
Other Gas Supply Expenses	2	66,292	1,849	0	0	1,849	4,553	0	0	4,553
Transmission Expense	2	19,040	531	0	0	531	1,308	0	0	1,308
Distribution Expenses										
Operation										
Load Dispatch	2	2,010	56	0	0	56	138	0	0	138
Mains and Services	22	640,496	9,711	0	318	10,029	23,917	0	496	24,413
Measuring Stations - General	18	9,946	277	0	0	277	683	0	0	683
Measuring Stations - Industrial	21	26,159	729	0	0	729	1,797	0	0	1,797
Measuring Stations - City Gate	19	65,393	1,823	0	0	1,823	4,491	0	0	4,491
Meters & House Regulators	16	168,630	0	0	1,929	1,929	0	0	3,026	3,026
Customer Installations	5	140,087	0	0	1,603	1,603	0	0	2,514	2,514
Other Gas Distribution	27	498,070	5,959	0	1,822	7,781	14,679	0	2,856	17,535
Rents	27	26,818	321	0	98	419	790	0	154	944
Supervision & Engineering	27	488,667	5,847	0	1,787	7,634	14,402	0	2,802	17,204
Total Operation Expense		2,066,276	24,723	0	7,557	32,280	60,897	0	11,848	72,745
Maintenance										
Structures & Improvements	13	25,627	715	0	0	715	1,760	0	0	1,760
Mains	13	156,421	4,362	0	0	4,362	10,743	0	0	10,743
Measuring Stations - General	18	13,443	375	0	0	375	923	0	0	923
Measuring Stations - Industrial	21	17,414	486	0	0	486	1,196	0	0	1,196
Measuring Stations - City Gate	19	31,204	870	0	0	870	2,143	0	0	2,143
Services	5	137,888	0	0	1,578	1,578	0	0	2,474	2,474
Meters & House Regulators	16	95,405	0	0	1,092	1,092	0	0	1,712	1,712
Other Equipment	28	258,302	3,684	0	1,445	5,129	9,071	0	2,265	11,336
Supervision & Engineering	28	137,235	1,957	0	768	2,725	4,819	0	1,203	6,022
Total Maintenance Expense		872,939	12,449	0	4,883	17,332	30,655	0	7,654	38,309
Total Distribution Expenses		2,939,215	37,172	0	12,440	49,612	91,552	0	19,502	111,054

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
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Twelve Months Ended December 31, 2018
Projected 2020

Description	Allocation Factor	Total Minnesota	Large Interruptible Sales			Large Interruptible Sales	Large Interruptible Transportation			Large Interruptible Transportation
			Demand	Energy	Customer		Demand	Energy	Customer	
Customer Accounts	4	11,614	0	0	4	4	0	0	6	6
Meter Reading	5	116,534	0	0	1,333	1,333	0	0	2,091	2,091
Customer Records & Collection	4	386,343	0	0	123	123	0	0	193	193
Uncollectible Accounts	6	196,357	0	0	0	0	0	0	0	0
Miscellaneous Customer Accounts	4	55,077	0	0	17	17	0	0	27	27
Customer Service & Information	4	39,504	0	0	13	13	0	0	20	20
Sales Expenses	4	9,498	0	0	3	3	0	0	5	5
Administration & General Expenses	30	2,604,365	32,937	0	11,023	43,960	81,122	0	17,280	98,402
CIP Base Expense	37	558,986	0	29,032	0	29,032	0	244,256	0	244,256
Total Gas O&M Expenses		20,872,387	196,659	976,722	24,956	1,198,337	178,535	244,256	39,124	461,915
O&M Excl. Cost of Gas and A&G		4,398,460	39,552	29,032	13,933	82,517	97,413	244,256	21,844	363,513
O&M Excl. Cost of Gas & CIP Base		6,443,839	72,489	0	24,956	97,445	178,535	0	39,124	217,659
Depreciation Expense										
Transmission Plant	2	106,123	2,959	0	0	2,959	7,289	0	0	7,289
Distribution Plant										
Land Rights	13	359	10	0	0	10	25	0	0	25
Structures & Improvements	23	970	27	0	0	27	67	0	0	67
Mains less Direct	13	664,470	18,529	0	0	18,529	45,636	0	0	45,636
Mains-Direct	Direct	0								
Meas. & Reg. Equip. - General	18	88,020	2,455	0	0	2,455	6,045	0	0	6,045
Meas. & Reg. Equip. - City Gate	19	26,962	752	0	0	752	1,852	0	0	1,852
Services less Direct	9	684,643	0	0	745	745	0	0	1,163	1,163
Services Direct	Direct	0								
Meters	5	682,072	0	0	7,804	7,804	0	0	12,238	12,238
Service Regulators	20	67,717	0	0	775	775	0	0	1,215	1,215
Ind. Meas. & Reg. Station Equipment	21	929	26	0	0	26	64	0	0	64
Cathodic Protection & Other Equipment	13	4,277	119	0	0	119	294	0	0	294
Total Distribution Plant		2,220,419	21,918	0	9,324	31,242	53,983	0	14,616	68,599
General Plant	38	131,526	1,717	0	303	2,020	4,230	0	474	4,704
Amort. of Intangible Plant - General	15	48,825	638	0	112	750	1,570	0	176	1,746
Amort. of Intangible Plant - CC&B	4	137,859	0	0	44	44	0	0	69	69

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
Embedded Class Cost of Service Study
Twelve Months Ended December 31, 2018
Projected 2020

Description	Allocation Factor	Total Minnesota	Large Interruptible Sales Demand	Large Interruptible Sales Energy	Large Interruptible Sales Customer	Large Interruptible Sales	Large Interruptible Transportation Demand	Large Interruptible Transportation Energy	Large Interruptible Transportation Customer	Large Interruptible Transportation
Common Plant	15	73,814	964	0	170	1,134	2,374	0	266	2,640
Intangible Plant - Common	15	106,219	1,387	0	244	1,631	3,416	0	383	3,799
Amort. Of Pref. Stock Redemption	15	777	10	0	2	12	25	0	3	28
Total Depreciation Expense		2,825,562	29,593	0	10,199	39,792	72,887	0	15,987	88,874
Taxes Other Than Income										
Ad Valorem Taxes	15	989,499	12,921	0	2,276	15,197	31,823	0	3,566	35,389
Other Taxes - Payroll, Franchise, Other	31	239,520	2,694	0	928	3,622	6,636	0	1,454	8,090
Other Taxes - Revenue	26	289	2	14	0	16	0	12	0	12
Total Taxes Other Than Income Taxes		1,229,308	15,617	14	3,204	18,835	38,459	12	5,020	43,491
Total Operating Expense		24,927,257	241,869	976,736	38,359	1,256,964	289,881	244,268	60,131	594,280
Interest Expense and Other Additions/Deductions	24	685,675	10,305	0	1,048	11,353	36,011	0	1,642	37,653
Taxable Income		(1,506,404)	(125,950)	208,052	(19,878)	62,224	(318,715)	744,161	(27,126)	398,320
Current Income Taxes	28.74%	(432,974)	(36,201)	59,798	(5,713)	17,884	(91,605)	213,887	(7,797)	114,485
Deferred Income Taxes	24	(157,868)	(2,373)	0	(241)	(2,614)	(8,291)	0	(378)	(8,669)
Total Income Taxes		(590,842)	(38,574)	59,798	(5,954)	15,270	(99,896)	213,887	(8,175)	105,816
Total Operating Expense		24,336,415	203,295	1,036,534	32,405	1,272,234	189,985	458,155	51,956	700,096
Operating Income:		(229,887)	(77,071)	148,254	(12,876)	58,307	(182,808)	530,274	(17,309)	330,157

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
EMBEDDED CLASS COST OF SERVICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2018
PROJECTED AVERAGE PLANT

		Total	Residential		
		Minnesota	Demand	Energy	Customer
		4,783,946	0	1,527,457	0
1	Dk Throughput Projected	100.000000%	0.000000%	31.928810%	0.000000%
		35,323	17,143	0	0
2	Design Day Peak @ Distribution	100.000000%	48.532118%	0.000000%	0.000000%
		41,185	17,143	0	0
3	Design Day Peak	100.000000%	41.624378%	0.000000%	0.000000%
		22,035	0	0	18,808
4	Average Customers	100.000000%	0.000000%	0.000000%	85.355116%
		30,765	0	0	18,808
5	Total Weighted Customers	100.000000%	0.000000%	0.000000%	61.134406%
		21,886	0	0	18,808
6	Average Res. & Firm General Cust.	100.000000%	0.000000%	0.000000%	85.936215%
		22,964	0	0	18,808
9	Weighted Services	100.000000%	0.000000%	0.000000%	81.902108%
		20,704,043	10,048,111	0	0
13	Distribution Mains less Direct Assignments	100.000000%	48.532119%	0.000000%	0.000000%
		47,546,452	10,805,258	0	19,064,945
15	Distribution Plant	100.000000%	22.725687%	0.000000%	40.097514%
		7,905,585	0	0	4,833,031
16	Meters & Regulators	100.000000%	0.000000%	0.000000%	61.134388%
		701,353	340,382	0	0
18	Meas. & Reg. Sta. Eqpt.- General	100.000000%	48.532195%	0.000000%	0.000000%
		657,599	319,147	0	0
19	Meas. & Reg. Eqpt.- City Gate	100.000000%	48.532161%	0.000000%	0.000000%
		1,022,916	0	0	625,353
20	Service Regulators	100.000000%	0.000000%	0.000000%	61.134346%

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
EMBEDDED CLASS COST OF SERVICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2018
PROJECTED AVERAGE PLANT

		Total	Residential		
		Minnesota	Demand	Energy	Customer
		37,008	17,960	0	0
21	Ind. Meas. & Reg. Sta. Eqpt.	100.000000%	48.530048%	0.000000%	0.000000%
		38,080,779	10,048,111	0	14,231,914
22	Mains & Services	100.000000%	26.386307%	0.000000%	37.372959%
		34,152	16,575	0	0
23	Structures and Improvements	100.000000%	48.533029%	0.000000%	0.000000%
		33,896,431	8,866,334	0	11,684,332
24	Net Gas Plant in Service	100.000000%	26.157132%	0.000000%	34.470685%
		64,948,541	15,274,120	0	24,892,098
25	Total Gas Plant in Service	100.000000%	23.517264%	0.000000%	38.325877%
		23,868,755	1,860,137	7,001,535	1,692,720
26	Projected Operating Revenue Excluding Other Revenues	100.000001%	7.793187%	29.333474%	7.091782%
		1,052,721	219,239	0	428,103
27	All Other Dist. Operation Exp.	100.000000%	20.825937%	0.000000%	40.666330%
		477,402	118,469	0	142,622
28	All Other Dist. Maintenance Exp.	100.000000%	24.815356%	0.000000%	29.874613%
		2,939,215	646,943	0	1,101,064
30	Distribution O&M	100.000000%	22.010742%	0.000000%	37.461159%
		6,443,839	1,261,597	0	2,745,185
31	O&M Excl. Cost of Gas & CIP Base	100.000000%	19.578344%	0.000000%	42.601701%
		13,869,562	1,860,137	4,025,460	0
33	Cost of Gas	100.000000%	13.411648%	29.023700%	0.000000%
		(1,506,404)	(2,192,021)	2,852,670	(2,935,256)
35	Taxable Income	99.999999%	145.513487%	-189.369518%	194.851846%
		32,664	17,143	0	0
36	Design Day Peak Excluding Transportation	100.000000%	52.482856%	0.000000%	0.000000%
		6,923,675	0	1,527,457	0
37	Throughput less CIP Base Exempt LI Transport Flex	100.000000%	0.000000%	22.061361%	0.000000%
		47,546,452	10,805,258	0	19,064,945
38	Distribution Plant Less Direct Assignment	100.000000%	22.725688%	0.000000%	40.097513%

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
EMBEDDED CLASS COST OF SERVICE STUDY
ALLOCATION FACTOR REPORT
TWELVE MONTHS ENDED DECEMBER 31, 2018
PROJECTED AVERAGE PLANT

		Total	Small Firm General			Large Firm General			Interruptible Sales - Grain Drying		
		Minnesota	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
1	Dk Throughput Projected	4,783,946 100.000000%	0 0.000000%	286,401 5.986711%	0 0.000000%	0 0.000000%	1,055,652 22.066553%	0 0.000000%	0 0.000000%	191,639 4.005877%	0 0.000000%
2	Design Day Peak @ Distribution	35,323 100.000000%	3,449 9.764176%	0 0.000000%	0 0.000000%	9,487 26.857855%	0 0.000000%	0 0.000000%	525 1.486284%	0 0.000000%	0 0.000000%
3	Design Day Peak	41,185 100.000000%	3,449 8.374408%	0 0.000000%	0 0.000000%	9,487 23.035086%	0 0.000000%	0 0.000000%	525 1.274736%	0 0.000000%	0 0.000000%
4	Average Customers	22,035 100.000000%	0 0.000000%	0 0.000000%	2,014 9.140005%	0 0.000000%	0 0.000000%	1,064 4.828682%	0 0.000000%	0 0.000000%	30 0.136147%
5	Total Weighted Customers	30,765 100.000000%	0 0.000000%	0 0.000000%	2,256 7.333008%	0 0.000000%	0 0.000000%	6,310 20.510320%	0 0.000000%	0 0.000000%	876 2.847392%
6	Average Res. & Firm General Cust.	21,886 100.000000%	0 0.000000%	0 0.000000%	2,014 9.202230%	0 0.000000%	0 0.000000%	1,064 4.861555%	0 0.000000%	0 0.000000%	0 0.000000%
9	Weighted Services	22,964 100.000000%	0 0.000000%	0 0.000000%	2,397 10.438077%	0 0.000000%	0 0.000000%	1,362 5.931022%	0 0.000000%	0 0.000000%	125 0.544330%
13	Distribution Mains less Direct Assignments	20,704,043 100.000000%	2,021,579 9.764175%	0 0.000000%	0 0.000000%	5,560,662 26.857856%	0 0.000000%	0 0.000000%	307,721 1.486285%	0 0.000000%	0 0.000000%
15	Distribution Plant	47,546,452 100.000000%	2,173,909 4.572179%	0 0.000000%	2,393,515 5.034056%	5,979,667 12.576474%	0 0.000000%	2,652,078 5.577867%	330,908 0.695968%	0 0.000000%	319,690 0.672374%
16	Meters & Regulators	7,905,585 100.000000%	0 0.000000%	0 0.000000%	579,718 7.333018%	0 0.000000%	0 0.000000%	1,621,460 20.510310%	0 0.000000%	0 0.000000%	225,103 2.847392%
18	Meas. & Reg. Sta. Eqpt.- General	701,353 100.000000%	68,481 9.764127%	0 0.000000%	0 0.000000%	188,368 26.857802%	0 0.000000%	0 0.000000%	10,424 1.486270%	0 0.000000%	0 0.000000%
19	Meas. & Reg. Eqpt.- City Gate	657,599 100.000000%	64,209 9.764157%	0 0.000000%	0 0.000000%	176,617 26.857857%	0 0.000000%	0 0.000000%	9,774 1.486316%	0 0.000000%	0 0.000000%
20	Service Regulators	1,022,916 100.000000%	0 0.000000%	0 0.000000%	75,011 7.333056%	0 0.000000%	0 0.000000%	209,803 20.510286%	0 0.000000%	0 0.000000%	29,126 2.847350%

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PROJECTED AVERAGE PLANT

		Total	Small Firm General			Large Firm General			Interruptible Sales - Grain Drying		
		Minnesota	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
		37,008	3,614	0	0	9,940	0	0	550	0	0
21	Ind. Meas. & Reg. Sta. Eqpt.	100.000000%	9.765456%	0.000000%	0.000000%	26.859058%	0.000000%	0.000000%	1.486165%	0.000000%	0.000000%
		38,080,779	2,021,579	0	1,813,797	5,560,662	0	1,030,618	307,721	0	94,587
22	Mains & Services	100.000000%	5.308660%	0.000000%	4.763025%	14.602280%	0.000000%	2.706399%	0.808074%	0.000000%	0.248385%
		34,152	3,335	0	0	9,172	0	0	508	0	0
23	Structures and Improvements	100.000000%	9.765167%	0.000000%	0.000000%	26.856407%	0.000000%	0.000000%	1.487468%	0.000000%	0.000000%
		33,896,431	1,783,815	0	1,450,300	4,906,658	0	1,393,480	271,528	0	157,781
24	Net Gas Plant in Service	100.000000%	5.262545%	0.000000%	4.278622%	14.475441%	0.000000%	4.110993%	0.801052%	0.000000%	0.465480%
		64,948,541	3,072,999	0	3,093,225	8,452,752	0	3,320,247	467,766	0	391,218
25	Total Gas Plant in Service	100.000000%	4.731437%	0.000000%	4.762578%	13.014537%	0.000000%	5.112119%	0.720210%	0.000000%	0.602351%
		23,868,755	348,779	1,230,891	555,864	1,285,573	4,370,344	363,888	66,173	725,363	43,626
26	Projected Operating Revenue Excluding Other Revenues	100.000001%	1.461237%	5.156913%	2.328835%	5.386008%	18.309895%	1.524537%	0.277237%	3.038965%	0.182775%
		1,052,721	44,109	0	53,146	121,327	0	80,653	6,715	0	10,382
27	All Other Dist. Operation Exp.	100.000000%	4.189999%	0.000000%	5.048441%	11.525086%	0.000000%	7.661384%	0.637871%	0.000000%	0.986206%
		477,402	23,836	0	17,107	65,562	0	47,849	3,629	0	6,643
28	All Other Dist. Maintenance Exp.	100.000000%	4.992857%	0.000000%	3.583353%	13.733080%	0.000000%	10.022790%	0.760156%	0.000000%	1.391490%
		2,939,215	130,162	0	135,596	358,022	0	245,799	19,815	0	32,524
30	Distribution O&M	100.000000%	4.428461%	0.000000%	4.613341%	12.180871%	0.000000%	8.362743%	0.674160%	0.000000%	1.106554%
		6,443,839	253,827	0	328,245	698,175	0	521,284	38,641	0	65,345
31	O&M Excl. Cost of Gas & CIP Base	100.000000%	3.939065%	0.000000%	5.093935%	10.834768%	0.000000%	8.089650%	0.599658%	0.000000%	1.014069%
		13,869,562	348,779	754,781	0	1,285,573	2,782,065	0	66,173	505,045	0
33	Cost of Gas	100.000000%	2.514708%	5.441996%	0.000000%	9.269024%	20.058781%	0.000000%	0.477110%	3.641391%	0.000000%
		(1,506,404)	(441,021)	452,972	(5,814)	(1,213,078)	1,502,997	(470,815)	(67,135)	204,837	(61,049)
35	Taxable Income	99.999999%	29.276409%	-30.069756%	0.385952%	80.528066%	-99.773832%	31.254232%	4.456640%	-13.597747%	4.052631%
		32,664	3,449	0	0	9,487	0	0	525	0	0
36	Design Day Peak Excluding Transportation	100.000000%	10.559025%	0.000000%	0.000000%	29.044208%	0.000000%	0.000000%	1.607274%	0.000000%	0.000000%
		6,923,675	0	286,401	0	0	1,055,652	0	0	191,639	0
37	Throughput less CIP Base Exempt LI Transport Flex	100.000000%	0.000000%	4.136546%	0.000000%	0.000000%	15.246989%	0.000000%	0.000000%	2.767880%	0.000000%
		47,546,452	2,173,909	0	2,393,515	5,979,667	0	2,652,078	330,908	0	319,690
38	Distribution Plant Less Direct Assignment	100.000000%	4.572179%	0.000000%	5.034056%	12.576474%	0.000000%	5.577867%	0.695968%	0.000000%	0.672374%

GREAT PLAINS NATURAL GAS CO.
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PROJECTED AVERAGE PLANT

		Total	Small Interruptible Sales			Small Interruptible Transportation		
		Minnesota	Demand	Energy	Customer	Demand	Energy	Customer
		4,783,946	0	392,421	0	0	85,118	0
1	Dk Throughput Projected	100.000000%	0.000000%	8.202873%	0.000000%	0.000000%	1.779242%	0.000000%
		35,323	1,075	0	0	233	0	0
2	Design Day Peak @ Distribution	100.000000%	3.043343%	0.000000%	0.000000%	0.659627%	0.000000%	0.000000%
		41,185	1,075	0	0	233	0	0
3	Design Day Peak	100.000000%	2.610174%	0.000000%	0.000000%	0.565740%	0.000000%	0.000000%
		22,035	0	0	95	0	0	6
4	Average Customers	100.000000%	0.000000%	0.000000%	0.431132%	0.000000%	0.000000%	0.027229%
		30,765	0	0	1515	0	0	96
5	Total Weighted Customers	100.000000%	0.000000%	0.000000%	4.924427%	0.000000%	0.000000%	0.312043%
		21,886	0	0	0	0	0	0
6	Average Res. & Firm General Cust.	100.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
		22,964	0	0	196	0	0	12
9	Weighted Services	100.000000%	0.000000%	0.000000%	0.853510%	0.000000%	0.000000%	0.052256%
		20,704,043	630,095	0	0	136,569	0	0
13	Distribution Mains less Direct Assignments	100.000000%	3.043343%	0.000000%	0.000000%	0.659625%	0.000000%	0.000000%
		47,546,452	677,574	0	537,617	146,859	0	33,749
15	Distribution Plant	100.000000%	1.425078%	0.000000%	1.130719%	0.308875%	0.000000%	0.070981%
		7,905,585	0	0	389,305	0	0	24,669
16	Meters & Regulators	100.000000%	0.000000%	0.000000%	4.924430%	0.000000%	0.000000%	0.312045%
		701,353	21,345	0	0	4,626	0	0
18	Meas. & Reg. Sta. Eqpt.- General	100.000000%	3.043403%	0.000000%	0.000000%	0.659582%	0.000000%	0.000000%
		657,599	20,013	0	0	4,338	0	0
19	Meas. & Reg. Eqpt.- City Gate	100.000000%	3.043344%	0.000000%	0.000000%	0.659673%	0.000000%	0.000000%
		1,022,916	0	0	50,373	0	0	3,192
20	Service Regulators	100.000000%	0.000000%	0.000000%	4.924451%	0.000000%	0.000000%	0.312049%

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PROJECTED AVERAGE PLANT

		Total	Small Interruptible Sales			Small Interruptible Transportation		
		Minnesota	Demand	Energy	Customer	Demand	Energy	Customer
		37,008	1,126	0	0	244	0	0
21	Ind. Meas. & Reg. Sta. Eqpt.	100.000000%	3.042585%	0.000000%	0.000000%	0.659317%	0.000000%	0.000000%
		38,080,779	630,095	0	148,312	136,569	0	9,080
22	Mains & Services	100.000000%	1.654627%	0.000000%	0.389467%	0.358630%	0.000000%	0.023844%
		34,152	1,039	0	0	225	0	0
23	Structures and Improvements	100.000000%	3.042282%	0.000000%	0.000000%	0.658819%	0.000000%	0.000000%
		33,896,431	555,989	0	266,393	120,507	0	16,693
24	Net Gas Plant in Service	100.000000%	1.640258%	0.000000%	0.785903%	0.355515%	0.000000%	0.049247%
		64,948,541	957,807	0	661,993	207,598	0	41,561
25	Total Gas Plant in Service	100.000000%	1.474717%	0.000000%	1.019258%	0.319635%	0.000000%	0.063991%
		23,868,755	135,503	1,551,754	160,950	0	110,228	14,400
26	Projected Operating Revenue Excluding Other Revenues	100.000001%	0.567700%	6.501194%	0.674313%	0.000000%	0.461809%	0.060330%
		1,052,721	13,748	0	17,697	2,978	0	1,116
27	All Other Dist. Operation Exp.	100.000000%	1.305949%	0.000000%	1.681072%	0.282886%	0.000000%	0.106011%
		477,402	7,429	0	11,488	1,611	0	728
28	All Other Dist. Maintenance Exp.	100.000000%	1.556131%	0.000000%	2.406358%	0.337451%	0.000000%	0.152492%
		2,939,215	40,570	0	55,742	8,791	0	3,521
30	Distribution O&M	100.000000%	1.380301%	0.000000%	1.896493%	0.299093%	0.000000%	0.119794%
		6,443,839	79,114	0	113,037	17,143	0	7,142
31	O&M Excl. Cost of Gas & CIP Base	100.000000%	1.227746%	0.000000%	1.754187%	0.266037%	0.000000%	0.110835%
		13,869,562	135,503	1,034,186	0	0	0	0
33	Cost of Gas	100.000000%	0.976981%	7.456515%	0.000000%	0.000000%	0.000000%	0.000000%
		(1,506,404)	(137,461)	485,867	(19,238)	(29,787)	103,355	3,029
35	Taxable Income	99.999999%	9.125109%	-32.253433%	1.277081%	1.977358%	-6.861041%	-0.201075%
		32,664	1,075	0	0	0	0	0
36	Design Day Peak Excluding Transportation	100.000000%	3.291085%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
		6,923,675	0	392,421	0	0	85,118	0
37	Throughput less CIP Base Exempt LI Transport Flex	100.000000%	0.000000%	5.667814%	0.000000%	0.000000%	1.229376%	0.000000%
		47,546,452	677,574	0	537,617	146,859	0	33,749
38	Distribution Plant Less Direct Assignment	100.000000%	1.425078%	0.000000%	1.130719%	0.308875%	0.000000%	0.070981%

GREAT PLAINS NATURAL GAS CO.
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		Total	Large Interruptible Sales			Large Interruptible Transportation		
		Minnesota	Demand	Energy	Customer	Demand	Energy	Customer
		4,783,946	0	359,600	0	0	885,658	0
1	Dk Throughput Projected	100.000000%	0.000000%	7.516807%	0.000000%	0.000000%	18.513127%	0.000000%
		35,323	985	0	0	2,426	0	0
2	Design Day Peak @ Distribution	100.000000%	2.788551%	0.000000%	0.000000%	6.868046%	0.000000%	0.000000%
		41,185	985	0	0	8,288	0	0
3	Design Day Peak	100.000000%	2.391647%	0.000000%	0.000000%	20.123831%	0.000000%	0.000000%
		22,035	0	0	7	0	0	11
4	Average Customers	100.000000%	0.000000%	0.000000%	0.031768%	0.000000%	0.000000%	0.049921%
		30,765	0	0	352	0	0	552
5	Total Weighted Customers	100.000000%	0.000000%	0.000000%	1.144157%	0.000000%	0.000000%	1.794247%
		21,886	0	0	0	0	0	0
6	Average Res. & Firm General Cust.	100.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
		22,964	0	0	25	0	0	39
9	Weighted Services	100.000000%	0.000000%	0.000000%	0.108866%	0.000000%	0.000000%	0.169831%
		20,704,043	577,343	0	0	1,421,963	0	0
13	Distribution Mains less Direct Assignments	100.000000%	2.788552%	0.000000%	0.000000%	6.868045%	0.000000%	0.000000%
		47,546,452	620,846	0	109,370	1,529,110	0	171,357
15	Distribution Plant	100.000000%	1.305767%	0.000000%	0.230028%	3.216034%	0.000000%	0.360399%
		7,905,585	0	0	90,453	0	0	141,846
16	Meters & Regulators	100.000000%	0.000000%	0.000000%	1.144166%	0.000000%	0.000000%	1.794251%
		701,353	19,558	0	0	48,169	0	0
18	Meas. & Reg. Sta. Eqpt.- General	100.000000%	2.788610%	0.000000%	0.000000%	6.868011%	0.000000%	0.000000%
		657,599	18,337	0	0	45,164	0	0
19	Meas. & Reg. Eqpt.- City Gate	100.000000%	2.788477%	0.000000%	0.000000%	6.868015%	0.000000%	0.000000%
		1,022,916	0	0	11,704	0	0	18,354
20	Service Regulators	100.000000%	0.000000%	0.000000%	1.144180%	0.000000%	0.000000%	1.794282%

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		Total	Large Interruptible Sales			Large Interruptible Transportation		
		Minnesota	Demand	Energy	Customer	Demand	Energy	Customer
		37,008	1,032	0	0	2,542	0	0
21	Ind. Meas. & Reg. Sta. Eqpt.	100.000000%	2.788586%	0.000000%	0.000000%	6.868785%	0.000000%	0.000000%
		38,080,779	577,343	0	18,917	1,421,963	0	29,511
22	Mains & Services	100.000000%	1.516101%	0.000000%	0.049676%	3.734070%	0.000000%	0.077496%
		34,152	952	0	0	2,346	0	0
23	Structures and Improvements	100.000000%	2.787538%	0.000000%	0.000000%	6.869290%	0.000000%	0.000000%
		33,896,431	509,440	0	51,805	1,780,228	0	81,148
24	Net Gas Plant in Service	100.000000%	1.502931%	0.000000%	0.152833%	5.251963%	0.000000%	0.239400%
		64,948,541	877,618	0	133,541	2,894,767	0	209,231
25	Total Gas Plant in Service	100.000000%	1.351251%	0.000000%	0.205610%	4.457016%	0.000000%	0.322149%
		23,868,755	124,170	1,184,788	19,320	0	988,429	34,320
26	Projected Operating Revenue Excluding Other Revenues	100.000001%	0.520220%	4.963761%	0.080943%	0.000000%	4.141100%	0.143786%
		1,052,721	12,596	0	3,850	31,026	0	6,036
27	All Other Dist. Operation Exp.	100.000000%	1.196518%	0.000000%	0.365719%	2.947220%	0.000000%	0.573371%
		477,402	6,808	0	2,670	16,765	0	4,186
28	All Other Dist. Maintenance Exp.	100.000000%	1.426052%	0.000000%	0.559277%	3.511715%	0.000000%	0.876829%
		2,939,215	37,172	0	12,440	91,552	0	19,502
30	Distribution O&M	100.000000%	1.264691%	0.000000%	0.423242%	3.114845%	0.000000%	0.663510%
		6,443,839	72,489	0	24,956	178,535	0	39,124
31	O&M Excl. Cost of Gas & CIP Base	100.000000%	1.124935%	0.000000%	0.387285%	2.770631%	0.000000%	0.607154%
		13,869,562	124,170	947,690	0	0	0	0
33	Cost of Gas	100.000000%	0.895270%	6.832876%	0.000000%	0.000000%	0.000000%	0.000000%
		(1,506,404)	(125,950)	208,052	(19,878)	(318,715)	744,161	(27,126)
35	Taxable Income	99.999999%	8.360971%	-13.811169%	1.319566%	21.157339%	-49.399829%	1.800712%
		32,664	985	0	0	0	0	0
36	Design Day Peak Excluding Transportation	100.000000%	3.015552%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
		6,923,675	0	359,600	0	0	3,025,387	0
37	Throughput less CIP Base Exempt LI Transport Flex	100.000000%	0.000000%	5.193774%	0.000000%	0.000000%	43.696260%	0.000000%
		47,546,452	620,846	0	109,370	1,529,110	0	171,357
38	Distribution Plant Less Direct Assignment	100.000000%	1.305767%	0.000000%	0.230028%	3.216034%	0.000000%	0.360399%

MDU Resources Group, Inc.

Building a Strong America®

Annual Report
—
Form 10-K
—
Proxy Statement

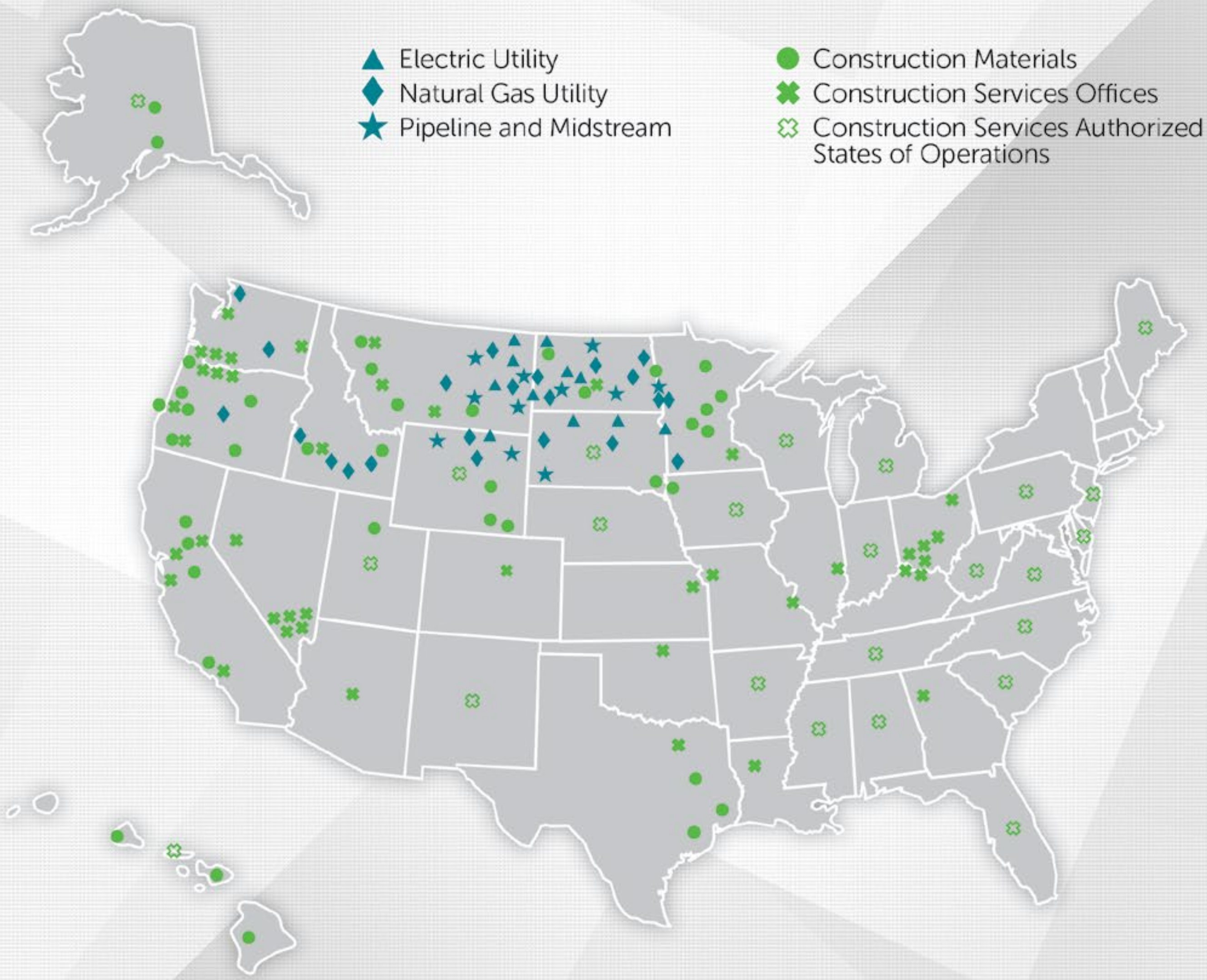
2018

MDU RESOURCES GROUP, INC.

MDU RESOURCES GROUP, INC.

Building a Strong America®

2018



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

MDU
LISTED
NYSE

Conducting business in 44 states

11,797 employees

1.8 Bcf/day of natural gas pipeline capacity

1.1 million utility customers

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

1 billion tons of aggregate reserves

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

Paid dividends **81** consecutive years

Increased dividends **28** consecutive years

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

MDU RESOURCES GROUP, INC.

Building a Strong America®

At December 31, 2018.

Highlights

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

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

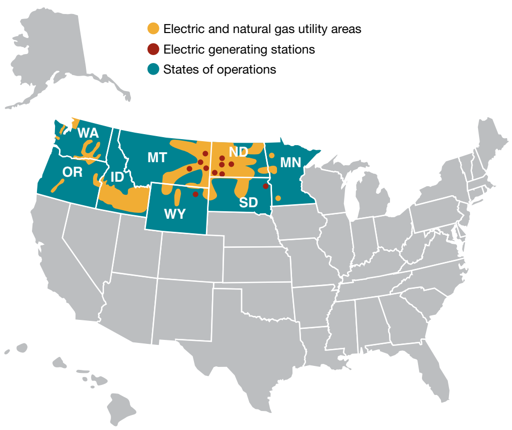
Regulated Energy Delivery

Electric and Natural Gas Utilities

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

2018 Key Statistics

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



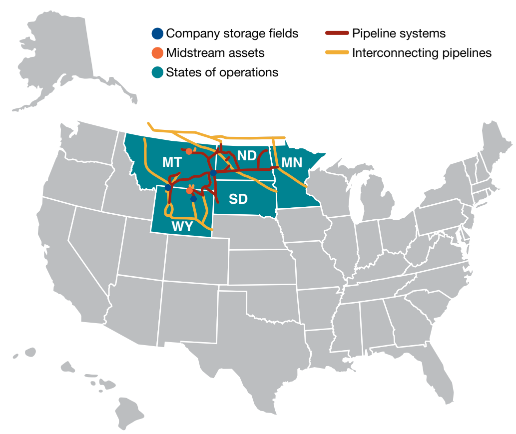
Regulated Energy Delivery

Pipeline and Energy Services

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

2018 Key Statistics

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



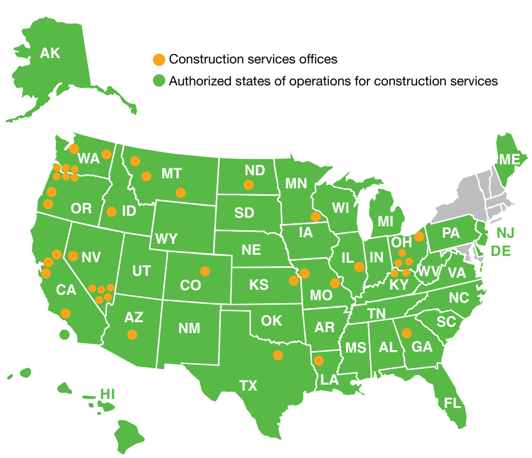
Construction Materials and Services

Construction Services

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

2018 Key Statistics

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



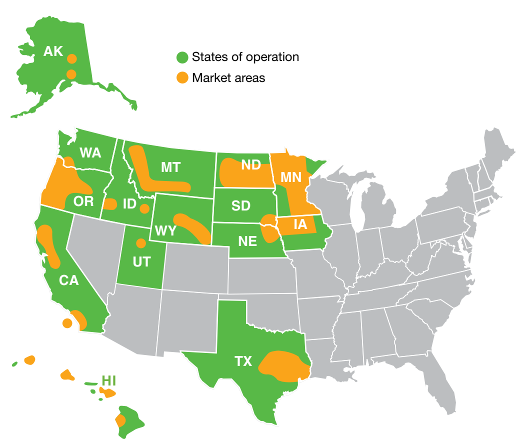
Construction Materials and Services

Construction Materials and Contracting

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

2018 Key Statistics

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



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

Report to Stockholders

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

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

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

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

Construction services breaks records

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

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

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

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

Construction materials has record backlog

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

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

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

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

Harry J. Pearce
Chair of the Board

David L. Goodin
President and Chief Executive Officer

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

Pipeline transports record volume

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

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

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

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

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

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

Utility customer base continues to grow

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

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

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

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

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

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

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

Sustainability a strong focus

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

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

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

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

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

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

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

Harry J. Pearce

Harry J. Pearce
Chair of the Board

David L. Goodin

David L. Goodin
President and Chief Executive Officer

February 22, 2019

Board of Directors

Harry J. Pearce
76 (22)
Detroit, Michigan

Chair of MDU Resources Board of Directors

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

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

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

President and Chief Executive Officer of MDU Resources

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

Thomas Everist
69 (24)
Sioux Falls, South Dakota

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

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

Karen B. Fagg
65 (14)
Billings, Montana

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

Expertise: Engineering, construction and business management.

Mark A. Hellerstein
66 (6)
Denver, Colorado

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

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

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

Vice Chair of MDU Resources Board of Directors

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

Expertise: Business management, engineering and finance.

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

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

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

Patricia L. Moss
65 (16)
Bend, Oregon

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

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

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

Formerly executive vice president and general counsel of Marriott International.

Expertise: Leadership, corporate governance and law.

David M. Sparby
64 (1)
Minneapolis, Minnesota

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

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

John K. Wilson
64 (16)
Omaha, Nebraska

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

Expertise: Public utilities, accounting and finance.

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

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

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

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

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

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

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

Corporate Management

David L. Goodin
57 (36)

President and Chief Executive Officer of MDU Resources

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

David C. Barney
63 (33)

President and Chief Executive Officer of Knife River Corporation

Formerly held executive and management positions with Knife River.

Trevor J. Hastings
45 (23)

President and Chief Executive Officer of WBI Holdings, Inc.

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

Anne M. Jones
55 (37)

Vice President of Human Resources of MDU Resources

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

Nicole A. Kivisto
45 (24)

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

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

Daniel S. Kuntz
65 (15)

Vice President, General Counsel and Secretary of MDU Resources

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

Peggy A. Link
52 (14)

Vice President and Chief Information Officer of MDU Resources

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

Jeffrey S. Thiede
56 (15)

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

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

Jason L. Vollmer
41 (14)

Vice President, Chief Financial Officer and Treasurer of MDU Resources

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

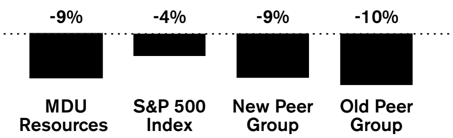
Other Corporate and Senior Company Officers
Stephanie A. Barth, 46 (23)
Vice President, Chief Accounting Officer and Controller of MDU Resources

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

Stockholder Return Comparison

Comparison of One-Year Total Stockholder Return

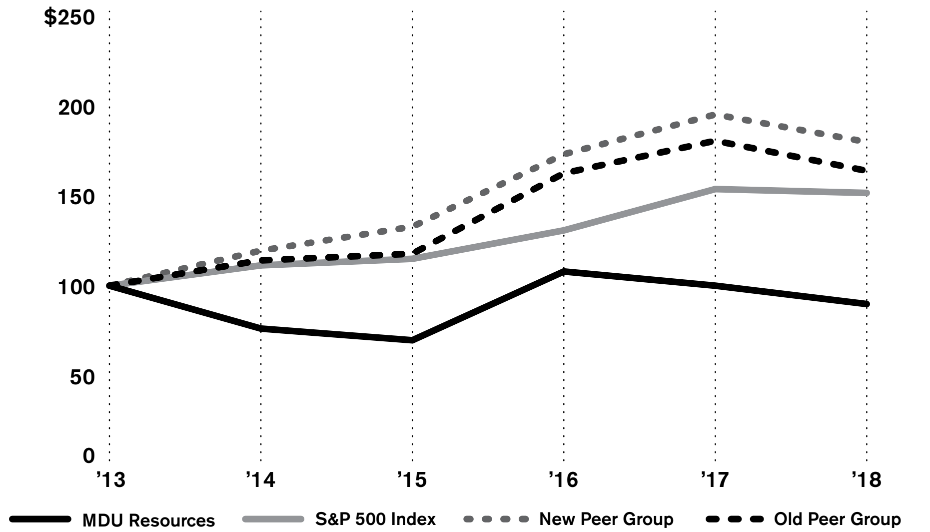
(as of December 31, 2018)



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

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

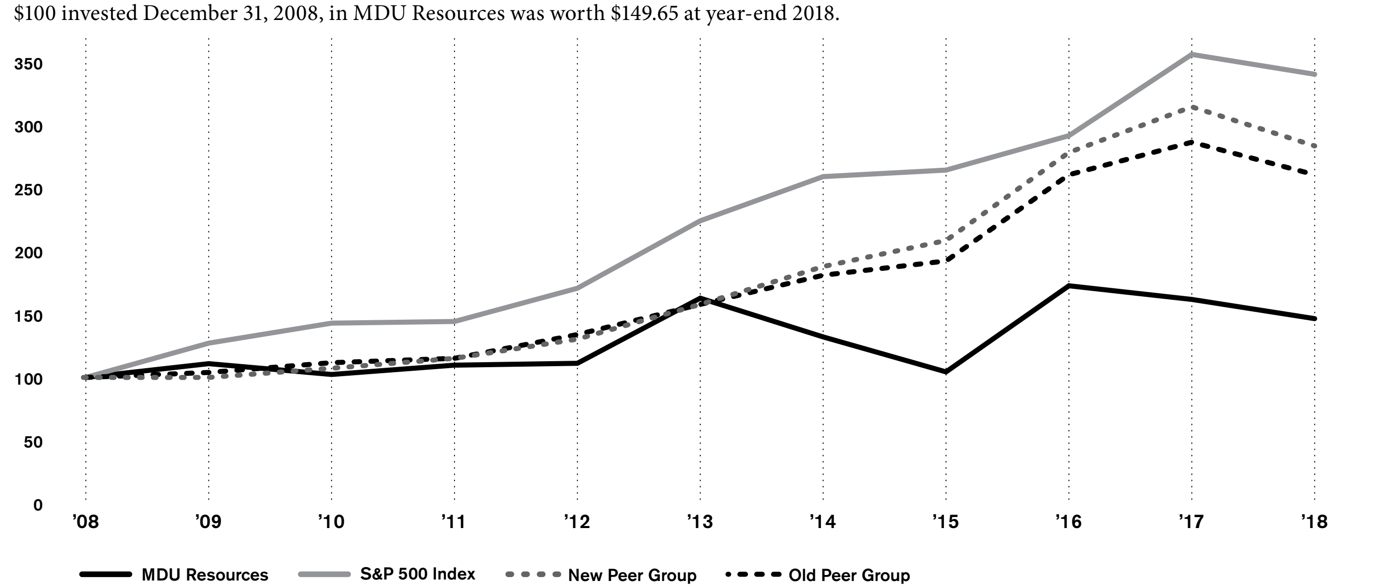
$100 invested December 31, 2013, in MDU Resources was worth $90.96 at year-end 2018.



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

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

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



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

Stockholder Return Comparison

Data is indexed to December 31, 2017, for the one-year total stockholder return comparison, December 31, 2013, for the five-year total stockholder return comparison and December 31, 2008, for the 10-year total stockholder return comparison for MDU Resources, the S&P 500 and the peer groups. Total stockholder return is calculated using the December 31 price for each year. It is assumed that all dividends are reinvested in stock at the frequency paid, and the returns of each component peer issuer of the group are weighted according to the issuer's stock market capitalization at the beginning of the period.

Effective January 1, 2018, a new peer group was established. This change was made to better reflect the makeup of the company relative to each business segment's size and nature of business. The charts show stockholder return performance for both the old and new peer groups.

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

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

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

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ____________ to ____________
Commission file number 1-03480

MDU RESOURCES GROUP, INC.

(Exact name of registrant as specified in its charter)

Delaware	30-1133956
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1200 West Century Avenue
P.O. Box 5650
Bismarck, North Dakota 58506-5650
(Address of principal executive offices)
(Zip Code)

(701) 530-1000
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $1.00	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐	Smaller reporting company ☐
	Emerging growth company ☐

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

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

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

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

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

Contents

The following abbreviations and acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
Army Corps	U.S. Army Corps of Engineers
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
Audit Committee	Audit Committee of the board of directors of the Company
Bcf	Billion cubic feet
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
Brazilian Transmission Lines	Company's former investment in companies owning three electric transmission lines in Brazil
BSSE	345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota
Btu	British thermal unit
Calumet	Calumet Specialty Products Partners, L.P.
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial's Consolidated EBITDA	Centennial's consolidated net income from continuing operations plus the related interest expense, taxes, depreciation, depletion, amortization of intangibles and any non-cash charge relating to asset impairment for the preceding 12-month period
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
Clean Air Act	Federal Clean Air Act
Clean Water Act	Federal Clean Water Act
Company	MDU Resources Group, Inc. (formerly known as MDUR Newco), which, as the context requires, refers to the previous MDU Resources Group, Inc. prior to January 1, 2019, and the new holding company of the same name after January 1, 2019
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
Coyote Station	427-MW coal-fired electric generating facility near Beulah, North Dakota (25 percent ownership)
CyROC	Cyber Risk Oversight Committee
Dakota Prairie Refinery	20,000-barrel-per-day diesel topping plant built by Dakota Prairie Refining in southwestern North Dakota
Dakota Prairie Refining	Dakota Prairie Refining, LLC, a limited liability company previously owned by WBI Energy and Calumet (previously included in the Company's refining segment)
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
dk	Decatherm
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
EBITDA	Earnings before interest, taxes, depreciation, depletion and amortization
EIN	Employer Identification Number
EPA	United States Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
ESA	Endangered Species Act
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings (previously referred to as the Company's exploration and production segment)
FIP	Funding improvement plan
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company prior to the closing of the Holding Company Reorganization and a public utility division of Montana-Dakota as of January 1, 2019
GVTC	Generation Verification Test Capacity

Holding Company Reorganization	The internal holding company reorganization completed on January 1, 2019, pursuant to the agreement and plan of merger, dated as of December 31, 2018, by and among Montana-Dakota, the Company and MDUR Newco Sub, which resulted in the Company becoming a holding company and owning all of the outstanding capital stock of Montana-Dakota.
IBEW	International Brotherhood of Electrical Workers
ICWU	International Chemical Workers Union
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
IPUC	Idaho Public Utilities Commission
Item 8	Financial Statements and Supplementary Data
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
Knife River - Northwest	Knife River Corporation - Northwest, an indirect wholly owned subsidiary of Knife River
K-Plan	Company's 401(k) Retirement Plan
kW	Kilowatts
kWh	Kilowatt-hour
LWG	Lower Willamette Group
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Mdk	Thousand dk
MDU Construction Services	MDU Construction Services Group, Inc., a direct wholly owned subsidiary of Centennial
MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of the Company
MDUR Newco	MDUR Newco, Inc., a public holding company created by implementing the Holding Company Reorganization, now known as the Company
MDUR Newco Sub	MDUR Newco Sub, Inc., a direct, wholly owned subsidiary of MDUR Newco, which was merged with and into Montana–Dakota in the Holding Company Reorganization
MEPP	Multiemployer pension plan
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million Btu
MMcf	Million cubic feet
MMdk	Million dk
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co. (formerly known as MDU Resources Group, Inc.), a public utility division of the Company prior to the closing of the Holding Company Reorganization and a direct wholly owned subsidiary of MDU Energy Capital as of January 1, 2019
Montana DEQ	Montana Department of Environmental Quality
MPPAA	Multiemployer Pension Plan Amendments Act of 1980
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
NGL	Natural gas liquids
Non-GAAP	Not in accordance with GAAP
Oil	Includes crude oil and condensate
OPUC	Oregon Public Utility Commission
Oregon DEQ	Oregon State Department of Environmental Quality
PCBs	Polychlorinated biphenyls
Pronghorn	Natural gas processing plant located near Belfield, North Dakota (WBI Energy Midstream's 50 percent ownership interests were sold effective January 1, 2017)
Proxy Statement	Company's 2019 Proxy Statement to be filed no later than April 30, 2019
PRP	Potentially Responsible Party
RCRA	Resource Conservation and Recovery Act
ROD	Record of Decision
RP	Rehabilitation plan
SDPUC	South Dakota Public Utilities Commission
SEC	United States Securities and Exchange Commission

Securities Act	Securities Act of 1933, as amended
Securities Act Industry Guide 7	Description of Property by Issuers Engaged or to be Engaged in Significant Mining Operations
Sheridan System	A separate electric system owned by Montana-Dakota
SSIP	System Safety and Integrity Program
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan which was terminated effective December 5, 2016
TCJA	Tax Cuts and Jobs Act
Tesoro	Tesoro Refining & Marketing Company LLC
Thurston County Superior Court	State of Washington Thurston County Superior Court
UA	United Association of Journeyman and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada
United States Supreme Court	Supreme Court of the United States
VIE	Variable interest entity
Washington DOE	Washington State Department of Ecology
WBI Energy	WBI Energy, Inc., a direct wholly owned subsidiary of WBI Holdings
WBI Energy Midstream	WBI Energy Midstream, LLC, an indirect wholly owned subsidiary of WBI Holdings
WBI Energy Transmission	WBI Energy Transmission, Inc., an indirect wholly owned subsidiary of WBI Holdings
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
WUTC	Washington Utilities and Transportation Commission
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
WYPSC	Wyoming Public Service Commission
ZRCs	Zonal resource credits - a MW of demand equivalent assigned to generators by MISO for meeting system reliability requirements

Forward-Looking Statements

This Form 10-K contains forward-looking statements within the meaning of Section 21E of the Exchange Act. Forward-looking statements are all statements other than statements of historical fact, including without limitation those statements that are identified by the words "anticipates," "estimates," "expects," "intends," "plans," "predicts" and similar expressions, and include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions (many of which are based, in turn, upon further assumptions) and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Item 7 - MD&A - Business Segment Financial and Operating Data.

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

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

Items 1 and 2. Business and Properties

General

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

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

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

The Company is organized into five reportable business segments. These business segments include: electric, natural gas distribution, pipeline and midstream, construction materials and contracting, and construction services. The Company's business segments are determined based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The internal reporting of these segments is defined based on the reporting and review process used by the Company's chief executive officer.

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

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

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

As of December 31, 2018, the Company had 11,797 employees with 218 employed at MDU Resources Group, Inc., 1,004 at Montana-Dakota, 338 at Cascade, 242 at Intermountain, 317 at WBI Holdings, 3,967 at Knife River and 5,711 at MDU Construction Services. The number of employees at certain Company operations fluctuates during the year depending upon the number and size of construction projects. The Company considers its relations with employees to be satisfactory.

The following information regarding the number of employees represented by labor contracts is as of December 31, 2018.

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

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

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

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

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

The majority of the labor contracts contain provisions that prohibit work stoppages or strikes and provide for binding arbitration dispute resolution in the event of an extended disagreement.

The Company's principal properties, which are of varying ages and are of different construction types, are generally in good condition, are well maintained and are generally suitable and adequate for the purposes for which they are used.

The financial results and data applicable to each of the Company's business segments, as well as their financing requirements, are set forth in Item 7 - MD&A and Item 8 - Note 15 and Supplementary Financial Information.

The operations of the Company and certain of its subsidiaries are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations; and state hazard communication standards. The Company believes that it is in substantial compliance with these regulations, except as to what may be ultimately determined with regard to items discussed in Environmental matters in Item 8 - Note 19. There are no pending CERCLA actions for any of the Company's properties, other than the Portland, Oregon, Harbor Superfund Site and the Bremerton Gasworks Superfund Site.

The Company produces GHG emissions primarily from its fossil fuel electric generating facilities, as well as from natural gas pipeline and storage systems, and operations of equipment and fleet vehicles. GHG emissions also result from customer use of natural gas for heating and other uses. As interest in reductions in GHG emissions has grown, the Company has developed renewable generation with lower or no GHG emissions. Governmental legislative and regulatory initiatives regarding environmental and energy policy are continuously evolving and could negatively impact the Company's operations and financial results. Until legislation and regulation are finalized, the impact of these measures cannot be accurately predicted. The Company will continue to monitor legislative and regulatory activity related to environmental and energy policy initiatives. Disclosure regarding specific environmental matters applicable to each of the Company's businesses is set forth under each business description later. In addition, for a discussion of the Company's risks related to environmental laws and regulations, see Item 1A - Risk Factors.

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

The Company created CyROC to oversee the Company's approach to cybersecurity. CyROC is responsible for supplying management at all levels and the Audit Committee with analyses, appraisals, recommendations and pertinent information concerning cyber defense of the Company's electronic information and information technology systems. CyROC provides a quarterly cybersecurity report to the Audit Committee. For a discussion of the Company's risks related to cybersecurity, see Item 1A - Risk Factors.

This annual report on Form 10-K, the Company's quarterly reports on Form 10-Q and current reports on Form 8-K, and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available free of charge through the Company's Web site as soon as reasonably practicable after the Company has electronically filed such reports with, or furnished such reports to, the SEC. The Company's Web site address is www.mdu.com. The information available on the Company's Web site is not part of this annual report on Form 10-K.

Electric

General Montana-Dakota provides electric service at retail, serving 143,022 residential, commercial, industrial and municipal customers in 184 communities and adjacent rural areas in Montana, North Dakota, South Dakota and Wyoming as of December 31, 2018. For more information on the retail customer classes served, see the table below. The principal properties owned by Montana-Dakota for use in its electric operations include interests in 16 electric generating units at 11 facilities and two small portable diesel generators, as further described under System Supply, System Demand and Competition, approximately 3,200 and 4,900 miles of transmission and distribution lines, respectively, and 75 transmission and 297 distribution substations. Montana-Dakota has obtained and holds, or is in the process of renewing, valid and existing franchises authorizing it to conduct its electric operations in all of the municipalities it serves where such franchises are required. Montana-Dakota intends to protect its service area and seek renewal of all expiring franchises. At December 31, 2018, Montana-Dakota's net electric plant investment was $1.5 billion and rate base was $1.2 billion.

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

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

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

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

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

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

Through MISO, Montana-Dakota has access to wholesale energy, ancillary services and capacity markets for its interconnected system. MISO is a regional transmission organization responsible for operational control of the transmission systems of its members. MISO provides security center operations, tariff administration and operates day-ahead and real-time energy markets, ancillary services and capacity markets. As a member of MISO, Montana-Dakota's generation is sold into the MISO energy market and its energy needs are purchased from that market.

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

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

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

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

Through the Sheridan System, Montana-Dakota serves Sheridan, Wyoming, and neighboring communities. The maximum peak demand experienced to date attributable to Montana-Dakota sales to retail customers on that system was approximately 63,686 kW in July 2018. Montana-Dakota has a power supply contract with Black Hills Power, Inc. to purchase up to 49,000 kW of capacity annually through December 31, 2023. Wygen III serves a portion of the needs of its Sheridan-area customers.

The following table sets forth details applicable to the Company's electric generating stations:

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

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

Virtually all of the current fuel requirements of the Heskett and Lewis & Clark stations are met with coal supplied by subsidiaries of Westmoreland Coal Company under contracts that expire in December 2021 and December 2020, respectively. The Heskett and Lewis & Clark coal supply agreements provide for the purchase of coal necessary to supply the coal requirements of these stations at contracted pricing. Montana-Dakota estimates the Heskett and Lewis & Clark coal requirement to be in the range of 425,000 to 460,000 tons and 250,000 to 350,000 tons per contract year, respectively.

The owners of Coyote Station, including Montana-Dakota, have a contract with Coyote Creek for coal supply to the Coyote Station that expires December 2040. Montana-Dakota estimates the Coyote Station coal supply agreement to be approximately 2.5 million tons per contract year. For more information, see Item 8 - Note 19.

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

Montana-Dakota has a coal supply agreement with Wyodak Resources Development Corp., to supply the coal requirements of Wygen III at contracted pricing through June 1, 2060. Montana-Dakota estimates the maximum annual coal consumption of the facility to be 585,000 tons.

The average cost of coal purchased, including freight, at Montana-Dakota's electric generating stations (including the Big Stone, Coyote and Wygen III stations) was as follows:

Years ended December 31,	**2018**	2017	2016
Average cost of coal per MMBtu	**$ 2.00**	$ 2.07	$ 1.89
Average cost of coal per ton	**$ 29.08**	$ 30.04	$ 27.45

Montana-Dakota expects that it has secured adequate capacity available through existing baseload generating stations, renewable generation, turbine peaking stations, demand reduction programs and firm contracts to meet the peak customer demand requirements of its customers through 2028. Future capacity that is needed to replace contracts, generation retirements and meet system growth requirements is expected to be met by constructing new generation resources, or acquiring additional capacity through power purchase contracts or the MISO capacity auction.

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

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

Regulatory Matters and Revenues Subject to Refund In North Dakota, Montana-Dakota's results of operations reflect monthly increases or decreases in electric fuel and purchased power costs (including demand charges) and Montana-Dakota is deferring those electric fuel and purchased power costs that are greater or less than amounts presently being recovered through its existing rate schedules. In Montana, a monthly Fuel and Purchased Power Tracking Adjustment mechanism allows Montana-Dakota's results of operations to reflect 90 percent of the increases or decreases in electric fuel and purchased power costs (including demand charges) and Montana-Dakota is deferring 90 percent of costs that are greater or less than amounts presently being recovered through its existing rate schedules. A fuel adjustment clause contained in South Dakota's jurisdictional electric rate schedules allows Montana-Dakota's results of operations to reflect monthly increases or decreases in electric fuel and purchased power costs. In Wyoming, an annual Electric Power Supply Cost Adjustment mechanism allows Montana-Dakota's results of operations to reflect increases or decreases in purchased power costs (including demand charges) related to power supply and Montana-Dakota is deferring costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments which are filed annually. Montana-Dakota's results of operations reflect 95 percent of the increases or decreases from the base purchased power costs and in addition also reflects 85 percent of the increases or decreases from the base coal price, which is also recovered through the Electric Power Supply Cost Adjustment. For more information on regulatory assets and liabilities, see Item 8 - Note 6.

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

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

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

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

Environmental Matters Montana-Dakota's electric operations are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations; and state hazard communication standards. Montana-Dakota believes it is in substantial compliance with these regulations.

Montana-Dakota's electric generating facilities have Title V Operating Permits, under the Clean Air Act, issued by the states in which they operate. Each of these permits has a five-year life. Near the expiration of these permits, renewal applications are submitted. Permits continue in force beyond the expiration date, provided the application for renewal is submitted by the required date, usually six months prior to expiration. The Title V Operating Permit renewal application for Coyote Station was submitted timely to the North Dakota Department of Health in September 2017, with the permit expected to be issued in 2019. Wygen III is allowed to operate under the facility's construction permit until the Title V Operating Permit is issued by the Wyoming Department of Environmental Quality. The Title V Operating Permit application for Wygen III was submitted timely in January 2011, with the permit expected to be issued in 2019.

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

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

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

Natural Gas Distribution

General The Company's natural gas distribution operations consist of Montana-Dakota, Cascade and Intermountain, which sell natural gas at retail, serving 957,727 residential, commercial and industrial customers in 339 communities and adjacent rural areas across eight states as of December 31, 2018, and provide natural gas transportation services to certain customers on the Company's systems. For more information on the retail customer classes served, see the table below. These services are provided through distribution systems aggregating approximately 19,400 miles. The natural gas distribution operations have obtained and hold, or are in the process of renewing, valid and existing franchises authorizing them to conduct their natural gas operations in all of the municipalities they serve where such franchises are required. These operations intend to protect their service areas and seek renewal of all expiring franchises. At December 31, 2018, the natural gas distribution operations' net natural gas distribution plant investment was $1.7 billion and rate base was $1.1 billion.

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

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

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

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

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

The natural gas distribution operations are subject to regulation by the IPUC, MNPUC, MTPSC, NDPSC, OPUC, SDPUC, WUTC and WYPSC regarding retail rates, service, accounting and certain security issuances.

System Supply, System Demand and Competition The natural gas distribution operations serve retail natural gas markets, consisting principally of residential and firm commercial space and water heating users, in portions of Idaho; western Minnesota; eastern Montana; North Dakota; central and eastern Oregon; western and north-central South Dakota; western, southeastern and south-central Washington; and northern Wyoming. These markets are highly seasonal and sales volumes depend largely on the weather, the effects of which are mitigated in certain jurisdictions by a weather normalization mechanism discussed in Regulatory Matters. In addition to the residential and commercial sales, the utilities transport natural gas for larger commercial and industrial customers who purchase their own supply of natural gas.

Competition in varying degrees exists between natural gas and other fuels and forms of energy. The natural gas distribution operations have established various natural gas transportation service rates for their distribution businesses to retain interruptible commercial and industrial loads. These services have enhanced the natural gas distribution operations' competitive posture with alternative fuels, although certain customers have bypassed the distribution systems by directly accessing transmission pipelines within close proximity. These bypasses did not have a material effect on results of operations.

The natural gas distribution operations and various distribution transportation customers obtain their system requirements directly from producers, processors and marketers. The Company's purchased natural gas is supplied by a portfolio of contracts specifying market-based pricing and is transported under transportation agreements with WBI Energy Transmission, Northern Border Pipeline Company, Northwest Pipeline LLC, South Dakota Intrastate Pipeline, TransCanada Corporation, Northern Natural Gas, Gas Transmission Northwest LLC, Northwestern Energy, Viking Gas Transmission Company, Westcoast Energy Inc., Ruby Pipeline LLC, Foothills Pipe Lines Ltd. and NOVA Gas Transmission Ltd. The natural gas distribution operations have contracts for storage services to provide gas supply during the winter heating season and to meet peak day demand with various storage providers, including WBI Energy Transmission, Dominion Energy Questar Pipeline, LLC, Northwest Pipeline LLC and Northern Natural Gas. In addition, certain of the operations have entered into natural gas supply management agreements with various parties. Demand for natural gas, which is a widely traded commodity, has historically been sensitive to seasonal heating and industrial load requirements as well as changes in market price. The natural gas distribution operations believe that, based on current and projected domestic and regional supplies of natural gas and the pipeline transmission network currently available through their suppliers and pipeline service providers, supplies are adequate to meet their system natural gas requirements for the next decade.

Regulatory Matters The natural gas distribution operations' retail natural gas rate schedules contain clauses permitting adjustments in rates based upon changes in natural gas commodity, transportation and storage costs. Current tariffs allow for recovery or refunds of under- or over-recovered gas costs through rate adjustments which are filed annually.

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

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

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

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

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

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

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

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

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

The natural gas distribution operations did not incur any material environmental expenditures in 2018. Except as to what may be ultimately determined with regard to the issues described in the following paragraph, the natural gas distribution operations do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2021.

Montana-Dakota has ties to six historic manufactured gas plants as a successor corporation or through direct ownership of the plant. Montana-Dakota is investigating one of these former manufactured gas plant sites and providing input on another site investigation conducted by a third party. To the extent not covered by insurance, Montana-Dakota may seek recovery in its natural gas rates charged to customers for certain investigation and remediation costs incurred for these sites. Cascade has ties to nine historic manufactured gas plants as a successor corporation or through direct ownership of the plant. Cascade is involved in the investigation and remediation of three of these manufactured gas plants in Washington and Oregon. See Item 8 - Note 19 for a further discussion of these three manufactured gas plants. To the extent not covered by insurance, Cascade will seek recovery of investigation and remediation costs through its natural gas rates charged to customers.

Pipeline and Midstream

General WBI Energy owns and operates both regulated and nonregulated businesses. The regulated business of this segment, WBI Energy Transmission, owns and operates approximately 4,000 miles of natural gas transmission, gathering and storage lines in Minnesota, Montana, North Dakota, South Dakota and Wyoming. WBI Energy Transmission's underground storage fields in Montana and Wyoming provide storage services to local distribution companies, industrial customers, natural gas marketers and others, and serve to enhance system reliability. Its system is strategically located near five natural gas producing basins, making natural gas supplies available to its transportation and storage customers. The system has 14 interconnecting points with other pipeline facilities allowing for the receipt and/or delivery of natural gas to and from other regions of the country and from Canada. Under the Natural Gas Act, as amended, WBI Energy Transmission is subject to the jurisdiction of the FERC regarding certificate, rate, service and accounting matters, and at December 31, 2018, its net plant investment was $458.1 million.

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

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

System Supply, System Demand and Competition Natural gas supplies emanate from traditional and nontraditional production activities in the region from both on-system and off-system supply sources. New incremental supply from nontraditional sources have developed, such as the Bakken area in Montana and North Dakota, which has helped offset declines in traditional regional supply sources and supports WBI Energy Transmission's transportation and storage services. In addition, off-system supply sources are available through the Company's interconnections with other pipeline systems. WBI Energy Transmission continues to look for opportunities to increase transportation, gathering and storage services through system expansion and/or other pipeline interconnections or enhancements that could provide substantial future benefits.

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

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

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

WBI Energy Transmission transports substantially all of Montana-Dakota's natural gas, primarily utilizing firm transportation agreements, which for 2018 represented 32 percent of WBI Energy Transmission's subscribed firm transportation contract demand. The majority of the firm transportation agreements with Montana-Dakota expire in June 2022. In addition, Montana-Dakota has contracts with WBI Energy Transmission to provide firm storage services to facilitate meeting Montana-Dakota's winter peak requirements expiring in July 2035.

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

Environmental Matters The pipeline and midstream operations are generally subject to federal, state and local environmental, facility-siting, zoning and planning laws and regulations. The Company believes it is in substantial compliance with those regulations.

Ongoing operations are subject to the Clean Air Act, the Clean Water Act, the RCRA and other state and federal regulations. Administration of many provisions of these laws has been delegated to the states where WBI Energy and its subsidiaries operate. Permit terms vary and all permits carry operational compliance conditions. Some permits require annual renewal, some have terms ranging from one to five years and others have no expiration date. Permits are renewed and modified, as necessary, based on defined permit expiration dates, operational demand and/or regulatory changes.

Detailed environmental assessments and/or environmental impact statements as required by the National Environmental Policy Act are included in the FERC's environmental review process for both the construction and abandonment of WBI Energy Transmission's natural gas transmission pipelines, compressor stations and storage facilities.

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

Construction Materials and Contracting

General Knife River operates construction materials and contracting businesses headquartered in Alaska, California, Hawaii, Idaho, Iowa, Minnesota, Montana, North Dakota, Oregon, South Dakota, Texas, Washington and Wyoming. These operations mine, process and sell construction aggregates (crushed stone, sand and gravel); produce and sell asphalt mix; and supply ready-mixed concrete. These products are used in most types of construction, performed by Knife River and other companies, including roads, freeways and bridges, as well as homes, schools, shopping centers, office buildings and industrial parks. Knife River focuses on vertical integration of its contracting services with its construction materials to support the aggregate based product lines including aggregate placement, asphalt and concrete paving, and site development and grading. Although not common to all locations, other products include the sale of cement, liquid asphalt for various commercial and roadway applications, various finished concrete products and other building materials and related contracting services.

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

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

Knife River's backlog is comprised of the anticipated revenues from the uncompleted portion of services to be performed under job-specific contracts. A project is included in backlog when a contract is awarded and agreement on contract terms has been reached. However, backlog does not contain contracts for time and material projects that a fixed amount cannot be determined. Backlog is comprised of: (a) original contract amounts, (b) change orders for which customers have approved and (c) claim amounts that have been made against customers for which are determined to have a legal basis under existing contractual arrangements and as to which recovery is considered to be probable. Such claim amounts were immaterial for all periods presented. Backlog may be subject to delay, default or cancellation at the election of the customers. Historically, cancellations have not had a materially adverse effect on backlog. Due to the nature of its contractual arrangements, in many instances Knife River's customers are not committed to the specific volumes of services to be purchased under a contract, but rather Knife River is committed to perform these services if and to the extent requested by the customer. Therefore, there can be no assurance as to the customers' requirements during a particular period or that such estimates, or backlog estimates in general, at any point in time are predictive of future revenues.

Competition Knife River's construction materials products and contracting services are marketed under highly competitive conditions. Price is the principal competitive force to which these products and services are subject, with service, quality, delivery time and proximity to the customer also being significant factors. Knife River focuses on markets located near aggregate sites to reduce transportation costs which allows Knife River to remain competitive with the pricing of aggregate products. The number and size of competitors varies in each of Knife River's principal market areas and product lines.

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

Knife River's customers are a diverse group which includes federal, state and municipal government agencies, commercial and residential developers, and private parties. The mix of sales by customer will vary each year depending on the work available. Knife River is not dependent on any single customer or group of customers for sales of its products and services, the loss of which would have a material adverse effect on its construction materials businesses.

Reserve Information Aggregate reserve estimates are calculated based on the best available data. This data is collected from drill holes and other subsurface investigations, as well as investigations of surface features such as mine high walls and other exposures of the aggregate reserves. Mine plans, production history and geologic data also are utilized to estimate reserve quantities.

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

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

Estimated reserves are probable reserves as defined in Securities Act Industry Guide 7. Remaining reserves are based on estimates of volumes that can be economically extracted and sold to meet current market and product applications. The reserve estimates include only salable tonnage and thus exclude waste materials that are generated in the crushing and processing phases of the operation. Approximately 938 million tons of the 1.0 billion tons of aggregate reserves are permitted reserves. The remaining reserves are on properties that are expected to be permitted for mining under current regulatory requirements. The data used to calculate the remaining reserves may require revisions in the future to account for changes in customer requirements and unknown geological occurrences. The years remaining were calculated by dividing remaining reserves by the three-year average sales, including estimated sales from acquired reserves prior to acquisition, from 2016 through 2018. Actual useful lives of these reserves will be subject to, among other things, fluctuations in customer demand, customer specifications, geological conditions and changes in mining plans.

The following table sets forth details applicable to the Company's aggregate reserves under ownership or lease as of December 31, 2018, and sales for the years ended December 31, 2018, 2017 and 2016:

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

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

The 1.0 billion tons of estimated aggregate reserves at December 31, 2018, are comprised of 518 million tons that are owned and 496 million tons that are leased. Approximately 48 percent of the tons under lease have lease expiration dates of 20 years or more. The weighted average years remaining on all leases containing estimated probable aggregate reserves is approximately 23 years, including options for renewal that are at Knife River's discretion. Based on a three-year average of sales from 2016 through 2018 of leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 44 years. Some sites have leases that expire prior to the exhaustion of the estimated reserves. The estimated reserve life assumes, based on Knife River's experience, that leases will be renewed to allow sufficient time to fully recover these reserves.

The changes in Knife River's aggregate reserves for the years ended December 31 were as follows:

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

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

Environmental Matters Knife River's construction materials and contracting operations are subject to regulation customary for such operations, including federal, state and local environmental compliance and reclamation regulations. Except as to the issues described later, Knife River believes it is in substantial compliance with these regulations. Individual permits applicable to Knife River's various operations are managed largely by local operations, particularly as they relate to application, modification, renewal, compliance and reporting procedures.

Knife River's asphalt and ready-mixed concrete manufacturing plants and aggregate processing plants are subject to the Clean Air Act and the Clean Water Act requirements for controlling air emissions and water discharges. Some mining and construction activities also are subject to these laws. In most of the states where Knife River operates, these regulatory programs have been delegated to state and local regulatory authorities. Knife River's facilities also are subject to the RCRA as it applies to the management of hazardous wastes and underground storage tank systems. These programs also have generally been delegated to the state and local authorities in the states where Knife River operates. Knife River's facilities must comply with requirements for managing wastes and underground storage tank systems.

Some Knife River activities are directly regulated by federal agencies. For example, certain in-water mining operations are subject to provisions of the Clean Water Act that are administered by the Army Corps. Knife River has several such operations, including gravel bar skimming and dredging operations, and Knife River has the associated permits as required. The expiration dates of these permits vary, with five years generally being the longest term.

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

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

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

Knife River has been successful in obtaining mining and other land use permit approvals so sufficient permitted reserves are available to support its operations. For mining operations, this often requires considerable advanced planning to ensure sufficient time is available to complete the permitting process before the newly permitted aggregate reserve is needed to support Knife River's operations.

Knife River's Gascoyne surface coal mine last produced coal in 1995 but continues to be subject to reclamation requirements of the Surface Mining Control and Reclamation Act, as well as the North Dakota Surface Mining Act. Portions of the Gascoyne Mine remain under reclamation bond until the 10-year revegetation liability period has expired. A portion of the original permit has been released from bond and additional areas are currently in the process of having the bond released. Knife River's intention is to request bond release as soon as it is deemed possible.

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

In December 2000, Knife River - Northwest was named by the EPA as a PRP in connection with the cleanup of a commercial property site, acquired by Knife River - Northwest in 1999, and part of the Portland, Oregon, Harbor Superfund Site. For more information, see Item 8 - Note 19.

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

Construction Services

General MDU Construction Services provides inside and outside specialty contracting services. Its outside services include design, construction and maintenance of overhead and underground electrical distribution and transmission lines, substations, external lighting, traffic signalization, and gas pipelines, as well as utility excavation and the manufacture and distribution of transmission line construction equipment. Its inside services include design, construction and maintenance of electrical and communication wiring and infrastructure, fire suppression systems, and mechanical piping and services. This segment also constructs and maintains renewable energy projects. These specialty contracting services are provided to utilities and large manufacturing, commercial, industrial, institutional and government customers.

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

MDU Construction Services operates a fleet of owned and leased trucks and trailers, support vehicles and specialty construction equipment, such as backhoes, excavators, trenchers, generators, boring machines and cranes. In addition, as of December 31, 2018, MDU Construction Services owned or leased facilities in 18 states. This space is used for offices, equipment yards, manufacturing, warehousing, storage and vehicle shops.

MDU Construction Services' backlog at December 31 was as follows:

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

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

MDU Construction Services' backlog is comprised of the anticipated revenues from the uncompleted portion of services to be performed under job-specific contracts. A project is included in backlog when a contract is awarded and agreement on contract terms has been reached. However, backlog does not contain contracts for time and material projects that a fixed amount cannot be determined. Backlog is comprised of: (a) original contract amounts, (b) change orders for which customers have approved, (c) pending change orders expected to receive confirmation in the ordinary course of business and (d) claim amounts that have been made against customers for which are determined to have a legal basis under existing contractual arrangements and as to which recovery is considered to be probable. Such claim amounts were immaterial for all periods presented. Backlog may be subject to delay, default or cancellation at the election of the customers. Historically, cancellations have not had a material adverse effect on backlog. Due to the nature of its contractual arrangements, in many instances MDU Construction Services' customers are not committed to the specific volumes of services to be purchased under a contract, but rather MDU Construction Services is committed to perform these services if and to the extent requested by the customer. Therefore, there can be no assurance as to the customers' requirements during a particular period or that such estimates, or backlog estimates in general, at any point in time are predictive of future revenues.

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

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

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

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

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

MDU Construction Services did not incur any material environmental expenditures in 2018 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2021.

Item 1A. Risk Factors

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

Economic Risks

The Company is subject to government regulations that may delay and/or have a negative impact on its business and its results of operations and cash flows. Statutory and regulatory requirements also may limit another party's ability to acquire the Company or impose conditions on an acquisition of or by the Company.

The Company's electric and natural gas transmission and distribution businesses are subject to comprehensive regulation by federal, state and local regulatory agencies with respect to, among other things, allowed rates of return and recovery of investment and cost, financing, rate structures, customer service, health care coverage and cost, income taxes, property and other taxes, franchises; recovery of purchased power and purchased natural gas costs; construction and siting of generation and transmission facilities. These governmental regulations significantly influence the Company's operating environment and may affect its ability to recover costs from its customers. The Company is unable to predict the impact on operating results from future regulatory activities of any of these agencies. Changes in regulations or the imposition of additional regulations could have an adverse impact on the Company's results of operations and cash flows.

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

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

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

Unfavorable economic conditions can negatively affect the level of public and private expenditures on projects and the timing of these projects which, in turn, can negatively affect the demand for the Company's products and services, primarily at the Company's construction businesses. The level of demand for construction products and services could be adversely impacted by the economic conditions in the industries the Company serves, as well as in the general economy. State and federal budget issues affect the funding available for infrastructure spending.

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

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

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

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

- A significant economic downturn.
- The financial distress of unrelated industry leaders in the same line of business.
- Deterioration in capital market conditions.
- Turmoil in the financial services industry.
- Volatility in commodity prices.
- Terrorist attacks.
- Cyberattacks.

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

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

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

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

Reductions in the Company's credit ratings could increase financing costs.

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

Increasing costs associated with health care plans may adversely affect the Company's results of operations.

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

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

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

Changes in tax law may negatively affect the Company's business.

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

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

The Company's operations could be negatively impacted by import tariffs and/or other government mandates.

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

Operational Risks

Significant portions of the Company's natural gas pipelines and power generation and transmission facilities are aging. The aging infrastructure may require significant additional maintenance or replacement that could adversely affect the Company's results of operations.

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

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

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

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

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

The backlogs at the Company's construction materials and contracting and construction services businesses may not accurately represent future revenue.
Backlog consists of the uncompleted portion of services to be performed under job-specific contracts. Contracts are subject to delay, default or cancellation, and the contracts in the Company's backlog are subject to changes in the scope of services to be provided, as well as adjustments to the costs relating to the applicable contracts. Backlog may also be affected by project delays or cancellations resulting from weather conditions, external market factors and economic factors beyond the Company's control. Accordingly, there is no assurance that backlog will be realized. The timing of contract awards, duration of large new contracts and the mix of services can significantly affect backlog. Backlog at any given point in time may not accurately represent the revenue or net income that is realized in any period, and the backlog as of the end of the year may not be indicative of the revenue and net income expected to be earned in the following year and should not be relied upon as a stand-alone indicator of future revenues or net income.

Environmental and Regulatory Risks

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

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

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

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

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

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

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

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

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

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

Existing environmental laws and regulations may be revised and new laws and regulations seeking to protect the environment may be adopted or become applicable to the Company. These laws and regulations could require the Company to limit the use or output of certain facilities; restrict the use of certain fuels; retire and replace certain facilities; install pollution controls; remediate environmental impacts; remove or reduce environmental hazards; or forego or limit the development of resources. Revised or new laws and regulations that increase compliance costs or restrict operations, particularly if costs are not fully recoverable from customers, could have a material adverse effect on the Company's results of operations and cash flows.

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

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

Initiatives to reduce GHG emissions could adversely impact the Company's operations.
Concern that GHG emissions are contributing to global climate change has led to international, federal and state legislative and regulatory proposals to reduce or mitigate the effects of GHG emissions. The Company’s primary GHG emission is carbon dioxide from fossil fuels combustion at Montana-Dakota's electric generating facilities, particularly its coal-fired facilities. Approximately 46 percent of Montana-Dakota's owned generating capacity and approximately 79 percent of the electricity it generated in 2018 was from coal-fired facilities.

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

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

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

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

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

Due to the uncertain availability of technologies to control GHG emissions and the unknown obligations that potential GHG emission legislation or regulations may create, the Company cannot determine the potential financial impact on its operations.

Other Risks

The Company's various businesses are seasonal and subject to weather conditions that can adversely affect the Company's operations, revenues and cash flows.

The Company's results of operations can be affected by changes in the weather. Weather conditions influence the demand for electricity and natural gas and affect the price of energy commodities. Utility operations have historically generated lower revenues when weather conditions are cooler than normal in the summer and warmer than normal in the winter particularly in jurisdictions that do not have decoupling mechanisms in place. Where decoupling mechanism are in place, there is no assurance the Company will continue to receive such regulatory protection from adverse weather in future rates.

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

Competition exists in all of the Company's businesses.

The Company's businesses are subject to competition. Construction services' competition is based primarily on price and reputation for quality, safety and reliability. Construction materials products are marketed under highly competitive conditions and are subject to competitive forces such as price, service, delivery time and proximity to the customer. The electric utility and natural gas industries also experience competitive pressures as a result of consumer demands, technological advances and other factors. The pipeline and midstream business competes with several pipelines for access to natural gas supplies and for gathering, transportation and storage business. New acquisition opportunities are subject to competitive bidding environments which impacts prices the Company must pay to successfully acquire new properties to grow its business. Competition could negatively affect the Company's results of operations, financial position and cash flows.

The Company's operations may be negatively affected if it is unable to obtain, develop and retain key personnel and skilled labor forces.

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

The Company's construction materials and contracting and construction services businesses may be exposed to warranty claims.

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

The Company is a holding company and relies on cash from its subsidiaries to pay dividends.

The Company is a holding company as a result of the Holding Company Reorganization. Its investments in its subsidiaries comprise the Company's primary assets. The Company depends on earnings, cash flows and dividends from its subsidiaries to pay dividends on its common stock. The Company's subsidiaries are separate legal entities that have no obligation to pay any amounts due on its obligations or to make funds available to pay dividends on common stock. Regulatory, contractual and legal limitations, as well as their capital requirements, affect the ability of the subsidiaries to pay dividends to the Company and thereby could restrict or influence the Company's ability or decision to pay dividends on its common stock which could adversely affect the Company's stock price.

Costs related to obligations under MEPPs could have a material negative effect on the Company's results of operations and cash flows.
Various operating subsidiaries of the Company participate in approximately 70 MEPPs for employees represented by certain unions. The Company is required to make contributions to these plans in amounts established under numerous collective bargaining agreements between the operating subsidiaries and those unions.

The Company may be obligated to increase its contributions to underfunded plans that are classified as being in endangered, seriously endangered or critical status as defined by the Pension Protection Act of 2006. Plans classified as being in one of these statuses are required to adopt RPs or FIPs to improve their funded status through increased contributions, reduced benefits or a combination of the two. Based on available information, the Company believes that approximately 30 percent of the MEPPs to which it contributes are currently in endangered, seriously endangered or critical status.

The Company may also be required to increase its contributions to MEPPs if the other participating employers in such plans withdraw from the plans and are not able to contribute amounts sufficient to fund the unfunded liabilities associated with their participation in the plans. The amount and timing of any increase in the Company's required contributions to MEPPs may also depend upon one or more factors including the outcome of collective bargaining; actions taken by trustees who manage the plans; actions taken by the plans' other participating employers; the industry for which contributions are made; future determinations that additional plans reach endangered, seriously endangered or critical status; newly-enacted government law or regulations and the actual return on assets held in the plans; among others. The Company could experience increased operating expenses as a result of required contributions to MEPPs, which could have a material adverse effect on the Company's results of operations, financial position or cash flows.

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

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

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

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

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

The Company's information systems experience on-going and often sophisticated cyber-attacks by a variety of sources with the apparent aim to breach our cyber-defenses. As cyber-attacks continue to increase in frequency and sophistication, the Company may be unable to prevent all such attacks in the future. The Company is continuously reevaluating the need to upgrade and/or replace systems and network infrastructure. These upgrades and/or replacements could adversely impact operations by imposing substantial capital expenditures, creating delays or outages, or experiencing difficulties transitioning to new systems. Systems implementation disruption and any other information technology disruption, if not anticipated and appropriately mitigated, could have an adverse effect on the Company.

Other factors that could impact the Company's businesses.
The following are other factors that should be considered for a better understanding of the risks to the Company. These other factors may materially negatively impact the Company's financial results in future periods.

- Acquisition, disposal and impairments of assets or facilities.
- Changes in operation, performance and construction of plant facilities or other assets.
- Changes in present or prospective generation.
- The availability of economic expansion or development opportunities.
- Population growth rates and demographic patterns.
- Market demand for, available supplies of, and/or costs of, energy- and construction-related products and services.
- The cyclical nature of large construction projects at certain operations.
- Unanticipated project delays or changes in project costs, including related energy costs.
- Unanticipated changes in operating expenses or capital expenditures.
- Labor negotiations or disputes.
- Inability of the contract counterparties to meet their contractual obligations.
- Changes in accounting principles and/or the application of such principles to the Company.
- Changes in technology.
- Changes in legal or regulatory proceedings.
- Losses or costs relating to litigation.
- The inability to effectively integrate the operations and the internal controls of acquired companies.

Item 1B. Unresolved Staff Comments

The Company has no unresolved comments with the SEC.

Item 3. Legal Proceedings

For information regarding legal proceedings required by this item, see Item 8 - Note 19, which is incorporated herein by reference.

Item 4. Mine Safety Disclosures

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

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

The Company's common stock is listed on the New York Stock Exchange under the symbol "MDU."

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

The Company depends on earnings and dividends from its subsidiaries to pay dividends on common stock. The Company has paid quarterly dividends for more than 80 consecutive years with an increase in the payout amount for the last 28 consecutive years. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. For more information on factors that may limit the Company's ability to pay dividends, see Item 8 - Note 11.

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

The following table includes information with respect to the Company's purchase of equity securities:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares (or Units) Purchased (1)	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (2)	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs (2)
October 1 through October 31, 2018	—	—	—	—
November 1 through November 30, 2018	38,605	$26.55	—	—
December 1 through December 31, 2018	—	—	—	—
Total	38,605		—	—

(1) Represents shares of common stock purchased on the open market in connection with annual stock grants made to the Company's non-employee directors.
(2) Not applicable. The Company does not currently have in place any publicly announced plans or programs to purchase equity securities.

Item 6. Selected Financial Data

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

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

** Based on continuing operations.

Item 6. Selected Financial Data (continued)

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

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

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

The Company is organized into five reportable business segments. These business segments include: electric, natural gas distribution, pipeline and midstream, construction materials and contracting, and construction services. The Company's business segments are determined based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The internal reporting of these segments is defined based on the reporting and review process used by the Company's chief executive officer.

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

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

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

Consolidated Earnings Overview

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

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

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

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

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

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

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

Business Segment Financial and Operating Data

Following are key financial and operating data for each of the Company's business segments. Also included are highlights on key growth strategies, projections and certain assumptions for the Company and its subsidiaries and other matters of the Company's business segments. Many of these highlighted points are "forward-looking statements." For more information, see Part I - Forward-Looking Statements. There is no assurance that the Company's projections, including estimates for growth and changes in earnings, will in fact be achieved. Please refer to assumptions contained in this section, as well as the various important factors listed in Item 1A - Risk Factors. Changes in such assumptions and factors could cause actual future results to differ materially from the Company's growth and earnings projections.

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

Electric and Natural Gas Distribution

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

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

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

The ability to grow through acquisitions is subject to significant competition and acquisition premiums. In addition, the ability of the segments to grow their service territory and customer base is affected by the economic environment of the markets served and competition from other energy providers and fuels. The construction of any new electric generating facilities, transmission lines and other service facilities is subject to increasing cost and lead time, extensive permitting procedures, and federal and state legislative and regulatory initiatives, which will likely necessitate increases in electric energy prices.

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

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

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

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

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

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

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

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

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

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

Interest expense: Comparable to the prior year.

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

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

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

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

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

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

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

Interest expense: Comparable to the prior year.

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

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

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

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

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

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

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

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

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

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

Interest expense: Comparable to the prior year.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Pipeline and Midstream

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Income taxes: Comparable to the prior year.

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

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

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

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

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

Construction Materials and Contracting

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

A key element of the Company's long-term strategy for this business is to further expand its market presence in the higher-margin materials business (rock, sand, gravel, liquid asphalt, asphalt concrete, ready-mixed concrete and related products), complementing and expanding on the segment's expertise. The Company's acquisitions in 2018 support this strategy.

As one of the country's largest sand and gravel producers, the segment continues to strategically manage its 1.0 billion tons of aggregate reserves in all its markets, as well as take further advantage of being vertically integrated. The segment's vertical integration allows the segment to manage operations from aggregate mining to final lay-down of concrete and asphalt, with control of and access to permitted aggregate reserves being significant. The Company's aggregate reserves are naturally declining and as a result, the Company seeks acquisition opportunities to replace the reserves. In 2018, the Company's aggregate reserves increased by nearly 50 million tons primarily due to acquisition activity.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Other income: Comparable to the prior year.

Interest expense: Comparable to the prior year.

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

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

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

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

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

Construction Services

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

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

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

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

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

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

Revenues: Comparable to the prior year.

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

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

Other income: Comparable to the prior year.

Interest expense: Comparable to the prior year.

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

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

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

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

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

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

Interest expense: Comparable to the prior year.

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

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

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

Other

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

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

Discontinued Operations

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

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

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

Intersegment Transactions

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

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

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

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

Liquidity and Capital Commitments

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

Cash flows

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

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

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

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

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

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

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

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

Defined benefit pension plans

The Company has noncontributory qualified defined benefit pension plans for certain employees. Plan assets consist of investments in equity and fixed-income securities. Various actuarial assumptions are used in calculating the benefit expense (income) and liability (asset) related to the pension plans. Actuarial assumptions include assumptions about the discount rate and expected return on plan assets. At December 31, 2018, the pension plans' accumulated benefit obligations exceeded these plans' assets by approximately $83.8 million. Pretax pension expense reflected in the Company's Consolidated Statements of Income for the years ended December 31, 2018, 2017 and 2016, was $843,000, $1.7 million and $2.0 million, respectively. The Company's pension expense is currently projected to be less than $1.0 million in 2019. Funding for the pension plans is actuarially determined. The minimum required contributions for the year ended December 31, 2018 were approximately $6.1 million. There were no minimum required contributions for 2017 and 2016. For more information on the Company's pension plans, see Item 8 - Note 16.

Capital expenditures

The Company's capital expenditures from continuing operations for 2016 through 2018 and as anticipated for 2019 through 2021 are summarized in the following table.

	Actual*			Estimated		
	2016	2017	**2018**	2019	2020	2021
	(In millions)					
Capital expenditures:						
Electric	$ 111	$ 109	**$ 186**	$ 104	$ 103	$ 88
Natural gas distribution	126	147	**206**	204	180	158
Pipeline and midstream	35	31	**70**	113	93	204
Construction materials and contracting	38	44	**280**	133	135	127
Construction services	60	19	**25**	25	17	18
Other	2	2	**2**	5	3	3
Total capital expenditures	$ 372	$ 352	**$ 769**	$ 584	$ 531	$ 598

* Capital expenditures for 2018, 2017 and 2016 include noncash transactions such as the issuance of the Company's equity securities in connection with acquisitions, capital expenditure-related accounts payable and AFUDC, totaling $33.4 million, $10.5 million and $(15.8) million, respectively.

The 2018 capital expenditures include the four acquisitions at the construction materials and contracting segment, as discussed in Item 8 - Note 3. The 2018 capital expenditures were funded by internal sources, issuance of long-term debt and issuance of the Company's equity securities. The Company has included in the estimated capital expenditures for 2019 through 2021 the Demicks Lake project, Line Section 22 Expansion project and North Bakken Expansion project, as previously discussed in Business Segment Financial and Operating Data.

Estimated capital expenditures for the years 2019 through 2021 include those for:

- System upgrades
- Routine replacements
- Service extensions
- Routine equipment maintenance and replacements
- Buildings, land and building improvements

- Pipeline, gathering and other midstream projects
- Power generation and transmission opportunities
- Environmental upgrades
- Other growth opportunities

The Company continues to evaluate potential future acquisitions and other growth opportunities that would be incremental to the outlined capital program; however, they are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the estimates in the preceding table. It is anticipated that all of the funds required for capital expenditures for the years 2019 through 2021 will be funded by various sources, including internally generated funds; the Company's credit facilities, as described later; issuance of long-term debt; and issuance of equity securities.

Capital resources

Certain debt instruments of the Company and its subsidiaries, including those discussed later, contain restrictive and financial covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions, all of which the Company and its subsidiaries, as applicable, were in compliance with at December 31, 2018. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued. For more information on the covenants, certain other conditions and cross-default provisions, see Item 8 - Note 8.

The following table summarizes the outstanding revolving credit facilities of the Company and its subsidiaries at December 31, 2018:

Company	Facility		Facility Limit		Amount Outstanding		Letters of Credit		Expiration Date
					(In millions)				
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement	(a)	$ 175.0		$ 48.5		$ —		6/8/23
Cascade Natural Gas Corporation	Revolving credit agreement		$ 75.0	(c)	$ 53.8		$ 2.2	(d)	4/24/20
Intermountain Gas Company	Revolving credit agreement		$ 85.0	(e)	$ 56.3		$ —		4/24/20
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(f)	$ 500.0		$ 289.6	(b)	$ —		9/23/21

(a) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $225.0 million). The amount outstanding under the revolving credit agreement was $48.5 million.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $100.0 million.
(d) Outstanding letter(s) of credit reduce the amount available under the credit agreement.
(e) Certain provisions allow for increased borrowings, up to a maximum of $110.0 million.
(f) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $600.0 million). There were no amounts outstanding under the revolving credit agreement.

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

Total equity as a percent of total capitalization was 55 percent and 59 percent at December 31, 2018 and 2017, respectively. This ratio is calculated as the Company's total equity, divided by the Company's total capital. Total capital is the Company's total debt, including short-term borrowings and long-term debt due within one year, plus total equity. This ratio is an indicator of how the Company is financing its operations, as well as its financial strength.

The following includes information related to the preceding table.

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

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

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

Cascade Cascade's credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Cascade's ratio of total debt to total capitalization as of December 31, 2018, was 51 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

Cascade's credit agreement also contains cross-default provisions. These provisions state that if Cascade fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, Cascade will be in default under the revolving credit agreement.

Intermountain Intermountain's credit agreement contains customary covenants and provisions, including a covenant of Intermountain not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Intermountain's ratio of total debt to total capitalization as of December 31, 2018, was 49 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

Intermountain's credit agreement also contains cross-default provisions. These provisions state that if Intermountain fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, or certain conditions result in an early termination date under any swap contract that is in excess of a specified amount, then Intermountain will be in default under the revolving credit agreement.

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

Prior to the maturity of the Centennial credit agreement, Centennial expects that it will negotiate the extension or replacement of this agreement, which provides credit support to access the capital markets. In the event Centennial is unable to successfully negotiate this agreement, or in the event the fees on this facility become too expensive, which Centennial does not currently anticipate, it would seek alternative funding.

WBI Energy Transmission WBI Energy Transmission has a $200.0 million uncommitted note purchase and private shelf agreement with an expiration date of May 16, 2019. WBI Energy Transmission had $140.0 million of notes outstanding at December 31, 2018, which reduced the remaining capacity under this uncommitted private shelf agreement to $60.0 million.

Off balance sheet arrangements

As of December 31, 2018, the Company had no material off balance sheet arrangements as defined by the rules of the SEC.

Contractual obligations and commercial commitments

For more information on the Company's contractual obligations on long-term debt, operating leases and purchase commitments, see Item 8 - Notes 8 and 19. At December 31, 2018, the Company's commitments under these obligations were as follows:

	Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
			(In millions)		
Long-term debt*	$ 251.9	$ 416.3	$ 273.0	$ 1,173.0	$ 2,114.2
Estimated interest payments**	83.0	153.9	123.6	472.5	833.0
Operating leases	37.7	44.2	18.9	49.1	149.9
Purchase commitments	418.1	384.8	200.1	622.4	1,625.4
	$ 790.7	$ 999.2	$ 615.6	$ 2,317.0	$ 4,722.5

* Unamortized debt issuance costs and discount are excluded from the table.
** Estimated interest payments are calculated based on the applicable rates and payment dates.

At December 31, 2018, the Company had total liabilities of $375.6 million related to asset retirement obligations that are excluded from the table above. Of the total asset retirement obligations, the current portion was $5.0 million at December 31, 2018, and was included in other accrued liabilities on the Consolidated Balance Sheet. The remainder, which constitutes the long-term portion of asset retirement obligations, was included in deferred credits and other liabilities - other on the Consolidated Balance Sheet. Due to the nature of these obligations, the Company cannot determine precisely when the payments will be made to settle these obligations. For more information, see Item 8 - Note 9.

Not reflected in the previous table are $382,000 in uncertain tax positions at December 31, 2018. For more information, see Item 8 - Note 13.

The Company's minimum funding requirements for its defined benefit pension plans for 2019, which are not reflected in the previous table, are $4.0 million. For information on potential contributions above the funding minimum requirements, see item 8 - Note 16.

The Company's MEPP contributions are based on union employee payroll, which cannot be determined in advance for future periods. The Company may also be required to make additional contributions to its MEPPs as a result of their funded status. For more information, see Item 1A - Risk Factors and Item 8 - Note 16.

New Accounting Standards

For information regarding new accounting standards, see Item 8 - Note 1, which is incorporated herein by reference.

Critical Accounting Policies Involving Significant Estimates

The Company has prepared its financial statements in conformity with GAAP. The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities, at the date of the financial statements, as well as the reported amounts of revenues and expenses during the reporting period. The Company's significant accounting policies are discussed in Item 8 - Note 1.

Estimates are used for items such as impairment testing of long-lived assets and goodwill; fair values of acquired assets and liabilities under the acquisition method of accounting; aggregate reserves; property depreciable lives; tax provisions; revenue recognized using the cost-to-cost measure of progress for contracts; uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; and the valuation of stock-based compensation. The Company's critical accounting policies are subject to judgments and uncertainties that affect the application of such policies. As discussed below, the Company's financial position or results of operations may be materially different when reported under different conditions or when using different assumptions in the application of such policies.

As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates. The following critical accounting policies involve significant judgments and estimates.

Impairment of long-lived assets and intangibles

The Company reviews the carrying values of its long-lived assets and intangibles, excluding assets held for sale, whenever events or changes in circumstances indicate that such carrying values may not be recoverable and at least annually for goodwill.

Goodwill The Company performs its goodwill impairment testing annually in the fourth quarter. In addition, the test is performed on an interim basis whenever events or circumstances indicate that the carrying amount of goodwill may not be recoverable. Examples of such events or circumstances may include a significant adverse change in business climate, weakness in an industry in which the Company's reporting units operate or recent significant cash or operating losses with expectations that those losses will continue.

The goodwill impairment test is a two-step process performed at the reporting unit level. The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. For more information on the Company's operating segments, see Item 8 - Note 15. The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. If the fair value of a reporting unit is less than its carrying value, step two of the test is performed to determine the amount of impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2018, 2017 and 2016, there were no impairment losses recorded. At December 31, 2018, the fair value substantially exceeded the carrying value at all reporting units.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the Company's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, risk adjusted cost of capital, operational plans, and current and future economic conditions, among others. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach. Under the income approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the risk adjusted cost of capital at each reporting unit. The risk adjusted cost of capital, which varies by reporting unit and is in the range of 5 percent to 9 percent, and a long-term growth rate projection of approximately 3 percent were utilized in the goodwill impairment test performed in the fourth quarter of 2018. Under the market approach, the Company estimates fair value using multiples derived from enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information.

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

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

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

Business combinations

The Company accounts for acquisitions on the Consolidated Financial Statements starting from the date of the acquisition, which is the date that control is obtained. The acquisition method of accounting requires acquired assets and liabilities assumed be recorded at their respective fair values as of the date of the acquisition. The excess of the purchase price over the fair value of the assets acquired and liabilities assumed is recorded as goodwill. The estimation of fair values of acquired assets and liabilities assumed by the Company requires significant judgment and requires various assumptions. Although independent appraisals may be used to assist in the determination of the fair value of certain assets and liabilities, the appraised values may be based on significant estimates provided by management. The amounts and useful lives assigned to depreciable and amortizable assets compared to amounts assigned to goodwill, which is not amortized, can affect the results of operations in the period of and periods subsequent to a business combination.

In determining fair values of acquired assets and liabilities assumed, the Company uses various observable inputs for similar assets or liabilities in active markets and various unobservable inputs, which includes the use of valuation models. Fair values are based on various factors including, but not limited to, age and condition of property, maintenance records, auction values for equipment with similar characteristics, recent sales and listings of comparable properties, data collected from drill holes and other subsurface investigations and geologic data. The Company primarily uses the market and cost approaches in determining the fair value of land and property, plant and equipment. A combination of the market and income approaches are used for aggregate reserves and intangibles, primarily a discounted cash flow model.

There is a measurement period after the acquisition date during which the Company may adjust the amounts recognized for a business combination. Any such adjustments are recorded in the period the adjustment is determined with the corresponding offset to goodwill. These adjustments are typically based on obtaining additional information that existed at the acquisition date regarding the assets acquired and the liabilities assumed. The measurement period ends once the Company has obtained all necessary information that existed as of the acquisition date, but does not extend beyond one year from the date of the acquisition. Once the measurement period has ended, any adjustments to assets acquired or liabilities assumed are recorded in income from continuing operations.

Revenue recognition

Revenue is recognized to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The recognition of revenue requires the Company to make estimates and assumptions that affect the reported amounts of revenue. The accuracy of revenues reported on the Consolidated Financial Statements depends on, among other things, management's estimates of total costs to complete projects because the Company uses the cost-to-cost measure of progress on construction contracts for revenue recognition.

To determine the proper revenue recognition method for contracts, the Company evaluates whether two or more contracts should be combined and accounted for as one single contract and whether the combined or single contract should be accounted for as more than one performance obligation. This evaluation requires significant judgment and the decision to combine a group of contracts or separate the combined or single contract into multiple performance obligations could change the amount of revenue and profit recorded in a given period. For most contracts, the customer contracts with the Company to provide a significant service of integrating a complex set of tasks and components into a single project. Hence, the Company's contracts are generally accounted for as one performance obligation.

The Company recognizes construction contract revenue over time using the cost-to-cost measure of progress for contracts because it best depicts the transfer of assets to the customer which occurs as the Company incurs costs on the contract. Under the cost-to-cost measure of progress, the costs incurred are compared with total estimated costs of a performance obligation. Revenues are recorded proportionately to the costs incurred. This method depends largely on the ability to make reasonably dependable estimates related to the extent of progress toward completion of the contract, contract revenues and contract costs. Inasmuch as contract prices are generally set before the work is performed, the estimates pertaining to every project could contain significant unknown risks such as volatile labor, material and fuel costs, weather delays, adverse project site conditions, unforeseen actions by regulatory agencies, performance by subcontractors, job management and relations with project owners. Changes in estimates could have a material effect on the Company's results of operations, financial position and cash flows.

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

Contracts are often modified to account for changes in contract specifications and requirements. The Company considers contract modifications to exist when the modification either creates new or changes the existing enforceable rights and obligations. Generally, contract modifications are for goods or services that are not distinct from the existing contract due to the significant integration of services provided in the context of the contract and are accounted for as if they were part of that existing contract. The effect of a contract modification on the transaction price and the measure of progress for the performance obligation to which it relates, is recognized as an adjustment to revenue on a cumulative catch-up basis.

The Company's construction contracts generally contain variable consideration including liquidated damages, performance bonuses or incentives, claims, unapproved/unpriced change orders and penalties or index pricing. The variable amounts usually arise upon achievement of certain performance metrics or change in project scope. The Company estimates the amount of revenue to be recognized on variable consideration using estimation methods that best predict the most likely amount of consideration the Company expects to be entitled to or expects to incur. The Company includes variable consideration in the estimated transaction price to the extent it is probable that a significant reversal of cumulative revenue recognized will not occur or when the uncertainty associated with the variable consideration is resolved. Changes in circumstances could impact management's estimates made in determining the value of variable consideration recorded. The Company updates its estimate of the transaction price each reporting period and the effect of variable consideration on the transaction price is recognized as an adjustment to revenue on a cumulative catch-up basis.

The Company believes its estimates surrounding the cost-to-cost method are reasonable based on the information that is known when the estimates are made. The Company has contract administration, accounting and management control systems in place that allow its estimates to be updated and monitored on a regular basis. Because of the many factors that are evaluated in determining bid prices, it is inherent that the Company's estimates have changed in the past and will continually change in the future as new information becomes available for each job.

Pension and other postretirement benefits

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. Various actuarial assumptions are used in calculating the benefit expense (income) and liability (asset) related to these plans. Costs of providing pension and other postretirement benefits bear the risk of change, as they are dependent upon numerous factors based on assumptions of future conditions.

The Company makes various assumptions when determining plan costs, including the current discount rates and the expected long-term return on plan assets, the rate of compensation increases, actuarially determined mortality data and health care cost trend rates. In selecting the expected long-term return on plan assets, which is considered to be one of the key variables in determining benefit expense or income, the Company considers historical returns, current market conditions and expected future market trends, including changes in interest rates and equity and bond market performance. Another key variable in determining benefit expense or income is the discount rate. In selecting the discount rate, the Company matches forecasted future cash flows of the pension and postretirement plans to a yield curve which consists of a hypothetical portfolio of high-quality corporate bonds with varying maturity dates, as well as other factors, as a basis. The Company's pension and other postretirement benefit plan assets are primarily made up of equity and fixed-income investments. Fluctuations in actual equity and bond market returns, as well as changes in general interest rates, may result in increased or decreased pension and other postretirement benefit costs in the future. Management estimates the rate of compensation increase based on long-term assumed wage increases and the health care cost trend rates are determined by historical and future trends. The Company estimates that a 50 basis point decrease in the discount rate or in the expected return on plan assets would each increase expense by less than $1.5 million (after tax) for the year ended December 31, 2018.

The Company believes the estimates made for its pension and other postretirement benefits are reasonable based on the information that is known when the estimates are made. These estimates and assumptions are subject to a number of variables and are expected to change in the future. Estimates and assumptions will be affected by changes in the discount rate, the expected long-term return on plan assets, the rate of compensation increase and health care cost trend rates. The Company plans to continue to use its current methodologies to determine plan costs. For more information on the assumptions used in determining plan costs, see Item 8 - Note 16.

Income taxes

The Company is required to make judgments regarding the potential tax effects of various financial transactions and ongoing operations to estimate the Company's obligation to taxing authorities. These tax obligations include income, real estate, franchise and sales/use taxes. Judgments related to income taxes require the recognition in the Company's financial statements a tax position that is more-likely-than-not to be sustained on audit.

Judgment and estimation is required in developing the provision for income taxes and the reporting of tax-related assets and liabilities and, if necessary, any valuation allowances. The interpretation of tax laws can involve uncertainty, since tax authorities may interpret such laws differently. Actual income tax could vary from estimated amounts and may result in favorable or unfavorable impacts to net income, cash flows, and tax-related assets and liabilities. In addition, the effective tax rate may be affected by other changes including the allocation of property, payroll and revenues between states.

The Company assesses the deferred tax assets for recoverability taking into consideration historical and anticipated earnings levels; the reversal of other existing temporary differences; available net operating losses and tax carryforwards; and available tax planning strategies that could be implemented to realize the deferred tax assets. Based on this assessment, management must evaluate the need for, and amount of, a valuation allowance against the deferred tax assets. As facts and circumstances change, adjustment to the valuation allowance may be required.

Non-GAAP Financial Measures

The Business Segment Financial and Operating Data includes financial information prepared in accordance with GAAP, as well as another financial measure, adjusted gross margin, that is considered a non-GAAP financial measure as it relates to the Company's electric and natural gas distribution segments. The presentation of adjusted gross margin is intended to be a useful supplemental financial measure for investors' understanding of the segments' operating performance. This non-GAAP financial measure should not be considered as an alternative to, or more meaningful than, GAAP financial measures such as operating income (loss) or earnings (loss). The Company's non-GAAP financial measure, adjusted gross margin, is not standardized; therefore, it may not be possible to compare this financial measure with other companies' gross margin measures having the same or similar names.

In addition to operating revenues and operating expenses, management also uses the non-GAAP financial measure of adjusted gross margin when evaluating the results of operations for the electric and natural gas distribution segments. Adjusted gross margin for the electric and natural gas distribution segments is calculated by adding back adjustments to operating income (loss). These add-back adjustments include: operation and maintenance expense; depreciation, depletion and amortization expense; and certain taxes, other than income.

Adjusted gross margin includes operating revenues less the cost of electric fuel and purchased power, purchased natural gas sold and certain taxes, other than income. These taxes, other than income, included as a reduction to adjusted gross margin relate to revenue taxes. These segments pass on to their customers the increases and decreases in the wholesale cost of power purchases, natural gas and other fuel supply costs in accordance with regulatory requirements. As such, the segments' revenues are directly impacted by the fluctuations in such commodities. Revenue taxes, which are passed back to customers, fluctuate with revenues as they are calculated as a percentage of revenues. For these reasons, period over period, the segments' operating income (loss) is generally not impacted. The Company's management believes the adjusted gross margin is a useful supplemental financial measure as these items are included in both operating revenues and operating expenses. The Company's management also believes that adjusted gross margin and the remaining operating expenses that calculate operating income (loss) are useful in assessing the Company's utility performance as management has the ability to influence control over the remaining operating expenses.

The following information reconciles operating income to adjusted gross margin for the electric segment.

Years ended December 31,	**2018**	2017	2016
		(In millions)	
Operating income	**$ 65.2**	$ 79.9	$ 67.9
Adjustments:			
Operating expenses:			
Operation and maintenance	**123.0**	122.2	115.8
Depreciation, depletion and amortization	**51.0**	47.7	50.2
Taxes, other than income	**14.5**	13.5	12.3
Total adjustments	**188.5**	183.4	178.3
Adjusted gross margin	**$ 253.7**	$ 263.3	$ 246.2

The following information reconciles operating income to adjusted gross margin for the natural gas distribution segment.

Years ended December 31,	**2018**	2017	2016
		(In millions)	
Operating income	**$ 72.3**	$ 84.3	$ 66.2
Adjustments:			
Operating expenses:			
Operation and maintenance	**173.4**	164.3	156.9
Depreciation, depletion and amortization	**72.5**	69.4	65.4
Taxes, other than income	**21.7**	20.5	19.6
Total adjustments	**267.6**	254.2	241.9
Adjusted gross margin	**$ 339.9**	$ 338.5	$ 308.1

Effects of Inflation

Inflation did not have a significant effect on the Company's operations in 2018, 2017 or 2016.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company is exposed to the impact of market fluctuations associated with interest rates. The Company has policies and procedures to assist in controlling these market risks and from time to time has utilized derivatives to manage a portion of its risk.

Interest rate risk

The Company uses fixed and variable rate long-term debt to partially finance capital expenditures and mandatory debt retirements. These debt agreements expose the Company to market risk related to changes in interest rates. The Company manages this risk by taking advantage of market conditions when timing the placement of long-term financing. The Company from time to time has utilized interest rate swap agreements to manage a portion of the Company's interest rate risk and may take advantage of such agreements in the future to minimize such risk. For additional information on the Company's long-term debt, see Item 8 - Notes 7 and 8.

At December 31, 2018 and 2017, the Company had no outstanding interest rate hedges.

The following table shows the amount of long-term debt, which excludes unamortized debt issuance costs and discount, and related weighted average interest rates, both by expected maturity dates, as of December 31, 2018.

	2019	2020	2021	2022	2023	Thereafter	Total	Fair Value
				(Dollars in millions)				
Long-term debt:								
Fixed rate	$ 51.9	$ 15.8	$ .8	$ 147.3	$ 77.2	$ 1,173.0	$ 1,466.0	$ 1,540.9
Weighted average interest rate	4.3%	5.1%	2.2%	4.5%	3.7%	4.7%	4.6%	—
Variable rate	200.0	$ 110.1	$ 289.6	—	$ 48.5	—	$ 648.2	$ 648.2
Weighted average interest rate	2.8%	4.4%	3.1%	—	2.8%	—	3.2%	—

Item 8. Financial Statements and Supplementary Data

Management's Report on Internal Control Over Financial Reporting

The management of MDU Resources Group, Inc. is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. The Company's internal control system is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2018. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework (2013)*.

Based on our evaluation under the framework in *Internal Control-Integrated Framework (2013)*, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2018.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2018, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.

David L. Goodin
President and Chief Executive Officer

Jason L. Vollmer
Vice President, Chief Financial Officer and Treasurer

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of MDU Resources Group, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2018, and the related notes and the financial statement schedules listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 22, 2019, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Deloitte & Touche LLP

Minneapolis, Minnesota
February 22, 2019

We have served as the Company's auditor since 2002.

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of MDU Resources Group, Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2018, based on criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control-Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2018, of the Company and our report dated February 22, 2019, expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Deloitte & Touche LLP

Minneapolis, Minnesota
February 22, 2019

Consolidated Statements of Income

Years ended December 31,	2018	2017	2016
	(In thousands, except per share amounts)		
Operating revenues:			
Electric, natural gas distribution and regulated pipeline and midstream	**$ 1,213,227**	$ 1,244,759	$ 1,141,454
Nonregulated pipeline and midstream, construction materials and contracting, construction services and other	**3,318,325**	3,198,592	2,987,374
Total operating revenues	**4,531,552**	4,443,351	4,128,828
Operating expenses:			
Operation and maintenance:			
Electric, natural gas distribution and regulated pipeline and midstream	**340,331**	326,687	312,211
Nonregulated pipeline and midstream, construction materials and contracting, construction services and other	**2,915,790**	2,808,779	2,581,299
Total operation and maintenance	**3,256,121**	3,135,466	2,893,510
Purchased natural gas sold	**404,153**	430,954	382,753
Depreciation, depletion and amortization	**220,205**	207,486	216,318
Taxes, other than income	**168,638**	166,673	151,826
Electric fuel and purchased power	**80,712**	78,724	75,512
Total operating expenses	**4,129,829**	4,019,303	3,719,919
Operating income	**401,723**	424,048	408,909
Other income (expense)	**(238)**	8,767	5,167
Interest expense	**84,614**	82,788	87,848
Income before income taxes	**316,871**	350,027	326,228
Income taxes	**47,485**	65,041	93,132
Income from continuing operations	**269,386**	284,986	233,096
Income (loss) from discontinued operations, net of tax (Note 4)	**2,932**	(3,783)	(300,354)
Net income (loss)	**272,318**	281,203	(67,258)
Loss from discontinued operations attributable to noncontrolling interest (Note 4)	**—**	—	(131,691)
Loss on redemption of preferred stocks (Note 10)	**—**	600	—
Dividends declared on preferred stocks	**—**	171	685
Earnings on common stock	**$ 272,318**	$ 280,432	$ 63,748
Earnings per common share - basic:			
Earnings before discontinued operations	**$ 1.38**	$ 1.46	$ 1.19
Discontinued operations attributable to the Company, net of tax	**.01**	(.02)	(.86)
Earnings per common share - basic	**$ 1.39**	$ 1.44	$ .33
Earnings per common share - diluted:			
Earnings before discontinued operations	**$ 1.38**	$ 1.45	$ 1.19
Discontinued operations attributable to the Company, net of tax	**.01**	(.02)	(.86)
Earnings per common share - diluted	**$ 1.39**	$ 1.43	$ .33
Weighted average common shares outstanding - basic	**195,720**	195,304	195,299
Weighted average common shares outstanding - diluted	**196,150**	195,687	195,618

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

Consolidated Statements of Comprehensive Income

Years ended December 31,	2018	2017	2016
		(In thousands)	
Net income (loss)	**$ 272,318**	$ 281,203	$ (67,258)
Other comprehensive income (loss):			
Reclassification adjustment for loss on derivative instruments included in net income (loss), net of tax of $429, $224 and $226 in 2018, 2017 and 2016, respectively	**162**	366	367
Postretirement liability adjustment:			
Postretirement liability gains (losses) arising during the period, net of tax of $1,471, $(1,162) and $(836) in 2018, 2017 and 2016, respectively	**4,441**	(1,812)	(1,470)
Amortization of postretirement liability losses included in net periodic benefit cost (credit), net of tax of $721, $645 and $1,425 in 2018, 2017 and 2016, respectively	**2,173**	1,013	2,506
Reclassification of postretirement liability adjustment from regulatory asset, net of tax of $0, $(876) and $0 in 2018, 2017 and 2016, respectively	**—**	(1,143)	—
Postretirement liability adjustment	**6,614**	(1,942)	1,036
Foreign currency translation adjustment:			
Foreign currency translation adjustment recognized during the period, net of tax of $(14), $(3) and $31 in 2018, 2017 and 2016, respectively	**(61)**	(6)	51
Reclassification adjustment for foreign currency translation adjustment included in net income (loss), net of tax of $75, $0 and $0 in 2018, 2017 and 2016, respectively	**249**	—	—
Foreign currency translation adjustment	**188**	(6)	51
Net unrealized loss on available-for-sale investments:			
Net unrealized loss on available-for-sale investments arising during the period, net of tax of $(38), $(75) and $(98) in 2018, 2017 and 2016, respectively	**(144)**	(139)	(182)
Reclassification adjustment for loss on available-for-sale investments included in net income (loss), net of tax of $35, $65 and $77 in 2018, 2017 and 2016, respectively	**131**	120	143
Net unrealized loss on available-for-sale investments	**(13)**	(19)	(39)
Other comprehensive income (loss)	**6,951**	(1,601)	1,415
Comprehensive income (loss)	**279,269**	279,602	(65,843)
Comprehensive loss from discontinued operations attributable to noncontrolling interest	**—**	—	(131,691)
Comprehensive income attributable to common stockholders	**$ 279,269**	$ 279,602	$ 65,848

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

Consolidated Balance Sheets

December 31,	2018	2017
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	**$ 53,948**	$ 34,599
Receivables, net	**722,945**	727,030
Inventories	**287,309**	226,583
Prepayments and other current assets	**119,500**	81,304
Current assets held for sale	**430**	479
Total current assets	**1,184,132**	1,069,995
Investments	**138,620**	137,613
Property, plant and equipment (Note 1)	**7,397,321**	6,770,829
Less accumulated depreciation, depletion and amortization	**2,818,644**	2,691,641
Net property, plant and equipment	**4,578,677**	4,079,188
Deferred charges and other assets:		
Goodwill (Note 5)	**664,922**	631,791
Other intangible assets, net (Note 5)	**10,815**	3,837
Other	**408,857**	407,850
Noncurrent assets held for sale	**2,087**	4,392
Total deferred charges and other assets	**1,086,681**	1,047,870
Total assets	**$ 6,988,110**	$ 6,334,666
Liabilities and Stockholders' Equity		
Current liabilities:		
Long-term debt due within one year	**$ 251,854**	$ 148,499
Accounts payable	**358,505**	312,327
Taxes payable	**41,929**	42,537
Dividends payable	**39,695**	38,573
Accrued compensation	**69,007**	72,919
Other accrued liabilities	**221,059**	186,010
Current liabilities held for sale	**4,001**	11,993
Total current liabilities	**986,050**	812,858
Long-term debt (Note 8)	**1,856,841**	1,566,354
Deferred credits and other liabilities:		
Deferred income taxes	**430,085**	347,271
Other	**1,148,359**	1,179,140
Total deferred credits and other liabilities	**1,578,444**	1,526,411
Commitments and contingencies (Notes 16, 18 and 19)		
Stockholders' equity:		
Common stock (Note 11)		
Authorized - 500,000,000 shares, $1.00 par value Issued - 196,564,907 shares in 2018 and 195,843,297 shares in 2017	**196,565**	195,843
Other paid-in capital	**1,248,576**	1,233,412
Retained earnings	**1,163,602**	1,040,748
Accumulated other comprehensive loss	**(38,342)**	(37,334)
Treasury stock at cost - 538,921 shares	**(3,626)**	(3,626)
Total stockholders' equity	**2,566,775**	2,429,043
Total liabilities and stockholders' equity	**$ 6,988,110**	$ 6,334,666

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

Consolidated Statements of Equity

Years ended December 31, 2018, 2017 and 2016

	Preferred Stock		Common Stock				Accumulated Other Comprehensive Loss	Treasury Stock			
	Shares	Amount	Shares	Amount	Other Paid-in Capital	Retained Earnings		Shares	Amount	Noncontrolling Interest	Total
	(In thousands, except shares)										
At December 31, 2015	150,000	$15,000	195,804,665	$195,805	$1,230,119	$ 996,355	$(37,148)	(538,921)	$(3,626)	$124,043	$2,520,548
Net income (loss)	—	—	—	—	—	64,433	—	—	—	(131,691)	(67,258)
Other comprehensive income	—	—	—	—	—	—	1,415	—	—	—	1,415
Dividends declared on preferred stocks	—	—	—	—	—	(685)	—	—	—	—	(685)
Dividends declared on common stock	—	—	—	—	—	(147,821)	—	—	—	—	(147,821)
Stock-based compensation	—	—	—	—	4,383	—	—	—	—	—	4,383
Net tax deficit on stock-based compensation	—	—	—	—	(1,663)	—	—	—	—	—	(1,663)
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	—	—	38,632	38	(361)	—	—	—	—	—	(323)
Contribution from noncontrolling interest	—	—	—	—	—	—	—	—	—	7,648	7,648
At December 31, 2016	150,000	15,000	195,843,297	195,843	1,232,478	912,282	(35,733)	(538,921)	(3,626)	—	2,316,244
Net income	—	—	—	—	—	281,203	—	—	—	—	281,203
Other comprehensive loss	—	—	—	—	—	—	(1,601)	—	—	—	(1,601)
Dividends declared on preferred stocks	—	—	—	—	—	(171)	—	—	—	—	(171)
Dividends declared on common stock	—	—	—	—	—	(151,966)	—	—	—	—	(151,966)
Stock-based compensation	—	—	—	—	3,375	—	—	—	—	—	3,375
Repurchase of common stock	—	—	—	—	—	—	—	(64,384)	(1,684)		(1,684)
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	—	—	—	—	(2,441)	—	—	64,384	1,684	—	(757)
Redemption of preferred stock	(150,000)	(15,000)	—	—	—	(600)	—	—	—	—	(15,600)
At December 31, 2017	—	—	195,843,297	195,843	1,233,412	1,040,748	(37,334)	(538,921)	(3,626)	—	2,429,043
Cumulative effect of adoption of ASU 2014-09	—	—	—	—	—	(970)	—	—	—	—	(970)
Adjusted balance at January 1, 2018	—	—	195,843,297	195,843	1,233,412	1,039,778	(37,334)	(538,921)	(3,626)	—	2,428,073
Net income	—	—	—	—	—	272,318	—	—	—	—	272,318
Other comprehensive income	—	—	—	—	—	—	6,951	—	—	—	6,951
Reclassification of certain prior period tax effects from accumulated other comprehensive loss	—	—	—	—	—	7,959	(7,959)	—	—	—	—
Dividends declared on common stock	—	—	—	—	—	(156,453)	—	—	—	—	(156,453)
Stock-based compensation	—	—	—	—	5,060	—	—	—	—	—	5,060
Repurchase of common stock	—	—	—	—	—	—	—	(182,424)	(5,020)	—	(5,020)
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	—	—	—	—	(7,350)	—	—	182,424	5,020	—	(2,330)
Issuance of common stock	—	—	721,610	722	17,454	—	—	—	—	—	18,176
At December 31, 2018	**—**	**$ —**	**196,564,907**	**$ 196,565**	**$ 1,248,576**	**$ 1,163,602**	**$ (38,342)**	**(538,921)**	**$ (3,626)**	**$ —**	**$ 2,566,775**

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

Consolidated Statements of Cash Flows

Years ended December 31,	2018	2017	2016
		(In thousands)	
Operating activities:			
Net income (loss)	$ **272,318**	$ 281,203	$ (67,258)
Income (loss) from discontinued operations, net of tax	**2,932**	(3,783)	(300,354)
Income from continuing operations	**269,386**	284,986	233,096
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	**220,205**	207,486	216,318
Deferred income taxes	**59,735**	(25,423)	(2,049)
Changes in current assets and liabilities, net of acquisitions:			
Receivables	**28,234**	(108,255)	(25,641)
Inventories	**(46,796)**	9,135	2,433
Other current assets	**(31,814)**	(30,588)	(17,925)
Accounts payable	**21,109**	26,013	7,039
Other current liabilities	**22,285**	4,648	36,146
Other noncurrent changes	**(38,521)**	(18,790)	(26,459)
Net cash provided by continuing operations	**503,823**	349,212	422,958
Net cash provided by (used in) discontinued operations	**(3,942)**	98,799	39,251
Net cash provided by operating activities	**499,881**	448,011	462,209
Investing activities:			
Capital expenditures	**(568,230)**	(341,382)	(388,183)
Acquisitions, net of cash acquired	**(167,692)**	—	—
Net proceeds from sale or disposition of property and other	**26,100**	126,588	44,826
Investments	**(2,321)**	(1,608)	(1,396)
Net cash used in continuing operations	**(712,143)**	(216,402)	(344,753)
Net cash provided by discontinued operations	**1,236**	2,234	39,658
Net cash used in investing activities	**(710,907)**	(214,168)	(305,095)
Financing activities:			
Issuance of long-term debt	**566,829**	140,812	309,064
Repayment of long-term debt	**(174,520)**	(217,394)	(315,647)
Payments of stock issuance costs	**(10)**	—	—
Dividends paid	**(154,573)**	(150,727)	(147,156)
Redemption of preferred stock	**—**	(15,600)	—
Repurchase of common stock	**(5,020)**	(1,684)	—
Tax withholding on stock-based compensation	**(2,330)**	(757)	(323)
Net cash provided by (used in) continuing operations	**230,376**	(245,350)	(154,062)
Net cash used in discontinued operations	**—**	—	(40,852)
Net cash provided by (used in) financing activities	**230,376**	(245,350)	(194,914)
Effect of exchange rate changes on cash and cash equivalents	**(1)**	(1)	4
Increase (decrease) in cash and cash equivalents	**19,349**	(11,508)	(37,796)
Cash and cash equivalents - beginning of year	**34,599**	46,107	83,903
Cash and cash equivalents - end of year	$ **53,948**	$ 34,599	$ 46,107

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

Notes to Consolidated Financial Statements

Note 1 - Summary of Significant Accounting Policies

Basis of presentation

The abbreviations and acronyms used throughout are defined following the Notes to Consolidated Financial Statements. The consolidated financial statements of the Company include the accounts of the following businesses: electric, natural gas distribution, pipeline and midstream, construction materials and contracting, construction services and other. The electric and natural gas distribution businesses, as well as a portion of the pipeline and midstream business, are regulated. Construction materials and contracting, construction services and the other businesses, as well as a portion of the pipeline and midstream business, are nonregulated. For further descriptions of the Company's businesses, see Note 15. Intercompany balances and transactions have been eliminated in consolidation, except for certain transactions related to the Company's regulated operations in accordance with GAAP. The statements also include the ownership interests in the assets, liabilities and expenses of jointly owned electric generating facilities.

The Company's regulated businesses are subject to various state and federal agency regulations. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the FERC. These accounting policies differ in some respects from those used by the Company's nonregulated businesses.

The Company's regulated businesses account for certain income and expense items under the provisions of regulatory accounting, which requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 6 for more information regarding the nature and amounts of these regulatory deferrals.

Depreciation, depletion and amortization expense is reported separately on the Consolidated Statements of Income and therefore is excluded from the other line items within operating expenses.

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

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

Due to the enactment of the TCJA, the regulated jurisdictions in which the Company's regulated businesses provide service requested the Company furnish plans for the effect of the reduced corporate tax rate, which impacted the Company's rates to customers. Therefore, the Company reserved for such impacts as an offset to revenue or passed back to customers through lower rates in certain jurisdictions. For more information on the details and statuses of the open requests, see Note 18.

Effective January 1, 2018, the Company adopted the requirements of the accounting standard update on revenue from contracts with customers following the modified retrospective method, as further discussed in this note, as well as in Note 2. As such, results for reporting periods beginning January 1, 2018, are presented under the new guidance, while prior period amounts are not adjusted and continue to be reported in accordance with the historic accounting for revenue recognition. Based on the Company's analysis, the Company did not identify a significant change in the timing of revenue recognition under the new guidance as compared to the historic accounting for revenue recognition.

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

The assets and liabilities for the Company's discontinued operations have been classified as held for sale and the results of operations are shown in income (loss) from discontinued operations, other than certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. At the time the assets were classified as held for sale, depreciation, depletion and amortization expense was no longer recorded. Unless otherwise indicated, the amounts presented in the accompanying notes to the consolidated financial statements relate to the Company's continuing operations. For more information on the Company's discontinued operations, see Note 4.

Management has also evaluated the impact of events occurring after December 31, 2018, up to the date of issuance of these consolidated financial statements.

Cash and cash equivalents

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

Accounts receivable and allowance for doubtful accounts

Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts, and costs and estimated earnings in excess of billings on uncompleted contracts. For more information, see Note 2. The total balance of receivables past due 90 days or more was $30.0 million and $34.7 million at December 31, 2018 and 2017, respectively.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts at December 31, 2018 and 2017, was $8.9 million and $8.1 million, respectively.

Accounts receivable also consists of accrued unbilled revenue representing revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota, Cascade and Intermountain was $96.2 million and $112.7 million at December 31, 2018 and 2017, respectively.

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

	2018	2017
	(In thousands)	
Short-term retainage*	**$ 56,228**	$ 57,134
Long-term retainage**	**4,152**	1,410
Total retainage	**$ 60,380**	$ 58,544

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

Inventories and natural gas in storage

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

	2018	2017
	(In thousands)	
Aggregates held for resale	**$ 139,681**	$ 115,268
Asphalt oil	**54,741**	30,360
Materials and supplies	**23,611**	18,650
Merchandise for resale	**22,552**	14,905
Natural gas in storage (current)	**22,117**	20,950
Other	**24,607**	26,450
Total	**$ 287,309**	$ 226,583

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was included in deferred charges and other assets - other and was $48.5 million and $49.3 million at December 31, 2018 and 2017, respectively.

Investments

The Company's investments include the cash surrender value of life insurance policies, an insurance contract, mortgage-backed securities and U.S. Treasury securities. The Company measures its investment in the insurance contract at fair value with any unrealized gains and losses recorded on the Consolidated Statements of Income. The Company has not elected the fair value option for its mortgage-backed securities and U.S. Treasury securities and, as a result, the unrealized gains and losses on these investments are recorded in accumulated other comprehensive income (loss). For more information, see Notes 7 and 16.

Property, plant and equipment

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

	2018	2017	2016
	(In thousands)		
AFUDC - borrowed	**$ 2,290**	$ 966	$ 914
AFUDC - equity	**$ 1,897**	$ 909	$ 565

Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable aggregate reserves, which are depleted based on the units-of-production method. The Company collects removal costs for plant assets in regulated utility rates. These amounts are recorded as regulatory liabilities, which are included in deferred credits and other liabilities - other.

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

	2018	2017	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	**$ 1,131,484**	$ 1,034,765	49
Distribution	**430,750**	415,543	46
Transmission	**302,315**	296,941	64
Construction in progress	**161,893**	117,906	—
Other	**122,127**	117,109	13
Natural gas distribution:			
Distribution	**1,981,356**	1,831,795	47
Construction in progress	**21,028**	19,823	—
Other	**496,708**	468,227	16
Pipeline and midstream:			
Transmission	**585,594**	516,932	54
Gathering	**37,829**	37,837	20
Storage	**49,101**	45,629	61
Construction in progress	**5,915**	17,488	—
Other	**45,763**	41,054	33
Nonregulated:			
Pipeline and midstream:			
Gathering and processing	**31,094**	31,678	19
Construction in progress	**86**	17	—
Other	**9,577**	9,649	10
Construction materials and contracting:			
Land	**109,541**	95,745	—
Buildings and improvements	**114,905**	102,435	20
Machinery, vehicles and equipment	**1,090,790**	947,979	12
Construction in progress	**22,507**	7,750	—
Aggregate reserves	**430,263**	406,139	*
Construction services:			
Land	**5,216**	5,216	—
Buildings and improvements	**29,795**	27,351	25
Machinery, vehicles and equipment	**145,859**	137,924	6
Other	**7,716**	6,774	3
Other:			
Land	**2,648**	2,837	—
Other	**25,461**	28,286	14
Less accumulated depreciation, depletion and amortization	**2,818,644**	2,691,641	
Net property, plant and equipment	**$ 4,578,677**	$ 4,079,188	

* Depleted on the units-of-production method based on recoverable aggregate reserves.

Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill and assets held for sale, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. The impairments are recorded in operation and maintenance expense on the Consolidated Statements of Income.

No significant impairment losses were recorded in 2018, 2017 or 2016, other than those related to the Company's assets held for sale and discontinued operations recorded in 2016. For more information regarding these impairments, see Note 4.

Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Goodwill

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

The goodwill impairment test is a two-step process performed at the reporting unit level. The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. For more information on the Company's operating segments, see Note 15. The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. If the fair value of a reporting unit is less than its carrying value, step two of the test is performed to determine the amount of impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2018, 2017 and 2016, there were no impairment losses recorded. At December 31, 2018, the fair value substantially exceeded the carrying value at all reporting units.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the Company's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, risk adjusted cost of capital, operational plans, and current and future economic conditions, among others. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach. Under the income approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the risk adjusted cost of capital at each reporting unit. The risk adjusted cost of capital, which varies by reporting unit and is in the range of 5 percent to 9 percent, and a long-term growth rate projection of approximately 3 percent were utilized in the goodwill impairment test performed in the fourth quarter of 2018. Under the market approach, the Company estimates fair value using multiples derived from enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information.

Revenue recognition

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

The electric and natural gas distribution segments generate revenue from the sales of electric and natural gas products and services, which includes retail and transportation services. These segments establish a customer's retail or transportation service account based on the customer's application/contract for service, which indicates approval of a contract for service. The contract identifies an obligation to provide service in exchange for delivering or standing ready to deliver the identified commodity; and the customer is obligated to pay for the service as provided in the applicable tariff. The product sales are based on a fixed rate that includes a base and per-unit rate, which are included in approved tariffs as determined by state or federal regulatory agencies. The quantity of the commodity consumed or transported determines the total per-unit revenue. The service provided, along with the product consumed or transported, are a single performance obligation because both are required in combination to successfully transfer the contracted product or service to the customer. Revenues are recognized over time as customers receive and consume the products and services. The method of measuring progress toward the completion of the single performance obligation is on a per-unit output method basis, with revenue recognized based on the direct measurement of the value to the customer of the goods or services transferred to date. For contracts governed by the 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 segment has no material obligations for returns, refunds or other similar obligations.

The pipeline and midstream segment generates revenue from providing natural gas transportation, gathering and underground storage services, as well as other energy-related services to both third parties and internal customers, largely the natural gas distribution segment. The pipeline and midstream segment establishes a contract with a customer based upon the customer's request for firm or interruptible natural gas transportation, storage or gathering service(s). The contract identifies an obligation for the segment to provide the requested service(s) in exchange for consideration from the customer over a specified term. Depending on the type of service(s) requested and contracted, the service provided may include transporting, gathering or storing an identified quantity of natural gas and/or standing ready to deliver or store an identified quantity of natural gas. Natural gas transportation, gathering and storage revenues are based on fixed rates, which may include reservation fees and/or per-unit commodity rates. The services provided by the segment are generally treated as single performance obligations satisfied over time simultaneous to when the service is provided and revenue is recognized. Rates for the segment's regulated services are based on its FERC approved tariff or customer negotiated rates on special projects, and rates for its non-regulated services are negotiated with its customers and set forth in the contract. For contracts governed by the company's tariff, amounts are billed on or before the ninth business day of the following month and the amount is due within 12 days of receipt of the invoice. For gathering contracts not governed by the tariff, amounts are due within twenty days of invoice receipt. For other contracts not governed by the tariff, payment terms are net 30 days. At this time, the segment has no material obligations for returns, refunds or other similar obligations.

The construction materials and contracting segment generates revenue from contracting services and construction materials sales. This segment focuses on the vertical integration of its contracting services with its construction materials to support the aggregate based product lines. This segment provides contracting services to a customer when a contract has been signed by both the customer and a representative of the segment obligating a service to be provided in exchange for the consideration identified in the contract. The nature of the services this segment provides generally includes integrating a set of services and related construction materials into a single project to create a distinct bundle of goods and services, which the Company evaluates to determine whether a separate performance obligation exists. The transaction price is the original contract price plus any subsequent change orders and variable consideration. Examples of variable consideration that exist in this segment's contracts include liquidated damages; performance bonuses or incentives and penalties; claims; unapproved/unpriced change orders; and index pricing. The variable amounts usually arise upon achievement of certain performance metrics or change in project scope. The Company estimates the amount of revenue to be recognized on variable consideration using estimation methods that best predict the most likely amount of consideration the Company expects to be entitled to or expects to incur. The Company includes variable consideration in the estimated transaction price to the extent it is probable that a significant reversal of cumulative revenue recognized will not occur or when the uncertainty associated with the variable consideration is resolved. Changes in circumstances could impact management's estimates made in determining the value of variable consideration recorded. The Company updates its estimate of the transaction price each reporting period and the effect of variable consideration on the transaction price is recognized as an adjustment to revenue on a cumulative catch-up basis. Revenue is recognized over time using the input method based on the measurement of progress on a project. The input method is the preferred method of measuring revenue because the costs incurred have been determined to represent the best indication of the overall progress toward the transfer of such goods or services promised to a customer. This segment also sells construction materials to third parties and internal customers. The contract for material sales is the use of a sales order or an invoice, which includes the pricing and payment terms. All material contracts contain a single performance obligation for the delivery of a single distinct product or a distinct separately identifiable bundle of products and services. Revenue is recognized at a point in time when the performance obligation has been satisfied with the delivery of the products or services. The warranties associated with the sales are those consistent with a standard warranty that the product meets certain specifications for quality or those required by law. For most contracts, amounts billed to customers are due within 30 days of receipt. There are no material obligations for returns, refunds or other similar obligations.

The construction services segment generates revenue from specialty contracting services which also includes the sale of construction equipment and other supplies. This segment provides specialty contracting services to a customer when a contract has been signed by both the customer and a representative of the segment obligating a service to be provided in exchange for the consideration identified in the contract. The nature of the services this segment provides generally includes multiple promised goods and services in a single project to create a distinct bundle of goods and services, which the Company evaluates to determine whether a separate performance obligation exists. The transaction price is the original contract price plus any subsequent change orders and variable consideration. Examples of variable consideration that exist in this segment's contracts include claims, unapproved/unpriced change orders, bonuses, incentives, penalties and liquidated damages. The variable amounts usually arise upon achievement of certain performance metrics or change in project scope. The Company estimates the amount of revenue to be recognized on variable consideration using estimation methods that best predict the most likely amount of consideration the Company expects to be entitled to or expects to incur. The Company includes variable consideration in the estimated transaction price to the extent it is probable that a significant reversal of cumulative revenue recognized will not occur or when the uncertainty associated with the variable consideration is resolved. Changes in circumstances could impact management's estimates made in determining the value of variable consideration recorded. The Company updates its estimate of the transaction price each reporting period and the effect of variable consideration on the transaction price is recognized as an adjustment to revenue on a cumulative catch-up basis. Revenue is recognized over time using the input method based on the measurement of progress on a project. The input method is the preferred method of measuring revenue because the costs incurred have been determined to represent the best indication of the overall progress toward the transfer of such goods or services promised to a customer. This segment also sells construction equipment and other supplies to third parties and internal customers. The contract for these sales is the use of a sales order or invoice, which includes the pricing and payment terms. All such contracts include a single performance obligation for the delivery of a single distinct product or a distinct separately identifiable bundle of products and services. Revenue is recognized at a point in time when the performance obligation has been satisfied with the delivery of the products or services. The warranties associated with the sales are those consistent with a standard warranty that the product meets certain specifications for quality or those required by law. For most contracts, amounts billed to customers are due within 30 days of receipt. There are no material obligations for returns, refunds or other similar obligations.

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

Asset retirement obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company either settles the obligation for the recorded amount or incurs a gain or loss at its nonregulated operations or incurs a regulatory asset or liability at its regulated operations. For more information on asset retirement obligations, see Note 9.

Legal costs

The Company expenses external legal fees as they are incurred.

Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments which are filed annually. Natural gas costs refundable through rate adjustments were $30.0 million and $28.5 million at December 31, 2018 and 2017, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $42.7 million and $14.5 million at December 31, 2018 and 2017, respectively, which is included in prepayments and other current assets.

Stock-based compensation

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

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

Income taxes

The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities by using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. Excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as a regulatory liability and are included in other liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

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

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

Earnings per common share

Basic earnings per common share were computed by dividing earnings on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of nonvested performance share awards and restricted stock units. Common stock outstanding includes issued shares less shares held in treasury. Earnings on common stock was the same for both the basic and diluted earnings per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings per share calculation was as follows:

	2018	2017	2016
		(In thousands)	
Weighted average common shares outstanding - basic	**195,720**	195,304	195,299
Effect of dilutive performance share awards	**430**	383	319
Weighted average common shares outstanding - diluted	**196,150**	195,687	195,618
Shares excluded from the calculation of diluted earnings per share	**10**	—	—

Use of estimates

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

New accounting standards

Recently adopted accounting standards

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

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

Under the modified retrospective approach, the guidance was applied only to contracts that were not completed as of January 1, 2018. Therefore, the Company recognized the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings at January 1, 2018. For the twelve months ended December 31, 2018, there were no material impacts to the financial statements as a result of applying the guidance. The cumulative effect of the changes made to the Consolidated Balance Sheet were as follows:

	December 31, 2017	Adjustments	January 1, 2018
		(In thousands)	
Liabilities and Stockholders' Equity			
Current liabilities:			
Other accrued liabilities	$ 186,010	$ 903	$ 186,913
Deferred credits and other liabilities:			
Deferred income taxes	347,271	(332)	346,939
Other	1,179,140	399	1,179,539
Commitments and contingencies			
Stockholders' equity:			
Common stockholders' equity:			
Retained earnings	1,040,748	(970)	1,039,778

The cumulative effect adjustment is related to prepaid natural gas transportation to storage contracts where a separate performance obligation existed and has not yet been satisfied. As such, these contracts were still open and met the criteria for a cumulative effect adjustment.

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

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

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

The Company adopted the guidance on January 1, 2018, on a retrospective basis. The guidance required the reclassification of all components of net periodic benefit costs, except for the service cost component, from operating expenses to other income on the Consolidated Statements of Income with no impact to earnings. As a result of the retrospective application of this change in accounting guidance, the Company reclassified $6.2 million and $4.5 million from operation and maintenance expense to other income on the Consolidated Statements of Income for the years ended December 31, 2017 and 2016, respectively. The Company also reclassified unrealized gains on investments used to satisfy obligations under the defined benefit plans of $10.8 million and $4.7 million for the years ended December 31, 2017 and 2016, respectively, which were included in operation and maintenance expense, to other income on the Consolidated Statements of Income. The guidance did not have a material effect on the Company's results of operations, cash flows or disclosures.

ASU 2018-02 - Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income In February 2018, the FASB issued guidance that allows an entity to reclassify the stranded tax effects resulting from the newly enacted federal corporate income tax rate from accumulated other comprehensive income (loss) to retained earnings. The guidance is effective for the Company on January 1, 2019, including interim periods, with early adoption permitted. The guidance can be applied using one of two methods. One method is to record the reclassification of the stranded income taxes at the beginning of the period of adoption. The other method is to apply the guidance retrospectively to each period in which the income tax effects of the TCJA are recognized in accumulated other comprehensive income (loss). The Company early adopted the guidance on January 1, 2018, and elected to reclassify the stranded income taxes at the beginning of the period. During the first quarter of 2018, the Company reclassified $7.9 million of stranded tax expense from accumulated other comprehensive loss to retained earnings. The guidance did not have a material effect on the Company's results of operations, cash flows or disclosures.

SEC File Number S7-15-16 - Disclosure Update and Simplification In October 2018, the SEC published guidance in the Federal Register on disclosure updates and simplifications. The guidance removed disclosures that are no longer considered cost beneficial, duplicative of GAAP required disclosures, clarified the specific requirements of disclosures and added disclosure requirements identified as relevant. The amendments were intended to facilitate disclosure of information to investors and simplify the compliance without significantly altering the total mix of information provided to investors. The guidance was effective for the Company on November 5, 2018, including interim periods. The Company adopted the guidance in the Annual Report on Form 10-K for the year ended December 31, 2018, which required minimal disclosure updates. The guidance was applied on a prospective basis and did not have a material effect on the Company's disclosures or certain sections of the Annual Report on Form 10-K.

Recently issued accounting standards not yet adopted

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

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

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

The Company formed a lease implementation team to review and assess existing contracts to identify and evaluate those containing leases. Additionally, the team has implemented new and revised existing software to meet the reporting and disclosure requirements of the standard. The Company also has assessed the impact the standard will have on its processes and internal controls and has identified new and updated existing internal controls and processes to ensure compliance with the new lease standard; such modifications were not deemed to be significant. During the assessment phase, the Company used various surveys, reconciliations and analytic methodologies to ensure the completeness of the lease inventory. The Company determined that most of the current operating leases are subject to the guidance and will be recognized as operating lease liabilities and right-of-use assets on the Consolidated Balance Sheets upon adoption. The Company expects the impact of the lessee guidance to be approximately $105 million to $125 million of an increase to assets and liabilities on January 1, 2019. In addition, the Company has evaluated the impact the new guidance will have on lease contracts where the Company is the lessor and does not anticipate a significant impact.

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

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

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

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

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

SEC Final Rulemaking Release Number 33-10570 - Modernization of Property Disclosures for Mining Registrants In November 2018, the SEC published guidance in the Federal Register on the modernization of property disclosures for mining registrants. The guidance requires additional disclosures related to activities under material mining operations to be included as an exhibit, including a technical report summary by a qualified person about an organization's mineral resources or mineral reserves; an overview of mining properties and operations; a summary of all mineral resources and mineral reserves as of the most recently completed fiscal year; a description of each material property, including the proposed program of exploration and development, stage of the development or production, and current production activities, among other things; and a description of the organization's internal controls surrounding mineral resource and reserve estimates. The guidance will be effective on a prospective basis for the Company on January 1, 2021, including interim periods, with early adoption permitted. The Company is evaluating the effects the adoption of the guidance will have on its disclosures in the Annual Report on Form 10-K.

Variable interest entities

The Company evaluates its arrangements and contracts with other entities to determine if they are VIEs and if so, if the Company is the primary beneficiary. GAAP provides a framework for identifying VIEs and determining when a company should include the assets, liabilities, noncontrolling interest and results of activities of a VIE in its consolidated financial statements.

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

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

Comprehensive income (loss)

Comprehensive income (loss) is the sum of net income (loss) as reported and other comprehensive income (loss). The Company's other comprehensive income (loss) resulted from losses on derivative instruments qualifying as hedges, postretirement liability adjustments, foreign currency translation adjustments and loss on available-for-sale investments.

The after-tax changes in the components of accumulated other comprehensive loss as of December 31, 2018, 2017 and 2016, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Post-retirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
			(In thousands)		
Balance at December 31, 2016	$ (2,300)	$ (33,221)	$ (149)	$ (63)	$ (35,733)
Other comprehensive loss before reclassifications	—	(1,812)	(6)	(139)	(1,957)
Amounts reclassified from accumulated other comprehensive loss	366	1,013	—	120	1,499
Amounts reclassified to accumulated other comprehensive loss from a regulatory asset	—	(1,143)	—	—	(1,143)
Net current-period other comprehensive income (loss)	366	(1,942)	(6)	(19)	(1,601)
Balance at December 31, 2017	(1,934)	(35,163)	(155)	(82)	(37,334)
Other comprehensive income (loss) before reclassifications	—	4,441	(61)	(144)	4,236
Amounts reclassified from accumulated other comprehensive loss	162	2,173	249	131	2,715
Net current-period other comprehensive income (loss)	162	6,614	188	(13)	6,951
Reclassification adjustment of prior period tax effects related to TCJA included in accumulated other comprehensive loss	(389)	(7,520)	(33)	(17)	(7,959)
Balance at December 31, 2018	**$ (2,161)**	**$ (36,069)**	**$ —**	**$ (112)**	**$ (38,342)**

The following amounts were reclassified out of accumulated other comprehensive loss into net income. The amounts presented in parenthesis indicate a decrease to net income on the Consolidated Statements of Income. The reclassifications for the years ended December 31 were as follows:

	2018	2017	Location on Consolidated Statements of Income
	(In thousands)		
Reclassification adjustment for loss on derivative instruments included in net income	$ (591)	$ (590)	Interest expense
	429	224	Income taxes
	(162)	(366)	
Amortization of postretirement liability losses included in net periodic benefit cost (credit)	(2,894)	(1,658)	Other income
	721	645	Income taxes
	(2,173)	(1,013)	
Reclassification adjustment for loss on foreign currency translation adjustment included in net income	(324)	—	Other income
	75	—	Income taxes
	(249)	—	
Reclassification adjustment for loss on available-for-sale investments included in net income	(166)	(185)	Other income
	35	65	Income taxes
	(131)	(120)	
Total reclassifications	$ (2,715)	$ (1,499)	

Note 2 - Revenue from Contracts with Customers

Disaggregation

In the following table, revenue is disaggregated by the type of customer or service provided. The Company believes this level of disaggregation best depicts how the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors. The table also includes a reconciliation of the disaggregated revenue by reportable segments. For more information on the Company's business segments, see Note 15.

Year ended December 31, 2018	Electric	Natural gas distribution	Pipeline and midstream	Construction materials and contracting	Construction services	Other	Total
				(In thousands)			
Residential utility sales	$ 121,477	$ 457,959	$ —	$ —	$ —	$ —	$ 579,436
Commercial utility sales	136,236	276,716	—	—	—	—	412,952
Industrial utility sales	34,353	24,603	—	—	—	—	58,956
Other utility sales	7,556	—	—	—	—	—	7,556
Natural gas transportation	—	43,238	89,159	—	—	—	132,397
Natural gas gathering	—	—	9,159	—	—	—	9,159
Natural gas storage	—	—	11,543	—	—	—	11,543
Contracting services	—	—	—	968,755	—	—	968,755
Construction materials	—	—	—	1,423,068	—	—	1,423,068
Intrasegment eliminations*	—	—	—	(465,969)	—	—	(465,969)
Inside specialty contracting	—	—	—	—	926,875	—	926,875
Outside specialty contracting	—	—	—	—	392,544	—	392,544
Other	31,568	14,579	18,865	—	525	11,259	76,796
Intersegment eliminations	—	—	(50,905)	(669)	(1,681)	(11,052)	(64,307)
Revenues from contracts with customers	331,190	817,095	77,821	1,925,185	1,318,263	207	4,469,761
Revenues out of scope	3,933	6,152	197	—	51,509	—	61,791
Total external operating revenues	$ 335,123	$ 823,247	$ 78,018	$ 1,925,185	$ 1,369,772	$ 207	$ 4,531,552

* Intrasegment revenues are presented within the construction materials and contracting segment to highlight the focus on vertical integration as this segment sells materials to both third parties and internal customers. Due to consolidation requirements, these revenues must be eliminated against construction materials to arrive at the external operating revenue total for the segment.

Contract balances

The timing of revenue recognition may differ from the timing of invoicing to customers. The timing of invoicing to customers does not necessarily correlate with the timing of revenues being recognized under the cost-to-cost method of accounting. Contracts from contracting services are billed as work progresses in accordance with agreed upon contractual terms. Generally, billing to the customer occurs contemporaneous to revenue recognition. A variance in timing of the billings may result in a contract asset or a contract liability. A contract asset occurs when revenues are recognized under the cost-to-cost measure of progress, which exceeds amounts billed on uncompleted contracts. Such amounts will be billed as standard contract terms allow, usually based on various measures of performance or achievement. A contract liability occurs when there are billings in excess of revenues recognized under the cost-to-cost measure of progress on uncompleted contracts. Contract liabilities decrease as revenue is recognized from the satisfaction of the related performance obligation. The changes in contract assets and liabilities were as follows:

	December 31, 2018	December 31, 2017	Change	Location on Consolidated Balance Sheets
	(In thousands)			
Contract assets	$ 104,239	$ 109,540	$ (5,301)	Receivables, net
Contract liabilities - current	(93,901)	(84,123)	(9,778)	Accounts payable
Contract liabilities - noncurrent	(135)	—	(135)	Deferred credits and other liabilities - other
Net contract assets	$ 10,203	$ 25,417	$ (15,214)	

At December 31, 2018, the Company's net contract assets decreased $15.2 million compared to December 31, 2017. Included in the change of total net contract assets was a decrease in contract assets due to revenue recognized in excess of billings on contracts and an increase in contract liabilities due to billings on contracts in excess of revenues recognized. The Company recognized $78.6 million in revenue for the year ended December 31, 2018, which was previously included in contract liabilities at December 31, 2017.

The Company recognized a net increase in revenues of $36.7 million for the year ended December 31, 2018, from performance obligations satisfied in prior periods.

Note 3 - Acquisitions

During 2018, the Company completed four acquisitions. The results of the acquired businesses have been included in the Company's construction materials and contracting segment and Consolidated Financial Statements beginning on the acquisition dates. Pro forma financial amounts reflecting the effects of the above acquisitions are not presented, as such acquisitions were not material, both individually and in the aggregate, to the Company's financial position or results of operations. The following is a listing of the acquisitions made during 2018:

- In April 2018, the Company acquired Teevin & Fischer Quarry, LLC, an aggregate producer that provides crushed rock and gravel to construction and retail customers in Oregon.
- In June 2018, the Company acquired Tri-City Paving, Inc., a general contractor and aggregate, asphalt and ready-mixed concrete supplier in Minnesota.
- In July 2018, the Company acquired Molalla Redi-Mix and Rock Products, Inc., a producer of ready-mixed concrete in Oregon.
- In October 2018, the Company acquired Sweetman Construction Company, a provider of aggregates, asphalt and ready-mixed concrete in South Dakota.

As of December 31, 2018, the gross aggregate consideration for these acquisitions, which were all accounted for as business combinations, was $168.1 million in cash, subject to certain adjustments, and 721,610 shares of common stock with a market value of $20.3 million as of the respective acquisition date. Due to the holding period restriction on the common stock, the share consideration has been discounted to a fair value of approximately $18.2 million, as reflected in the Company's financial statements. In addition to the issuance of the Company's equity securities, the Company issued debt to finance these acquisitions. As of December 31, 2018, costs incurred for acquisitions were $1.5 million and included in operation and maintenance expense on the Consolidated Statements of Income. The acquisitions are subject to customary adjustments based on, among other things, the amount of cash, debt and working capital in the businesses as of the closing dates.

The Company preliminarily allocated the purchase price of the acquisitions to the assets acquired and liabilities assumed based on their estimated fair values as of the acquisition dates and are considered provisional until final fair values are determined or the measurement period has passed. The Company expects to record adjustments as it accumulates the information needed to estimate the fair value of assets acquired and liabilities assumed, including working capital balances, estimated fair value of identifiable intangible assets, property, plant and equipment, total consideration and goodwill. The excess of the purchase price over the aggregate fair values was recorded as goodwill. The Company calculated the fair value of the assets acquired using the market or cost approach (or a combination of both). Fair values for some of the assets were determined based on Level 3 inputs including estimated future cash flows, discount rates, growth rates, sales projections, retention rates and terminal values, all of which require significant management judgment and are susceptible to change. The final fair value of the net assets acquired may result in adjustments to the assets and liabilities, including goodwill, and will be made as soon as practical, but no later than one year from the respective acquisition dates. However, any subsequent measurement period adjustments are not expected to have a material impact on the Company's results of operations. The discount rate used in calculating the fair value of the common stock issued was determined by a Black-Scholes-Merton model. The model used Level 2 inputs including risk-free interest rate, volatility range and dividend yield.

The aggregate total consideration for the acquisitions and the preliminary amounts allocated to the assets acquired and liabilities assumed based on the estimated fair values as of the respective acquisition dates were as follows:

		2018 Acquisitions
		(In thousands)
Assets		
Current assets:		
Receivables, net	$	18,984
Inventories		10,329
Other current assets		515
Total current assets		29,828
Property, plant and equipment		131,766
Deferred charges and other assets:		
Goodwill		33,131
Other intangible assets, net		8,227
Other		927
Total deferred charges and other assets		42,285
Total assets acquired	$	203,879
Liabilities		
Current liabilities	$	11,122
Deferred credits and other liabilities:		
Asset retirement obligation		914
Deferred income taxes		5,565
Total deferred credits and other liabilities		6,479
Total liabilities assumed	$	17,601
Total consideration (fair value)	$	186,278

Note 4 - Discontinued Operations

The assets and liabilities of the Company's discontinued operations have been classified as held for sale and the results of operations are shown in income (loss) from discontinued operations, other than certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. At the time the assets were classified as held for sale, depreciation, depletion and amortization expense was no longer recorded.

Dakota Prairie Refining On June 24, 2016, WBI Energy entered into a membership interest purchase agreement with Tesoro to sell all of the outstanding membership interests in Dakota Prairie Refining to Tesoro. WBI Energy and Calumet each previously owned 50 percent of the Dakota Prairie Refining membership interests and were equal members in building and operating Dakota Prairie Refinery. To effectuate the sale, WBI Energy acquired Calumet's 50 percent membership interest in Dakota Prairie Refining on June 27, 2016. The sale of the membership interests to Tesoro closed on June 27, 2016. The sale of Dakota Prairie Refining reduced the Company's risk by decreasing exposure to commodity prices.

In connection with the sale of Dakota Prairie Refining, Centennial guaranteed certain debt obligations of Dakota Prairie Refining and Tesoro agreed to indemnify Centennial for any losses and litigation expenses arising for the guarantee. On October 17, 2018, Centennial was released of any further liabilities or obligations under this guarantee. For more information related to the guarantee, see Note 19.

The carrying amounts of the major classes of assets and liabilities classified as held for sale, related to the operations of and activity associated with Dakota Prairie Refining, on the Company's Consolidated Balance Sheets at December 31 were as follows:

		2018		2017
		(In thousands)		
Assets				
Current assets:				
Income taxes receivable*	$	—	$	1,778
Total current assets held for sale		—		1,778
Total assets held for sale	$	—	$	1,778
Liabilities				
Deferred credits and other liabilities:				
Deferred income taxes**	$	—	$	37
Total noncurrent liabilities held for sale		—		37
Total liabilities held for sale	$	—	$	37

* On the Company's Consolidated Balance Sheets, these amounts were reclassified to taxes payable and are reflected in current liabilities held for sale.

** On the Company's Consolidated Balance Sheets, these amounts were reclassified to deferred charges and other assets - deferred income taxes and are reflected in noncurrent assets held for sale.

The Company retained certain liabilities of Dakota Prairie Refining which were reflected in current liabilities held for sale on the Consolidated Balance Sheet at December 31, 2016. In the first quarter of 2017, the Company recorded a reversal of a previously accrued liability of $7.0 million ($4.3 million after tax) due to the resolution of a legal matter. As of December 31, 2018, Dakota Prairie Refining incurred no material exit and disposal costs, and does not expect to incur any future material exit and disposal costs.

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the second quarter of 2016, the fair value assessment was determined using the market approach based on the sale transaction to Tesoro. The fair value assessment indicated an impairment based on the carrying value exceeding the fair value, which resulted in the Company recording an impairment of $251.9 million ($156.7 million after tax) in the quarter ended June 30, 2016. The impairment was included in operating expenses from discontinued operations. The fair value of Dakota Prairie Refining's assets have been categorized as Level 3 in the fair value hierarchy.

Fidelity In the second quarter of 2015, the Company began the marketing and sale process of Fidelity with an anticipated sale to occur within one year. Between September 2015 and March 2016, the Company entered into purchase and sale agreements to sell substantially all of Fidelity's oil and natural gas assets. The completion of these sales occurred between October 2015 and April 2016. In July 2018, the Company completed the sale of a majority of the remaining property, plant and equipment. The sale of Fidelity was part of the Company's strategic plan to grow its capital investments in the remaining business segments and to focus on creating a greater long-term value.

The carrying amounts of the major classes of assets and liabilities classified as held for sale, related to the operations of Fidelity, on the Company's Consolidated Balance Sheets at December 31 were as follows:

	2018	2017
	(In thousands)	
Assets		
Current assets:		
Receivables, net	**$ 430**	$ 479
Total current assets held for sale	**430**	479
Noncurrent assets:		
Net property, plant and equipment	**—**	1,631
Deferred income taxes	**1,926**	2,637
Other	**161**	161
Total noncurrent assets held for sale	**2,087**	4,429
Total assets held for sale	**$ 2,517**	$ 4,908
Liabilities		
Current liabilities:		
Accounts payable	**$ 80**	$ 30
Taxes payable	**1,451**	10,857
Other accrued liabilities	**2,470**	2,884
Total current liabilities held for sale	**4,001**	13,771
Total liabilities held for sale	**$ 4,001**	$ 13,771

At December 31, 2018 and 2017, the Company's deferred tax assets included in assets held for sale were largely comprised of $1.9 million and $2.6 million, respectively, of federal and state net operating loss carryforwards and state alternative minimum tax credits. The Company realized substantially all of the outstanding net operating loss carryforwards from prior periods in 2017.

At December 31, 2017, the Company had federal income tax net operating loss carryforwards and various state income tax net operating loss carryforwards of $4.4 million and $13.8 million, respectively. At December 31, 2018, the Company had no federal or state income tax net operating loss carryforwards.

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the first quarter of 2016, the fair value assessment was determined using the market approach largely based on a purchase and sale agreement. The estimated fair value exceeded the carrying value and the Company recorded an impairment reversal of $1.4 million ($900,000 after tax) in the first quarter of 2016. In the second quarter of 2016, the fair value assessment was determined using the income and market approaches. The income approach was determined by using the present value of future estimated cash flows. The market approach was based on market transactions of similar properties. The estimated carrying value exceeded the fair value and the Company recorded an impairment of $900,000 ($600,000 after tax) in the second quarter of 2016.

The Company has incurred $10.5 million of exit and disposal costs to date and has incurred no exit or disposal costs in 2018. The Company does not expect to incur any additional material exit and disposal costs in connection with Fidelity. The exit and disposal costs are associated with severance and other related matters and exclude the office lease expiration discussed in the following paragraph.

Fidelity vacated its office space in Denver, Colorado in 2016. The Company incurred lease payments of approximately $900,000 in 2016. Lease termination payments of $3.2 million were made during the second quarter of 2016. Existing office furniture and fixtures were relinquished to the lessor in the second quarter of 2016.

Dakota Prairie Refining and Fidelity The reconciliation of the major classes of income and expense constituting pretax income (loss) from discontinued operations, which includes Dakota Prairie Refining and Fidelity, to the after-tax income (loss) from discontinued operations on the Company's Consolidated Statements of Income for the years ended December 31 were as follows:

	2018	2017	2016
	(In thousands)		
Operating revenues	$ **(459)**	$ 465	$ 123,024
Operating expenses	**921**	(4,607)	513,813
Operating income (loss)	**(1,380)**	5,072	(390,789)
Other income (expense)	**12**	(13)	306
Interest expense	**575**	250	1,753
Income (loss) from discontinued operations before income taxes	**(1,943)**	4,809	(392,236)
Income taxes*	**(4,875)**	8,592	(91,882)
Income (loss) from discontinued operations	**2,932**	(3,783)	(300,354)
Loss from discontinued operations attributable to noncontrolling interest	**—**	—	(131,691)
Income (loss) from discontinued operations attributable to the Company	$ **2,932**	$ (3,783)	$ (168,663)

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

The pretax income (loss) from discontinued operations attributable to the Company, related to the operations of and activity associated with Dakota Prairie Refining, was $(7,000), $6.9 million and $(253.5) million for the years ended December 31, 2018, 2017 and 2016, respectively.

Note 5 - Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December 31, 2018, were as follows:

	Balance at January 1, 2018	Goodwill Acquired During the Year	Balance at December 31, 2018
		(In thousands)	
Natural gas distribution	$ 345,736	$ —	$ 345,736
Construction materials and contracting	176,290	33,131	209,421
Construction services	109,765	—	109,765
Total	$ 631,791	$ 33,131	$ 664,922

The changes in the carrying amount of goodwill for the year ended December 31, 2017, were as follows:

	Balance at January 1, 2017	Goodwill Acquired During the Year	Balance at December 31, 2017
		(In thousands)	
Natural gas distribution	$ 345,736	$ —	$ 345,736
Construction materials and contracting	176,290	—	176,290
Construction services	109,765	—	109,765
Total	$ 631,791	$ —	$ 631,791

During 2018, the Company completed four acquisitions and the results of the acquired businesses have been included in the Company's construction materials and contracting segment. At December 31, 2018, the construction materials and contracting segment's goodwill increased by $33.1 million and other intangible assets increased by $8.2 million for these acquisitions. For more information about these acquisitions, see Note 3.

Other amortizable intangible assets at December 31 were as follows:

	2018	2017
	(In thousands)	
Customer relationships	$ 22,720	$ 15,248
Less accumulated amortization	13,535	13,382
	9,185	1,866
Noncompete agreements	2,605	2,430
Less accumulated amortization	1,956	1,805
	649	625
Other	6,458	6,990
Less accumulated amortization	5,477	5,644
	981	1,346
Total	$ 10,815	$ 3,837

Amortization expense for amortizable intangible assets for the years ended December 31, 2018, 2017 and 2016, was $1.2 million, $2.0 million and $2.5 million, respectively. The amounts of estimated amortization expense for identifiable intangible assets as of December 31, 2018, were:

	2019	2020	2021	2022	2023	Thereafter
			(In thousands)			
Amortization expense	$ 1,856	$ 1,486	$ 1,096	$ 1,072	$ 1,006	$ 4,299

Note 6 - Regulatory Assets and Liabilities

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

	Estimated Recovery Period *	2018	2017
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(e)	$ 165,898	$ 163,896
Asset retirement obligations (a)	Over plant lives	60,097	56,078
Natural gas costs recoverable through rate adjustments (b)	Up to 1 year	42,652	14,465
Taxes recoverable from customers (a)	Over plant lives	11,946	12,073
Manufactured gas plant sites remediation (a)	-	16,504	18,213
Long-term debt refinancing costs (a)	Up to 19 years	4,898	5,563
Costs related to identifying generation development (a)	Up to 8 years	2,508	2,960
Other (a) (b)	Up to 20 years	35,614	27,715
Total regulatory assets		340,117	300,963
Regulatory liabilities:			
Taxes refundable to customers (c)		277,833	279,668
Plant removal and decommissioning costs (c)		173,143	176,190
Natural gas costs refundable through rate adjustments (d)		29,995	28,514
Pension and postretirement benefits (c)		15,264	16,021
Other (c) (d)		25,197	18,905
Total regulatory liabilities		521,432	519,298
Net regulatory position		$ (181,315)	$ (218,335)

* Estimated recovery period for regulatory assets currently being recovered in rates charged to customers.
(a) Included in deferred charges and other assets - other on the Consolidated Balance Sheets.
(b) Included in prepayments and other current assets on the Consolidated Balance Sheets.
(c) Included in deferred credits and other liabilities - other on the Consolidated Balance Sheets.
(d) Included in other accrued liabilities on the Consolidated Balance Sheets.
(e) Recovered as expense is incurred or cash contributions are made.

The regulatory assets are expected to be recovered in rates charged to customers. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates. As of December 31, 2018 and 2017, approximately $313.5 million and $269.1 million, respectively, of regulatory assets were not earning a rate of return.

In the fourth quarter of 2017, the Company performed a one-time revaluation of the Company's regulated deferred tax assets and liabilities for the reduction of the corporate tax rate from 35 percent to 21 percent effective January 1, 2018, as identified in the TCJA. In the fourth quarter of 2017, the revaluation of the deferred tax assets and liabilities resulted in a decrease of $15.5 million in taxes recoverable from customers and an increase of $270.0 million in taxes refundable to customers. The revaluation of the Company's regulatory deferred tax assets and liabilities were deferred as the Company worked with the various regulators to plan for amounts expected to be returned to customers. All amounts related to the TCJA are reserved or passed back to customers. The Company has tax settlements in place in most jurisdictions, with new rates in place in 2018 or expected to be in place in the first half of 2019. TCJA filings are pending in Wyoming and Oregon. For more information on the various rate cases, see Note 18. There were no significant changes between the preliminary estimate and final determination of taxes refundable to or recoverable from customers. These regulatory amounts will largely be refunded over the remaining life of the related assets.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of regulatory accounting for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income or accumulated other comprehensive income (loss) in the period in which the discontinuance of regulatory accounting occurs.

Note 7 - Fair Value Measurements

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments, which consist of an insurance contract, to satisfy its obligations under its unfunded, nonqualified benefit plans for executive officers and certain key management employees, and invests in these fixed-income and equity securities for the purpose of earning investment returns and capital appreciation. These investments, which totaled $73.8 million and $77.4 million at December 31, 2018 and 2017, respectively, are classified as investments on the Consolidated Balance Sheets. The net unrealized loss on these investments for the year ended December 31, 2018, was $3.6 million. The net unrealized gains on these investments for the years ended December 31, 2017 and 2016, were $9.3 million and $3.4 million, respectively. The change in fair value, which is considered part of the cost of the plan, is classified in other income on the Consolidated Statements of Income. In connection with the adoption of ASU 2017-07, as discussed in Note 1, the Company has elected to reclassify prior period unrealized gains from operation and maintenance expense to other income on the Consolidated Statements of Income.

The Company did not elect the fair value option, which records gains and losses in income, for its available-for-sale securities, which include mortgage-backed securities and U.S. Treasury securities. These available-for-sale securities are recorded at fair value and are classified as investments on the Consolidated Balance Sheets. Unrealized gains or losses are recorded in accumulated other comprehensive income (loss). Details of available-for-sale securities were as follows:

December 31, 2018	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Mortgage-backed securities	$ 10,473	$ 21	$ 162	$ 10,332
U.S. Treasury securities	179	—	—	179
Total	$ 10,652	$ 21	$ 162	$ 10,511

December 31, 2017	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Mortgage-backed securities	$ 10,342	$ 4	$ 129	$ 10,217
U.S. Treasury securities	205	—	1	204
Total	$ 10,547	$ 4	$ 130	$ 10,421

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

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

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

	Fair Value Measurements at December 31, 2018, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2018
		(In thousands)		
Assets:				
Money market funds	$ —	$ 10,799	$ —	$ 10,799
Insurance contract*	—	73,838	—	73,838
Available-for-sale securities:				
Mortgage-backed securities	—	10,332	—	10,332
U.S. Treasury securities	—	179	—	179
Total assets measured at fair value	$ —	$ 95,148	$ —	$ 95,148

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

	Fair Value Measurements at December 31, 2017, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2017
		(In thousands)		
Assets:				
Money market funds	$ —	$ 6,965	$ —	$ 6,965
Insurance contract*	—	77,388	—	77,388
Available-for-sale securities:				
Mortgage-backed securities	—	10,217	—	10,217
U.S. Treasury securities	—	204	—	204
Total assets measured at fair value	$ —	$ 94,774	$ —	$ 94,774

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

The Company applies the provisions of the fair value measurement standard to its nonrecurring, non-financial measurements, including long-lived asset impairments. These assets are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances. The Company reviews the carrying value of its long-lived assets, excluding goodwill, whenever events or changes in circumstances indicate that such carrying amounts may not be recoverable.

The Company performed a fair value assessment of the assets acquired and liabilities assumed in the business combinations that occurred during 2018. For more information on these Level 2 and Level 3 fair value measurements, see Note 3.

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. For more information on these Level 3 nonrecurring fair value measurements, see Note 4.

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

	2018		2017	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	**$ 2,108,695**	**$ 2,183,819**	$ 1,714,853	$ 1,826,256

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

Note 8 - Debt

Certain debt instruments of the Company and its subsidiaries, including those discussed later, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions. At December 31, 2018, the Company and its subsidiaries, as applicable, complied with all applicable financial covenants and restrictions. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

The following table summarizes the outstanding revolving credit facilities of the Company and its subsidiaries:

Company	Facility		Facility Limit		Amount Outstanding at December 31, 2018		Amount Outstanding at December 31, 2017		Letters of Credit at December 31, 2018		Expiration Date
							(In millions)				
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement	(a)	$ 175.0		$ 48.5		$ 73.8	(b)	$ —		6/8/23
Cascade Natural Gas Corporation	Revolving credit agreement		$ 75.0	(c)	$ 53.8		$ 17.3		$ 2.2	(d)	4/24/20
Intermountain Gas Company	Revolving credit agreement		$ 85.0	(e)	$ 56.3		$ 40.0		$ —		4/24/20
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(f)	$ 500.0		$ 289.6	(b)	$ 14.6	(b)	$ —		9/23/21

(a) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $225.0 million). The amount outstanding under the revolving credit agreement was $48.5 million.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $100.0 million.
(d) Outstanding letter(s) of credit reduce the amount available under the credit agreement.
(e) Certain provisions allow for increased borrowings, up to a maximum of $110.0 million.
(f) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $600.0 million). There were no amounts outstanding under the revolving credit agreement.

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

The following includes information related to the preceding table.

Long-term debt

MDU Resources Group, Inc. The Company's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings.

The credit agreement contains customary covenants and provisions, including covenants of the Company not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent or (B) the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than

65 percent. The Company's ratio of funded debt to total capitalization at December 31, 2018, was 45 percent. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

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

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

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

The credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Cascade's ratio of total debt to total capitalization at December 31, 2018, was 51 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

Cascade's credit agreement also contains cross-default provisions. These provisions state that if Cascade fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, Cascade will be in default under the revolving credit agreement.

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

The credit agreement contains customary covenants and provisions, including a covenant of Intermountain not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Intermountain's ratio of total debt to total capitalization at December 31, 2018, was 49 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

Intermountain's credit agreement also contains cross-default provisions. These provisions state that if Intermountain fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, or certain conditions result in an early termination date under any swap contract that is in excess of a specified amount, then Intermountain will be in default under the revolving credit agreement.

Centennial Centennial's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings.

Centennial's revolving credit agreement contains customary covenants and provisions, including a covenant of Centennial, not to permit, as of the end of any fiscal quarter, the ratio of total consolidated debt to total consolidated capitalization to be greater than 65 percent. Centennial's ratio of total debt to total capitalization at December 31, 2018, was 38 percent. Other covenants include restricted payments, restrictions on the sale of certain assets, limitations on subsidiary indebtedness, minimum consolidated net worth, limitations on priority debt and the making of certain loans and investments.

Certain of Centennial's financing agreements contain cross-default provisions. These provisions state that if Centennial or any subsidiary of Centennial fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the applicable agreements will be in default.

WBI Energy Transmission WBI Energy Transmission has a $200.0 million uncommitted note purchase and private shelf agreement with an expiration date of May 16, 2019. WBI Energy Transmission had $140.0 million of notes outstanding at December 31, 2018, which reduced the remaining capacity under this uncommitted private shelf agreement to $60.0 million. This agreement contains customary covenants and provisions, including a covenant of WBI Energy Transmission not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. WBI Energy Transmission's total debt to total capitalization at December 31, 2018, was

40 percent. Other covenants include a limitation on priority debt and restrictions on the sale of certain assets and the making of certain investments.

Long-term Debt Outstanding Long-term debt outstanding was as follows:

	Weighted Average Interest Rate at December 31, 2018	2018	2017
		(In thousands)	
Senior Notes due on dates ranging from July 1, 2019 to January 15, 2055	**4.57%**	**$ 1,381,000**	$ 1,499,916
Commercial paper supported by revolving credit agreements	**3.10%**	**338,100**	88,350
Term Loan Agreements due on dates ranging from October 17, 2019 to September 3, 2032	**2.75%**	**209,800**	—
Credit agreements due on April 24, 2020	**4.40%**	**110,100**	57,300
Medium-Term Notes due on dates ranging from September 1, 2020 to March 16, 2029	**6.68%**	**50,000**	50,000
Other notes due on dates ranging from July 1, 2019 to November 30, 2038	**5.22%**	**25,229**	24,982
Less unamortized debt issuance costs		**5,207**	5,694
Less discount		**327**	1
Total long-term debt		**2,108,695**	1,714,853
Less current maturities		**251,854**	148,499
Net long-term debt		**$ 1,856,841**	$ 1,566,354

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

	2019	2020	2021	2022	2023	Thereafter
			(In thousands)			
Long-term debt maturities	$ 251,854	$ 125,912	$ 290,413	$ 147,314	$ 125,714	$ 1,173,022

Note 9 - Asset Retirement Obligations

The Company records obligations related to retirement costs of natural gas distribution mains and lines, natural gas transmission lines, storage facilities, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties, special handling and disposal of hazardous materials at certain electric generating facilities, natural gas distribution facilities and buildings, and certain other obligations as asset retirement obligations.

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

	2018	2017
	(In thousands)	
Balance at beginning of year	**$ 341,969**	$ 314,970
Liabilities incurred	**13,424**	15,110
Liabilities acquired	**1,002**	—
Liabilities settled	**(3,699)**	(4,981)
Accretion expense*	**18,242**	16,839
Revisions in estimates	**4,615**	31
Balance at end of year	**$ 375,553**	$ 341,969

* Includes $16.8 million and $15.6 million in 2018 and 2017, respectively, related to regulatory assets.

The Company believes that largely all expenses related to asset retirement obligations at the Company's regulated operations will be recovered in rates over time and, accordingly, defers such expenses as regulatory assets. For more information on the Company's regulatory assets and liabilities, see Note 6.

Note 10 - Preferred Stocks

The Company currently has 500,000 shares of preferred stock authorized to be issued with a $100 par value; 1,000,000 shares of preferred stock A authorized to be issued with no par value; and 500,000 shares of preference stock authorized to be issued with no par value. At December 31, 2018, there were no shares outstanding. At December 31, 2017, there were no shares outstanding. In 2016, dividends declared on the 4.50% Series and 4.70% Series preferred stocks were $4.50 and $4.70 per share, respectively. On April 1, 2017, the Company redeemed all outstanding 4.50% Series and 4.70% Series preferred stocks at $105 per share and $102 per share, respectively, for a repurchase price of approximately $15.6 million and $300,000 of redeemable preferred stock classified as long-term debt.

Note 11 - Common Stock

For the years 2018, 2017 and 2016, dividends declared on common stock were $.7950, $.7750 and $.7550 per common share, respectively.

The Stock Purchase Plan provided interested investors the opportunity to make optional cash investments and to reinvest all or a percentage of their cash dividends in shares of the Company's common stock. The K-Plan provides participants the option to invest in the Company's common stock. For the years ended December 31, 2018, 2017 and 2016, the K-Plan purchased shares of common stock on the open market. At December 31, 2018, there were 7.8 million shares of common stock reserved for original issuance under the K-Plan. From January 2016 through December 4, 2016, the Stock Purchase Plan purchased shares of common stock on the open market. On December 5, 2016, the Stock Purchase Plan was terminated and all remaining shares reserved for original issuance under the plan were de-registered.

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

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

Note 12 - Stock-Based Compensation

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

Total stock-based compensation expense (after tax) was $4.6 million, $2.7 million and $3.3 million in 2018, 2017 and 2016, respectively.

As of December 31, 2018, total remaining unrecognized compensation expense related to stock-based compensation was approximately $7.2 million (before income taxes) which will be amortized over a weighted average period of 1.7 years.

Stock awards

Non-employee directors receive shares of common stock in addition to and in lieu of cash payment for directors' fees. Shares of common stock were issued under the non-employee director stock compensation plan or the non-employee director long-term incentive compensation plan. There were 38,605 shares with a fair value of $1.0 million, 40,572 shares with a fair value of $1.1 million and 37,218 shares with a fair value of $1.1 million issued to non-employee directors during the years ended December 31, 2018, 2017 and 2016, respectively.

Restricted stock awards

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

Performance share awards

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

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

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

Under the market condition for these performance share awards, participants may earn from zero to 200 percent of the apportioned target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value as determined by Monte Carlo simulation. The blended volatility term structure ranges are comprised of 50 percent historical volatility and 50 percent implied volatility. Risk-free interest rates were based on U.S. Treasury security rates in effect as of the grant date. Assumptions used for grants applicable to the market condition for certain performance shares issued in 2018, 2017 and 2016 were:

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

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

There were no performance shares that vested in 2018. The fair value of the performance shares that vested during the years ended December 31, 2017 and 2016, was $9.6 million and $953,000, respectively.

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

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

Note 13 - Income Taxes

The components of income before income taxes from continuing operations for each of the years ended December 31 were as follows:

	2018	2017	2016
		(In thousands)	
United States	**$ 317,655**	$ 350,064	$ 326,252
Foreign	**(784)**	(37)	(24)
Income before income taxes from continuing operations	**$ 316,871**	$ 350,027	$ 326,228

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

	2018	2017	2016
		(In thousands)	
Current:			
Federal	**$ (15,901)**	$ 74,272	$ 81,989
State	**3,651**	16,192	13,190
Foreign	**—**	—	2
	(12,250)	90,464	95,181
Deferred:			
Income taxes:			
Federal	**50,755**	(24,497)	(2,102)
State	**7,206**	(864)	1,184
Investment tax credit - net	**1,774**	(62)	(1,131)
	59,735	(25,423)	(2,049)
Total income tax expense	**$ 47,485**	$ 65,041	$ 93,132

In accordance with the accounting guidance on accounting for income taxes, the tax effects of the change in tax laws or rates are to be recorded in the period of enactment. The TCJA was enacted on December 22, 2017, as discussed in Note 1. Therefore, the reduction in the corporate tax rate from 35 percent to 21 percent required the Company to prepare a one-time revaluation of the Company's deferred tax assets and liabilities in the fourth quarter of 2017, the period of enactment. The deferred taxes were revalued at the new tax rate because deferred taxes should reflect what the Company expects to pay or receive in future periods under the applicable tax rate. As a result of the revaluation, the Company reduced the value of these assets and liabilities and recorded a tax benefit from continuing operations of $39.5 million on the Consolidated Statements of Income for the year ended December 31, 2017. Included in the tax benefit from continuing operations was income tax expense of $7.7 million related to amounts in accumulated other comprehensive loss and $1.0 million related to the Company's assets held for sale.

The Company's regulated operations prepared a one-time revaluation of the Company's regulatory deferred tax assets and liabilities in the fourth quarter of 2017 related to the enactment of the TCJA. The revaluation is being deferred under regulatory accounting as the Company works with the various regulators to plan for amounts expected to be returned to customers, as discussed in Notes 6 and 18. The revaluation of the deferred tax assets and liabilities resulted in a net decrease of $285.5 million in the fourth quarter of 2017. In the third quarter of 2018, the Company reversed a regulatory liability recorded in 2017 based on a FERC final accounting order being issued, which resulted in a $4.2 million tax benefit. These regulatory amounts will largely be refunded over the remaining life of the related assets.

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

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

	2018	2017
	(In thousands)	
Deferred tax assets:		
Postretirement	**$ 51,930**	$ 55,736
Compensation-related	**29,885**	16,298
Alternative minimum tax credit carryforward	**13,404**	37,683
Federal renewable energy credit	**8,015**	19,367
Customer advances	**7,734**	8,712
Asset retirement obligations	**7,083**	6,380
Legal and environmental contingencies	**6,729**	7,363
Other	**37,347**	35,738
Total deferred tax assets	**162,127**	187,277
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	**476,832**	429,577
Postretirement	**44,432**	43,505
Intangible asset amortization	**17,752**	16,979
Other	**39,712**	32,591
Total deferred tax liabilities	**578,728**	522,652
Valuation allowance	**13,484**	11,896
Net deferred income tax liability	**$ 430,085**	$ 347,271

As of December 31, 2018 and 2017, the Company had various state income tax net operating loss carryforwards of $153.2 million and $130.1 million, respectively, and federal and state income tax credit carryforwards, excluding alternative minimum tax credit carryforwards, of $43.5 million and $52.5 million, respectively. Included in the state credits are various regulatory investment tax credits of approximately $32.2 million and $28.0 million at December 31, 2018 and 2017, respectively. The federal income tax credit carryforwards expire in 2037 and 2038 if not utilized and state income tax credit carryforwards are due to expire between 2020 and 2046. Changes in tax regulations or assumptions regarding current and future taxable income could require additional valuation allowances in the future. The alternative minimum tax credit carryforwards are refundable. For information regarding net operating loss carryforwards and valuation allowances related to discontinued operations, see Note 4.

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

	2018
	(In thousands)
Change in net deferred income tax liability from the preceding table	**$ 82,814**
Deferred taxes associated with other comprehensive income	**(2,679)**
Deferred taxes associated with TCJA enactment for regulated activities	**(13,776)**
Deferred taxes associated with acquisitions	**(5,565)**
Other	**(1,059)**
Deferred income tax expense for the period	**$ 59,735**

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

Years ended December 31,	2018		2017		2016	
	Amount	**%**	Amount	%	Amount	%
			(Dollars in thousands)			
Computed tax at federal statutory rate	**$ 66,543**	**21.0**	$ 122,509	35.0	$ 114,179	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax	**12,190**	**3.8**	10,724	3.1	9,027	2.8
Federal renewable energy credit	**(11,759)**	**(3.7)**	(13,958)	(4.0)	(13,544)	(4.2)
Tax compliance and uncertain tax positions	**(2,725)**	**(.9)**	(643)	(.2)	(3,028)	(.9)
Domestic production deduction	**—**	**—**	(6,849)	(2.0)	(6,251)	(1.9)
Excess deferred income tax amortization	**(9,319)**	**(2.9)**	(397)	—	(828)	(.2)
TCJA revaluation	**(5,947)**	**(1.9)**	(47,242)	(13.5)	—	—
TCJA revaluation related to accumulated other comprehensive loss balance	**(42)**	**—**	7,735	2.2	—	—
Other	**(1,456)**	**(.4)**	(6,838)	(2.0)	(6,423)	(2.1)
Total income tax expense	**$ 47,485**	**15.0**	$ 65,041	18.6	$ 93,132	28.5

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction, and various state, local and foreign jurisdictions. The Company is no longer subject to U.S. federal or non-U.S. income tax examinations by tax authorities for years ending prior to 2015. With few exceptions, as of December 31, 2018, the Company is no longer subject to state and local income tax examinations by tax authorities for years ending prior to 2014.

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

	2018	2017	2016
		(In thousands)	
Balance at beginning of year	**$ —**	$ —	$ —
Additions based on tax positions related to current year	**120**	—	—
Additions for tax positions of prior years	**262**	—	—
Balance at end of year	**$ 382**	$ —	$ —

Included in income tax expense is interest on uncertain tax positions. For the years ended December 31, 2018, 2017 and 2016, the Company recognized approximately $31,000, $99,000 and $92,000, respectively, of interest income in income tax expense. At December 31, 2018, the Company had no accrued receivables for interest. At December 31, 2017, the Company had accrued receivables of approximately $46,000, for interest.

Note 14 - Cash Flow Information

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

	2018	2017	2016
		(In thousands)	
Interest, net*	**$ 83,009**	$ 79,638	$ 87,920
Income taxes paid, net**	**$ 16,041**	$ 112,137	$ 105,908

* AFUDC - borrowed was $2.3 million, $966,000 and $914,000 for the years ended December 31, 2018, 2017 and 2016, respectively.

** Income taxes paid, net of discontinued operations, were $5.5 million, $9.7 million and $1.3 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Noncash investing transactions at December 31 were as follows:

	2018	2017	2016
		(In thousands)	
Property, plant and equipment additions in accounts payable	**$ 42,355**	$ 29,263	$ 22,712
Issuance of common stock in connection with acquisition	**$ 18,186**	$ —	$ —

Note 15 - Business Segment Data

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The internal reporting of these operating segments is defined based on the reporting and review process used by the Company's chief executive officer. The vast majority of the Company's operations are located within the United States.

The electric segment generates, transmits and distributes electricity in Montana, North Dakota, South Dakota and Wyoming. The natural gas distribution segment distributes natural gas in those states, as well as in Idaho, Minnesota, Oregon and Washington. These operations also supply related value-added services.

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

The construction materials and contracting segment operations mine, process and sell construction aggregates (crushed stone, sand and gravel); produce and sell asphalt mix; and supply ready-mixed concrete. This segment focuses on vertical integration of its contracting services with its construction materials to support the aggregate based product lines including aggregate placement, asphalt and concrete paving, and site development and grading. Although not common to all locations, other products include the sale of cement, liquid asphalt for various commercial and roadway applications, various finished concrete products and other building materials and related contracting services. This segment operates in the central, southern and western United States and Alaska and Hawaii.

The construction services segment provides inside and outside specialty contracting services. Its outside services include design, construction and maintenance of overhead and underground electrical distribution and transmission lines, substations, external lighting, traffic signalization, and gas pipelines, as well as utility excavation and the manufacture and distribution of transmission line construction equipment. Its inside services include design, construction and maintenance of electrical and communication wiring and infrastructure, fire suppression systems, and mechanical piping and services. This segment also constructs and maintains renewable energy projects. These specialty contracting services are provided to utilities and large manufacturing, commercial, industrial, institutional and government customers.

The Other category includes the activities of Centennial Capital, which insures various types of risks as a captive insurer for certain of the Company's subsidiaries. The function of the captive insurer is to fund the self-insured layers of the insured Company's general liability, automobile liability, pollution liability and other coverages. Centennial Capital also owns certain real and personal property. The Other category also includes certain general and administrative costs (reflected in operation and maintenance expense) and interest expense which were previously allocated to the refining business and Fidelity and do not meet the criteria for income (loss) from discontinued operations. The Other category also includes Centennial Resources' former investment in Brazil.

Discontinued operations includes the results and supporting activities of Dakota Prairie Refining and Fidelity other than certain general and administrative costs and interest expense as described above. For more information on discontinued operations, see Note 4.

The information below follows the same accounting policies as described in Note 1. Information on the Company's segments as of December 31 and for the years then ended was as follows:

	2018	2017	2016
		(In thousands)	
External operating revenues:			
Regulated operations:			
Electric	**$ 335,123**	$ 342,805	$ 322,356
Natural gas distribution	**823,247**	848,388	766,115
Pipeline and midstream	**54,857**	53,566	52,983
	1,213,227	1,244,759	1,141,454
Nonregulated operations:			
Pipeline and midstream	**23,161**	19,602	39,602
Construction materials and contracting	**1,925,185**	1,811,964	1,873,696
Construction services	**1,369,772**	1,366,317	1,072,663
Other	**207**	709	1,413
	3,318,325	3,198,592	2,987,374
Total external operating revenues	**$ 4,531,552**	$ 4,443,351	$ 4,128,828
Intersegment operating revenues:			
Regulated operations:			
Electric	**$ —**	$ —	$ —
Natural gas distribution	**—**	—	—
Pipeline and midstream	**50,580**	48,867	48,794
	50,580	48,867	48,794
Nonregulated operations:			
Pipeline and midstream	**325**	178	223
Construction materials and contracting	**669**	565	574
Construction services	**1,681**	1,285	609
Other	**11,052**	7,165	7,230
	13,727	9,193	8,636
Intersegment eliminations	**(64,307)**	(58,060)	(57,430)
Total intersegment operating revenues	**$ —**	$ —	$ —
Depreciation, depletion and amortization:			
Electric	**$ 50,982**	$ 47,715	$ 50,220
Natural gas distribution	**72,486**	69,381	65,426
Pipeline and midstream	**17,896**	16,788	24,885
Construction materials and contracting	**61,158**	55,862	58,413
Construction services	**15,728**	15,739	15,307
Other	**1,955**	2,001	2,067
Total depreciation, depletion and amortization	**$ 220,205**	$ 207,486	$ 216,318
Operating income (loss):			
Electric	**$ 65,148**	$ 79,902	$ 67,929
Natural gas distribution	**72,336**	84,239	66,166
Pipeline and midstream	**36,128**	36,004	42,864
Construction materials and contracting	**141,426**	143,230	178,753
Construction services	**86,764**	81,292	53,546
Other	**(79)**	(619)	(349)
Total operating income	**$ 401,723**	$ 424,048	$ 408,909

	2018	2017	2016
		(In thousands)	
Interest expense:			
Electric	$ 25,860	$ 25,377	$ 24,982
Natural gas distribution	30,768	31,234	30,405
Pipeline and midstream	5,964	4,990	7,903
Construction materials and contracting	17,290	14,778	15,265
Construction services	3,551	3,742	4,059
Other	2,762	3,564	5,854
Intersegment eliminations	(1,581)	(897)	(620)
Total interest expense	$ 84,614	$ 82,788	$ 87,848
Income taxes:			
Electric	$ (6,482)	$ 7,699	$ 1,449
Natural gas distribution	4,075	22,756	9,181
Pipeline and midstream	2,677	12,281	12,408
Construction materials and contracting	28,357	5,405	60,625
Construction services	20,000	25,558	17,748
Other	(1,142)	(1,809)	(2,028)
Intersegment eliminations	—	(6,849)	(6,251)
Total income taxes	$ 47,485	$ 65,041	$ 93,132
Earnings on common stock:			
Regulated operations:			
Electric	$ 47,000	$ 49,366	$ 42,222
Natural gas distribution	37,732	32,225	27,102
Pipeline and midstream	26,905	20,620	22,060
	111,637	102,211	91,384
Nonregulated operations:			
Pipeline and midstream	1,554	(127)	1,375
Construction materials and contracting	92,647	123,398	102,687
Construction services	64,309	53,306	33,945
Other	(761)	(1,422)	(3,231)
	157,749	175,155	134,776
Intersegment eliminations (a)	—	6,849	6,251
Earnings on common stock before income (loss) from discontinued operations	269,386	284,215	232,411
Income (loss) from discontinued operations, net of tax (a)	2,932	(3,783)	(300,354)
Loss from discontinued operations attributable to noncontrolling interest	—	—	(131,691)
Earnings on common stock	$ 272,318	$ 280,432	$ 63,748
Capital expenditures:			
Electric	$ 186,105	$ 109,107	$ 111,134
Natural gas distribution	205,896	146,981	126,272
Pipeline and midstream	70,057	31,054	34,467
Construction materials and contracting	280,396	44,302	37,845
Construction services	25,081	18,630	60,344
Other	1,768	1,850	2,358
Total capital expenditures (b)	$ 769,303	$ 351,924	$ 372,420

		2018	2017	2016
			(In thousands)	
Assets:				
Electric (c)	$	**1,613,822**	$ 1,470,922	$ 1,406,694
Natural gas distribution (c)		**2,375,871**	2,201,081	2,099,296
Pipeline and midstream		**616,959**	566,295	550,615
Construction materials and contracting		**1,508,032**	1,238,696	1,220,459
Construction services		**604,798**	591,382	513,093
Other (d)		**266,111**	261,419	283,255
Assets held for sale		**2,517**	4,871	211,055
Total assets	$	**6,988,110**	$ 6,334,666	$ 6,284,467
Property, plant and equipment:				
Electric (c)	$	**2,148,569**	$ 1,982,264	$ 1,888,613
Natural gas distribution (c)		**2,499,093**	2,319,845	2,179,413
Pipeline and midstream		**764,959**	700,284	672,199
Construction materials and contracting		**1,768,006**	1,560,048	1,549,375
Construction services		**188,586**	177,265	171,361
Other		**28,108**	31,123	49,268
Less accumulated depreciation, depletion and amortization		**2,818,644**	2,691,641	2,578,902
Net property, plant and equipment	$	**4,578,677**	$ 4,079,188	$ 3,931,327

(a) Includes eliminations for the presentation of income tax adjustments between continuing and discontinued operations.
(b) Capital expenditures for 2018, 2017 and 2016 include noncash transactions such as the issuance of the Company's equity securities in connection with acquisitions, capital expenditure-related accounts payable and AFUDC, totaling $33.4 million, $10.5 million and $(15.8) million, respectively.
(c) Includes allocations of common utility property.
(d) Includes assets not directly assignable to a business (i.e. cash and cash equivalents, certain accounts receivable, certain investments and other miscellaneous current and deferred assets).

Note 16 - Employee Benefit Plans

Pension and other postretirement benefit plans

The Company has noncontributory qualified defined benefit pension plans and other postretirement benefit plans for certain eligible employees. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans.

Prior to 2013, defined benefit pension plan benefits and accruals for all nonunion and certain union plans were frozen and on June 30, 2015, the remaining union plan was frozen. These employees were eligible to receive additional defined contribution plan benefits. In October 2018, the Company transferred the liability of certain participants in the defined benefit pension plan, who are currently receiving benefits, to an annuity company. The transfer of the benefit payments for these participants reduces the Company's liability and future premiums.

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

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

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

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	**2018**	2017
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 445,923**	$ 436,307	**$ 91,206**	$ 89,304
Service cost	**—**	—	**1,494**	1,508
Interest cost	**14,591**	16,207	**2,899**	3,265
Plan participants' contributions	**—**	—	**1,282**	1,368
Actuarial (gain) loss	**(32,637)**	19,119	**(10,115)**	1,781
Benefits paid	**(36,275)**	(25,710)	**(5,565)**	(6,020)
Benefit obligation at end of year	**391,602**	445,923	**81,201**	91,206
Change in net plan assets:				
Fair value of plan assets at beginning of year	**354,384**	333,509	**88,739**	82,846
Actual gain (loss) on plan assets	**(21,138)**	45,473	**(2,781)**	9,612
Employer contribution	**10,838**	1,112	**842**	933
Plan participants' contributions	**—**	—	**1,281**	1,368
Benefits paid	**(36,275)**	(25,710)	**(5,565)**	(6,020)
Fair value of net plan assets at end of year	**307,809**	354,384	**82,516**	88,739
Funded status - over (under)	**$ (83,793)**	$ (91,539)	**$ 1,315**	$ (2,467)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Deferred charges and other assets - other	**$ —**	$ —	**$ 20,843**	19,114
Other accrued liabilities	**—**	—	**660**	612
Deferred credits and other liabilities - other	**83,793**	91,539	**18,868**	20,969
Benefit obligation assets (liabilities) - net amount recognized	**$ (83,793)**	$ (91,539)	**$ 1,315**	$ (2,467)
Amounts recognized in accumulated other comprehensive (income) loss or regulatory assets (liabilities) consist of:				
Actuarial loss	**$ 188,735**	$ 186,486	**$ 10,316**	$ 13,423
Prior service credit	**—**	—	**(10,238)**	(11,632)
Total	**$ 188,735**	$ 186,486	**$ 78**	$ 1,791

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. Accumulated other comprehensive (income) loss in the table above includes amounts related to regulated operations, which are recorded as regulatory assets (liabilities) and are expected to be reflected in rates charged to customers over time. For more information on regulatory assets (liabilities), see Note 6.

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

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

	2018	2017
	(In thousands)	
Projected benefit obligation	**$ 391,602**	$ 445,923
Accumulated benefit obligation	**$ 391,602**	$ 445,923
Fair value of plan assets	**$ 307,809**	$ 354,384

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

	Pension Benefits			Other Postretirement Benefits		
	2018	2017	2016	**2018**	2017	2016
			(In thousands)			
Components of net periodic benefit cost (credit):						
Service cost	**$ —**	$ —	$ —	**$ 1,494**	$ 1,508	$ 1,647
Interest cost	**14,591**	16,207	17,218	**2,899**	3,265	3,688
Expected return on assets	**(20,753)**	(20,528)	(20,924)	**(4,866)**	(4,641)	(4,533)
Amortization of prior service credit	**—**	—	—	**(1,394)**	(1,371)	(1,371)
Recognized net actuarial loss	**7,005**	6,355	6,215	**640**	857	1,491
Net periodic benefit cost (credit), including amount capitalized	**843**	2,034	2,509	**(1,227)**	(382)	922
Less amount capitalized	**—**	310	381	**153**	(370)	(52)
Net periodic benefit cost (credit)	**843**	1,724	2,128	**(1,380)**	(12)	974
Other changes in plan assets and benefit obligations recognized in accumulated comprehensive (income) loss or regulatory assets (liabilities):						
Net (gain) loss	**9,254**	(5,827)	(3,789)	**(2,467)**	(3,190)	(3,523)
Amortization of actuarial loss	**(7,005)**	(6,355)	(6,215)	**(640)**	(857)	(1,491)
Amortization of prior service credit	**—**	—	—	**1,394**	1,371	1,371
Total recognized in accumulated other comprehensive (income) loss or regulatory assets (liabilities)	**2,249**	(12,182)	(10,004)	**(1,713)**	(2,676)	(3,643)
Total recognized in net periodic benefit cost (credit), accumulated other comprehensive (income) loss and regulatory assets (liabilities)	**$ 3,092**	**$ (10,458)**	**$ (7,876)**	**$ (3,093)**	**$ (2,688)**	**$ (2,669)**

The estimated net loss for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss and regulatory assets into net periodic benefit cost in 2019 is $5.6 million. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss and regulatory assets into net periodic benefit cost (credit) in 2019 are $500,000 and $1.4 million, respectively. Prior service cost is amortized on a straight line basis over the average remaining service period of active participants.

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

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	**2018**	2017
Discount rate	**4.03%**	3.38%	**4.05%**	3.41%
Expected return on plan assets	**6.75%**	6.75%	**5.75%**	5.75%
Rate of compensation increase	**N/A**	N/A	**3.00%**	3.00%

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

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	**2018**	2017
Discount rate	**3.38%**	3.83%	**3.41%**	3.86%
Expected return on plan assets	**6.75%**	6.75%	**5.75%**	5.75%
Rate of compensation increase	**N/A**	N/A	**3.00%**	3.00%

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

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

	2018	2017
Health care trend rate assumed for next year	**7.5% – 8.1%**	7.5% – 8.5%
Health care cost trend rate - ultimate	**4.5%**	4.5%
Year in which ultimate trend rate achieved	**2024**	2024

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

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

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 223	$ (184)
Effect on postretirement benefit obligation	$ 4,296	$ (3,622)

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

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

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

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

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

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

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

	Fair Value Measurements at December 31, 2018, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2018
		(In thousands)		
Assets:				
Cash equivalents	$ —	$ 4,930	$ —	$ 4,930
Equity securities:				
U.S. companies	11,038	—	—	11,038
International companies	—	967	—	967
Collective and mutual funds*	145,960	51,600	—	197,560
Corporate bonds	—	73,110	—	73,110
Municipal bonds	—	10,624	—	10,624
U.S. Government securities	479	5,896	—	6,375
Total assets measured at fair value	$ 157,477	$ 147,127	$ —	$ 304,604

* Collective and mutual funds invest approximately 27 percent in common stock of international companies, 31 percent in corporate bonds, 18 percent in common stock of large-cap U.S. companies, 5 percent in cash equivalents 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	$ —	$ 3,814	$ —	$ 3,814
Equity securities:				
U.S. companies	13,345	—	—	13,345
International companies	1,766	—	—	1,766
Collective and mutual funds*	171,822	67,749	—	239,571
Corporate bonds	—	74,956	—	74,956
Municipal bonds	—	8,546	—	8,546
U.S. Government securities	1,038	8,293	—	9,331
Total assets measured at fair value	$ 187,971	$ 163,358	$ —	$ 351,329

* Collective and mutual funds invest approximately 31 percent in common stock of international companies, 28 percent in corporate bonds, 19 percent in common stock of large-cap U.S. companies, 7 percent in cash equivalents, 1 percent in U.S. Government securities 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	$ —	$ 3,866	$ —	$ 3,866
Equity securities:				
U.S. companies	1,767	—	—	1,767
International companies	—	2	—	2
Insurance contract*	1	76,880	—	76,881
Total assets measured at fair value	$ 1,768	$ 80,748	$ —	$ 82,516

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

	Fair Value Measurements at December 31, 2017, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2017
		(In thousands)		
Assets:				
Cash equivalents	$ —	$ 4,815	$ —	$ 4,815
Equity securities:				
U.S. companies	2,316	—	—	2,316
International companies	4	—	—	4
Insurance contract*	3	81,601	—	81,604
Total assets measured at fair value	$ 2,323	$ 86,416	$ —	$ 88,739

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

The Company expects to contribute approximately $4.0 million to its defined benefit pension plans and approximately $700,000 to its postretirement benefit plans in 2019.

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

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
		(In thousands)	
2019	$ 24,026	$ 5,332	$ 117
2020	24,287	5,232	112
2021	24,633	5,201	105
2022	24,929	5,259	98
2023	25,173	5,270	90
2024 - 2028	124,688	25,851	320

Nonqualified benefit plans

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

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

	2018	2017
	(In thousands)	
Projected benefit obligation	**$ 93,988**	$ 102,484
Accumulated benefit obligation	**$ 93,988**	$ 102,484

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

	2018	2017	2016
		(In thousands)	
Components of net periodic benefit cost:			
Service cost	**$ 185**	$ 289	$ 493
Interest cost	**3,157**	3,494	3,742
Amortization of prior service cost	**—**	—	(80)
Recognized net actuarial loss	**1,047**	883	952
Curtailment gain	**—**	—	(3,292)
Net periodic benefit cost	**$ 4,389**	$ 4,666	$ 1,815

Weighted average assumptions used at December 31 were as follows:

	2018	2017
Benefit obligation discount rate	**3.86%**	3.20%
Benefit obligation rate of compensation increase	**N/A**	N/A
Net periodic benefit cost discount rate	**3.20%**	3.56%
Net periodic benefit cost rate of compensation increase	**N/A**	N/A

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

	2019	2020	2021	2022	2023	Thereafter
			(In thousands)			
Nonqualified benefits	$ 7,350	$ 7,766	$ 7,787	$ 7,018	$ 7,213	$ 36,885

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Expenses incurred under this plan for 2018, 2017 and 2016 were $597,000, $736,000 and $395,000, respectively.

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

	2018	2017
	(In thousands)	
Investments		
Insurance contract*	$ 73,838	$ 77,388
Life insurance**	37,274	38,568
Other	10,818	6,971
Total investments	$ 121,930	$ 122,927

* For more information on the insurance contract, see Note 7.
** Investments of life insurance are carried on plan participants (payable upon the employee's death).

Defined contribution plans

The Company sponsors various defined contribution plans for eligible employees and the costs incurred under these plans were $42.4 million in 2018, $41.2 million in 2017 and $40.9 million in 2016.

Multiemployer plans

The Company contributes to a number of MEPPs under the terms of collective-bargaining agreements that cover its union-represented employees. The risks of participating in these multiemployer plans are different from single-employer plans in the following aspects:

- Assets contributed to the MEPP by one employer may be used to provide benefits to employees of other participating employers
- If a participating employer stops contributing to the plan, the unfunded obligations of the plan may be borne by the remaining participating employers
- If the Company chooses to stop participating in some of its MEPPs, the Company may be required to pay those plans an amount based on the underfunded status of the plan, referred to as a withdrawal liability

The Company's participation in these plans is outlined in the following table. Unless otherwise noted, the most recent Pension Protection Act zone status available in 2018 and 2017 is for the plan's year-end at December 31, 2017, and December 31, 2016, respectively. The zone status is based on information that the Company received from the plan and is certified by the plan's actuary. Among other factors, plans in the red zone are generally less than 65 percent funded, plans in the yellow zone are between 65 percent and 80 percent funded, and plans in the green zone are at least 80 percent funded.

Pension Fund	EIN/Pension Plan Number	Pension Protection Act Zone Status		FIP/RP Status Pending/ Implemented	Contributions			Surcharge Imposed	Expiration Date of Collective Bargaining Agreement	
		2018	2017		**2018**	2017	2016			
					(In thousands)					
Alaska Laborers-Employers Retirement Fund	91-6028298-001	Yellow as of 6/30/2018	Yellow as of 6/30/2017	Implemented	**$ 732**	$ 690	$ 766	No	12/31/2018	*
Construction Industry and Laborers Joint Pension Trust for So Nevada, Plan A	88-0135695-001	Red	Red	Implemented	**346**	377	523	No	6/30/2019	
Edison Pension Plan	93-6061681-001	Green	Green	No	**12,111**	12,725	6,242	No	6/30/2019	
IBEW Local 212 Pension Trust	31-6127280-001	Green as of 4/30/2018	Green as of 4/30/2017	No	**1,341**	1,312	1,146	No	6/2/2019	
IBEW Local 357 Pension Plan A	88-6023284-001	Green	Green	No	**3,460**	3,286	3,016	No	5/31/2021	
IBEW Local 648 Pension Plan	31-6134845-001	Yellow as of 2/28/2018	Red as of 2/28/2017	Implemented	**2,175**	2,254	773	No	8/29/2021	
IBEW Local 82 Pension Plan	31-6127268-001	Green as of 6/30/2018	Green as of 6/30/2017	No	**1,569**	1,757	2,560	No	12/1/2019	
Idaho Plumbers and Pipefitters Pension Plan	82-6010346-001	Green as of 5/31/2018	Green as of 5/31/2017	No	**1,247**	1,156	1,221	No	9/30/2019	
Minnesota Teamsters Construction Division Pension Fund	41-6187751-001	Green as of 11/30/2017	Green as of 11/30/2016	No	**740**	826	690	No	4/30/2019	
National Automatic Sprinkler Industry Pension Fund	52-6054620-001	Red	Red	Implemented	**738**	718	775	No	3/31/2021-7/31/2024	
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	**8,468**	8,891	6,366	No	1/31/2018-5/31/2022	
Pension Trust Fund for Operating Engineers	94-6090764-001	Yellow	Red	Implemented	**2,403**	2,391	2,069	No	6/15/2019-6/30/2020	
Sheet Metal Workers Pension Plan of Southern CA, AZ, and NV	95-6052257-001	Yellow	Yellow	Implemented	**1,774**	1,016	1,087	No	6/30/2019	
Southwest Marine Pension Trust	95-6123404-001	Red	Red	Implemented	**81**	48	50	No	1/31/2019	*
Other funds					**21,537**	19,298	17,243			
Total contributions					**$ 58,722**	$ 56,745	$ 44,527			

* Plan includes contributions required by collective bargaining agreements which have expired, but contain provisions automatically renewing their terms in the absence of a subsequent negotiated agreement.

The Company was listed in the plans' Forms 5500 as providing more than 5 percent of the total contributions for the following plans and plan years:

Pension Fund	Year Contributions to Plan Exceeded More Than 5 Percent of Total Contributions (as of December 31 of the Plan's Year-End)
Edison Pension Plan	2017 and 2016
IBEW Local 82 Pension Plan	2017 and 2016
IBEW Local 124 Pension Trust Fund	2017 and 2016
IBEW Local 212 Pension Trust Fund	2017 and 2016
IBEW Local 357 Pension Plan A	2017 and 2016
IBEW Local 648 Pension Plan	2017 and 2016
Idaho Plumbers and Pipefitters Pension Plan	2017 and 2016
International Union of Operating Engineers Local 701 Pension Trust Fund	2017 and 2016
Minnesota Teamsters Construction Division Pension Fund	2017 and 2016
Pension and Retirement Plan of Plumbers and Pipefitters Local 525	2017 and 2016

On September 24, 2014, Knife River provided notice to the Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming that it was withdrawing from the plan effective October 26, 2014. In the fourth quarter of 2016, Knife River and the plan entered into a settlement agreement whereby the plan administrator assessed Knife River's final withdrawal liability with quarterly payments of approximately $42,000 until all benefits are satisfied. Knife River discounted the expected future payments. Based on this calculation, Knife River adjusted its liability accrual from $16.4 million to $5.2 million in the fourth quarter of 2016.

The Company also contributes to a number of multiemployer other postretirement plans under the terms of collective-bargaining agreements that cover its union-represented employees. These plans provide benefits such as health insurance, disability insurance and life insurance to retired union employees. Many of the multiemployer other postretirement plans are combined with active multiemployer health and welfare plans. The Company's total contributions to its multiemployer other postretirement plans, which also includes contributions to active multiemployer health and welfare plans, were $53.3 million, $52.2 million and $36.1 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Amounts contributed in 2018, 2017 and 2016 to defined contribution multiemployer plans were $31.1 million, $32.2 million and $23.8 million, respectively.

Note 17 - Jointly Owned Facilities

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

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

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

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

Note 18 - Regulatory Matters

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

MNPUC

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

MTPSC

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

On September 28, 2018, Montana-Dakota filed an application with the MTPSC for an electric rate increase of approximately $11.9 million annually or approximately 18.9 percent above current rates. The requested increase is primarily to recover investments in facilities to enhance safety and reliability and the depreciation and taxes associated with the increase in investment. The increase was offset by tax savings related to the TCJA. This matter is pending before the MTPSC.

NDPSC

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

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

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

OPUC

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

On May 31, 2018, Cascade filed a general rate case with the OPUC requesting an overall increase of approximately $2.3 million or approximately 3.5 percent on an annual basis, which incorporates the impact of the TCJA. On January 22, 2019, Cascade filed a stipulation with the OPUC for an annual increase in revenues of $1.7 million with a $500,000 reduction for excess deferred income taxes, for a net increase of $1.2 million. This matter is pending before the OPUC.

SDPUC

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

WUTC

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

WYPSC

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

FERC

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

On July 18, 2018, the FERC issued a final rule on Rate Changes Relating to Federal Income Tax Rate reductions resulting from the TCJA which requires natural gas pipeline companies to make a one-time informational filing to evaluate the impact of the lower corporate income tax rate and also select one of four options presented by the FERC to address the impact. In accordance with WBI Energy Transmission's offer of settlement and stipulation and agreement with the FERC dated June 4, 2014, the Company is to make a filing with new proposed rates to be effective no later than May 1, 2019. On October 31, 2018, the Company filed a rate case with the FERC. Due to the timing of the rate case filing, the Company was exempt from the one-time informational filing required by the FERC's final rule. On November 30, 2018, the FERC issued an order accepting and suspending tariff records, subject to refund, and establishing hearing procedures. The FERC order accepted the Company's rate case filing and suspended the associated tariff records to be effective May 1, 2019, subject to refund and the outcome of a hearing.

Note 19 - Commitments and Contingencies

The Company is party to claims and lawsuits arising out of its business and that of its consolidated subsidiaries, which may include, but are not limited to, matters involving property damage, personal injury, and environmental, contractual, statutory and regulatory obligations. The Company accrues a liability for those contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, in some circumstances, an estimate of the possible loss. Accruals are based on the best information available, but in certain situations management is unable to estimate an amount or range of a reasonably possible loss including, but not limited to when: (1) the damages are unsubstantiated or indeterminate, (2) the proceedings are in the early stages, (3) numerous parties are involved, or (4) the matter involves novel or unsettled legal theories.

The Company has accrued liabilities of $30.4 million and $35.4 million, which have not been discounted, including liabilities held for sale, for contingencies, including litigation, production taxes, royalty claims and environmental matters at December 31, 2018 and 2017, respectively. This includes amounts that have been accrued for matters discussed in Environmental matters within this note. The Company will continue to monitor each matter and adjust accruals as might be warranted based on new information and further developments. Management believes that the outcomes with respect to probable and reasonably possible losses in excess of the amounts accrued, net of insurance recoveries, while uncertain, either cannot be estimated or will not have a material effect upon the Company's financial position, results of operations or cash flows. Unless otherwise required by GAAP, legal costs are expensed as they are incurred.

Environmental matters

Portland Harbor Site In December 2000, Knife River - Northwest was named by the EPA as a PRP in connection with the cleanup of a riverbed site adjacent to a commercial property site acquired by Knife River - Northwest from Georgia-Pacific West, Inc. in 1999. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. To date, costs of the overall remedial investigation and feasibility study of the harbor site are being recorded, and initially paid, through an administrative consent order by the LWG, a group of several entities, which does not include Knife River - Northwest or Georgia-Pacific West, Inc. Investigative costs are indicated to be in excess of $100 million. On January 6, 2017, Region 10 of the EPA issued an ROD with its selected remedy for cleanup of the in-river portion of the site. Implementation of the remedy is expected to take up to 13 years with a present value cost estimate of approximately $1 billion. Corrective action will not be taken until remedial design/remedial action plans are approved by the EPA. Knife River - Northwest also received notice in January 2008 that the Portland Harbor Natural Resource Trustee Council intends to perform an injury assessment to natural resources resulting from the release of hazardous substances at the Harbor Superfund Site. The Portland Harbor Natural Resource Trustee Council indicates the injury determination is appropriate to facilitate early settlement of damages and restoration for natural resource injuries. It is not possible to estimate the costs of natural resource damages until an assessment is completed and allocations are undertaken.

Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon DEQ and other information available, Knife River - Northwest does not believe it is a responsible party. In addition, Knife River - Northwest has notified Georgia-Pacific West, Inc., that it intends to seek indemnity for liabilities incurred in relation to the above matters pursuant to the terms of their sale agreement. Knife River - Northwest has entered into an agreement tolling the statute of limitations in connection with the LWG's potential claim for contribution to the costs of the remedial investigation and feasibility study. By letter in March 2009, LWG stated its intent to file suit against Knife River - Northwest and others to recover LWG's investigation costs to the extent Knife River - Northwest cannot demonstrate its non-liability for the contamination or is unwilling to participate in an alternative dispute resolution process that has been established to address the matter. At this time, Knife River - Northwest has agreed to participate in the alternative dispute resolution process.

The Company believes it is not probable that it will incur any material environmental remediation costs or damages in relation to the above referenced matter.

Manufactured Gas Plant Sites There are three claims against Cascade for cleanup of environmental contamination at manufactured gas plant sites operated by Cascade's predecessors. The accruals related to these claims are reflected in regulatory assets. For more information, see Note 6.

The first claim is for contamination at a site in Eugene, Oregon, which was received in 1995. The Oregon DEQ released an ROD in January 2015 that selected a remediation alternative for the site as recommended in an earlier staff report. The total estimated cost for the selected remediation, including long-term maintenance, is approximately $3.5 million of which $400,000 has been incurred. Cascade and other PRPs will share in the cleanup costs with Cascade expecting to pay approximately 50 percent of the remediation and maintenance costs. Cascade has an accrual balance of $1.5 million for remediation of this site. In January 2013, the OPUC approved Cascade's application to defer environmental remediation costs at the Eugene site for a period of 12 months starting November 30, 2012. Cascade received orders reauthorizing the deferred accounting for the 12-month periods starting November 30, 2013, December 1, 2014, December 1, 2015, December 1, 2016, December 1, 2017 and December 1, 2018.

The second claim is for contamination at the Bremerton Gasworks Superfund Site in Bremerton, Washington which was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants requiring further investigation and cleanup. The EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from $340,000 to $6.4 million. In April 2010, the Washington DOE issued notice it considered Cascade a PRP for hazardous substances at the site. In May 2012, the EPA added the site to the National Priorities List of Superfund sites. Cascade has entered into an administrative settlement agreement and consent order with the EPA regarding the scope and schedule for a remedial investigation and feasibility study for the site. Current estimates for the cost to complete the remedial investigation and feasibility study are approximately $7.6 million of which $3.1 million has been incurred. Cascade has accrued $4.5 million for the remedial investigation and feasibility study, as well as $6.4 million for remediation of this site; however, the accrual for remediation costs will be reviewed and adjusted, if necessary, after completion of the remedial investigation and feasibility study. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs incurred in relation to the environmental remediation of this site. The WUTC approved the petition in September 2010, subject to conditions set forth in the order.

The third claim is for contamination at a site in Bellingham, Washington. Cascade received notice from a party in May 2008 that Cascade may be a PRP, along with other parties, for contamination from a manufactured gas plant owned by Cascade and its predecessor from about 1946 to 1962. Other PRPs reached an agreed order and work plan with the Washington DOE for completion of a remedial investigation and feasibility study for the site. A feasibility study prepared in March 2018 identifies five cleanup action alternatives for the site with estimated costs ranging from $8.0 million to $20.4 million with a selected preferred alternative having an estimated total cost of $9.3 million. Cascade believes its proportional share of any liability will be relatively small in comparison to other PRPs. The plant manufactured gas from coal between approximately 1890 and 1946. In 1946, shortly after Cascade's predecessor acquired the plant, it converted the plant to a propane-air gas facility. There are no documented wastes or by-products resulting from the mixing or distribution of propane-air gas. Cascade has recorded an accrual for this site for an amount that is not material.

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

Operating leases

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

	2019	2020	2021	2022	2023	Thereafter
			(In thousands)			
Operating leases	$ 37,740	$ 26,255	$ 17,868	$ 11,647	$ 7,278	$ 49,098

Rent expense was $74.6 million, $73.7 million and $65.0 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Purchase commitments

The Company has entered into various commitments, largely construction, natural gas and coal supply, purchased power, natural gas transportation and storage, and service, shipping and construction materials supply contracts, some of which are subject to variability in volume and price. The commitment terms vary in length, up to 42 years. The commitments under these contracts as of December 31, 2018, were:

	2019	2020	2021	2022	2023	Thereafter
			(In thousands)			
Purchase commitments	$ 418,106	$ 215,069	$ 169,716	$ 115,884	$ 84,268	$ 622,383

These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2018, 2017 and 2016, were $548.0 million, $516.1 million and $539.3 million, respectively.

Guarantees

In June 2016, WBI Energy sold all of the outstanding membership interests in Dakota Prairie Refining. In connection with the sale, Centennial agreed to continue to guarantee certain debt obligations of Dakota Prairie Refining which were expected to mature in 2023. Tesoro agreed to indemnify Centennial for any losses and litigation expenses arising from the guarantee. Continuation of the guarantee was required as a condition to the sale of Dakota Prairie Refining. On October 17, 2018, Centennial was released from this guarantee of certain debt obligations of Dakota Prairie Refining.

In 2009, multiple sale agreements were signed to sell the Company's ownership interests in the Brazilian Transmission Lines. In connection with the sale, Centennial agreed to guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries who were the sellers in three purchase and sale agreements for periods ranging up to 10 years from the date of sale. The guarantees were required by the buyers as a condition to the sale of the Brazilian Transmission Lines.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to construction contracts, insurance deductibles and loss limits, and certain other guarantees. At December 31, 2018, the fixed maximum amounts guaranteed under these agreements aggregated $196.3 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate to $85.3 million in 2019; $104.0 million in 2020; $500,000 in 2021; $500,000 in 2022; $500,000 in 2023; $1.5 million thereafter; and $4.0 million, which has no scheduled maturity date. There were no amounts outstanding under the above guarantees at December 31, 2018. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

Certain subsidiaries have outstanding letters of credit to third parties related to insurance policies and other agreements, some of which are guaranteed by other subsidiaries of the Company. At December 31, 2018, the fixed maximum amounts guaranteed under these letters of credit aggregated $30.0 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these letters of credit aggregate to $6.7 million in 2019 and $23.3 million in 2020. There were no amounts outstanding under the above letters of credit at December 31, 2018. In the event of default under these letter of credit obligations, the subsidiary guaranteeing the letter of credit would be obligated for reimbursement of payments made under the letter of credit.

In addition, Centennial, Knife River and MDU Construction Services have issued guarantees to third parties related to the routine purchase of maintenance items, materials and lease obligations for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under these obligations, Centennial, Knife River or MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company were reflected on the Consolidated Balance Sheet at December 31, 2018.

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. At December 31, 2018, approximately $697.9 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Variable interest entities

The Company evaluates its arrangements and contracts with other entities to determine if they are VIEs and if so, if the Company is the primary beneficiary.

Fuel Contract Coyote Station entered into a coal supply agreement with Coyote Creek that provides for the purchase of coal necessary to supply the coal requirements of the Coyote Station for the period May 2016 through December 2040. Coal purchased under the coal supply agreement is reflected in inventories on the Company's Consolidated Balance Sheets and is recovered from customers as a component of electric fuel and purchased power.

The coal supply agreement creates a variable interest in Coyote Creek due to the transfer of all operating and economic risk to the Coyote Station owners, as the agreement is structured so that the price of the coal will cover all costs of operations, as well as future reclamation costs. The Coyote Station owners are also providing a guarantee of the value of the assets of Coyote Creek as they would be required to buy the assets at book value should they terminate the contract prior to the end of the contract term and are providing a guarantee of the value of the equity of Coyote Creek in that they are required to buy the entity at the end of the contract term at equity value. Although the Company has determined that Coyote Creek is a VIE, the Company has concluded that it is not the primary beneficiary of Coyote Creek because the authority to direct the activities of the entity is shared by the four unrelated owners of the Coyote Station, with no primary beneficiary existing. As a result, Coyote Creek is not required to be consolidated in the Company's financial statements.

At December 31, 2018, the Company's exposure to loss as a result of the Company's involvement with the VIE, based on the Company's ownership percentage was $38.5 million.

Note 20 - Subsequent Event

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

Supplementary Financial Information

Quarterly Data (Unaudited)

The following unaudited information shows selected items by quarter for the years 2018 and 2017:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
2018				
Operating revenues	$ **976,293**	$ **1,064,597**	$ **1,280,787**	$ **1,209,875**
Operating expenses	**906,917**	**990,605**	**1,140,783**	**1,091,524**
Operating income	**69,376**	**73,992**	**140,004**	**118,351**
Income from continuing operations	**41,960**	**44,075**	**107,369**	**75,982**
Income (loss) from discontinued operations, net of tax	**477**	**(273)**	**(118)**	**2,846**
Net income	**42,437**	**43,802**	**107,251**	**78,828**
Earnings per common share - basic:				
Earnings before discontinued operations	**.22**	**.22**	**.55**	**.39**
Discontinued operations, net of tax	**—**	**—**	**—**	**.01**
Earnings per common share - basic	**.22**	**.22**	**.55**	**.40**
Earnings per common share - diluted:				
Earnings before discontinued operations	**.22**	**.22**	**.55**	**.39**
Discontinued operations, net of tax	**—**	**—**	**—**	**.01**
Earnings per common share - diluted	**.22**	**.22**	**.55**	**.40**
Weighted average common shares outstanding:				
Basic	**195,304**	**195,524**	**196,018**	**196,023**
Diluted	**195,982**	**196,169**	**196,265**	**196,385**
2017				
Operating revenues	$ 937,925	$ 1,067,639	$ 1,272,548	$ 1,165,239
Operating expenses	872,139	988,979	1,117,228	1,040,957
Operating income	65,786	78,660	155,320	124,282
Income from continuing operations	35,638	44,405	89,549	115,394
Income (loss) from discontinued operations, net of tax	1,687	(3,190)	(2,198)	(82)
Net income	37,325	41,215	87,351	115,312
Earnings per common share - basic:				
Earnings before discontinued operations	.18	.22	.46	.59
Discontinued operations, net of tax	.01	(.01)	(.01)	—
Earnings per common share - basic	.19	.21	.45	.59
Earnings per common share - diluted:				
Earnings before discontinued operations	.18	.22	.46	.59
Discontinued operations, net of tax	.01	(.01)	(.01)	—
Earnings per common share - diluted	.19	.21	.45	.59
Weighted average common shares outstanding:				
Basic	195,304	195,304	195,304	195,304
Diluted	196,023	195,973	195,783	195,617

Notes:
- Fourth quarter 2017 reflects an income tax benefit of $39.5 million related to the TCJA. For more information, see Note 13.

Certain operations of the Company are highly seasonal and revenues from and certain expenses for such operations may fluctuate significantly among quarterly periods. Accordingly, quarterly financial information may not be indicative of results for a full year.

Definitions

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

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
Brazilian Transmission Lines	Company's former investment in companies owning three electric transmission lines in Brazil
Calumet	Calumet Specialty Products Partners, L.P.
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial's Consolidated EBITDA	Centennial's consolidated net income from continuing operations plus the related interest expense, taxes, depreciation, depletion, amortization of intangibles and any non-cash charge relating to asset impairment for the preceding 12-month period
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
Company	MDU Resources Group, Inc. (formerly known as MDUR Newco), which, as the context requires, refers to the previous MDU Resources Group, Inc. prior to January 1, 2019, and the new holding company of the same name after January 1, 2019
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
Coyote Station	427-MW coal-fired electric generating facility near Beulah, North Dakota (25 percent ownership)
Dakota Prairie Refinery	20,000-barrel-per-day diesel topping plant built by Dakota Prairie Refining in southwestern North Dakota
Dakota Prairie Refining	Dakota Prairie Refining, LLC, a limited liability company previously owned by WBI Energy and Calumet (previously included in the Company's refining segment)
EBITDA	Earnings before interest, taxes, depreciation, depletion and amortization
EIN	Employer Identification Number
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings (previously referred to as the Company's exploration and production segment)
FIP	Funding improvement plan
GAAP	Accounting principles generally accepted in the United States of America
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company prior to the closing of the Holding Company Reorganization and a public utility division of Montana-Dakota as of January 1, 2019
Holding Company Reorganization	The internal holding company reorganization completed on January 1, 2019, pursuant to the agreement and plan of merger, dated as of December 31, 2018, by and among Montana-Dakota, the Company and MDUR Newco Sub, which resulted in the Company becoming a holding company and owning all of the outstanding capital stock of Montana-Dakota.
IBEW	International Brotherhood of Electrical Workers
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
Knife River - Northwest	Knife River Corporation - Northwest, an indirect wholly owned subsidiary of Knife River
K-Plan	Company's 401(k) Retirement Plan
LWG	Lower Willamette Group
MDU Construction Services	MDU Construction Services Group, Inc., a direct wholly owned subsidiary of Centennial
MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of the Company
MDUR Newco	MDUR Newco, Inc., a public holding company created by implementing the Holding Company Reorganization, now known as the Company
MDUR Newco Sub	MDUR Newco Sub, Inc., a direct, wholly owned subsidiary of MDUR Newco, which was merged with and into Montana–Dakota in the Holding Company Reorganization
MEPP	Multiemployer pension plan
MISO	Midcontinent Independent System Operator, Inc.

MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co. (formerly known as MDU Resources Group, Inc.), a public utility division of the Company prior to the closing of the Holding Company Reorganization and a direct wholly owned subsidiary of MDU Energy Capital as of January 1, 2019
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
Oil	Includes crude oil and condensate
OPUC	Oregon Public Utility Commission
Oregon DEQ	Oregon State Department of Environmental Quality
PRP	Potentially Responsible Party
ROD	Record of Decision
RP	Rehabilitation plan
SDPUC	South Dakota Public Utilities Commission
SEC	United States Securities and Exchange Commission
SSIP	System Safety and Integrity Program
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan which was terminated effective December 5, 2016
TCJA	Tax Cuts and Jobs Act
Tesoro	Tesoro Refining & Marketing Company LLC
VIE	Variable interest entity
Washington DOE	Washington State Department of Ecology
WBI Energy	WBI Energy, Inc., a direct wholly owned subsidiary of WBI Holdings
WBI Energy Transmission	WBI Energy Transmission, Inc., an indirect wholly owned subsidiary of WBI Holdings
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
WUTC	Washington Utilities and Transportation Commission
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
WYPSC	Wyoming Public Service Commission

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

The following information includes the evaluation of disclosure controls and procedures by the Company's chief executive officer and the chief financial officer, along with any significant changes in internal controls of the Company.

Evaluation of Disclosure Controls and Procedures

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. The Company's disclosure controls and other procedures are designed to provide reasonable assurance that information required to be disclosed in the reports that the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The Company's disclosure controls and procedures include controls and procedures designed to provide reasonable assurance that information required to be disclosed is accumulated and communicated to management, including the Company's chief executive officer and chief financial officer, to allow timely decisions regarding required disclosure. The Company's management, with the participation of the Company's chief executive officer and chief financial officer, has evaluated the effectiveness of the Company's disclosure controls and procedures. Based upon that evaluation, the chief executive officer and the chief financial officer have concluded that, as of the end of the period covered by this report, such controls and procedures were effective at a reasonable assurance level.

Changes in Internal Controls

No change in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the three months ended December 31, 2018, that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

The information required by this item is included in this Form 10-K at Item 8 - Management's Report on Internal Control Over Financial Reporting.

Attestation Report of the Registered Public Accounting Firm

The information required by this item is included in this Form 10-K at Item 8 - Report of Independent Registered Public Accounting Firm.

Item 9B. Other Information

None.

Item 10. Directors, Executive Officers and Corporate Governance

Information required by this item will be included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 11. Executive Compensation

Information required by this item will be included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Equity Compensation Plan Information

The following table includes information as of December 31, 2018, with respect to the Company's equity compensation plans:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights		(b) Weighted average exercise price of outstanding options, warrants and rights		(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))	
Equity compensation plans approved by stockholders (1)	691,629	(2)	$ —	(3)	4,357,330	(4)(5)
Equity compensation plans not approved by stockholders	N/A		N/A		N/A	
Total	691,629		$ —		4,357,330	

(1) Consists of the Non-Employee Director Long-Term Incentive Compensation Plan and the Long-Term Performance-Based Incentive Plan.
(2) Consists of performance shares and restricted stock awards.
(3) No weighted average exercise price is shown for the performance shares or restricted stock awards because such awards have no exercise price.
(4) This amount includes 4,041,479 shares available for future issuance under the Long-Term Performance-Based Incentive Plan in connection with grants of restricted stock, performance units, performance shares or other equity-based awards.
(5) This amount includes 315,851 shares available for future issuance under the Non-Employee Director Long-Term Incentive Compensation Plan.

The remaining information required by this item will be included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item will be included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

Information required by this item will be included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 15. Exhibits, Financial Statement Schedules

(a) Financial Statements, Financial Statement Schedules and Exhibits

Index to Financial Statements and Financial Statement Schedules

1. Financial Statements

The following consolidated financial statements required under this item are included under Item 8 - Financial Statements and Supplementary Data.

2. Financial Statement Schedules

The following financial statement schedules are included in Part IV of this report.

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

Years ended December 31,	2018	2017	2016
		(In thousands)	
Operating revenues	$ 628,331	$ 623,693	$ 561,266
Operating expenses	540,125	520,069	469,853
Operating income	88,206	103,624	91,413
Other income	1,504	4,876	2,282
Interest expense	32,761	31,997	31,519
Income before income taxes	56,949	76,503	62,176
Income taxes	(4,259)	13,800	6,355
Equity in earnings of subsidiaries from continuing operations	208,177	222,283	177,275
Net income from continuing operations	269,385	284,986	233,096
Equity in earnings (loss) of subsidiaries from discontinued operations attributable to the Company	2,933	(3,783)	(168,663)
Loss on redemption of preferred stocks	—	600	—
Dividends declared on preferred stocks	—	171	685
Earnings on common stock	$ 272,318	$ 280,432	$ 63,748
Comprehensive income	$ 279,269	$ 279,602	$ 65,848

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

MDU RESOURCES GROUP, INC.
Schedule I - Condensed Financial Information of Registrant (Unconsolidated)
Condensed Balance Sheets

December 31,	2018	2017
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	**$ 2,271**	$ 843
Receivables, net	**92,724**	83,453
Accounts receivable from subsidiaries	**36,015**	34,029
Inventories	**13,293**	13,864
Prepayments and other current assets	**14,488**	34,400
Total current assets	**158,791**	166,589
Investments	**76,202**	76,779
Investment in subsidiaries	**1,790,886**	1,704,908
Property, plant and equipment	**2,846,715**	2,631,161
Less accumulated depreciation, depletion and amortization	**836,735**	797,130
Net property, plant and equipment	**2,009,980**	1,834,031
Deferred charges and other assets:		
Goodwill	**4,812**	4,812
Other	**180,473**	175,599
Total deferred charges and other assets	**185,285**	180,411
Total assets	**$ 4,221,144**	$ 3,962,718
Liabilities and Stockholders' Equity		
Current liabilities:		
Long-term debt due within one year	**$ 200,711**	$ 100,011
Accounts payable	**50,051**	47,000
Accounts payable to subsidiaries	**12,438**	7,234
Taxes payable	**24,704**	13,717
Dividends payable	**39,695**	38,573
Accrued compensation	**14,346**	20,017
Other accrued liabilities	**54,099**	36,881
Total current liabilities	**396,044**	263,433
Long-term debt	**586,012**	612,493
Deferred credits and other liabilities:		
Deferred income taxes	**165,122**	147,847
Other	**507,191**	509,902
Total deferred credits and other liabilities	**672,313**	657,749
Commitments and contingencies		
Stockholders' equity:		
Common stock		
Authorized - 500,000,000 shares, $1.00 par value		
Issued - 196,564,907 shares in 2018 and 195,843,297 shares in 2017	**196,565**	195,843
Other paid-in capital	**1,248,576**	1,233,412
Retained earnings	**1,163,602**	1,040,748
Accumulated other comprehensive loss	**(38,342)**	(37,334)
Treasury stock at cost - 538,921 shares	**(3,626)**	(3,626)
Total stockholders' equity	**2,566,775**	2,429,043
Total liabilities and stockholders' equity	**$ 4,221,144**	$ 3,962,718

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

MDU RESOURCES GROUP, INC.
Schedule I - Condensed Financial Information of Registrant (Unconsolidated)
Condensed Statements of Cash Flows

Years ended December 31,	2018	2017	2016
		(In thousands)	
Net cash provided by operating activities	$ **294,379**	$ 284,075	$ 238,125
Investing activities:			
Capital expenditures	**(242,692)**	(146,370)	(159,570)
Net proceeds from sale or disposition of property and other	**5,032**	(5,665)	3,784
Investments in and advances to subsidiaries	**(40,000)**	(40,000)	(5,000)
Advances from subsidiaries	**70,000**	40,000	15,000
Investments	**(528)**	(468)	(129)
Net cash used in investing activities	**(208,188)**	(152,503)	(145,915)
Financing activities:			
Issuance of long-term debt	**199,422**	70,080	106,420
Repayment of long-term debt	**(125,961)**	(37,569)	(50,010)
Payments of stock issuance costs	**(10)**	—	—
Dividends paid	**(154,573)**	(150,727)	(147,156)
Redemption of preferred stock	**—**	(15,600)	—
Repurchase of common stock	**(1,920)**	(564)	—
Tax withholding on stock-based compensation	**(1,721)**	(508)	(226)
Net cash used in financing activities	**(84,763)**	(134,888)	(90,972)
Increase (decrease) in cash and cash equivalents	**1,428**	(3,316)	1,238
Cash and cash equivalents - beginning of year	**843**	4,159	2,921
Cash and cash equivalents - end of year	$ **2,271**	$ 843	$ 4,159

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

Notes to Condensed Financial Statements

Note 1 - Summary of Significant Accounting Policies

Basis of presentation The condensed financial information reported in Schedule I is being presented to comply with Rule 12-04 of Regulation S-X. The information is unconsolidated and is presented for the parent company only, which is comprised of MDU Resources Group, Inc. (the Company) and Montana-Dakota and Great Plains, public utility divisions of the Company as of December 31, 2018, prior to the Holding Company Reorganization. In Schedule I, investments in subsidiaries are presented under the equity method of accounting where the assets and liabilities of the subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded on the Condensed Balance Sheets. The income from subsidiaries is reported as equity in earnings of subsidiaries on the Condensed Statements of Income. The consolidated financial statements of MDU Resources Group, Inc. reflect certain businesses as discontinued operations. These statements should be read in conjunction with the consolidated financial statements and notes thereto of MDU Resources Group, Inc.

Earnings per common share Please refer to the Consolidated Statements of Income of the registrant for earnings per common share. In addition, see Item 8 - Note 1 for information on the computation of earnings per common share.

Note 2 - Debt At December 31, 2018, the Company had long-term debt maturities, excluding unamortized debt issuance costs, of $200.7 million in 2019, $700,000 in 2020, $700,000 in 2021, $700,000 in 2022, $49.2 million in 2023 and $536.7 million scheduled to mature in years after 2023.

For more information on debt, see Item 8 - Note 8.

Note 3 - Dividends The Company depends on earnings and dividends from its subsidiaries to pay dividends on common stock. Cash dividends paid to the Company by subsidiaries were $115.9 million, $116.1 million and $115.8 million for the years ended December 31, 2018, 2017 and 2016, respectively.

MDU RESOURCES GROUP, INC.

Schedule II - Consolidated Valuation and Qualifying Accounts

For the years ended December 31, 2018, 2017 and 2016

Description	Balance at Beginning of Year	Additions: Charged to Costs and Expenses	Additions: Other *	Deductions **	Balance at End of Year
	(In thousands)				
Allowance for doubtful accounts:					
2018	**$ 8,069**	**$ 7,532**	**$ 1,121**	**$ 7,872**	**$ 8,850**
2017	10,479	7,024	989	10,423	8,069
2016	9,835	8,302	851	8,509	10,479

* Recoveries.
** Uncollectible accounts written off.

All other schedules are omitted because of the absence of the conditions under which they are required, or because the information required is included in the Company's Consolidated Financial Statements and Notes thereto.

Item 16. Form 10-K Summary

None.

3. Exhibits

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference: Form	Period Ended	Exhibit	Filing Date	File Number
2(a)	Membership Interest Purchase Agreement, dated as of June 24, 2016, between WBI Energy, Inc. and Tesoro Refining & Marketing Company LLC		8-K/A		2.1	7/21/16	1-03480
2(b)	Purchase and Sale Agreement, dated as of June 9, 2016, by and among Calumet North Dakota, LLC, WBI Energy, Inc., and as applicable, MDU Resources Group, Inc., Centennial Energy Holdings, Inc., and Calumet Specialty Products Partners, L.P.		8-K/A		2.2	7/21/16	1-03480
2(c)	Amendment No. 1 to Purchase and Sale Agreement, dated as of June 9, 2016, by and among Calumet North Dakota, LLC, WBI Energy, Inc., and as applicable, MDU Resources Group, Inc., Centennial Energy Holdings, Inc., and Calumet Specialty Products Partners, L.P.		8-K/A		2.3	7/21/16	1-03480
2(d)	Agreement and Plan of Merger, dated December 31, 2018, by and among MDU Resources Group, Inc., MDUR Newco, Inc. MDU Newco Sub, Inc.		8-K		2(a)	1/2/19	1-03480
3(a)	Certificate of Merger, dated December 31, 2018		8-K		3(a)	1/2/19	1-03480
3(b)	Amended and Restated Certificate of Incorporation of MDU Resources Group, Inc.		8-K		3(a)	1/2/19	1-03480
3(c)	Amended and Restated Bylaws of MDU Resources Group, Inc.		8-K		3.1	2/15/19	1-03480
4(a)	Indenture, dated as of December 15, 2003, between MDU Resources Group, Inc. and The Bank of New York, as trustee		S-8		4(f)	1/21/04	333-112035
4(b)	First Supplemental Indenture, dated as of November 17, 2009, between MDU Resources Group, Inc. and the Bank of New York Mellon, as trustee		10-K	12/31/09	4(c)	2/17/10	1-03480
4(c)	Centennial Energy Holdings, Inc. Amended and Restated Master Shelf Agreement, effective as of April 29, 2005, among Centennial Energy Holdings, Inc., the Prudential Insurance Company of America and certain investors described therein		10-Q	6/30/05	4(a)	8/3/05	1-03480

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference Form	Period Ended	Exhibit	Filing Date	File Number
4(d)	Letter Amendment No. 1 to Amended and Restated Master Shelf Agreement, dated May 17, 2006, among Centennial Energy Holdings, Inc., the Prudential Insurance Company of America, and certain investors described in the Letter Amendment		10-Q	6/30/06	4(a)	8/4/06	1-03480
4(e)	Letter Amendment No. 2 to Amended and Restated Master Shelf Agreement, dated December 19, 2007, among Centennial Energy Holdings, Inc., the Prudential Insurance Company of America, and certain investors described in the Letter Amendment		10-K	12/31/15	4(e)	2/19/16	1-03480
4(f)	Letter Amendment No. 3 to Amended and Restated Master Shelf Agreement, dated December 18, 2015, among Centennial Energy Holdings, Inc., the Prudential Insurance Company of America, and certain investors described in the Letter Amendment		10-K	12/31/15	4(f)	2/19/16	1-03480
4(g)	MDU Resources Group, Inc. Credit Agreement, dated May 26, 2011, among MDU Resources Group, Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent		10-K	12/31/11	4(e)	2/24/12	1-03480
4(h)	First Amendment to Credit Agreement, dated October 4, 2012, among MDU Resources Group, Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent		10-Q	9/30/12	4	11/7/12	1-03480
4(i)	Second Amendment to Credit Agreement, dated May 8, 2014 among MDU Resources Group Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent		10-Q	6/30/14	4(a)	8/8/14	1-03480
4(j)	Third Amended and Restated Credit Agreement, dated May 8, 2014, among Centennial Energy Holdings Inc., U.S. Bank National Association, as Administrative Agent, and The Several Financial Institutions party thereto		10-Q	6/30/14	4(b)	8/8/14	1-03480
4(k)	Fourth Amended and Restated Credit Agreement, dated as of September 23, 2016, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Several Financial Institutions party thereto		10-Q	9/30/16	4	11/7/16	1-03480
4(l)	First Amendment to the Fourth Amended and Restated Credit Agreement, dated as of October 26, 2018, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Several Financial Institutions party thereto	X					1-03480
4(m)	MDU Energy Capital, LLC Master Shelf Agreement, dated as of August 9, 2007, among MDU Energy Capital, LLC, Prudential Investment Management, Inc., the Prudential Insurance Company of America and the holders of the notes thereunder		8-K		4	8/16/07	1-03480
4(n)	Amendment No. 1 to Master Shelf Agreement, dated October 1, 2008, among MDU Energy Capital, LLC, Prudential Investment Management, Inc., the Prudential Insurance Company of America, and the holders of the notes thereunder		10-Q	9/30/08	4(b)	11/5/08	1-03480
4(o)	Indenture dated as of August 1, 1992, between Cascade Natural Gas Corporation and The Bank of New York relating to Medium-Term Notes, filed by Cascade Natural Gas Corporation		8-K		4	8/12/92	1-07196
4(p)	First Supplemental Indenture dated as of October 25, 1993, between Cascade Natural Gas Corporation and The Bank of New York relating to Medium-Term Notes and the 7.5% Notes due November 15, 2031, filed by Cascade Natural Gas Corporation		10-Q	6/30/93	4		1-07196
4(q)	Second Supplemental Indenture, dated January 25, 2005, between Cascade Natural Gas Corporation and The Bank of New York, as trustee, filed by Cascade Natural Gas Corporation		8-K		4.1	1/26/05	1-07196

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference Form	Period Ended	Exhibit	Filing Date	File Number
4(r)	Third Supplemental Indenture dated as of March 8, 2007, between Cascade Natural Gas Corporation and The Bank of New York Trust Company, N.A., as Successor Trustee, filed by Cascade Natural Gas Corporation		8-K		4.1	3/8/07	1-07196
4(s)	MDU Resources Group, Inc. Credit Agreement, dated June 8, 2018, among MDU Resources Group, Inc, Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent		10-Q	6/30/18	4(a)	8/3/18	1-03480
+10(a)	MDU Resources Group, Inc. Supplemental Income Security Plan, as amended and restated May 10, 2017		10-Q	6/30/17	10(d)	8/4/17	1-03480
+10(b)	MDU Resource Group, Inc. Director Compensation Policy, as amended November 15, 2018	X					1-03480
+10(c)	Deferred Compensation Plan for Directors, as amended May 15, 2008		10-Q	6/30/08	10(a)	8/7/08	1-03480
+10(d)	Non-Employee Director Stock Compensation Plan, as amended May 12, 2011		10-Q	6/30/11	10(a)	8/5/11	1-03480
+10(e)	MDU Resources Group, Inc. Non-Employee Director Long-Term Incentive Compensation Plan, as amended May 17, 2012		10-Q	6/30/12	10(a)	8/7/12	1-03480
+10(f)	MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan, as amended February 11, 2016		10-K	12/31/15	10(f)	2/19/16	1-03480
+10(g)	MDU Resources Group, Inc. Executive Incentive Compensation Plan, as amended May 10, 2017, and Rules and Regulations, as amended May 9, 2017		10-Q	6/30/17	10(b)	8/4/17	1-03480
+10(h)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 10, 2016		8-K		10.3	2/18/16	1-03480
+10(i)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 16, 2017		8-K		10.1	2/21/17	1-03480
+10(j)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 14, 2018		8-K		10.1	2/21/18	1-03480
+10(k)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 14, 2019	X					1-03480
+10(l)	Form of Annual Incentive Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 10, 2016		8-K		10.2	2/18/16	1-03480
+10(m)	Restricted Stock Unit Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 14, 2018		8-K		10.3	2/21/18	1-03480
+10(n)	Form of MDU Resources Group, Inc. Indemnification Agreement for Section 16 Officers and Directors, dated May 15, 2014		8-K		10.1	5/15/14	1-03480
+10(o)	Form of Amendment No. 1 to Indemnification Agreement, dated May 15, 2014		8-K		10.2	5/15/14	1-03480
+10(p)	MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart, as of October 10, 2017		10-Q	9/30/17	10(b)	11/3/17	1-03480
+10(q)	MDU Resources Group, Inc. Nonqualified Defined Contribution Plan, as amended May 10, 2017		10-Q	6/30/17	10(c)	8/4/17	1-03480
+10(r)	MDU Resources Group, Inc. 401(k) Retirement Plan, as restated January 1, 2017		10-Q	3/31/17	10(a)	5/8/17	1-03480
+10(s)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 31, 2017		10-Q	3/31/17	10(b)	5/8/17	1-03480

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference Form	Period Ended	Exhibit	Filing Date	File Number
+10(t)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated April 10, 2017		10-Q	6/30/17	10(e)	8/4/17	1-03480
+10(u)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 30, 2017		10-Q	9/30/17	10(a)	11/3/17	1-03480
+10(v)	Employment Letter for Jeffrey S. Thiede, dated May 16, 2013		10-K	12/31/13	10(ab)	2/21/14	1-03480
+10(w)	Jason L. Vollmer Offer Letter, dated March 7, 2016		8-K		10.2	3/8/16	1-03480
+10(x)	Jason L. Vollmer Offer Letter, dated September 20, 2017		8-K		10.1	9/21/17	1-03480
21	Subsidiaries of MDU Resources Group, Inc.	X					
23	Consent of Independent Registered Public Accounting Firm	X					
31(a)	Certification of Chief Executive Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X					
31(b)	Certification of Chief Financial Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X					
32	Certification of Chief Executive Officer and Chief Financial Officer furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	X					
95	Mine Safety Disclosures	X					
101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document						
101.SCH	XBRL Taxonomy Extension Schema Document						
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document						
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document						
101.LAB	XBRL Taxonomy Extension Label Linkbase Document						
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document						

+ Management contract, compensatory plan or arrangement.

MDU Resources Group, Inc. agrees to furnish to the SEC upon request any instrument with respect to long-term debt that MDU Resources Group, Inc. has not filed as an exhibit pursuant to the exemption provided by Item 601(b)(4)(iii)(A) of Regulation S-K.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

MDU Resources Group, Inc.

Date:	February 22, 2019	By:	/s/ David L. Goodin
			David L. Goodin (President and Chief Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant in the capacities and on the date indicated.

Signature	Title	Date
/s/ David L. Goodin David L. Goodin (President and Chief Executive Officer)	Chief Executive Officer and Director	February 22, 2019
/s/ Jason L. Vollmer Jason L. Vollmer (Vice President, Chief Financial Officer and Treasurer)	Chief Financial Officer	February 22, 2019
/s/ Stephanie A. Barth Stephanie A. Barth (Vice President, Chief Accounting Officer and Controller)	Chief Accounting Officer	February 22, 2019
/s/ Harry J. Pearce Harry J. Pearce (Chair of the Board)	Director	February 22, 2019
/s/ Thomas Everist Thomas Everist	Director	February 22, 2019
/s/ Karen B. Fagg Karen B. Fagg	Director	February 22, 2019
/s/ Mark A. Hellerstein Mark A. Hellerstein	Director	February 22, 2019
/s/ Dennis W. Johnson Dennis W. Johnson	Director	February 22, 2019
/s/ William E. McCracken William E. McCracken	Director	February 22, 2019
/s/ Patricia L. Moss Patricia L. Moss	Director	February 22, 2019
/s/ Edward A. Ryan Edward A. Ryan	Director	February 22, 2019
/s/ David M. Sparby David M. Sparby	Director	February 22, 2019
/s/ John K. Wilson John K. Wilson	Director	February 22, 2019

MDU RESOURCES GROUP, INC.

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

David L. Goodin
President and
Chief Executive Officer

March 22, 2019

Fellow Stockholders:

I invite you to join me, our Board of Directors and members of our senior management team for our annual meeting at 11 a.m. CDT May 7, 2019, at 909 Airport Road in Bismarck, North Dakota.

At the meeting, stockholders will vote on the items outlined in this proxy statement, including election of our Board of Directors, approval of our independent auditors, and approval of the amended certificates of incorporation for MDU Resources Group and Montana-Dakota Utilities.

Our director slate up for election includes three candidates who have not previously been on the ballot: Edward A. Ryan, David M. Sparby and Chenxi Wang. Edward and David were appointed to the board during 2018. Chenxi has been put forward as a candidate by our Nominating and Governance Committee because of her expertise in technology and cybersecurity. These three new candidates will help ensure a smooth leadership transition as Bart Holaday did not stand for re-election in 2018 and Harry Pearce and Bill McCracken will not stand for re-election this year. Our corporate bylaws state that directors are not eligible for election to the board after their 76th birthday. We deeply appreciate the diligent and faithful service that Harry, Bart and Bill have provided to MDU Resources' stockholders. Harry, especially, has served you well in his 22 years as a director, including five years as independent lead director and the past 14 years as chair of the board.

Also before stockholders for a vote are resolutions to amend the certificates of incorporation for MDU Resources and Montana-Dakota Utilities. These amendments follow the reorganization of our corporate structure at the start of 2019. The reorganization was undertaken to further delineate the separation between our utility companies and our other businesses. Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. were originally structured as divisions of MDU Resources, as required by the Public Utility Holding Company Act of 1935. The Energy Policy Act of 2005 repealed the PUHCA and allowed us to restructure these companies as a subsidiary. Montana-Dakota Utilities is now a subsidiary of MDU Resources and Great Plains Natural Gas is a division of Montana-Dakota Utilities. This reorganization simplifies our corporate structure and provides greater flexibility in our financing options.

In addition to the business items to be conducted at the annual meeting, I will provide an overview of our strong 2018 financial results and the acquisitions and other growth projects we accomplished. We started 2019 with strong momentum, and I will tell you more about the record backlog of work we have at our construction operations and the additional growth projects we expect to complete this year.

I look forward to seeing you May 7. Details on how to receive an admission ticket to attend our annual meeting are included in the Notice of Annual Meeting of Stockholders as well as on page 67 of this Proxy Statement.

If you cannot attend the annual stockholder meeting, your vote is still important to us. I ask that you please promptly follow the instructions on your notice or proxy card to vote.

We appreciate your continued investment in MDU Resources and remain committed to providing the long-term value you expect.

Sincerely,

David L. Goodin
President and Chief Executive Officer

MDU RESOURCES GROUP, INC.

1200 West Century Avenue

Mailing Address:
P.O. Box 5650
Bismarck, North Dakota 58506-5650
(701) 530-1000

NOTICE OF ANNUAL MEETING OF STOCKHOLDERS TO BE HELD MAY 7, 2019

March 22, 2019

NOTICE IS HEREBY GIVEN that the Annual Meeting of Stockholders of MDU Resources Group, Inc. will be held at 909 Airport Road, Bismarck, North Dakota 58504, on Tuesday, May 7, 2019, at 11:00 a.m., Central Daylight Saving Time, for the following purposes:

Items of Business

1. Election of directors;
2. Advisory vote to approve the compensation paid to the company's named executive officers;
3. Ratification of the appointment of Deloitte & Touche LLP as the company's independent registered public accounting firm for 2019;
4. Approval of an Amendment to Montana-Dakota Utilities Co.'s Restated Certificate of Incorporation;
5. Approval of Amendments to Update and Modernize the Company's Amended and Restated Certificate of Incorporation; and
6. Transaction of any other business that may properly come before the meeting or any adjournment(s) thereof.

Record Date

The board of directors has set the close of business on March 8, 2019, as the record date for the determination of common stockholders who will be entitled to notice of, and to vote at, the meeting and any adjournment(s) thereof.

Meeting Attendance

All stockholders as of the record date of March 8, 2019, are cordially invited and urged to attend the annual meeting. You must request an admission ticket to attend. If you are a stockholder of record and plan to attend the meeting, please contact MDU Resources Group, Inc. by email at CorporateSecretary@mduresources.com or by telephone at 701-530-1010 to request an admission ticket. A ticket will be sent to you by mail.

If your shares are held beneficially in the name of a bank, broker, or other holder of record, and you plan to attend the annual meeting, you will need to submit a written request for an admission ticket by mail to: Investor Relations, MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506 or by email at CorporateSecretary@mduresources.com. The request must include proof of stock ownership as of March 8, 2019, such as a bank or brokerage firm account statement or a legal proxy from the bank, broker, or other holder of record confirming ownership. A ticket will be sent to you by mail.

Requests for admission tickets must be received no later than May 1, 2019. You must present your admission ticket and state-issued photo identification, such as a driver's license, to gain admittance to the meeting.

Proxy Materials

Notice of Availability of Proxy Materials will be sent on or about March 22, 2019. The Notice contains basic information about the annual meeting and instructions on how to view our proxy materials and vote electronically on the Internet. Stockholders who do not receive the Notice will receive a paper copy of our proxy materials, which will be sent on or about March 28, 2019.

By order of the Board of Directors,

Daniel S. Kuntz
Secretary

Important Notice Regarding the Availability of Proxy Materials for the Stockholder Meeting to be Held on May 7, 2019. The 2019 Notice of Annual Meeting and Proxy Statement and 2018 Annual Report to Stockholders are available at www.mdu.com/proxymaterials.

TABLE OF CONTENTS

PROXY STATEMENT SUMMARY

To assist you in reviewing the company's 2018 performance and voting your shares, we call your attention to key elements of our 2019 Proxy Statement. The following is only a summary and does not contain all the information you should consider. You should read the entire Proxy Statement carefully before voting. For more information about these topics, please review the full Proxy Statement and our 2018 Annual Report to Stockholders.

Meeting Information

Time and Date:
11:00 a.m. Central Daylight Saving Time Tuesday, May 7, 2019
Place:
MDU Service Center 909 Airport Road Bismarck, ND 58504

Summary of Stockholder Voting Matters

Voting Matters	Board Vote Recommendation	See Page
Item 1. Election of Directors	FOR Each Nominee	7
Item 2. Advisory Vote to Approve the Compensation Paid to the Company's Named Executive Officers	FOR	29
Item 3. Ratification of the Appointment of Deloitte & Touche LLP as the Company's Independent Registered Public Accounting Firm for 2019	FOR	57
Item 4. Approval of an Amendment to Montana-Dakota Utilities Co.'s Restated Certificate of Incorporation	FOR	60
Item 5. Approval of Amendments to Update and Modernize the Company's Amended and Restated Certificate of Incorporation	FOR	61

Corporate Governance Highlights

MDU Resources Group, Inc. is committed to strong corporate governance practices. The following highlights our corporate governance practices and policies. See the sections entitled "Corporate Governance" and "Executive Compensation" for more information on the following:

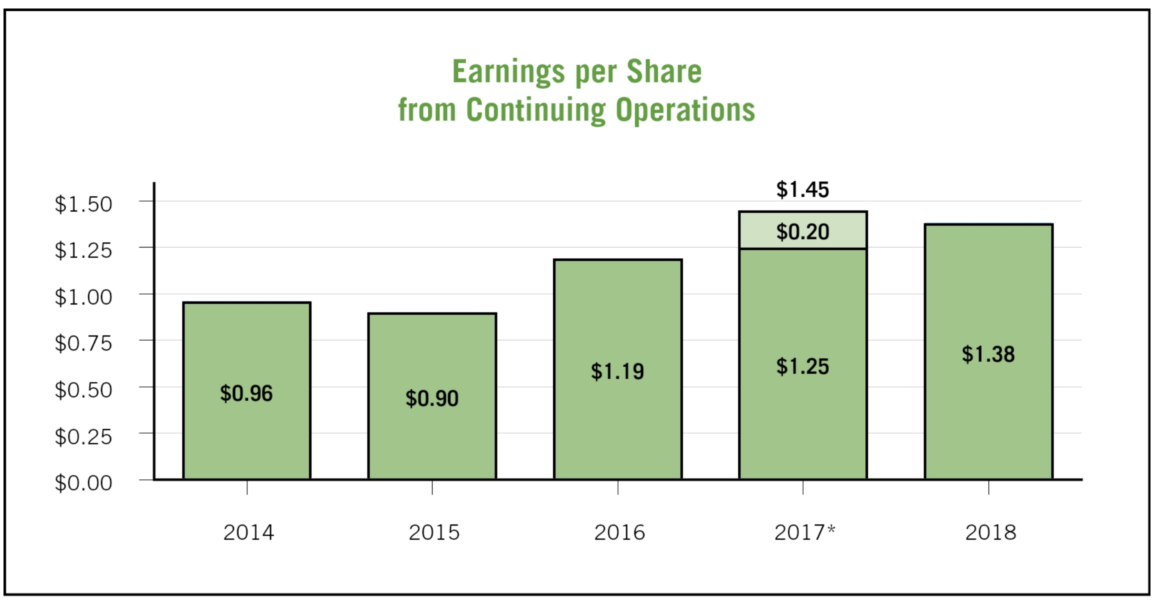
- ✓ Annual Election of All Directors
- ✓ Majority Voting for Directors
- ✓ Succession Planning and Implementation Process
- ✓ Separate Board Chair and CEO
- ✓ Executive Sessions of Independent Directors at Every Regularly Scheduled Board Meeting
- ✓ Annual Board and Committee Self-Evaluations
- ✓ Risk Oversight by Full Board and Committees
- ✓ All Directors are Independent Other Than Our CEO
- ✓ "Proxy Access" Allowing Stockholders to Nominate Directors in Accordance With the Terms of Our Bylaws
- ✓ Standing Committees Consist Entirely of Independent Directors
- ✓ Active Investor Outreach Program
- ✓ Stock Ownership Requirements for Directors and Executive Officers
- ✓ Anti-Hedging and Anti-Pledging Policies for Directors and Executive Officers
- ✓ No Related Party Transactions by Our Directors or Executive Officers
- ✓ Compensation Recovery/Clawback Policy
- ✓ Annual Advisory Approval on Executive Compensation
- ✓ Mandatory Retirement for Directors at Age 76
- ✓ Directors May Not Serve on More Than Three Public Boards Including the Company's Board

Business Performance Highlights

Our overall performance in 2018 was consistent with our long-term strategy as we focused on growing our regulated energy delivery and construction materials and services business segments. In addition to our 2018 financial performance highlighted on the next page:

- Our electric distribution segment completed the purchase of the Thunder Spirit Wind Farm expansion in southwest North Dakota. The purchase boosts the production capacity of the wind farm from 107.5 megawatts to 155 megawatts of renewable energy. This increases the segment's renewable generation capacity from 22% to 27% of its total generation capacity. Construction continued in 2018 on the 345-kilovolt transmission line project from Ellendale, North Dakota, to Big Stone City, South Dakota, and was completed in February 2019.
- Our construction materials and contracting segment completed the following four acquisitions during 2018:
  - Sweetman Const. Co. located in Sioux Falls, South Dakota;
  - Teevin & Fischer Quarry, LLC located in northern Oregon;
  - Tri-City Paving, Inc. located in Little Falls, Minnesota; and
  - Molalla Redi-Mix and Rock Products, Inc. located south of Portland, Oregon.
- The pipeline and midstream segment in 2018 had record transportation volumes for the second consecutive year. The segment expanded Line Section 27 of its natural gas transportation system in northwestern North Dakota. The project involved construction of approximately 13 miles of pipeline and associated facilities. The expansion provides Line Section 27 with capacity to transport over 600,000 dekatherms per day. The segment also completed construction of its 38-mile Valley Expansion Project transmission line in eastern North Dakota and western Minnesota. The segment is proceeding with construction planning on its Demicks Lake Project in McKenzie County, North Dakota, and Line Section 22 Project near Billings, Montana. Both of these projects are expected to be completed in 2019.
- On January 1, 2019, we completed a holding company reorganization to provide additional financing flexibility and further separation between the company's utility and other business segments. As a result of the reorganization, all of the company's utility operations will be conducted through wholly-owned subsidiaries.

Including our accomplishments in 2018, we are optimistic about the company's future financial performance. The chart below shows our progress over the last five years.



* MDU Resources Group, Inc. reported 2017 earnings from continuing operations of $1.45 per share which included a non-recurring benefit of 20 cents per share attributable to the federal Tax Cuts and Jobs Act that was signed into law on December 22, 2017.

2018 Financial Performance Highlights

- Strong year-over-year performance from continuing operations at both our regulated energy segments and our construction materials and services segments resulted in earnings per share from continuing operations of $1.38 per share compared to $1.45 per share in 2017, which included a benefit of 20 cents per share attributable to the federal Tax Cuts and Jobs Act. Including discontinued operations, 2018 earnings were $272.3 million, or $1.39 per share, compared to $280.4 million, or $1.43 cents per share, in 2017.
- Return of stockholder value through dividends:
  - Increased dividend for 28th straight year; and
  - Paid uninterrupted dividend for 81 straight years.
- Maintained BBB+ stable credit rating from Standard & Poor's and Fitch rating agencies.[1]

28 Years of Consecutive Dividend Increases	Dividends Paid $739 Million Over the Last 5 Years	81 Years of Uninterrupted Dividend Payments

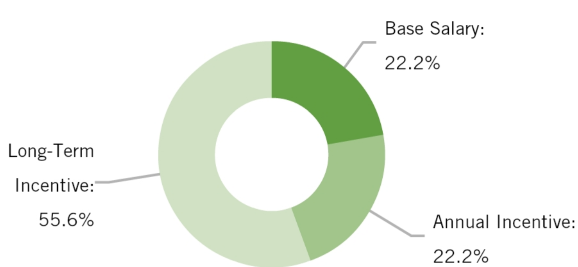
Compensation Highlights

The company's executive compensation is focused on paying for performance. Our compensation program is structured to strongly align compensation with the company's financial performance as a substantial portion of our executive compensation is based upon performance incentive awards.

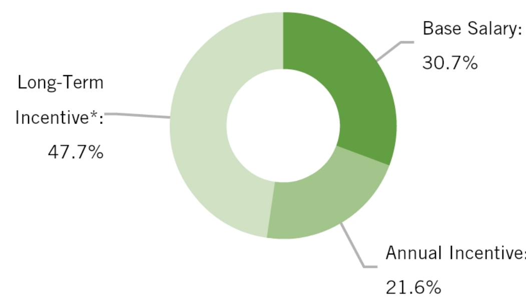
- Over 75% of our chief executive officer's target compensation and over 58% of our other named executive officers' target compensation is performance based.
- 100% of our chief executive officer's annual and long-term incentive compensation is tied to performance against pre-established, specific, measurable financial goals.
- We require our executive officers to own a significant amount of company stock based upon a multiple of their base salary.

2018 Named Executive Officer Target Pay Mix

CEO Target Pay Mix



Other Named Executive Officers Average Target Pay Mix



*Includes time-vesting restricted stock units for certain named executive officers.

[1] A securities rating is not a recommendation to buy, sell, or hold securities, and it may be revised or withdrawn at any time by the rating agency.

Key Features of Our Executive Compensation Program

What We Do

- ☑ **Pay for Performance** - Annual and long-term award incentives tied to performance measures set by the compensation committee comprise the largest portion of executive compensation.
- ☑ **Independent Compensation Committee -** All members of the compensation committee meet the independence standards under the New York Stock Exchange listing standards and the Securities and Exchange Commission rules.
- ☑ **Independent Compensation Consultant** - The compensation committee retains an independent compensation consultant to evaluate executive compensation plans and practices.
- ☑ **Competitive Compensation** - Executive compensation reflects executive performance, experience, relative value compared to other positions within the company, relationship to competitive market value compensation, business segment economic environment, and the actual performance of the overall company and the business segments.
- ☑ **Annual Cash Incentive** - Payment of annual cash incentive awards are based on business segment and overall company performance against pre-established financial measures.
- ☑ **Long-Term Equity Incentive** - The long-term performance-based equity incentive in the form of performance shares represents approximately 56% of our CEO's and approximately 37% of our other named executive officers' 2018 target compensation, which may only be earned based on achievement of established performance measures at the end of a three-year period.
- ☑ **Annual Compensation Risk Analysis** - We regularly analyze the risks related to our compensation programs and conduct an annual broad risk assessment.
- ☑ **Stock Ownership and Retention Requirements** - Executive officers are required to own, within five years of appointment or promotion, company common stock equal to a multiple of their base salary. The executive officers also must retain at least 50% of the net after-tax shares of stock vested through the long-term incentive plan for at least two years or until termination of employment.
- ☑ **Clawback Policy** - If the company's audited financial statements are restated, the compensation committee may, or shall if required, demand repayment of some or all incentives paid to our executive officers within the last three years.

What We Do Not Do

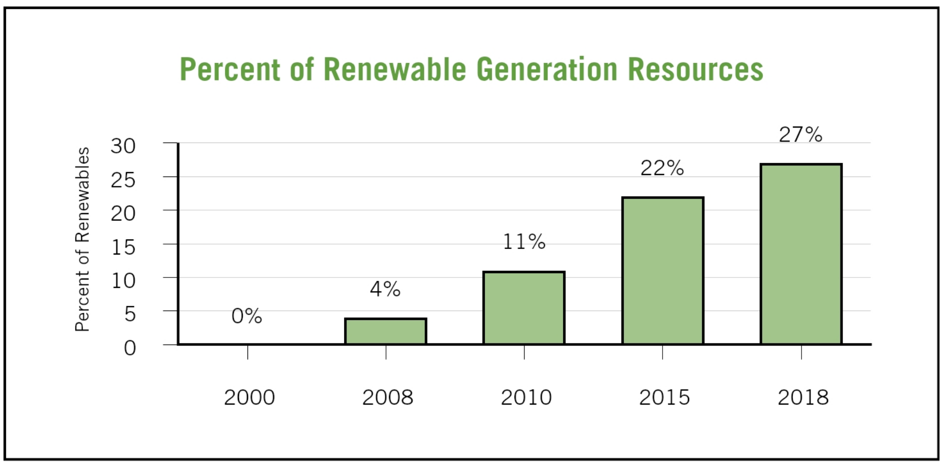
- ☒ **Stock Options** - The company does not use stock options as a form of incentive compensation.
- ☒ **Employment Agreements** - Executives do not have employment agreements entitling them to specific payments upon termination or a change of control of the company.
- ☒ **Perquisites** - Executives do not receive perquisites that materially differ from those available to employees in general.
- ☒ **Hedge Stock** - Executives and directors are not allowed to hedge company securities.
- ☒ **Pledge Stock** - Executives and directors are not allowed to pledge company securities in margin accounts or as collateral for loans.
- ☒ **No Dividends or Dividend Equivalents on Unvested Shares** - We do not provide for payment of dividends or dividend equivalents on unvested share awards.

Corporate Responsibility, Environmental, and Sustainability

MDU Resources Group, Inc. is Building a Strong America® by providing essential products and services to our customers with a long-term view toward sustainable operations. To ensure we can continue to provide these products and services in the communities where we do business, we recognize that we must preserve the trust our communities place in us to be a good corporate citizen. We remain committed to pursuing responsible corporate governance and environmental practices and to maintaining the health and safety of the public and our employees. Learn about our sustainability efforts in our Sustainability Report, which is available at www.mdu.com/sustainability. To better serve our investors and other stakeholders, in 2019 we will begin reporting environmental, social, governance, and sustainability (ESG/sustainability) metrics relevant and important to our operations in frameworks that will provide our stakeholders more uniform and transparent data and information, allowing for comparison with our peers and other companies operating in our industries. For our electric and natural gas distribution segments, as well as our pipeline and midstream segment, we intend to report ESG/sustainability metrics using the reporting templates developed by the Edison Electric Institute and the American Gas Association. For our other business segments, we intend to report ESG/sustainability information under the framework developed by the Sustainability Accounting Standards Board (SASB) for our applicable industries. The use of the metrics developed by these organizations provides for ESG/sustainability reporting tailored to our industries.

These are some highlights of our recent efforts regarding sustainability:

- As our renewable generation resource capacity has increased, the carbon dioxide (CO_2) emission intensity of our electric generation resource fleet has been reduced by approximately 24% since 2003. We expect it to continue to decline in future years.
- Renewable resources comprised approximately 27% of our electric generation resource nameplate capacity at December 31, 2018.



- Approximately 21% of the electricity delivered to our customers from company-owned generation in 2018 was from renewable resources.
- We invested approximately $133 million in environmental emission control equipment and other environmental improvements at our coal-fired electric generation plants since 2013. The investments have resulted in substantial reductions in mercury, sulfur dioxide, nitrogen oxide, and filterable particulate emissions from our coal-fired electric generation resources.
- Montana-Dakota Utilities Co. produces renewable natural gas (RNG) from the Billings Regional Landfill in Montana. The project came online at the end of 2010 and has produced approximately 1.1 million dekatherm of RNG through year-end 2018. The RNG is supplied to the vehicle fuel market generating renewable identification numbers (RINS) and low carbon fuel standard (LCFS) credits in California and Oregon. In calendar year 2018, the Billings Landfill Plant produced approximately 1.86 million RINs and 3,250 LCFS credits.
- Our utility companies received high scores in customer satisfaction. Cascade Natural Gas Corporation ranked first, Intermountain Gas Company second, and Montana-Dakota Utilities Co. third among West Region mid-sized natural gas utilities in the 2018 J.D. Power Gas Utility Residential Customer Satisfaction Survey.
- We were recognized on the Thomson Reuters 2017 Top 25 Global Multiline Utilities list. The list recognizes companies that have demonstrated a commitment to energy leadership in these areas: financial, management and investor confidence, risk and resilience, legal compliance, innovation, people and social sustainability, environmental impact, and reputation.

- Knife River Corporation produces and places warm-mix asphalt in applications where warm-mix asphalt is allowed. Warm-mix asphalt is produced at cooler temperatures than traditional hot-mix asphalt methods, which reduces the amount of fuel needed in the production process and thereby reduces emissions and fumes.
- Knife River Corporation continued its practice of recycling and reusing building materials. This conserves natural resources, uses less energy, alleviates waste disposal problems in local landfills, and ultimately costs less for the consumer.
- Our subsidiary, Bombard Renewable Energy, was ranked No. 13 on Solar Power World's 2018 Top 500 Solar Contractors List. The list ranks companies according to their influence in the U.S. solar industry based on how many kilowatts of solar generation they installed in 2017.
- The MDU Resources Foundation awarded grants of $1.68 million to educational and nonprofit institutions in 2018. Since its incorporation in 1983, the foundation has contributed more than $34 million to worthwhile causes in categories of education, civic and community activities, culture and arts, environmental stewardship, and health and human services.
- We encourage and support community volunteerism by our employees. The MDU Resources Foundation contributes a $500 grant to an eligible nonprofit organization after an employee volunteers a minimum of 25 hours to the organization during non-company hours during a calendar year. In 2018, the foundation granted $40,500 under this program, matching over 4,850 employee volunteer hours.

21% of 2018 Electricity Generated From Renewable Resources	Grants Awarded $1.68 Million in 2018	24% Reduction in CO_2 Intensity Since 2003

BOARD OF DIRECTORS

ITEM 1. ELECTION OF DIRECTORS

The board currently consists of eleven directors, all of whom, except Harry J. Pearce and William E. McCracken, are standing for election to the board at the 2019 Annual Meeting of Stockholders to hold office until the 2020 annual meeting and until their successors are duly elected and qualified. Mr. Pearce and Mr. McCracken will be retiring following the annual meeting in accordance with our retirement age limits. In February 2019, the board of directors determined to reduce the number of directors to ten effective with the 2019 annual meeting and has nominated Chenxi Wang as a new director nominee to stand for election to the board at the annual meeting.

The board has affirmatively determined that all the director nominees, other than David L. Goodin, our president and chief executive officer, are independent in accordance with New York Stock Exchange (NYSE) rules, our governance guidelines, and our bylaws.

Our bylaws provide for a majority voting standard for the election of directors. See "Additional Information - Majority Voting" below for further detail.

Each of the director nominees has consented to be named in this proxy statement and to serve as a director, if elected. We do not know of any reason why any nominee would be unable or unwilling to serve as a director, if elected. If, however, a nominee becomes unable to serve or will not serve, proxies may be voted for the election of such other person nominated by the board as a substitute or the board may further reduce the number of directors.

Information about each director nominee's share ownership is presented below under "Security Ownership."

The shares represented by the proxies received will be voted for the election of each of the ten nominees named below, unless you indicate in the proxy that your vote should be cast against any or all the director nominees or that you abstain from voting. Each nominee elected as a director will continue in office until his or her successor has been duly elected and qualified or until the earliest of his or her resignation, retirement, or death.

The ten nominees for election to the board at the 2019 annual meeting, all proposed by the board, are listed below with brief biographies.

The board of directors recommends that the stockholders vote FOR the election of each nominee.

Director Nominees

Thomas Everist
Age 69

Independent Director Since 1995
Compensation Committee

Other Current Public Boards:
--Raven Industries, Inc.

Mr. Everist has more than 44 years of business experience in the construction materials and aggregate mining industry. He has business leadership and management experience serving as president and chair of his companies for over 31 years. Mr. Everist also has experience serving as a director and chair of another public company, which enhances his contributions to our board.

Career Highlights

- President and chair of The Everist Company, Sioux Falls, South Dakota, an investment and land development company, since April 2002. Prior to January 2017, The Everist Company was engaged in aggregate, concrete, and asphalt production.
- Managing member of South Maryland Creek Ranch, LLC, a land development company; president of SMCR, Inc., an investment company, since June 2006; and managing member of MCR Builders, LLC, which provides residential building services to South Maryland Creek Ranch, LLC, since November 2014.
- Director and chair of the board of Everist Health, Inc., Ann Arbor, Michigan, which provides solutions for personalized medicines, since 2002, and chief executive officer from August 2012 to December 2012.
- President and chair of L.G. Everist, Inc., Sioux Falls, South Dakota, an aggregate production company, from 1987 to April 2002.

Other Leadership Experience

- Director of publicly traded Raven Industries, Inc., Sioux Falls, South Dakota, a general manufacturer of electronics, flow controls, and engineered films, since 1996, and chair from April 2009 to May 2017.
- Director of Showplace Wood Products, Inc., Sioux Falls, South Dakota, a custom cabinets manufacturer, since January 2000.
- Director of Bell, Inc., Sioux Falls, South Dakota, a manufacturer of folding cartons and packages, since April 2011.
- Director of Angiologix Inc., Mountain View, California, a medical diagnostic device company, from July 2010 through October 2011 when it was acquired by Everist Genomics, Inc.
- Member of the South Dakota Investment Council, the state agency responsible for prudently investing state funds, from July 2001 to June 2006.

Education

- Bachelor's degree in mechanical engineering and a master's degree in construction management from Stanford University.

Karen B. Fagg
Age 65

Independent Director Since 2005
Compensation Committee
Nominating and Governance Committee

Ms. Fagg brings experience to our board in construction and engineering, energy, and the responsible development of natural resources, which are all important aspects of our business. In addition to her industry experience, Ms. Fagg has over 20 years of business leadership and management experience, including over eight years as president, chief executive officer, and chair of her own company, as well as knowledge and experience acquired through her service on a number of Montana state and community boards.

Career Highlights

- Vice president of DOWL LLC, dba DOWL HKM, an engineering and design firm, from April 2008 until her retirement in December 2011.
- President of HKM Engineering, Inc., Billings, Montana, an engineering and physical science services firm, from April 1995 to June 2000, and chair, chief executive officer, and majority owner from June 2000 through March 2008. HKM Engineering, Inc. merged with DOWL LLC on April 1, 2008.
- Employed with MSE, Inc., Butte, Montana, an energy research and development company, from 1976 through 1988, and vice president of operations and corporate development director from 1993 to April 1995.
- Director of the Montana Department of Natural Resources and Conservation, Helena, Montana, the state agency charged with promoting stewardship of Montana's water, soil, energy, and rangeland resources; regulating oil and gas exploration and production; and administering several grant and loan programs, for a four-year term from 1989 through 1992.

Other Leadership Experience

- Director of the Billings Catholic Schools Board from December 2011 through December 2018, including a term as chair; and director of St. Vincent's Healthcare Board from October 2003 to October 2009 and from January 2016 to present, including a term as chair.
- Former member of several state and community boards, including the First Interstate BancSystem Foundation, from June 2013 to 2016; the Montana Justice Foundation, whose mission is to achieve equal access to justice for all Montanans through effective funding and leadership, from 2013 into 2015; Board of Trustees of Carroll College from 2005 through 2010; Montana Board of Investments, the state agency responsible for prudently investing state funds, from 2002 through 2006; Montana State University's Advanced Technology Park from 2001 to 2005; and Deaconess Billings Clinic Health System from 1994 to 2002.

Education

- Bachelor's degree in mathematics from Carroll College in Helena, Montana.

David L. Goodin
Age 57

Director Since 2013
President and Chief Executive Officer

As chief executive officer of MDU Resources Group, Inc., Mr. Goodin is the only officer of the company that serves on our board. With over 35 years of significant, hands-on experience at our company, Mr. Goodin's long history and deep knowledge and understanding of MDU Resources Group, Inc., its operating companies, and its lines of business bring continuity to the board. In addition, Mr. Goodin provides the board with valuable insight into management's views and perspectives, as well as the day-to-day operations of the company.

Career Highlights

- President and chief executive officer and a director of the company since January 4, 2013.
- Prior to January 4, 2013, served as chief executive officer and president of Intermountain Gas Company, Cascade Natural Gas Corporation, Montana-Dakota Utilities Co., and Great Plains Natural Gas Co.
- Began his career in 1983 at Montana-Dakota Utilities Co. as a division electrical engineer and served in positions of increasing responsibility until 2007 when he was named president of Cascade Natural Gas Corporation; positions included division electric superintendent, electric systems manager, vice president-operations, and executive vice president-operations and acquisitions.

Other Leadership Experience

- Member of the U.S. Bancorp Western North Dakota Advisory Board since January 2013.
- Director of Sanford Bismarck, an integrated health system dedicated to the work of health and healing, and Sanford Living Center, since January 2011.
- Former board member of several industry associations, including the American Gas Association, the Edison Electric Institute, the North Central Electric Association, the Midwest ENERGY Association, and the North Dakota Lignite Energy Council.

Education and Professional

- Bachelor of science degree in electrical and electronics engineering from North Dakota State University and a master's degree in business administration from the University of North Dakota.
- The Advanced Management Program at Harvard School of Business.
- Registered professional engineer in North Dakota.

Mark A. Hellerstein
Age 66

Independent Director Since 2013
Audit Committee

Mr. Hellerstein has extensive business experience in the energy industry as a result of his 17 years of senior management experience and service as board chair of St. Mary Land & Exploration Company (now SM Energy Company). As a certified public accountant, on inactive status, with extensive financial experience as a result of his employment as chief financial officer with several companies, including public companies, Mr. Hellerstein contributes significant finance and accounting knowledge to our board and audit committee.

Career Highlights

- Chief executive officer of St. Mary Land & Exploration Company (now SM Energy Company), an energy company engaged in the acquisition, exploration, development, and production of crude oil, natural gas, and natural gas liquids, from 1995 until February 2007; president from 1992 until June 2006; and executive vice president and chief financial officer from 1991 until 1992. He was first elected to the board of St. Mary in 1992 and served as chair from 2002 until May 2009.
- Several positions prior to joining St. Mary in 1991, including chief financial officer of CoCa Mines Inc., which mined and extracted minerals from lands previously held by the public through the Bureau of Land Management; American Golf Corporation, which manages and owns golf courses in the United States; and Worldwide Energy Corporation, an oil and gas acquisition, exploration, development, and production company with operations in the United States and Canada.

Other Leadership Experience

- Director of Transocean Inc., a leading provider of offshore drilling services for oil and gas wells, from December 2006 to November 2007.
- Director of the Denver Children's Advocacy Center, whose mission is to provide a continuum of care for traumatized children and their families, from August 2006 until December 2011, including chair for the last three years.

Education and Professional

- Bachelor's degree in accounting from the University of Colorado.
- Certified public accountant, on inactive status.

Dennis W. Johnson
Age 69

Independent Director Since 2001
Audit Committee
Nominating and Governance Committee

Vice Chair of the Board

Mr. Johnson brings to our board over 44 years of experience in business management, manufacturing, and finance, holding positions as chair, president, and chief executive officer of TMI Corporation for 37 years, as well as through his prior service as a director of the Federal Reserve Bank of Minneapolis. As a result of his service on a number of state and local organizations in North Dakota, Mr. Johnson has significant knowledge of local, state, and regional issues involving North Dakota, a state where we have significant operations and assets.

Career Highlights

- Vice chair of the board of the company effective February 15, 2018.
- Chair, president, and chief executive officer of TMI Corporation, and chair and chief executive officer of TMI Transport Corporation, manufacturers of casework and architectural woodwork in Dickinson, North Dakota; employed since 1974 and serving as president or chief executive officer since 1982.

Other Leadership Experience

- Member of the Bank of North Dakota Advisory Board of Directors since August 2017.
- President of the Dickinson City Commission from July 2000 through October 2015.
- Director of the Federal Reserve Bank of Minneapolis from 1993 through 1998.
- Served on numerous industry, state, and community boards, including the North Dakota Workforce Development Council (chair); the Decorative Laminate Products Association; the North Dakota Technology Corporation; and the business advisory council of the Steffes Corporation, a metal manufacturing and engineering firm.
- Served on North Dakota Governor Sinner's Education Action Commission; the North Dakota Job Service Advisory Council; the North Dakota State University President's Advisory Council; North Dakota Governor Schafer's Transition Team; and chaired North Dakota Governor Hoeven's Transition Team.

Education

- Bachelor of science in electrical and electronics engineering and master of science in industrial engineering from North Dakota State University.

Patricia L. Moss
Age 65

Independent Director Since 2003
Compensation Committee
Nominating and Governance Committee

Other Current Public Boards:
--First Interstate BancSystem, Inc.
--Aquila Group of Funds

Ms. Moss has business experience and knowledge of the Pacific Northwest economy and state, local, and regional issues where a significant portion of our operations are located. Ms. Moss provides our board with experience in finance and banking, as well as experience in business development through her work at Cascade Bancorp and Bank of the Cascades, and on the Oregon Investment Fund Advisory Council, the Oregon Business Council, and the Oregon Growth Board. Ms. Moss also has experience as a certified senior professional in human resources.

Career Highlights

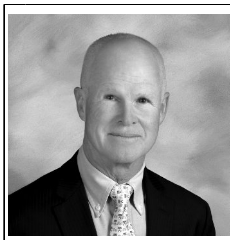
- President and chief executive officer of Cascade Bancorp, a financial holding company, Bend, Oregon, from 1998 to January 3, 2012; chief executive officer of Cascade Bancorp's principal subsidiary, Bank of the Cascades, from 1998 to January 3, 2012, serving also as president from 1998 to 2003; and chief operating officer, chief financial officer and secretary of Cascade Bancorp from 1987 to 1998.

Other Leadership Experience

- Member of the Oregon Investment Council, which oversees the investment and allocation of all state of Oregon trust funds, since December 2018.
- Director of First Interstate BancSystem, Inc., since May 30, 2017.
- Director of Cascade Bancorp and Bank of the Cascades from 1993, and vice chair from January 3, 2012 until May 30, 2017 when Cascade Bancorp merged into First Interstate BancSystem, Inc., and became First Interstate Bank.
- Chair of the Bank of the Cascades Foundation Inc. from 2014 to July 31, 2018; co-chair of the Oregon Growth Board, a state board created to improve access to capital and create private-public partnerships, from May 2012 through December 2018; and a member of the Board of Trustees for the Aquila Group of Funds, whose core business is mutual fund management and provision of investment strategies to fund shareholders, from January 2002 to May 2005 (one fund) and from June 2015 to present (currently three funds).
- Former director of the Oregon Investment Fund Advisory Council, a state-sponsored program to encourage the growth of small businesses in Oregon; the Oregon Business Council, with a mission to mobilize business leaders to contribute to Oregon's quality of life and economic prosperity; the North Pacific Group, Inc., a wholesale distributor of building materials, industrial, and hardwood products; Clear Choice Health Plans Inc., a multi-state insurance company; and City of Bend's Juniper Ridge management advisory board.

Education

- Bachelor of science in business administration from Linfield College in Oregon and master's studies at Portland State University.
- Commercial banking school certification at the ABA Commercial Banking School at the University of Oklahoma.



Edward A. Ryan
Age 65

Independent Director Since 2018
Audit Committee
Nominating and Governance Committee

Mr. Ryan, through his position as executive vice president and general counsel at Marriott International, Inc., brings extensive experience to our board in acquisitions, contracts, compliance, legal matters, SEC reporting, and labor relations. Mr. Ryan's experience significantly contributes to the board's oversight of compliance and corporate governance.

Career Highlights

- Advisor to the chief executive officer and president of Marriott International from December 2017 to December 31, 2018.
- Executive vice president and general counsel of Marriott International from December 2006 to December 2017; senior vice president and associate general counsel from 1999 to November 2006; assumed responsibility for all corporate transactions and corporate governance in 2005; and joined Marriott International as assistant general counsel in May 1996.
- Private law practice from 1979 to 1996.

Other Leadership Experience

- Director of Goodwill of Greater Washington, D.C., a non-profit organization whose mission is to transform lives and communities through education and employment, since January 2015, as well as vice chair since January 2019 and chair of the finance committee since January 2018.

Education

- Juris doctor degree from the University of Pennsylvania Law School.
- Bachelor's degree in economics and international relations from the University of Pennsylvania.

David M. Sparby
Age 64

Independent Director Since 2018
Audit Committee

Mr. Sparby has over 32 years of broad public utility experience through his positions as senior vice president and group president, revenue, of Xcel Energy Inc., president and chief executive officer of its subsidiary, Northern States Power-Minnesota (NSP-Minnesota), and chief financial officer of Xcel Energy. Mr. Sparby's public utility and renewable energy expertise contributes to the board's knowledge of the public utility and natural gas pipeline industries.

Career Highlights

- Senior vice president and group president, revenue, of Xcel Energy and president and chief executive officer of its subsidiary, NSP-Minnesota, from May 2013 until his retirement in December 2014; senior vice president and group president, from September 2011 to May 2013; chief financial officer from March 2009 to September 2011; and president and chief executive officer of NSP-Minnesota from 2008 to March 2009. He joined Xcel Energy, or its predecessor Northern States Power Company, as an attorney in 1982 and held positions of increasing responsibility.
- Attorney with the State of Minnesota, Office of Attorney General, from 1980 to 1982, during which period his responsibilities included representation of the Department of Public Service and the Minnesota Public Utilities Commission.

Other Leadership Experience

- Board of Trustees of Mitchell Hamline School of Law since July 2011, including executive committee and committee chair positions.
- Board of Trustees of the College of St. Scholastica since July 2012, including vice chair and executive committee positions.

Education

- Juris doctor degree from William Mitchell College of Law.
- Bachelor's degree in history from College of St. Scholastica and a master's degree in business administration from University of St. Thomas.

Chenxi Wang
Age 49

Independent Director Nominee

Ms. Wang has extensive technology and cybersecurity expertise through her experience, including founder and managing general partner of Rain Capital Fund, L.P., chief strategy officer at Twistlock, vice president, cloud security & strategy at Ciphercloud, and vice president, strategy and market intelligence at Intel Security. She is a sought-after public speaker on issues of technology and cybersecurity.

Career Highlights

- Founder and managing general partner of Rain Capital Fund, L.P., a cybersecurity-focused venture fund aiming to fund early-stage, transformative technology innovations in the security market with a goal of supporting women and minority entrepreneurs, since December 2017.
- Chief strategy officer at Twistlock, an automated and scalable cloud native cybersecurity platform, from August 2015 to February 2017.
- Vice president, cloud security & strategy of CipherCloud, a cloud security software company, from January 2015 to August 2015.
- Vice president of strategy of Intel Security, a company focused on developing proactive, proven security solutions and services that protect systems, networks, and mobile devices, from April 2013 to January 2015.
- Principal analyst and vice president of research at Forrester Research, a market research company that provides advice on existing and potential impact of technology, from January 2007 to April 2013.
- Assistant research professor and associate professor of computer engineering at Carnegie Mellon University from September 2001 through August 2007.

Other Leadership Experience

- Board of directors of OWASP Global Foundation, a nonprofit global community that drives visibility and evolution in the safety and security of the world's software, since January 2018 and vice chair from January 2018 to December 2018.
- Board of advisors of Keyp GmbH, a Munich-based software company with a mission to provide enterprises convenient access to the digital identity ecosystem, since December 2017.
- Program co-chair (security and privacy track) for the Grace Hopper Conference 2016 and 2017, the world's largest gathering of women in computing.

Education

- Doctor of Philosophy (Ph.D.) in computer science from University of Virginia.
- Bachelor's degree in computer science from Lock Haven University of Pennsylvania.

John K. Wilson
Age 64

Independent Director Since 2003
Audit Committee

Mr. Wilson has an extensive background in finance and accounting, as well as experience with mergers and acquisitions, through his education and work experience at a major accounting firm and his later public utility experience in his positions as controller and vice president of Great Plains Natural Gas Co., president of Great Plains Energy Corp., and president, chief financial officer, and treasurer for Durham Resources, LLC, and all Durham Resources entities. Mr. Wilson contributes business management and public utility knowledge to our board.

Career Highlights

- President of Durham Resources, LLC, a privately held financial management company, in Omaha, Nebraska, from 1994 to December 31, 2008; president of Great Plains Energy Corp., a public utility holding company and an affiliate of Durham Resources, LLC, from 1994 to July 1, 2000; and vice president of Great Plains Natural Gas Co., an affiliate company of Durham Resources, LLC, until July 1, 2000.
- Executive director of the Robert B. Daugherty Foundation in Omaha, Nebraska, since January 2010.
- Held positions of audit manager at Peat, Marwick, Mitchell (now known as KPMG), controller for Great Plains Natural Gas Co., and chief financial officer and treasurer for all Durham Resources entities.

Other Leadership Experience

- Director of HDR, Inc., an international architecture and engineering firm, since December 2008; and director of Tetrad Corporation, a privately held investment company, since April 2010, both located in Omaha, Nebraska.
- Former director of Bridges Investment Fund, Inc., a mutual fund, from April 2003 to April 2008; director of the Greater Omaha Chamber of Commerce from January 2001 through December 2008; member of the advisory board of U.S. Bank NA Omaha from January 2000 to July 2010; and the advisory board of Duncan Aviation, an aircraft service provider, headquartered in Lincoln, Nebraska, from January 2010 to February 2016.

Education and Professional

- Bachelor's degree in business administration, cum laude, from the University of Nebraska – Omaha.
- Certified public accountant, on inactive status.

Additional Information - Majority Voting

A majority of votes cast is required to elect a director in an uncontested election. A majority of votes cast means the number of votes cast "for" a director's election must exceed the number of votes cast "against" the director's election. "Abstentions" and "broker non-votes" do not count as votes cast "for" or "against" the director's election. In a contested election, which is an election in which the number of nominees for director exceeds the number of directors to be elected and which we do not anticipate, directors will be elected by a plurality of the votes cast.

Unless you specify otherwise when you submit your proxy, the proxies will vote your shares of common stock "for" all directors nominated by the board of directors. If a nominee becomes unavailable for any reason or if a vacancy should occur before the election, which we do not anticipate, the proxies will vote your shares in their discretion for another person nominated by the board.

Our policy on majority voting for directors contained in our corporate governance guidelines requires any proposed nominee for re-election as a director to tender to the board, prior to nomination, his or her irrevocable resignation from the board that will be effective, in an uncontested election of directors only, upon:

- receipt of a greater number of votes "against" than votes "for" election at our annual meeting of stockholders; and
- acceptance of such resignation by the board of directors.

Following certification of the stockholder vote, the nominating and governance committee will promptly recommend to the board whether or not to accept the tendered resignation. The board will act on the nominating and governance committee's recommendation no later than 90 days following the date of the annual meeting.

Brokers may not vote your shares on the election of directors if you have not given your broker specific instructions on how to vote. Please be sure to give specific voting instructions to your broker so your vote can be counted.

Board Evaluations and Process for Selecting Directors

In the annual board evaluation process, the nominating and governance committee evaluates our directors considering the current needs of the board and the company. In addition, during the year, the committee discusses board succession and reviews potential candidates. The committee may also retain a third party to assist in identifying potential nominees; none were retained in 2018.

Our annual board evaluation process involves assessments at the board and board committee levels. These annual evaluations are conducted by the chair of the nominating and governance committee and periodically by an independent third party.

Our governance guidelines provide that directors are not eligible to be nominated or appointed to the board if they are 76 years or older at the time of the election or appointment. Term limits on directors' service have not been instituted.

Director Qualifications, Skills, and Experience

Director nominees are chosen to serve on the board based on their qualifications, skills, and experience, as discussed in their biographies, and how those characteristics supplement the resources and talent on the board and serve the current needs of the board and the company.

In making its nominations, the nominating and governance committee also assesses each director nominee by a number of key characteristics, including character, success in a chosen field of endeavor, background in publicly traded companies, independence, and willingness to commit the time needed to satisfy the requirements of board and committee membership. Although the committee has no formal policy regarding diversity, the committee also considers diversity in gender, ethnic background, geographic area of residence, skills, and professional experience in recommending director nominees.

The following shows core specialized competencies and other characteristics of the director nominees.

CORE SPECIALIZED COMPETENCES

EXECUTIVE MANAGEMENT/PUBLIC COMPANY
Served as CEO or other senior executive of an organization or as a director of another publicly traded company
100%

INDUSTRY EXPERIENCE
Experience in our businesses and related industries, including public utilities, natural gas pipelines, construction, engineering, aggregate mining
70%

ACCOUNTING/FINANCE
Experience in the preparation and review of financial statements and financial reports
60%

LEGAL/CORPORATE GOVERNANCE
Experience in dealing with complex legal and public company governance issues
60%

CAPITAL MARKETS
Experience overseeing company financings, investments, capital structures, and financial strategy
70%

ENVIRONMENT/SCIENCE
Experience addressing environmental and sustainability issues relating to our businesses
30%

INFORMATION TECHNOLOGY/CYBERSECURITY
Oversight of or significant background working with information technology systems, data management and cybersecurity risks
10%

GOVERNMENT/REGULATORY/PUBLIC AFFAIRS
Background or experience in governmental regulations and public policy issues affecting our businesses
60%

RISK MANAGEMENT AND COMPLIANCE
Regulatory and compliance expertise or experience in the identification, assessment and mitigation of risks facing our company
100%

INDEPENDENCE

The company's corporate governance guidelines require that a substantial majority of the board must be independent. The board has determined that all director nominees, other than Mr. Goodin, meet the independence standards set by the NYSE and SEC.

90%
Nominee Independence

TENURE

The average tenure of the director nominees is approximately 9.5 years, which reflects a balance of company experience and new perspectives.

# of Years of Service

- 0-4: 3
- 5-10: 2
- 11+: 5

GENDER DIVERSITY

The board is committed to having a diverse and broadly inclusive membership. Three of our 10 director nominees are women.

70% **30%**

Board Composition and Refreshment

The nominating and governance committee is focused on ensuring that the board reflects a diversity of experience, skills, and backgrounds. Each of the current directors, other than Harry J. Pearce and William E. McCracken, has been nominated for election to the board of directors upon recommendation by the nominating and governance committee and each has decided to stand for election. Messrs. Pearce and McCracken were not eligible for re-election under the company's age limit policy that provides no individual is eligible for election to the board of directors after his or her 76th birthday.

With the retirement of former board member A. Bart Holaday at the annual meeting in May 2018 and Harry J. Pearce and William E. McCracken reaching our board retirement age limit and retiring from the board at our 2019 annual meeting, the committee identified qualified diverse director candidates with commensurate experience and background as replacement board members.

In evaluating the board retirements and current needs of the board and the company, the nominating and governance committee focused on identifying board candidates that would add gender diversity to the board as well as background and core competencies in the fields of regulated energy delivery, technology and cybersecurity, and public company governance. Potential director nominees were brought to the attention of the nominating and governance committee by board members, management, organizations, and database searches.

In 2018, the nominating and governance committee identified a need for additional expertise in the operation of electric and natural gas utilities and natural gas transmission pipelines. At December 31, 2018, approximately 66% of our capital was invested in these business segments which generated approximately 28% of our 2018 revenues. After serving in several positions during his 32-year career with Xcel Energy, including chief financial officer, and most recently as senior vice president, revenue group, and chief executive officer of its subsidiary, Northern States Power-Minnesota, David M. Sparby brings a vast amount of experience related to the electric and natural gas distribution and pipeline industries. Mr. Sparby was appointed to the board of directors on August 16, 2018.

With the anticipated retirement of Harry J. Pearce, the nominating and governance committee identified a director nominee with extensive risk management and public company governance experience. Prior to his retirement in 2017, Edward A. Ryan served as executive vice president and general counsel for Marriott International, Inc. where his responsibilities included chair of the company's legal and ethical steering and enterprise crisis management committees. Mr. Ryan was appointed to the board of directors on November 15, 2018.

With the anticipated retirement of William E. McCracken, the nominating and governance committee identified a director nominee that would bring diversity as well as technology and cybersecurity expertise to the board. Chenxi Wang has held positions with various organizations related to technology and security software and is a frequent speaker on issues of technology and cybersecurity. She is currently the founder and general partner of Rain Capital Fund, L.P., an early stage venture capital firm focused on cybersecurity innovation and artificial intelligence for its clients and the promotion of women entrepreneurs. Ms. Wang also provides gender, ethnic, age, and geographic diversity to the board.

By tenure, if the nominees are elected, the board will comprise of three directors who have served from 0-4 years, two directors who have served from 5-10 years, and five directors who have served over 11 years. This mix provides a balance of experience and institutional knowledge with fresh perspectives.

CORPORATE GOVERNANCE AND THE BOARD OF DIRECTORS

Director Independence

The board of directors has adopted guidelines on director independence that are included in our corporate governance guidelines. Our guidelines require that a substantial majority of the board consists of independent directors. In general, the guidelines require that an independent director must have no material relationship with the company directly or indirectly, except as a director. The board determines independence on the basis of the standards specified by the New York Stock Exchange (NYSE), the additional standards referenced in our corporate governance guidelines, and other facts and circumstances the board considers relevant. Based on its review, the board has determined that all directors and director nominees, except for our chief executive officer Mr. Goodin, have no material relationship with us and are independent.

In determining director independence, the board of directors reviewed and considered information about any transactions, relationships, and arrangements between the non-employee directors and director nominees and their immediate family members and affiliated entities on the one hand, and the company and its affiliates on the other, and in particular the following transactions, relationships, and arrangements:

- *Charitable contributions by the MDU Resources Foundation (Foundation) to nonprofit organizations where a director, a director nominee, or their spouse, serves or has served as a director, chair, or vice chair of the board of trustees, trustee or member of the organization or related entity:* Charitable contributions by the Foundation to four nonprofit organizations that collectively amounted to $27,500 in 2018. None of the contributions made to any of the nonprofit entities exceeded the greater of $1 million or 2% of the relevant entity's consolidated gross revenues.

- *Business relationships with entities with which a director or director nominee is affiliated*: Mr. Wilson is a member of the board of directors of HDR, Inc., an architectural, engineering, environmental, and consulting firm. The company paid HDR, Inc. or its affiliates approximately $1 million in 2018 directly or through a third party for services which were provided in the ordinary course of business and on substantially the same terms prevailing for comparable services from other consulting firms. Mr. Wilson had no role in securing or promoting the HDR, Inc. services.

The board has also determined that all members of the audit, compensation, and nominating and governance committees of the board are independent in accordance with our guidelines and applicable NYSE and Securities Exchange Act of 1934 rules.

Stockholder Engagement

The company has an active stockholder outreach program. We believe in providing transparent and timely information to our investors. Each year we routinely engage directly or indirectly with our stockholders, including our top institutional stockholders. During 2018, the company held meetings, conference calls, and webcasts with a diverse mix of stockholders. Throughout the year, we held meetings or telephone conferences with eleven of the institutional investors included in our year-end top 30 stockholders. In our meetings or conferences, we discussed a variety of topics including longer-term company strategy and our capital expenditure forecast; shorter-term operational and financial updates; environmental, social, and corporate governance; and previously announced strategic initiatives. The company also held telephone conferences with a proxy advisory firm to discuss corporate governance, executive compensation practices, and other topics.

Board Leadership Structure

The board separated the positions of chair of the board and chief executive officer in 2006, and our bylaws and corporate governance guidelines currently require that our chair be independent. The board believes this structure provides balance and is currently in the best interest of the company and its stockholders. Separating these positions allows the chief executive officer to focus on the full-time job of running our business, while allowing the chair of the board to lead the board in its fundamental role of providing advice to and independent oversight of management. The chair meets regularly between board meetings with the chief executive officer and consults with the chief executive officer regarding the board meeting agendas, the quality and flow of information provided to the board, and the effectiveness of the board meeting process. The board believes this split structure recognizes the time, effort, and energy the chief executive officer is required to devote to the position in the current business environment, as well as the commitment required to serve as the chair, particularly as the board's oversight responsibilities continue to grow and demand more time and attention. The fundamental role of the board of directors is to provide oversight of the management of the company in good faith and in the best interests of the company and its stockholders. Having an independent chair is a means to ensure the chief executive officer is accountable for managing the company in close alignment with the interests of stockholders, including with respect to risk management as discussed below. An independent chair is in a position to encourage frank and lively discussions, including during regularly scheduled executive sessions consisting of only independent directors, and to assure that the company has adequately assessed all appropriate business risks before adopting its final business plans and strategies. The board believes that having separate positions and having an independent outside director serve as chair is the appropriate leadership structure for the company at this time and demonstrates our commitment to good corporate governance. With the retirement of Mr. Pearce at the annual meeting, the board will elect a new independent chair at its May board meeting.

Board's Role in Risk Oversight

Risk is inherent with every business, and how well a business manages risk can ultimately determine its success. We face a number of risks, including economic risks, operational risks, environmental and regulatory risks, the impact of competition, climate and weather conditions, limitations on our ability to pay dividends, pension plan obligations, cyberattacks or acts of terrorism, and third party liabilities. Management is responsible for identifying material risks, implementing appropriate risk management strategies, and providing information regarding material risks and risk management to the board. The board, as a whole and through its committees, has responsibility for the oversight of risk management. In its risk oversight role, the board of directors has the responsibility to satisfy itself that the risk management processes designed and implemented by management are adequate for identifying, assessing, and managing risk.

The board believes establishing the right "tone at the top" and full and open communication between management and the board of directors are essential for effective risk management and oversight. Our chair meets regularly with our chief executive officer to discuss strategy and risks facing the company. Senior management attends the quarterly board meetings and is available to address any questions or concerns raised by the board on risk management-related and any other matters. Each quarter, the board of directors receives presentations from senior management on strategic matters involving our operations. Senior management annually presents an assessment to the board of critical enterprise risks that threaten the company's strategy and business model, including risks inherent in the key assumptions underlying the company's business strategy for value creation. Periodically, the board receives presentations from external experts on matters of strategic importance to the board. In 2018, the board heard presentations from external experts regarding climate change and its risks and opportunities, oil and natural gas exploration in the Bakken geological formation in North Dakota, and projected natural gas processing and transportation needs in North Dakota. At least annually, the board holds strategic planning sessions with senior management to discuss strategies, key challenges, and risks and opportunities for the company.

The company has also developed a robust compliance program to promote a culture of compliance, consistent with the right tone at the top, to mitigate risk. The program includes training and adherence to our code of conduct and legal compliance guide. We further mitigate risk through our internal audit and legal departments.

While the board is ultimately responsible for risk oversight at our company, our three standing board committees assist the board in fulfilling its oversight responsibilities in certain areas of risk.

- The audit committee assists the board in fulfilling its oversight responsibilities with respect to risk management in a general manner and specifically in the areas of financial reporting, internal controls, cybersecurity, and compliance with legal and regulatory requirements, and, in accordance with NYSE requirements, discusses with the board policies with respect to risk assessment and risk management and their adequacy and effectiveness. The audit committee receives regular reports on the company's compliance program, including reports received through our anonymous reporting hot line. It also receives reports and regularly meets with the company's external and internal auditors. During each of its quarterly meetings in 2018, the audit committee received presentations from management on cybersecurity and the company's mitigation of cybersecurity risks. The entire board was present for these presentations. Risk assessment and mitigation reports are regularly provided by management to the audit committee or the full board. This opens the opportunity for discussions about areas where the company may have material risk exposure, steps taken to manage such exposure, and the company's risk tolerance in relation to company strategy. The audit committee reports regularly to the board of directors on the company's management of risks in the audit committee's areas of responsibility.

- The compensation committee assists the board in fulfilling its oversight responsibilities with respect to the management of risks arising from our compensation policies and programs.

- The nominating and governance committee assists the board in fulfilling its oversight responsibilities with respect to the management of risks associated with board organization, membership and structure, succession planning for our directors and executive officers, and corporate governance.

Board Meetings and Committees

During 2018, the board of directors held four regular meetings and two special meetings. Each director attended at least 75% of the combined total meetings of the board and the committees on which the director served during 2018 (held during the period he or she has been a director). Directors are encouraged to attend our annual meeting of stockholders. All directors attended our 2018 Annual Meeting of Stockholders.

The non-employee directors meet in executive session at each regularly scheduled quarterly board of directors meeting. The chair of the board presides at the executive session of the non-employee directors held in connection with each regularly scheduled quarterly board of directors meeting.

The board has standing audit, compensation, and nominating and governance committees. The table below provides current committee membership.

Name	Audit Committee	Compensation Committee	Nominating and Governance Committee
Thomas Everist		C	
Karen B. Fagg		●	C
Mark A. Hellerstein	●		
Dennis W. Johnson	C		●
William E. McCracken		●	●
Patricia L. Moss		●	●
Edward A. Ryan	●		●
David M. Sparby	●		
John K. Wilson	●		

C - Chair

● - Member

Below is a description of each standing committee of the board. The board has affirmatively determined that each of these standing committees consists entirely of independent directors pursuant to rules established by the NYSE, rules promulgated under the Securities and Exchange Commission (SEC), and the director independence standards established by the board. The board has also determined that each member of the audit committee and the compensation committee is independent under the criteria established by the NYSE and the SEC for audit committee and compensation committee members, as applicable.

Nominating and Governance Committee

Met Six Times in 2018

The nominating and governance committee met six times during 2018. The committee members are Karen B. Fagg, chair, Dennis W. Johnson, William E. McCracken, Patricia L. Moss, and Edward A. Ryan.

The nominating and governance committee provides recommendations to the board with respect to:

- board organization, membership, and function;
- committee structure and membership;
- succession planning for our executive management and directors; and
- our corporate governance guidelines.

The nominating and governance committee assists the board in overseeing the management of risks in the committee's areas of responsibility.

The committee identifies individuals qualified to become directors and recommends to the board the nominees for director for the next annual meeting of stockholders. The committee also identifies and recommends to the board individuals qualified to become our principal officers and the nominees for membership on each board committee. The committee oversees the evaluation of the board and management.

In identifying nominees for director, the committee consults with board members, management, consultants, and other individuals likely to possess an understanding of our business and knowledge concerning suitable director candidates.

Our corporate governance guidelines include our policy on consideration of director candidates recommended to us. We will consider candidates that our stockholders recommend in the same manner we consider other nominees. Stockholders who wish to recommend a director candidate may submit recommendations, along with the information set forth in the guidelines, to the nominating and governance committee chair in care of the secretary at MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506-5650.

Stockholders who wish to nominate persons for election to our board at an annual meeting of stockholders must follow the applicable procedures set forth in Section 2.08 or 2.10 of our bylaws. Our bylaws are available on our website. See "Stockholder Proposals, Director Nominations, and Other Items of Business for 2020 Annual Meeting" in the section entitled "Information about the Annual Meeting" for further details.

In evaluating director candidates, the committee, in accordance with our corporate governance guidelines, considers an individual's:

- background, character, and experience, including experience relative to our company's lines of business;
- skills and experience which complement the skills and experience of current board members;
- success in the individual's chosen field of endeavor;
- skill in the areas of accounting and financial management, banking, business management, human resources, marketing, operations, public affairs, law, technology, risk management, governance, and operations abroad;
- background in publicly traded companies including service on other public company boards of directors;
- geographic area of residence;
- diversity of business and professional experience, skills, gender, and ethnic background, as appropriate in light of the current composition and needs of the board;
- independence, including any affiliation or relationship with other groups, organizations, or entities; and
- compliance with applicable law and applicable corporate governance, code of conduct and ethics, conflict of interest, corporate opportunities, confidentiality, stock ownership and trading policies, and other policies and guidelines of the company.

In addition, our bylaws contain requirements that a person must meet to qualify for service as a director.

The nominating and governance committee assesses the effectiveness of this policy annually in connection with the nomination of directors for election at the annual meeting of stockholders. The composition of the current board and the board nominees reflects diversity in business and professional experience, skills, ethnicity, gender, and geography.

Audit Committee — Met Eight Times in 2018

The audit committee is a separately-designated committee established in accordance with Section 3(a)(58)(A) of the Securities Exchange Act of 1934.

The audit committee met eight times during 2018. The audit committee members are Dennis W. Johnson, chair, Mark A. Hellerstein, Edward A. Ryan, David M. Sparby, and John K. Wilson. The board of directors has determined that Messrs. Johnson, Hellerstein, Sparby, and Wilson are "audit committee financial experts" as defined by SEC rules and all audit committee members are financially literate within the meaning of the listing standards of the NYSE. All members also meet the independence standard for audit committee members under our director independence guidelines, the NYSE listing standards, and SEC rules.

The audit committee assists the board of directors in fulfilling its oversight responsibilities to the stockholders and serves as a communication link among the board, management, the independent registered public accounting firm, and the internal auditors. The audit committee:

- assists the board's oversight of
  - the integrity of our financial statements and system of internal controls;
  - the company's compliance with legal and regulatory requirements and the code of conduct;
  - the independent registered public accounting firm's qualifications and independence;
  - the performance of our internal audit function and independent registered public accounting firm;
  - management of risk in the audit committee's areas of responsibility; and
- arranges for the preparation of and approves the report that SEC rules require we include in our annual proxy statement. See the section entitled "Audit Committee Report" for further information.

Compensation Committee

Met Four Times in 2018

During 2018, the compensation committee met four times. The compensation committee consists entirely of independent directors within the meaning of the company's corporate governance guidelines and the NYSE listing standards and who meet the definitions of non-employee directors for purposes of Rule 16-b under the Exchange Act. Members of the compensation committee are Thomas Everist, chair, Karen B. Fagg, William E. McCracken, and Patricia L. Moss.

The compensation committee assists the board of directors in fulfilling its responsibilities relating to the company's compensation policy and programs. It has the direct responsibility for determining compensation for our Section 16 officers and for overseeing the company's management of risk in its areas of responsibility. In addition, the compensation committee reviews and recommends any changes to director compensation policies to the board of directors. The authority and responsibility of the compensation committee is outlined in the compensation committee's charter.

The compensation committee uses the analysis and recommendations from outside consultants, the chief executive officer, and the human resources department in making its compensation decisions. The chief executive officer, the vice president-human resources, and the general counsel regularly attend compensation committee meetings. The committee meets in executive session as needed. The processes and procedures for consideration and determination of compensation of the Section 16 officers, as well as the role of our executive officers, are discussed in the "Compensation Discussion and Analysis."

The compensation committee has sole authority to retain compensation consultants, legal counsel, or other advisers to assist in consideration of the compensation of the chief executive officer, the other Section 16 officers, and the board of directors, and the committee is directly responsible for the appointment, compensation, and oversight of the work of such advisers. The compensation committee's practice has been to retain a compensation consultant every other year to conduct a competitive analysis on executive compensation. The competitive analysis is conducted internally by the human resources department in the other years. In 2018, the compensation committee retained a compensation consultant, Meridian Compensation Partners, LLC, to conduct a competitive analysis on executive compensation for 2019. Prior to retaining an adviser, the compensation committee considers all factors relevant to ensure the adviser's independence from management. Annually the compensation committee conducts a potential conflicts of interest assessment raised by the work of any compensation consultant and how such conflicts, if any, should be addressed. The compensation committee requested and received information from Meridian Compensation Partners, LLC to assist in its potential conflicts of interest assessment. Based on its review and analysis, the compensation committee determined in 2018 that Meridian Compensation Partners, LLC was independent from management.

The board of directors determines compensation for our non-employee directors based upon recommendations from the compensation committee. The compensation committee's practice has been to retain a compensation consultant every other year to conduct a competitive analysis on director compensation. In 2018, the analysis of non-employee director compensation was performed by the human resources department. Meridian Compensation Partners, LLC will conduct the analysis in 2019.

Compensation Policies and Practices as They Relate to Risk Management

The human resources department has conducted an assessment of the risks arising from our compensation policies and practices for all employees and concluded that none of these risks is reasonably likely to have a material adverse effect on the company. Based on the human resources department's assessment and taking into account information received from the risk identification process, senior management and our management policy committee concluded that risks arising from our compensation policies and practices are not reasonably likely to have a material adverse effect on the company. After review and discussion with senior management, the compensation committee concurred with this assessment.

As part of its assessment of the risks arising from our compensation policies and practices, the human resources department identified the principal areas of risk faced by the company that may be affected by our compensation policies and practices, including any risks resulting from our operating businesses' compensation policies and practices. In assessing the risks arising from our compensation policies and practices, the human resources department identified the following practices designed to prevent excessive risk taking:

- Business management and governance practices:
  - risk management is a specific performance competency included in the annual performance assessment of Section 16 officers;
  - board oversight on capital expenditure and operating plans promotes careful consideration of financial assumptions;

  - limitation on business acquisitions without board approval;
  - employee integrity training programs and anonymous reporting systems;
  - quarterly risk assessment reports at audit committee meetings; and
  - prohibitions on holding company stock in an account that is subject to a margin call, pledging company stock as collateral for a loan, and hedging of company stock by Section 16 officers and directors.

- Executive compensation practices:
  - active compensation committee review of executive compensation, including portions of executive compensation based upon the company's total stockholder return in relation to that of the company's peer group;
  - the initial determination of a position's salary grade to be at or near the 50th percentile of base salaries paid to similar positions at peer group companies and/or relevant industry companies;
  - consideration of peer group and/or relevant industry practices to establish appropriate compensation target amounts;
  - a balanced compensation mix of fixed salary and annual and long-term incentives tied primarily to the company's financial and stock performance;
  - use of interpolation for annual and long-term incentive awards to avoid payout cliffs;
  - negative discretion to adjust any annual incentive award payment downward;
  - use of caps on annual incentive awards (maximum of 200% for regulated segments and 240% for construction materials and services segments) and long-term incentive stock grant awards (200% of target);
  - ability to clawback incentive payments in the event of a financial restatement;
  - use of performance shares and restricted stock units, rather than stock options or stock appreciation rights, as an equity component of incentive compensation;
  - use of performance shares for long-term incentive awards with relative total stockholder return, earnings before interest, taxes, depreciation, and amortization (EBITDA) growth, and earnings growth performance components;
  - use of three-year performance periods for long-term incentive awards to discourage short-term risk-taking;
  - substantive annual incentive goals measured primarily by earnings, EBITDA, and earnings per share criteria, which encourage balanced performance and are important to stockholders;
  - use of financial performance metrics that are readily monitored and reviewed;
  - regular review of the appropriateness of the companies in the peer group;
  - stock ownership requirements for the board and for executives receiving long-term incentive awards;
  - mandatory holding periods for 50% of any net after-tax shares earned under long-term incentive awards; and
  - use of independent consultants to assist in establishing pay targets and compensation structure at least biennially.

Stockholder Communications with the Board

Stockholders and other interested parties who wish to contact the board of directors or any individual director, including our non-employee chair or non-employee directors as a group, should address a communication in care of the secretary at MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506-5650. The secretary will forward all communications.

Additional Governance Features

Board and Committee Evaluations

Our corporate governance guidelines provide that the board of directors, in coordination with the nominating and governance committee, will annually review and evaluate the performance and functioning of the board and its committees. The self-evaluations are intended to facilitate a candid assessment and discussion by the board and each committee of its effectiveness as a group in fulfilling its responsibilities, its performance as measured against the corporate governance guidelines, and areas for improvement. The board and committee members are provided with a questionnaire to facilitate discussion. The results of the evaluations are reviewed and discussed in executive sessions of the committees and the board of directors.

Director Resignation Upon Change of Job Responsibility

Our corporate governance guidelines require a director to tender his or her resignation after a material change in job responsibility. In 2018, no directors or director nominees submitted resignations under this requirement.

Majority Voting in Uncontested Director Elections

Our corporate governance guidelines require that in uncontested elections (those where the number of nominees does not exceed the number of directors to be elected), director nominees must receive the affirmative vote of a majority of the votes cast to be elected to our board of directors. Contested director elections (those where the number of director nominees exceeds the number of directors to be elected) are governed by a plurality of the vote of shares present in person or represented by proxy at the meeting.

The board has adopted a director resignation policy for incumbent directors in uncontested elections. Any proposed nominee for re-election as a director shall, before he or she is nominated to serve on the board, tender to the board his or her irrevocable resignation that will be effective, in an uncontested election of directors only, upon (i) such nominee's receipt of a greater number of votes "against" election than votes "for" election at our annual meeting of stockholders; and (ii) acceptance of such resignation by the board of directors.

Director Overboarding Policy

Our bylaws and corporate governance guidelines state that a director may not serve on more than three public company boards, including the company's board. Currently, all of our directors are in compliance of this policy.

Board Refreshment

The company regularly evaluates the need for board refreshment. The nominating and governance committee and the board are focused on identifying individuals whose skills and experiences will enable them to make meaningful contributions to shaping the company's business strategy. As part of its consideration of director succession, the nominating and governance committee from time to time reviews, including when considering potential candidates, the appropriate skills and characteristics required of board members. The board believes it is important to consider diversity of skills, expertise, race, ethnicity, gender, age, education, geography, cultural background, and professional experiences in evaluating board candidates for expected contributions to an effective board. Independent directors may not serve on the board beyond the next annual meeting of stockholders after attaining the age of 76. We believe the mandatory retirement age allows us to benefit from experienced directors, with industry expertise, company institutional knowledge and historical perspective, stability, and comfort with challenging company management, while maintaining our ability to refresh the board through the addition of new members. In connection with our mandatory retirement for directors, Harry J. Pearce and William E. McCracken will retire as directors at the completion of their current term following the 2019 annual meeting.

Prohibitions on Hedging/Pledging Company Stock

The director compensation policy prohibits directors from hedging their ownership of common stock, pledging company stock as collateral for a loan, or holding company stock in an account that is subject to a margin call.

Code of Conduct

We have a code of conduct and ethics, which we refer to as the Leading With Integrity Guide. It applies to all directors, officers, and employees.

We intend to satisfy our disclosure obligations regarding amendments to, or waivers of, any provision of the code of conduct that applies to our principal executive officer, principal financial officer, and principal accounting officer and that relates to any element of the code of ethics definition in Regulation S-K, Item 406(b), and waivers of the code of conduct for our directors or executive officers, as required by NYSE listing standards, by posting such information on our website.

Proxy Access

In February 2018, the board of directors amended our bylaws to implement proxy access with the following parameters:

Ownership Threshold:	3% of outstanding shares of our common stock
Nominating Group Size:	Up to 20 stockholders may combine to reach the 3% ownership threshold
Holding Period:	Continuously for three years
Number of Nominees:	The greater of two nominees or 20% of our board

We believe these proxy access parameters reflect a well designed and balanced approach to proxy access that mitigates the risk of abuse and protects the interests of all of our stockholders. Stockholders who wish to nominate directors for inclusion in our Proxy Statement in accordance with proxy access must follow the procedures in Section 2.10 of our bylaws. See "Stockholder Proposals, Director Nominations, and Other Items of Business for 2020 Annual Meeting."

Corporate Governance Materials

Stockholders can see our bylaws, corporate governance guidelines, board committee charters, and Leading With Integrity Guide on our website.

Corporate Governance Materials	Website
• Bylaws	http://www.mdu.com/governance
• Corporate Governance Guidelines	http://www.mdu.com/governance
• Board Committee Charters for the Audit, Compensation, and Nominating and Governance Committees	http://www.mdu.com/governance
• Leading With Integrity Guide	http://www.mdu.com/commitmenttointegrity

Related Person Transaction Disclosure

The board of directors' policy for the review of related person transactions is contained in our corporate governance guidelines. The policy requires the audit committee to review any transaction, arrangement or relationship, or series thereof:

- in which the company was or will be a participant;
- the amount involved exceeds $120,000; and
- a related person had or will have a direct or indirect material interest.

The purpose of this review is to determine whether this transaction is in the best interests of the company.

Related persons are directors, director nominees, executive officers, holders of 5% or more of our voting stock, and their immediate family members. Related persons are required promptly to report to our general counsel all proposed or existing related person transactions in which they are involved.

If our general counsel determines that the transaction is required to be disclosed under the SEC rules, the general counsel furnishes the information to the chair of the audit committee. After its review, the committee makes a determination or a recommendation to the board and officers of the company with respect to the related person transaction. Upon receipt of the committee's recommendation, the board of directors or officers, as the case may be, take such action as they deem appropriate in light of their responsibilities under applicable laws and regulations.

We had no related person transactions in 2018.

COMPENSATION OF NON-EMPLOYEE DIRECTORS

Director Compensation for 2018

MDU Resources' non-employee directors are compensated for their service according to the MDU Resources Group Inc. Director Compensation Policy. Only one company employee, David L. Goodin, the company's president and chief executive officer, serves as a director. Mr. Goodin receives no additional compensation for his service on the board. Director compensation is reviewed annually by the compensation committee with analysis provided by an independent consultant in odd numbered years and analysis prepared by the company's human resources department in even numbered years. The company's human resources department provided the director compensation analysis for 2018. The analysis included research on market trends in director compensation as well as a review of director compensation practices of our peer group companies. Based on the analysis, the compensation committee recommended and the board concurred that no changes would be made to board member compensation for 2018. The following table outlines the compensation paid to our non-employee directors for 2018.

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)[1]	All Other Compensation ($)[2]	Total ($)
Thomas Everist	80,000	110,000	83	190,083
Karen B. Fagg	80,000	110,000	583	190,583
Mark A. Hellerstein	70,000	110,000	83	180,083
A. Bart Holaday	29,167	45,833	35	75,035
Dennis W. Johnson	85,000	110,000	83	195,083
William E. McCracken	70,000	110,000	83	180,083
Patricia L. Moss	70,000	110,000	83	180,083
Harry J. Pearce	160,000	145,000	83	305,083
Edward A. Ryan	11,667	18,333	7	30,007
David M. Sparby	29,167	45,833	28	75,028
John K. Wilson	70,000	110,000	83	180,083

1 Directors receive an annual payment of $110,000 in company common stock, except the non-executive chair who receives $145,000 in company common stock, under the MDU Resources Group, Inc. Non-Employee Director Long-Term Incentive Compensation Plan. Directors serving less than a full year receive a prorated stock payment based on the number of months served. All stock payments are measured in accordance with Financial Accounting Standards Board (FASB) generally accepted accounting principles for stock-based compensation in FASB Accounting Standards Codification Topic 718. The grant date fair value is based on the purchase price of our common stock on the grant date of November 20, 2018, which was $26.55 per share. The amount paid in cash for fractional shares is included in the amount reported in the stock awards column to this table. As of December 31, 2018, there are no outstanding stock awards or options associated with the Non-Employee Director Long-Term Incentive Compensation Plan.

2 Includes group life insurance premiums and charitable donations made on behalf of the director as applicable. Amounts for life insurance premiums reflect prorated amounts for directors serving less than a full year based on the number of months served.

The following table shows the annual cash and stock retainers payable to our non-employee directors.

Base Cash Retainer	$ 70,000
Additional Cash Retainers:	
Non-Executive Chair	90,000
Audit Committee Chair	15,000
Compensation Committee Chair	10,000
Nominating and Governance Committee Chair	10,000
Annual Stock Grant[1] - Directors (other than Non-Executive Chair)	110,000
Annual Stock Grant[2] - Non-Executive Chair	145,000

1 The annual stock grant is a grant of shares of company common stock equal in value to $110,000.

2 The annual stock grant is a grant of shares of company common stock equal in value to $145,000.

There are no meeting fees paid to directors.

Other Compensation

In addition to liability insurance, we maintain group life insurance in the amount of $100,000 on each non-employee director for the benefit of their beneficiaries during the time they serve on the board. The annual cost per director is $82.80. Directors who contribute to the company's Good Government Fund may designate up to two charities to receive a matching donation from the MDU Resources Foundation based on their contributions to the fund. Directors are reimbursed for all reasonable travel expenses, including spousal expenses in connection with attendance at meetings of the board and its committees. Perquisites, if any, were below the disclosure threshold in 2018.

Deferral of Compensation

Directors may defer all or any portion of the annual cash retainer and any other cash compensation paid for service as a director pursuant to the Deferred Compensation Plan for Directors. Deferred amounts are held as phantom stock with dividend accruals and are paid out in cash over a five-year period after the director leaves the board.

Post-Retirement

Our post-retirement income plan for directors was terminated in May 2001 for current and future directors. The net present value of each director's benefit was calculated and converted into phantom stock. Payment is deferred pursuant to the Deferred Compensation Plan for Directors and will be made in cash over a five-year period after the director's retirement from the board.

Stock Ownership Policy

Our director stock ownership policy contained in our corporate governance guidelines requires each director to own our common stock equal in value to five times the director's annual cash base retainer. Shares acquired through purchases on the open market and received through our Non-Employee Director Long-Term Incentive Plan are considered in ownership calculations as is ownership of our common stock by a spouse. A director is allowed five years commencing January 1 of the year following the year of the director's initial election to the board to meet the requirements. The level of common stock ownership is monitored with an annual report made to the compensation committee of the board. All directors are in compliance with the stock ownership policy or are within the first five years of their election to the board. For further details on our director's stock ownership, see the section entitled "Security Ownership."

SECURITY OWNERSHIP

Security Ownership Table

The table below sets forth the number of shares of our common stock that each director and each nominee for director, each current named executive officer, and all directors and executive officers as a group owned beneficially as of February 28, 2019. Unless otherwise indicated, each person has sole investment and voting power (or share such power with his or her spouse) of the shares noted.

Name[1]	Shares of Common Stock Beneficially Owned	Percent of Class
David C. Barney	44,313 [2,3]	*
Thomas Everist	861,692	*
Karen B. Fagg	73,314	*
David L. Goodin	264,925 [2]	*
Mark A. Hellerstein	24,000	*
Dennis W. Johnson	92,352 [4]	*
Nicole A. Kivisto	59,635 [2,5]	*
William E. McCracken	24,000	*
Patricia L. Moss	76,328	*
Harry J. Pearce	246,740	*
Edward A. Ryan	10,690	*
David M. Sparby	1,726	*
Jeffrey S. Thiede	43,540 [2]	*
Jason L. Vollmer	11,374 [2]	*
Chenxi Wang	—	*
John K. Wilson	129,601	*
All directors and executive officers as a group (20 in number)	2,069,126 [2,6]	1.05%

* Less than one percent of the class. Percent of class is calculated based on 196,338,488 outstanding shares as of February 28, 2019.

1 The table includes the ownership of all current directors, director nominees, current named executive officers, and other executive officers of the company without naming them.

2 Includes full shares allocated to the officer's account in our 401(k) retirement plan.

3 The total includes 687 shares owned by Mr. Barney's spouse.

4 Mr. Johnson disclaims all beneficial ownership of the 163 shares owned by his spouse.

5 The total includes 531 shares owned by Ms. Kivisto's spouse.

6 Includes shares owned by a director's or executive's spouse regardless of whether the director or executive claims beneficial ownership.

Hedging Policy

The company's Director Compensation Policy and its Executive Compensation Policy prohibit our directors and executives from hedging their ownership of company stock. The Director Compensation Policy applies to all directors who are not full-time employees of the company. The Executive Compensation Policy applies to the executives of the company designated as an officer for purposes of Section 16 of the Securities Exchange Act of 1934 as well as all other executives of the company and its subsidiaries who participate in its Long-Term Performance-Based Incentive Plan and its Executive Incentive Compensation Plan. Under the policies, directors and executives are prohibited from engaging in transactions that allow them to own stock technically but without the full benefits and risks of such ownership, including, but not limited to, zero-cost collars, equity swaps, straddles, prepaid variable forward contracts, security futures contracts, exchange funds, forward sale contracts, and other financial transactions that allow the director or executive to benefit from the devaluation of the company's stock.

The company policies also prohibit directors, executives, and related persons from holding company stock in a margin account, with certain exceptions, or pledging company securities as collateral for a loan. Company common stock may be held in a margin brokerage account only if the stock is explicitly excluded from any margin, pledge, or security provisions of the customer agreement. Company common stock may be held in a cash account, which is a brokerage account that does not allow any extension of credit on securities. "Related person" means an executive officer's or director's spouse, minor child, and any person (other than a tenant or domestic employee) sharing the household of a director or executive officer, as well as any entities over which a director or executive officer exercises control.

Greater Than 5% Beneficial Owners

Based solely on filings with the SEC, the table below shows information regarding the beneficial ownership of more than five percent of the outstanding shares of our common stock.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common Stock	**The Vanguard Group**	21,436,898 [1]	10.93%
	100 Vanguard Blvd.		
	Malvern, PA 19355		
Common Stock	**BlackRock, Inc.**	18,376,417 [2]	9.40%
	55 East 52nd Street		
	New York, NY 10055		
Common Stock	**State Street Corporation**	12,377,612 [3]	6.30%
	State Street Financial Center		
	One Lincoln Street		
	Boston, MA 02111		

1 Based solely on the Schedule 13G, Amendment No. 7, filed on February 11, 2019, The Vanguard Group reported sole dispositive power with respect to 21,336,371 shares, shared dispositive power with respect to 100,527 shares, sole voting power with respect to 94,745 shares, and shared voting power with respect to 22,519 shares. These shares include 74,426 shares beneficially owned by Vanguard Fiduciary Trust Company, a wholly-owned subsidiary of The Vanguard Group, Inc., as a result of its serving as investment manager of collective trust accounts, and 42,838 shares beneficially owned by Vanguard Investments Australia, Ltd., a wholly-owned subsidiary of The Vanguard Group, Inc., as a result of its serving as investment manager of Australian investment offerings.

2 Based solely on the Schedule 13G, Amendment No. 9, filed on February 6, 2019, BlackRock, Inc. reported sole voting power with respect to 17,339,702 shares and sole dispositive power with respect to 18,376,417 shares as the parent holding company or control person of BlackRock Life Limited, BlackRock International Limited, BlackRock Advisors, LLC, BlackRock (Netherlands) B.V., BlackRock Fund Advisors, BlackRock Institutional Trust Company, National Association, BlackRock Asset Management Ireland Limited, BlackRock Financial Management, Inc., BlackRock Asset Management Schweiz AG, BlackRock Investment Management, LLC, BlackRock Investment Management (UK) Limited, BlackRock Asset Management Canada Limited, BlackRock (Luxembourg) S.A., BlackRock Investment Management (Australia) Limited, BlackRock Advisors (UK) Limited, BlackRock Asset Management North Asia Limited, and BlackRock Fund Managers Ltd.

3 Based solely on the Schedule 13G, filed on February 14, 2019, State Street Corporation reported shared voting and dispositive power with respect to 12,377,612 shares as the parent holding company or control person of SSGA Funds Management, Inc., State Street Global Advisors Limited (UK), State Street Global Advisors LTD (Canada), State Street Global Advisors, Australia Limited, State Street Global Advisors Asia LTD, State Street Global Advisors Singapore LTD, State Street Global Advisors GmbH, State Street Global Advisors Ireland Limited, and State Street Global Advisors Trust Company.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16 of the Securities Exchange Act of 1934, as amended, requires officers, directors, and holders of more than 10% of our common stock to file reports of their trading in our equity securities with the SEC. Based solely on a review of Forms 3, 4, and 5, and any amendments to these forms furnished to us during and with respect to 2018, or written representations that no Forms 5 were required, we believe that all such reports were timely filed.

EXECUTIVE COMPENSATION

ITEM 2. ADVISORY VOTE TO APPROVE THE COMPENSATION PAID TO THE COMPANY'S NAMED EXECUTIVE OFFICERS

In accordance with Section 14A of the Securities Exchange Act of 1934 and Rule 14a-21(a), we are asking our stockholders to approve, in an advisory vote, the compensation of our named executive officers as disclosed in this Proxy Statement pursuant to Item 402 of Regulation S-K. As discussed in the Compensation Discussion and Analysis, the compensation committee and board of directors believe that the current executive compensation program directly links compensation of the named executive officers to our financial performance and aligns the interests of the named executive officers with those of our stockholders. The compensation committee and board of directors also believe that the executive compensation program provides the named executive officers with a balanced compensation package that includes an appropriate base salary along with competitive annual and long-term incentive compensation targets. These incentive programs are designed to reward the named executive officers on both an annual and long-term basis if they attain specified goals.

Our overall compensation program and philosophy for 2018 was built on a foundation of these guiding principles:

- we pay for performance, with over 60% of our 2018 total target direct compensation for the named executive officers in the form of performance-based incentive compensation;

- we review competitive compensation data for the named executive officers, to the extent available, and incorporate internal equity in the final determination of target compensation levels;

- we align executive compensation and performance by using annual performance incentives based on criteria that are important to stockholder value, including earnings, earnings per share, and earnings before interest, taxes, depreciation, and amortization (EBITDA); and

- we align executive compensation and performance by using long-term performance incentives based on total stockholder return relative to our peer group and financial measures important to company growth.

We are asking our stockholders to indicate their approval of our named executive officer compensation as disclosed in this Proxy Statement, including the Compensation Discussion and Analysis, the executive compensation tables, and narrative discussion. This vote is not intended to address any specific item of compensation, but rather the overall compensation of our named executive officers for 2018. Accordingly, the following resolution is submitted for stockholder vote at the 2019 annual meeting:

> "RESOLVED, that the compensation paid to the company's named executive officers, as disclosed pursuant to Item 402 of Regulation S-K, including the Compensation Discussion and Analysis, compensation tables, and narrative discussion of this Proxy Statement, is hereby approved."

As this is an advisory vote, the results will not be binding on the company, the board of directors, or the compensation committee and will not require us to take any action. The final decision on the compensation of the named executive officers remains with the compensation committee and the board of directors, although the board and compensation committee will consider the outcome of this vote when making future compensation decisions. We intend to hold this advisory vote every year until at least the next stockholder advisory vote on the frequency of this vote.

The board of directors recommends a vote "for" the approval, on a non-binding advisory basis, of the compensation of the company's named executive officers, as disclosed in this Proxy Statement.

Approval of the compensation of the named executive officers requires the affirmative vote of a majority of the common stock present in person or represented by proxy at the meeting and entitled to vote on the proposal. Abstentions will count as votes against this proposal. Broker non-vote shares are not entitled to vote on this proposal and, therefore, are not counted in the vote.

INFORMATION CONCERNING EXECUTIVE OFFICERS

Information concerning the executive officers, including their ages as of December 31, 2018, present corporate positions, and business experience during the past five years, is as follows:

Name	Age	Present Corporate Position and Business Experience
David L. Goodin	57	Mr. Goodin was elected president and chief executive officer of the company and a director effective January 4, 2013. For more information about Mr. Goodin, see the section entitled "Item 1. Election of Directors."
David C. Barney	63	Mr. Barney was elected president and chief executive officer of Knife River Corporation effective April 30, 2013, and president effective January 1, 2012.
Trevor J. Hastings	45	Mr. Hastings was elected president and chief executive officer of WBI Holdings, Inc. effective October 16, 2017. Prior to that, he was vice president-business development and operations support of Knife River Corporation effective January 11, 2012.
Anne M. Jones	55	Ms. Jones was elected vice president-human resources effective January 1, 2016. Prior to that, she was vice president-human resources, customer service, and safety at Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation, and Intermountain Gas Company effective July 1, 2013, and director of human resources for Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. effective June 2008.
Nicole A. Kivisto	45	Ms. Kivisto was elected president and chief executive officer of Montana-Dakota Utilities Co., Cascade Natural Gas Corporation, and Intermountain Gas Company effective January 9, 2015. Prior to that, she was vice president of operations for Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. effective January 3, 2014, and vice president, controller and chief accounting officer for the company effective February 17, 2010.
Daniel S. Kuntz	65	Mr. Kuntz was elected vice president, general counsel and secretary effective January 1, 2017. Prior to that, he was general counsel and secretary effective January 9, 2016, associate general counsel effective April 1, 2007, and assistant secretary effective August 17, 2007.
Margaret (Peggy) A. Link	52	Ms. Link was elected vice president and chief information officer effective December 1, 2017. Prior to that, she was chief information officer effective January 1, 2016, assistant vice president-technology and cybersecurity officer effective January 1, 2015, and director shared IT services effective June 2, 2009.
Jeffrey S. Thiede	56	Mr. Thiede was elected president and chief executive officer of MDU Construction Services Group, Inc. effective April 30, 2013, and president effective January 1, 2012.
Jason L. Vollmer	41	Mr. Vollmer was elected vice president, chief financial officer and treasurer effective September 30, 2017. Prior to that, he was vice president, chief accounting officer and treasurer effective March 19, 2016, treasurer and director of cash and risk management effective November 29, 2014, manager of treasury services and risk management effective June 30, 2014, and manager of treasury services, cash and risk management effective April 11, 2011.

COMPENSATION DISCUSSION AND ANALYSIS

The Compensation Discussion and Analysis describes how our named executive officers were compensated for 2018 and how their 2018 compensation aligns with our pay for performance philosophy. It also describes the oversight of the compensation committee and the rationale and processes used to determine the 2018 compensation of our named executive officers including the objectives and specific elements of our compensation program.

The Compensation Discussion and Analysis may contain statements regarding corporate performance targets and goals. The targets and goals are disclosed in the limited context of our compensation programs and should not be understood to be statements of management's expectations or estimates of results or other guidance. We specifically caution investors not to apply these statements to other contexts.

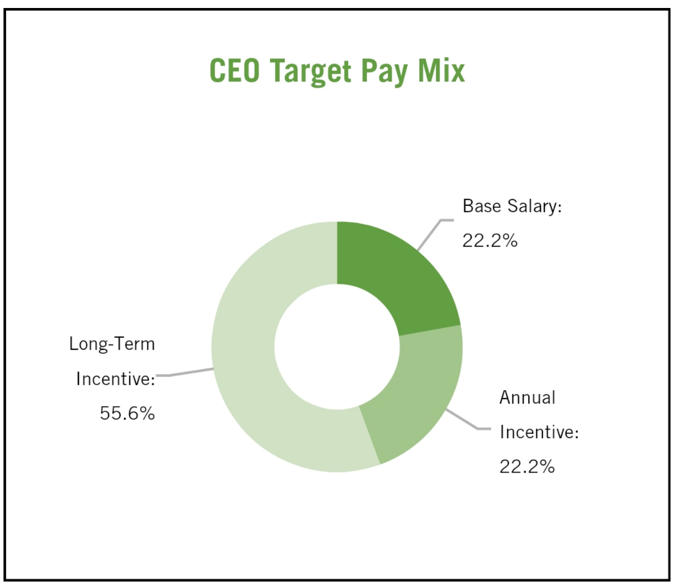
Our Named Executive Officers for 2018 were:

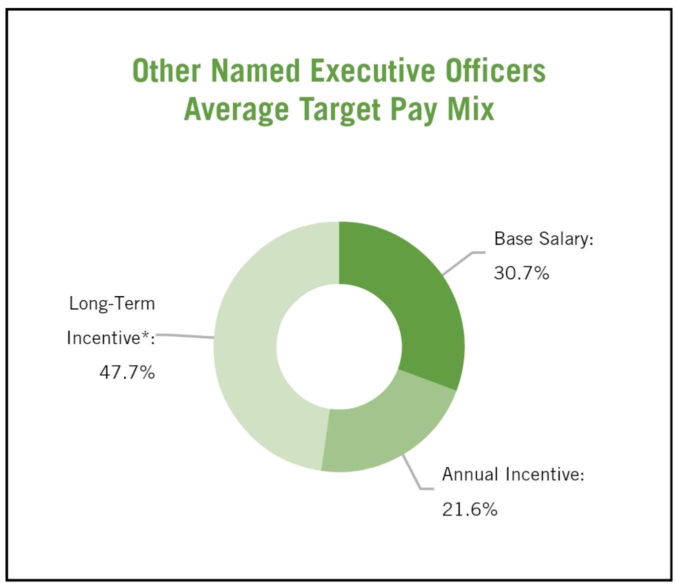
David L. Goodin	President and Chief Executive Officer (CEO)
Jason L. Vollmer	Vice President, Chief Financial Officer (CFO) and Treasurer
David C. Barney	President and Chief Executive Officer - Construction Materials and Contracting Segment
Jeffrey S. Thiede	President and Chief Executive Officer - Construction Services Segment
Nicole A. Kivisto	President and Chief Executive Officer - Electric and Natural Gas Distribution Segments

Executive Summary

Pay for Performance

To ensure management's interests are aligned with those of our stockholders and the performance of the company, the majority of the CEO's and the other named executive officers' target compensation is dependent on the achievement of company performance targets. The charts below show the target pay mix for the CEO and average target pay mix of the other named executive officers, including base salary and the annual and long-term incentives.





*Includes time-vesting restricted stock units for certain named executive officers.

Annual Base Salary

We provide our executive officers with base salary at a sufficient level to attract, recruit, and retain executives with the knowledge, skills, and abilities necessary to successfully execute their job responsibilities. Consistent with our compensation philosophy of linking pay to performance, our executives receive a relatively smaller percentage of their overall target compensation in the form of base salary. In establishing base salaries, the compensation committee considers each executive's individual performance, the scope and complexities of their responsibilities, internal equity, and whether the base salary is competitive as measured against the base salaries of similarly situated executives in our peer group and market compensation data.

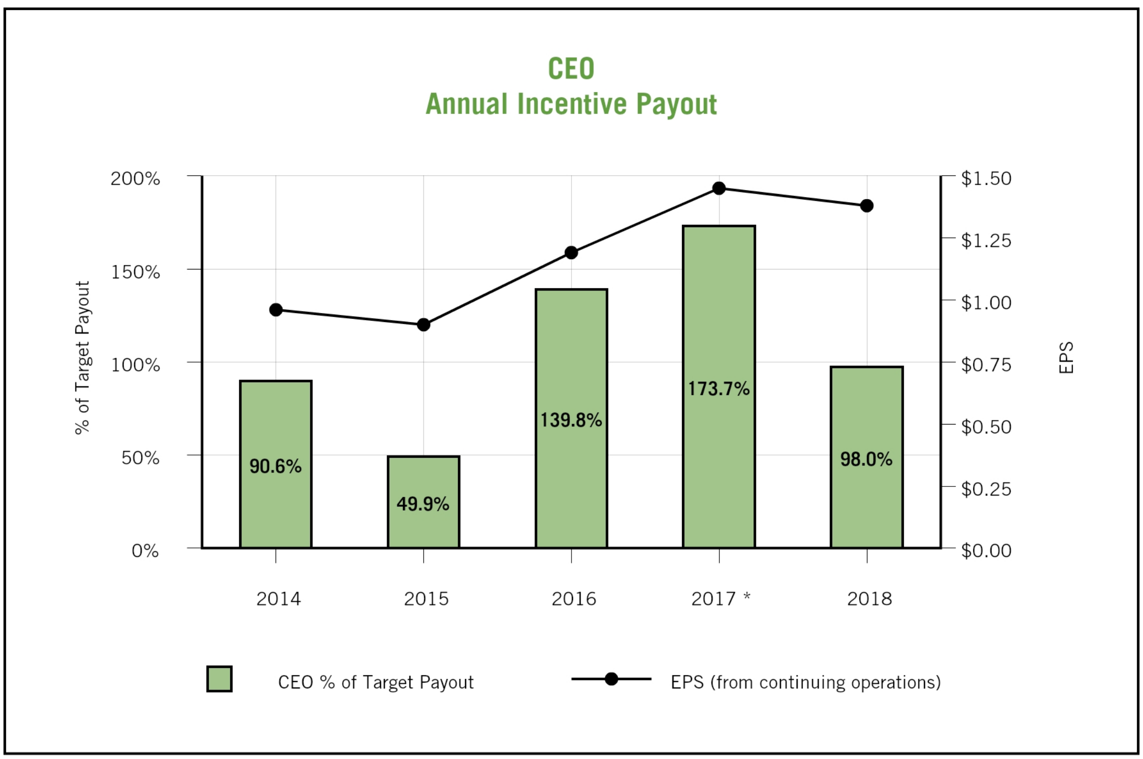
Annual Cash Incentive Awards

Annual cash incentive awards for our executive officers are linked to performance by rewarding achievement of financial goals and ensuring our executive officers are focused and accountable for our growth and profitability. The design of the annual cash incentive award opportunities for 2018 was the same as the design used in 2017. Each executive is assigned a target annual incentive award based on a percentage of the executive's base salary. The actual annual cash incentive realized is determined by multiplying the target award by the payout percentage associated with achievement of the executive's performance measures.

The compensation committee selected specific business segment financial performance measures for the business segment executives which represented 80% of their annual award opportunity. The other 20% of the business segment executives' annual award opportunity was based on the achievement of overall company earnings per share (EPS). These measures incentivize our business segment executives to focus on the success and performance of their business segment while keeping the overall success of the company in mind.

The annual cash incentive award for corporate executives (including our CEO and CFO) is based on the achievement of the performance measures for each business segment executive and weighted by each business segment's invested capital relative to the company's total invested capital. The corporate executives' target awards are multiplied by the sum of the weighted achievement percentage for each business segment executive to derive the corporate executives' realized annual awards. This incentivizes the corporate executives to assist the business segments in their success while still emphasizing overall company performance. See the "Annual Incentives" section within this Compensation Discussion and Analysis for further details on our company's annual cash incentive program.

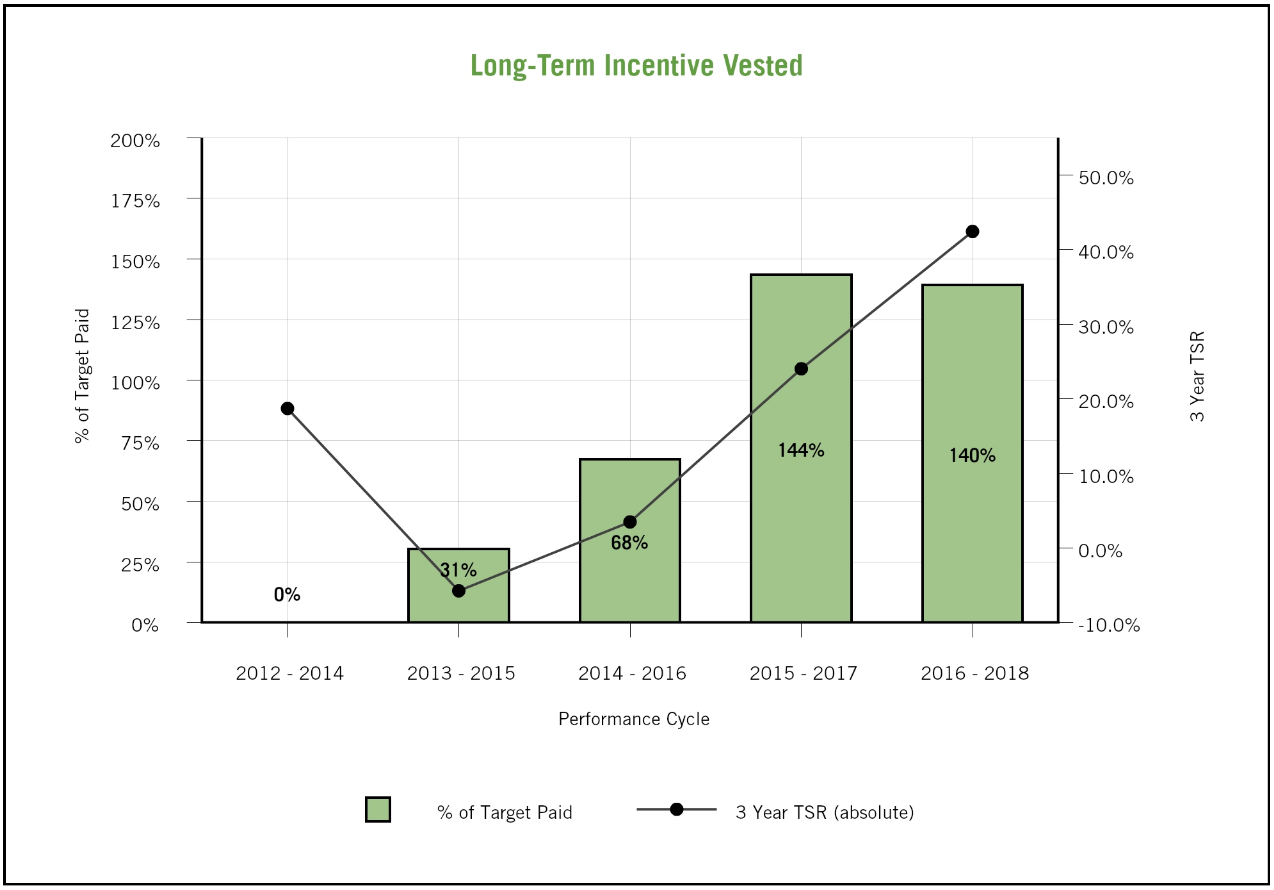
The following chart shows the percentage payout of the annual incentive target realized by our CEO with a comparison to earnings per share from continuing operations for the last five years. The chart demonstrates the alignment between our financial performance and realized annual cash incentive compensation.



* MDU Resources Group, Inc. reported 2017 earnings from continuing operations of $1.45 per share which included a non-recurring benefit of 20 cents per share attributable to the federal Tax Cuts and Jobs Act that was signed into law on December 22, 2017.

Long-Term Equity-Based Incentive Awards

Our compensation committee and the board approve grants of long-term incentives to our executives in the form of performance shares which vest into company stock plus dividend equivalents at the end of a three-year performance cycle upon achievement of established performance measures. The following chart depicts the actual vesting percentage for the last five performance cycles and demonstrates the alignment between total stockholder return (TSR) and realized long-term incentive compensation by our executives.



In their February 2018 meeting, the compensation committee and the board approved off-cycle awards to Messrs. Barney and Thiede of time-vesting restricted stock units which will vest on December 31, 2020, if the executives remain employed through the vesting date. The compensation committee believed the restricted stock unit awards incentivize Messrs. Barney and Thiede to continue their employment for the next three years and grow their respective business segments during that time.

See the “Long-Term Incentives” section within this Compensation Discussion and Analysis for further details on the company’s long-term incentive program.

With the majority of our executive officer’s compensation dependent on the achievement of performance measures set by the compensation committee, we believe there is substantial alignment between executive pay and the company’s performance.

Stockholder Advisory Vote (“Say on Pay”)

At our 2018 Annual Meeting of Stockholders, 95.9% of the votes cast on the “Say on Pay” proposal approved the compensation of our named executive officers. The compensation committee viewed the 2018 vote as an expression of the stockholders general satisfaction with the company’s executive compensation programs. The compensation committee reviewed and considered the 2018 vote on “Say on Pay” in setting compensation for 2019 by continuing to link performance-based annual and long-term incentives to company financial performance and stockholder value.

Compensation Practices

Our practices and policies ensure alignment between the interests of our stockholders and our executives as well as effective compensation governance.

What We Do
☑ **Pay for Performance** - Annual and long-term award incentives tied to performance measures set by the compensation committee comprise the largest portion of executive compensation.
☑ **Independent Compensation Committee** - All members of the compensation committee meet the independence standards under the New York Stock Exchange listing standards and the Securities and Exchange Commission rules.
☑ **Independent Compensation Consultant** - The compensation committee retains an independent compensation consultant to evaluate executive compensation plans and practices.
☑ **Competitive Compensation** - Executive compensation reflects executive performance, experience, relative value compared to other positions within the company, relationship to competitive market value compensation, business segment economic environment, and the actual performance of the overall company and the business segments.
☑ **Annual Cash Incentive** - Payment of annual cash incentive awards are based on business segment and overall company performance against pre-established financial measures.
☑ **Long-Term Equity Incentive** - The long-term performance-based equity incentive in the form of performance shares represents approximately 56% of our CEO's and approximately 37% of our other named executive officers' 2018 target compensation, which may only be earned based on achievement of established performance measures at the end of a three-year period.
☑ **Annual Compensation Risk Analysis** - We regularly analyze the risks related to our compensation programs and conduct an annual broad risk assessment.
☑ **Stock Ownership and Retention Requirements** - Executive officers are required to own, within five years of appointment or promotion, company common stock equal to a multiple of their base salary. The executive officers also must retain at least 50% of the net after-tax shares of stock vested through the long-term incentive plan for at least two years or until termination of employment.
☑ **Clawback Policy** - If the company's audited financial statements are restated, the compensation committee may, or shall if required, demand repayment of some or all incentives paid to our executive officers within the last three years.

What We Do Not Do
☒ **Stock Options** - The company does not use stock options as a form of incentive compensation.
☒ **Employment Agreements** - Executives do not have employment agreements entitling them to specific payments upon termination or a change of control of the company.
☒ **Perquisites** - Executives do not receive perquisites that materially differ from those available to employees in general.
☒ **Hedge Stock** - Executives and directors are not allowed to hedge company securities.
☒ **Pledge Stock** - Executives and directors are not allowed to pledge company securities in margin accounts or as collateral for loans.
☒ **No Dividends or Dividend Equivalents on Unvested Shares** - We do not provide for payment of dividends or dividend equivalents on unvested share awards.

2018 Compensation Framework

Objectives of our Compensation Program

We have a written executive compensation policy for our executive officers, including all the named executive officers. Our policy's stated objectives are to:

- recruit, motivate, reward, and retain high performing executive talent required to create superior long-term total stockholder return in comparison to our peer group;
- reward executives for short-term performance, as well as for growth in enterprise value over the long-term;

- provide a competitive compensation package relative to industry-specific and general industry comparisons and internal equity;
- ensure effective utilization and development of talent by working in concert with other management processes - for example, performance appraisal, succession planning, and management development; and
- ensure that compensation programs do not encourage or reward excessive or imprudent risk taking.

Compensation Decision Process for 2018

For 2018, the compensation committee made recommendations to the board of directors regarding compensation of all executive officers, and the board of directors then approved the recommendations. The CEO's role in the process includes the assessment of executive officer performance and recommending base salaries for the executive officers other than himself. The CEO attended all compensation committee meetings but was not present during discussions of his compensation. The compensation committee established and approved base salaries and performance measures for the annual and long-term incentive compensation for 2018. They also certified the achievement of performance measures in 2017 associated with annual and long-term incentive compensation.

At least every two years, the compensation committee hires an independent consulting firm to assess and recommend competitive pay levels, including base salaries and incentive compensation, associated with executive officer positions. Typically the consulting firm conducts its analysis in even numbered years. In odd numbered years, the assessment is performed by the company's human resources department using a variety of industry specific sources. In August 2017, the company's human resources department prepared the analysis of and provided recommendations for the 2018 compensation structure.

Components of Compensation

The components of our executive officer's compensation are selected to drive financial and operational results as well as align the executive officer's interests with those of our stockholders. The components of our executive compensation include:

Component	Payments	Purpose	How Determined	How it Links to Performance
Base Salary	Assured	Provides sufficient, regularly paid income to recruit and retain executives with the knowledge, skills, and abilities necessary to successfully execute their job responsibilities.	Based on recommendation from the CEO for executives other than himself and analysis of peer company and industry compensation information.	Base salary is a means to attract and retain talented executives capable of driving success and performance.
Annual Cash Incentive	Performance Based At Risk	Provides an opportunity to earn annual incentive compensation to ensure focus on annual financial results and to be competitive from a total renumeration standpoint.	Annual cash incentives are calculated as a percentage of base salary with payout based on the achievement of performance measures established in advance by the compensation committee.	Annual incentive performance measures are tied to the achievement of financial goals aimed to drive the success of the company and the individual business segments.
Performance Shares	Performance Based At Risk	Provides an opportunity to earn long-term compensation to ensure focus on stockholder return and to be competitive from a total renumeration standpoint.	Performance share award opportunities are calculated as a percentage of base salary with vesting based on the company's achievement of financial measures established by the compensation committee as well as total stockholder return in comparison to the company's peer group over a three-year performance cycle.	Fosters ownership in company stock and aligns the executive's interests with those of stockholders in increasing stockholder value.
Restricted Stock Units	Time Vested	Provides an opportunity to earn long-term compensation to promote retention of executive talent, focus on long-term business segment growth, and to be competitive from a total renumeration standpoint.	Restricted stock unit awards are determined by the compensation committee and vest at the end of a three-year period if the executive remains employed by the company.	Fosters ownership in company stock and incentivizes executives to remain employed with the company while aligning the executive's interests with those of the stockholder in increasing stockholder value.

Allocation of Total Target Compensation for 2018

Total target compensation consists of base salary plus target annual and long-term incentive compensation. Performance-based incentive compensation, which consists of annual cash incentive and three-year performance share award opportunities, comprises the largest portion of our named executive officers' total target compensation because:

- our named executive officers are in positions to drive, and therefore bear high levels of responsibility for, our corporate performance;
- incentive compensation is dependent upon our performance;
- incentive compensation helps ensure focus on performance measures that are aligned with our overall strategy; and
- the interests of the named executive officers are aligned with those of stockholders by making a significant portion of their target compensation contingent upon results beneficial to stockholders.

To foster and reward long-term growth, the compensation committee generally allocates a higher percentage of total target compensation to the target long-term incentive than to the target annual incentive for our higher level executives because they are in a better position to influence long-term performance. The long-term incentive awards, if earned by achieving established measures, are paid in company common stock. These awards, combined with our stock retention requirements and our stock ownership policy, promote ownership of our stock by the executive officers. The compensation committee believes the executive officers, as stockholders, will be motivated to deliver results that build value for all stockholders over the long term.

Peer Group

The compensation committee evaluates the company's compensation plan and its performance relative to a group of peer companies in determining compensation and the vesting of long-term incentive compensation. The companies included in our peer group are evaluated every year and are selected as representatives of the industries in which we operate. The 2018 peer group includes twelve companies in regulated energy delivery businesses, and eight companies in the construction materials or construction services businesses. In determining the 2018 peer group, we removed five companies, namely Avista Corporation, National Fuel Gas Company, IES Holdings, Inc., Quanta Services, Inc., and Sterling Construction Company, Inc., due to size, industry focus, or pending merger. Companies added to the 2018 peer group were Otter Tail Corporation, Portland General Electric Company, Southwest Gas Holdings, Inc., Spire, Inc., MasTec, Inc., and Summit Materials, Inc. due to their industry focus, relative size, and geographic location. The following chart depicts the companies in our 2018 peer group.

2018 Peer Companies

Regulated Energy Delivery	Construction Materials and Services
ALLETE, Inc.	EMCOR Group, Inc.
Alliant Energy Corporation	Granite Construction Incorporated
Atmos Energy Corporation	Martin Marietta Materials, Inc.
Black Hills Corporation	MasTec, Inc.
IDACORP, Inc.	MYR Group, Inc.
Northwest Natural Gas Company	Summit Materials, Inc.
NorthWestern Corporation	U.S. Concrete, Inc.
Otter Tail Corporation	Vulcan Materials Company
Portland General Electric Company	
Southwest Gas Holdings, Inc.	
Spire Inc.	
Vectren Corporation	

2018 Compensation for Our Named Executive Officers

2018 Base Salary and Incentive Targets

At its November 2017 meeting, the compensation committee approved 2018 base salaries for the named executive officers. Mr. Goodin was not present during the portion of the meeting where the compensation committee discussed and approved the president and CEO base salary for 2018. At its February 2018 meeting, the compensation committee approved the target annual and long-term incentive opportunities for our named executive officers. In determining base salaries, target cash annual incentives, target long-term incentives, and total direct compensation for our named executive officers, the compensation committee received and considered company and individual performance, market and peer data, responsibilities, experience, tenure in position, internal equity, and input and recommendations from the CEO and human resources department. The following information relates to each named executive officer's base salary, target cash annual incentive, target long-term incentive, and total direct compensation:

David L. Goodin	2018 ($)	Compensation Component as a % of Base Salary
Base Salary	824,460	
Target Annual Incentive Opportunity	824,460	100%
Target Long-Term Performance Share Incentive Opportunity	2,061,150	250%
Target Total Potential Direct Compensation	3,710,070	
The compensation committee considered information provided in the 2016 and 2017 compensation studies showing Mr. Goodin's base salary, total cash compensation, and long-term incentives were below market levels and increased Mr. Goodin's base salary by 4% and long-term incentive target from 225% to 250% for 2018. No changes were made to Mr. Goodin's annual incentive target as a percentage of base salary.		

Jason L. Vollmer	2018 ($)	Compensation Component as a % of Base Salary
Base Salary	350,000	
Target Annual Incentive Opportunity	227,500	65%
Target Long-Term Performance Share Incentive Opportunity	420,000	120%
Target Total Potential Direct Compensation	997,500	
For 2018, Mr. Vollmer's base salary remained at $350,000, which was set when he was promoted to CFO effective September 30, 2017. His annual and long-term incentive targets were set at 65% and 120% of his base salary, respectively.		

David C. Barney	2018 ($)	Compensation Component as a % of Base Salary
Base Salary	455,000	
Target Annual Incentive Opportunity	341,250	75%
Target Long-Term Performance Share Incentive Opportunity	546,000	120%
Target Restricted Stock Units Opportunity	300,000	66%
Target Total Potential Direct Compensation	1,642,250	
Mr. Barney received a 6.5% increase in base salary for 2018. For 2018, the compensation committee maintained Mr. Barney's target annual incentive opportunity at 75% of his base salary but increased his long-term incentive opportunity from 90% to 120%. Mr. Barney also received a grant of 11,419 restricted stock units which vest on December 31, 2020, if he remains employed by the company.		

Jeffrey S. Thiede	2018 ($)	Compensation Component as a % of Base Salary
Base Salary	455,000	
Target Annual Incentive Opportunity	341,250	75%
Target Long-Term Performance Share Incentive Opportunity	546,000	120%
Target Restricted Stock Units Opportunity	300,000	66%
Target Total Potential Direct Compensation	1,642,250	
Mr. Thiede received a 3.9% increase in his base salary for 2018. For 2018, the compensation committee maintained Mr. Thiede's target annual incentive opportunity at 75% of base salary but increased his long-term incentive opportunity from 90% to 120%. Mr. Thiede also received a grant of 11,419 restricted stock units which vest on December 31, 2020, if he remains employed by the company.		

Nicole A. Kivisto	2018 ($)	Compensation Component as a % of Base Salary
Base Salary	430,000	
Target Annual Incentive Opportunity	279,500	65%
Target Long-Term Performance Share Incentive Opportunity	516,000	120%
Target Total Potential Direct Compensation	1,225,500	
Ms. Kivisto received a base salary increase of 13.8% for 2018. The compensation committee maintained her target annual incentive opportunity at 65% of base salary but increased her long-term incentive opportunity from 90% to 120% of base salary for 2018.		

Annual Incentives

Annual incentive awards are determined for business segment executives by the achievement of specific performance measures selected by the compensation committee including financial performance measures specific to each business segment and a performance measure tied to overall company earnings per share. For corporate executives, annual incentive awards are determined as the sum of a weighted percentage award payout of each business segment based upon achievement of its performance measures. Percentage award payouts for the business segments are weighted by the business segment's invested capital relative to the company's total invested capital. Through this, our business segment executives are incentivized to primarily focus on the success and performance of their business segment while keeping the overall financial success of the company in mind, whereas our corporate executives are incentivized to assist in the success and performance of all lines of business.

The compensation committee considered and selected objective financial performance measures to ensure that compensation to the executives reflects the success of their respective business segments and the company as well as value provided to our stockholders. Each business segment president's annual incentive performance measures include a corporate earnings per share performance measure representing 20% of the target award opportunity and a business segment financial performance measure representing 80% of the target award opportunity. The following annual incentive performance measures for 2018 were adopted by the compensation committee for the business segment presidents (exclusive of the MDU Resources Group, Inc. corporate executive officers) at its February 2018 meeting:

Measure	Applies to	Purpose	Measurement	Target	Weight	How Target was Selected
MDU Resources Diluted Adjusted Earnings per Share (EPS)	All Business Segment Presidents	EPS is a generally accepted accounting principle (GAAP) measurement and is a key driver of stockholder return. This goal applies to the presidents of all business segments to engage them as members of the company's management policy committee in the overall success of the company.	GAAP EPS (diluted) before discontinued operations plus earnings/losses from any operations discontinued after December 31, 2017, and adjusted to remove: - the effect on earnings at the company level of intersegment earnings eliminations; - the effect on earnings from losses on asset sales/ dispositions approved by the board; - the effect on earnings from withdrawal liabilities relating to multiemployer pension plans; and - the effect on earnings from transaction costs for completed acquisitions or mergers.	$1.35	20%	Target reflects EPS performance within the range of guidance for 2018 while also being higher than 2017 target. The target reflects an aggregation of the 2018 business unit financial goals and is higher than 2017 actual results minus the effect of the federal Tax Cuts and Jobs Act on 2017 results.
Business Segment Earnings	Electric and Natural Gas Distribution Segments President	Provides a measure of financial performance and an incentive to drive business results.	GAAP business segment earnings before discontinued operations plus earnings/losses from any operations discontinued after December 31, 2017, and adjusted to remove: - the effect on earnings from losses on asset sales/ dispositions approved by the board; and - the effect on earnings from transaction costs for completed acquisitions or mergers.	$89.1 million	80%	Target reflects the 2018 financial goal for the business segment and exceeds the segments' 2017 target and actual results.
	Pipeline and Midstream Segment President			$22.2 million	80%	Target reflects the 2018 financial goal of the business segment and exceeds the segment's 2017 target and actual results.
Business Segment Earnings Before Interest, Tax, Depreciation, and Amortization (EBITDA)	Construction Materials and Contracting Segment President	Provides a measure of financial performance common to the industries in which these segments operate.	EBITDA from continuing operations adjusted to remove: - the effect on earnings from losses on asset sales/ dispositions approved by the board; - the effect on earnings from withdrawal liabilities relating to multiemployer plans; and - the effect on earnings from transaction costs for completed acquisitions or mergers.	$197.5 million	80%	Target reflects the 2018 financial goal of the business segment, sufficient to exceed the segment's risk adjusted capital costs, incentivize growth of the business segment, and exceed 2017 actual results adjusted to remove the effect of the federal Tax Cuts and Jobs Act.
	Construction Services Segment President			$100.1 million	80%	Target reflects the 2018 financial goal of the business segment, sufficient to exceed the segment's risk adjusted capital costs, incentivize growth of the business segment, and exceed 2017 actual results.

Actual performance results are compared to target performance measures to arrive at a percent of target achieved. The percent of target achieved is translated into a payout percentage of the target award opportunity. Achievement of 100% of the performance target corresponds to a payout equal to the target annual award opportunity. Receipt of a payout requires threshold achievement of a performance measure which varies by business segment. Achievement below the threshold level of the performance measure results in no payout of the target award opportunity attributable to the measure. For the company EPS performance measure, threshold payout requires achievement of 85% of the target performance measure which results in a payout of 25% of the award opportunity attributable to the company EPS performance measure. For the electric and natural gas distribution segments, the pipeline and midstream segment, the construction materials and contracting segment, and the construction services business segment's performance measures, threshold payout requires achievement of 90%, 85%, 75%, and 65% of the target performance measures, respectively, resulting in business segment target award payouts of 50%, 25%, 25%, and 25%, respectively. Maximum payouts also vary by business segment. For the company EPS performance measure, as well as the electric and natural gas distribution segments and the pipeline and midstream segment, maximum payout of the business segment award opportunity is 200%, and for the construction materials and contracting segment and the construction services segment, payout of 250% of the business segment award opportunity is received if the percent of target performance achieved is 115% or greater. Results achieved between payout levels are calculated using linear interpolation.

2018 Annual Incentive Results

The 2018 performance measure results, percent of target achieved based on those results, and the associated payout percentages are presented below:

Business Segment	Performance Measure	Result	Percent of Performance Measure Achieved	Percent of Award Opportunity Payout	Weight	Weighted Award Opportunity Payout %
All Business Segments	Earnings per Share	$1.35	100.0%	100.0%	20%	20.0%
Electric and Natural Gas Distribution	Earnings	$84.7 million	95.1%	75.7%	80%	60.6%
Pipeline and Midstream	Earnings	$24.0 million	108.1%	154.1%	80%	123.3%
Construction Materials and Contracting	EBITDA	$200.6 million	101.6%	115.9%	80%	92.7%
Construction Services	EBITDA	$103.6 million	103.5%	135.1%	80%	108.1%

For our corporate named executive officers, namely Messrs. Goodin and Vollmer, the compensation committee continued to base the payout of the annual cash incentives on the achievement of performance measures at the business segments weighted by each business segment's average invested capital relative to the company's total invested capital. The compensation committee believes this approach provides alignment between our corporate executives and business segment performance. Messrs. Goodin's and Vollmer's 2018 annual cash incentives were earned at 98.0% of the target award opportunity based on the following proportional weighted sum of the annual business segment payouts:

Business Segment	Column A Business Segment Award Opportunity Payout	Column B Percentage of Average Invested Capital	Column A x Column B
Electric and Natural Gas Distribution	80.6%	58.5%	47.2%
Pipeline and Midstream	143.3%	8.7%	12.5%
Construction Materials and Contracting	112.7%	23.9%	26.9%
Construction Services	128.1%	8.9%	11.4%
Total Payout Percentage			98.0%

Based on the achievement of the performance targets, the named executive officers received the following 2018 annual incentive compensation:

Name	Target Annual Incentive ($)	Annual Incentive Earned	
		Payout as a % of Target (%)	Amount ($)
David L. Goodin	824,460	98.0	807,971
Jason L. Vollmer	227,500	98.0	222,950
David C. Barney	341,250	112.7	384,589
Jeffrey S. Thiede	341,250	128.1	437,141
Nicole A. Kivisto	279,500	80.6	225,277

Long-Term Incentives

Long-term incentive compensation comprises approximately 56% of the CEO's 2018 total target direct compensation and 48% of the average of the other named executive officer's target total direct compensation. Stock earned under long-term incentive compensation is subject to our stock retention requirements. If the executive's employment is terminated during the performance period for cause at any time, or for any reason other than cause before the executive has reached age 55 and completed ten years of service, all performance shares and related dividend equivalents are forfeited. Restricted stock units are forfeited or canceled if the executive ceases to be an employee of the company or an affiliate except for employment termination due to death, disability, or change of control.

Grant of 2018-2020 Long-Term Performance Share Awards

For 2018, the compensation committee approved performance share awards which may vest at the end of a three-year period between 0% and 200% based on the achievement of three performance measures:

- Total stockholder return relative to that of the peer group companies represents 50% of the award and was selected to align the award with the company's performance relative to our peers;

- Compound annual growth rate in earnings from continuing operations before interest, taxes, depreciation, depletion, and amortization (EBITDA) represents 25% of the award which encourages strategic growth and focuses on controllable costs; and

- Compound annual growth rate in earnings from continuing operations represents 25% of the award which encourages quality earnings and continued growth of the company.

For the awards made in 2018, the compensation committee added the EBITDA and earnings growth measures to incentivize participants to focus on company growth in addition to total stockholder return during the performance period. Earnings used to calculate EBITDA growth and earnings growth will be adjusted for (i) the effect on earnings from losses on asset sales/dispositions approved by the board; (ii) the effect on earnings from withdrawal liabilities relating to multiemployer pension plans; and (iii) the effect on earnings from transaction costs for completed acquisitions or mergers.

On February 15, 2018, for the 2018-2020 performance period, the compensation committee determined the target number of performance shares for each named executive officer by multiplying the named executive officer's 2018 base salary by a target long-term incentive percentage and then dividing by the average of the closing prices of our stock from January 1 through January 22, 2018, which was $26.27 per share. Based on this price, the board of directors, upon recommendation of the compensation committee, awarded the following target performance share opportunities to the named executive officers:

Name	Base Salary to Determine Target ($)	Target Long-Term Performance Share Incentive % of Base Salary (%)	Long-Term Performance Share Incentive Target ($)	Performance Share Opportunities (#)
David L. Goodin	824,460	250	2,061,150	78,460
Jason L. Vollmer	350,000	120	420,000	15,987
David C. Barney	455,000	120	546,000	20,784
Jeffrey S. Thiede	455,000	120	546,000	20,784
Nicole A. Kivisto	430,000	120	516,000	19,642

Restricted Stock Units Subject to Service Based Vesting

For 2018, the compensation committee also awarded 11,419 restricted stock units to each of Messrs. Barney and Thiede, which will vest on December 31, 2020, provided they remain employed until that date. The restricted stock unit awards represent $300,000 divided by the average closing stock price from January 1 through January 22, 2018 of $26.27 per share. The compensation committee believes the off-cycle restricted stock awards further incentivize both Messrs. Barney and Thiede to continue their employment with the company for the next three years while the company emphasizes the growth of their respective business segments. Dividend equivalents are credited to each restricted stock unit during the vesting period to the same extent that dividends are paid on shares of our common stock, but such dividend equivalents are paid only to the extent the underlying restricted stock unit vests based on the satisfaction of the service requirement. Dividend equivalents are paid at the time of settlement in cash.

Vesting of 2016-2018 Performance Share Awards

For the 2016-2018 performance period, the long-term incentive program consisted solely of performance shares. The performance criteria used for the 2016-2018 performance period was total stockholder return as a percentile of the total stockholder return for our peer companies. Our total stockholder return ranking over the performance period was at the 60th percentile which resulted in vesting at 140% of the target performance shares and dividend equivalents. The named executive officers received the following long-term compensation for the 2016-2018 performance period:

Name	Target Performance Shares (#)	Performance Shares Vested (#)	Dividend Equivalents ($)
David L. Goodin	98,764	138,269	321,475
Jason L. Vollmer	4,767	6,673	15,515
David C. Barney	18,920	26,488	61,585
Jeffrey S. Thiede	19,767	27,673	64,340
Nicole A. Kivisto	16,744	23,441	54,500

Stock Retention Requirement

The named executive officers must retain 50% of the net after-tax shares vested pursuant to the long-term incentive awards for at least two years from the date the vested shares are issued or the executive's termination of employment. The compensation committee may also require the executive officer to retain share awards net of taxes if the executive has not met the stock ownership requirements under the company's stock ownership policy for executives.

Other Benefits

The company provides post employment benefit plans and programs in which our named executive officers may be participants. We believe it is important to provide post-employment benefits which approximate retirement benefits paid by other employers to executives in similar positions. The compensation committee periodically reviews the benefits provided to maintain a market-based benefits package. Our named executive officers participated in the following plans during 2018 which are described below:

Plans	David L. Goodin	Jason L. Vollmer	David C. Barney	Jeffrey S. Thiede	Nicole A. Kivisto
401(k) Retirement Plan	Yes	Yes	Yes	Yes	Yes
Pension Plans	Yes	Yes	No	No	Yes
Supplemental Income Security Plan	Yes	No	Yes	No	Yes
Nonqualified Defined Contribution Plan	No	Yes	Yes	Yes	No

401(k) Retirement Plan

The named executive officers as well as all employees working a minimum of 1,000 hours per year are eligible to participate in the 401(k) plan and defer annual income up to the IRS limit. The company provides a match up to 3% depending on the employee's elected deferral rate. Contributions and the company match are invested in various funds based on the employee's election including company common stock.

In 2010, the company began offering increased company contributions to our 401(k) plan in lieu of pension plan contributions. For non-bargaining unit employees hired after 2006 or employees who were not previously participants in the pension plan, the added retirement contribution is 5% of plan eligible compensation. For non-bargaining unit employees hired prior to 2006 who were participants in the pension plan, the added retirement contributions are based on the employee's age as of December 31, 2009. The retirement contribution is 11.5% for Mr. Goodin, 9.0% for Ms. Kivisto, 7.0% for Mr. Vollmer, and 5.0% for Messrs. Barney and Thiede. These amounts may be reduced in accordance with the provisions of the 401(k) plan to ensure compliance with IRS limits.

Pension Plans

Effective in 2006, the defined benefit pension plans were closed to new non-bargaining unit employees and as of December 31, 2009, the defined benefit plans were frozen. For further details regarding the company's pension plans, please refer to the section entitled "Pension Benefits for 2018."

Supplemental Income Security Plan

We offered certain key managers and executives benefits under a nonqualified retirement plan, referred to as the Supplemental Income Security Plan (SISP). The SISP provides participants with additional retirement income and death benefits. Effective February 11, 2016, the SISP was amended to exclude new participants to the plan and freeze current benefit levels for existing participants. For further details regarding the company's SISP, please refer to the section entitled "Pension Benefits for 2018." Named executive officers participating in the SISP are Messrs. Goodin, Barney, and Ms. Kivisto.

The following table reflects our named executive officers' SISP benefits as of December 31, 2018:

	SISP Benefits	
Name	Annual Death Benefit ($)	Annual Retirement Benefit ($)
David L. Goodin	552,960	276,480
Jason L. Vollmer	n/a	n/a
David C. Barney	262,464	131,232
Jeffrey S. Thiede	n/a	n/a
Nicole A. Kivisto	96,000	48,000

Nonqualified Defined Contribution Plan

The company adopted the Nonqualified Defined Contribution Plan (NQDCP) effective January 1, 2012, to provide retirement and deferred compensation for a select group of management and other highly compensated employees. The compensation committee, upon recommendation from the CEO, determines which employees will participate in the NQDCP and the amount of contributions for any year. After satisfying a vesting requirement for each contribution, distributions will be made in accordance with the terms of the plan. For further details regarding the company's NQDCP, please refer to the section entitled "Nonqualified Deferred Compensation for 2018."

For 2018, the compensation committee selected and approved contributions of $35,000 to Mr. Vollmer, $150,000 to Mr. Barney, and $100,000 to Mr. Thiede. The contributions awarded to Messrs. Vollmer, Barney, and Thiede represent 10.00%, 32.97%, and 21.98% of their base salaries, respectively.

Employment and Severance Agreements

We currently do not have employment or severance agreements with our executives entitling them to specific payments upon termination of employment or a change of control of the company. The compensation committee generally considers providing severance benefits on a case-by-case basis. Any post-employment or change of control benefits available to our executives are addressed within our incentive and retirement plans. Please refer to the section entitled "Potential Payments upon Termination or Change of Control."

Compensation Governance

Impact of Tax and Accounting Treatment

The compensation committee may consider the impact of tax and/or accounting treatment in determining compensation.

Section 162(m) of the Internal Revenue Code limits the deductibility of certain compensation to $1 million paid to certain officers as a business expense in any tax year. The federal Tax Cuts and Jobs Act (Tax Reform), signed into law in December 2017, expanded the number of individuals covered by the Section 162(m) deductibility limit and repealed the exception for performance-based compensation, effective for taxable years beginning after December 31, 2017. Incentive compensation approved by the compensation committee prior to Tax Reform for our CEO and those executive officers whose overall compensation was likely to exceed $1 million was generally structured to meet the requirements for the performance-based exception for deductibility for purposes of Section 162(m). As a result of Tax Reform, compensation paid to our covered executive officers in excess of $1 million will not be deductible, unless it qualifies for transition relief applicable to certain arrangements in place as of November 2, 2017.

The compensation committee also considers the accounting and cash flow implications of various forms of executive compensation. We expense salaries and annual incentive compensation as earned. For our equity awards, we record the accounting expense in accordance with Financial Accounting Standards Board 718, which is generally expensed over the vesting period.

Stock Ownership Requirements

Executives participating in our Long-Term Performance-Based Incentive Plan are required within five years of appointment or promotion into an executive level to own our common stock equal to a multiple of their base salary as outlined in the stock ownership policy. Stock owned through our 401(k) plan or by a spouse is considered in ownership calculations. The level of stock ownership compared to the ownership requirement is determined based on the closing sale price of our stock on the last trading day of the year and base salary at December 31 of the same year. The table shows the named executive officers' holdings as a multiple of their base salary.

Name	Ownership Policy Multiple of Base Salary within 5 Years	Actual Holdings as a Multiple of Base Salary[1]	Ownership requirement must be met by:
David L. Goodin	4X	7.7	1/1/2018
Jason L. Vollmer	3X	0.8	1/1/2023
David C. Barney	3X	2.3	1/1/2019
Jeffrey S. Thiede	3X	2.3	1/1/2019
Nicole A. Kivisto	3X	3.3	1/1/2020

[1] Includes stock awards earned net of taxes for the 2016-2018 performance period.

The compensation committee determined that Messrs. Barney and Thiede, who have not met the stock ownership requirement within the required time frame, are required to retain all stock vesting through the Long-Term Performance-Based Incentive Plan, net of taxes, until the stock ownership requirement is met.

Deferral of Annual Incentive Compensation

We provide executives the opportunity to defer receipt of earned annual incentives. If an executive chooses to defer all or part of an annual incentive, we credit the deferral with interest at a rate determined by the compensation committee. For 2018, the compensation committee chose an interest rate of 4.28% based on an average of the Moody's U.S. Long-Term Corporate Bond Yield Average for "A" and "Baa" rated companies. The compensation committee's reasons for using this interest rate recognized incentive deferrals are a low-cost source of capital for the company and are unsecured obligations and, therefore, carry a higher risk to the executives.

Clawback

In February 2016, we amended our Long-Term Performance-Based Incentive Plan and Executive Incentive Compensation Plan sections regarding the repayment of incentive compensation due to accounting restatements, commonly referred to as a clawback policy. The compensation committee may, or shall if required, take action to recover incentive-based compensation from specific executives in the event the company is required to restate its financial statements due to material noncompliance with any financial reporting requirements under the securities laws.

Policy Regarding Hedging Stock Ownership

Our executive compensation policy prohibits executive officers, which includes our named executive officers, from hedging their ownership of company common stock. Executives may not enter into transactions that allow the executive to benefit from devaluation of our stock or otherwise own stock technically but without the full benefits and risks of such ownership. See the section entitled "Security Ownership" for our policy on margin accounts and pledging of our stock.

COMPENSATION COMMITTEE REPORT

The compensation committee has reviewed and discussed the Compensation Discussion and Analysis required by Regulation S-K, Item 402(b), with management. Based on the review and discussions referred to in the preceding sentence, the compensation committee recommended to the board of directors that the Compensation Discussion and Analysis be included in our Proxy Statement on Schedule 14A.

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

EXECUTIVE COMPENSATION TABLES

Summary Compensation Table 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	2016	425,000	288,598	489,600	—	122,708	1,325,906
Services Group, Inc.							
Nicole A. Kivisto[5]	2018	430,000	609,197	225,277	210	34,494	1,299,178
President and CEO of Montana-Dakota Utilities Co.	2017	378,000	286,955	433,906	96,931	33,049	1,228,841

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

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

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

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

[3] All Other Compensation is comprised of:

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

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

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

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

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

Grants of Plan-Based Awards in 2018

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

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

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

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

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

Annual Incentive

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

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

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

Long-Term Incentive

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

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

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

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

Nonqualified Defined Contribution Plan

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

Salary and Bonus in Proportion to Total Compensation

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

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

Outstanding Equity Awards at Fiscal Year-End 2018

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

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

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

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

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

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

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

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

Option Exercises and Stock Vested During 2018

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

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

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

Pension Benefits for 2018

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

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

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

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

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

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

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

Pension Plan

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

Supplemental Income Security Plan

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

Basic SISP Benefits

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

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

Participants can elect to receive the Basic SISP as:

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

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

Excess SISP Benefits

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

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

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

Nonqualified Deferred Compensation for 2018

Deferred Annual Incentive Compensation

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

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

Nonqualified Defined Contribution Plan

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

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

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

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

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

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

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

Potential Payments upon Termination or Change of Control

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

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

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

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

Compensation

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

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

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

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

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

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

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

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

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

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

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

Benefits and Perquisites

Supplemental Income Security Plan

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

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

AUDIT MATTERS

ITEM 3: RATIFICATION OF THE APPOINTMENT OF DELOITTE & TOUCHE LLP AS THE COMPANY'S INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM FOR 2019

The audit committee at its February 2019 meeting appointed Deloitte & Touche LLP as our independent registered public accounting firm for fiscal year 2019. The board of directors concurred with the audit committee's decision. Deloitte & Touche LLP has served as our independent registered public accounting firm since fiscal year 2002.

Although your ratification vote will not affect the appointment or retention of Deloitte & Touche LLP for 2019, the audit committee will consider your vote in determining its appointment of our independent registered public accounting firm for the next fiscal year. The audit committee, in appointing our independent registered public accounting firm, reserves the right, in its sole discretion, to change an appointment at any time during a fiscal year if it determines that such a change would be in our best interests.

A representative of Deloitte & Touche LLP will be present at the annual meeting and will be available to respond to appropriate questions. We do not anticipate that the representative will make a prepared statement at the annual meeting; however, he or she will be free to do so if he or she chooses.

The board of directors recommends a vote "for" the ratification of the appointment of Deloitte & Touche LLP as our independent registered public accounting firm for fiscal year 2019.

Ratification of the appointment of Deloitte & Touche LLP as our independent registered public accounting firm for 2019 requires the affirmative vote of a majority of our common stock present in person or represented by proxy at the annual meeting and entitled to vote on the proposal. Abstentions will count as votes against this proposal.

Annual Evaluation and Selection of Deloitte & Touche LLP

The audit committee annually evaluates the performance of its independent registered public accounting firm, including the senior audit engagement team, and determines whether to re-engage the current independent accounting firm or consider other firms. Factors considered by the audit committee in deciding whether to retain the current independent accounting firm include:

- Deloitte & Touche LLP's capabilities considering the complexity of our business and the resulting demands placed on Deloitte & Touche LLP in terms of technical expertise and knowledge of our industry and business;
- the quality and candor of Deloitte & Touche LLP's communications with the audit committee and management;
- Deloitte & Touche LLP's independence;
- the quality and efficiency of the services provided by Deloitte & Touche LLP, including input from management on Deloitte & Touche LLP's performance and how effectively Deloitte & Touche LLP demonstrated its independent judgment, objectivity, and professional skepticism;
- external data on audit quality and performance, including recent Public Company Accounting Oversight Board reports on Deloitte & Touche LLP and its peer firms; and
- the appropriateness of Deloitte & Touche LLP's fees, tenure as our independent auditor, including the benefits of a longer tenure, and the controls and processes in place that help ensure Deloitte & Touche LLP's continued independence.

Based on this evaluation, the audit committee and the board believe that retaining Deloitte & Touche LLP to serve as our independent registered public accounting firm for the fiscal year ending December 31, 2019, is in the best interests of our company and its stockholders.

In accordance with rules applicable to mandatory partner rotation, Deloitte & Touche LLP's lead engagement partner for our audit was changed in 2017. The audit committee oversees the process for, and ultimately approves, the selection of the lead engagement partner.

Audit Fees and Non-Audit Fees

The following table summarizes the aggregate fees that our independent registered public accounting firm, Deloitte & Touche LLP, billed or is expected to bill us for professional services rendered for 2018 and 2017:

	2018	2017
Audit Fees [1]	$ 2,657,405	$ 2,327,450
Audit-Related Fees [2]	—	46,790
Tax Fees [3]	—	17,483
All Other Fees [4]	3,150	—
Total Fees [5]	$ 2,660,555	$ 2,391,723
Ratio of Tax and All Other Fees to Audit and Audit-Related Fees	0.1 %	0.7 %

1 Audit fees for 2018 and 2017 consisted of fees for services rendered for the annual audit of our consolidated financial statements and internal control over financial reporting, statutory and regulatory audits, reviews of quarterly financial statements, and other filings with the SEC.

2 Audit-related fees for 2017 are associated with Intermountain Gas Company Investment Tax Credit procedures and supplemental schedule review for Knife River Corporation's Northwest Region.

3 Tax fees for 2017 consisted of fees for tax training for regulated operations.

4 All other fees relate to training.

5 Total fees reported above include out-of-pocket expenses related to the services provided of $330,000 for 2018 and $282,483 for 2017.

Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of the Independent Registered Public Accounting Firm

The audit committee pre-approved all services Deloitte & Touche LLP performed in 2018 in accordance with the pre-approval policy and procedures the audit committee adopted in 2003. This policy is designed to achieve the continued independence of Deloitte & Touche LLP and to assist in our compliance with Sections 201 and 202 of the Sarbanes-Oxley Act of 2002 and related rules of the SEC.

The policy defines the permitted services in each of the audit, audit-related, tax, and all other services categories, as well as prohibited services. The pre-approval policy requires management to submit annually for approval to the audit committee a service plan describing the scope of work and anticipated cost associated with each category of service. At each regular audit committee meeting, management reports on services performed by Deloitte & Touche LLP and the fees paid or accrued through the end of the quarter preceding the meeting. Management may submit requests for additional permitted services before the next scheduled audit committee meeting to the designated member of the audit committee, Dennis W. Johnson, for approval. The designated member updates the audit committee at the next regularly scheduled meeting regarding any services approved during the interim period. At each regular audit committee meeting, management may submit to the audit committee for approval a supplement to the service plan containing any request for additional permitted services.

In addition, prior to approving any request for audit-related, tax, or all other services of more than $50,000, Deloitte & Touche LLP will provide a statement setting forth the reasons why rendering of the proposed services does not compromise Deloitte & Touche LLP's independence. This description and statement by Deloitte & Touche LLP may be incorporated into the service plan or included as an exhibit thereto or may be delivered in a separate written statement.

AUDIT COMMITTEE REPORT

In connection with our financial statements for the year ended December 31, 2018, the audit committee has (1) reviewed and discussed the audited financial statements with management; (2) discussed with the independent registered public accounting firm (the Auditors) the matters required to be discussed by Public Company Accounting Oversight Board Auditing Standard No. 1301, Communications with Audit Committees; and (3) received the written disclosures and the letter from the Auditors required by applicable requirements of the Public Company Accounting Oversight Board regarding the Auditors' communications with the audit committee concerning independence, and has discussed with the Auditors their independence.

Based on the review and discussions referred to above, the audit committee recommended to the board of directors that the audited financial statements be included in our Annual Report on Form 10-K for the year ended December 31, 2018, for filing with the SEC.

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

OTHER MATTERS

ITEM 4. APPROVAL OF AN AMENDMENT TO MONTANA-DAKOTA UTILITIES CO.'S RESTATED CERTIFICATE OF INCORPORATION

General

On January 1, 2019, we completed a holding company reorganization pursuant to Section 251(g) of the General Corporation Law of the State of Delaware (the "DGCL") to provide additional financing flexibility and further separation between our utility companies and other businesses (the "Reorganization"). As a result of the Reorganization, Montana-Dakota Utilities Co., formerly known as MDU Resources Group, Inc. ("Montana-Dakota"), became a wholly-owned subsidiary of a new public holding company (the "Company").

As required by Section 251(g) of the DGCL, Montana-Dakota's Restated Certificate of Incorporation, as amended in connection with the Reorganization (the "Montana-Dakota Charter"), provides that any act or transaction involving Montana-Dakota, other than the election or removal of directors, that requires for its adoption under the DGCL or the Montana-Dakota Charter the approval of the stockholders of Montana-Dakota will also require the approval of the Company's stockholders by the same vote as is required by the DGCL and the Montana-Dakota Charter (the "Pass-Through Provision"). Absent a provision like the Pass-Through Provision, there is no general requirement under Delaware law that stockholders of a parent entity vote on transactions involving the parent entity's wholly-owned subsidiaries.

Accordingly, the Pass-Through Provision permits stockholders of the Company, the public holding company, to have direct voting rights as to matters affecting the Company's wholly-owned subsidiary, Montana-Dakota, that would otherwise only require the approval of Montana-Dakota's sole stockholder. This is highly unusual for a public holding company and restricts the Company's flexibility to realize the desired effects of the Reorganization.

For example, the Pass-Through Provision would require Montana-Dakota to obtain approval from the Company's stockholders, in addition to obtaining the approval of Montana-Dakota's sole stockholder, prior to making amendments to the Montana-Dakota Charter. As was required by Section 251(g) of the DGCL, the Montana-Dakota Charter is substantially identical to the Company's amended and restated certificate of incorporation, as currently in effect, with the exception of the Pass-Through Provision and certain amendments that are permissible and/or required under Section 251(g) of the DGCL. However, now that the Company is the public holding company, certain amendments to the Montana-Dakota Charter are desired in order to eliminate duplicative and unnecessary provisions in the Montana-Dakota Charter, including many provisions that are not typical or relevant for a wholly-owned subsidiary.

The deletion of the Pass-Through Provision will put the Company in the same position as substantially all other public holding companies that operate through multiple subsidiaries. It is uncommon in business organizations that operate in a holding company structure for the stockholders of the holding company to have direct voting rights as to matters that affect only subsidiaries of the holding company. Obtaining consent from a public corporation's stockholders for such internal matters would add significant expense and delay and prevent the Company from achieving the flexibility and efficiency it sought to achieve by implementing the holding company structure. By removing this requirement, the Company will gain the flexibility and efficiency currently realized by nearly all other companies who operate under the same, or similar, holding company and subsidiary structure. Specifically, the removal of the Pass-Through Provision will allow Montana-Dakota to implement further amendments to the Montana-Dakota Charter to eliminate duplicative and inapplicable charter provisions that are no longer reflective of our current holding company structure. The removal of the Pass-Through Provision would also allow Montana-Dakota's sole stockholder, without a special vote of the Company's stockholders for each amendment, to adopt amendments to the Montana-Dakota Charter such as those more typically found in the charters of wholly-owned subsidiaries whose shares are not listed for trading on any stock exchange.

The board believes that the deletion of the Pass-Through Provision will provide the Company with the flexibility to manage its organization under the holding company structure more efficiently and effectively. Our board therefore seeks approval from the Company's stockholders to amend the Montana-Dakota Charter in order to remove the Pass-Through Provision.

The Pass-Through Provision that would be eliminated by the proposed amendment reads as follows:

> Any act or transaction by or involving the Corporation, other than the election or removal of directors of the Corporation, that requires for its adoption under the General Corporation Law of Delaware or this Restated Certificate of Incorporation the approval of the stockholders of the Corporation shall, in accordance with Section 251(g) of the General Corporation Law of Delaware, require, in addition, the approval of the stockholders of MDU Resources Group, Inc. (or any successor thereto by merger), by the same vote as is required by the General Corporation Law of Delaware and/or this Restated Certificate of Incorporation.

Impact on Stockholder Rights

Removing the Pass-Through Provision from the Montana-Dakota Charter would have no effect on the right of stockholders of the Company to vote on matters relating to the Company, such as elections of directors, a merger or consolidation of the Company, a sale of all or substantially all of the Company's assets, amendments to the Company's amended and restated certificate of incorporation, or any other acts or transactions requiring the approval of the Company stockholders under applicable law. If the proposed amendment is approved by the Company's stockholders and effected, then the pass-through voting requirement at Montana-Dakota would be eliminated, and the Company would no longer be required to obtain the additional approval of the Company's stockholders for acts or transactions by or involving Montana-Dakota in the manner currently required by the Pass-Through Provision.

Required Vote

Approval requires the affirmative vote of a majority of outstanding shares of our common stock. Abstentions and broker non-votes will count as votes against this proposal.

The board of directors recommends a vote "for" the approval of the adoption of amendment of the Montana-Dakota charter to remove the pass-through provision.

ITEM 5. APPROVAL OF AMENDMENTS TO UPDATE AND MODERNIZE THE COMPANY'S AMENDED AND RESTATED CERTIFICATE OF INCORPORATION, INCLUDING REMOVING THE REQUIREMENT OF ACTION BY A TWO-THIRDS VOTE OF CONTINUING DIRECTORS FOR CERTAIN BOARD ACTIONS

The company's predecessor was incorporated in 1924, and its certificate of incorporation has been amended numerous times during the company's long corporate existence. The board believes the current amended and restated certificate of incorporation (the "current certificate") contains many outdated provisions and references that are no longer necessary or consistent with the company's present situation or modern certificates of incorporation generally, including language requiring action by two-thirds of the company's "continuing directors" for certain board actions.

The board of directors has determined that it is in the best interests of the company and its stockholders to amend and restate the current certificate to update and modernize certain of its provisions, including as follows (with further discussion below):

- **Removing Requirement of Action by a Two-Thirds Vote of Continuing Directors for Certain Board Actions.** Revise language requiring action by two-thirds of the company's continuing directors for certain board actions and instead require action by a simple majority of the board for those actions.

- **Updating Capital Stock Provisions, Including "Blank Check" Preferred Stock.** Update the company's capital stock provisions, including those relating to the preferred and preference stock, to a more standard structure and formulation for "blank check" preferred stock; and remove references to certain classes and previous series of preferred and preference stock which are no longer relevant to the company.

- **Modernizing Corporate Purpose and Director Powers and Duties Language.** Modernize provisions relating to the corporate purpose of the company and the powers and duties of the company's board of directors to be more customary and consistent with Delaware law.

- **Housekeeping Revisions.** Make other immaterial, non-substantive and ministerial changes, including reorganizing and renumbering certain provisions; correcting various references to statutes, names and dates; and deleting, consolidating and updating provisions to be consistent with Delaware law.

The board of directors has approved, and recommends the company's stockholders approve, these proposed amendments to and restatement of the current certificate (as amended and restated, the "revised certificate"). A copy of the revised certificate reflecting these proposed amendments is attached as Appendix A to this Proxy Statement. Additions to and reorganization of text of our current certificate are indicated by underlining, and deletions of text from our current certificate are indicated by strike-outs.

The descriptions of these proposed amendments are summaries and are qualified in their entirety by reference to the revised certificate. If approved by our stockholders, the proposed amendments will become effective upon the filing of a revised certificate incorporating these amendments with the Secretary of State of the State of Delaware, which filing would be made promptly after the annual meeting; provided that the board may abandon such proposed filing without further action by the stockholders if the board deems it to be in the best interests of stockholders.

Removing Requirement of Action by a Two-Thirds Vote of Continuing Directors for Certain Board Actions

In 2010, the board and the company's stockholders voted to repeal certain supermajority voting provisions in the company's certificate of incorporation relating to business combinations and make other related amendments to the certificate of incorporation. At that time, the then board had reviewed the advantages and disadvantages of such supermajority requirements and had determined their removal was in line with furthering the company's goal of ensuring the company's corporate governance policies, among other things, enhanced accountability to stockholders.

Pursuant to similar considerations, the current board has determined that removing the language requiring action by two-thirds of the company's "continuing directors" for certain board actions and related language (the "continuing director supermajority provisions"), to be advisable. The board believes that removing the continuing director supermajority provisions for the board actions further described below and instead having the full board take action by majority vote provides for more equitable board decision-making and makes each director more accountable to the company and its stockholders. These changes are also consistent with current practice and preferences of many other companies, investors, and corporate governance advisors.

The board believes it desirable to amend the continuing director supermajority provisions of the current certificate as follows:

Setting the Board Size. Article THIRTEENTH, section (a) of the current certificate provides that the number of directors constituting the board shall be not less than six nor more than fifteen persons, with the exact number of directors fixed by board resolution adopted by two-thirds of the continuing directors. Article VI, section 2 of the revised certificate provides that the number of directors constituting the board shall be not less than six nor more than fifteen, with the exact number of directors fixed by board resolution adopted by a majority of the board. The board believes the revised language provides a more equitable method of setting the size of the board and makes each member more accountable to the company and its stockholders.

Filling Board Vacancies and Newly Created Directorships. Article THIRTEENTH, section (b) of the current certificate provides that vacancies of the board and newly created directorships resulting from an increase in the authorized number of directors shall be filled by a two-thirds vote of the continuing directors. Article VI, section 5 of the revised certificate provides that vacancies of the board and newly created directorships resulting from an increase in the authorized number of directors shall be filled by a majority vote of the directors. The board believes the revised language provides a more equitable method for filling vacancies and newly created directorships of the board and makes each member more accountable to the company and its stockholders.

Calling Special Meetings of Stockholders. Article SIXTEENTH of the current certificate provides, among other things, that a special meeting of stockholders of the company shall be called by the chairman, president, or the secretary of the company upon the written request of two-thirds of the continuing directors. Article VII of the revised certificate provides that a special meeting of stockholders of the company shall be called by the chairman, president, or the secretary of the company upon the written request of a majority of the board. The board believes that the revised language provides a more equitable method for the board to determine whether to request a special meeting of stockholders and makes each member more accountable to the company and its stockholders.

Related Changes. Article THIRTEENTH, sections (e) and (f) of the current certificate are removed in their entirety in the revised certificate, as they are related exclusively to defining the term "continuing director," which would no longer be used in the revised certificate.

Updating Capital Stock Provisions, Including "Blank Check" Preferred Stock

Article FOURTH of the current certificate provides for four classes of stock: common stock, preferred stock, preferred stock A, and preference stock. The company is authorized to issue a total of 502,000,000 shares of stock, which includes: 500,000,000 shares of common stock, par value $1.00 per share; 500,000 shares of preferred stock, par value $100.00 per share; 1,000,000 shares of preferred stock A, without par value; and 500,000 shares of preference stock, without par value. Article FOURTH also provides that preferred stock may be issued as either 4.50% series preferred stock or pursuant to blank check preferred stock provisions, and preferred stock A and preference stock may be issued pursuant to blank check preferred stock A or preference stock provisions, as the case may be. The current certificate's concept of "blank check" for preferred, preferred A and preference stock refers to authorized and unissued stock of a class, where the rights, preferences, powers and limitations of a series may be expressly determined by the board consistent with the provisions of Article FOURTH. In other words, the board is empowered to provide the specific terms and conditions of such series within the requirements of Article FOURTH.

In order to shorten and simplify the company's capital stock structure in the revised certificate, the board wishes to remove provisions in the current certificate relating to all prior series of preferred stock (including 4.50% series, 4.70% series and 5.10% series), the entire class of preferred stock A and the entire class and prior series (including series B preference) of preference stock. This proposed amendment removes classes and series of stock (and the related language) that are no longer relevant to the company or its capital stock structure, as the company currently has no shares (in any series) of preferred stock, preferred A stock or preference stock outstanding, having redeemed the last outstanding shares of its preferred stock in April 2017.

In the revised certificate, Article IV continues to provide the company authority to issue a total of 502,000,000 shares of stock, but instead of four classes of stock (i.e., common stock, preferred stock, preferred A stock, and preference stock), the company has two classes of stock: 500,000,000 shares of common stock, par value $1.00 per share, and 2,000,000 shares of preferred stock, par value $100.00 per share. Article IV also updates the "blank check" preferred stock provision to a more customary formulation for modern certificates of incorporation and to be more consistent with the language of the DGCL. These proposed amendments included in Article IV do not substantively change the board's current rights to issue preferred stock, including its ability to set the relative rights, preferences, powers, and limitations of a series.

Under the updated capital stock provisions provided in the revised certificate, the board maintains its flexibility to seek future financing needs through equity (including customized preferred stock) financing as conditions may require without the delay, uncertainty and expense of obtaining stockholder approval for such transactions.

Modernizing Corporate Purpose and Director Powers and Duties Language

Corporate Purpose. Article III of the revised certificate amends Article THIRD of the current certificate by retaining only its first sentence, which provides that the company's purpose is to engage in any lawful act or activity in accordance with Delaware law, and by removing the second sentence of Article THIRD, which lists non-exclusive examples of activities within the company's corporate purpose. The board believes that the revised language is a more customary formulation for modern certificates of incorporation and that it is preferable to simply state that the company may engage in any lawful act or activity, without including a specific list of its non-exclusive business activities.

Director Powers. Article NINTH of the current certificate provides a non-exclusive list of various powers conferred on the board. Article VI of the revised certificate removes such non-exclusive list and simply provides that the business and affairs of the company shall be managed by the board and that the board is empowered to exercise all such powers and do all such things (in addition to those conferred by the company's certificate of incorporation and bylaws and by statute) as may be exercised and done by the company, unless prohibited by statute or by the company's certificate of incorporation. Pursuant to similar considerations regarding the proposed amendment to the corporate purpose provision, the board believes that the revised language is a more customary formulation for modern certificates of incorporation and that it is preferable to have broad and general language regarding the powers conferred on the board, without including a specific list of non-exclusive board powers.

Director Duties. Article FOURTEENTH of the current certificate provides a non-exclusive list of factors that the board may consider when, in exercising its judgment as to what is in the best interests of the company and its stockholders, it evaluates a proposal by a party to make a tender or exchange offer for securities of the company; effect a merger, consolidation or other business combination with the company; or effect any other transaction having similar effects upon the properties, operations, or control of the company. This non-exclusive list includes "the projected social, legal and economic effects of the proposed action or transaction upon the Corporation or its Subsidiaries, its employees, suppliers, customers and others having similar relationships with the Corporation, and the communities in which the Corporation and its Subsidiaries do business." The language of Article FOURTEENTH of the current certificate is removed entirely in the revised certificate. Under Delaware law, it is the board's obligation for those transactions referenced in Article FOURTEENTH of the current certificate to act, exercising its appropriate judgment, in the best interests of the company and its stockholders. The board believes that removal of Article FOURTEENTH is preferable because the non-exclusive list includes reference to consideration of constituencies other than the company's stockholders, whose interests may conflict with, detract from, or otherwise not be in the best interests of the company and its stockholders. By eliminating Article FOURTEENTH, the board's obligations in connection with a transaction will simply be governed by Delaware law rather than any express language in the revised certificate as is the case with most every other publicly traded company.

Housekeeping Revisions

In furtherance of the board's goal of updating and modernizing the current certificate, the revised certificate includes the following housekeeping revisions:

- Removing the language of Article SEVENTH of the current certificate, which provides that the company is to have perpetual existence, as perpetual existence is already the default under Delaware law;
- Removing the language of Article EIGHTH of the current certificate, which provides that the private property of company stockholders shall not be subject to the payment of corporate debts, as such protection is already provided under Delaware law without such provision;
- Adding Article IX of the revised certificate, which consolidates into one provision the rights of the company to amend, alter, change, or repeal any provision of the company's certificate of incorporation and the rights relating to the board's and the stockholders' powers to adopt, amend, or repeal the company bylaws (including through adding language consistent with Delaware law and the board and stockholder approval standards which currently apply to the company);
- Reorganizing and renumbering certain provisions, including deleting Articles in the current certificate that had been "[RESERVED]" and reorganizing and renumbering provisions in the revised certificate under headings titled Articles I-IX (with numbered subsections thereunder); and
- Updating references to statutes, names, and dates, including correcting certain Delaware statutory references, revising language to be more gender inclusive and updating names and dates to reflect current circumstances.

Approval requires the affirmative vote of a majority of the outstanding shares of common stock. Abstentions and broker non-votes will count as votes against this proposal.

The board recommends a vote "for" this proposal for approval of the amendments to update and modernize the company's amended and restated certificate of incorporation, including removing the requirement of action by a two-thirds vote of continuing directors for certain board actions.

INFORMATION ABOUT THE ANNUAL MEETING

Who can Vote?

Stockholders of record at the close of business on March 8, 2019, are entitled to vote each share they owned on that date on each matter presented at the meeting and any adjournment(s) thereof. As of March 8, 2019, we had 196,564,951 shares of common stock outstanding entitled to one vote per share.

Distribution of our Proxy Materials using Notice and Access

We distributed proxy materials to certain of our stockholders via the Internet under the SEC's "Notice and Access" rules to reduce our costs and decrease the environmental impact of our proxy materials. Using this method of distribution, on or about March 22, 2019, we mailed a Notice Regarding the Availability of Proxy Materials (Notice) that contains basic information about our 2019 annual meeting and instructions on how to view all proxy materials, and vote electronically, on the Internet. If you received the Notice and prefer to receive a paper copy of the proxy materials, follow the instructions in the Notice for making this request and the materials will be sent promptly to you via the preferred method. Stockholders who do not receive the Notice will receive a paper copy of our proxy materials, which will be sent on or about March 28, 2019.

How to Vote

You are encouraged to vote in advance of the meeting using one of the following voting methods, even if you are planning to attend the 2019 Annual Meeting of Stockholders.

Registered Stockholders: Stockholders of record who hold their shares directly with our stock registrar can vote any one of four ways:

Via the Internet: Go to the website shown on the Notice or Proxy Card, if you received one, and follow the instructions.

By Telephone: Call the telephone number shown on the Notice or Proxy Card, if you received one, and follow the instructions given by the voice prompts.

Voting via the Internet or by telephone authorizes the named proxies to vote your shares in the same manner as if you marked, signed, dated, and returned a Proxy Card by mail. Your voting instructions may be transmitted up until 11:59 p.m. Eastern Time on May 6, 2019.

By Mail: If you received paper copies of the Proxy Statement, Annual Report, and Proxy Card, mark, sign, date, and return the Proxy Card in the postage-paid envelope provided.

In Person: Attend the annual meeting, or send a personal representative with an appropriate proxy, to vote by ballot at the meeting.

Beneficial Stockholders: Stockholders whose shares are held beneficially in the name of a bank, broker, or other holder of record (sometimes referred to as holding shares "in street name"), will receive voting instructions from said bank, broker, or other holder of record. **If you wish to vote in person at the meeting, you must obtain a legal proxy from your bank, broker, or other holder of record of your shares and present it at the meeting.**

See discussion below regarding the MDU Resources Group, Inc. 401(k) Plan for voting instructions for shares held under our 401(k) plan.

Revoking Your Proxy or Changing Your Vote

You may change your vote at any time before the proxy is exercised.

Registered Stockholders:

- *If you voted by mail*: you may revoke your proxy by executing and delivering a timely and valid later dated proxy, by voting by ballot at the meeting, or by giving written notice of revocation to the corporate secretary.
- *If you voted via the Internet or by telephone*: you may change your vote with a timely and valid later Internet or telephone vote, as the case may be, or by voting by ballot at the meeting.
- Attendance at the meeting will not have the effect of revoking a proxy unless (1) you give proper written notice of revocation to the corporate secretary before the proxy is exercised, or (2) you vote by ballot at the meeting.

Beneficial Stockholders: Follow the specific directions provided by your bank, broker, or other holder of record to change or revoke any voting instructions you have already provided. Alternatively, you may vote your shares by ballot at the meeting if you obtain a legal proxy from your bank, broker, or other holder of record and present it at the meeting.

Discretionary Voting Authority

If you complete and submit your proxy voting instructions, the individuals named as proxies will follow your instructions. If you are a stockholder of record and you submit proxy voting instructions but do not direct how to vote on each item, the individuals named as proxies will vote as the board recommends on each proposal. The individuals named as proxies will vote on any other matters properly presented at the annual meeting in accordance with their discretion. Our bylaws set forth requirements for advance notice of any nominations or agenda items to be brought up for voting at the annual meeting, and we have not received timely notice of any such matters, other than the items from the board of directors described in this Proxy Statement.

Voting Standards

A majority of outstanding shares of stock entitled to vote must be present in person or represented by proxy to hold the meeting. Abstentions and broker non-votes are counted for purposes of determining whether a quorum is present at the annual meeting.

If you are a beneficial holder and do not provide specific voting instruction to your broker, the organization that holds your shares will not be authorized to vote your shares, which would result in broker non-votes, on proposals other than the ratification of the selection of our independent registered public accounting firm for 2019.

The following chart describes the proposals to be considered at the annual meeting, the vote required to elect directors and to adopt each other proposal, and the manner in which votes will be counted:

Item No.	Proposal	Voting Options	Vote Required to Adopt the Proposal	Effect of Abstentions	Effect of "Broker Non-Votes"
1	Election of Directors	For, against, or abstain on each nominee	A nominee for director will be elected if the votes cast for such nominee exceed the votes cast against such nominee.	No effect	No effect
2	Advisory Vote to Approve the Compensation Paid to the Company's Named Executive Officers	For, against, or abstain	The affirmative vote of a majority of the shares of common stock represented at the annual meeting and entitled to vote thereon	Same effect as votes against	No effect
3	Ratification of the Appointment of Deloitte & Touche LLP as the Company's Independent Registered Public Accounting Firm for 2018	For, against, or abstain	The affirmative vote of a majority of the shares of common stock represented at the annual meeting and entitled to vote thereon	Same effect as votes against	Brokers have discretion to vote
4	Approval of an Amendment to Montana-Dakota Utilities Co.'s Restated Certificate of Incorporation	For, against, or abstain	The affirmative vote of a majority of the outstanding shares of common stock	Same effect as votes against	Same effect as votes against
5	Approval of Amendments to Update and Modernize the Company's Amended and Restated Certificate of Incorporation	For, against, or abstain	The affirmative vote of a majority of the outstanding shares of common stock	Same effect as votes against	Same effect as votes against

Proxy Solicitation

The board of directors is furnishing proxy materials to solicit proxies for use at the Annual Meeting of Stockholders on May 7, 2019, and any adjournment(s) thereof. Proxies are solicited principally by mail, but directors, officers, and employees of MDU Resources Group, Inc. or its subsidiaries may solicit proxies personally, by telephone, or by electronic media, without compensation other than their regular compensation. Okapi Partners, LLC additionally will solicit proxies for approximately $8,500 plus out-of-pocket expenses. We will pay the cost of soliciting proxies and will reimburse brokers and others for forwarding proxy materials to stockholders.

Electronic Delivery of Proxy Statement and Annual Report Documents

For stockholders receiving proxy materials by mail, you can elect to receive an email in the future that will provide electronic links to these documents. Opting to receive your proxy materials online will save the company the cost of producing and mailing documents to your home or business and will also give you an electronic link to the proxy voting site.

- **Registered Stockholders:** If you vote on the Internet, simply follow the prompts for enrolling in the electronic proxy delivery service. You may also enroll in the electronic proxy delivery service at any time in the future by going directly to http://enroll.icsdelivery.com/mdu to request electronic delivery. You may revoke an electronic delivery election at this site at any time.
- **Beneficial Stockholders:** If you hold your shares in a brokerage account, you may also have the opportunity to receive copies of the proxy materials electronically. You may enroll in the electronic proxy delivery service at any time by going directly to http://enroll.icsdelivery.com/mdu to request electronic delivery. You may also revoke an electronic delivery election at this site at any time. In addition, you may also check the information provided in the proxy materials mailed to you by your bank or broker regarding the availability of this service or contact your bank or broker to request electronic delivery.

Householding of Proxy Materials

In accordance with a Notice sent to eligible stockholders who share a single address, we are sending only one Annual Report to Stockholders and one Proxy Statement to that address unless we received instructions to the contrary from any stockholder at that address. This practice, known as "householding," is designed to reduce our printing and postage costs. However, if a stockholder of record wishes to receive a separate Annual Report to Stockholders and Proxy Statement in the future, he or she may contact the Office of the Treasurer at MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506-5650, Telephone Number: (701) 530-1000. Eligible stockholders of record who receive multiple copies of our Annual Report to Stockholders and Proxy Statement can request householding by contacting us in the same manner. Stockholders who own shares through a bank, broker, or other nominee can request householding by contacting the nominee.

We will promptly deliver, upon written or oral request, a separate copy of the Annual Report to Stockholders and Proxy Statement to a stockholder at a shared address to which a single copy of the document was delivered.

MDU Resources Group, Inc. 401(k) Plan

This Proxy Statement is being used to solicit voting instructions from participants in the MDU Resources Group, Inc. 401(k) Plan with respect to shares of our common stock that are held by the trustee of the plan for the benefit of plan participants. If you are a plan participant and also own other shares as a registered stockholder or beneficial owner, you will separately receive a Notice or proxy materials to vote those other shares you hold outside of the MDU Resources Group, Inc. 401(k) Plan. If you are a plan participant, you must instruct the plan trustee to vote your shares by utilizing one of the methods described on the voting instruction form that you receive in connection with shares held in the plan. If you do not give voting instructions, the trustee generally will vote the shares allocated to your personal account in accordance with the recommendations of the board of directors. Your voting instructions may be transmitted up until 11:59 p.m. Eastern Time on May 2, 2019.

Annual Meeting Admission and Guidelines

Admission: All stockholders as of the record date of March 8, 2019, are cordially invited and urged to attend the annual meeting. **You must request an admission ticket to attend.** If you are a stockholder of record and plan to attend the meeting, please contact MDU Resources by email at CorporateSecretary@mduresources.com or by telephone at 701-530-1010 to request an admission ticket. A ticket will be sent to you by mail.

If your shares are held beneficially in the name of a bank, broker, or other holder of record, and you plan to attend the annual meeting, you will need to submit a written request for an admission ticket by mail to: Investor Relations, MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506 or email at CorporateSecretary@mduresources.com. The request must include proof of stock ownership as of March 8, 2019, such as a bank or brokerage firm account statement or a legal proxy from the bank, broker, or other holder of record confirming ownership. A ticket will be sent to you by mail.

Requests for admission tickets must be received no later than May 1, 2019. You must present your admission ticket and state-issued photo identification, such as a driver's license, to gain admittance to the meeting.

Guidelines: The business of the meeting will follow as set forth in the agenda which you will receive at the meeting entrance. The use of cameras or sound recording equipment is prohibited, except by the media or those employed by the company to provide a record of the proceedings. The use of cell phones and other personal communication devices is also prohibited during the meeting. All devices must be turned off or muted. No firearms or weapons, banners, packages, or signs will be allowed in the meeting room. MDU Resources Group, Inc. reserves the right to inspect all items, including handbags and briefcases, that enter the meeting room.

Conduct of the Meeting

Neither the board of directors nor management intends to bring before the meeting any business other than the matters referred to in the Notice of Annual Meeting and this Proxy Statement. We have not been informed that any other matter will be presented at the meeting by others. However, if any other matters are properly brought before the annual meeting, or any adjournment(s) thereof, your proxies include discretionary authority for the persons named in the proxy to vote or act on such matters in their discretion.

Stockholder Proposals, Director Nominations, and Other Items of Business for 2020 Annual Meeting

Stockholder Proposals for Inclusion in Next Year's Proxy Statement. To be included in the proxy materials for our 2020 annual meeting, a stockholder proposal must be received by the corporate secretary no later than November 23, 2019, unless the date of the 2020 annual meeting is more than 30 days before or after May 7, 2020, in which case the proposal must be received a reasonable time before we begin to print and mail our proxy materials. The proposal must also comply with all applicable requirements of Rule 14a-18 under the Securities Exchange Act of 1934.

Director Nominations From Stockholders for Inclusion in Next Year's Proxy Statement. If a stockholder or group of stockholders wishes to nominate one or more director candidates to be included in our proxy statement for the 2020 annual meeting through our proxy access bylaw provision, we must receive proper written notice of the nomination not later than 120 or earlier than 150 days before the anniversary date that the definitive proxy statement was first released to stockholders in connection with the annual meeting, or between October 24, 2019 and November 23, 2019. In the event that the 2020 annual meeting is more than 30 days before or after May 7, 2020, the notice must be delivered no earlier than the 150th day prior to such meeting and no later than the 120th day prior to such meeting or the 10th day following the date on which public announcement of the meeting date is first made. In addition, the nomination must otherwise comply with the requirements in our bylaws. The requirements of such notice can be found in our bylaws, a copy of which is on our website, at www.mdu.com/governance.

Director Nominations and Other Stockholder Proposals Raised From the Floor at the 2020 Annual Meeting of Stockholders. Under our bylaws, if a stockholder intends to nominate a person as a director, or present other items of business at an annual meeting, the stockholder must provide written notice of the director nomination or stockholder proposal within 90 to 120 days prior to the anniversary of the most recent annual meeting. Notice of director nominations or stockholder proposals for our 2020 annual meeting must be received between January 8, 2020 and February 7, 2020, and meet all the requirements and contain all the information, including the completed questionnaire for director nominations, provided by our bylaws. The requirements for such notice can be found in our bylaws, a copy of which is on our website, at www.mdu.com/governance.

We will make available to our stockholders to whom we furnish this Proxy Statement a copy of our Annual Report on Form 10-K, excluding exhibits, for the year ended December 31, 2018, which is required to be filed with the SEC. You may obtain a copy, without charge, upon written or oral request to the Office of the Treasurer of MDU Resources Group, Inc., 1200 West Century Avenue, Mailing Address: P.O. Box 5650, Bismarck, North Dakota 58506-5650, Telephone Number: (701) 530-1000. You may also access our Annual Report on Form 10-K through our website at www.mdu.com.

By order of the Board of Directors,

Daniel S. Kuntz
Secretary
March 22, 2019

APPENDIX A.

AMENDED AND RESTATED CERTIFICATE OF INCORPORATION
OF
~~MDUR NEWCO~~MDU RESOURCES GROUP, INC.

~~MDUR NEWCO~~MDU RESOURCES GROUP, INC., a corporation organized and existing under the laws of the State of Delaware, hereby certifies as follows:

1. The ~~original certificate of incorporation of~~ present name of the corporation is MDU RESOURCES GROUP, INC. (the "Corporation").

2. The Corporation was incorporated under the name "MDUR Newco, Inc.~~ was filed~~" by the filing of its original Certificate of Incorporation with the Office of the Secretary of State of the State of Delaware on September 21, ~~2018 (~~2018, which was amended by the filing of its Amended and Restated Certificate of Incorporation with the Office of the Secretary of State of the State of Delaware effective as of January 1, 2019 (as amended, the "Original Certificate of Incorporation").

~~2. MDUR Newco, Inc.~~3. The Corporation is filing this ~~a~~Amended and ~~r~~Restated ~~c~~Certificate of ~~i~~Incorporation (the "Certificate of Incorporation"), which restates, integrates and further amends the provisions of the Original Certificate of Incorporation, and which was duly adopted in accordance with Sections ~~242, 245 and 228 (by written consent of the sole stockholder of MDUR Newco, Inc.)~~228, 242 and 245 of the General Corporation Law of the State of Delaware.

~~3.~~4. The text of the Original Certificate of Incorporation is hereby amended and restated in its entirety by this Certificate of Incorporation, effective as of ~~12:02~~ [______] [a/p].m. Eastern Standard Time on ~~January 1,~~[______], 2019, as to read in full as follows:

ARTICLE I

NAME

~~FIRST.~~ The name of this Corporation is MDU RESOURCES GROUP, INC. (the "Corporation").

ARTICLE II

REGISTERED OFFICE AND AGENT

~~SECOND.~~ The registered office of the Corporation in the State of Delaware is located at 1209 Orange Street, Wilmington, New Castle County, Delaware 19801. The name of its registered agent at such address is The Corporation Trust Company.

ARTICLE III

CORPORATE PURPOSE

~~THIRD.~~ The purpose of the Corporation is to engage in any lawful act or activity for which corporations may be organized under the General Corporation Law of the State of Delaware. ~~Included within this purpose, without limiting the generality of the foregoing sentence is (1) to own and operate electric and gas public utility systems and (2) to transact business as a multidimensional natural resource company~~

ARTICLE IV

CAPITAL STOCK

(1) **Authorized Shares**.

~~The Corporation shall have and exercise all the powers conferred upon corporations by the General Corporation Law of Delaware.~~

~~FOURTH.~~ The total number of shares of stock which the Corporation shall have authority to issue is Five Hundred Two Million (502,000,000) divided into ~~four~~two classes, namely, Preferred Stock~~, Preferred Stock A, Preference Stock,~~ and Common Stock. The total number of shares of such Preferred Stock authorized is ~~Five Hundred Thousand (500,000~~Two Million (2,000,000) shares of the par value of One Hundred Dollars ($100) per share (hereinafter called the "Preferred ~~Stock") amounting in the aggregate to Fifty Million Dollars ($50,000,000). The total number of shares of such Preferred Stock A authorized is One Million (1,000,000) shares without par value (hereinafter called the "Preferred Stock A"). The total number of shares of such Preference Stock authorized is Five Hundred Thousand (500,000) shares without par value (hereinafter called the "Preference~~ Stock"). The total number of shares of such Common Stock authorized is Five Hundred Million (500,000,000) of the par value of One and no/100 Dollars ($1.00) per share (hereinafter called the "Common Stock")~~, amounting in the aggregate to Five Hundred Million Dollars ($500,000,000)~~.

~~The Preferred Stock and the Preferred Stock A shall rank equally with no preference or priority of the Preferred Stock over the Preferred Stock A or of the Preferred Stock A over the Preferred Stock with respect to earnings, and assets upon liquidation, dissolution or winding up of the Corporation, and the Preferred Stock and the Preferred Stock A shall be senior to the Preference Stock with respect to earnings, and assets upon liquidation, dissolution or winding up of the Corporation, and the Preference Stock in turn shall be senior to the Common Stock with respect thereto.~~

~~The description of such classes of stock, and the designations and the powers, preferences and rights and the qualifications, limitations or restrictions thereof are as follows:~~

~~1.~~ (2) **Preferred Stock.** The Preferred Stock may be issued ~~from time to time either (a) as Preferred Stock of a series to be designated 4.50% Series Preferred Stock, or (b) if so determined~~ from time to time by resolution or resolutions adopted by the Board of Directors either in whole or in part as one or more other series, each series to be appropriately designated by distinguishing number, letter or title prior to the issue of any shares thereof. ~~One Hundred Thousand (100,000) shares of the Preferred Stock are hereby designated as 4.50% Series Preferred Stock. The number of shares of the Preferred Stock so designated as 4.50% Series Preferred Stock may be increased (but not above the number of shares then authorized) or decreased (but not below the number of shares thereof then outstanding) by a~~The description and terms of the Preferred Stock of any series shall be fixed and determined by the Board of Directors at the time of the authorization of the issue of the original shares of each such series, including such voting powers, full or limited, or no voting powers, and such designations, preferences, and relative, participating, optional, or other rights and such qualifications, limitations, or restrictions thereof, as shall be stated and expressed in the resolution or resolutions adopted by the Board of Directors ~~in the same manner as the Board may by resolution create other series of the~~ providing for the issuance of such shares and as may be permitted by the General Corporation Law of the State of Delaware. The Board of Directors is also expressly authorized to increase or decrease the number of shares of any series of Preferred Stock subsequent to the issuance of shares of that series of Preferred Stock, but not below the number of shares of such series of Preferred Stock then outstanding. In case the number of shares of any series of Preferred Stock shall be decreased in accordance with the foregoing sentence, the shares constituting such decrease shall resume the status that they had prior to the adoption of the resolution originally fixing the number of shares of such series of Preferred Stock. The number of authorized shares of Preferred Stock may be increased or decreased (but not below the number of shares thereof then outstanding) by the affirmative vote of the holders of a majority of the voting power of the Corporation's outstanding capital stock entitled to vote thereon, without a separate vote of the holders of the Preferred Stock, or of any series thereof, unless a vote of any such holders is required pursuant to the terms of any certificate of designation filed with respect to any series of Preferred Stock.

~~2. The Preferred Stock of all series shall be of the same class and of equal rank and shall be identical in all respects except that~~

(3) **Common Stock.** The preferences, limitations, voting powers and relative rights of the Common Stock (subject to the preferences and rights of the Preferred Stock as determined by the Board of Directors pursuant to Paragraph (2) of this Article IV) are as follows:

(a) ~~the maximum dividend rate of the 4.50% Series Preferred Stock shall be four and fifty hundredths per cent (4.50%) per annum, and the maximum dividend rate of the Preferred Stock of each other series shall be such rate as shall have been fixed and determined by the Board of Directors to accrue in respect of the shares of stock of each such other series from a date to be determined as hereinafter provided;~~Voting Rights. Except as otherwise expressly provided in this Certificate of Incorporation or required by applicable law, each holder of Common Stock shall be entitled to one vote for each share of Common Stock held as of the applicable record date on any matter that is submitted to a vote of the stockholders of this Corporation (including, without limitation, any matter voted on at a stockholders' meeting).

(b) ~~the amount per share which the Preferred Stock shall be entitled to receive as a premium in case of the redemption thereof shall be Five Dollars ($5.00) per share in the case of the 4.50% Series Preferred Stock, and in the case of each other series of the Preferred Stock shall be such amount, if any, as shall have been fixed and determined by the Board of Directors;~~

~~(c) a sinking fund or other retirement obligation may be provided for each series of the Preferred Stock, other than the 4.50% Series Preferred Stock, at such rate and on such terms as shall have been fixed and determined by the Board of Directors in respect of the shares of stock of each such series;~~

~~(d) the shares of each series of the Preferred Stock, other than the 4.50% Series Preferred Stock, may be made convertible into, or exchangeable for, shares of any other class or classes, or of any other series of the same or of any other class or classes, of stock of the Corporation, at such price or prices, or at such rates of exchange and with such adjustments as shall have been fixed and determined by the Board of Directors in respect of the shares of stock of each such series; and~~

~~(e) the shares of each series of the Preferred Stock, other than the 4.50% Series Preferred Stock, shall possess such voting power, in addition to that provided for in paragraph 13, as shall have been fixed and determined by the Board of Directors in respect of the shares of stock of each such series.~~

~~The description and terms of the Preferred Stock of each series in the foregoing particulars (except as in this section fixed and determined in respect of the 4.50% Series Preferred Stock) shall be fixed and determined by the Board of Directors at the time of the authorization of the issue of the original shares of each such other series. All shares of each series shall be alike in every particular.~~

~~3. The Preferred Stock A may be issued from time to time by resolution or resolutions adopted by the Board of Directors, either in whole or in part as one or more series, each series to be appropriately designated by distinguishing number, letter or title prior to the issue of any shares thereof.~~

~~4. The Preferred Stock A of all series shall be of the same class and of equal rank and shall be identical in all respects except that~~

~~(a) the maximum dividend rate of the Preferred Stock A of each series shall be such rate as shall have been fixed and determined by the Board of Directors to accrue in respect of the shares of stock of each such series from a date to be determined as hereinafter provided;~~

~~(b) the terms and conditions on which the shares of each series may be redeemed and in the amount or amounts per share which the Preferred Stock A of each series shall be entitled to receive in case of the redemption thereof shall be such as shall have been fixed and determined by the Board of Directors for each such series;~~

~~(c) the amount per share which the Preferred Stock A of each series shall be entitled to receive in the event of any liquidation, dissolution or winding up of this Corporation, whether voluntary or involuntary, shall be such amount as shall have been fixed and determined by the Board of Directors for such purpose for each such series;~~

~~(d) a sinking fund or other retirement obligation may be provided for any or all series of the Preferred Stock A, at such rate and on such terms as shall have been fixed and determined by the Board of Directors in respect of the shares of stock of each such series;~~

~~(e) the shares of any or all series of the Preferred Stock A may be made convertible into, or exchangeable for, shares of any other class or classes, or of any other series of the same or of any other class or classes, of stock of the Corporation, at such price or prices, or at such rates of exchange and with such adjustments as shall have been fixed and determined by the Board of Directors in respect of the shares of stock of each such series; and~~

~~(f) the shares of each series of the Preferred Stock A shall possess such voting power, in addition to that provided for in paragraph 13, as shall have been fixed and determined by the Board of Directors in respect of the shares of stock of each such series.~~

~~The description and terms of the Preferred Stock A of each series in the foregoing particulars and the number of shares constituting each series shall be fixed and determined by the Board of Directors at the time of the authorization of the issue of the original shares of each such series. All shares of each series shall be alike in every particular.~~

~~5. The Preference Stock may be issued from time to time by resolution or resolutions adopted by the Board of Directors, either in whole or in part as one or more series, each series to be appropriately designated by distinguishing number, letter or title prior to the issue of any shares thereof.~~

~~6. The Preference Stock of all series shall be of the same class and of equal rank and shall be identical in all respects except that~~

~~(a) the maximum dividend rate of the Preference Stock of each series shall be such rate as shall have been fixed and determined by the Board of Directors to accrue in respect of the shares of stock of each such series from a date to be determined as hereinafter provided;~~

~~(b) the terms and conditions on which the shares of each series may be redeemed and the and the amount or amounts per share which the Preference Stock of each series shall be entitled to receive in case of the redemption thereof shall be such as shall have been fixed and determined by the Board of Directors for each such series;~~

~~(c) the amount per share which the Preference Stock of each series shall be entitled to receive in the event of any liquidation, dissolution or winding up of this Corporation, whether voluntary or involuntary, shall be such amount as shall have been fixed and determined by the Board of Directors for such purpose for each such series;~~

~~(d) a sinking fund or other retirement obligation may be provided for any or all series of the Preference Stock, at such rate and on such terms as shall have been fixed and determined by the Board of Directors in respect of the shares of stock of each such series; and~~

~~(e) the shares of any or all series of the Preference Stock may be made convertible into, or exchangeable for, shares of the Common Stock, at such price or prices, or at such rates of exchange and with such adjustments as shall have been fixed and determined by the Board of Directors in respect of the shares of stock of each such series.~~

~~The description and terms of the Preference Stock of each series in the foregoing particulars and the number of shares constituting each series shall be fixed and determined by the Board of Directors at the time of the authorization of the issue of the original shares of each such series. All shares of each series shall be alike in every particular.~~

~~7. In preference to the Preference Stock and the Common Stock, out of the surplus or net profits of this Corporation, as and when declared by the Board of Directors, the holders of the 4.50% Series Preferred Stock shall be entitled to receive dividends at but not exceeding the maximum dividend rate herein fixed and determined, and the holders of the other series of Preferred Stock and all series of the Preferred Stock A shall be entitled to receive dividends, in preference to the Preference Stock and the Common Stock, out of the surplus or net profits of this Corporation, as and when declared by the Board of Directors, at but not exceeding the maximum dividend rates fixed and determined by the Board of Directors and expressed in the certificates therefor, payable quarterly on January 1st, April 1st, July 1st, and October 1st in each year, before any dividends shall be declared or paid upon or set apart for the Preference Stock or the Common Stock and before any sum shall be paid or set apart for the purchase or redemption of any series of the Preferred Stock, the Preferred Stock A or the Preference Stock, or the Common Stock. Such dividends on the Preferred Stock shall be cumulative from such date or dates as the Board of Directors shall fix at the time of issue thereof, or if no such date or dates shall be fixed, then from the respective dates of issue thereof, so that if in any dividend period or periods full cumulative dividends, at the maximum rates fixed and determined therefor, accrued on all outstanding shares of Preferred Stock and Preferred Stock A for all past dividend periods and for the then current dividend period, shall not have been paid, the~~

~~deficiency shall be declared and paid or set apart for payment before any dividends shall be declared or paid upon or set apart for the Preference Stock or for the Common Stock and before any sum shall be paid or set apart for the purchase or redemption of any series of the Preferred Stock, the Preferred Stock A or the Preference Stock, or the Common Stock.~~

~~If at any time Preferred Stock or Preferred Stock A of more than one series shall be outstanding, any dividends paid upon the Preferred Stock or the Preferred Stock A in an amount less than full cumulative dividends accrued or in arrears upon all the Preferred Stock and the Preferred Stock A outstanding shall be divided among the outstanding series of the Preferred Stock and the Preferred Stock A in proportion to the aggregate amounts which would be distributable to each series of the Preferred Stock and the Preferred Stock A if full cumulative dividends were at said time to be declared and paid thereon.~~

~~8. Subject to the prior rights and preferences of the Preferred Stock and the Preferred Stock A hereinbefore set forth, out of the surplus or net profits of this Corporation remaining after full cumulative dividends as aforesaid upon all series of the Preferred Stock and the Preferred Stock A then outstanding have been paid for all past dividend periods and after full cumulative dividends upon all series of the Preferred Stock and the Preferred Stock A for the current dividend period have been declared and paid or set apart for payment, then, as and when declared by the Board of Directors, the holders of the Preference Stock of all series shall be entitled to receive dividends at but not exceeding the maximum dividend rates fixed and determined by the Board of Directors and expressed in the resolution or resolutions authorizing the creation and issuance of each such series, payable quarterly on January 1st, April 1st, July 1st, and October 1st in each year, before any dividends shall be declared or paid upon or set apart for the Common Stock and before any sum shall be paid or set apart for the purchase or redemption of the Preference Stock of any series or the Common Stock. Such dividends on the Preference Stock shall be cumulative from such date or dates as the Board of Directors shall fix at the time of issue thereof, or if no such date or dates shall be fixed, then from the respective dates of issue thereof, so that if in any dividend period or periods full cumulative dividends, at the maximum rates fixed and determined therefor, accrued on all outstanding shares of Preference Stock for all past dividend periods and for the then current dividend period, shall not have been paid, the deficiency shall be declared and paid or set apart for payment before any dividends shall be declared or paid upon or set apart for the Common Stock and before any sum shall be paid or set apart for the purchase or redemption of the Preference Stock of any series or the Common Stock.~~

~~If at any time the Preference Stock of more than one series shall be outstanding, any dividends paid upon the Preference Stock in an amount less than full cumulative dividends accrued or in arrears upon all the Preference Stock outstanding shall be divided among the outstanding series of Preference Stock in proportion to the aggregate amounts which would be distributable to the Preference Stock of each series if full cumulative dividends were at said time to be declared and paid thereon.~~

~~9. Subject to the prior rights and preferences of the Preferred Stock, the Preferred Stock A and the Preference Stock hereinbefore set forth, out of any surplus or net profits of this Corporation remaining after full cumulative dividends as aforesaid upon all series of the Preferred Stock, the Preferred Stock A and the Preference Stock then outstanding have been paid for all past dividend periods and after full cumulative dividends upon all series of the Preferred Stock, the Preferred Stock A and the Preference Stock for the current dividend period have been declared and paid or set apart for payment and after making such provision, if any, as the Board of Directors may deem necessary for working capital, then and not otherwise, dividends may be declared and paid upon the Common Stock, to the exclusion of the holders of the Preferred Stock, the Preferred Stock A and the Preference Stock, and no holder of any series of the Preferred Stock, the Preferred Stock A or the Preference Stock shall be entitled to receive or shall receive dividends in excess of the maximum dividend rates herein set forth or fixed in the certificates therefor or in the resolution~~

~~or resolutions authorizing the creation and issuance of each such series.~~

~~The right to receive any dividends which may be declared payable in stock of any class is vested in the holders of the Common Stock exclusively, but no such dividends shall be declared in any dividend period unless full cumulative dividends upon all series of the Preferred Stock, the Preferred Stock A and the Preference Stock then outstanding shall have been paid for all past dividend periods and shall have been declared and paid or set apart for payment for the current dividend period.~~

~~10. All series of the Preferred Stock and the Preferred Stock A shall be preferred as to both earnings, and assets, and in the event of any liquidation, dissolution or winding up of this Corporation, whether voluntary or involuntary, before any assets of the Corporation shall be distributed among or paid over to the holders of the Preference Stock or the Common Stock, the holders of the Preferred Stock of each series shall be entitled to be paid One Hundred Dollars ($100.00) per share, and the holders of the Preferred Stock A of each series shall be entitled to be paid that amount which shall have been fixed and determined for such purpose by the Board of Directors in the resolution or resolutions authorizing the creation and issuance of each such series, in each case together with a sum of money equivalent in the case of each share of stock to all cumulative dividends on the Preferred Stock or the Preferred Stock A, as the case may be, accrued and in arrears thereon, before any distribution of the assets shall be made to the holders of the Preference Stock or the Common Stock, but the holders of the Preferred Stock and the Preferred Stock A shall not be entitled to any further participation in such distribution, and the holders of the Common Stock, subject to the prior rights and preferences of the Preference Stock, shall be entitled, to the exclusion of the holders of the Preferred Stock, the Preferred Stock A and the Preference Stock, to share ratably in all the assets of this Corporation remaining after payment to the holders of the Preferred Stock, and the Preferred Stock A and the Preference Stock of their full preferential amounts. If upon any such liquidation, dissolution or winding up of this Corporation, the assets distributable among the holders of the Preferred Stock and the Preferred Stock A shall be insufficient to permit the payment in full to such holders of the preferential amounts aforesaid, then the entire assets of this Corporation to be distributed shall be distributed among the holders of the Preferred Stock and the Preferred Stock A then outstanding ratably in proportion to the full preferential amounts to which they are respectively entitled.~~

~~11. As hereinbefore set forth, the Preference Stock of all series shall rank junior to all series of the Preferred Stock and the Preferred Stock A with respect to both earnings, and assets, and in the event of any liquidation, dissolution or winding up of this Corporation, whether voluntary or involuntary, after payment to the holders of the Preferred Stock and the Preferred Stock A of all amounts payable to them in such event and before any assets of the Corporation shall be distributed among or paid over to the holders of the Common Stock, the holders of the Preference Stock of each series shall be entitled to be paid that amount which shall have been fixed and determined for such purpose by the Board of Directors in the resolution or resolutions authorizing the creation and issuance of each such series, in each case together with a sum of money equivalent in the case of each share of stock to all cumulative dividends on the Preference Stock, accrued and in arrears thereon, before any distribution of the assets shall be made to the holders of the Common Stock, but the holders of the Preference Stock shall not be entitled to any further participation in such distribution, and the holders of the Common Stock shall be entitled, to the exclusion of the holders of the Preferred Stock, the Preferred Stock A and the Preference Stock, to share ratably in all the assets of this Corporation remaining after payment to the holders of the Preferred Stock, the Preferred Stock A and the Preference Stock of their full preferential amounts aforesaid. If upon any such liquidation, dissolution or winding up of this Corporation, the assets distributable among the holders of the Preference Stock shall be insufficient to permit the payment in full to such holders of the preferential amounts aforesaid, then the entire assets of this Corporation to be distributed, after payment to the holders of the Preferred Stock and the Preferred Stock A of all amounts payable to them in such event, shall be distributed among the holders~~

~~of the Preference Stock then outstanding ratably in proportion to the full preferential amounts to which they are entitled.~~

~~Nothing in paragraph 10 or this paragraph 11 shall be deemed to prevent the purchase or redemption of any series of the Preferred Stock, the Preferred Stock A or the Preference Stock, in any manner permitted by paragraph 12. A consolidation or merger of this Corporation with any other corporation or corporations shall not be regarded as a liquidation, dissolution or winding up of this Corporation within the meaning of paragraph 10 or this paragraph 11, but no such consolidation or merger shall in any manner impair the rights or preferences of any of the Preferred Stock, the Preferred Stock A or the Preference Stock.~~

~~12. This Corporation may at the option of the Board of Directors from time to time on any dividend payment date redeem the whole or any part of any series of the Preferred Stock, the Preferred Stock A or the Preference Stock; with respect to the Preferred Stock, by paying One Hundred Dollars ($100.00) per share for each share thereof so redeemed, plus a premium of such additional amount per share as herein fixed and determined for the 4.50% Series Preferred Stock, and in the case of any other series of the Preferred Stock, such premium, if any, as shall have been fixed and determined by the Board of Directors, together in each case with the amount of any dividends accrued and in arrears thereon; with respect to the Preferred Stock A and the Preference Stock, by paying the appropriate amount per share which shall have been fixed and determined by the Board of Directors in the resolution or resolutions authorizing the creation and issuance of each such series of the Preferred Stock A or the Preference Stock, together in each case with the amount of any dividends accrued and in arrears thereon. Notice of such election to redeem shall, not less than thirty days prior to the dividend date upon which the stock is to be redeemed, be mailed to each holder of stock so to be redeemed at his address as it appears on the books of the Corporation. In case less than all of the outstanding Preferred Stock, the Preferred Stock A or the Preference Stock of any series is to be redeemed, the amount to be redeemed may be determined by the Board of Directors; the method of effecting such redemption, whether by lot or pro rata or otherwise, is to be determined by the Board of Directors at the time of issuance. If, on or before the redemption date named in such notice, the funds necessary for such redemption shall have been set aside by the Corporation so as to be available for payment on demand to the holders of the stock so called for redemption, then, notwithstanding that any certificate of stock so called for redemption shall not have been surrendered for cancellation, the dividends thereon shall cease to accrue from and after the date of redemption so designated, and all rights with respect to such stock so called for redemption, including any right to vote or otherwise participate in the determination of any proposed corporate action, shall forthwith after such redemption date cease and determine, except only the right of the holder to receive the redemption price therefor but without interest.~~

~~13. Except as otherwise required by the laws of Delaware and except as may be otherwise provided herein and by the Board of Directors in accordance with paragraphs 2(e) and 4(f), the holders of the Common Stock shall exclusively possess all voting power for the election of directors and for all other purposes, and the holders of the Preferred Stock, the Preferred Stock A and the Preference Stock shall have no voting power, and no owner or holder thereof shall vote thereon or be entitled to receive notice of any meeting of the stockholders; provided that if at any time and whenever cumulative dividends on the Preferred Stock or on the Preferred Stock A shall be in default and unpaid, in whole or in part, for a period of one year, the holders of the Preferred Stock and the Preferred Stock A shall have the same voting powers as the holders of the Common Stock, to-wit: one vote for each share of stock; and further provided that if at any time and whenever cumulative dividends on the Preference Stock shall be in default and unpaid, in whole or in part, for a period of one year, the holders of the Preference Stock shall have the same voting powers as the holders of the Common Stock, to-wit: one vote for each share of stock, and the holders of the Preferred Stock and the Preferred Stock A or the Preference Stock, as the case may be, shall be entitled to~~

~~receive notices of meetings of stockholders, and such voting power shall so continue to vest in the holders of the Preferred Stock and the Preferred Stock A or the Preference Stock, as the case may be, until all arrears in the payment of cumulative dividends on the Preferred Stock and the Preferred Stock A or on the Preference Stock, as the case may be, shall have been paid and the dividends thereon for the current dividend period shall have been declared and the funds for the payment thereof set aside, on the condition, however, that as often as thereafter defaulted dividends shall have been paid in full and provision made for the current dividend as herein provided (and such payment shall be made as promptly as shall be consistent with the best interests of the Corporation), the holders of the Preferred Stock and the Preferred Stock A or of the Preference Stock, as the case may be, shall be divested of such voting power and the voting power shall revest exclusively in the holders of the Common Stock, subject always to the same provisions for the vesting of voting power in the holders of the Preferred Stock and the Preferred Stock A or of the Preference Stock, as the case may be, in case of any similar default or defaults in the payment of cumulative dividends either on the Preferred Stock or the Preferred Stock A or on the Preference Stock, as the case may be, for one year and the revesting of such entire voting power in the holders of the Common Stock, in the event that such default or defaults shall be cured as above provided.~~

Dividends and Distributions. Subject to the preferences applicable to any series of Preferred Stock, if any, outstanding at any time, shares of Common Stock shall be entitled to receive dividends, if any, as may be declared from time to time by the Board of Directors out of legally available funds. Subject to the preferences applicable to any series of Preferred Stock, if any, outstanding at any time, the shares of Common Stock are entitled to the net assets of this corporation upon dissolution in accordance with the General Corporation Law of the State of Delaware.

~~14. The vote or consent of the holders of a majority of the Preference Stock at the time outstanding, voting as a class, shall be required for any amendment of the Certificate of Incorporation altering materially any existing provision of the Preference Stock, for the creation, or an increase in the authorized amount, of any class of stock ranking, as to earnings, and assets, prior to, or on a parity with, the Preference Stock, or for an increase in the authorized amount of the Preference Stock; provided, however, that if any amendment of the Certificate of Incorporation shall affect adversely the rights or preferences of one or more, but not all, of the series of the Preference Stock at the time outstanding or shall unequally adversely affect the rights or preferences of different series of the Preference Stock at the time outstanding, the vote or consent of the holders of a majority of such shares of each such series so adversely or unequally adversely affected shall be required in lieu of or (if such vote or consent is required by law) in addition to the vote or consent of the holders of a majority of the outstanding shares of the Preference Stock, voting as a class.~~

~~15.~~ (4) **No Pre-emptive Rights**. No holder of stock of this Corporation of any class shall have any pre-emptive or preferential rights of subscription to any shares of any class of stock of this Corporation, whether now or hereafter authorized, or to any obligations convertible into stock of the Corporation, issued or sold, nor any right of subscription to any thereof other than such, if any, as the Board of Directors in its discretion may from time to time determine, and at such price as the Board of Directors may from time to time fix and determine pursuant to the authority conferred by this Certificate~~; and any shares of stock or convertible obligations which the Board of Directors may determine to offer for subscription to the holders of stock may, as said Board shall determine, be offered exclusively to holders of the Preferred Stock, to holders of the Preferred Stock A, to holders of the Preference Stock or to holders of the Common Stock, or partly to the holders of the Preferred Stock, partly to the holders of the Preferred Stock A, partly to the holders of the Preference Stock and partly to the holders of the Common Stock, and in such case in such proportions as among said classes of stock as the Board of Directors in its discretion may determine~~ of Incorporation.

~~**16. 4.70% Series Preferred Stock**~~

~~1. The designation of the Series shall be "4.70% Series Preferred Stock" (Cumulative) (hereinafter called the "4.70% Series") and the number of shares which shall constitute said Series shall be 50,000; and such number shall not be increased.~~

~~2. The annual dividend rate of the 4.70% Series shall be four and seventy hundredths per cent. (4.70%) of the par value of said shares, and no more, and the date from which dividends shall accrue in respect of all shares of the 4.70% Series shall be the date of issue thereof.~~

~~3. The price at which the shares of the 4.70% Series may be redeemed shall be as specified in Paragraph 6 of Article FOURTH of the Certificate of Incorporation, as amended, plus a premium of $2 per share, together with the amount of any dividends accrued and in arrears thereon.~~

~~4. So long as any of the shares of the 4.70% Series are outstanding, in addition to any other vote or consent of stockholders required in the Certificate of Incorporation, as amended, or by law, the vote or consent of the holders of at least sixty-six and two-thirds per cent. (66-2/3%) of the shares of the 4.70% Series at the time outstanding, given in person or by proxy, either in writing without a meeting (if permitted by law) or at any meeting called for the purpose, shall be necessary to effect or validate:~~

~~(a) any amendment, alteration or repeal of any of the provisions of the Certificate of Incorporation, as amended, or By-Laws of the Corporation, which affects adversely the voting powers, rights or preferences of the holders of the 4.70% Series;~~

~~(b) the authorization or creation of, or the increase in the authorized amount of, any stock of any class or any security convertible into stock of any class ranking prior to the Preferred Stock;~~

~~(c) the voluntary dissolution, liquidation or winding up of the affairs of the Corporation, or the sale, lease or conveyance by the Corporation of all or substantially all its property or assets;~~

~~(d) the merger or consolidation of the Corporation with or into any other corporation, unless the Corporation resulting from such merger or consolidation will have after such merger or consolidation no class of stock and no other securities convertible into stock of any class either authorized or outstanding which stock shall rank prior to the Preferred Stock, except the same number of shares of such stock and the same amount of such other securities with the same rights and preferences as such stock and securities of the Corporation respectively authorized and outstanding immediately preceding such merger or consolidation, and each holder of Preferred Stock immediately preceding such merger or consolidation shall receive the same number of shares, with the same rights and preferences, of the resulting corporation; or~~

~~(e) the purchase or redemption (for sinking fund purposes or otherwise) of less than all of the Preferred Stock at the time outstanding unless the full dividend on all shares of Preferred Stock of all series then outstanding shall have been paid or declared and a sum sufficient for payment thereof set apart; provided, however, that the amendment of the provisions of the Certificate of Incorporation, as amended, so as to authorize or create or to increase the authorized amount (a) of the Common Stock and any other class of stock of the Corporation hereafter authorized over which the Preferred Stock has preference or priority in the payment of dividends or in the distribution of assets on any liquidation, dissolution or winding up of the Corporation or (b) of stock of any class ranking on a parity with the~~

~~Preferred Stock, shall not be deemed to affect adversely the voting powers, rights or preferences of the holders of the 4.70% Series; and provided further, that no such consent of the holders of the 4.70% Series shall be required, if at or prior to the time when such amendment, alteration or repeal is to take effect or when the authorization, creation or increase of any such prior stock or convertible security is to be made, or when such consolidation or merger, voluntary liquidation, dissolution or winding up, sale, lease, conveyance, purchase or redemption is to take effect, as the case may be, either (I) the consent of the holders of at least sixty-six and two-thirds per cent. (66-2/3%) of the shares of the Preferred Stock at the time outstanding shall have been so given to any such action except an amendment, alteration or repeal affecting the shares of the 4.70% Series differently from other series of Preferred Stock, or (II) provision is to be made for the redemption of all shares of the 4.70% Series at the time outstanding.~~

~~5. So long as any shares of the 4.70% Series are outstanding, in addition to any other vote or consent of stockholders required in the Certificate of Incorporation, as amended, or by law, the vote or consent of the holders of a majority of the shares of the 4.70% Series at the time outstanding, given in person or by proxy, either in writing without a meeting (if permitted by law) or at any meeting called for the purpose, shall be necessary to effect or validate any increase in the authorized amount of the Preferred Stock, or the authorization or creation of, or the increase in the authorized amount of, any stock of any class or any security convertible into stock of any class ranking on a parity with the Preferred Stock including any such action taken in connection with the merger or consolidation of the Corporation with or into any other corporation by either party thereto; provided, however, that no such consent of the holders of the 4.70% Series shall be required if, at or prior to the time the authorization or increase of any such parity stock or convertible security or any such additional shares of Preferred Stock is to be made, as the case may be, either (I) the consent of the holders of a majority of the shares of the Preferred Stock at the time outstanding shall have been so given to any such action, or (II) provision is to be made for the redemption of all shares of the 4.70% Series at the time outstanding.~~

~~6. No sinking fund or other retirement obligation shall be provided for the shares of the 4.70% Series.~~

~~17. 5.10% Series Preferred Stock~~

~~1. The designation of the Series shall be "5.10% Series Preferred Stock" (Cumulative) (hereinafter called the "5.10% Series") and the number of shares which shall constitute said Series shall be 50,000; such number shall not be increased and shall be decreased by the number of shares of said Series at any time retired by the Company.~~

~~2. The annual dividend rate of the 5.10% Series shall be five and ten hundredths per cent (5.10%) of the par value of said shares, and no more, and the date from which dividends shall accrue in respect of all shares of the 5.10% Series shall be the date of issue thereof.~~

~~3. The price at which the shares of the 5.10% Series may be redeemed shall be as specified in paragraph 6 of Article FOURTH of the Certificate of Incorporation, as amended, plus a premium of $2.00 per share, together with the amount of any dividends accrued and in arrears thereon.~~

~~4. So long as any of the shares of the 5.10% Series are outstanding, in addition to any other vote or consent of stockholders required in the Certificate of Incorporation, as amended, or by law, the vote or consent of the holders of at least sixty-six and two-thirds per cent. (66 2/3%) of the shares of the 5.10%~~

~~Series at the time outstanding, given in person or by proxy, either in writing without a meeting (if permitted by law) or at any meeting called for the purpose, shall be necessary to effect or validate:~~

~~(a) any amendment, alteration or repeal of any of the provisions of the Certificate of Incorporation, as amended, or By-Laws of the Corporation, which affects adversely the voting powers, rights or preferences of the holders of the 5.10% Series;~~

~~(b) the authorization or creation of, or the increase in the authorized amount of, any stock of any class or any security convertible into stock of any class ranking prior to the Preferred Stock;~~

~~(c) the voluntary dissolution, liquidation or winding up of the affairs of the Corporation, or the sale, lease or conveyance by the Corporation of all or substantially all its property or assets;~~

~~(d) the merger or consolidation of the Corporation with or into any other corporation, unless the corporation resulting from such merger or consolidation will have after such merger or consolidation no class of stock and no other securities convertible into stock of any class either authorized or outstanding which stock shall rank prior to the Preferred Stock, except the same number of shares of such stock and the same amount of such other securities with the same rights and preferences as such stock and securities of the Corporation respectively authorized and outstanding immediately preceding such merger or consolidation, and each holder of Preferred Stock immediately preceding such merger or consolidation shall receive the same number of shares, with the same rights and preferences, of the resulting corporation; or~~

~~(e) the purchase or redemption (for sinking fund purposes or otherwise) of less than all of the Preferred Stock at the time outstanding unless the full dividend on all shares of Preferred Stock of all series then outstanding shall have been paid or declared and a sum sufficient for payment thereof set apart;~~

~~provided, however, that the amendment of the provisions of the Certificate of Incorporation, as amended, so as to authorize or create or to increase the authorized amount (a) of the Common Stock and any other class of stock of the Corporation hereafter authorized over which the Preferred Stock has preference or priority in the payment of dividends or in the distribution of assets on any liquidation, dissolution or winding up of the Corporation or (b) of any class ranking on a parity with the Preferred Stock, shall not be deemed to affect adversely the voting powers, rights or preferences of the holders of the 5.10% Series; and provided further, that no such consent of the holders of the 5.10% Series shall be required, if at or prior to the time when such amendment, alteration or repeal is to take effect or when the authorization, creation or increase of any such prior stock or convertible security is to be made, or when such consolidation or merger, voluntary liquidation, dissolution or winding up, sale, lease, conveyance, purchase or redemption is to take effect, as the case may be, either (i) the consent of the holders of at least sixty-six and two-thirds per cent. (66 2/3%) of the shares of the Preferred Stock at the time outstanding shall have been so given to any such action except an amendment, alteration or repeal affecting the shares of the 5.10% Series differently from other series of Preferred Stock, or (ii) provision is to be made for the redemption of all shares of the 5.10% Series at the time outstanding.~~

~~5. So long as any shares of the 5.10% Series are outstanding, in addition to any other vote or consent of stockholders required in the Certificate of Incorporation, as amended, or by law, the vote or consent of the holders of a majority of the shares of the 5.10% Series at the time outstanding, given in person or by proxy, either in writing without a meeting (if permitted by law) or at any meeting called for the~~

~~purpose, shall be necessary to effect or validate any increase in the authorized amount of the Preferred Stock, or the authorization or creation of, or the increase in the authorized amount of, any stock of any class or any security convertible into stock of any class ranking on a parity with the preferred Stock including any such action taken in connection with the merger or consolidation of the Corporation with or into any other corporation by either party thereto; provided, however, that no such consent of the holders of the 5.10% Series shall be required if, at or prior to the time the authorization or increase of any such parity stock or convertible security or any such additional shares of Preferred Stock so to be made, as the case may be, either (i) the consent of the holders of a majority of the shares of the Preferred Stock at the time outstanding shall have been so given to any such action, or (ii) provision is to be made for the redemption of all shares of the 5.10% Series at the time outstanding.~~

~~6. As a sinking fund for the retirement of the shares of the 5.10% Series, the Company agrees to purchase (out of any funds of the Company legally available therefor after full dividends on the Preferred Stock of all Series then outstanding for all past dividend periods and for the current period have been paid or declared and a sum sufficient for the payment thereof set apart) 1,000 shares of the 5.10% Series in each year, at the price of $100 per share together with the amount of any dividends accrued and unpaid thereon; provided that no shares of the 5.10% Series shall be purchased pursuant to this paragraph unless tendered by the holders thereof as hereinafter provided; and provided further that the purchase obligation of the Company under this paragraph shall not be cumulative from year to year even though less than 1,000 shares of said Series may be purchased in any year if in such year the Company shall have duly called for tenders and purchased shares duly tendered as hereinafter provided. Shares of the 5.10% Series purchased pursuant to this paragraph shall be cancelled and retired. The Company will, at least 40 and not more than 50 days before each January 1, mail a letter to all holders of record of shares of the 5.10% Series, stating that it is calling for tenders of 1,000 shares of said Series for purchase and retirement under the sinking fund on the following January 1, at $100 per share and accrued and unpaid dividends; the letter shall ask each holder of shares of the 5.10% Series to indicate, by return letter to be received by the Company at a date fixed at least 20 and not more than 25 days before such January 1, the number of shares, if any, which such holder tenders for sale; if more than 1,000 shares are duly tendered by all holders of record, the Company shall first purchase from each holder tendering shares the number of shares tendered up to a number of shares (rounding to the nearest 10 shares) equal as nearly as practicable to 2% of the sum of (i) the number of shares of the 5.10% Series then of record in the name of such holder, and (ii) the number of shares of said Series previously retired that were of record in the name of such holder at the time of their redemption or purchase for retirement, and thereafter purchases shall be made pro rata (as nearly as practicable and rounding to the nearest 10 shares) on the basis of the shares of said Series duly tendered for sale or, in the case of holders duly tendering 1,000 shares, held of record; within three days after the date on which tenders are to be received, the Company shall by letter notify all holders of record of shares of the 5.10% Series of the number of shares tendered and the number of shares held by each holder to be retired; and the Company shall make payment for shares purchased pursuant to this paragraph upon surrender of stock certificates to the Transfer Agent on or after the January 1 retirement date.~~

~~18. Series B Preference Stock~~

~~Section 1. Designation and Amount. The shares of such series shall be designated as "Series B Preference Stock" (the "Series B Preference Stock") and the number of shares constituting the Series B Preference Stock shall be 125,000. Such number of shares may be increased or decreased by resolution of the Board of Directors; provided, that no decrease shall reduce the number of shares of Series B Preference Stock to a number less than the number of shares then outstanding plus the number of shares reserved for issuance upon the exercise of outstanding options, rights or warrants or upon the conversion of any outstanding securities issued by the Corporation convertible into Series B Preference Stock.~~

~~Section 2. Dividends and Distributions.~~

~~(A) Subject to the rights of the holders of any shares of any series of Preferred Stock or Preferred Stock A (or any similar stock) ranking prior and superior to the Series B Preference Stock with respect to dividends, the holders of shares of Series B Preference Stock, equally with holders of all other series of Preference Stock and in preference to the holders of Common Stock, par value $1.00 per share (the "Common Stock"), of the Corporation, and of any other junior stock, shall be entitled to receive, when, as and if declared by the Board of Directors out of funds legally available for the purpose, quarterly dividends payable in cash on the first day of January, April, July, and October in each year (each such date being referred to herein as a "Quarterly Dividend Payment Date"), commencing on the first Quarterly Dividend Payment Date after the first issuance of a share or fraction of a share of Series B Preference Stock, in an amount per share (rounded to the nearest cent) equal to the greater of (a) $1.00 or (b) subject to the provision for adjustment hereinafter set forth, 1,000 times the aggregate per share amount of all cash dividends, and 1,000 times the aggregate per share amount (payable in kind) of all non-cash dividends or other distributions, other than a dividend payable in shares of Common Stock or a subdivision of the outstanding shares of Common Stock (by reclassification or otherwise), declared on the Common Stock since the immediately preceding Quarterly Dividend Payment Date or, with respect to the first Quarterly Dividend Payment Date, since the first issuance of any share or fraction of a share of Series B Preference Stock. In the event the Corporation shall at any time declare or pay any dividend on the Common Stock payable in shares of Common Stock, or effect a subdivision or combination or consolidation of the outstanding shares of Common Stock (by reclassification or otherwise than by payment of a dividend in shares of Common Stock) into a greater or lesser number of shares of Common Stock, then in each such case the amount to which holders of shares of Series B Preference Stock were entitled immediately prior to such event under clause (b) of the preceding sentence shall be adjusted by multiplying such amount by a fraction, the numerator of which is the number of shares of Common Stock outstanding immediately after such event and the denominator of which is the number of shares of Common Stock that were outstanding immediately prior to such event.~~

~~(B) The Corporation shall declare a dividend or distribution on the Series B Preference Stock as provided in paragraph (A) of this Section immediately after it declares a dividend or distribution on the Common Stock (other than a dividend payable in shares of Common Stock); provided that, in the event no dividend or distribution shall have been declared on the Common Stock during the period between any Quarterly Dividend Payment Date and the next subsequent Quarterly Dividend Payment Date, a dividend of $1.00 per share on the Series B Preference Stock shall nevertheless be payable on such subsequent Quarterly Dividend Payment Date.~~

~~(C) Dividends shall begin to accrue and be cumulative on outstanding shares of Series B Preference Stock from the Quarterly Dividend Payment Date next preceding the date of issue of such shares, unless the date of issue of such shares is prior to the record date for the first Quarterly Dividend Payment Date, in which case dividends on such shares shall begin to accrue from the date of issue of such shares, or unless the date of issue is a Quarterly Dividend Payment Date or is a date after the record date for the determination of holders of shares of Series B Preference Stock entitled to receive a quarterly dividend and before such Quarterly Dividend Payment Date, in either of which events such dividends shall begin to accrue and be cumulative from such Quarterly Dividend Payment Date. Accrued but unpaid dividends shall not bear interest. Dividends paid on the shares of Series B Preference Stock in an amount less than the total amount of such dividends at the time accrued and payable on such shares shall be allocated pro rata on a share-by-share basis among all such shares at the time outstanding. The Board of Directors may fix a record date for the determination of holders of shares of Series B Preference Stock entitled to receive payment of a dividend or distribution declared thereon, which record date shall be not more than 60 days prior to the date fixed for the payment thereof.~~

~~Section 3. Voting Rights. The holders of shares of Series B Preference Stock shall have no voting rights except as otherwise provided by law or as set forth in the Corporation's Certificate of Incorporation.~~

~~Section 4. Certain Restrictions.~~

~~(A) Whenever quarterly dividends or other dividends or distributions payable on the Series B Preference Stock as provided in Section 2 are in arrears, thereafter and until all accrued and unpaid dividends and distributions, whether or not declared, on shares of Series B Preference Stock outstanding shall have been paid in full, the Corporation shall not:distributions, whether or not declared, on shares of Series B Preference Stock outstanding shall have been paid in full, the Corporation shall not:~~

~~(i) declare or pay dividends, or make any other distributions, on any shares of stock ranking junior (either as to dividends or upon liquidation, dissolution, or winding up) to the Series B Preference Stock;~~

~~(ii) declare or pay dividends, or make any other distributions, on any shares of stock ranking on a parity (either as to dividends or upon liquidation, dissolution, or winding up) with the Series B Preference Stock, except dividends paid ratably on the Series B Preference Stock and all such parity stock on which dividends are payable or in arrears in proportion to the total amounts to which the holders of all such shares are then entitled;~~

~~(iii) redeem or purchase or otherwise acquire for consideration shares of any stock ranking junior (either as to dividends or upon liquidation, dissolution, or winding up) to the Series B Preference Stock, provided that the Corporation may at any time redeem, purchase or otherwise acquire shares of any such junior stock in exchange for shares of any stock of the Corporation ranking junior (either as to dividends or upon dissolution, liquidation or winding up) to the Series B Preference Stock; or~~

~~(iv) redeem or purchase or otherwise acquire for consideration any shares of Series B Preference Stock, or any shares of stock ranking on a parity with the Series B Preference Stock, except in accordance with a purchase offer made in writing or by publication (as determined by the Board of Directors) to all holders of such shares upon such terms as the Board of Directors, after consideration of the respective annual dividend rates and other relative rights and preferences of the respective series and classes, shall determine in good faith will result in fair and equitable treatment among the respective series or classes.~~

~~(B) The Corporation shall not permit any subsidiary of the Corporation to purchase or otherwise acquire for consideration any shares of stock of the Corporation unless the Corporation could, under paragraph (A) of this Section 4, purchase or otherwise acquire such shares at such time and in such manner.~~

~~Section 5. Reacquired Shares. Any shares of Series B Preference Stock purchased or otherwise acquired by the Corporation in any manner whatsoever shall be retired and cancelled promptly after the acquisition thereof. All such shares shall upon their cancellation become authorized but unissued shares of Preference Stock and may be reissued as part of a new series of Preference Stock subject to the conditions and restrictions on issuance set forth herein, in the Certificate of Incorporation, or in any other Certificate of Designations creating a series of Preference Stock or any similar stock or as otherwise required by law.~~

~~Section 6. Liquidation, Dissolution, or Winding Up. Upon any liquidation, dissolution, or winding up of the Corporation, no distribution shall be made (1) to the holders of shares of stock ranking junior (either as to dividends or upon liquidation, dissolution, or winding up) to the Series B Preference Stock unless, prior thereto, the holders of shares of Series B Preference Stock shall have received $1,000 per share, plus an amount equal to accrued and unpaid dividends and distributions thereon, whether or not declared, to the date of such payment,~~

~~provided that the holders of shares of Series B Preference Stock shall be entitled to receive an aggregate amount per share, subject to the provision for adjustment hereinafter set forth, equal to 1,000 times the aggregate amount to be distributed per share to holders of shares of Common Stock, or (2) to the holders of shares of stock ranking on a parity (either as to dividends or upon liquidation, dissolution, or winding up) with the Series B Preference Stock, except distributions made ratably on the Series B Preference Stock and all such parity stock in proportion to the total amounts to which the holders of all such shares are entitled upon such liquidation, dissolution, or winding up. In the event the Corporation shall at any time declare or pay any dividend on the Common Stock payable in shares of Common Stock, or effect a subdivision or combination or consolidation of the outstanding shares of Common Stock (by reclassification or otherwise than by payment of a dividend in shares of Common Stock) into a greater or lesser number of shares of Common Stock, then in each such case the aggregate amount to which holders of shares of Series B Preference Stock were entitled immediately prior to such event under the proviso in clause (1) of the preceding sentence shall be adjusted by multiplying such amount by a fraction the numerator of which is the number of shares of Common Stock outstanding immediately after such event and the denominator of which is the number of shares of Common Stock that were outstanding immediately prior to such event.~~

~~Section 7. Consolidation, Merger, etc. In case the Corporation shall enter into any consolidation, merger, combination, or other transaction in which the shares of Common Stock are exchanged for or changed into other stock or securities, cash and/or any other property, then in any such case each share of Series B Preference Stock shall at the same time be similarly exchanged or changed into an amount per share, subject to the provision for adjustment hereinafter set forth, equal to 1,000 times the aggregate amount of stock, securities, cash and/or any other property (payable in kind), as the case may be, into which or for which each share of Common Stock is changed or exchanged. In the event the Corporation shall at any time declare or pay any dividend on the Common Stock payable in shares of Common Stock, or effect a subdivision or combination or consolidation of the outstanding shares of Common Stock (by reclassification or otherwise than by payment of a dividend in shares of Common Stock) into a greater or lesser number of shares of Common Stock, then in each such case the amount set forth in the preceding sentence with respect to the exchange or change of shares of Series B Preference Stock shall be adjusted by multiplying such amount by a fraction, the numerator of which is the number of shares of Common Stock outstanding immediately after such event and the denominator of which is the number of shares of Common Stock that were outstanding immediately prior to such event.~~

~~Section 8. No Redemption. The shares of Series B Preference Stock shall not be redeemable.~~

~~Section 9. Rank. The Series B Preference Stock shall rank, with respect to the payment of dividends and the distribution of assets, junior to all series of any class of the Corporation's Preferred Stock and Preferred Stock A, shall rank equally with all other series of the Corporation's Preference Stock, and shall rank superior to the Common Stock and any other class or series of junior stock.~~

~~Section 10. Amendment. The Certificate of Incorporation of the Corporation shall not be amended in any manner which would materially alter or change the powers, preferences, or special rights of the Series B Preference Stock so as to affect them adversely without the affirmative vote of the holders of at least a majority of the outstanding shares of Series B Preference Stock, voting together as a single class.~~

~~FIFTH~~. **[RESERVED]**

~~SIXTH~~. **[RESERVED]**

SEVENTH. ~~The Corporation is to have perpetual existence.~~

~~EIGHTH. The private property of the stockholders of the Corporation shall not be subject to the payment of corporate debts to any extent whatever.~~

~~NINTH. In furtherance, and not in limitation of the powers conferred by statute, the Board of Directors is expressly authorized:~~

~~Except as otherwise set forth therein, to make, alter or repeal the By-Laws of the Corporation.~~

~~To authorize and cause to be executed mortgages and liens upon the real and personal property of the Corporation.~~

~~To set apart out of any of the funds of the Corporation available for dividends a reserve or reserves for any proper purpose or to abolish any such reserve in the manner in which it was created.~~

~~By resolution or resolutions, passed by a majority of the whole Board to designate one or more committees, each committee to consist of two or more of the directors of the Corporation, which, to the extent provided in said resolution or resolutions or in the By-Laws of the Corporation, shall have and may exercise the powers of the Board of Directors in the management of the business and affairs of the Corporation, and may have power to authorize the seal of the Corporation to be affixed to all papers which may require it. Such committee or committees shall have such name or names as may be stated in the By-Laws of the Corporation or as may be determined from time to time by resolution adopted by the Board of Directors.~~

~~When and as authorized by the affirmative vote of the holders of a majority of the stock issued and outstanding having voting power given at a stockholders' meeting duly called for that purpose, or when authorized by the written consent of the holders of a majority of the voting stock issued and outstanding, to sell, lease or exchange all of the property and assets of the Corporation, including its good will and its corporate franchises, upon such terms and conditions and for such consideration, which may be whole or in part shares of stock in, and/or other securities of, any other corporation or corporations, as its Board of Directors shall deem expedient and for the best interests of the Corporation.~~

~~The Corporation may in its By-Laws confer powers upon its Board of Directors in addition to the foregoing, and in addition to the powers and authorities expressly conferred upon it by statute.~~

~~Both stockholders and directors shall have power, if the By-Laws so provide, to hold their meetings, and to have one or more offices within or without the State of Delaware, and to keep the books of the surviving Corporation (subject to the provisions of the statutes), outside of the State of Delaware at such places as may be from time to time designated by the Board of Directors.~~

~~TENTH. This Corporation reserves the right to amend, alter, change or repeal any provision contained in this Certificate of Incorporation in the manner now or hereafter prescribed by statute, and all rights conferred upon stockholders herein are granted subject to this reservation.~~

~~ELEVENTH. Whenever a compromise or arrangement is proposed between this Corporation and its creditors or any class of them and/or between this Corporation and its stockholders or any class of them, any court of equitable jurisdiction within the State of Delaware may, on the application in a summary way of this Corporation or of any creditor or stockholder thereof, or on the application of any receiver or receivers appointed for this Corporation under the provisions of Section 3883 of the Revised Code of 1915 of said State, or on the application of trustees in dissolution or of any receiver or receivers appointed for this Corporation under the~~

~~provisions of Section 43 of the General Corporation Law of the State of Delaware, order a meeting of the creditors or class of creditors, and/or of stockholders or class of stockholders of this Corporation, as the case may be, to be summoned in such manner as the said Court directs. If a majority in number representing three-fourths in value of the creditors or class of creditors, and/or of the stockholders or class of stockholders of this Corporation, as the case may be, agree to any compromise or arrangement and to any reorganization of this Corporation as consequence of such compromise or arrangement, the said compromise or arrangement and the said reorganization shall, if sanctioned by the Court to which the said application has been made, be binding on all the creditors or class of creditors, and/or on all the stockholders or class of stockholders, of this Corporation, as the case may be, and also on this Corporation.~~

~~TWELFTH~~. **~~[RESERVED]~~**

~~THIRTEENTH.~~

ARTICLE V

MATTERS RELATING TO DIRECTORS

(1) **Director Powers**. The business and affairs of the Corporation shall be managed by the Board of Directors. In addition to the powers and authority expressly conferred upon the Board of Directors by statute or by this Certificate of Incorporation or the Corporation's Bylaws, the Board of Directors is hereby empowered to exercise all such powers and do all such things as may be exercised or done by the Corporation unless specifically prohibited by statute or by the Certificate of Incorporation.

(~~a) The business and affairs of the Corporation shall be managed by the Board of Directors consisting of not less than six nor more than fifteen persons. The exact number of directors within the limitations specified in the preceding sentence~~2) **Board Size**. The total number of authorized directors constituting the Board of Directors shall be not less than six nor more than fifteen persons, with the exact number of directors fixed from time to time by the Board of Directors pursuant to a resolution adopted by ~~two-thirds~~a majority of the ~~Continuing~~ Board of Directors.

(3) **Vote by Ballot**. The directors need not be elected by ballot unless required by the ~~By-Laws~~Bylaws of the Corporation.

(4) **Term**. At each annual meeting of stockholders, the directors shall be elected for terms expiring at the next annual meeting of stockholders. Each director shall hold office for the term for which he or she is elected or appointed and until his or her successor shall be elected and qualified or until his or her earlier resignation, removal from office or death. In the event of any increase or decrease in the authorized number of directors, each director then serving as such shall nevertheless continue as director until the expiration of his or her current term, or until his or her earlier resignation, removal from office or death.

(~~b)~~5) **Vacancies and Newly Created Directorships**. Newly created directorships resulting from any increase in the authorized number of directors or any vacancies in the Board of Directors resulting from death, resignation, retirement, disqualification, removal from office or other cause shall be filled by a ~~two-thirds~~majority vote of the ~~Continuing Directors~~ directors then in office, or a sole remaining director, although less than a quorum, and directors so chosen shall hold office for a term expiring at the next annual meeting of stockholders. If one or more directors shall resign from the Board of Directors effective as of a future date, such vacancy or vacancies shall be filled pursuant to the provisions hereof, and such new directorship(s) shall become effective when such resignation or resignations shall become effective, and each director so chosen shall hold office for a term expiring at the next annual meeting of stockholders.

~~**(c) [RESERVED]**~~

~~(d) Any directors elected pursuant to special voting rights of one or more series of Preferred Stock, voting as a class, shall be excluded from, and for no purpose be counted in, the scope and operation of the foregoing provisions, unless expressly stated.~~

~~(e) For purposes of this Article THIRTEENTH, the following terms shall have the meanings hereinafter set forth:~~

~~(i) "Affiliate" or "Associate" shall have the respective meanings ascribed to such terms in the General Rules and Regulations under the Securities Exchange Act of 1934 as in effect on January 1, 1985.~~

~~(ii) A person shall be a "Beneficial Owner" of any Voting Stock:~~

~~(A) which such person or any of its Affiliates or Associates beneficially owns, directly or indirectly; or~~

~~(B) which such person or any of its Affiliates or Associates has (1) the right to acquire (whether such right is exercisable immediately or only after the passage of time), pursuant to any agreement, arrangement or understanding or upon the exercise of conversion rights, exchange rights, warrants or options, or otherwise, or (2) the right to vote pursuant to any agreement, arrangement or understanding; or~~

~~(C) which are beneficially owned, directly or indirectly, by any other person with which such person or any of its Affiliates or Associates has any agreement, arrangement or understanding for the purpose of acquiring, holding, voting or disposing of any shares of Voting Stock.~~

~~(iii) "Continuing Director" shall mean any member of the Board of Directors of the Corporation who is unaffiliated with, and not a nominee of, any Interested Stockholder and was a member of the Board of Directors prior to the time that any Interested Stockholder became an Interested Stockholder and any successor of a Continuing Director who is unaffiliated with, and not a nominee of, any Interested Stockholder and is designated to succeed a Continuing Director by two-thirds of the Continuing Directors then on the Board of Directors.~~

~~(iv) "Interested Stockholder" shall mean any person (other than the Corporation or any Subsidiary) who or which:~~

~~(A) is the Beneficial Owner, directly or indirectly, of more than 10 percent of the voting power of the then outstanding Voting Stock; or~~

~~(B) is an Affiliate of the Corporation and at any time within the two-year period immediately prior to the date in question, became the Beneficial Owner, directly or indirectly, of more than 10 percent of the voting power of the then outstanding Voting Stock; or~~

~~(C) is an assignee of or has otherwise succeeded to any shares of Voting Stock which were at any time within the two-year period immediately prior to the date in question beneficially owned by any Interested Stockholder, if such assignment or succession shall have occurred in the course of a transaction or series of transactions not involving a public offering within the meaning of the Securities Act of 1933.~~

~~For the purpose of determining whether a person is an Interested Stockholder pursuant to this Article THIRTEENTH, Section (e)(iv), the number of shares of Voting Stock deemed to be outstanding shall include shares deemed owned through application of Section (e)(ii) of this Article THIRTEENTH but shall not include any other shares of Voting Stock which may be issuable pursuant to any agreement, arrangement or understanding, or upon exercise of conversion rights, warrants or options, or otherwise.~~

~~(v) A "person" shall mean any individual, firm, partnership, trust, corporation or other entity.~~

~~(vi) "Subsidiary" means any corporation of which a majority of any class of equity security is owned, directly or indirectly, by the Corporation; provided, however, that for the purposes of the definition of Interested Stockholder set forth in Section (e)(iv) of this Article THIRTEENTH, the term "Subsidiary" shall mean only a corporation of which a majority of each class of equity security is owned, directly or indirectly, by the Corporation.~~

~~(vii) "Voting Stock" shall mean each share of stock of the Corporation generally entitled to vote in elections of directors.~~

~~The Continuing Directors of the Corporation shall have the power and duty to determine, on the basis of information known to them after reasonable inquiry, all facts necessary to determine the applicability of the various provisions of this Article THIRTEENTH, including (A) whether a person is an Interested Stockholder, (B) the number of shares of Voting Stock beneficially owned by any person, and (C) whether a person is an Affiliate or Associate of another. Any such determination made in good faith shall be binding and conclusive on all parties.~~

~~(f) Capitalized terms used and not defined in Article FOURTEENTH or in Article SIXTEENTH of the Certificate of Incorporation which are defined in Section (e) of this Article THIRTEENTH shall have the meanings, for purposes of Article FOURTEENTH and Article SIXTEENTH of the Certificate of Incorporation, ascribed to such terms in Section (e) of this Article THIRTEENTH.~~

FOURTEENTH~~. The Board of Directors, in evaluating any proposal by another party to (a) make a tender or exchange offer for any securities of the Corporation, (b) effect a merger, consolidation or other business combination of the Corporation or (c) effect any other transaction having an effect upon the properties, operations or control of the Corporation similar to a tender or exchange offer for any securities of the Corporation or a merger, consolidation or other business combination of the Corporation, as the case may be, whether by an Interested Stockholder or otherwise, may, in connection with the exercise of its judgment as to what is in the best interests of the Corporation and its stockholders, give due consideration to the following:~~

~~(i) the consideration to be received by the Corporation or its stockholders in connection with such transaction in relation not only to the then current market price for the outstanding capital stock of the Corporation, but also to the market price for the capital stock of the Corporation over a period of years, the estimated price that might be achieved in a negotiated sale of the Corporation as a whole or in part~~

~~through orderly liquidation, the premiums over market price for the securities of other corporations in similar transactions, current political, economic and other factors bearing on securities prices and the Corporation's financial condition, future prospects and future value as an independent Corporation;~~

~~(ii) the character, integrity and business philosophy of the other party or parties to the transaction and the management of such party or parties;~~

~~(iii) the business and financial conditions and earnings prospects of the other party or parties to the transaction, including, but not limited to, debt service and other existing or likely financial obligations of such party or parties, the intention of the other party or parties to the transaction regarding the use of the assets of the Corporation to finance the acquisition, and the possible effect of such conditions upon the Corporation and its Subsidiaries and the other elements of the communities in which the Corporation and its Subsidiaries operate or are located;~~

~~(iv) the projected social, legal and economic effects of the proposed action or transaction upon the Corporation or its Subsidiaries, its employees, suppliers, customers and others having similar relationships with the Corporation, and the communities in which the Corporation and its Subsidiaries do business;~~

~~(v) the general desirability of the continuance of the Corporation as an independent entity; and~~

~~(vi) such other factors as the Continuing Directors may deem relevant.~~

~~FIFTEENTH~~. **~~[RESERVED]~~**

ARTICLE VI

STOCKHOLDER ACTIONS

~~SIXTEENTH.~~ Any action required or permitted to be taken by the stockholders of the Corporation must be effected at a duly called annual or special meeting of stockholders of the Corporation and may not be effected by any consent in writing by such stockholders. Special meetings of stockholders of the Corporation may be called only by the Chairman or President and shall be called by the Chairman, President or the Secretary upon the written request of ~~two-thirds~~a majority of the ~~Continuing~~ Board of Directors. Stockholders of the Corporation shall not be entitled to request a special meeting of stockholders.

ARTICLE VII

DIRECTOR LIABILITY

~~SEVENTEENTH.~~ No director of the Corporation shall be liable to the Corporation or its stockholders for monetary damages for breach of fiduciary duty as a director, except for liability (a) for any breach of the director's duty of loyalty to the Corporation or its stockholders, (b) for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law, (c) under Section 174 of the Delaware General Corporation Law, or (d) for any transaction from which the director derived an improper personal benefit.

ARTICLE VIII

CREDITOR COMPROMISES

Whenever a compromise or arrangement is proposed between this Corporation and its creditors or any class of them and/or between this Corporation and its stockholders or any class of them, any court of equitable jurisdiction within the State of Delaware may, on the application in a summary way of this Corporation or of any creditor or stockholder thereof, or on the application of any receiver or receivers appointed for this Corporation under Section 291 of Title 8 of the Delaware Code, or on the application of trustees in dissolution or of any receiver or receivers appointed for this Corporation under Section 279 of Title 8 of the Delaware Code, order a meeting of the creditors or class of creditors, and/or of stockholders or class of stockholders of this Corporation, as the case may be, to be summoned in such manner as the said Court directs. If a majority in number representing three-fourths in value of the creditors or class of creditors, and/or of the stockholders or class of stockholders of this Corporation, as the case may be, agree to any compromise or arrangement and to any reorganization of this Corporation as consequence of such compromise or arrangement, the said compromise or arrangement and the said reorganization shall, if sanctioned by the Court to which the said application has been made, be binding on all the creditors or class of creditors, and/or on all the stockholders or class of stockholders, of this Corporation, as the case may be, and also on this Corporation.

ARTICLE IX

AMENDMENT OF CERTIFICATE OF INCORPORATION AND BYLAWS

Except as otherwise expressly provided by this Certificate of Incorporation, the Corporation reserves the right to amend, alter, change or repeal any provision of this Certificate of Incorporation in the manner now or hereafter prescribed by law, and all the provisions of this Certificate of Incorporation and all rights conferred on stockholders, directors, officers and other persons in this Certificate of Incorporation are subject to this reserved power. Except as otherwise expressly provided by this Certificate of Incorporation, the Board of Directors shall have the power to adopt, amend or repeal the Corporation's Bylaws. Any adoption, amendment or repeal of the Corporation's Bylaws by the Board of Directors shall require the approval of a majority of the Board of Directors. The stockholders of the Corporation shall have the power to adopt, amend or repeal the Corporation's Bylaws.

[*Signature Page Follows*]

IN WITNESS WHEREOF, ~~MDUR Newco, Inc.~~the Corporation has caused ~~its corporate seal to be hereunto affixed, and~~ this Amended and Restated Certificate of Incorporation to be signed by David L. Goodin, its President and Chief Executive Officer, ~~and Daniel S. Kuntz, its Secretary, on December 31, 2018.~~on [_______], 2019.

~~MDUR NEWCO~~ MDU RESOURCES GROUP, INC.

~~ATTEST:~~

~~/s/ Daniel S. Kuntz~~
~~Daniel S. Kuntz~~
~~Secretary~~

By: /s/ David L. Goodin
David L. Goodin
President and Chief Executive Officer

[Signature Page to Certificate of Incorporation]

Stockholder Information

Corporate Headquarters

MDU Resources Group, Inc.
Street Address: 1200 W. Century Ave.
Bismarck, ND 58503

Mailing Address: P.O. Box 5650
Bismarck, ND 58506-5650

Telephone: 701-530-1000
Toll-Free Telephone: 866-760-4852
www.mdu.com

The company has filed as exhibits to its Annual Report on Form 10-K the CEO and CFO certifications as required by Section 302 of the Sarbanes-Oxley Act.

The company also submitted the required annual CEO certification to the New York Stock Exchange.

Common Stock

MDU Resources' common stock is listed on the NYSE under the symbol MDU. The stock began trading on the NYSE in 1948 and is included in the Standard & Poor's MidCap 400 index. Average daily trading volume in 2018 was 827,903 shares.

Common Stock Prices

	High	Low	Close
2018			
First Quarter	$28.23	$24.29	$28.16
Second Quarter	29.28	27.05	28.68
Third Quarter	29.62	25.33	25.69
Fourth Quarter	26.96	22.73	23.84
2017			
First Quarter	$29.74	$25.83	$27.37
Second Quarter	27.89	25.58	26.20
Third Quarter	27.73	25.14	25.95
Fourth Quarter	28.22	25.89	26.88

Shareowner Service Plus Plan

The Shareowner Service Plus Plan provides interested investors the opportunity to purchase shares of MDU Resources' common stock and to reinvest all or a percentage of dividends without incurring brokerage commissions or service charges. The plan is sponsored and administered by Equiniti Trust Company, transfer agent and registrar for MDU Resources. For more information, contact Equiniti Trust Company at 877-536-3553 or visit www.shareowneronline.com.

2019 Key Dividend Dates

	Ex-Dividend Date	Record Date	Payment Date
First Quarter	March 13	March 14	April 1
Second Quarter	June 12	June 13	July 1
Third Quarter	September 11	September 12	October 1
Fourth Quarter	December 11	December 12	January 1, 2020

Key dividend dates are subject to the discretion of the Board of Directors.

Annual Meeting

11 a.m. CDT May 7, 2019
Montana-Dakota Utilities Co. Service Center
909 Airport Road
Bismarck, North Dakota

Shareholder Information and Inquiries

Registered shareholders have electronic access to their accounts by visiting www.shareowneronline.com. Shareowner Online allows shareholders to view their account balance, dividend information, reinvestment details and more. The stock transfer agent maintains stockholder account information.

Communications regarding stock transfer requirements, lost certificates, dividends or change of address should be directed to the stock transfer agent.

Company information, including financial reports, is available at www.mdu.com.

Shareholder Contact

Dustin J. Senger
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Email: investor@MDUResources.com

Analyst Contact

Jason L. Vollmer
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Email: Jason.Vollmer@MDUResources.com

Transfer Agent and Registrar for All Classes of Stock

Equiniti Trust Company
Stock Transfer Department
P.O. Box 64874
St. Paul, MN 55164-0874
Telephone: 651-450-4064
Toll-Free Telephone: 877-536-3553
www.shareowneronline.com

Independent Registered Public Accounting Firm

Deloitte & Touche LLP
50 S. Sixth St., Suite 2800
Minneapolis, MN 55402-1538

Note: This information is not given in connection with any sale or offer for sale or offer to buy any security.

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MDU
LISTED
NYSE

MDU RESOURCES
GROUP, INC.

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY - MINNESOTA
CALCULATION OF GROSS REVENUE CONVERSION FACTOR
TWELVE MONTHS ENDING DECEMBER 31, 2018
PROJECTED 2019 - 2020

	Statutory	Effective	
Federal Tax Rate	21.00%	18.942%	1/
State Tax Rate	9.80%	9.800%	
Effective Federal and State Tax Rate		28.742%	
1- Tax rate		71.258%	
Revenue Conversion Factor 2/		1.403351	

1/ State tax is deductible from federal taxes.
2/ [1/(1-Tax Rate)].