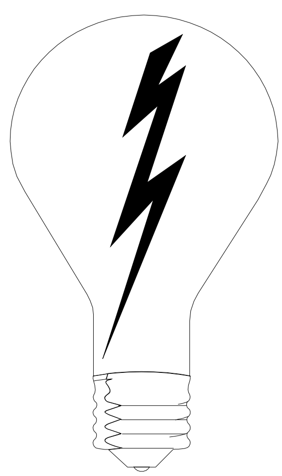
YEAR ENDING 2021

ANNUAL REPORT
OF

NorthWestern Energy

ELECTRIC UTILITY

Docket 2022.01.001



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

Electric Annual Report

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Sch. 1	IDENTIFICATION

Legal Name of Respondent:	NorthWestern Corporation
Name Under Which Respondent Does Business:	NorthWestern Energy
Date Utility Service First Offered in Montana:	Electricity - Dec 12, 1912 Natural Gas - Jan 01, 1933 Propane - Oct 13, 1995
Person Responsible for Report:	Jeff B. Berzina
Telephone Number for Report Inquiries:	(406) 497-2759
Address for Correspondence Concerning Report:	11 East Park Street Butte, MT 59701

If direct control over respondent is held by another entity, provide below the name, address, means by which control is held and percent ownership of controlling entity:

N/A

Sch. 2	BOARD OF DIRECTORS	
	Director's Name & Address (City, State)	Remuneration
1		
2	See NorthWestern Corporation's Annual Report on Form 10-K	
3	to the SEC for the Corporate Board of Directors.	
4		
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Sch. 3	OFFICERS		
	Title	Department Supervised	Name
	Chief Executive Officer	Executive	Robert Rowe
	President and Chief Operating Officer	Distribution Operations - MT/SD/NE	Brian Bird
		Supply Operations	
		Transmission Operations	
		Business Technology	
		Energy Risk Management	
		Flight Services, Executive Compensation	
	Vice President,	Legal Services	Heather Grahame
	General Counsel and Regulatory and	Corporate Secretary	
	Federal Government Affairs	Risk Management	
		Regulatory Affairs	
		Federal Governmental Affairs	
	Vice President,	Distribution Operations - MT/SD/NE	Curt Pohl
	Distribution	Construction, Asset Management	
		Labor and Operational Performance	
		Project Management	
		Safety/Health/Environmental Services	
		Business Development and Strategic Support	
	Vice President,	Transmission Planning, Engineering, Construction,	Michael Cashell
	Transmission	and Operations	
		Gas Transmission & Storage	
		Substation Operations	
		Transmission Policy, Services, and Operations	
		Transmission Market Strategy	
		Grid Real Time and Scada Operations	
		FERC and NERC Compliance	
		Support Services	
	Vice President,	Thermal and Wind Generation	John Hines
	Supply and Montana Government Affairs	Hydro Operations	
		Environmental and Lands Permitting & Compliance	
		Long Term Resources	
		Energy Supply Marketing Operations	
		Montana Government Affairs	
		Brand, Advertising, and	Bobbi Schroeppel
	Vice President,	Customer Communications	
	Customer Care, Communications and	Customer Experience and Support	
	Human Resources	Customer Interaction	
		Community Connections	
		Revenue Cycle Management	
		Human Resources	
	Chief Audit & Compliance Officer	Internal Audit	Michael Nieman
		Enterprise Risk and Business Continuity	
	Vice President and Chief Financial Officer	Tax, Internal Audit and Compliance	Crystal Lail
		Financial Planning & Analysis	
		Controller and Treasury Functions	
		Investory Relations and Corporate Finance	
	Vice President,	Business Technology	Jeanne Vold
	Technology	Customer Systems & Solutions	
		Data & Analytics	
		Operation Technology	
		Security	

Reflects active officers as of December 31, 2021.

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		**$ 183,106**	**98.00%**
NorthWestern Corporation:			
Montana Utility Operations	Electric Utility Natural Gas Utility Natural Gas Pipeline (including Canadian Montana Pipeline Corp., Havre Pipline Company, LLC Lodge Creek Pipelines, LLC and Willow Creek Gathering, LLC) Propane Utility		
South Dakota Utility Operations	Electric Utility Natural Gas Utility		
Nebraska Utility Operations	Natural Gas Utility		
Unregulated Operations		**$ 3,734**	**2.00%**
Direct Subsidiaries:			
NorthWestern Services, LLC	Nonregulated natural gas marketing, property management		
Clark Fork and Blackfoot, LLC	Former Milltown hydroelectric facility		
Risk Partners Assurance, Ltd.	Captive insurance company		
NorthWestern Energy Solutions, Inc	Non-regulated customer services		
Total Corporation		**$ 186,840**	**100.00%**

Sch. 5

CORPORATE ALLOCATIONS

Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
Controller	Includes the following departments: Controller, Accounting Accounts Payable, Payroll, Financial Reporting, Regulatory Affairs Finance and Compensation & Benefits	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	$19,322,654	83.23%	$3,892,247
Customer Care	Includes the following departments: Customer Care Combined, Customer Care SD&NE CC MT, Business Develop, Contributions, Print Services CC - Assoc & Dispatch Human Resources, and Regulatory Support Services	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	19,896,187	71.43%	7,957,351
Legal Department	Includes the following departments: Chief Legal, Contracts Administration, Regulatory Affairs MT, SD & NE Public and Regulartory Affairs and Risk Management	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	17,919,953	78.32%	4,959,156
Finance	Includes the following departments: CFO, Treasury, FP&A Tax , Investor Relations, Corporate Aircraft, Business Technology Applications, Architecture & Governanace	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	24,963,730	78.73%	6,743,226
Executive Department	Includes the following departments: CEO, and Board of Directors	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	3,600,329	76.40%	1,111,928
Audit & Controls	Includes the following departments: Internal Audit and Enterprise Risk Management	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	851,286	78.00%	240,106
Distribution	Includes the following departments: Sioux Falls Facilities and Helena Building	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	49,415	78.00%	13,937
TOTAL			$86,603,554	77.66%	$24,917,951

Sch. 6	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Utility	% of Total Affil. Rev.	Charges to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4	**Total Nonutility Subsidiaries**			$0		$0
5	**Total Nonutility Subsidiaries Revenues**			$0		
6						
7						
8						
9	**Utility Subsidiaries**					
10						
11	**Total Utility Subsidiaries**			$0		$0
12	Canadian-Montana Pipeline Corporation	Natural gas pipeline	Contract rate	$249,654		
13						
14	Havre Pipeline Company, LLC	Natural gas gathering,	Gathering rate based on cost,	2,786,709		
15		transmission, & compression	transmission & compression			
16			are at tariffed rates			
17	**Total Utility Subsidiaries Revenues**			$3,036,363		
18	**TOTAL AFFILIATE TRANSACTIONS**			$0		$0

Sch. 7	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Affiliate	% of Total Affil. Exp.	Revenues to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4						
5						
6	**Total Nonutility Subsidiaries**			$0		$0
7	**Total Nonutility Subsidiaries Expenses**			$0		
8						
9						
10						
11	**Utility Subsidiaries**					
12						
13	Havre Pipeline Company, LLC	Administration Fee	Negotiated Contract Rate	500,400.00	14.9%	500,400.00
14	Havre Pipeline Company, LLC	Labor Cost	Actual Expense	1,398,864.85	37.5%	$1,398,865
15						
16	**Total Utility Subsidiaries**			1,899,264.85		$1,899,265
17	**Total Utility Subsidiaries Expenses**			$3,548,889		
18	**TOTAL AFFILIATE TRANSACTIONS**			$1,899,265		$1,899,265

Sch. 8	MONTANA UTILITY INCOME STATEMENT - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	400 Operating Revenues	$ 1,062,759,806	$ 182,781,837	$ 879,977,969	$ 796,805,500	10.44%
3						
4	**Total Operating Revenues**	1,062,759,806	182,781,837	879,977,969	796,805,500	10.44%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expenses	484,092,963	86,418,907	397,674,056	363,023,227	9.55%
9	402 Maintenance Expense	48,389,356	10,097,553	38,291,803	36,655,087	4.47%
10	403 Depreciation Expense	142,943,303	29,203,133	113,740,170	108,345,193	4.98%
11	404-405 Amort. of Electric Plant	6,526,947	1,197,482	5,329,465	4,932,343	8.05%
12	406 Amort. of Plant Acquisition Adj.	10,249,919	1,200,394	9,049,525	9,049,525	0.00%
13	407.3 Regulatory Amortizations - Debit	13,407,216	1,224,069	12,183,147	1,258,438	>300.00%
14	407.4 Regulatory Amortizations - Credit	(15,887,780)	-	(15,887,780)	(14,549,439)	-9.20%
15	408.1 Taxes Other Than Income Taxes	141,143,613	6,321,141	134,822,472	140,453,582	-4.01%
16	409.1 Income Taxes - Federal	(3,710,988)	(7,510,432)	3,799,444	(5,432,160)	169.94%
17	- Other	3,139,706	88,695	3,051,011	-	-
18	410.1 Deferred Income Taxes-Dr.	71,864,710	10,120,366	61,744,344	76,760,293	-19.56%
19	411.1 Deferred Income Taxes-Cr.	(70,429,420)	(8,635,404)	(61,794,016)	(77,270,229)	20.03%
20	411.4 Investment Tax Credit Adj.	278,029	38,459	239,570	-	-
21	411.6 Gain from Disposition of Property	-	-	-	-	-
22	411.7 Loss from Disposition of Property	-	-	-	-	-
23	411.8 SO2 Allowances	2,678	(1)	2,679	(2,679)	200.00%
24						
25	**Total Operating Expenses**	832,010,252	129,764,362	702,245,890	643,223,181	9.18%
26	**NET OPERATING INCOME**	$ 230,749,554	$ 53,017,475	$ 177,732,079	$ 153,582,319	15.72%

This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4.

Sch. 9	MONTANA REVENUES - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	**Sales to Ultimate Consumers**					
3						
4	440 Residential	$ 396,667,149	$ 65,545,708	$ 331,121,441	$ 320,367,451	3.36%
5	442 Commercial	455,887,584	106,359,484	349,528,100	333,157,860	4.91%
6	Industrial	51,238,503	-	51,238,503	50,699,200	1.06%
7	444 Public Street, Highway Lighting					
8	& Other Sales to Public Authorities	17,372,687	2,594,326	14,778,361	15,671,385	-5.70%
9	448 Interdepartmental Sales	858,550	-	858,550	880,014	-2.44%
10						
11	**Total Sales to Ultimate Consumers**	922,024,473	174,499,518	747,524,955	720,775,910	3.71%
12	447 Sales for Resale	31,170,157	-	31,170,157	16,720,587	86.42%
13						
14	**Total Sales of Electricity**	953,194,630	174,499,518	778,695,112	737,496,497	5.59%
15	449.1 Provision for Rate Refunds	9,872,744	-	9,872,744	(18,807,571)	152.49%
16						
17	**Total Revenue Net of Rate Refunds**	963,067,374	174,499,518	788,567,856	718,688,926	9.72%
18						
19	**Other Operating Revenues**					
20	450 Forfeited Discounts & Late Pymt Rev	435,650	435,650	-	-	-
21	451 Miscellaneous Service Revenue	221,410	221,410	-	-	-
22	453 Sales of Water & Water Power	-	-	-	-	-
23	454 Rent From Electric Property	4,001,541	177,687	3,823,854	3,886,769	-1.62%
24	456 Other Electric Revenues	95,033,831	7,447,572	87,586,259	74,229,805	17.99%
25						
26	**Total Other Operating Revenue**	99,692,432	8,282,319	91,410,113	78,116,574	17.02%
27	**TOTAL OPERATING REVENUE**	$ 1,062,759,806	$ 182,781,837	$ 879,977,969	$ 796,805,500	10.44%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Power Production Expenses**					
2						
3	**Steam Power Generation-Operation**					
4	500 Supervision & Engineering	836,325	806,576	29,749	33,361	-10.83%
5	501 Fuel	44,346,022	16,017,053	28,328,969	19,536,379	45.01%
6	502 Steam Expenses	3,516,005	1,733,967	1,782,038	1,725,039	3.30%
7	503 Steam from Other Sources	-	-	-	-	-
8	505 Electric Plant	802,829	605,247	197,582	138,726	42.43%
9	506 Miscellaneous Steam Power	3,470,783	1,317,257	2,153,526	2,284,043	-5.71%
10	507 Rents	33,465	33,465	-	-	-
11	**Total Operation-Steam Power Gen.**	53,005,429	20,513,565	32,491,864	23,717,548	37.00%
12	**Steam Power Generation-Maintenance**					
13	510 Supervision & Engineering	1,255,207	657,661	597,546	543,793	9.88%
14	511 Structures	1,006,897	371,582	635,315	628,661	1.06%
15	512 Steam Boiler Plant	9,435,530	3,563,491	5,872,039	5,731,181	2.46%
16	513 Electric Plant	2,285,342	876,875	1,408,467	1,234,088	14.13%
17	514 Miscellaneous Steam Plant	871,492	472,199	399,293	420,690	-5.09%
18	**Total Maintenance-Steam Power Gen.**	14,854,468	5,941,808	8,912,660	8,558,413	4.14%
19	**Total Steam Power Generation**	67,859,897	26,455,373	41,404,524	32,275,961	28.28%
20	**Hydro Power Generation-Operation**					
21	535 Supervision & Engineering	613,183	-	613,183	562,952	8.92%
22	536 Water for Power	942,963	-	942,963	1,032,891	-8.71%
23	537 Hydraulic Expenses	3,804,078	-	3,804,078	3,659,840	3.94%
24	538 Electric Expenses	3,315,092	-	3,315,092	3,294,278	0.63%
25	539 Miscellaneous Hydraulic Power	3,269,367	-	3,269,367	2,749,172	18.92%
26	540 Rents	788,771	-	788,771	786,169	0.33%
27	**Total Operation-Hydro Power Gen.**	12,733,454	-	12,733,454	12,085,302	5.36%
28	**Hydro Power Generation-Maintenance**					
29	541 Supervision & Engineering	517,919	-	517,919	518,067	-0.03%
30	542 Structures	683,786	-	683,786	456,912	49.65%
31	543 Reservoirs, Dams & Waterways	758,707	-	758,707	803,272	-5.55%
32	544 Electric Plant	1,006,837	-	1,006,837	1,599,873	-37.07%
33	545 Miscellaneous Hydro Plant	540,434	-	540,434	283,095	90.90%
34	**Total Maintenance-Hydro Power Gen.**	3,507,683	-	3,507,683	3,661,219	-4.19%
35	**Total Hydraulic Power Generation**	16,241,137	-	16,241,137	15,746,521	3.14%
36	**Other Power Generation-Operation**					
37	546 Supervision & Engineering	657,935	244,941	412,994	399,101	3.48%
38	547 Fuel	23,477,997	6,101,979	17,376,018	6,865,218	153.10%
39	548 Generation Expenses	7,456,228	4,012,439	3,443,789	3,019,833	14.04%
40	549 Miscellaneous Other Power	1,230,945	472,217	758,728	751,983	0.90%
41	550 Rents	-	-	-	-	-
42	**Total Operation-Other Power Gen.**	32,823,105	10,831,576	21,991,529	11,036,135	99.27%
43	**Other Power Generation-Maintenance**					
44	551 Supervision & Engineering	26,695	26,695	-	-	-
45	552 Structures	64,563	63,642	921	12,329	-92.53%
46	553 Generating & Electric Plant	2,039,100	685,369	1,353,731	1,109,775	21.98%
47	554 Miscellaneous Other Power Plant	149,348	16,833	132,515	106,009	25.00%
48	**Total Maintenance-Other Power Gen.**	2,279,706	792,539	1,487,167	1,228,113	21.09%
49	**Total Other Power Generation**	35,102,811	11,624,115	23,478,696	12,264,248	91.44%
50	**Other Power Supply Expenses**					
51	555 Purchased Power	257,640,492	26,145,726	231,494,766	182,098,891	27.13%
52	556 System Control & Load Dispatch	280,190	280,190	-	-	-
53	557 Other Expenses	(49,075,418)	(11,258,979)	(37,816,439)	13,407,964	>-300.00%
54	**Total Other Power Supply Expenses**	208,845,264	15,166,937	193,678,327	195,506,855	-0.94%
55	**Total Power Production Expenses**	328,049,109	53,246,425	274,802,684	255,793,585	7.43%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	**Transmission Expenses**					
3						
4	**Transmission-Operation**					
5	560 Supervision & Engineering	2,795,081	259,011	2,536,070	2,331,786	8.76%
6	561 Load Dispatching	63,158	63,158	-	-	-
7	561.1 Load Dispatch - Reliability	815,677	-	815,677	898,953	-9.26%
8	561.2 Load Disp-Monitor/Op	887,058	101,269	785,789	676,041	16.23%
9	561.3 Load Disp-Srv/Schedu	1,213,918	3,000	1,210,918	1,130,026	7.16%
10	561.4 Relia Pln/StdDev-RTO	-	-	-	-	-
11	561.5 Reliab, Plan, Stds	88,280	88,280	-	-	-
12	561.6 Transmission Service Studies	-	-	-	-	-
13	561.8 Sch,Sys&Ctrl Srv-RTO			-	-	-
14	562 Station Expenses	1,541,331	122,936	1,418,395	1,387,307	2.24%
15	563 Overhead Lines	1,482,862	336,415	1,146,447	1,010,848	13.41%
16	564 Underground Lines	-	-	-	-	-
17	565 Transmission of Elec. by Others	27,314,196	20,061,598	7,252,598	6,340,813	14.38%
18	566 Miscellaneous Transmission	280,251	72,606	207,645	61,555	237.33%
19	567 Rents	1,051,313	(4,682)	1,055,995	889,746	18.68%
20	**Total Operation-Transmission**	37,533,125	21,103,591	16,429,534	14,727,075	11.56%
21	**Transmission-Maintenance**					
22	568 Supervision & Engineering	589,057	61,491	527,566	506,129	4.24%
23	569 Structures	28,013	17,725	10,288	33,403	-69.20%
24	569.1 Maintenance of Computer Hardware	1,072,036	-	1,072,036	862,582	24.28%
25	569.2 Maintenance of Computer Software	2,787	-	2,787	2,366	17.79%
26	569.3 Maint-Comm Equip	107,053	107,053	-	-	-
27	570 Station Equipment	772,362	104,632	667,730	694,527	-3.86%
28	571 Overhead Lines	4,160,441	245,451	3,914,990	3,276,274	19.50%
29	572 Underground Lines	201	201	-	-	-
30	573 Miscellaneous Transmission Plant	-	-	-	-	-
31	**Total Maintenance-Transmission**	6,731,950	536,553	6,195,397	5,375,281	15.26%
32	**Total Transmission Expenses**	44,265,075	21,640,144	22,624,931	20,102,356	12.55%
33						
34	**Regional Market Operation**					
35	575.1 Operation Supervision	-	-	-	-	-
36	575.2 Day-Ahead & Real-time Admin	403,856	403,856	-	-	-
37	575.3 Transmision Rights Mkt Admin	-	-	-	-	-
38	575.5 Ancillary Services Mkt Admin	115,387	115,387	-	-	-
39	575.6 Market Monitoring & Complaince	57,694	57,694	-	-	-
40	**Total Operation-Regional Market**	576,937	576,937	-	-	-
41						
42	**Distribution Expenses**					
43						
44	**Distribution-Operation**					
45	580 Supervision & Engineering	3,368,548	541,208	2,827,340	2,842,451	-0.53%
46	581 Load Dispatching	-	-	-	-	-
47	582 Station Expenses	1,612,336	199,114	1,413,222	1,192,337	18.53%
48	583 Overhead Lines	1,933,124	476,232	1,456,892	1,672,554	-12.89%
49	584 Underground Lines	2,886,644	771,002	2,115,642	2,001,546	5.70%
50	585 Street Lighting & Signal Systems	189,357	64,770	124,587	229,415	-45.69%
51	586 Meters	2,543,121	482,932	2,060,189	1,893,487	8.80%
52	587 Customer Installations	1,627,282	233,672	1,393,610	1,305,414	6.76%
53	588 Miscellaneous Distribution	2,946,278	749,140	2,197,138	2,075,647	5.85%
54	589 Rents	79,059	-	79,059	96,152	-17.78%
55	**Total Operation-Distribution**	17,185,749	3,518,070	13,667,679	13,309,003	2.69%
56	**Distribution-Maintenance**					
57	590 Supervision & Engineering	1,377,389	211,907	1,165,482	1,142,614	2.00%
58	591 Structures	35,634	-	35,634	38,824	-8.22%
59	592 Station Equipment	721,566	153,299	568,267	360,265	57.74%
60	593 Overhead Lines	13,347,613	1,582,703	11,764,910	11,889,375	-1.05%
61	594 Underground Lines	1,082,934	149,145	933,789	928,536	0.57%
62	595 Line Transformers	118,022	6,097	111,925	91,275	22.62%
63	596 Street Lighting, Signal Systems	635,363	276,397	358,966	510,305	-29.66%
64	597 Meters	1,547,624	175,004	1,372,620	1,124,848	22.03%
65	598 Miscellaneous Distribution Plant	44,445	44,445	-	-	-
66	**Total Maintenance-Distribution**	18,910,590	2,598,997	16,311,593	16,086,042	1.40%
67	**Total Distribution Expenses**	36,096,339	6,117,067	29,979,272	29,395,045	1.99%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	**Customer Accounts Expenses**					
3						
4	**Customer Accounts-Operation**					
5	901 Supervision	-	-	-	-	-
6	902 Meter Reading	1,600,412	75,956	1,524,456	1,358,111	12.25%
7	903 Customer Records & Collection	7,599,920	1,223,896	6,376,024	5,972,809	6.75%
8	904 Uncollectible Accounts	160,180	365,482	(205,302)	3,676,054	-105.58%
9	905 Miscellaneous Customer Accts.	87,471	52,210	35,261	(203)	>300.00%
10	**Total Customer Accounts Expenses**	9,447,983	1,717,544	7,730,439	11,006,771	-29.77%
11						
12	**Customer Service & Information**					
13						
14	**Customer Service-Operation**					
15	907 Supervision	-	-	-	-	-
16	908 Customer Assistance	3,452,008	1,035,167	2,416,841	2,443,744	-1.10%
17	909 Inform. & Instruct. Advertising	1,169,119	115,219	1,053,900	919,043	14.67%
18	910 Misc. Customer Service & Info.	625,631	64,120	561,511	596,808	-5.91%
19	**Total Customer Service & Info. Expense**	5,246,758	1,214,506	4,032,252	3,959,595	1.83%
20						
21	**Sales Expenses**					
22						
23	**Sales-Operation**					
24	911 Supervision	-	-	-	-	-
25	912 Demonstrating & Selling			-	-	-
26	913 Advertising	354,189	26,514	327,675	297,533	10.13%
27	916 Miscellaneous Sales	-	-	-	-	-
28	**Total Sales Expenses**	354,189	26,514	327,675	297,533	10.13%
29						
30	**Administrative & General Expenses**					
31						
32	**Admin. & General-Operation**					
33	920 Admin. & General Salaries	32,114,944	4,259,952	27,854,992	24,413,610	14.10%
34	921 Office Supplies & Expenses	11,591,266	2,154,431	9,436,835	8,453,747	11.63%
35	922 Admin. Expense Transferred-Cr.	(7,333,865)	(1,112,650)	(6,221,215)	(5,652,438)	-10.06%
36	923 Outside Services Employed	9,575,955	955,732	8,620,223	5,226,982	64.92%
37	924 Property Insurance	3,097,423	743,827	2,353,596	2,233,186	5.39%
38	925 Injuries & Damages	9,118,837	1,168,602	7,950,235	7,255,854	9.57%
39	926 Employee Pensions & Benefits	30,465,000	2,538,658	27,926,342	18,378,626	51.95%
40	927 Franchise Requirements	-	-	-	-	-
41	928 Regulatory Commission Expenses	2,627,288	1,895	2,625,393	2,450,808	7.12%
42	929 Duplicate Charges-Cr.	-	-	-	-	-
43	930 Miscellaneous General Expenses	13,594,531	731,109	12,863,422	13,342,904	-3.59%
44	931 Rents	1,489,591	308,111	1,181,480	1,274,131	-7.27%
45	**Total Operation-Admin. & General**	106,340,970	11,749,667	94,591,303	77,377,410	22.25%
46	**Admin. & General-Maintenance**					
47	935 General Plant	2,104,959	227,656	1,877,303	1,746,019	7.52%
48	**Total Maintenance-Admin. & General**	2,104,959	227,656	1,877,303	1,746,019	7.52%
49	**Total Admin. & General Expenses**	108,445,929	11,977,323	96,468,606	79,123,429	21.92%
50	**TOTAL OPER. & MAINT. EXPENSES**	532,482,319	96,516,460	435,965,859	399,678,314	9.08%

Sch.11	MONTANA TAXES OTHER THAN INCOME - ELECTRIC			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	5,080,053	4,914,186	3.38%
3	Property Taxes	124,421,573	130,610,703	-4.74%
4	Electric Energy License Tax	802,263	779,747	2.89%
5	Crow Tribe RR and Utility Tax	84,948	84,948	0.00%
6	Fort Peck	0	-	-
7	City Tax	1,680	2,115	-20.57%
8	Consumer Counsel Tax	383,542	312,244	22.83%
9	Public Service Commission Tax	1,484,780	1,083,585	37.02%
10	Heavy Highway Use Tax	14,596	18,734	-22.09%
11	Vehicle Use Tax	209,169	193,238	8.24%
12	Wholesale Energy Transaction Tax	1,372,494	1,382,279	-0.71%
13	Delaware Franchise Tax	150,054	150,165	-0.07%
14	Invasive Species	817,320	921,638	-11.32%
15				
16				
17				
18	**TOTAL TAXES OTHER THAN INCOME**	$134,822,472	$140,453,582	-4.01%
19				
20				

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	A EXCAVATION	Excavation Contractor	148,804.75
2	ACUREN INSPECTION INC	Inspection Services	88,392.60
3	AFFCO INC	Hydro Construction Services	1,352,481.02
4	AION ENERGY LLC	Program Management Services	168,023.09
5	AMERICAN INNOVATIONS INC	Software Support Services	134,740.95
6	ANDRITZ HYDRO CORP	Hydro Upgrade Services	3,140,965.27
7	ARCADIS US INC	Engineering Services	136,211.08
8	ARCOS LLC	Call-out Services	142,354.58
9	ASCEND ANALYTICS LLC	Hydro Expert Analysis	406,623.89
10	ASPLUNDH TREE EXPERT LLC	Tree Trimming	5,668,597.07
11	ASSOCIATED UNDERWATER SERVICE	Inspection Services	218,488.10
12	AURITAS LLC	Computer Consulting Services	251,577.50
13	AUTOMOTIVE RENTALS INC	Fleet Management	8,336,656.78
14	AVEVA SOFTWARE, LLC	Computer Support Services	731,571.15
15	BART ENGINEERING COMPANY	Engineering Services	535,620.00
16	BEACON COMMUNICATIONS LLC	Software Maintenance	531,293.13
17	BERGY'S LLC	Construction	1,267,631.54
18	BIG SKY LAND RESOURCES, LLC	Excavation Contractor	742,897.13
19	BILLINGS FLYING SERVICE, INC.	Powerline Services	112,290.00
20	BISON ENGINEERING INC	Engineering Services	238,324.41
21	BLUE MOUNTAIN DIRECTIONAL DRI	Boring Services	508,220.84
22	BRANDENBURG INDUSTRIAL SERVIC	Demolition Services	1,428,100.00
23	BROADRIDGE ICS	Shareholder Services	90,459.98
24	BURK EXCAVATION AND UTILITIES	Construction	160,404.56
25	CATERPILLAR POWER GENERATION	Generation Services	21,029,854.10
26	CENTRON SERVICES INC	Customer Collection service	125,768.03
27	CLEARESULT CONSULTING INC	Energy Efficiency Consultants	123,966.10
28	CN UTILITY CONSULTING INC	Utility Consulting Services	556,455.86
29	CONTINENTAL STEEL WORKS	Fabrication Services	1,804,034.43
30	COPPER CREEK LLC	Construction	358,729.57
31	CORNERSTONE ENERGY SERVICES	Energy Services	290,821.39
32	CRANE SERVICES & INSPECTIONS	DOT Inspections	124,517.23
33	CRIST, KROGH, BUTLER & NORD L	Legal Services	330,189.78
34	CROWLEY FLECK PLLP	Legal Services	91,252.40
35	CTA INC.	Energy Conservation Consultants	1,477,806.00
36	D & A TRENCHING	Excavating Services	295,141.00
37	DAKOTA DIRECTIONAL LLC	Boring Services	76,206.85
38	DAVEY TREE SURGERY COMPANY	Tree Trimming	3,930,139.00
39	DELOITTE & TOUCHE	Audit Services	1,388,153.08
40	DEPT OF HEALTH & HUMAN SERVIC	Weatherization Program Services	1,839,320.24
41	DHC INC	Boring Services	129,123.00
42	DIETZEL ENTERPRISES INC	Construction	597,724.64
43	DIRECTIONAL ZONE INC	Boring Services	195,978.00
44	DJ&A P C CONSULTING ENGINEER	Engineering Services	147,722.89
45	DNV GL ENERGY INSIGHTS USA INC	Software Support Services	4,490,491.02
46	DGR ENGINEERING	Engineering Services	582,285.32
47	DOBLE ENGINEERING CO	Engineering Services	196,871.50
48	DORSEY & WHITNEY LLP	Legal Services	1,518,948.72
49	DOWL HKM	Geotechnical Services	172,276.17
50	E SOURCE COMPANIES LLC	Consulting Services	217,228.00
51	ELLIOT CONSTRUCTION	Boring Services	1,514,509.11
52	ELM LOCATING & UTILITY SERVIC	Locating Services and Excavation Notificat	4,521,173.05
53	ENERGY AND ENVIRONMENTAL ECON	Consulting Services	90,723.75
54	ENERGY CONTRACT SERVICES LLC	Inspection Services	1,155,798.75
55	ENERGY LABORATORIES INC	Environmental Consultants	90,046.00
56	ENERGY SHARE OF MONTANA	USBC Services	1,101,245.00
57	EVERGREEN CAISSONS INC	Construction	124,000.00
58	FAGEN	Construction	23,150,029.01
59	FENCECRAFTERS HELENA INC	Repair Services	77,690.00

Sch. 12A	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
60	FIRSTMARK CONSTRUCTION	Construction	323,652.00
61	FLYNN WRIGHT INC	Advertising Services	1,553,174.21
62	FOUR CORNERS RECYCLING, LLC	Recovery Services	158,403.50
63	GARTNER INC	Information Technology Consulting	345,863.81
64	GE RENEWABLES GRID, LLC	Software Support Services	530,446.75
65	GEI CONSULTANTS INC	Environmental Consultants	551,485.63
66	GENERAL ELECTRIC INTERNATIONA	Plant Operator Services	6,251,736.58
67	GEOSPATIAL INNOVATIONS INC	Data Collection Services	158,218.00
68	GREGG ENGINEERING	Informational Technology Simulation	97,720.00
69	GUY TABACCO CONSTRUCTION	Construction	699,063.18
70	H & H ASPHALT & MAINTENANCE L	Asphalt Services	111,378.68
71	H & H CONTRACTING INC	Concrete and Asphalt Services	690,665.51
72	HAIDER CONSTRUCTION	Boring Services	411,819.46
73	H2E INC	Engineering Services	844,106.00
74	HDR ENGINEERING INC	Engineering Services	4,915,874.30
75	HEATH CONSULTANTS INC	Gas Leak Surveys	538,554.02
76	HIGHMARK MEDIA	Safety Training	110,825.00
77	IMCO GENERAL CONSTRUCTION INC	Construction	2,315,678.94
78	INFOSYS LIMITED	Consulting Services	402,116.88
79	INTEC SERVICES INC	Pole Inspection Services	2,753,688.29
80	ITRON INC	Meter Installation	21,326,927.44
81	IVANS BORING	Boring Services	471,024.92
82	J D POWER AND ASSOCIATES	Energy Study	92,030.00
83	J2 BUSINESS PRODUCTS	Copier Maintenance	129,494.97
84	JACOBSEN TREE	Tree Trimming	999,759.33
85	JAN HORSFALL	Board of Director Fees	80,000.00
86	JARES FENCE COMPANY INC	Fence Materials/Installation	108,144.00
87	JEFFERY CONTRACTING LLC	Construction	1,534,489.10
88	JEFFREY W YINGLING	Board of Director Fees	77,611.57
89	JODY KLESSENS CONSTRUCTION LLC	Construction Service	88,886.40
90	JONES DAY	Legal Services	229584.5
91	KARV LLC	Boring Services	197,132.40
92	KM CONSTRUCTION CO INC	Construction	137,080.50
93	KNIFE RIVER	Construction	186,342.97
94	LIEN TRANSPORTATION SERVICE	Transport Services	167,252.09
95	LIQUID GOLD WELL SERVICE INC	Well Services	77,188.50
96	LOCKMER PLUMBING HEATING &	Gas Meter Relocations	287,022.09
97	LOCKMER SHEET METAL	Installation Services	160,198.23
98	M & P EXCAVATING	Excavation Services	424,717.40
99	M&D CONSTRUCTION INC	Construction	341,987.90
100	MAHVASH MAYA YAZDI	Board of Director Fees	82965.39
101	MAP MECHANICAL CONTRACTORS	Demolition Services	452632.02
102	MCMILLEN LLC	Design Services	11,443,418.66
103	MERCER HUMAN RESOURCE CONSULT	HR Consulting	196,458.00
104	MERIDIAN IT INC	Information Technology Services	108,242.45
105	MERKEL ENGINEERING INC	Consulting Services	537,929.38
106	MICHAELS FENCE & SUPPLY CO	Installation Services	121,757.62
107	MICHELS CORPORATION	Construction	8,657,658.10
108	MIDCON UNDERGROUND CONSTRUCTI	Construction	1,199,930.94
109	MINUTEMAN AVIATION INC.	Helicopter Charter Services	160,643.50
110	MISSOULA CONCRETE CONSTRUCTION	Construction	109,805.00
111	MONTANA FISH WILDLIFE & PARKS	Wildlife Monitoring Services	785,665.88
112	MOODY'S INVESTORS SERVICE	Debt Rating Services	223,500.00
113	MORGAN, LEWIS & BOCKIUS LLP	Legal Services	136,654.80
114	MORRISON MAIERLE INC	Engineering Services	497,461.52
115	MOUNTAIN POWER CONSTRUCTION C	Electric Construction and Maintenance	26,232,113.71
116	MOUNTAIN WEST HOLDING COMPANY	Traffic Safety Services	547,942.15
117	MP SYSTEMS	Electric Construction Service	212,138.66
118	MPW INDUSTRIAL WATER SERVICES	Demineralizer System Services	438,056.96
119	NAES CORPORATON	Generation Services	117,636.38

Sch. 12B	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
120	NATIONAL CENTER FOR APPROPRIA	Conservation Program Consultants	463,433.83
121	NEELY ELECTRIC INC	Electric Services	148,572.70
122	NORTHERN HYDRAULICS INC	Construction	81,393.93
123	NORTHWEST ENERGY EFFICIENCY	Energy Services	1,282,895.60
124	OLSSON ASSOCIATES	Surveying Services	121,767.03
125	OMEGA MORAN INC	Traffic Safety Services	174,073.50
126	ONSITE DISTRIBUTED POWER, LLC	Installation Services	702,456.00
127	OPEN ACCESS TECHNOLOGY INT'L	Software Support Services	1,018,435.55
128	OUTBACK POWER COMPANY	Construction Service	330,364.36
129	PAR ELECTRIC CONTRACTORS INC	Electric Construction and Maintenance	22,169,543.90
130	PINNACLE RESEARCH & CONSULTING	Consulting Services	399,108.31
131	PIONEER TECHNICAL SERVICES INC	Environmental Services	219,606.36
132	PIONEER WIRELINE SERVICES	Rig Services	195,393.54
133	POTEET CONSTRUCTION	Traffic Safety Services	109,857.00
134	POWER SETTLEMENTS CONSULTING &	Consulting Services	266,000.00
135	POWERPLAN INC	Software Support Services	2,353,786.06
136	PRICEWATERHOUSECOOPERS LLP	Consulting Services	2,989,991.27
137	PRO PIPE CORPORATION	Welding Services	124,797.50
138	QUANTA UTILITY ENGINEERING	Engineering Services	7,398,841.44
139	RIVER DESIGN GROUP INC	Engineering Services	205,212.90
140	ROCKY MOUNTAIN CONTRACTORS INC	Electric Construction and Maintenance	34,497,196.17
141	ROCKY MOUNTAIN ROTORS MONTANA	Line Maintenance	249,471.58
142	ROD TABBERT CONSTRUCTION INC	Construction	281,926.91
143	ROSEN USA INC	Inspection Services	757,146.00
144	ROUNDS BROTHERS TRENCHING	Boring Services	876,913.27
145	SCENIC CITY ENTERPRISES INC	Construction	131,350.00
146	SCHNABEL ENGINEERING LLC	Consulting Services	618,706.19
147	SHAW PIPELINE SERVICES	Construction Service	362,013.89
148	SIDEWINDERS LLC	Generator Repair Services	1,143,823.87
149	SILVERTECH, INC.	Website Redesign	359,612.00
150	SPHERION STAFFING	Temporary Labor	123,359.51
151	STANDARD & POOR'S FINANCIAL S	Debt Rating Services	228,000.00
152	STATE LINE CONTRACTORS INC	Electric Construction and Maintenance	531,988.14
153	STEPHEN P ADIK	Board of Director Fees	76,216.29
154	STINSON LEONARD STREET LLP	Legal Services	616,190.63
155	SUPERIOR CONCRETE PRODUCTS INC	Construction	550,389.00
156	TERRA REMOTE SENSING (USA) INC	Surveying Services	664,262.75
157	TERRACON CONSULTANTS INC	Geotechnical Services	85,705.61
158	THE ELECTRIC COMPANY OF SOUTH	Construction	1,362,562.53
159	THE MOSAIC COMPANY	Training	576,382.50
160	THOMPSON HINE LLP	Benefits Audit Services	229,289.63
161	TIMBERLINE SECURITY & SERVICES	Security Services	246,806.96
162	TLC SEPTIC SERVICE	Excavation Contractor	288,779.90
163	TODD O BRUESKE CONSTRUCTION	Construction	447,204.23
164	TOWNSEND CONTROLS & ELECTRIC	Construction	89,784.55
165	TRADEMARK ELECTRIC INC	Construction	1,066,480.74
166	TROUTMAN SANDERS LLP	Legal Services	96,092.50
167	ULTEIG ENGINEERS INC	Project Manager Services	230,431.63
168	ULTIMATE LANDSCAPE REPAIR LLC	Landscape service	1,004,115.92
169	UNDERGROUND CONSTRUCTION	Construction	95,723.00
170	UNITED STATES GEOLOGICAL SURV	Environmental Consulting	215,200.00
171	UTILICAST LLC	Consulting Services	1,359,863.39
172	UTILITIES UNDERGROUND LOCATION	Excavation Location Services	235,325.15
173	VAISALA INC	Wind Forecasting Services	148,782.00
174	VARSITY CONTRACTORS INC(KELLER BERGENSONS SERVICE)	Janitorial Services	253,303.86
175	VEOLIA ES TECNICAL SOLUTIONS	Oil Recycling	147,059.46
176	VERMILLON CONSULTING	Consulting Services	75,499.94
177	VERTEX	Billing Services and Programming	2,844,616.00

Sch. 12C	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
178	VERTIV CORPORATION	Maintenance Service	83,977.06
179	VINE ENTERPRISES,INC	Fence Materials/Installation	80,550.46
180	WARREN TRANSPORT INC	Hauling Services	76,537.31
181	WATER & ENVIRONMENTAL TECHNOL	Engineering Services	1,260,280.12
182	WATSON TRUCKING OF HAVRE LLC	Hauling Services	102,485.00
183	WELFL CONSTRUCTION CO	Construction Service	1,128,690.09
184	WILLIS TOWERS WATSON US LLC	Compensation Services	138,290.60
185	WRIGHT AND SUDLOW INC	Construction Service	118,276.18
186	ZACHA UNDERGROUND CONSTRUCTIO	Construction	99,277.84
	Total of Payments Set Forth Above		**$ 300,612,376**
	1/ This schedule includes payments for professional services over $75,000.		Schedule 12C

Sch. 13 POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS

Description	Total Company	Montana	% Montana
There are three employee political action committees (PAC)s:			
a. NorthWestern Energy Montana Employee PAC for Montana employees;			
b. Employees of NorthWestern Corporation (NorthWestern Energy) PAC for South Dakota employees;			
c. NorthWestern Public Service Employees PAC for Nebraska employees.			
All of the money contributed by members is dedicated to support political candidates, state and local political party organizations, and ballot issues. No company funds may be spent in support of a political candidate. Nominal administrative costs for such things as duplicating, postage, and meeting expenses are paid by the company as provided by law. These costs are charged to shareholder expense.			
TOTAL Contributions	$ -	$ -	0.00%

Sch. 14	**Pension Costs** 1/			
1	Plan Name: NorthWestern Energy Pension Plan			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Projected Unit Credit	IRS Code: ________________________		
4	Annual Contribution by Employer: Variable	Is the Plan Over Funded? No		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year	$ 757,399,423	$ 675,493,587	12.13%
8	Service cost	12,104,357	10,239,856	18.21%
9	Interest cost	17,383,148	21,063,387	-17.47%
10	Plan participants' contributions	-	-	-
11	Amendments	-	-	-
12	Actuarial (gain) loss	(26,749,118)	79,799,204	-133.52%
13	Settlements	(93,487,667)	-	-
14	Benefits paid	(30,378,468)	(29,196,611)	-4.05%
15	Benefit obligation at end of year	$ 636,271,675	$ 757,399,423	-15.99%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 619,075,010	$ 545,796,194	13.43%
18	Actual return on plan assets	33,662,299	92,274,164	-63.52%
19	Settlements	(93,487,667)	-	-
20	Employer contribution	9,000,000	10,201,263	-11.78%
21	Plan participants' contributions	-	-	-
22	Benefits paid	(30,378,468)	(29,196,611)	-4.05%
23	Fair value of plan assets at end of year	$ 537,871,174	$ 619,075,010	-13.12%
24	**Funded Status**	$ (98,400,501)	$ (138,324,413)	28.86%
26	Unrecognized net actuarial gain (loss)	-	-	-
27	Unrecognized prior service cost	-	-	-
29	Prepaid (accrued) benefit cost	$ (98,400,501)	$ (138,324,413)	28.86%
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	2.75%	2.30%	19.57%
32	Expected return on plan assets	4.17%	4.49%	-7.13%
33	Rate of compensation increase	1.00% Union & 2.67% Non-Union	1.00% Union & 2.67% Non-Union	0.00%
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	$ 12,104,357	$ 10,239,856	18.21%
36	Interest cost	17,383,148	21,063,387	-17.47%
37	Expected return on plan assets	(25,006,749)	(24,029,522)	-4.07%
38	Settlement (gain) loss recognized	11,291,216	-	-
39	Recognized net actuarial gain	6,535,904	5,027,792	30.00%
40	Net periodic benefit cost (SEC Basis)	$ 22,307,876	$ 12,301,513	81.34%
41	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
42	Pension Costs	$ 9,000,000	$ 10,201,263	-11.78%
43	Pension Costs Capitalized	2,222,709	2,515,102	-11.63%
44	Accumulated Pension Asset (Liability) at Year End	$ (98,400,501)	$ (138,324,413)	28.86%
45	Number of Company Employees:			
46	Covered by the Plan 2/	2,497	2,539	-1.65%
47	Not Covered by the Plan 2/	890	799	11.39%
48	Active	528	570	-7.37%
49	Retired	1,668	1,654	0.85%
50	Deferred Vested Terminated 2/	301	315	-4.44%

1/ NorthWestern Corporation has a separate pension plan covering South Dakota and Nebraska employees that is not reflected above.

2/This plan was closed to new entrants effective 10/03/08.

Sch. 14a	Pension Costs **1/**			
1	Plan Name: NorthWestern Energy 401k Retirement Savings Plan			
2	Defined Benefit Plan? No	Defined Contribution Plan? Yes		
3	Actuarial Cost Method? N/A	IRS Code: 401(k)		
4	Annual Contribution by Employer: Variable	Is the Plan Over Funded? N/A		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year			0.00%
8	Service cost			0.00%
9	Interest cost			0.00%
10	Plan participants' contributions	Not Applicable		
11	Amendments			0.00%
12	Actuarial loss			0.00%
13	Acquisition			0.00%
14	Benefits paid			0.00%
15	Benefit obligation at end of year	$ -	$ -	0.00%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 456,200,434	$ 413,343,235	-9.39%
18	Actual return on plan assets			0.00%
19	Acquisition			0.00%
20	Employer contribution 2/	$ 11,789,193	$ 11,118,667	6.03%
21	Plan participants' contributions			0.00%
22	Benefits paid			0.00%
23	Fair value of plan assets at end of year 2/	$ 492,289,539	$ 456,200,434	7.91%
24	**Funded Status**	Not Applicable		
25	Unrecognized net actuarial loss		0	0.00%
26	Unrecognized prior service cost		0	0.00%
27	Prepaid (accrued) benefit cost	$ -	$ -	0
28				
29	**Weighted-average Assumptions as of Year End**	Not Applicable		
30	Discount rate		0.00%	0.00%
31	Expected return on plan assets		0.00%	0.00%
32	Rate of compensation increase		0.00%	0.00%
33				
34	**Components of Net Periodic Benefit Costs**	Not Applicable		
35	Service cost			0.00%
36	Interest cost			0.00%
37	Expected return on plan assets			0.00%
38	Amortization of prior service cost			0.00%
39	Recognized net actuarial loss			0.00%
40	Net periodic benefit cost (SEC Basis)	$ -	$ -	0
41				
42	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
43	401(k) Plan Defined Contribution Costs	$ 9,118,650	$ 8,506,877	7.19%
44	401(k) Plan Defined Contribution Costs Capitalized	2,252,012	2,097,355	7.37%
45	Accumulated Pension Asset (Liability) at Year End	Not Applicable		
46	**Number of Company Employees:**	3/	3/	
47	Covered by the Plan - Eligible	1,494	1,538	-2.86%
48	Not Covered by the Plan		0	0.00%
49	Active - Participating	1,475	1,527	-3.41%
50	Retired		0	0.00%
51	Vested Former Employees, Retirees and Active-	372	312	19.23%
52	Noncontributing			

2/ This plan covers all NorthWestern Corporation employees.
3/ Represents total company 401(k) plan participants.

Sch. 15	**Other Post Employment Benefits (OPEBS)**			
	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number: D2018.2.12			
4	Order number: 7604U			
5	Amount recovered through rates	($1,560,428)	($1,399,829)	-11.47%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	2.40%	1.80%	33.33%
8	Expected return on plan assets	4.08%	4.71%	-13.38%
9	Medical Cost Inflation Rate 3/	5.00% fixed rate annually	5.00% fixed rate annually	
10	Actuarial Cost Method	Method Allocated from the Date of Hire		
11	Rate of compensation increase	1.00% Union & 2.67% Non-Union	1.00% Union & 2.67% Non-Union	
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	**Union Employees - VEBA - Yes, tax advantaged**			
14	**Non-Union Employees - 401(h) - Yes, tax advantaged**			
15	Describe any Changes to the Benefit Plan:			
16	Bargaining employees of the Hydro generation facility are first reflected in the the determination of expense for			

1/ Obtained from NorthWestern Energy-Montana's 2021 FASB 106 Valuation. Assumptions and data are as of December 31, 2021.

2/ Obtained from NorthWestern Energy-Montana's 2020 FASB 106 Valuation. Assumptions and data are as of December 31, 2020.

3/ First Year, Ultimate, Years to Reach Ultimate.

Sch. 15a	Other Post Employment Benefits (OPEBS) (continued)			
	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan			0.00%
3	Not Covered by the Plan			0.00%
4	Active			0.00%
5	Retired			0.00%
6	Spouses/Dependants covered by the Plan			0.00%
7	**Montana 4/**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year	$15,771,574	$14,641,862	7.72%
10	Service cost	356,316	318,337	11.93%
11	Interest Cost	279,258	435,820	-35.92%
12	Plan participants' contributions	1,043,792	920,456	13.40%
13	Amendments	-	-	-
14	Actuarial loss/(gain)	566,496	2,496,048	-77.30%
15	Acquisition	-	-	-
16	Benefits paid	(3,727,430)	(3,040,949)	-22.57%
17	Benefit obligation at end of year	$14,290,006	$15,771,574	-9.39%
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	$23,095,215	$21,479,179	7.52%
20	Actual return on plan assets	3,349,308	2,723,057	23.00%
21	Acquisition	-	-	-
22	Employer contribution	1,528,139	1,013,472	50.78%
23	Plan participants' contributions	1,043,792	920,456	13.40%
24	Benefits paid	(3,727,430)	(3,040,949)	-22.57%
25	Fair value of plan assets at end of year	$25,289,024	$23,095,215	9.50%
26	**Funded Status**	$10,999,018	$7,323,641	50.19%
27	Unrecognized net transition (asset)/obligation	-	-	-
28	Unrecognized net actuarial loss/(gain)	-	-	-
29	Unrecognized prior service cost	-	-	-
30	Prepaid (accrued) benefit cost	$10,999,018	$7,323,641	50.19%
31	**Components of Net Periodic Benefit Costs**			
32	Service cost	$356,316	$318,337	11.93%
33	Interest cost	279,258	435,820	-35.92%
34	Expected return on plan assets	(919,362)	(982,650)	6.44%
35	Amortization of transitional (asset)/obligation	-	-	-
36	Amortization of prior service cost	(1,986,424)	(2,032,850)	2.28%
37	Recognized net actuarial loss/(gain)	-	-	-
38	Net periodic benefit cost	($2,270,212)	($2,261,343)	-0.39%
39	**Accumulated Post Retirement Benefit Obligation**			
40	Amount Funded through VEBA	$ -	$ -	-
41	Amount Funded through 401(h)	-	-	-
42	Amount Funded through other - Company funds	1,528,139	1,013,472	50.78%
43	TOTAL	$1,528,139	$1,013,472	50.78%
44	Amount that was tax deductible - VEBA	$ -	$ -	-
45	Amount that was tax deductible - 401(h)	-	-	-
46	Amount that was tax deductible - Other	(1,560,428)	(1,399,829)	-11.47%
47	TOTAL	($1,560,428)	($1,399,829)	-11.47%
48	**Montana Intrastate Costs:**			
49	Pension Costs	($1,560,428)	($1,399,829)	-11.47%
50	Pension Costs Capitalized	($385,375)	($345,125)	-11.66%
51	Accumulated Pension Asset (Liability) at Year End	$10,999,018	$7,323,641	50.19%
52	**Number of Montana Employees:**			
53	Covered by the Plan	1,357	1,444	-6.02%
54	Not Covered by the Plan	1,996	1,940	2.89%
55	Active	503	545	-7.71%
56	Retired	776	812	-4.43%
57	Spouses/Dependants covered by the Plan	78	87	-10.34%
	4/ There is approximately an additional $3,017,963 and $3,374,035 in other company OPEBS liabilities outstanding at December 31, 2021 and 2020, respectively for other supplemental retirement agreements in addition to what is reflected for Montana above.			

SCHEDULE 16

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Note: This schedule includes the ten most highly compensated employees assigned or allocated to Montana that are not already included on Sch 17.

Line No.	Name/Title	Base Salary 1/	Bonuses 2/	Other 3/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation 4/
1	John D. Hines Vice President, Supply & Montana Government Affairs	305,021	129,830 A	34,166 B 227,164 C 45,614 D 5,221 E	747,016	833,548	-10.4%
	Bobbi L. Schroeppel Vice President, Customer Care, Communications & Human Resources	300,832	128,048 A	54,834 B 224,045 C 1,509 D	709,268	691,652	2.5%
3	Michael R. Cashell Vice President, Transmission	299,523	127,490 A	30,944 B 223,070 C 0 D 6,196 E	687,223	1,010,716	-32.0%
4	Jeanne M. Vold Vice President, Technology	246,398	106,000 A	46,418 B 150,000 C 5,430 D 6,096 E 2,776 F	563,118	373,727	50.7%
5	Michael L. Nieman Chief Audit and Compliance Officer	246,138	65,521 A	58,238 B 60,750 C 0 D 1,227 E	431,874	455,201	-5.1%
6	Daniel L. Rausch Treasurer	238,892	64,105 A	55,851 B 57,596 C 2,536 D 8,307 E	427,287	426,027	0.3%
7	Jeffrey B. Berzina Controller	222,981	59,625 A	48,551 B 52,501 C	383,658		
8	Jason Merkel General Manager, Operations & Construction	210,798	56,078 A	34,665 B 52,122 C 0 D 2,406 E	356,069	646,587	-44.9%
9	Bleau J. LaFave Director, Long-Term Resources	192,554	44,520 A	48,309 B 36,712 C 0 D 7,942 E	330,037	337,076	-2.1%
10	Timothy P. Olson Corporate Counsel & Corporate Secretary	195,104	41,522 A	46,648 B 38,593 C	321,867	313,141	2.8%

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary 1/	Bonuses 2/	Other 3/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation 4/

1/ Base pay in 2021 reflects the results of 26 pay periods. There were 27 pay periods in 2020.

2/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2021 Annual Incentive Compensation Plan. Amounts were earned in 2021 and paid in the first quarter of 2022. Based on company

on a 2017 test period.

3/ All Other Compensation for named employees consists of the following:

B> Employer contributions to benefits generally available to all employees on a nondiscriminatory basis - medical, dental, vision, employee assistance program, group term life, health savings account, wellness incentive, 401(k) match, and non-elective 401(k) contribution, as applicable.

C> Values reflect the grant date fair value for performance stock awards. Stock based compensation is not included in rate recovery.

D> Change in pension value over previous year. The present value of accumulated benefits was calculated assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2021.

E> Vacation sold back during the year at 75 percent of the rate of pay at the time of sellback.

4/ % Increase Total Compensation includes the actuarial change in pension value. Excluding the change in pension value, individual compensation changed as follows:

Hines	15.7%	Rausch	7.3%
Schroeppel	8.5%	Berzina	
Cashell	11.5%	Merkel	5.0%
Vold	60.1%	Lafave	6.3%
Nieman	3.7%	Olson	2.8%

SCHEDULE 17

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Note: This schedule contains the five most highly compensated corporate officers who are assigned or allocated to Montana.

Line No.	Name/Title	Base Salary 1/	Bonuses 2/	Other 3/	Total Compensation 4/	Total Compensation Reported Last Year	% Increase Total Compensation 5/
1	Robert C. Rowe Chief Executive Officer	674,138	717,359 A	40,921 B 1,906,246 C 77,372 D 29,331 E	3,445,367	3,102,048	11.1%
2	Brian B. Bird President & Chief Operating Officer	494,774	397,500 A	58,615 B 850,000 C 8,196 D 2,776 F 766 G	1,812,627	1,331,564	36.1%
3	Heather H. Grahame General Counsel & Vice President, Regulatory & Federal Government Affairs	439,769	257,380 A	52,981 B 501,825 C 182 E	1,252,137	1,148,498	9.0%
4	Crystal D. Lail Vice President, Chief Financial Officer	362,307	198,750 A	41,737 B 431,250 C 1,954 D 6,680 E 2,776 F	1,045,454	597,855	74.9%
5	Curtis T. Pohl Vice President, Distribution	316,847	134,864 A	55,003 B 251,640 C 2,553 D 2,516 E	763,423	770,427	-0.9%

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary 1/	Bonuses 2/	Other 3/	Total Compensation 4/	Total Compensation Reported Last Year	% Increase Total Compensation 5/

1/ Base pay in 2021 reflects the results of 26 pay periods. There were 27 pay periods in 2020.

2/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2021 Annual Incentive Compensation Plan. Amounts were earned in 2021 and paid in the first quarter of 2022. Based on company

on a 2017 test period.

3/ All Other Compensation for named employees consists of the following:

B> Employer contributions to benefits generally available to all employees on a nondiscriminatory basis - medical, dental, vision, employee assistance program, group term life, health savings account, wellness incentive, 401(k) match, and non-elective 401(k) contribution, as applicable.

C> Values reflect the grant date fair value for performance stock awards. Stock based compensation is not included in rate recovery.

D> Change in pension value over previous year. The present value of accumulated benefits was calculated assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2021.

E> Vacation sold back during the year at 75 percent of the rate of pay at the time of sellback.

F> Value of executive physical examination and associated tax gross-up.

G> Imputed income - facilities

4/ Stock-based compensation is paid by shareholders.

Recovery of non-stock-based compensation is based on 2017 ("test year") costs, which are reviewed by the Montana Consumer Counsel, other parties, and MPSC staff. There is no specific recovery of these or most other expenses.

Shareholders vote on executive compensation, and have consistently approved at above 96%, most recently 98.7%.

Our Chief Executive Officer's compensation is 79% at-risk. Overall executive compensation is discussed in the Compensation Disclosure and Analysis section of our annual Proxy Statement.

5/ % Increase Total Compensation includes the actuarial change in pension value. Excluding the change in pension value, individual compensation changed as follows:

Rowe	14.7%
Bird	38.5%
Grahame	9.0%
Lail	85.6%
Pohl	5.9%

Sch. 18	BALANCE SHEET 1/				
	Account Title	This Year	Last Year	Variance	% Change
1	**Assets and Other Debits**				
2	**Utility Plant**				
3	101 Plant in Service	$6,684,746,970	$6,398,242,253	$286,504,717	4.48%
4	101.1 Property Under Capital Leases	42,280,372	43,061,890	(781,518)	-1.81%
5	103 Experimental Electric Plant Unclassified	4,092,785	2,928,663	1,164,122	39.75%
6	105 Plant Held for Future Use	5,492,985	5,499,197	(6,212)	-0.11%
7	107 Construction Work in Progress	284,729,122	166,454,010	$118,275,112	71.06%
8	108 Accumulated Depreciation Reserve	(2,475,484,210)	(2,365,692,029)	($109,792,181)	4.64%
9	108.1 Accumulated Depreciation - Capital Leases	(31,162,371)	(29,151,894)	($2,010,477)	6.90%
10	111 Accumulated Amortization & Depletion Reserves	(94,343,642)	(89,972,714)	($4,370,928)	4.86%
11	114 Electric Plant Acquisition Adjustments	481,574,396	481,574,396	-	0.00%
12	115 Accumulated Amortization-Electric Plant Acq. Adj.	(71,878,462)	(61,628,544)	(10,249,918)	16.63%
13	116 Utility Plant Adjustments	357,585,527	357,585,527	-	0.00%
14	117 Gas Stored Underground-Noncurrent	36,190,017	36,196,864	(6,847)	-0.02%
15	**Total Utility Plant**	5,223,823,489	4,945,097,619	278,725,870	5.64%
16	**Other Property and Investments**				
17	121 Nonutility Property	686,805	686,805	-	0.00%
18	122 Accumulated Depr. & Amort.-Nonutilility Property	(29,270)	(29,180)	(90)	0.31%
19	123.1 Investments in Assoc Companies and Subsidiaries	(114,137,258)	(118,287,100)	4,149,842	-3.51%
20	124 Other Investments	20,451,942	45,234,617	(24,782,675)	-54.79%
21	128 Miscellaneous Special Funds	-	250,000	(250,000)	-100.00%
22	LT Portion of Derivative Assets - Hedges	-	-	-	-
23	**Total Other Property & Investments**	(93,027,781)	(72,144,858)	(20,882,923)	28.95%
24	**Current and Accrued Assets**				
25	131 Cash	2,376,145	5,600,771	(3,224,626)	-57.57%
26	134 Other Special Deposits	14,658,170	9,670,292	4,987,878	51.58%
27	135 Working Funds	23,250	22,950	300	1.31%
28	142 Customer Accounts Receivable	86,846,850	73,728,730	13,118,120	17.79%
29	143 Other Accounts Receivable	8,867,792	14,106,165	(5,238,373)	-37.14%
30	144 Accumulated Provision for Uncollectible Accounts	(2,319,115)	(5,609,532)	3,290,417	-58.66%
31	146 Accounts Receivable-Associated Companies	2,818,214	1,752,345	1,065,869	60.83%
32	151 Fuel Stock	7,509,623	6,561,464	948,159	14.45%
33	154 Plant Materials and Operating Supplies	53,538,725	43,691,819	9,846,906	22.54%
34	164 Gas Stored - Current	18,828,613	10,010,097	8,818,516	88.10%
35	165 Prepayments	20,500,469	15,375,451	5,125,018	33.33%
36	172 Rents Receivable	54,488	49,263	5,225	10.61%
37	173 Accrued Utility Revenues	98,149,252	80,492,128	17,657,124	21.94%
38	174 Miscellaneous Current & Accrued Assets	258,106	194,030	64,076	33.02%
39	**Total Current & Accrued Assets**	312,110,582	255,645,973	56,464,609	22.09%
40	**Deferred Debits**				
41	181 Unamortized Debt Expense	11,120,970	13,376,263	(2,255,293)	-16.86%
42	182 Regulatory Assets	685,148,784	712,384,890	(27,236,106)	-3.82%
43	183 Preliminary Survey and Investigation Charges	-	2,286,180	(2,286,180)	-100.00%
44	184 Clearing Accounts	4,169	3,635	534	14.69%
45	186 Miscellaneous Deferred Debits	8,619,588	7,565,277	1,054,311	13.94%
46	189 Unamortized Loss on Reacquired Debt	25,635,857	28,350,312	(2,714,455)	-9.57%
47	190 Accumulated Deferred Income Taxes	160,914,104	178,891,654	(17,977,550)	-10.05%
48	191 Unrecovered Purchased Gas Costs	94,663,379	5,905,571	88,757,808	>300.00%
49	**Total Deferred Debits**	986,106,851	948,763,782	37,343,069	3.94%
50	**TOTAL ASSETS and OTHER DEBITS**	$ 6,429,013,141	$ 6,077,362,516	$ 351,650,625	5.79%

Sch. 18	cont. **BALANCE SHEET 1/**				
	Account Title	This Year	Last Year	Variance	% Change
1	**Liabilities and Other Credits**				
2	**Proprietary Capital**				
3	201 Common Stock Issued	$ 576,063	$ 541,448	$ 34,615	6.39%
4	211 Miscellaneous Paid-In Capital	1,716,226,995	1,513,785,478	202,441,517	13.37%
5	216 Unappropriated Retained Earnings	726,326,379	667,969,228	58,357,151	8.74%
6	217 Reacquired Capital Stock	(98,248,245)	(98,075,421)	(172,824)	0.18%
7	219 Accumulated Other Comprehensive Income	(5,167,596)	(5,126,145)	(41,451)	0.81%
8	**Total Proprietary Capital**	2,339,713,596	2,079,094,588	260,619,008	12.54%
9	**Long Term Debt**				
10	221 Bonds	2,179,660,000	2,079,660,000	100,000,000	4.81%
11	224 Other Long Term Debt	373,000,000	248,976,900	124,023,100	49.81%
12	226 (Less) Unamortized Discount on Long Term Debt-Debit	61,389	-	61,389	-
13	**Total Long Term Debt**	2,552,598,611	2,328,636,900	223,961,711	9.62%
14	**Other Noncurrent Liabilities**				
15	227 Obligations Under Capital Leases-Noncurrent	12,829,411	16,379,639	(3,550,228)	-21.67%
16	228.2 Accumulated Provision for Injuries and Damages	7,061,829	6,050,644	1,011,185	16.71%
17	228.3 Accumulated Provision for Pensions and Benefits	6,434,213	10,240,902	(3,806,689)	-37.17%
18	228.4 Accumulated Miscellaneous Operating Provisions	88,530,057	106,746,764	(18,216,707)	-17.07%
19	229 Accumulated Provision for Rate Refunds	-	10,712,124	(10,712,124)	-100.00%
20	230 Asset Retirement Obligations	40,747,410	45,355,157	(4,607,747)	-10.16%
21	**Total Other Noncurrent Liabilities**	155,602,920	195,485,230	(39,882,310)	-20.40%
22	**Current and Accrued Liabilities**				
23	231 Notes Payable	-	100,000,000	(100,000,000)	-100.00%
24	232 Accounts Payable	120,452,816	104,724,988	15,727,828	15.02%
25	234 Accounts Payable to Associated Companies	1,837,642	1,775,914	61,728	3.48%
26	235 Customer Deposits	8,573,478	6,000,316	2,573,162	42.88%
27	236 Taxes Accrued	45,815,514	61,045,637	(15,230,123)	-24.95%
28	237 Interest Accrued	18,567,598	18,073,738	493,860	2.73%
29	241 Tax Collections Payable	2,178,547	1,432,362	746,185	52.09%
30	242 Miscellaneous Current and Accrued Liabilities	63,691,699	75,300,722	(11,609,023)	-15.42%
31	243 Obligations Under Capital Leases-Current	4,012,828	3,912,103	100,725	2.57%
32	**Total Current and Accrued Liabilities**	265,130,122	372,265,780	(107,135,658)	-28.78%
33	**Deferred Credits**				
34	252 Customer Advances for Construction	80,779,904	65,186,426	15,593,478	23.92%
35	253 Other Deferred Credits	173,125,630	199,645,159	(26,519,529)	-13.28%
36	254 Regulatory Liabilities	185,656,769	187,832,431	(2,175,662)	-1.16%
37	255 Accumulated Deferred Investment Tax Credits	517,968	278,674	239,294	85.87%
38	281-283 Accumulated Deferred Income Taxes	675,887,621	648,937,328	26,950,293	4.15%
39	**Total Deferred Credits**	1,115,967,892	1,101,880,018	14,087,874	1.28%
40	**TOTAL LIABILITIES and OTHER CREDITS**	$ 6,429,013,141	$ 6,077,362,516	$ 351,650,625	5.79%
41					
42	1/ This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory				
43	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the				
44	equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian				
45	Montana Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4.				
46					
47					
48					
49					
50					Schedule 18A

NOTES TO FINANCIAL STATEMENTS

(1) Nature of Operations and Basis of Consolidation

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and / or natural gas to approximately 753,600 customers in Montana, South Dakota, Nebraska and Yellowstone National Park. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have generated and distributed electricity and distributed natural gas in Montana since 2002.

The Financial Statements for the periods included herein have been prepared by NorthWestern Corporation (NorthWestern, we or us), pursuant to the rules and regulations of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases. The preparation of financial statements in conformity with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases requires management to make estimates and assumptions that may affect the reported amounts of assets, liabilities, revenues and expenses during the reporting period. Actual results could differ from those estimates.

(2) Significant Accounting Policies

Financial Statement Presentation

The financial statements are presented on the basis of the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than GAAP. This report differs from GAAP due to FERC requiring the presentation of subsidiaries on the equity method of accounting, which differs from Accounting Standards Codification (ASC) 810, Consolidation. ASC 810 requires that all majority-owned subsidiaries be consolidated (see Note 4). The other significant differences consist of the following:

- Earnings per share and footnotes for revenue from contracts with customers, segment and related information, and quarterly financial data (unaudited) are not presented;
- Removal and decommissioning costs of generation, transmission and distribution assets are reflected in the Balance Sheets as a component of accumulated depreciation of $479.3 million and $464.7 million as of December 31, 2021 and December 31, 2020, respectively, in accordance with regulatory treatment as compared to regulatory liabilities for GAAP purposes;
- Goodwill is reflected in the Balance Sheets as a utility plant adjustments of $357.6 million as of December 31, 2021 and December 31, 2020, respectively, in accordance with regulatory treatment, as compared to goodwill for GAAP purposes (see Note 8);
- The write-down of plant values associated with the 2002 acquisition of the Montana operations is reflected in the Balance Sheets as a component of accumulated depreciation of $147.6 million for December 31, 2021 and December 31, 2020, respectively, in accordance with regulatory treatment as compared to plant for GAAP purposes;

- The current portion of gas stored underground is reflected in the Balance Sheets as current and accrued assets, as compared to inventory for GAAP purposes;
- Operating lease right of use assets are reflected in the Balance Sheets as capital leases of $2.1 million and $2.9 million as of December 31, 2021 and December 31, 2020, respectfully, in accordance with regulatory treatment, as compared to non-current assets for GAAP purposes;
- Operating lease liabilities are reflected in the Balance Sheets as current and long term obligations under capital leases of $2.1 million and $2.9 million as of December 31, 2021 and December 31, 2020, respectfully, in accordance with regulatory treatment, as compared to accrued expenses and long term liabilities for GAAP purposes;
- Unamortized debt expense is classified in the Balance Sheets as deferred debits in accordance with regulatory treatment, as compared to long-term debt for GAAP purposes;
- Current and long-term debt is classified in the Balance Sheets as all long-term debt in accordance with regulatory treatment, while current and long-term debt are presented separately for GAAP reporting;
- The current portion of the provision for injuries and damages and the expected insurance proceeds receivable related to the provision for injuries and damages are reported as a current liability for GAAP purposes, as compared to a non-current liability for FERC purposes;
- Accumulated deferred tax assets and liabilities are classified in the Balance Sheets as gross non-current deferred debits and credits, respectively, while GAAP presentation reflects a net non-current deferred tax liability;
- Stranded tax effects associated with the Tax Cuts and Jobs Act are included in accumulated other comprehensive income (AOCI) in accordance with regulatory treatment, while included in retained earnings for GAAP purposes;
- Uncertain tax positions related to temporary differences are classified in the Balance Sheets within the deferred tax accounts in accordance with regulatory treatment, as compared to other noncurrent liabilities for GAAP purposes. In addition, interest related to uncertain tax positions is recognized in interest expense in accordance with regulatory treatment, as compared to income tax expense for GAAP purposes;
- Net periodic benefit costs and net periodic post retirement benefit costs are reflected in operating expense for FERC purposes, as compared to the GAAP presentation, which reflects the current service costs component of the net periodic benefit costs in operating expenses and the other components outside of income from operations. In addition, only the service cost component of net periodic benefit cost is eligible for capitalization for GAAP purposes, as compared to the total net periodic benefit costs for FERC purposes;
- Regulatory assets and liabilities are reflected in the Balance Sheets as non-current items, while current and non-current amounts are presented separately for GAAP;
- Unbilled revenue is reflected in the Balance Sheets in Accrued utility revenues in accordance with regulatory treatment, as compared to Accounts receivable, net for GAAP purposes;
- Implementation costs associated with cloud computing arrangements are reflected on the Balance Sheets as Miscellaneous Intangible Plant in accordance with regulatory treatment, as compared to Other current assets for GAAP purposes. Additionally, these cash outflows are presented within investing activities cash outflows in the Statement of

Cash Flows in accordance with regulatory treatment, as compared to operating activities cash outflows for GAAP purposes; and

- GAAP revenue differs from FERC revenue primarily due to the equity method of accounting as discussed above, netting of electric purchases and sales for resale in revenue for the GAAP presentation as compared to a gross presentation for FERC purposes (with the exception of those transactions in a regional transmission organization (RTO)), the netting of RTO transmission transactions for the GAAP presentation as compared to a gross presentation for FERC purposes, and the classification of regulatory amortizations in revenue for GAAP purposes as compared to expense for FERC purposes.

Use of Estimates

The preparation of financial statements in conformity with the regulatory basis of accounting requires us 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 and the reported amounts of revenues and expenses during the reporting period. Estimates are used for such items as long-lived asset values and impairment charges, long-lived asset useful lives, tax provisions, uncertain tax position reserves, asset retirement obligations, regulatory assets and liabilities, allowances for uncollectible accounts, our Qualifying Facilities liability, environmental liabilities, unbilled revenues and actuarially determined benefit costs and liabilities. We revise the recorded estimates when we receive better information or when we can determine actual amounts. Those revisions can affect operating results.

Revenue Recognition

The Company recognizes revenue as customers obtain control of promised goods and services in an amount that reflects consideration expected in exchange for those goods or services. Generally, the delivery of electricity and natural gas results in the transfer of control to customers at the time the commodity is delivered and the amount of revenue recognized is equal to the amount billed to each customer, including estimated volumes delivered when billings have not yet occurred.

Cash Equivalents

We consider all highly liquid investments with maturities of three months or less at the time of purchase to be cash equivalents.

Accounts Receivable, Net

Accounts receivable are net of allowances for uncollectible accounts of $2.3 million and $5.6 million at December 31, 2021 and December 31, 2020. Unbilled revenues were $98.1 million and $80.5 million at December 31, 2021 and December 31, 2020, respectively.

Inventories

Inventories are stated at average cost. Inventory consisted of the following (in thousands):

	December 31,	
	2021	2020
Fuel stock	$ 7,510	$ 6,561
Plant materials and operating supplies	53,539	43,692
Gas stored underground (including the non-current portion reflected in utility plant)	55,019	46,207
Total Inventories	$ 116,068	$ 96,460

Regulation of Utility Operations

Our regulated operations are subject to the provisions of ASC 980, Regulated Operations. Regulated accounting is appropriate provided that (i) rates are established by or subject to approval by independent, third-party regulators, (ii) rates are designed to recover the specific enterprise's cost of service, and (iii) in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be charged to and collected from customers.

Our Financial Statements reflect the effects of the different rate making principles followed by the jurisdictions regulating us. The economic effects of regulation can result in regulated companies recording costs that have been, or are deemed probable to be, allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as regulatory assets and recorded as expenses in the periods when those same amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (Accumulated Provision for Rate Refunds).

If we were required to terminate the application of these provisions to our regulated operations, all such deferred amounts would be recognized in the Statements of Income at that time. This would result in a charge to earnings and AOCI, net of applicable income taxes, which could be material. In addition, we would determine any impairment to the carrying costs of deregulated plant and inventory assets.

Derivative Financial Instruments

We account for derivative instruments in accordance with ASC 815, Derivatives and Hedging. All derivatives are recognized in the Balance Sheets at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair-value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash-flow hedge). For fair-value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash-flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in AOCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For other derivative contracts that do not qualify or are not designated for hedge accounting, changes in the fair value of the derivatives are recognized in earnings each period. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Statements of Cash Flows, depending on the underlying nature of the hedged items.

Revenues and expenses on contracts that are designated as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but on an accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time, and price is not tied to an unrelated underlying derivative. As part of our regulated electric and gas operations, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the exceptions, the fair value of the related contract would be reflected as an asset or liability and immediately recognized through earnings. See Note 9 - Risk Management and Hedging Activities, for further discussion of our derivative activity.

Utility Plant

Utility plant stated at original cost, including contracted services, direct labor and material, allowance for funds used during construction (AFUDC), and indirect charges for engineering, supervision and similar overhead items. All expenditures for maintenance and repairs of utility plant are charged to the appropriate maintenance expense accounts. A betterment or replacement of a unit of property is accounted for as an addition and retirement of utility plant. At the time of such a retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal. Also included in plant and equipment are assets under finance lease, which are stated at the present value of minimum lease payments.

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to net interest charges, while the equity component is included in other income. This rate averaged 6.6% and 6.7% for Montana for 2021 and 2020, respectively. This rate averaged 6.4% and 6.7% for South Dakota for 2021 and 2020, respectively. AFUDC capitalized totaled $15.9 million and $9.8 million for the years ended December 31, 2021 and 2020, respectively, for Montana and South Dakota combined.

We record provisions for depreciation at amounts substantially equivalent to calculations made on a straight-line method by applying various rates based on useful lives of the various classes of properties (ranging from 2 to 96 years) determined from engineering studies. As a percentage of the depreciable utility plant at the beginning of the year, our provision for depreciation of utility plant was approximately 2.8% for 2021 and 2020.

Depreciation rates include a provision for our share of the estimated costs to decommission our jointly owned plants at the end of the useful life. The annual provision for such costs is included in depreciation expense, while the accumulated provisions are included in accumulated depreciation.

Pension and Postretirement Benefits

We have liabilities under defined benefit retirement plans and a postretirement plan that offers certain health care and life insurance benefits to eligible employees and their dependents. The costs of these plans are dependent upon numerous factors, assumptions and estimates, including determination of discount rate, expected return on plan assets, rate of future compensation increases, age and mortality and employment periods. In determining the projected benefit obligations and costs, assumptions can change from period to period and may result in material changes in the cost and liabilities we recognize.

Income Taxes

We follow the liability method in accounting for income taxes. Deferred income tax assets and liabilities represent the future effects on income taxes from temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to reverse. The probability of realizing deferred tax assets is based on forecasts of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. We establish a valuation allowance when it is more likely than not that all, or a portion of, a deferred tax asset will not be realized.

Exposures exist related to various tax filing positions, which may require an extended period of time to resolve and may result in income tax adjustments by taxing authorities. We have reduced deferred tax assets or established liabilities based on our best estimate of future probable adjustments related to these exposures. On a quarterly basis, we evaluate exposures in light of any additional information and make adjustments as necessary to reflect the best estimate of the future outcomes. We believe our deferred tax assets and established liabilities are appropriate for estimated exposures; however, actual results may differ from these estimates. The resolution of tax matters in a particular future period could have a material impact on our Statements of Income and provision for income taxes.

Environmental Costs

We record environmental costs when it is probable we are liable for the costs and we can reasonably estimate the liability. We may defer costs as a regulatory asset if there is precedent for recovering similar costs from customers in rates. Otherwise, we expense the costs. If an environmental cost is related to facilities we currently use, such as pollution control equipment, then we may capitalize and depreciate the costs over the remaining life of the asset, assuming the costs are recoverable in future rates or future cash flows.

Our remediation cost estimates are based on the use of an environmental consultant, our experience, our assessment of the current situation and the technology currently available for use in the remediation. We regularly adjust the recorded costs as we revise estimates and as remediation proceeds. If we are one of several designated responsible parties, then we estimate and record only our share of the cost.

Supplemental Cash Flow Information

	Year Ended December 31,	
	2021	2020
	(in thousands)	
Cash paid (received) for:		
Income taxes	$ 4,330	$ 115
Interest	87,221	84,922
Significant non-cash transactions:		
Capital expenditures included in trade accounts payable	29,034	21,430
NMTC debt extinguishment included in other noncurrent assets[(1)]	18,169	
NMTC debt extinguishment included in utility plant[(1)]	6,594	
NMTC debt extinguishment included in long-term debt[(1)]	1,259	

(1) See Note 12 - Long-Term Debt for further information regarding these non-cash transactions.

The following table provides a reconciliation of cash, working funds, other special funds, and special deposits reported within the Balance Sheets that sum to the total of the same such amounts shown in the Statements of Cash Flows (in thousands):

	December 31,	
	2021	2020
Cash	$ 2,377	$ 5,601
Working funds	23	23
Other special funds	—	250
Special deposits	14,658	9,670
Total shown in the Statement of Cash Flows	$ 17,058	$ 15,554

Other special funds and special deposits consist primarily of funds held in trust accounts to satisfy the requirements of certain stipulation agreements and insurance reserve requirements.

Accounting Standards Issued

At this time, we are not expecting the adoption of recently issued accounting standards to have a material impact to our financial condition, results of operations, and cash flows.

(3) Regulatory Matters

FERC Financial Audit

We are subject to FERC's jurisdiction and regulations with respect to rates for electric transmission service in interstate commerce and electricity sold at wholesale rates, the issuance of certain securities, and incurrence of certain long-term debt, among other things. The Division of Audits and Accounting in the Office of Enforcement of FERC initiated a routine audit of NorthWestern Corporation for the period of January 1, 2018 to the present to evaluate our compliance with FERC accounting and financial reporting requirements. We responded to several sets of data requests as part of the audit process and in April 2022 received a draft audit report from FERC. Based on review of the draft report, we believe final resolution of the identified audit findings and recommendations will not have a material financial impact on us.

(4) Equity Investments

The following table presents our equity investments reflected in the investments in subsidiary companies on the Balance Sheets (in thousands):

	December 31,	
	2021	2020
Colstrip Unit 4 Basis Adjustment	$ (133,648)	$ (137,401)
Havre Pipeline Company, LLC	12,130	13,219
NorthWestern Services, LLC	2,065	2,018
NorthWestern Energy Solutions, Inc.	4,126	2,629
Risk Partners Assurance, Ltd.	1,190	1,248
Total Investments in Subsidiary Companies	**$ (114,137)**	**$ (118,287)**

(5) Regulatory Assets and Liabilities

We prepare our Financial Statements in accordance with the provisions of ASC 980, as discussed in Note 2 - Significant Accounting Policies. Pursuant to this guidance, certain expenses and credits, normally reflected in income as incurred, are deferred and recognized when included in rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded based on management's assessment that it is probable that a cost will be recovered or that an obligation has been incurred. Accordingly, we have recorded the following major classifications of regulatory assets and liabilities that will be recognized in expenses and revenues in future periods when the matching revenues are collected or refunded. These regulatory items have corresponding assets and liabilities that will be paid for or refunded in future periods.

	Note Reference	Remaining Amortization Period	December 31, 2021	December 31, 2020
			(in thousands)	
Flow-through income taxes	14	Plant Lives	$ 464,664	$ 420,925
Pension	16	See Note 16	98,336	138,567
Excess deferred income taxes	14	Plant Lives	60,813	67,256
Employee related benefits	16	Various	21,648	22,516
State & local taxes & fees		Various	6,514	17,904
Environmental clean-up	19	Various	11,262	11,127
Other		Various	21,912	34,090
Total Regulatory Assets			**$ 685,149**	**$ 712,385**
Excess deferred income taxes	14	Plant Lives	158,047	165,434
Unbilled revenue		1 Year	16,430	12,072
Gas storage sales		19 years	7,466	7,887
State & local taxes & fees		1 Year	3,021	1,783
Environmental clean-up and other		Various	693	656
Total Regulatory Liabilities			**$ 185,657**	**$ 187,832**

Income Taxes

Flow-through income taxes primarily reflect the effects of plant related temporary differences such as flow-through of depreciation, repairs related deductions, and removal costs that we will recover or refund in future rates. We amortize these amounts as temporary differences reverse. Excess deferred income tax assets and liabilities are recorded as a result of the Tax Cuts and Jobs Act and will be recovered or refunded in future rates. See Note 14 - Income Taxes for further discussion.

Pension and Employee Related Benefits

We recognize the unfunded portion of plan benefit obligations in the Balance Sheets, which is remeasured at each year end, with a corresponding adjustment to regulatory assets/liabilities as the costs associated with these plans are recovered in rates. The MPSC allows recovery of pension costs on a cash funding basis. The portion of the regulatory asset related to our

Montana pension plan will amortize as cash funding amounts exceed accrual expense under GAAP. The SDPUC allows recovery of pension costs on an accrual basis. The MPSC allows recovery of postretirement benefit costs on an accrual basis.

State & Local Taxes & Fees (Montana Property Tax Tracker)

Under Montana law, we are allowed to track the changes in the actual level of state and local taxes and fees and recover the increase in rates, less the amount allocated to FERC jurisdictional customers and net of the related income tax benefit.

Environmental Clean-up

Environmental clean-up costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss the specific sites and clean-up requirements further in Note 19 - Commitments and Contingencies. Environmental clean-up costs are typically recoverable in customer rates when they are actually incurred. When cost projections become known and measurable, we coordinate with the appropriate regulatory authority to determine a recovery period.

Gas Storage Sales

A regulatory liability was established in 2000 and 2001 based on gains on cushion gas sales in Montana. This gain is being flowed to customers over a period that matches the depreciable life of surface facilities that were added to maintain deliverability from the field after the withdrawal of the gas. This regulatory liability is a reduction of rate base.

Unbilled Revenue

In accordance with regulatory guidance in South Dakota, we recognize revenue when it is billed. Accordingly, we record a regulatory liability to offset unbilled revenue.

(6) Utility Plant

The following table presents the major classifications of our net utility plant (in thousands):

	Estimated Useful Life	December 31,	
		2021	2020
		(in thousands)	
Land and improvements	53 – 96	$ 169,843	$ 165,620
Building and improvements	23 – 73	510,994	516,678
Storage, distribution, and transmission	15 – 95	4,115,327	3,881,961
Generation	23 – 72	2,038,965	2,003,072
Construction work in process	—	284,729	166,454
Other equipment	2 – 45	383,059	363,976
Total utility plant		7,502,917	7,097,760
Less accumulated depreciation		(2,672,869)	(2,546,445)
Net utility plant		$ 4,830,048	$ 4,551,315

Net utility plant under capital (finance) lease were $9.2 million and $11.3 million as of December 31, 2021 and 2020, respectively, which included $9.0 million and $11.1 million as of December 31, 2021 and 2020, respectively, related to a long-term power supply contract with the owners of a natural gas fired peaking plant, which has been accounted for as a finance lease.

Jointly Owned Electric Generating Plant

We have an ownership interest in four base-load electric generating plants, all of which are coal fired and operated by other companies. We have an undivided interest in these facilities and are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated. Our interest in each plant is reflected in the Balance Sheets on a pro rata basis and our share of operating expenses is reflected in the Statements of Income. The participants each finance their own investment.

Information relating to our ownership interest in these facilities is as follows (in thousands):

	Big Stone (SD)	Neal #4 (IA)	Coyote (ND)	Colstrip Unit 4 (MT)
December 31, 2021				
Ownership percentages	23.4 %	8.7 %	10.0 %	30.0 %
Plant in service	$ 154,375	$ 62,865	$ 51,652	$ 324,433
Accumulated depreciation	45,895	37,749	41,918	114,830
December 31, 2020				
Ownership percentages	23.4 %	8.7 %	10.0 %	30.0 %
Plant in service	$ 153,632	$ 62,927	$ 51,586	$ 317,438
Accumulated depreciation	44,329	37,000	41,402	106,679

(7) Asset Retirement Obligations

We are obligated to dispose of certain long-lived assets upon their abandonment. We recognize a liability for the legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event. We measure the liability at fair value when incurred and capitalize a corresponding amount as part of the book value of the related assets, which increases our utility plant and asset retirement obligations (ARO). The increase in the capitalized cost is included in determining depreciation expense over the estimated useful life of these assets. Since the fair value of the ARO is determined using a present value approach, accretion of the liability due to the passage of time is recognized each period and recorded as a regulatory asset until the settlement of the liability. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment. If the obligation is settled for an amount other than the carrying amount of the liability, we will recognize a regulatory asset or liability for the difference, which will be surcharged/refunded to customers through the rate making process. We record regulatory assets and liabilities for differences in timing of asset retirement costs recovered in rates and AROs recorded since asset retirement costs are recovered through rates charged to customers.

Our AROs relate to the reclamation and removal costs at our jointly-owned coal-fired generation facilities, U.S. Department of Transportation requirements to cut, purge and cap retired natural gas pipeline segments, our obligation to plug and abandon oil and gas wells at the end of their life, and to remove all above-ground wind power facilities and restore the soil surface at the end of their life. The following table presents the change in our ARO (in thousands):

	December 31,	
	2021	2020
Liability at January 1,	$ 45,355	$ 42,449
Accretion expense	2,233	2,070
Liabilities incurred	—	—
Liabilities settled	(2,906)	(4,061)
Revisions to cash flows	(3,935)	4,897
Liability at December 31,	$ 40,747	$ 45,355

During the twelve months ended December 31, 2021 our ARO liability decreased $2.9 million for partial settlement of the legal obligations at our jointly-owned coal-fired generation facilities. Additionally, during the twelve months ended December 31, 2021, our ARO liability decreased $4.1 million related to changes in both the timing and amount of retirement cost estimates.

In addition, we have identified removal liabilities related to our electric and natural gas transmission and distribution assets that have been installed on easements over property not owned by us. The easements are generally perpetual and only require remediation action upon abandonment or cessation of use of the property for the specified purpose. The ARO liability is not estimable for such easements as we intend to utilize these properties indefinitely. In the event we decide to abandon or cease the use of a particular easement, an ARO liability would be recorded at that time. We also identified AROs associated with our hydroelectric generating facilities; however, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the Financial Statements.

We collect removal costs in rates for certain transmission and distribution assets that do not have associated AROs. Generally, the accrual of future non-ARO removal obligations is not required; however, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates.

(8) Utility Plant Adjustments

We completed our annual utility plant adjustments impairment test as of April 1, 2021 and no impairment was identified. We calculate the fair value of our reporting units by considering various factors, including valuation studies based primarily on a discounted cash flow analysis, with published industry valuations and market data as supporting information. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in our service territory, regulatory stability, and commodity prices (where appropriate), as well as other factors that affect our revenue, expense and capital expenditure projections.

(9) Risk Management and Hedging Activities

Nature of Our Business and Associated Risks

We are exposed to certain risks related to the ongoing operations of our business, including the impact of market fluctuations in the price of electricity and natural gas commodities and changes in interest rates. We rely on market purchases to fulfill a portion of our electric and natural gas supply requirements. Several factors influence price levels and volatility. These factors include, but are not limited to, seasonal changes in demand, weather conditions, available generating assets within regions, transportation availability and reliability within and between regions, fuel availability, market liquidity, and the nature and extent of current and potential federal and state regulations.

Objectives and Strategies for Using Derivatives

To manage our exposure to fluctuations in commodity prices we routinely enter into derivative contracts. These types of contracts are included in our electric and natural gas supply portfolios and are used to manage price volatility risk by taking advantage of fluctuations in market prices. While individual contracts may be above or below market value, the overall portfolio approach is intended to provide greater price stability for consumers. We do not maintain a trading portfolio, and our derivative transactions are only used for risk management purposes consistent with regulatory guidelines.

In addition, we may use interest rate swaps to manage our interest rate exposures associated with new debt issuances or to manage our exposure to fluctuations in interest rates on variable rate debt.

Accounting for Derivative Instruments

We evaluate new and existing transactions and agreements to determine whether they are derivatives. The permitted accounting treatments include: normal purchase normal sale (NPNS); cash flow hedge; fair value hedge; and mark-to-market. Mark-to-market accounting is the default accounting treatment for all derivatives unless they qualify, and we specifically designate them, for one of the other accounting treatments. Derivatives designated for any of the elective accounting treatments must meet specific, restrictive criteria both at the time of designation and on an ongoing basis. The changes in the fair value of recognized derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and the type of hedge transaction.

Normal Purchases and Normal Sales

We have applied the NPNS scope exception to our contracts involving the physical purchase and sale of gas and electricity at fixed prices in future periods. During our normal course of business, we enter into full-requirement energy contracts, power purchase agreements and physical capacity contracts, which qualify for NPNS. All of these contracts are accounted for using the accrual method of accounting; therefore, there were no unrealized amounts recorded in the Financial Statements at December 31, 2021 and 2020. Revenues and expenses from these contracts are reported on a gross basis in the appropriate revenue and expense categories as the commodities are received or delivered.

Credit Risk

Credit risk is the potential loss resulting from counterparty non-performance under an agreement. We manage credit risk with policies and procedures for, among other things, counterparty analysis and exposure measurement, monitoring and mitigation. We limit credit risk in our commodity and interest rate derivatives activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis.

We are exposed to credit risk through buying and selling electricity and natural gas to serve customers. We may request collateral or other security from our counterparties based on the assessment of creditworthiness and expected credit exposure. It is possible that volatility in commodity prices could cause us to have material credit risk exposures with one or more counterparties. We enter into commodity master enabling agreements with our counterparties to mitigate credit exposure, as these agreements reduce the risk of default by allowing us or our counterparty the ability to make net payments. The agreements generally are: (1) Western Systems Power Pool agreements – standardized power purchase and sales contracts in the electric industry; (2) International Swaps and Derivatives Association agreements – standardized financial gas and electric contracts; (3) North American Energy Standards Board agreements – standardized physical gas contracts; and (4) Edison Electric Institute Master Purchase and Sale Agreements – standardized power sales contracts in the electric industry.

Many of our forward purchase contracts contain provisions that require us to maintain an investment grade credit rating from each of the major credit rating agencies. If our credit rating were to fall below investment grade, the counterparties could require immediate payment or demand immediate and ongoing full overnight collateralization on contracts in net liability positions.

Interest Rate Swaps Designated as Cash Flow Hedges

We have previously used interest rate swaps designated as cash flow hedges to manage our interest rate exposures associated with new debt issuances. We have no interest rate swaps outstanding. These swaps were designated as cash flow hedges with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in AOCI. We reclassify these gains from AOCI into interest on long-term debt during the periods in which the hedged interest payments occur. The following table shows the effect of these interest rate swaps previously terminated on the Financial Statements (in thousands):

Cash Flow Hedges	Location of Amount Reclassified from AOCI to Income	Amount Reclassified from AOCI into Income during the Year Ended December 31, 2021
Interest rate contracts	Interest on long-term debt	$ 614

A pre-tax loss of approximately $14.0 million is remaining in AOCI as of December 31, 2021, and we expect to reclassify approximately $0.6 million of pre-tax losses from AOCI into interest on long-term debt during the next twelve months. These amounts relate to terminated swaps.

(10) Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (i.e., an exit price). Measuring fair value requires the use of market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, corroborated by market data, or generally unobservable. Valuation techniques are required to maximize the use of observable inputs and minimize the use of unobservable inputs.

Applicable accounting guidance establishes a hierarchy that prioritizes the inputs used to measure fair value, and requires fair value measurements to be categorized based on the observability of those inputs. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3 inputs). The three levels of the fair value hierarchy are as follows:

- Level 1 – Unadjusted quoted prices available in active markets at the measurement date for identical assets or liabilities;
- Level 2 – Pricing inputs, other than quoted prices included within Level 1, which are either directly or indirectly observable as of the reporting date; and
- Level 3 – Significant inputs that are generally not observable from market activity.

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. Due to the short-term nature of cash and cash equivalents, accounts receivable, net, and accounts payable, the carrying amount of each such items approximates fair value. The table below sets forth by level within the fair value hierarchy the gross components of our assets and liabilities measured at fair value on a recurring basis. NPNS transactions are not included in the fair values by source table as they are not recorded at fair value. See Note 9 - Risk Management and Hedging Activities for further discussion.

We record transfers between levels of the fair value hierarchy, if necessary, at the end of the reporting period. There were no transfers between levels for the periods presented.

December 31, 2021	**Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Margin Cash Collateral Offset**	**Total Net Fair Value**
			(in thousands)		
Special deposits	$ 14,658	$ —	$ —	$ —	$ 14,658
Rabbi trust investments	18,234	—	—	—	18,234
Total	**$ 32,892**	**$ —**	**$ —**	**$ —**	**$ 32,892**
December 31, 2020					
Special deposits	$ 9,670	$ —	$ —	$ —	$ 9,670
Rabbi trust investments	27,027	—	—	—	27,027
Total	**$ 36,697**	**$ —**	**$ —**	**$ —**	**$ 36,697**

Special deposits represent amounts held in money market mutual funds. Rabbi trust investments represent assets held for non-qualified deferred compensation plans, which consist of our common stock and actively traded mutual funds with quoted prices in active markets.

Financial Instruments

The estimated fair value of financial instruments is summarized as follows (in thousands):

	December 31, 2021		December 31, 2020	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt	$ 2,552,660	$ 2,838,518	$ 2,328,637	$ 2,643,131

The estimated fair value amounts have been determined using available market information and appropriate valuation methodologies; however, considerable judgment is required in interpreting market data to develop estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we would realize in a current market exchange.

We determined fair value for long-term debt based on interest rates that are currently available to us for issuance of debt with similar terms and remaining maturities, except for publicly traded debt, for which fair value is based on market prices for the same or similar issues or upon the quoted market prices of U.S. treasury issues having a similar term to maturity, adjusted for our bond issuance rating and the present value of future cash flows. These are significant other observable inputs, or level 2 inputs, in the fair value hierarchy.

(11) Unsecured Credit Facilities

Credit Facility

We have a $425 million Credit Facility which matures September 2, 2023. The Credit Facility includes uncommitted features that allow us to request up to two one-year extensions to the maturity date and increase the size by an additional $75 million with the consent of the lenders. The facility does not amortize and is unsecured. Borrowings may be made at interest rates equal to the Eurodollar rate, plus a margin of 112.5 to 175.0 basis points, or a base rate, plus a margin of 12.5 to 75.0 basis points. A total of ten banks participate in the facility, with no one bank providing more than 16 percent of the total availability. Commitment fees for the Credit Facility were $0.4 million and $0.6 million for the years ended December 31, 2021 and 2020.

The availability under the facilities in place for the years ended December 31 is shown in the following table (in millions):

	2021	2020
Unsecured revolving line of credit, expiring September 2023	$ 425.0	$ 425.0
Unsecured revolving line of credit, expiring March 2023	25.0	25.0
	450.0	**450.0**
Amounts outstanding at December 31:		
Eurodollar borrowings	373.0	222.0
Letters of credit	—	—
	373.0	**222.0**
Net availability as of December 31	**$ 77.0**	**$ 228.0**

The Credit Facility includes covenants that require us to meet certain financial tests, including a maximum debt to capitalization ratio not to exceed 65 percent. The facility also contains covenants which, among other things, limit our ability to engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, and enter into transactions with affiliates. A default on the South Dakota or Montana First Mortgage Bonds would trigger a cross default on the Credit Facility; however, a default on the Credit Facility would not trigger a default on the South Dakota or Montana First Mortgage Bonds.

(12) Long-Term Debt

Long-term debt consisted of the following (in thousands):

	Due	December 31, 2021	December 31, 2020
Unsecured Debt:			
Unsecured Revolving Line of Credit	2023	$ 373,000	$ 222,000
Secured Debt:			
Mortgage bonds—			
South Dakota—5.01%	2025	64,000	64,000
South Dakota—4.15%	2042	30,000	30,000
South Dakota—4.30%	2052	20,000	20,000
South Dakota—4.85%	2043	50,000	50,000
South Dakota—4.22%	2044	30,000	30,000
South Dakota—4.26%	2040	70,000	70,000
South Dakota—3.21%	2030	50,000	50,000
South Dakota—2.80%	2026	60,000	60,000
South Dakota—2.66%	2026	45,000	45,000
Montana—5.71%	2039	55,000	55,000
Montana—5.01%	2025	161,000	161,000
Montana—4.15%	2042	60,000	60,000
Montana—4.30%	2052	40,000	40,000
Montana—4.85%	2043	15,000	15,000
Montana—3.99%	2028	35,000	35,000
Montana—4.176%	2044	450,000	450,000
Montana—3.11%	2025	75,000	75,000
Montana—4.11%	2045	125,000	125,000
Montana—4.03%	2047	250,000	250,000
Montana—3.98%	2049	150,000	150,000
Montana—3.21%	2030	100,000	100,000
Montana—1.00%	2024	100,000	—
Pollution control obligations—			
Montana—2.00%	2023	144,660	144,660
Other Long Term Debt:			
New Market Tax Credit Financing—1.146%	2046	—	26,977
Total Long-Term Debt		$ 2,552,660	$ 2,328,637

Secured Debt

First Mortgage Bonds and Pollution Control Obligations

The South Dakota First Mortgage Bonds are a series of general obligation bonds issued under our South Dakota indenture. These bonds are secured by substantially all of our South Dakota and Nebraska electric and natural gas assets.

The Montana First Mortgage Bonds and Montana Pollution Control Obligations are secured by substantially all of our Montana electric and natural gas assets.

In May 2020, we issued $100 million principal amount of Montana First Mortgage Bonds and $50 million principal amount of South Dakota First Mortgage Bonds, each at a fixed interest rate of 3.21 percent maturing on May 15, 2030. These bonds were issued in a transaction exempt from the registration requirements of the Securities Act of 1933. Proceeds were used to repay a portion of our outstanding borrowings under our revolving credit facilities and for other general corporate purposes. The bonds are secured by our electric and natural gas assets in Montana and South Dakota.

In March 2021, we issued and sold $100 million aggregate principal amount of Montana First Mortgage Bonds (the bonds) at a fixed interest rate of 1.00 percent maturing on March 26, 2024. The net proceeds were used to repay in full our outstanding $100 million term loan that was due April 2, 2021. We may redeem some or all of the bonds at any time in whole, or from time to time in part, at our option, on or after March 26, 2022, at a redemption price equal to 100% of the principal amount of the bonds to be redeemed, plus accrued and unpaid interest on the principal amount of the bonds being redeemed to, but excluding, the redemption date. The bonds are secured by our electric and natural gas assets in Montana and Wyoming.

As of December 31, 2021, we were in compliance with our financial debt covenants.

Other Long-Term Debt

In July 2021, our two loans totaling $27.0 million associated with the New Market Tax Credit (NMTC) financing agreement were extinguished. These loans were satisfied with our $18.2 million investment in the entities created in relation to the NMTC transaction, investor forgiveness of $7.9 million for substantially all of the benefits derived from the tax credits, and cash payment of $0.9 million. In accordance with our last rate case filing in the state of Montana, the portion of the loan forgiven, less unamortized debt issuance costs of $1.3 million, was recorded as a reduction to the cost of the office building associated with the NMTC financing agreement. This cash payment is reflected within the financing activities section of our Statement of Cash Flows for the year ended December 31, 2021; however, the remaining reduction to Long-term debt, Other investments, and Utility plant are non-cash financing activities that are not reflected within our Statement of Cash Flows for the year ended December 31, 2021.

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt, during the next five years are $517.7 million in 2023, $100.0 million in 2024, $300.0 million in 2025 and $105.0 million in 2026.

(13) Related Party Transactions

Accounts receivable from and payables to associated companies primarily include intercompany billings for direct charges, overhead, and income tax obligations. The following table reflects our accounts receivable from and accounts payable to associated companies (in thousands):

	December 31,	
	2021	2020
Accounts Receivable from Associated Companies:		
Havre Pipeline Company, LLC	$ 2,729	$ 1,673
NorthWestern Energy Solutions, Inc.	71	61
Risk Partners Assurance, Ltd.	18	18
	$ 2,818	$ 1,752
Accounts Payable to Associated Companies:		
NorthWestern Services, LLC	$ 1,837	$ 1,776

(14) Income Taxes

Our effective tax rate typically differs from the federal statutory tax rate primarily due to the regulatory impact of flowing through the federal and state tax benefit of repairs deductions, state tax benefit of accelerated tax depreciation deductions (including bonus depreciation when applicable) and production tax credits. The regulatory accounting treatment of these deductions requires immediate income recognition for temporary tax differences of this type, which is referred to as the flow-through method. When the flow-through method of accounting for temporary differences is reflected in regulated revenues, we record deferred income taxes and establish related regulatory assets and liabilities.

The components of the net deferred income tax assets and liabilities recognized in our Balance Sheets are related to the following temporary differences (in thousands):

	December 31,	
	2021	2020
Production tax credit	$ 75,092	$ 63,542
Pension / postretirement benefits	21,435	31,866
Customer advances	21,271	17,165
Unbilled revenue	10,704	14,429
Compensation accruals	10,612	11,748
Environmental liability	5,704	6,039
Reserves and accruals	5,105	6,265
Interest rate hedges	3,158	3,171
NOL carryforward	—	16,525
Other, net	7,833	8,142
Deferred Tax Asset	**160,914**	**178,892**
Excess tax depreciation	(438,319)	(423,181)
Flow through depreciation	(92,502)	(80,938)
Goodwill amortization	(91,689)	(91,647)
Regulatory assets and other	(53,896)	(53,450)
Deferred Tax Liability	**(676,406)**	**(649,216)**

Uncertain Tax Positions

We recognize tax positions that meet the more-likely-than-not threshold as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. The change in unrecognized tax benefits is as follows (in thousands):

	2021	2020
Unrecognized Tax Benefits at January 1	$ 33,491	$ 35,085
Gross increases - tax positions in prior period	293	120
Gross increases - tax positions in current period	—	—
Gross decreases - tax positions in current period	(1,735)	(1,714)
Lapse of statute of limitations	—	—
Unrecognized Tax Benefits at December 31	$ 32,049	$ 33,491

Our unrecognized tax benefits include approximately $28.1 million and $28.0 million related to tax positions as of December 31, 2021 and 2020 that if recognized, would impact our annual effective tax rate. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitation within the next twelve months.

Our policy is to recognize interest related to uncertain tax positions in interest expense. As of December 31, 2021, we have accrued $0.5 million for the payment of interest in the Balance Sheets. As of December 31, 2020, we did not have any amounts accrued for the payment of interest.

Tax years 2018 and forward remain subject to examination by the IRS and state taxing authorities.

(15) Comprehensive Income (Loss)

The following tables display the components of Other Comprehensive Income (Loss), after-tax, and the related tax effects (in thousands):

	December 31,					
	2021			2020		
	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount
Foreign currency translation adjustment	$ (58)	$ —	$ (58)	$ 88	$ —	$ 88
Reclassification of net income (loss) on derivative instruments	614	(162)	452	614	(162)	452
Postretirement medical liability adjustment	(585)	149	(436)	2,462	(623)	1,839
Other comprehensive income (loss)	$ (29)	$ (13)	$ (42)	$ 3,164	$ (785)	$ 2,379

Balances by classification included within AOCI on the Balance Sheets are as follows, net of tax (in thousands):

	December 31, 2021	December 31, 2020
Foreign currency translation	$ 1,443	$ 1,501
Derivative instruments designated as cash flow hedges	(8,127)	(8,579)
Postretirement medical plans	1,516	1,952
Accumulated other comprehensive loss	$ (5,168)	$ (5,126)

The following table displays the changes in AOCI by component, net of tax (in thousands):

	December 31, 2021 Year Ended				
	Affected Line Item in the Statements of Income	**Interest Rate Derivative Instruments Designated as Cash Flow Hedges**	**Postretirement Medical Plans**	**Foreign Currency Translation**	**Total**
Beginning balance		$ (8,579)	$ 1,952	$ 1,501	$ (5,126)
Other comprehensive income before reclassifications				(58)	(58)
Amounts reclassified from AOCI	Interest on long-term debt	452			452
Amounts reclassified from AOCI			(436)		(436)
Net current-period other comprehensive income		452	(436)	(58)	(42)
Ending Balance		$ (8,127)	$ 1,516	$ 1,443	$ (5,168)

	Affected Line Item in the Statements of Income	Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
	December 31, 2020 Year Ended				
Beginning balance		$ (9,031)	$ 113	$ 1,413	$ (7,505)
Other comprehensive income before reclassifications				88	88
Amounts reclassified from AOCI	Interest on long-term debt	452			452
Amounts reclassified from AOCI			1,839		1,839
Net current-period other comprehensive income		452	1,839	88	2,379
Ending Balance		$ (8,579)	$ 1,952	$ 1,501	$ (5,126)

(16) Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

We sponsor and/or contribute to pension and postretirement health care and life insurance benefit plans for eligible employees. The pension plan for our South Dakota and Nebraska employees is referred to as the NorthWestern Corporation plan, and the pension plan for our Montana employees is referred to as the NorthWestern Energy plan, and collectively they are referred to as the Plans. We utilize a number of accounting mechanisms that reduce the volatility of reported pension costs. Differences between actuarial assumptions and actual plan results are deferred and are recognized into earnings only when the accumulated differences exceed 10 percent of the greater of the projected benefit obligation or the market-related value of plan assets. If necessary, the excess is amortized over the average remaining service period of active employees. The Plans' funded status is recognized as an asset or liability in our Financial Statements. See Note 5 - Regulatory Assets and Liabilities, for further discussion on how these costs are recovered through rates charged to our customers.

Benefit Obligation and Funded Status

Following is a reconciliation of the changes in plan benefit obligations and fair value of plan assets, and a statement of the funded status (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2021	2020	2021	2020
Change in benefit obligation:				
Obligation at beginning of period	$ 820,979	$ 735,564	$ 19,146	$ 20,272
Service cost	12,994	11,116	407	370
Interest cost	18,759	22,840	317	492
Actuarial loss	(28,905)	84,479	415	123
Settlements(1)	(93,488)	—	—	390
Benefits paid	(33,537)	(33,020)	(2,977)	(2,501)
Benefit Obligation at End of Period	$ 696,802	$ 820,979	$ 17,308	$ 19,146
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 688,456	$ 609,000	$ 23,096	$ 21,479
Return on plan assets	33,868	101,075	3,349	2,723
Employer contributions	10,200	11,401	1,821	1,395
Settlements(1)	(93,488)	—	—	—
Benefits paid	(33,537)	(33,020)	(2,977)	(2,501)
Fair value of plan assets at end of period	$ 605,499	$ 688,456	$ 25,289	$ 23,096
Funded Status	$ (91,303)	$ (132,523)	$ 7,981	$ 3,950
Amounts Recognized in the Balance Sheet Consist of:				
Noncurrent asset	8,297	7,001	11,914	8,436
Total Assets	8,297	7,001	11,914	8,436
Current liability	(11,200)	(11,200)	(1,575)	(1,712)
Noncurrent liability	(88,400)	(128,324)	(2,358)	(2,774)
Total Liabilities	(99,600)	(139,524)	(3,933)	(4,486)
Net amount recognized	$ (91,303)	$ (132,523)	$ 7,981	$ 3,950
Amounts Recognized in Regulatory Assets Consist of:				
Prior service credit	—	—	1,870	3,857
Net actuarial loss	(62,448)	(115,987)	1,366	(497)
Amounts recognized in AOCI consist of:				
Prior service cost	—	—	(95)	(246)
Net actuarial gain	—	—	2,500	3,246
Total	$ (62,448)	$ (115,987)	$ 5,641	$ 6,360

(1) In December 2021, we entered into a group annuity contract from an insurance company to provide for the payment of pension benefits to 1,062 NorthWestern Energy Pension Plan participants. We purchased the contract with $93.5 million of plan assets. The insurance company took over the payments of these benefits starting January 1, 2022. This transaction settled $93.5 million of our NorthWestern Energy Pension Plan obligation. As a result of this transaction, during the twelve months ended December 31, 2021, we recorded a non-cash, non-operating settlement charge of $11.3 million. This charge is recorded within operating expenses, net on the Statements of Income. As discussed within Note 5 – Regulatory Assets and Liabilities, this charge was deferred as a regulatory asset on the Balance Sheets, with a corresponding decrease to operating expenses on the Statements of Income.

The actuarial gain/loss is primarily due to the change in discount rate assumption and actual asset returns compared with expected amounts. The total projected benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets were as follows (in millions):

	NorthWestern Energy Pension Plan	
	December 31,	
	2021	2020
Projected benefit obligation	$ 636.3	$ 757.4
Accumulated benefit obligation	636.3	757.4
Fair value of plan assets(1)	537.9	619.1

As of December 31, 2021, the fair value of the NorthWestern Corporation pension plan assets exceed the total projected and accumulated benefit obligation and are therefore excluded from this table.

(1) Fair value of plan assets was impacted by the group annuity contract discussed above.

Net Periodic Cost (Credit)

The components of the net costs (credits) for our pension and other postretirement plans are as follows (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2021	2020	2021	2020
Components of Net Periodic Benefit Cost				
Service cost	$ 12,994	$ 11,116	$ 407	$ 370
Interest cost	18,759	22,840	327	492
Expected return on plan assets	(27,061)	(26,162)	(919)	(983)
Amortization of prior service cost (credit)	—	—	(1,835)	(1,882)
Recognized actuarial loss (gain)	6,536	5,028	(898)	(61)
Settlement loss recognized(1)	11,291	—	—	390
Net Periodic Benefit Cost (Credit)	$ 22,519	$ 12,822	$ (2,918)	$ (1,674)
Regulatory deferral of net periodic benefit cost(2)	(13,308)	(2,100)	—	—
Previously deferred costs recognized(2)	—	71	709	861
Amount Recognized in Income	$ 9,211	$ 10,793	$ (2,209)	$ (813)

(1) Settlement loss is related to partial annuitization of NorthWestern Energy Pension Plan effective December 1, 2021.

(2) Net periodic benefit costs for pension and postretirement benefit plans are recognized for financial reporting based on the authorization of each regulatory jurisdiction in which we operate. A portion of these costs are recorded in regulatory assets and recognized in the Statements of Income as those costs are recovered through customer rates.

For purposes of calculating the expected return on pension plan assets, the market-related value of assets is used, which is based upon fair value. The difference between actual plan asset returns and estimated plan asset returns are amortized equally over a period not to exceed five years.

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2021 and 2020. The actuarial assumptions used to compute net periodic pension cost and postretirement benefit cost are based upon information available as of the beginning of the year, specifically, market interest rates, past experience and management's best estimate of future economic conditions. Changes in these assumptions may impact future benefit costs and obligations. In computing future costs and obligations, we must make assumptions about such things as employee mortality and turnover, expected salary and wage increases, discount rate, expected return on plan assets, and expected future cost increases. Two of these assumptions have the most impact on the level of cost: (1) discount rate and (2) expected rate of return on plan assets.

On an annual basis, we set the discount rate using a yield curve analysis. This analysis includes constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year, projected benefit cash flow from our plans. The increase in the discount rate during 2021 decreased our projected benefit obligation by approximately $45.1 million.

In determining the expected long-term rate of return on plan assets, we review historical returns, the future expectations for returns for each asset class weighted by the target asset allocation of the pension and postretirement portfolios, and long-term inflation assumptions. Based on the target asset allocation for our pension assets and future expectations for asset returns, we increased our long term rate of return on assets assumption for NorthWestern Energy Pension Plan to 4.26 percent and decreased our assumption on the NorthWestern Corporation Pension Plan to 2.66 percent for 2022.

The weighted-average assumptions used in calculating the preceding information are as follows:

	Pension Benefits December 31,		Other Postretirement Benefits December 31,	
	2021	2020	2021	2020
Discount rate	2.65-2.75 %	2.20-2.30 %	2.35-2.40 %	1.8 %
Expected rate of return on assets	3.01-4.17	3.45-4.49	4.08	4.71
Long-term rate of increase in compensation levels (non-union)	2.84	2.84	2.84	2.84
Long-term rate of increase in compensation levels (union)	2.00	2.00	2.00	2.00
Interest crediting rate	3.30-6.00	3.30-6.00	N/A	N/A

The postretirement benefit obligation is calculated assuming that health care costs increase by a 5.00 percent fixed rate. The company contribution toward the premium cost is capped, therefore future health care cost trend rates are expected to have a minimal impact on company costs and the accumulated postretirement benefit obligation.

Investment Strategy

Our investment goals with respect to managing the pension and other postretirement assets are to meet current and future benefit payment needs while maximizing total investment returns (income and appreciation) after inflation within the constraints of diversification, prudent risk taking, Prudent Man Rule of the Employee Retirement Income Security Act of 1974 and liability-based considerations. Each plan is diversified across asset classes to achieve optimal balance between risk and return and between income and growth through capital appreciation. Our investment philosophy is based on the following:

- Each plan should be substantially invested as long-term cash holdings reduce long-term rates of return;
- Pension Plan portfolio risk is described by volatility in the funded status of the Plans;
- It is prudent to diversify each plan across the major asset classes;
- Equity investments provide greater long-term returns than fixed income investments, although with greater short-term volatility;
- Fixed income investments of the plans should strongly correlate with the interest rate sensitivity of the plan's aggregate liabilities in order to hedge the risk of change in interest rates negatively impacting the pension plans overall funded status, (such assets will be described as Fixed Income Security assets);
- Allocation to foreign equities increases the portfolio diversification and thereby decreases portfolio risk while providing for the potential for enhanced long-term returns;
- Active management can reduce portfolio risk and potentially add value through security selection strategies;
- A portion of plan assets should be allocated to passive, indexed management funds to provide for greater diversification and lower cost; and
- It is appropriate to retain more than one investment manager, provided that such managers offer asset class or style diversification.

Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

The most important component of an investment strategy is the portfolio asset mix, or the allocation between the various classes of securities available. The mix of assets is based on an optimization study that identifies asset allocation targets in order to achieve the maximum return for an acceptable level of risk, while minimizing the expected contributions and pension and postretirement expense. In the optimization study, assumptions are formulated about characteristics, such as expected asset class investment returns, volatility (risk), and correlation coefficients among the various asset classes, and making adjustments to reflect future conditions expected to prevail over the study period. Based on this, the target asset allocation established, within an allowable range of plus or minus 5 percent, is as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2021	2020	2021	2020	2021	2020
Fixed income securities	55.0 %	55.0 %	90.0 %	80.0 %	40.0 %	40.0 %
Non-U.S. fixed income securities	4.0	4.0	1.0	2.0	—	—
Global equities	41.0	41.0	9.0	18.0	60.0	60.0

The actual allocation by plan is as follows:

	NorthWestern Energy Pension		NorthWestern Corporation Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2021	2020	2021	2020	2021	2020
Cash and cash equivalents	0.1 %	— %	0.4 %	0.7 %	0.1 %	1.0 %
Fixed income securities	53.8	52.7	89.5	77.3	33.7	37.9
Non-U.S. fixed income securities	3.9	3.8	0.9	2.6	—	—
Global equities	42.2	43.5	9.2	19.4	66.2	61.1
	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %

Generally, the asset mix will be rebalanced to the target mix as individual portfolios approach their minimum or maximum levels. Debt securities consist of U.S. and international instruments. Core domestic portfolios can be invested in government, corporate, asset-backed and mortgage-backed obligation securities. While the portfolio may invest in high yield securities, the average quality must be rated at least “investment grade" by rating agencies. Performance of fixed income investments is measured by both traditional investment benchmarks as well as relative changes in the present value of the plan's liabilities. Equity investments consist primarily of U.S. stocks including large, mid and small cap stocks, which are diversified across investment styles such as growth and value. We also invest in global equities with exposure to developing and emerging markets. Derivatives, options and futures are permitted for the purpose of reducing risk but may not be used for speculative purposes.

Our plan assets are primarily invested in common collective trusts (CCTs), which are invested in equity and fixed income securities. In accordance with our investment policy, these pooled investment funds must have an adequate asset base relative to their asset class and be invested in a diversified manner and have a minimum of three years of verified investment performance experience or verified portfolio manager investment experience in a particular investment strategy and have management and oversight by an investment advisor registered with the Securities and Exchange Commission (SEC). Investments in a collective investment vehicle are valued by multiplying the investee company’s net asset value per share with the number of units or shares owned at the valuation date. Net asset value per share is determined by the trustee. Investments held by the CCT, including collateral invested for securities on loan, are valued on the basis of valuations furnished by a pricing service approved by the CCT’s investment manager, which determines valuations using methods based on quoted closing market prices on national securities exchanges, or at fair value as determined in good faith by the CCT’s investment manager if applicable. The funds do not contain any redemption restrictions. The direct holding of NorthWestern Corporation stock is not permitted; however, any holding in a diversified mutual fund or collective investment fund is permitted. During 2019, due to proposed changes in the John Hancock participating group annuity contract held by the NorthWestern Corporation plan, we elected to discontinue the contract effective January 1, 2020.

Cash Flows

In accordance with the Pension Protection Act of 2006 (PPA), and the relief provisions of the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), we are required to meet minimum funding levels in order to avoid required contributions and benefit restrictions. We have elected to use asset smoothing provided by the WRERA, which allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of funding requirements. Additional funding relief was passed in the American Rescue Plan Act of 2021, providing for longer amortization and interest rate smoothing, which we elected to use. We expect to continue to make contributions to the pension plans in 2022 and future years that reflect the minimum requirements and discretionary amounts consistent with the amounts recovered in rates. Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact our funding requirements.

Due to the regulatory treatment of pension costs in Montana, pension expense for 2021 and 2020 was based on actual contributions to the plan. Annual contributions to each of the pension plans are as follows (in thousands):

	2021	2020
NorthWestern Energy Pension Plan (MT)	$ 9,000	$ 10,201
NorthWestern Corporation Pension Plan (SD and NE)	1,200	1,200
	$ 10,200	$ 11,401

We estimate the plans will make future benefit payments to participants as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2022	$ 28,842	$ 2,579
2023	30,368	2,296
2024	31,933	1,952
2025	33,410	1,435
2026	34,692	1,381
2027-2031	183,671	5,352

Defined Contribution Plan

Our defined contribution plan permits employees to defer receipt of compensation as provided in Section 401(k) of the Internal Revenue Code. Under the plan, employees may elect to direct a percentage of their gross compensation to be contributed to the plan. We contribute various percentage amounts of the employee's gross compensation contributed to the plan. Matching contributions for the years ended December 31, 2021 and 2020 were $11.8 million and $11.1 million, respectively.

(17) Stock-Based Compensation

We grant stock-based awards through our Amended and Restated Equity Compensation Plan (ECP), which includes restricted stock awards and performance share awards. As of December 31, 2021, there were 828,486 shares of common stock remaining available for grants. The remaining vesting period for awards previously granted ranges from one to five years if the service and/or performance requirements are met. Nonvested shares do not receive dividend distributions. The long-term incentive plan provides for accelerated vesting in the event of a change in control.

We account for our share-based compensation arrangements by recognizing compensation costs for all share-based awards over the respective service period for employee services received in exchange for an award of equity or equity-based compensation. The compensation cost is based on the fair value of the grant on the date it was awarded.

Performance Unit Awards

Performance unit awards are granted annually under the ECP. These awards vest at the end of the three-year performance period if we have achieved certain performance goals and the individual remains employed by us. The exact number of shares issued will vary from 0 percent to 200 percent of the target award, depending on actual company performance relative to the performance goals. These awards contain both market- and performance-based components. The performance goals are independent of each other and equally weighted, and are based on two metrics: (i) EPS growth level and average return on equity; and (ii) total shareholder return (TSR) relative to a peer group.

Fair value is determined for each component of the performance unit awards. The fair value of the earnings per share component is estimated based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends, multiplied by an estimated performance multiple determined on the basis of historical experience, which is subsequently trued up at vesting based on actual performance. The fair value of the TSR portion is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. The following summarizes the significant assumptions used to determine the fair value of performance shares and related compensation expense as well as the resulting estimated fair value of performance shares granted:

	2021	2020
Risk-free interest rate	0.19 %	1.42 %
Expected life, in years	3	3
Expected volatility	28.2% to 38.5%	14.9% to 19.7%
Dividend yield	4.3 %	3.1 %

The risk-free interest rate was based on the U.S. Treasury yield of a three-year bond at the time of grant. The expected term of the performance shares is three years based on the performance cycle. Expected volatility was based on the historical volatility for the peer group. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest.

A summary of nonvested shares as of and changes during the year ended December 31, 2021, are as follows:

	Performance Unit Awards	
	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	130,571	$ 66.27
Granted	104,927	$ 50.53
Vested	(69,867)	$ 60.41
Forfeited	(3,108)	$ 59.14
Remaining nonvested grants	162,523	$ 58.76

We recognized compensation expense of $3.9 million and $2.2 million for the years ended December 31, 2021 and 2020, respectively, and related income tax benefit of $(0.2) million and $(0.6) million for the years ended December 31, 2021 and 2020, respectively. As of December 31, 2021, we had $5.7 million of unrecognized compensation cost related to the nonvested portion of outstanding awards, which is reflected as nonvested stock as a portion of additional paid in capital in our Statements of Common Shareholders' Equity. The cost is expected to be recognized over a weighted-average period of 2 years. The total fair value of shares vested was $4.2 million and $5.1 million for the years ended December 31, 2021 and 2020, respectively.

Retirement/Retention Restricted Share Awards

In December 2011, an executive retirement / retention program was established that provides for the annual grant of restricted share units. These awards are subject to a five-year performance and vesting period. The performance measure for these awards requires net income for the calendar year of at least three of the five full calendar years during the performance period to exceed net income for the calendar year the awards are granted. Once vested, the awards will be paid out in shares of common stock in five equal annual installments after a recipient has separated from service. The fair value of these awards is measured based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends.

A summary of nonvested shares as of and changes during the year ended December 31, 2021, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	77,967	$ 50.86
Granted	24,385	43.29
Vested	(15,033)	45.78
Forfeited	—	—
Remaining nonvested grants	87,319	$ 49.63

Director's Deferred Compensation

Nonemployee directors may elect to defer up to 100 percent of any qualified compensation that would be otherwise payable to him or her, subject to compliance with our 2005 Deferred Compensation Plan for Nonemployee Directors and Section 409A of the Internal Revenue Code. The deferred compensation may be invested in NorthWestern stock or in designated investment funds. Compensation deferred in a particular month is recorded as a deferred stock unit (DSU) on the first of the following month based on the closing price of NorthWestern stock or the designated investment fund. The DSUs are marked-to-market on a quarterly basis with an adjustment to director’s compensation expense. Based on the election of the nonemployee director, following separation from service on the Board, other than on account of death, he or she shall be paid a distribution either in a lump sum or in approximately equal installments over a designated number of years (not to exceed 10 years).

Following is a summary of the components of DSUs issued and compensation expense attributable to the DSUs (in millions, except DSU amounts):

	December 31,			
	2021		2020	
DSUs Issued		18,741		21,434
Compensation expense		1.1		1.5
Change in value of shares		1.3		(2.9)
Total compensation (benefit) expense	$	2.4	$	(1.4)
DSUs withdrawn		186,137		613
Value of DSUs withdrawn	$	12.1	$	0.1

(18) Common Stock

We have 250,000,000 shares authorized consisting of 200,000,000 shares of common stock with a $0.01 par value and 50,000,000 shares of preferred stock with a $0.01 par value. Of these shares, 2,865,957 shares of common stock are reserved for the incentive plan awards. For further detail of grants under this plan see Note 17 - Stock-Based Compensation.

Repurchase of Common Stock

Shares tendered by employees to us to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock awards totaled 16,880 and 35,378 during the years ended December 31, 2021 and 2020, respectively, and are reflected in reacquired capital stock. These shares were credited to reacquired capital stock based on their fair market value on the vesting date.

Issuance of Common Stock

In April 2021, we entered into an Equity Distribution Agreement with BofA Securities, Inc., CIBC World Markets Corp, Credit Suisse Securities (USA) LLC, and J.P. Morgan Securities LLC, collectively the sales agents, pursuant to which we may offer and sell shares of our common stock from time to time, having an aggregate gross sales price of up to $200.0 million, through an At-the-Market (ATM) offering program, including an equity forward sales component. This is a three-year agreement, expiring on February 11, 2024. During the twelve months ended December 31, 2021, we issued 1,966,117 shares of our common stock under the ATM program at an average price of $63.81, for net proceeds of $124.2 million, which is net of sales commissions and other fees paid of approximately $1.3 million. We do not anticipate needing to issue equity through the ATM program during 2022.

On November 17, 2021, we announced a registered public offering of 6,074,767 shares of our common stock at a public offering price of $53.50 per share, for an issuance amount of $325.0 million. In conjunction with this offering, we granted the underwriters an option to purchase up to 911,215 additional shares, which was subsequently exercised in full, for an additional issuance amount of $48.8 million. Of the total 6,985,982 shares of common stock offered, we initially sold 1,401,869 shares, $75.0 million in gross proceeds, directly to the underwriters in the offering, with cash proceeds received at closing. The remaining 5,584,113 shares were sold under forward sales agreements which provide for settlement on a settlement date or dates to be specified at our discretion, but which is expected to occur on or prior to February 28, 2023. The cumulative shares issued under the forward sales agreement is limited to one and one-half times the base number of shares within the agreement, or 8,376,170 shares.

The forward sales agreements will be physically settled with common shares issued by us, unless we elect to settle the agreements in cash or to net share settle the agreements, subject to certain conditions. On a settlement date or dates, if we decide to physically settle the forward sales agreement, we will issue shares of common stock to the forward purchaser at the then-applicable forward sale price and receive issuance proceeds at that time. The forward sale price will initially be $51.8950 per share, which is subject to adjustment based on a floating interest rate factor equal to the overnight bank funding rate less a spread of 75 basis points, and will be subject to decrease on certain dates specified in the forward sale agreement by amounts related to expected dividends on shares of common stock during the term of the forward sale agreement.

At December 31, 2021, we could have settled the forward sale agreement with physical delivery of 5,584,113 shares of common stock to the counterparty in exchange for cash of $286.1 million. The forward sale could have also been settled at December 31, 2021, with delivery of approximately $24.2 million of cash or approximately 435,522 shares of common stock to the counterparty, if we had elected to net cash or net share settle, respectfully.

The forward sale agreement has been classified as an equity transaction because it is indexed to our common stock, physical settlement is within our control, and the other requirements necessary for equity classification are met. As a result of the equity classification, no gain or loss will be recognized within earnings due to subsequent changes in the fair value of the forward sales agreement.

(19) Commitments and Contingencies

Qualifying Facilities Liability

Our QF liability primarily consists of unrecoverable costs associated with three contracts covered under the Public Utility Regulatory Practices Act (PURPA). These contracts require us to purchase minimum amounts of energy at prices ranging from $64 to $136 per MWH through 2029. As of December 31, 2021, our estimated gross contractual obligation related to these contracts was approximately $466.9 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $388.4 million through 2029. As contractual obligations are settled, the related purchases and sales are recorded within Operation expenses and Operating revenues in our Statements of Income. The present value of the remaining liability is recorded in Accumulated miscellaneous operating provisions in our Balance Sheets. The following summarizes the change in the liability (in thousands):

	December 31,	
	2021	2020
Beginning QF liability	$ 81,379	$ 92,937
Settlements[(1)]	(22,497)	(18,665)
Interest on long-term debt	6,061	7,107
Ending QF liability	$ 64,943	$ 81,379

(1) The settlements amount includes (i) a higher periodic adjustment of $4.3 million due to actual price escalation, which was more than previously modeled; (ii) lower costs of approximately $1.7 million, due to a $2.6 million reduction in costs for the adjustment to actual output and pricing for the current contract year as compared with a $0.9 million reduction in costs in

the prior period; and (iii) a favorable adjustment of approximately $7.0 million decreasing the QF liability associated with a one-time clarification in contract term.

The following summarizes the estimated gross contractual obligation less amounts recoverable through rates (in thousands):

	Gross Obligation	Recoverable Amounts	Net
2022	$ 80,355	$ 60,639	$ 19,716
2023	82,452	61,280	21,172
2024	75,113	60,706	14,407
2025	60,360	52,950	7,410
2026	55,393	46,274	9,119
Thereafter	113,199	106,563	6,636
Total[1]	$ 466,872	$ 388,412	$ 78,460

(1) This net unrecoverable amount represents the undiscounted difference between the total gross obligations and recoverable amounts. The ending QF liability in the table above represents the present value of this net unrecoverable amount.

Long Term Supply and Capacity Purchase Obligations

We have entered into various commitments, largely purchased power, electric transmission, coal and natural gas supply and natural gas transportation contracts. These commitments range from one to 24 years. Costs incurred under these contracts are included in Operating expenses in the Statements of Income and were approximately $286.7 million and $206.6 million for the years ended December 31, 2021 and 2020, respectively. As of December 31, 2021, our commitments under these contracts were $283.2 million in 2022, $269.7 million in 2023, $221.8 million in 2024, $219.4 million in 2025, $172.2 million in 2026, and $1.5 billion thereafter. These commitments are not reflected in our Financial Statements.

Hydroelectric License Commitments

With the 2014 purchase of hydroelectric generating facilities and associated assets located in Montana, we assumed two Memoranda of Understanding (MOUs) existing with state, federal and private entities. The MOUs are periodically updated and renewed and require us to implement plans to mitigate the impact of the projects on fish, wildlife and their habitats, and to increase recreational opportunities. The MOUs were created to maximize collaboration between the parties and enhance the possibility to receive matching funds from relevant federal agencies. Under these MOUs, we have a remaining commitment to spend approximately $26.7 million between 2022 and 2040. These commitments are not reflected in our Financial Statements.

ENVIRONMENTAL LIABILITIES AND REGULATION

Environmental Matters

The operation of electric generating, transmission and distribution facilities, and gas gathering, storage, transportation and distribution facilities, along with the development (involving site selection, environmental assessments, and permitting) and construction of these assets, are subject to extensive federal, state, and local environmental and land use laws and regulations. Our activities involve compliance with diverse laws and regulations that address emissions and impacts to the environment, including air and water, protection of natural resources, avian and wildlife. We monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are implemented, our policy is to assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance.

Our environmental exposure includes a number of components, including remediation expenses related to the cleanup of current or former properties, and costs to comply with changing environmental regulations related to our operations. At present, our environmental reserve, which relates primarily to the remediation of former manufactured gas plant sites owned by us or for which we are responsible, is estimated to range between $24.1 million to $30.7 million. As of December 31, 2021, we had a reserve of approximately $26.9 million, which has not been discounted. Environmental costs are recorded when it is probable we are liable for the remediation and we can reasonably estimate the liability. We use a combination of site investigations and monitoring to formulate an estimate of environmental remediation costs for specific sites. Our monitoring procedures and development of actual remediation plans depend not only on site specific information but also on coordination with the different environmental regulatory agencies in our respective jurisdictions; therefore, while remediation exposure exists, it may be many years before costs are incurred.

Over time, as costs become determinable, we may seek authorization to recover such costs in rates or seek insurance reimbursement as available and applicable; therefore, although we cannot guarantee regulatory recovery, we do not expect these costs to have a material effect on our financial position or results of operations.

The following summarizes the change in our environmental liability (in thousands):

	December 31,	
	2021	2020
Liability at January 1,	$ 28,895	$ 30,276
Deductions	(2,799)	(2,977)
Charged to costs and expense	770	1,596
Liability at December 31,	$ 26,866	$ 28,895

Over time, as costs become determinable, we may seek authorization to recover such costs in rates or seek insurance reimbursement as available and applicable; therefore, although we cannot guarantee regulatory recovery, we do not expect these costs to have a material effect on our financial position or results of operations.

Manufactured Gas Plants - Approximately $22.1 million of our environmental reserve accrual is related to the following manufactured gas plants.

South Dakota - A formerly operated manufactured gas plant located in Aberdeen, South Dakota, has been identified on the Federal Comprehensive Environmental Response, Compensation, and Liability Information System list as contaminated with coal tar residue. We are currently conducting feasibility studies, implementing remedial actions pursuant to work plans approved by the South Dakota Department of Agriculture and Natural Resources, and conducting ongoing monitoring and operation and maintenance activities. As of December 31, 2021, the reserve for remediation costs at this site was approximately $8.1 million, and we estimate that approximately $3.0 million of this amount will be incurred through 2025.

Nebraska - We own sites in North Platte, Kearney, and Grand Island, Nebraska on which former manufactured gas facilities were located. We are currently working independently to fully characterize the nature and extent of potential impacts associated with these Nebraska sites. Our reserve estimate includes assumptions for site assessment and remedial action work. At present, we cannot determine with a reasonable degree of certainty the nature and timing of any risk-based remedial action at our Nebraska locations.

Montana - We own or have responsibility for sites in Butte, Missoula, and Helena, Montana on which former manufactured gas plants were located. The Butte and Helena sites, both listed as high priority sites on Montana's state superfund list, were placed into the Montana Department of Environmental Quality (MDEQ) voluntary remediation program for cleanup due to soil and groundwater impacts. Soil and coal tar were removed at the sites in accordance with the MDEQ requirements. Groundwater monitoring is conducted semiannually at both sites. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of additional remedial actions and/or investigations, if any, at the Butte site.

In August 2016, the MDEQ sent us a Notice of Potential Liability and Request for Remedial Action regarding the Helena site. In October 2019, we submitted a third revised Remedial Investigation Work Plan (RIWP) for the Helena site addressing MDEQ comments. The MDEQ approved the RIWP in March 2020 and we expect work at the Helena site to continue into 2022.

MDEQ has indicated it expects to proceed in listing the Missoula site as a Montana superfund site. After researching historical ownership, we have identified another potentially responsible party with whom we have entered into an agreement allocating third-party costs to be incurred in addressing the site. The other party has assumed the lead role at the site and has submitted a voluntary remediation plan for the Missoula site to MDEQ. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of risk-based remedial action, if any, at the Missoula site.

Global Climate Change - National and international actions have been initiated to address global climate change and the contribution of greenhouse gas (GHG) including, most significantly, carbon dioxide (CO2). These actions include legislative proposals, Executive and Environmental Protection Agency (EPA) actions at the federal level, state level activity, investor activism and private party litigation relating to GHG emissions. Coal-fired plants have come under particular scrutiny due to their level of GHG emissions. We have joint ownership interests in four coal-fired electric generating plants, all of which are operated by other companies. We are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated.

While numerous bills have been introduced that address climate change from different perspectives, Congress has not passed any federal climate change legislation regarding GHG emissions from coal fired plants, and we cannot predict the timing or form of any potential legislation. In 2019, the EPA finalized the Affordable Clean Energy Rule (ACE), which repealed the 2015 Clean Power Plan (CPP) in regulating GHG emissions from coal-fired plants. The U.S. Court of Appeals for the District of Columbia Circuit issued an opinion on January 19, 2021, vacating the ACE and remanding it to EPA for further action. The United States Supreme Court agreed to review the case in October 2021 and oral argument regarding the scope of EPA's authority to regulate GHG emissions is scheduled to take place February 28, 2022, with a decision expected the following summer. It also is widely expected that the Biden Administration will develop an alternative plan for reducing GHG emissions from coal-fired plants, and in a memorandum dated February 12, 2021, EPA stated its belief that the January 19, 2021 opinion left neither the ACE nor the CPP rules in place.

We cannot predict whether or how GHG emission regulations will be applied to our plants, including any actions taken by the relevant state authorities. In addition, it is unclear how pending or future litigation relating to GHG matters will impact us. As GHG regulations are implemented, it could result in additional compliance costs impacting our future results of operations and financial position if such costs are not recovered through regulated rates. We will continue working with federal and state regulatory authorities, other utilities, and stakeholders to seek relief from any GHG regulations that, in our view, disproportionately impact customers in our region.

Future additional environmental requirements could cause us to incur material costs of compliance, increase our costs of procuring electricity, decrease transmission revenue and impact cost recovery. Technology to efficiently capture, remove and/or sequester such GHG emissions may not be available within a timeframe consistent with the implementation of any such requirements. Physical impacts of climate change also may present potential risks for severe weather, such as droughts, fires, floods, ice storms and tornadoes, in the locations where we operate or have interests. These potential risks may impact costs for electric and natural gas supply and maintenance of generation, distribution, and transmission facilities.

Clean Air Act Rules and Associated Emission Control Equipment Expenditures - The EPA has proposed or issued a number of rules under different provisions of the Clean Air Act (CAA) that could require the installation of emission control equipment at the generation plants in which we have joint ownership. Air emissions at our thermal generating plants are managed by the use of emissions and combustion controls and monitoring, and sulfur dioxide allowances. These measures are anticipated to be sufficient to permit the facilities to continue to meet current air emissions compliance requirements.

Regional Haze Rules - In January 2017, the EPA published amendments to the requirements under the CAA for state plans for protection of visibility - regional haze rules. Among other things, these amendments revised the process and requirements for the state implementation plans and extended the due date for the next periodic comprehensive regional haze state implementation plan revisions from 2018 to 2021.

The states of Montana, North Dakota and South Dakota are expected to develop and submit to EPA, for its approval, their respective State Implementation Plans (SIP) for Regional Haze compliance. While these states, among others, did not meet the EPA’s July 31, 2021 submission deadline, we still expect each state to submit its SIP in 2022. The draft Montana SIP does not require any additional controls at Colstrip Units 3 and 4. The draft North Dakota SIP does not require any additional controls at the Coyote generating facility, however the EPA, following a preliminary review, has asked North Dakota to reassess its determination regarding Coyote. The draft South Dakota SIP does not require any additional controls at the Big Stone generating facility. Until these SIPs are submitted and approved by EPA, the potential remains that installation of additional emissions controls might be required at these facilities.

Jointly Owned Plants - We have joint ownership in generation plants located in South Dakota, North Dakota, Iowa, and Montana that are or may become subject to the various regulations discussed above that have been or may be issued or proposed.

Other - We continue to manage equipment containing polychlorinated biphenyl (PCB) oil in accordance with the EPA's Toxic Substance Control Act regulations. We will continue to use certain PCB-contaminated equipment for its remaining useful life and will, thereafter, dispose of the equipment according to pertinent regulations that govern the use and disposal of such equipment.

We routinely engage the services of a third-party environmental consulting firm to assist in performing a comprehensive evaluation of our environmental reserve. Based upon information available at this time, we believe that the current environmental reserve properly reflects our remediation exposure for the sites currently and previously owned by us. The portion of our environmental reserve applicable to site remediation may be subject to change as a result of the following uncertainties:

- We may not know all sites for which we are alleged or will be found to be responsible for remediation; and
- Absent performance of certain testing at sites where we have been identified as responsible for remediation, we cannot estimate with a reasonable degree of certainty the total costs of remediation.

LEGAL PROCEEDINGS

Pacific Northwest Solar Litigation

Pacific Northwest Solar, LLC (PNWS) is a solar QF developer seeking to construct small solar facilities in Montana. We began negotiating with PNWS in early 2016 to purchase the output from 21 of its proposed facilities pursuant to our standard QF-1 Tariff, which is applicable to projects no larger than 3 MWs.

On June 16, 2016, however, the MPSC suspended the availability of the QF-1 Tariff standard rates for that category of solar projects, which included the projects proposed by PNWS. The MPSC exempted from the suspension any projects for which a QF had both submitted a signed power purchase agreement and had executed an interconnection agreement with us by June 16, 2016. Although we had signed four power purchase agreements with PNWS as of that date, we had not entered into interconnection agreements with PNWS for any of those projects. As a result, none of the PNWS projects in Montana qualified for the exemption.

In November 2016, PNWS sued us in state court seeking unspecified damages for breach of contract and a judicial declaration that some or all of the 21 proposed power purchase agreements it had proposed to us were in effect despite the MPSC's Order. We removed the state lawsuit to the United States District Court for the District of Montana (Court).

PNWS also requested the MPSC to exempt its projects from the tariff suspension and allow those projects to receive the QF-1 tariff rate that had been in effect prior to the suspension. We joined in PNWS's request for relief with respect to four of the projects, but the MPSC did not grant any of the relief requested by PNWS or us.

In August 2017, we entered into a non-monetary, partial settlement with PNWS in which PNWS amended its original complaint to limit its claims for enforcement and/or damages to only four of the 21 power purchase agreements. As a result, the damages sought by the plaintiff was reduced to approximately $8 million for the alleged breach of the four power purchase agreements. We participated in an unsuccessful mediation on January 24, 2019 and subsequent settlement efforts also have been unsuccessful.

On August 31, 2021, the Court ruled that the four agreements are valid and enforceable contracts and that NorthWestern breached the agreements on June 16, 2016 by refusing to go forward with the projects in spite of the MPSC's Orders. On December 15, 2021, after a three-day trial, the jury determined that PNWS had sustained $0.4 million in damages and the judge subsequently entered judgment against us in that amount.

We filed a post-trial motion on January 13, 2022 seeking to have the judgement set aside. On February 9, 2022, the judge denied our post-trial potion. The plaintiff did not seek any post-trial relief and the deadline for doing so has passed. On March 2, 2022, we filed a Notice of Appeal to the U.S. Court of Appeals for the Ninth Circuit. The plaintiff has fifteen days in which to file a cross-appeal.

State of Montana - Riverbed Rents

On April 1, 2016, the State of Montana (State) filed a complaint on remand (the State's Complaint) with the Montana First Judicial District Court (State District Court), naming us, along with Talen Montana, LLC (Talen) as defendants. The State claimed it owns the riverbeds underlying 10 of our, and formerly Talen's, hydroelectric facilities (dams, along with reservoirs and tailraces) on the Missouri, Madison and Clark Fork Rivers, and seeks rents for Talen's and our use and occupancy of such lands. The facilities at issue include the Hebgen, Madison, Hauser, Holter, Black Eagle, Rainbow, Cochrane, Ryan, and Morony facilities on the Missouri and Madison Rivers and the Thompson Falls facility on the Clark Fork River. We acquired these facilities from Talen in November 2014.

The litigation has a long prior history. In 2012, the United States Supreme Court issued a decision holding that the Montana Supreme Court erred in not considering a segment-by-segment approach to determine navigability and relying on present day recreational use of the rivers. It also held that what it referred to as the Great Falls Reach "at least from the head of the first waterfall to the foot of the last" was not navigable for title purposes, and thus the State did not own the riverbeds in that segment. The United States Supreme Court remanded the case to the Montana Supreme Court for further proceedings not inconsistent with its opinion. Following the 2012 remand, the case laid dormant for four years until the State's Complaint was filed with the State District Court. On April 20, 2016, we removed the case from State District Court to the United States District Court for the District of Montana (Federal District Court). The State filed a motion to remand. Following briefing and argument, on October 10, 2017, the Federal District Court entered an order denying the State's motion.

Because the State's Complaint included a claim that the State owned the riverbeds in the Great Falls Reach, on October 16, 2017, we and Talen renewed our earlier-filed motions seeking to dismiss the portion of the State's Complaint concerning the Great Falls Reach in light of the United States Supreme Court's decision. On August 1, 2018, the Federal District Court granted the motions to dismiss the State's Complaint as it pertains to approximately 8.2 miles of riverbed from "the head of the Black Eagle Falls to the foot of the Great Falls." In particular, the dismissal pertained to the Black Eagle Dam, Rainbow Dam and reservoir, Cochrane Dam and reservoir, and Ryan Dam and reservoir. While the dismissal of these four facilities may be subject to appeal, that appeal would not likely occur until after judgment in the case. On February 12, 2019, the Federal District Court granted our motion to join the United States as a defendant to the litigation. As a result, on October 31, 2019, the State filed and served an Amended Complaint including the United States as a defendant and removing claims of ownership for the hydroelectric facilities on the Great Falls Reach, except for the Morony and the Black Eagle Developments. We and Talen filed answers to the Amended Complaint on December 13, 2019, and the United States answered on February 5, 2020. A bench trial before the Federal District Court commenced January 4, 2022 and concluded on January 18, 2022. This bench trial addressed the issue of navigability of the segments at issue. The parties must submit amended findings of fact and conclusions of law, along with post-trial briefing, by April 29, 2022. A decision on navigability is expected following such submissions. Damages were bifurcated by agreement and will be tried separately, should the Federal District Court find any segments navigable.

We dispute the State's claims and intend to vigorously defend the lawsuit. At this time, we cannot predict an outcome. If the Federal District Court determines the riverbeds are navigable under the remaining six facilities that were not dismissed and if it calculates damages as the State District Court did in 2008, we estimate the annual rents could be approximately $3.8 million commencing when we acquired the facilities in November 2014. We anticipate that any obligation to pay the State rent for use and occupancy of the riverbeds would be recoverable in rates from customers, although there can be no assurances that the MPSC would approve any such recovery.

Colstrip Arbitration and Litigation

As part of the settlement of litigation brought by the Sierra Club and the Montana Environmental Information Center against the owners and operator of Colstrip, the owners of Units 1 and 2 agreed to shut down those units no later than July 2022. In January 2020, the owners of Units 1 and 2 closed those two units. We do not have ownership in Units 1 and 2, and decisions regarding those units, including their shut down, were made by their respective owners. The six owners of Units 3 and 4 currently share the operating costs pursuant to the terms of an operating agreement among them, the Ownership and Operation Agreement (O&O Agreement). Costs of common facilities were historically shared among the owners of all four units. With the closure of Units 1 and 2, we have incurred additional operating costs with respect to our interest in Unit 4 and expect to experience a negative impact on our transmission revenue due to reduced amounts of energy transmitted across our transmission lines. We expect to incorporate any reduction in revenue in our next general electric rate filing, resulting in lower revenue credits to certain customers.

The remaining depreciable life of our investment in Colstrip Unit 4 is through 2042. Recovery of costs associated with the closure of the facility is subject to MPSC approval. Three of the joint owners of Units 3 and 4 are subject to regulation in Washington and in May 2019, the Washington state legislature enacted a statute mandating Washington electric utilities to "eliminate coal-fired resources from [their] allocation of electricity" on or before December 31, 2025, after which date they may no longer include their share of coal-fired resources in their regulated electric supply portfolio. As a result of the Washington legislation, four of the six joint owners of Units 3 and 4 requested the operator prepare a 2021 budget reflecting closure of Units 3 and 4 by 2025, and alternately a closure of Unit 3 by 2025 and a closure of Unit 4 by 2027. Differing viewpoints on closure dates delayed approval of the 2021 budget, until it was approved on March 22, 2021. Budgeting for 2022 was also delayed, with the same four joint owners demanding substantial budget reductions, but was ultimately approved on January 21, 2022. Such budgeting pressures may result in future budgets that may not be sufficient to maintain the reliability of Units 3 and 4.

While we believe closure requires each owner's consent, there are differences among the owners as to this issue under the O&O Agreement. On March 12, 2021, we initiated an arbitration under the O&O Agreement (the "Arbitration"), which seeks to resolve the primary issue of whether closure of Units 3 and 4 can be accomplished without each joint owner's consent and to clarify the obligations of the joint owners to continue to fund operations until all joint owners agree on closure.

The Arbitration has given rise to three lawsuits concerning the number of arbitrators, the venue and the applicable arbitration laws. The four joint owners from the Pacific Northwest assert the Arbitration must be conducted under the O&O Agreement, with one arbitrator, in Spokane County, Washington, and pursuant to the Washington Arbitration Act. The fifth joint owner asserts the Arbitration must be conducted per the terms of Montana Senate Bill 265 (SB 265), which requires the Arbitration be conducted, with three arbitrators, in Montana and pursuant to the Montana Uniform Arbitration Act. The three initiated lawsuits do not make direct financial demands, and instead, are intended to address issues related to process for the Arbitration.

Since the Arbitration was initiated, and despite the litigation, we have worked and continue to work with the other joint owners to arrive at an agreed upon process for the Arbitration.

Colstrip Coal Dust Litigation

On December 14, 2020, a claim was filed against Talen Montana, LLC, the operator of the Colstrip Steam Plant, in the Montana Sixteenth Judicial District Court, Rosebud County, Cause No. CV-20-58. The plaintiffs allege they have suffered adverse effects from coal dust generated during operations associated with the Colstrip Steam Plant. On August 26, 2021, the claim was amended to add in excess of 100 plaintiffs. It also added NorthWestern, as well as the other owners of the Colstrip Steam Plant, and Westmoreland Rosebud Mining LLC, as defendants. Plaintiffs are seeking economic damages, costs and disbursements, punitive damages, attorneys' fees, and an injunction prohibiting defendants from allowing coal dust to blow onto plaintiffs' properties.

Since this lawsuit is in its early stages, we are unable to predict outcomes or estimate a range of reasonably possible losses.

Other Legal Proceedings

We are also subject to various other legal proceedings, governmental audits and claims that arise in the ordinary course of business. In the opinion of management, the amount of ultimate liability with respect to these other actions will not materially affect our financial position, results of operations, or cash flows.

Sch.19	MONTANA PLANT IN SERVICE - ELECTRIC					
	Account Number & Title	This Year MT Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	**Intangible Plant**					
3	301 Organization	19,995	$ -	$ 19,995	$ 19,995	0.00%
4	302 Franchises and Consents	19,288,558	-	19,288,558	18,713,879	3.07%
5	303 Miscellaneous Intangible Plant	7,266,663	-	7,266,663	2,237,200	224.81%
6	**Total Intangible Plant**	26,575,215	-	26,575,215	20,971,074	26.72%
7						
8	**Production Plant**					
9						
10	**Steam Production**					
11	310 Land and Land Rights	-	-			-
12	311 Structures and Improvements	-	-			-
13	312 Boiler Plant Equipment	-	-	-	-	-
14	313 Engines, Engine Driven Generator	-	-	-	-	-
15	314 Turbogenerator Units	-	-	-	-	-
16	315 Accessory Electric Equipment	-	-	-	-	-
17	316 Misc. Power Plant Equipment	447,832,465	-	447,832,465	435,436,861	2.85%
18	**Total Steam Production Plant**	447,832,465	-	447,832,465	435,436,861	2.85%
19						
20	**Nuclear Production**					
21	320 - 325 Not Applicable	-	-	-	-	-
22	**Total Nuclear Production Plant**	-	-	-	-	-
23						
24	**Hydraulic Production**					
25	330 Land and Land Rights	5,900,898	-	5,900,898	5,884,456	0.28%
26	331 Structures and Improvements	125,423,709	-	125,423,709	124,894,234	0.42%
27	332 Reservoirs, Dams and Waterways	177,907,561	-	177,907,561	177,509,945	0.22%
28	333 Water Wheel, Turbine, Generators	151,379,697	-	151,379,697	140,295,773	7.90%
29	334 Accessory Electric Equipment	88,750,061	-	88,750,061	86,002,570	3.19%
30	335 Misc. Power Plant Equipment	20,419,217	-	20,419,217	20,357,320	0.30%
31	336 Roads, Railroads and Bridges	2,493,836	-	2,493,836	2,493,836	0.00%
32	**Total Hydraulic Production Plant**	572,274,979	-	572,274,979	557,438,134	2.66%
33						
34	**Other Production**					
35	340 Land and Land Rights	3,819,385		3,819,384.85	2,005,777.75	90.42%
36	341 Structures and Improvements	59,449,471	19,232	59,430,239.08	59,430,239.08	0.00%
37	342 Fuel Holders & Accessories	21,230,045	112,084	21,117,960.86	21,117,960.86	0.00%
38	343 Prime Movers	104,189,628		104,189,627.52	102,331,431.94	1.82%
39	344 Generators	55,657,436	2,177,823	53,479,613.69	53,479,613.69	0.00%
40	345 Accessory Electric Equipment	19,203,828	770,151	18,433,677.24	18,186,115.89	1.36%
41	346 Misc. Power Plant Equipment	28,134,319	7,268	28,127,050.11	26,562,396.02	5.89%
42	**Total Other Production Plant**	291,684,111	3,086,557	288,597,553	283,113,535	1.94%
43	**Total Production Plant**	1,311,791,555	3,086,557	1,308,704,997	1,275,988,530	2.56%

Sch. 19 cont.	MONTANA PLANT IN SERVICE - ELECTRIC					
	Account Number & Title	This Year MT Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	**Transmission Plant**					
3	350 Land and Land Rights	40,237,210		40,237,210	39,367,412	2.21%
4	352 Structures and Improvements	38,688,898		38,688,898	34,444,659	12.32%
5	353 Station Equipment	310,674,497	7,251	310,667,246	282,383,309	10.02%
6	354 Towers and Fixtures	30,317,776		30,317,776	28,717,133	5.57%
7	355 Poles and Fixtures	427,533,322	1,997,809	425,535,513	389,808,920	9.17%
8	356 Overhead Conductors & Devices	174,615,905	830,112	173,785,793	169,290,480	2.66%
9	357 Underground Conduit	137,878	102,286	35,592	35,592	0.00%
10	358 Undergrnd Conductors & Devices	1,935,349	554,036	1,381,313	2,202,176	-37.28%
11	359 Roads and Trails	2,519,647	44,906	2,474,741	2,474,735	0.00%
12	**Total Transmission Plant**	1,026,660,481	3,536,400	1,023,124,081	948,724,417	7.84%
13						
14	**Distribution Plant**					
15	360 Land and Land Rights	14,264,151	601	14,263,550.67	14,391,096.86	-0.89%
16	361 Structures and Improvements	36,244,429	1,299,812	34,944,616.97	35,571,699.55	-1.76%
17	362 Station Equipment	253,396,251	4,675,515	248,720,735.16	254,283,441.45	-2.19%
18	363 Storage Battery Equipment	-				-
19	364 Poles, Towers, and Fixtures	341,701,090	415,454	341,285,636.28	320,653,283.94	6.43%
20	365 Overhead Conductors & Devices	139,507,503	494,264	139,013,239.28	134,126,064.41	3.64%
21	366 Underground Conduit	155,966,719	619,430	155,347,289.30	142,512,421.13	9.01%
22	367 Undergrnd Conductors & Devices	249,832,503	3,785,810	246,046,692.34	232,831,162.27	5.68%
23	368 Line Transformers	246,552,091	919,102	245,632,989.30	235,164,616.47	4.45%
24	369 Services	162,264,238	464,704	161,799,534.04	151,282,704.83	6.95%
25	370 Meters	65,110,676	107,483	65,003,193.63	56,064,966.19	15.94%
26	371 Installations on Cust. Premises	-				-
27	372 Leased Property on Cust. Premises	-				-
28	373 Street Lighting and Signal Systems	76,698,030	19,872.21	76,678,157.94	68,229,059	12.38%
29	**Total Distribution Plant**	1,741,537,682	12,802,047	1,728,735,635	1,645,110,516	5.08%
30						
31	**General Plant**					
32	389 Land and Land Rights	689,633	506,968.71	182,664.77	182,665	0.00%
33	390 Structures and Improvements	10,804,083		10,804,082.73	10,697,093	1.00%
34	391 Office Furniture and Equipment	1,590,880		1,590,880.19	1,607,693	-1.05%
35	392 Transportation Equipment	62,881,983	229,388.89	62,652,593.62	59,742,385	4.87%
36	393 Stores Equipment	955,765		955,764.85	984,380	-2.91%
37	394 Tools, Shop & Garage Equipment	10,229,525	-	10,229,525.49	9,860,529	3.74%
38	395 Laboratory Equipment	1,046,044		1,046,044.29	1,215,039	-13.91%
39	396 Power Operated Equipment	5,897,810		5,897,810.00	5,899,875	-0.04%
40	397 Communication Equipment	49,859,140	2,050,053.67	47,809,086.02	41,603,403	14.92%
41	398 Miscellaneous Equipment	2,110,622		2,110,622.45	2,111,267	-0.03%
42	399 Other Tangible Equipment	-			-	-
43	**Total General Plant**	146,065,486	2,786,411	143,279,074	133,904,330	7.00%
44	**Total Plant in Service**	4,252,630,419	22,211,416	4,230,419,003	4,024,698,866	5.11%
45						
46	4101 El Plant Allocated from Common	110,533,552		110,533,552	115,116,296	-3.98%
47	103 Experimental Electric Plant Unclassified	4,092,785	679,910	3,412,875	2,928,663	16.53%
48	105 El Plant Held for Future Use	5,463,119		5,463,119	5,469,331	(0.00)
49	107 El Construction Work in Progress	145,724,447	792,664	144,931,783	76,918,786	88.42%
50						
51						
52	**TOTAL ELECTRIC PLANT**	$ 4,518,444,322	$ 23,683,990	$ 4,494,760,332	$ 4,225,131,942	6.38%

Sch. 19 cont. **MONTANA PLANT IN SERVICE - ELECTRIC**

	CONSOLIDATED PLANT IN SERVICE	December 31, 2021	December 31, 2020
1			
2	Montana Electric	$ 4,230,419,003	$ 4,024,698,866
3	Yellowstone National Park	22,211,416	21,309,430
4	Montana Natural Gas (Includes CMP)	955,270,296	921,821,582
5	Common	163,830,981	170,239,284
6	Townsend Propane	1,523,174	1,523,174
7	South Dakota Electric	975,412,139	946,530,965
8	South Dakota Natural Gas	233,394,205	220,364,733
9	South Dakota Common	68,846,326	63,763,314
10	Asset Retirement Obligation	33,839,429	27,990,906
11	**TOTAL PLANT**	$ 6,684,746,970	$ 6,398,242,253

Sch. 20	MONTANA DEPRECIATION SUMMARY - ELECTRIC						
	Functional Plant Class	Montana Plant Cost	This Year MT Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	Current Avg. Rate
1	**Accumulated Depreciation**						
2							
3	Steam Production	$ 448,011,550	$ 137,958,730		$ 137,958,730	$ 124,798,087	2.94%
4							
5	Nuclear Production	-					-
6							
7	Hydraulic Production	572,274,979	142,909,696	-	142,909,696	137,821,039	2.00%
8							
9	Other Production	291,684,111	90,839,326	2,397,109	88,442,217	77,690,021	3.61%
10							
11	Transmission	1,026,660,481	386,121,516	2,197,455	383,924,061	371,923,994	2.95%
12							
13	Distribution	1,741,538,282	776,490,440	5,661,679	770,828,761	739,564,291	3.12%
14							
15	General and Intangible	172,640,701	92,890,751	866,195	92,024,555	86,891,158	7.27%
16							
17	Common	110,535,073	29,668,724	-	29,668,724	28,613,794	5.57%
18							
19							
20	**Total Accum Depreciation**	$ 4,363,345,177	$ 1,656,879,182	$ 11,122,437	$ 1,645,756,744	$ 1,567,302,384	3.11%
21							
22							
23							

		December 31,	
24	**Consolidated**		
25	**Accumulated Depreciation**	2021	2020
26			
27	Montana Electric	$1,616,088,021	1,538,688,590
28	Yellowstone National Park	11,122,437	10,775,157
29	Montana Natural Gas (Includes CMP)	398,507,251	379,512,122
30	Common	46,114,248	44,485,802
31	Townsend Propane	1,047,214	1,006,510
32	South Dakota Electric	339,038,874	321,722,932
33	South Dakota Natural Gas	104,065,010	99,910,123
34	South Dakota Common	21,986,176	20,058,902
35	Acquisition Writedown	40,572,152	43,276,641
36	Basin Creek Capital Lease	31,162,371	29,151,894
37	FIN 47	273,733	2,584,933
38	CWIP-Capital Retirement Clearing	-8,987,263	(6,356,971)
39	**Total Consolidated Accum Depreciation**	$2,600,990,223	$2,484,816,637

Sch. 21	MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED) - ELECTRIC					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	151 Fuel Stock	$ 1,858,899	$ -	$ 1,858,899	$ 1,576,044	17.95%
3						
4	154 Plant Materials & Operating Supplies					
5	Assigned and Allocated to:					
6	Operation & Maintenance	-		-	-	-
7	Construction	-		-	-	-
8	Production Plant	6,877,787		6,877,787	5,779,767	19.00%
9	Transmission Plant	5,722,792		5,722,792	4,770,498	19.96%
10	Distribution Plant	20,477,736		20,477,736	16,453,182	24.46%
11						
12						
13	**Total MT Materials and Supplies**	$ 34,937,214	$ -	$ 34,937,214	$ 28,579,491	22.25%
14						
15						

16	**Consolidated**	December 31,	
17	**Fuel Stock**	2021	2020
18			
19	Montana Electric	$1,858,899	$1,576,044
20	South Dakota	5,650,724	4,985,419
21			
22	**Total Fuel Stock**	$7,509,623	$6,561,463
23			
24			
25			

26	**Consolidated**	December 31,	
27	**Materials and Supplies**	2021	2020
28			
29	Montana Electric	33,078,315	$27,003,447
30	Montana Natural Gas	5,410,308	5,100,789
31	South Dakota	15,050,102	11,587,583
32			
33	**Total Consolidated Materials and Supplies**	53,538,725	$43,691,819

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - ELECTRIC				
	Commission Accepted - Most Recent		% Capital Structure	% Cost Rate	Weighted Cost
2	**Regulated Electric Transmission, Distribution and Production Utility**				
4	Docket Number:	2018.02.012			
5	Order Number :	7604u			
6	Effective Date:	December 20, 2019			
8	Common Equity		49.38%	9.65%	4.77%
9	Long Term Debt		50.62%	4.26%	2.16%
11	**TOTAL**		100.00%		6.92%
13	**Colstrip Unit 4**				
15	Docket Number:	2018.02.012			
16	Order Number :	7604u			
17	Effective Date:	December 20, 2019			
19	Common Equity		50.00%	10.00%	5.00%
20	Long Term Debt		50.00%	6.50%	3.25%
22	**TOTAL**		100.00%		8.25%

Sch. 23	STATEMENT OF CASH FLOWS			
	Description	This year	Last Year	% Change
1	Increase/(Decrease) in Cash & Cash Equivalents:			
2	**Cash Flows from Operating Activities:**			
3	Net Income	$ 186,839,752	$ 155,215,334	20.37%
4	Noncash Charges (Credits) to Income:			
5	Depreciation and Depletion	159,403,530	151,822,661	4.99%
6	Amortization, Net	32,746,162	32,493,241	0.78%
7	Other Noncash Charges to Net Income, Net	13,533,571	9,164,507	47.67%
8	Deferred Income Taxes, Net	971,152	(8,915,420)	110.89%
9	Investment Tax Credit Adjustments, Net	239,294	(3,229)	>300.00%
10	Change in Operating Receivables, Net	(22,324,551)	2,531,086	>-300.00%
11	Change in Materials, Supplies & Inventories, Net	(19,613,582)	(7,107,682)	-175.95%
12	Change in Operating Payables & Accrued Liabilities, Net	(4,575,338)	36,683,477	-112.47%
13	Allowance for Funds Used During Construction (AFUDC)	(11,082,078)	(6,890,979)	-60.82%
14	Change in Other Assets & Liabilities, Net	(121,016,076)	25,733,749	>-300.00%
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	(2,599,655)	(4,306,292)	39.63%
17	Change in Regulatory Assets	10,802,572	(22,881,012)	147.21%
18	Change in Regulatory Liabilities	(2,175,661)	(9,752,604)	77.69%
19	**Net Cash Provided by Operating Activities**	221,149,090	353,786,837	-37.49%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(435,651,210)	(407,029,942)	-7.03%
22	(Net of AFUDC)			
23	Investment in Equity Securities	(1,505,221)	(41,825)	>-300.00%
24	Proceeds from Sale of Assets	-	-	-
25	**Net Cash Used in Investing Activities**	(437,156,431)	(407,071,767)	-7.39%
26	**Cash Flows from Financing Activities:**			
27	Proceeds from Issuance of:			
28	Issuance of Long-Term Debt	99,915,000	150,000,000	-33.39%
29	Issuance of Notes Payable	-	100,000,000	-100.00%
30	Line of Credit Borrowings, Net	-	-	100.00%
31	Proceeds From Issuance of Common Stock, Net	196,246,244	-	100.00%
32	Payments for Retirement of:			
33	Repayments of Short Term Borrowings, Net	(100,000,000)	-	-
34	Repayments of Long Term Borrowings, Net	(955,280)	-	-
35	Line of Credit Repayments, Net	151,000,000	(67,000,000)	>300.00%
36	Dividends on Common Stock	(128,482,602)	(120,349,736)	-6.76%
37	Other Financing Activities:			
38	Debt Financing Costs	(909,219)	(2,577,869)	64.73%
39	Treasury Stock Activity	706,750	(1,391,881)	150.78%
40	**Net Cash Used in Financing Activities**	217,520,893	58,680,515	270.69%
41	**Net Increase/Decrease in Cash and Cash Equivalents**	1,513,552	5,395,584	-71.95%
42	**Cash and Cash Equivalents at Beginning of Year**	15,544,013	10,148,429	53.17%
43	**Cash and Cash Equivalents at End of Year**	$ 17,057,565	$ 15,544,013	9.74%
44				
45	This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory			
46	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity			
47	method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana			
48	Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4.			
49				
50				
51				
52				
53				

Sch. 24	MONTANA LONG TERM DEBT 2021								
	Description	Issue Date	Maturity Date	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem./Disc.	Total Cost %
1									
2	**First Mortgage Bonds**								
4	5.71% Series ($55M), Due 2039	10/15/09	10/15/39	55,000,000	54,450,000	55,000,000	5.71%	3,158,845	5.74%
5	5.01% Series ($225M), Due 2025	05/27/10	05/01/25	161,000,000	160,075,635	161,000,000	5.01%	8,585,842	5.33%
6	4.15% Series($60M), Due 2042	08/10/12	08/10/42	60,000,000	59,623,329	60,000,000	4.15%	2,502,562	4.17%
7	4.30% Series($40M), Due 2052	08/10/12	08/10/52	40,000,000	39,748,886	40,000,000	4.30%	1,726,280	4.32%
8	4.85% Series($65M), Due 2043	12/19/13	12/19/43	15,000,000	14,905,880	15,000,000	4.85%	730,647	4.87%
9	3.99% Series($35M), Due 2028	12/19/13	12/19/28	35,000,000	34,807,797	35,000,000	3.99%	1,409,343	4.03%
10	4.176% Series($450M), Due 2044	11/14/14	11/14/44	450,000,000	445,072,899	450,000,000	4.18%	19,570,295	4.35%
11	3.11% Series($75M), Due 2025	06/23/15	07/01/25	75,000,000	74,563,893	75,000,000	3.11%	2,746,650	3.66%
12	4.11% Series($125M), Due 2045	06/23/15	07/01/45	125,000,000	124,273,156	125,000,000	4.11%	5,367,425	4.29%
13	4.03% Series ($250M) Due 2047	11/06/17	11/06/47	250,000,000	248,778,070	250,000,000	4.03%	10,644,517	4.26%
14	3.98% Series($50M), Due 2049	06/26/19	06/26/49	50,000,000	49,538,281	50,000,000	3.98%	2,005,288	4.01%
14	3.98% Series($150M), Due 2049	09/17/19	09/17/49	100,000,000	99,389,221	100,000,000	3.98%	3,996,904	4.00%
14	3.21% Series($100M) Due 2030	05/15/20	05/15/30	100,000,000	99,516,844	100,000,000	3.21%	3,269,953	3.27%
15	1.00% Series($100M) Due 2024	03/26/21	03/26/24	100,000,000	99,442,399	99,938,611	1.00%	1,228,950	1.23%
16	**Total First Mortgage Bonds**			$ 1,616,000,000	$ 1,604,186,291	$ 1,615,938,611		$ 66,943,501	4.14%
17									
18	**Pollution Control Bonds**								
19	2.00% Series ($144.7M), Due 2023	08/11/16	08/01/23	$ 144,660,000	$ 143,067,684	$ 144,660,000	2.000%	$ 3,627,593	2.51%
20									
21	**Total Pollution Control Bonds**			$ 144,660,000	$ 143,067,684	$ 144,660,000		$ 3,627,593	2.51%
22									
23	**Other Long-Term Debt**								
24									
25									
26	**Total Other Long Term Debt**			$ -	$ -	$ -		$ -	
27									
28	**TOTAL LONG TERM DEBT**			$ 1,760,660,000	$ 1,747,253,975	$ 1,760,598,611		$ 70,571,094	4.01%
29									
30									
31	This schedule does not reflect our obligations under capital lease which total $12,796,408								
32									
33									
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43									
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45									

Sch. 25	PREFERRED STOCK									
	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1										
2	Not Applicable									
3										
4										
5										
6										
7										
8										
9										
10										
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22										
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27										
28										
29										
30										
31										
32	**TOTAL**					0		0	0	

Sch. 26

COMMON STOCK

	Avg. Number of Shares Outstanding 1/	Book Value Per Share	Basic Earnings Per Share	Dividends Per Share (Declared)	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio
January	50,601,501	$41.51				$59.61	53.16	
February	50,672,048	41.98				61.10	53.71	
March	50,675,247	41.71	$1.25	0.620		66.27	58.05	
April	50,706,342	41.93				70.80	64.30	
May	51,074,734	42.35				69.63	62.46	
June	51,560,053	42.23	0.72	0.620		65.28	59.29	
July	51,561,266	42.59				64.63	58.92	
August	52,088,451	43.09				65.05	61.15	
September	52,605,730	42.71	0.68	0.620		65.62	57.23	
October	52,653,710	42.93				60.40	56.09	
November	54,057,097	43.44				58.98	53.66	
December	54,060,648	43.28	$0.96	0.620		57.65	54.14	
TOTAL Year End	51,709,229	$43.28	$3.61	$2.48	31.30%	$56.83		15.7

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for the twelve months ended December 31, 2021.

Sch. 27	MONTANA EARNED RATE OF RETURN - ELECTRIC				
		Description	This Year	Last Year	% Change
1		**Rate Base**			
2	101	Plant in Service	$4,659,295,591	$4,448,078,879	4.75%
3	108	Accumulated Depreciation	(1,570,697,176)	(1,484,802,437)	-5.78%
4					
5	**Net Plant in Service**		$3,088,598,415	$2,963,276,442	4.23%
6		Additions:			
7	154, 156	Materials & Supplies	$25,867,705	$23,635,906	9.44%
8	165	Prepayments			
9		Other Additions	17,518,276	20,026,811	-12.53%
10					
11	**Total Additions**		$43,385,981	$43,662,716	-0.63%
12		Deductions:			
13	190	Accumulated Deferred Income Taxes	$178,385,231	$169,887,317	5.00%
14	252	Customer Advances for Construction	57,807,749	47,518,533	21.65%
15	255	Accumulated Def. Investment Tax Credits			
16		Other Deductions	114,896,088	110,514,466	3.96%
17					
18	**Total Deductions**		$351,089,068	$327,920,316	7.07%
19	**Total Rate Base**		$2,780,895,327	$2,679,018,843	3.80%
20	**Net Earnings**		$ 177,732,079	$ 153,582,319	15.72%
21	**Rate of Return on Average Rate Base**		6.391%	5.733%	11.48%
22	**Rate of Return on Average Equity 1/**		8.347%	6.913%	20.74%
23					
24		**Major Normalizing and**			
25		**Commission Ratemaking Adjustments**			
26		Rate Schedule Revenues	($1,258,771)	$7,219,259	-117.44%
27		Transmission Revenues 2/	(19,807,574)		-
28					-
29		CU4 and Deadband Disallowance 3/		9,422,209	-100.00%
30		DGGS cancelled project 4/	1,204,674		-
31		Environmental True-up Sites 5/	81,400		-
32					-
33					-
34					-
35		Non-Allowables:			-
36		Advertising	340,910	307,535	10.85%
37		Dues, Contributions, Other	63,818	62,409	2.26%
38					-
39		Associated Income Taxes 6/	5,107,574	(5,233,596)	197.59%
40					
41	**Total Adjustments**		($14,267,968)	$11,777,815	-221.14%
42	**Revised Net Earnings**		$163,464,111	$165,360,134	-1.15%
43		**Rate Base Adjustment**			
44		Stipulation with MCC 7/	($15,607,998)	($16,473,665)	5.25%
45					
46	**Revised Rate Base**		$2,765,287,329	$2,662,545,178	3.86%
47	**Adjusted Rate of Return on Average Rate Base**		5.911%	6.211%	-4.82%
48	**Adjusted Rate of Return on Average Equity 1/**		7.350%	7.907%	-7.04%
49					
50	1/ Return on Equity calculated using the capital structure approved in Docket No. D2018.2.12.				
51					
52	2/ Transmission revenue subject to FERC true-up.				
53					
54	3/ In Docket No. 2019.09.058 the Commission disallowed $3,765,739 of deadband and sharing of				
55	Qualifying Facilities costs, $5,656.470 of disallowed Colstrip Unit 4 replacement power costs, and				
56	$458,028 of interest associated with those costs.				
57					
58	4/ Recognized expenses due to DGGS cancelled project.				
59					
60	5/ Removal of increase to environmental liability recorded in 2021.				
61					
62	6/ Associated income taxes include an interest synchronization adjustment based upon the approved				
63	capital structure in Docket No. D2018.2.12.				
64					
65	7/ Per NWE/MCC Stipulation Agreement Docket No. D2007.7.82 reflecting two-thirds of the $38.8 million				
66	allocated to electric as a rate base reduction.				
67					
68					

Sch. 27	cont. MONTANA EARNED RATE OF RETURN - ELECTRIC			
	Description	This Year	Last Year	% Change
1				
2	**Detail - Other Additions**			
3				
4	Cost of Refinancing Debt	15,822,981	18,467,725	-14.32%
5	Fuel Stock	1,695,294	1,559,086	8.74%
6				-
7				
8	**Total Other Additions**	$17,518,276	$20,026,811	-12.53%
9				
10	**Detail - Other Deductions**			
11	Personal Injury and Property Damage	$4,207,739	$4,774,577	-11.87%
12	Gross Cash Requirements	38,876,402	35,345,413	9.99%
13	Regulatory Liability (TCJA)	71,811,947	70,394,475	2.01%
14	MPSC/MCC Taxes	$0	$0	-
15				
16	**Total Other Deductions**	$114,896,088	$110,514,466	3.96%
17				
18				
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Sch. 28	MONTANA COMPOSITE STATISTICS - ELECTRIC (EXCLUDES YNP)		
	Description		Amount
1			
2		**Plant (Intrastate Only)**	
3			
4	101	Plant in Service (Includes Allocation from Common)	4,340,952,555
5	103	Experimental Electric Plant Unclassified	3,412,875
6	105	Plant Held for Future Use	5,463,119
7	107	Construction Work in Progress	144,931,783
8	114	Plant Acquisition Adjustments	481,574,396
9	151-163	Materials & Supplies	34,937,214
10		(Less):	
11	108, 111, 115	Depreciation & Amortization Reserves	1,686,328,896
12	252	Customer Advances	61,991,244
13	**NET BOOK COSTS**		3,262,951,802
14			
15		**Revenues & Expenses**	
16			
17	400	Operating Revenues	879,977,969
18			
19	**Total Operating Revenues**		879,977,969
20			
21	401-402	Other Operating Expenses (including regulatory amortizations)	432,261,226
22	403-407	Depreciation & Amortization Expenses	128,119,160
23	408.1	Taxes Other than Income Taxes	134,822,472
24	409-411	Federal & State Income Taxes	7,040,353
25	411.8	SO2 Allowances	2,679
26			
27	**Total Operating Expenses**		702,245,890
28	**Net Operating Income**		177,732,079
29			
30	415-421.1	Other Income	5,503,315
31	421.2-426.5	Other Deductions	1,260,888
32	**NET INCOME BEFORE INTEREST EXPENSE**		$ 181,974,506
33			
34		**Average Customers (Intrastate Only)**	
35		Residential	311,771
36		Commercial & Industrial	71,562
37		Other (including interdepartmental)	5,651
38			
39	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		388,984
40			
41		**Other Statistics (Intrastate Only)**	
42		Average Annual Residential Use (Kwh)	8,747
43		Average Annual Residential Cost per (Kwh)	$0.121
44		Average Residential Monthly Bill	$88.51
45			
46		Plant in Service (Gross) per Customer	$11,160

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,150	481	114	6	601
2	Alberton	420	396	92	13	501
3	Alder	103	232	95	20	347
4	Amsterdam	180	133	39	8	180
5	Anaconda	9,298	4,411	909	55	5,375
6	Armington	-	1	-	-	1
7	Arrow Creek	-	4	4	-	8
8	Augusta	309	270	115	5	390
9	Avon	111	96	65	3	164
10	Barber	-	46	11	-	57
11	Basin	212	172	79	2	253
12	Bearcreek	79	64	26	2	92
13	Belfry	218	172	64	16	252
14	Belgrade	7,389	9,397	2,544	110	12,051
15	Belt	597	650	261	14	925
16	Benchland	-	6	6	-	12
17	Big Sandy	598	330	138	5	473
18	Big Sky	2,308	4,265	1,018	26	5,309
19	Big Timber	1,641	1,265	428	34	1,727
20	Billings	104,170	50,364	9,071	668	60,103
21	Black Eagle	904	452	186	14	652
22	Bonner	1,663	78	64	1	143
23	Boulder	1,183	875	275	26	1,176
24	Box Elder	87	150	67	9	226
25	Bozeman	37,280	34,350	7,279	432	42,061
26	Brady	140	82	39	5	126
27	Bridger	708	463	182	17	662
28	Broadview	192	229	163	3	395
29	Buffalo	-	-	3	5	8
30	Butte	33,525	15,430	2,765	268	18,463
31	Cameron	-	421	138	4	563
32	Canyon Creek	-	196	42	8	246
33	Cardwell	-	-	1	-	1
34	Carter	58	117	73	4	194
35	Cascade	685	1,154	365	28	1,547
36	Centerville	-	13	12	1	26
37	Checkerboard	-	54	9	1	64
38	Chester	847	471	316	17	804
39	Chinook	1,203	806	329	17	1,152
40	Choteau	1,684	1,002	390	27	1,419
41	Churchill	902	713	144	26	883
42	Clancy	1,661	918	178	8	1,104
43	Clinton	1,052	106	39	1	146
44	Coffee Creek	-	54	28	1	83
45	Collins	-	1	5	-	6
46	Colstrip	2,214	965	235	35	1,235
47	Columbus	1,893	1,040	357	20	1,417
48	Conrad	2,570	1,251	480	28	1,759
49	Corbin	-	1	2	-	3
50	Corvallis	976	906	187	39	1,132
51	Craig	43	97	42	6	145

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Custer	159	2	3	-	5
2	Darby	720	827	266	16	1,109
3	De Borgia	78	162	40	2	204
4	Deer Lodge	3,111	2,117	626	76	2,819
5	Denton	255	179	90	1	270
6	Dillon	4,134	2,116	619	63	2,798
7	Divide	-	71	17	5	93
8	Dodson	124	117	73	5	195
9	Drummond	309	375	223	31	629
10	Dutton	316	238	121	3	362
11	East Helena	1,984	3,296	475	30	3,801
12	Edgar	114	170	57	9	236
13	Elliston	219	216	66	3	285
14	Ennis	838	2,048	636	38	2,722
15	Fairfield	708	410	168	31	609
16	Fishtail	-	50	6	-	56
17	Florence	765	437	158	17	612
18	Floweree	-	105	62	2	169
19	Fort Belknap	1,293	435	103	22	560
20	Fort Benton	1,464	850	384	35	1,269
21	Fort Harrison	-	-	93	3	96
22	Fromberg	438	322	84	10	416
23	Gallatin Gateway	856	811	272	13	1,096
24	Gardiner	875	848	325	12	1,185
25	Garrison	96	126	64	7	197
26	Geraldine	261	283	154	2	439
27	Geyser	87	68	38	4	110
28	Gildford	179	88	67	2	157
29	Glasgow	3,250	1,678	736	58	2,472
30	Glasgow Air Base		1	1	-	2
31	Gold Creek	-	81	44	5	130
32	Grantsdale	-	19	3	1	23
33	Great Falls	58,505	30,170	5,532	378	36,080
34	Greycliff	112	51	28	12	91
35	Hall	-	298	88	21	407
36	Hamilton	4,348	5,754	1,512	118	7,384
37	Hardin	3,505	1,420	469	24	1,913
38	Harlem	808	452	207	26	685
39	Harlowton	997	683	293	10	986
40	Harrison	137	198	64	26	288
41	Haugan	-	88	38	2	128
42	Havre	10,026	4,919	1,299	185	6,403
43	Helena	53,457	26,561	5,506	435	32,502
44	Hingham	118	107	75	2	184
45	Hinsdale	217	135	57	6	198
46	Hobson	215	169	61	8	238
47	Huson	210	146	35	2	183
48	Hysham	312	-	1	-	1
49	Inverness	55	42	29	1	72
50	Jardine	57	1	1	-	2
51	Jeffers	-	3	1	-	4

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Jefferson City	472	375	63	4	442
2	Joliet	595	515	151	21	687
3	Joplin	157	97	49	2	148
4	Judith Gap	126	88	55	5	148
5	Kremlin	98	71	37	1	109
6	Laurel	6,718	3,300	537	22	3,859
7	Lavina	187	204	112	13	329
8	Lennep	-	19	13	1	33
9	Lewistown	5,910	3,377	937	61	4,375
10	Lincoln	1,013	1,093	307	11	1,411
11	Livingston	7,044	5,243	1,229	74	6,546
12	Logan	99	59	25	2	86
13	Lohman	-	29	29	5	63
14	Lolo	3,892	1,642	212	18	1,872
15	Loma	85	69	43	4	116
16	Lothair	-	14	13	-	27
17	Malta	1,997	1,321	519	46	1,886
18	Manhattan	1,520	1,381	397	98	1,876
19	Martinsdale	64	124	88	15	227
20	Marysville	80	76	39	2	117
21	Maxville	130	4	1	-	5
22	McAllister	-	279	63	8	350
23	Melrose	-	2	1	-	3
24	Melstone	96	160	278	22	460
25	Melville	-	69	52	3	124
26	Milltown	-	78	22	4	104
27	Missoula	66,788	39,305	6,872	598	46,775
28	Moccasin	-	49	34	2	85
29	Molt	-	34	36	-	70
30	Monarch	-	332	63	2	397
31	Montana City	2,715	1,188	229	4	1,421
32	Moore	193	109	43	5	157
33	Musselshell	60	64	30	1	95
34	Nashua	290	193	67	3	263
35	Neihart	51	201	43	1	245
36	Nevada City	-	-	8	-	8
37	Norris	-	53	48	2	103
38	Nye	-	16	2	1	19
39	Paradise	163	161	66	9	236
40	Park City	983	443	88	6	537
41	Philipsburg	820	1,996	383	23	2,402
42	Plains	1,048	1,780	498	29	2,307
43	Pompey's Pillar		1	-	-	1
44	Pony	118	148	32	4	184
45	Power	179	90	47	2	139
46	Pray	681	30	1	-	31
47	Radersburg	66	86	29	2	117
48	Ramsay	-	76	35	1	112
49	Raynesford	-	72	43	2	117
50	Red Lodge	2,125	2,110	431	27	2,568
51	Reedpoint	193	168	61	4	233
52	Ringling	-	42	29	3	74

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Roberts	-	4	-	-	4
2	Rocker	-	67	23	2	92
3	Rockvale	-	2	1	-	3
4	Roscoe	15	93	11	-	104
5	Roundup	1,788	1,100	398	19	1,517
6	Rudyard	258	149	70	2	221
7	Ryegate	245	146	72	9	227
8	Saco	197	167	101	2	270
9	Saint Marie	264	291	54	3	348
10	Saint Regis	319	569	199	12	780
11	Saltese	-	39	22	1	62
12	Sand Coulee	212	157	52	3	212
13	Sapphire Village	-	70	11	-	81
14	Shawmut	42	55	37	2	94
15	Sheridan	642	1,008	272	44	1,324
16	Silesia	96	45	10	1	56
17	Silverbow	-	10	8	1	19
18	Springdale	42	40	12	7	59
19	Square Butte	-	36	20	1	57
20	Stanford	401	344	215	8	567
21	Stevensville	1,809	2,367	640	77	3,084
22	Stockett	169	165	64	1	230
23	Sumatra	-	-	9	-	9
24	Superior	812	934	280	24	1,238
25	Taft	-	-	3	-	3
26	Tampico	-	9	5	-	14
27	Thompson Falls	1,313	1,209	373	31	1,613
28	Three Forks	1,869	1,567	561	72	2,200
29	Toston	108	51	41	26	118
30	Townsend	1,878	1,457	415	21	1,893
31	Tracy	-	88	12	4	104
32	Turah	306	40	2	-	42
33	Twin Bridges	375	324	177	26	527
34	Twodot	-	56	50	6	112
35	Ulm	738	439	137	11	587
36	Utica	-	2	6	1	9
37	Valier	509	372	179	45	596
38	Vaughn	658	242	55	6	303
39	Victor	745	831	297	24	1,152
40	Virginia City	190	211	108	2	321
41	Wagner	-	46	26	1	73
42	Walkerville	675	256	32	3	291
43	Warm Springs	-	-	3	-	3
44	Washoe	-	6	2	-	8
45	West Yellowstone	1,271	2	11	-	13
46	White Sulphur Springs	939	817	401	63	1,281
47	Whitehall	1,038	1,045	325	66	1,436
48	Wickes	-	1	-	-	1
49	Williamsburg	-	-	1	-	1
50	Willow Creek	210	152	66	23	241

Sch. 29	Montana Customer Information- Electric, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Windham	-	45	33	3	81
2	Winston	147	154	53	3	210
3	Wolf Creek	-	431	173	11	615
4	Yellowstone Club	-	627	14	-	641
5	Zurich	-	104	86	11	201
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49	**Total**	503,001	311,771	71,562	5,651	388,984

1/ Customer populations represent an average of the 12 month period from 01/01/21 through 12/31/21. YNP customer counts have been excluded.

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
3	Executive	2	3	3
4	Customer Care	136	151	144
5	Finance	160	156	158
6	Distribution	457	442	450
7	Transmission	313	305	309
8	Supply	124	116	120
9	Legal	27	23	25
10		`	`	
11				
12				
13				
14				
15				
16				
17	**TOTAL EMPLOYEES**	1,219	1,196	1,208

1/ Consistent with prior years, part time employees have been converted to full-time equivalents.

Sch. 31	MONTANA CONSTRUCTION BUDGET 2022 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3	MT Transmission - Billings Rimrock Substation rebuild	$20,718,587	$20,718,587
4	MT Distribution - Transformer purchases new connects	10,495,778	10,495,778
5	MT Distribution - Missoula City Substation rebuild	7,078,542	7,078,542
6	MT Distribution - System Rural Reliability initiative	6,000,000	6,000,000
7	MT Transmission - Line Creek to Red Lodge 50Kv rebuild	4,923,581	4,923,581
8	MT Transmission - 2nd Laurel City 100kv capacity	4,593,134	4,593,134
9	MT Transmission - Meadow to Midway reconductor capacity	3,382,978	3,382,978
10	MT Transmission - Bonner to Mill Creek A pole replacements	2,421,718	2,421,718
11	MT Transmission - South Butte 161-100kv's substation capacity	2,415,537	2,415,537
12	MT Distribution - Lewistown base pole replacements	2,306,370	2,306,370
13	MT Distribution - LED street lights program	2,272,005	2,272,005
14	MT Distribution - Great Falls base pole replacements	2,097,868	2,097,868
15	MT Transmission - Three Rivers to Clyde Park pole replacements	2,024,093	2,024,093
16	MT Transmission - Rattlesnake to Kerr A pole replacements	1,899,423	1,899,423
17	MT Transmission - Laurel Auto Substation rebuild	1,840,381	1,840,381
18	MT Transmission - East Gallatin transformer capacity upgrade	1,815,008	1,815,008
19	MT Transmission - Thompson Falls to Kerr A pole replacements	1,733,723	1,733,723
20	MT Distribution - Helena division forest management program	1,551,335	1,551,335
21	MT Transmission - Mill Creek to Dillon Salmon pole replacements	1,504,874	1,504,874
22	MT Transmission - Great Falls Switchyard to Riverview NW reconductor	1,476,799	1,476,799
23	MT Distribution - capacity Skalkaho cutover	1,349,621	1,349,621
24	MT Transmission - Steamplant 230kv cap and pin substation	1,307,341	1,307,341
25	MT Distribution - Missoula division forrest management program	1,284,053	1,284,053
26	MT Distribution - Misoula Reserve St Bank 3 substation capacity	1,235,514	1,235,514
27	MT Distribution - LED yard lights replacement program	1,226,987	1,226,987
28	MT Distribution - Bozeman base pole replacements	1,219,297	1,219,297
29	MT Transmission - Chester Capacitor sub maintenance	1,203,384	1,203,384
30	MT Transmission - Rainbow-Two Dot 100kv line compliance	1,202,717	1,202,717
31	MT Transmission - South Butte Bank 3 substation capacity	1,136,918	1,136,918
32	MT Distribution - Butte Base Pole Replacements	1,070,676	1,070,676
33	MT Transmission - Hamilton Heights substation maintenance	1,060,734	1,060,734
34	MT Distribution - Billings Meridian 84 46th St W underground cable	1,057,663	1,057,663
35	MT Transmission - Millcreek 230kv cap and pin substation	1,050,838	1,050,838
36	SD Distribution - Huron Alpena LSI capacity	3,127,861	0
37	SD Distribution - LED proactive light replacements	1,500,410	0
38	20 SD Transmission Worst Circuit	1,444,702	0
39			
40	All Other Projects < $1 Million Each and blankets	103,609,948	77,559,404
41	**Total Electric Utility Construction Budget**	**207,640,399**	**175,516,883**
42			
43	**Natural Gas Operations**		
44	MT Transmission - Morel-Butte transmission line replacement	$21,697,162	$21,697,162
45	MT Transmission - Byron pipeline purchase and upgrade	8,206,448	$8,206,448
46	MT Transmission - Marias Valier pipeline Loop	6,463,260	$6,463,260
47	MT Transmission - Meriwether compressor addition	5,858,022	$5,858,022
48	MT Distribution - Butte Division base gas one plan	4,370,824	$4,370,824
49	MT Transmission - LNG facilitiy east line	2,143,934	$2,143,934
50	MT Facilities - Kalispell gas garage addition	1,585,056	$1,585,056
51	MT Transmission - CARCB pipeline Loop	1,566,463	1,566,463
52	MT Distribution - gas meters and regulators	1,497,750	1,497,750
53	MT Distribution - Bozeman Division base gas one plan	1,396,608	1,396,608
54	MT Distribution - Whitefish Mountain capacity upgrade	1,271,171	1,271,171
55	MT Distribution - compliance NPRM required projects	1,012,881	1,012,881
56	SD Transmission - Millbank line reroute and DOT	3,485,687	0
57	SD Distribution - Yankton Full Circle capacity	2,019,343	0
58			
59	All Other Projects < $1 Million Each and blankets	33,513,432	$20,462,176
60	**Total Natural Gas Utility Construction Budget**	**$96,088,045**	**$77,531,758**
61			
62	**Common**		
63	MT Common - Distribution AMI Metering and Infrastructure	$32,502,123	$32,502,123
64	MT Common - Fleet vehicles and equipment	5,745,000	5,745,000
65	MT Common - BT SAP Hana implementation	2,390,545	2,390,545
66	SD Common - Fleet vehicles and equipment	1,528,000	-
67	SD Common - BT SAP Hana implementation	455,915	-
68			
69	All Other Projects < $1 Million Each and blankets	18,237,475	$14,750,644
70	(Includes BT, Communications, Facilities, Land, Customer Service)		
71	**Total Common Utility Construction Budget**	**60,859,058**	**55,388,312**
72			
73	**MT/SD Generation**		
74	MT Yellowstone Generation Station	$167,889,926	167,889,926
75	MT Hydro Maroney Spillway Gate Upgrade	13,559,010	13,559,010
76	MT Generation Interconnect - Laurel Auto Network	4,107,995	4,107,995
77	MT Hydro CCH Intake Screen Upgrade	3,659,278	3,659,278
78	MT Hydro CCH U2 Turbine Upgrade	2,727,688	2,727,688
79	MT Hydro Hauser U5 Turb-Gen Upgrade	2,471,904	2,471,904
80	MT Hydro Black Eagle U3 Turbine Upgrade	1,961,581	1,961,581
81	Mt Hydro Holter U1 Turbine Upgrade	1,697,259	1,697,259
82	MT Hydro CCH U2 Gen Restack & Rewind	1,552,975	1,552,975
83	MT Hydro Holter U1 Generator Rewind	1,325,862	1,325,862
84	MT Hydro Mystic Bridge Across Slide Area	1,203,918	1,203,918
85	MT Generation Interconnect - Laurel Auto TPIF	1,184,326	1,184,326
86	MT Hydro Holter U3 Turbine Upgrade	1,035,515	1,035,515
87	MT Generation Thompson Falls Relicensing	1,001,101	1,001,101
88	SD Generation - Huron Bob Glanzer Generating Station	3,492,277	-
89			
90	All Other Projects < $1 Million Each and blankets	$12,761,221	$10,751,520
91	**Total MT/SD Generation**	**221,631,836**	**216,129,858**
92	**TOTAL CONSTRUCTION BUDGET**	**$586,219,337**	**$524,566,811**

Sch. 32	TOTAL SYSTEM & MONTANA PEAK AND ENERGY					
		System Peak and Energy				
		Peak Day	Peak Hour	Peak Day Volume Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	January	27	9:00	1,855	797,073	115,155
2	February	11	20:00	2,048	670,944	105,816
3	March	1	8:00	1,704	778,997	67,617
4	April	1	9:00	1,615	572,911	94,270
5	May	17	19:00	1,612	644,571	43,740
6	June	30	18:00	2,113	609,257	83,332
7	July	27	18:00	2,115	644,758	52,598
8	August	16	17:00	1,977	749,218	44,287
9	September	7	18:00	1,703	661,707	66,747
10	October	12	9:00	1,602	655,052	79,874
11	November	11	18:00	1,698	727,420	70,986
12	December	27	18:00	2,014	671,029	133,076
13	**TOTALS**				8,182,935	957,499
14		Montana Peak and Energy				
15		Peak	Peak	Peak Day Volume	Total Monthly Volumes	Non-Requirements
16		Day	Hour	Megawatts	Energy (Mwh)	Sales For Resale (Mwh)
17	January					
18	February					
19	March					
20	April					
21	May					
22	June					
23	July			SAME AS ABOVE		
24	August					
25	September					
26	October					
27	November					
28	December					
29	**TOTALS**				-	-

Sch. 33	MONTANA SYSTEM SOURCES & DISPOSITION OF ENERGY			
	Sources	Megawatthours	Dispositions	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	2,031,531		
3	Nuclear	-	**Sales to Ultimate Consumers**	6,194,427
4	Hydro - Conventional	2,094,750	(Include Interdepartmental) 1/	
5	Hydro - Pumped Storage	-		
6	Other	426,098	Sales for Resale	
7	(Less) Energy for Pumping	-	Requirement Sales	
8	**Net Generation**	4,552,379	Non-Requirement Sales	957,499
9	**Purchases**	3,633,687	**Sales for Resale**	957,499
10	Power Exchanges			
11	Received	32,615		
12	Delivered	35,746	Energy Furnished w/o Charge	-
13	**Net Power Exchanges**	(3,131)	**Energy Furnished**	-
14	Transmission Wheeling for Others		Energy Used Within Utility	
15	Received	12,395,553	Electric Department	
16	Delivered	12,395,553	(Less) Station Use	-
17	**Net Transmission Wheeling**	-	**Net Energy Used Within Util.**	-
18	**Transmission by Others Losses**	-	**Energy Losses**	1,031,009
19	**TOTAL SOURCES**	8,182,935	**TOTAL DISPOSITIONS**	8,182,935

1/ The megawatts hours listed above do not include sales to billed choice customers, consistent with the presentation used in the corresponding schedule on FERC Form 1. It also includes unbilled consumption of (9,923) megawatt hours.

Sch. 34	SOURCES OF MONTANA ELECTRIC SUPPLY				
	Type	Plant Name	Location	Nameplate Capacity (MW)	Net Generation (Mwh)
1	Steam Generation	Colstrip Unit 4	Colstrip, MT	222.0	2,031,531
2	Gas Turbine Generation	Dave Gates Station	Anaconda, MT	150.0	271,438
3	Wind Generation	Spion Kop	Judith Basin County, MT	40.0	120,348
4	Wind Generation	Two Dot	Two Dot, MT	11.3	34,312
5	Hydro Generation	Black Eagle	Great Falls, MT	21.8	100,002
6	Hydro Generation	Cochrane	Great Falls, MT	59.9	222,000
7	Hydro Generation	Hauser	Helena, MT	18.7	115,892
8	Hydro Generation	Holter	Helena, MT	53.6	201,007
9	Hydro Generation	Madison	Ennis, MT	12.7	1,185
10	Hydro Generation	Morony	Great Falls, MT	46.5	231,680
11	Hydro Generation	Mystic	Columbus, MT	11.3	53,604
12	Hydro Generation	Rainbow	Great Falls, MT	59.0	310,711
13	Hydro Generation	Ryan	Great Falls, MT	55.2	387,793
14	Hydro Generation	Thompson Falls	Thompson Falls, MT	92.4	470,876
15	Total Generation			854.2	4,552,379
		Source of capacity	Seller	Avg Monthly Billing Demand (MW)	Annual Energy (Mwh)
16	Qualifying Facility Purchases	Wind	71 Ranch		10,974
17	Qualifying Facility Purchases	Hydro	Barney Creek		55
18	Qualifying Facility Purchases	Thermal	Billings Generation Inc.		458,524
19	Qualifying Facility Purchases	Wind	Big Timber Wind LLC		78,869
20	Qualifying Facility Purchases	Solar	Black Eagle Solar, LLC		5,676
21	Qualifying Facility Purchases	Hydro	Boulder Hydro		1,045
22	Qualifying Facility Purchases	Hydro	Cascade Creek		251
23	Qualifying Facility Purchases	Thermal	Colstrip Energy Ltd/Montana One		322,002
24	Qualifying Facility Purchases	Wind	Cycle Horseshoe Bend Wind, LLC		2,659
25	Qualifying Facility Purchases	Wind	DA Winds		10,904
26	Qualifying Facility Purchases	Wind	Fairfield Wind, LLC		27,531
27	Qualifying Facility Purchases	Hydro	Flint Creek Hydroelectric, LLC		10,976
28	Qualifying Facility Purchases	Wind	Gordon Butte Wind, LLC		36,817
29	Qualifying Facility Purchases	Solar	Great Divide Solar, LLC		6,232
30	Qualifying Facility Purchases	Wind	Greenfield Wind, LLC		85,298
31	Qualifying Facility Purchases	Solar	Green Meadow Solar, LLC		5,860
32	Qualifying Facility Purchases	Hydro	Hanover Hydro Project		313
33	Qualifying Facility Purchases	Hydro	Hydrodynamics - South Dry Creek		2,782
34	Qualifying Facility Purchases	Hydro	Hydrodynamics - Strawberry Creek		1,270
35	Qualifying Facility Purchases	Hydro	KEC Fighting Creek		3,237
36	Qualifying Facility Purchases	Hydro	Lower South Fork Hydro, LLC		459
37	Qualifying Facility Purchases	Solar	Magpie Solar, LLC		5,633
38	Qualifying Facility Purchases	Wind	Musselshell Wind Project 1, LLC		24,040
39	Qualifying Facility Purchases	Wind	Musselshell Wind Project 2, LLC		28,853
40	Qualifying Facility Purchases	Wind	Oversight Resources		10,281
41	Qualifying Facility Purchases	Hydro	Pine Creek		1,206
42	Qualifying Facility Purchases	Hydro	Pony Hydro		712
43	Qualifying Facility Purchases	Solar	River Bend Solar, LLC		3,845
44	Qualifying Facility Purchases	Hydro	Ross Creek Hydro		1,809
45	Qualifying Facility Purchases	Solar	South Mills Solar 1, LLC		6,416
46	Qualifying Facility Purchases	Wind	South Peak Wind		293,532
47	Qualifying Facility Purchases	Hydro	State of Montana - DNRC/Broadwater Dam		21,276
48	Qualifying Facility Purchases	Wind	Stillwater Wind, LLC		260,109
49	Qualifying Facility Purchases	Wind	Two Dot Wind, Broadview East, LLC		4,901
50	Qualifying Facility Purchases	Hydro	Wisconsin Creek, LLC		529
51					
52					
53					
54					
55	Subtotal			0.0	1,734,873

Sch. 34A	SOURCES OF MONTANA ELECTRIC SUPPLY				
		see descriptions below	Seller	Annual Peak (MW) 1/	Annual Energy (Mwh)
1	Purchased Power	SF	Avangrid Renewables, LLC		30,230
2	Purchased Power	SF	Avista Corporation		46,211
3	Purchased Power	SF	Basin Electric Power Cooperative		28,367
4	Purchased Power	LU	Basin Creek Energy Partners	52.0	119,698
5	Purchased Power	SF	Black Hills Power Inc.		650
6	Purchased Power	SF	Bonneville Power Administration		79,889
7	Purchased Power	SF	Dynasty Power Inc.		1,004
8	Purchased Power	SF	Clatskanie Peoples Utility District		1,336
9	Purchased Power	SF	Conoco Phillips Corp		10,697
10	Purchased Power	SF	EDF Trading North America, LLC		130,323
11	Purchased Power	SF	Energy Keepers, Inc.		36,028
12	Purchased Power	SF	Eugene Water & Electric Board		5,102
13	Purchased Power	SF	Invenergy Energy Marketing LLC-Electric		462,499
14	Purchased Power	SF	Exelon Generation Company, LLC		3,518
15	Purchased Power	SF	Idaho Power Company		3,767
16	Purchased Power	SF	Guzman Energy, LLC		22,382
17	Purchased Power	SF	Macquarie Energy LLC		36,465
18	Purchased Power	SF	Morgan Stanley Capital Group, Inc.		451,298
19	Purchased Power	SF	PacifiCorp		5,050
20	Purchased Power	SF	Portland General Electric		109,979
21	Purchased Power	SF	Powerex Corp.		27,928
22	Purchased Power	SF	Puget Sound Energy		42,332
23	Purchased Power	SF	Rainbow Energy Marketing Corporation		22,061
24	Purchased Power	SF	Seattle City Light		13,816
25	Purchased Power	SF	Shell Energy North America		24,095
26	Purchased Power	SF	Tacoma Power		10,817
27	Purchased Power	LF	Talen Energy Marketing, LLC		1,860
28	Purchased Power	SF	The Energy Authority, Inc.		36,811
29	Purchased Power	LU	Tiber Montana, LLC	not available	52,390
30	Purchased Power	LF	TransAlta Energy Marketing (US), Inc		18,900
31	Purchased Power	SF	Heartland Generation Ltd		41
32	Purchased Power	LU	Turnbull Hydro, LLC	13.0	24,416
33	Purchased Power	SF	Western Area Power Administration		37,302
34	Subtotal			65.0	1,897,262
35	Reserve Sharing				1,552
36	Total Purchases				3,633,687

1/ Annual peak information is provided, where available, for sellers from whom we purchase all of their output.

LF - for long-term firm service

LU - for long-term service from a designated generating unit

SF - for short-term service

Sch. 34B **THERMAL GENERATION OUTAGE REPORT**

This schedule intentionally omitted.

Schedule 34B contains operations data for Colstrip Unit 3 and Colstrip Unit 4 that is considered trade secret and confidential by Talen Montana, LLC (“Talen”).

NorthWestern will provide this schedule upon request, subject to a Commission order in response to Talen’s request to maintain the confidentiality of the data.

Sch. 34C	THERMAL GENERATION OUTAGE REPORT		
Unit	**Outage Start Date**	**Description**	**Outage Duration (hours)**
DGGS Unit 1	3/29/2021	Generator minor inspection.	61
	5/3/2021	Annual outage and borescope inspection	86
	6/8/2021	Bearing replacement	38
	10/15/2021	Engine repair	99
DGGS Unit 2	5/11/2021	Annual outage and borescope inspection	61
	10/14/2021	Engine inspection/overhaul	1668
DGGS Unit 3	4/1/2021	Generator cooler replacement.	13
	5/7/2021	Annual outage and borescope inspection	88
	6/3/2021	Generator bearings and oils system high temp	16
	7/10/2021	change scupper valve	59

Only outages greater than 12 hours are reported. Does not reflect partial outages of a unit.

Sch. 34D

HYDRO GENERATION OUTAGE REPORT

	Plant	Unit Name	Outage Start Date	Description	Outage Duration (hours)
1	**Black Eagle**	BE 2	1/4/2021	Annual Maintenance	194
2		BE 1	1/1/2021	Turbine replacement	8,760
3		BE 3	1/18/2021	Annual Maintenance	169
4		BE 2	4/5/2021	Substation breaker replacement/ upgrade	100
5		BE 3	4/5/2021	Substation breaker replacement/ upgrade	100
6		BE 2	8/23/2021	Capacitor bank installation	51
7		BE 3	8/23/2021	Capacitor bank installation	51
8					
9	**Cochrane**	CCH 1	3/10/2021	Inspection	849
10		CCH 2	4/14/2021	Main Transformer work	482
11		CCH 2	6/29/2021	Thrust bearing temp rate change.	21
12		CCH 1	11/30/2021	Inspection	757
13		CCH 2	11/9/2021	Inspection and maintenance	505
14					
15	**Hauser**	HAU 2	1/1/2021	Unit upgrade/replacement of turbine and generator	2,121
16		HAU 2	3/30/2021	Commissioning and testing after overhaul	19
17		HAU 2	3/31/2021	Commissioning and testing after overhaul	17
18		HAU 2	4/1/2021	Commissioning and testing after overhaul	91
19		HAU 2	4/12/2021	Work on shaft seal	71
20		HAU 1	4/13/2021	Plant battery replacement	28
21		HAU 3	4/13/2021	Plant battery replacement	27
22		HAU 4	4/13/2021	Plant battery replacement	55
23		HAU 5	4/13/2021	Plant battery replacement	48
24		HAU 6	4/13/2021	Plant battery replacement	55
25		HAU 6	4/26/2021	Fiber optic upgrade	275
26		HAU 4	4/26/2021	Fiber optic upgrade	275
27		HAU 2	4/26/2021	Fiber optic upgrade	271
28		HAU 3	6/17/2021	Generator Efficiency	1,658
29		HAU 5	4/15/2021	Unit Refurb/replacement/upgrade	6,258
30		HAU 4	8/26/2021	Transmission Work	32
31		HAU 2	8/26/2021	Transmission Work	32
32		HAU 1	8/31/2021	Annual inspection and maintenance	1,036
33		HAU 3	10/18/2021	Annual condition assessment	409
34		HAU 1	11/23/2021	Station service upgrade	31
35		HAU 2	11/23/2021	Station service upgrade	31
36		HAU 4	11/23/2021	Station service upgrade	32
37		HAU 6	11/23/2021	Station service upgrade	31
38					
39	**Holter**	HLT 3	1/1/2021	Major generator and turbine upgrade	8,760
40		HLT 1	3/1/2021	Bus Work	776
41		HLT 2	3/1/2021	Bus Work	772
42		HLT 4	4/2/2021	100 kv upgrade	672
43					
44	**Madison**	MAD 1	1/1/2021	Unit upgrade/replacement of turbine and generator	8,369
45		MAD 2	1/1/2021	Unit upgrade/replacement of turbine and generator.	8,480
46		MAD 3	1/1/2021	Unit upgrade/replacement of turbine and generator.	8,760
47		MAD 4	1/1/2021	Unit upgrade/replacement of turbine and generator	8,760
48		MAD 1	12/16/2021	Shares surge chamber w/U2 thus cannot run U1 while co	21
49		MAD 2	12/20/2021	Unit upgrade	271
50					
51					

Only outages greater than 12 hours are reported. Low water events are excluded.

Sch. 34E	HYDRO GENERATION OUTAGE REPORT			
Plant	**Unit Name**	**Outage Start Date**	**Description**	**Outage Duration (hours)**
Morony	MOR 1	1/18/2021	Annual Maintenance	176.35
	MOR 2	1/26/2021	Annual Maintenance	149.48
Mystic	MYS 1	1/1/2021	Generator thrusting to the side.	2502
	MYS 1	1/1/2021	Testing/routine operations	1257.33
	MYS 1	2/22/2021	Annual inspection and maintenance	21.7
	MYS 1	2/23/2021	Generator testing	358.98
	MYS 1	3/10/2021	Inspection/ Testing	652.22
	MYS 2	5/11/2021	Headgate closed due to PCS/ Logic problems	15.32
	MYS 2	8/30/2021	PCS Control Upgrades	233.38
	MYS 1	8/30/2021	PCS Control Upgrades	190.22
	MYS 1	9/7/2021	PCS Control Upgrades	16.12
	MYS 1	11/15/2021	Transmission lines downed by wind	12
	MYS 2	11/15/2021	Transmission lines downed by wind	12.08
Mystic	MYS 1	1/1/2021	Generator bearings and lube oil system	70.59
	MYS 1	1/1/2021	Inspection	1257.33
	MYS 1	2/22/2021	Inspection	21.7
	MYS 1	2/23/2021	Inspection/ Testing	358.98
	MYS 1	3/10/2021	Inspection	652.22
	MYS 2	5/11/2021	PLC - logic problems	15.32
	MYS 2	8/30/2021	PLC - upgrades	233.38
	MYS 1	8/30/2021	PLC - upgrades	190.22
	MYS 1	9/7/2021	DCS - upgrades	16.12
	MYS 2	11/15/2021	Storms (ice, snow, etc)	12.08
Rainbow	RNB 9	10/4/2021	Annual Maintenance	385.98
Ryan	RYN 5	1/1/2021	Annual inspection and maintenance	278.8
	RYN 5	1/13/2021	Replace generator vibration sensor	18.37
	RYN 2	2/1/2021	Annual Maintenance	2743.78
	RYN 2	5/26/2021	Lube oil supply leak	17.88
	RYN 3	6/23/2021	Lube oil level low	17.77
	RYN 4	7/6/2021	Annual Maintenance	3054.78
	RYN 1	11/8/2021	Annual maintenance and inspection	170.78
	RYN 4	11/10/2021	Commissioning after annual maintenance outage	15.72
	RYN 4	11/30/2021	Maintenance work on lube oil system	138.15
	RYN 3	12/6/2021	Annual inspection and maintenance	615.78
	RYN 4	12/21/2021	Maintenance on lube oil system	31.47
	RYN 3	12/6/2021	Annual inspection and maintenance	615.78
	RYN 4	12/21/2021	Maintenance on lube oil system	31.47
Thompson Falls	THF 1	1/13/2021	No available transmission lines due to high winds	25.07
	THF 3	1/13/2021	No available transmission lines due to high winds	25.1
	THF 5	1/13/2021	No available transmission lines due to high winds	25.05
	THF 6	1/13/2021	No available transmission lines due to high winds	25.07
	THF 7	1/13/2021	No available transmission lines due to high winds	26.02
	THF 3	1/15/2021	Exciter field ground loss of power	63.18
	THF 5	2/8/2021	Annual Maintenance	918.17
	THF 3	3/22/2021	Annual Maintenance	357.92
	THF 6	1/19/2021	Annual outage	392.98
	THF 7	9/16/2021	annual maintenance and inspection	601.33
	THF 1	10/13/2021	annual maintenance and inspection	363.5

Only outages greater than 12 hours are reported. Low water events are excluded.

Sch. 35	MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS					
Program Description (These are Electric DSM Programs)	Current Year Expenditures	Previous Year Expenditures	% Change	Planned Savings (MW & MWh)	Achieved Savings (MW & MWh)	Difference (MW & MWh)
2021 E+ Residential Lighting Program*	$ 1,219,826	$ 603,090	102.26%	0.076	0.136	0.060
- Initiated 2005, 2021 weighted average program life = 14 years, 4054 participants.				8,103	14,447	6,344
2021 E+ Residential Electric Existing Program	$ 3,001	$ -	0.00%	-	-	-
- Reinitiated 2021, 2021 weighted average program life = 16 years, 25 participants.				37	66	29
2021 E+ Residential Electric New Construction Program	$ 370	$ -	0.00%	-	-	-
- Reinitiated 2021, 2021 weighted average program life = 0 years, 0 participants.				-	-	-
2021 E+ Commercial Lighting Program	$ 4,397,841	$ 5,198,510	-15.40%	-	-	-
- Initiated 2005, 2021 weighted average program life = 14 years, 972 participants.				17,504	31,208	13,704
2021 E+ Electric Business Partners Program	$ 250,106	$ 440,677	-43.25%	-	-	-
- Initiated 2005, 2021 weighted average program life = 19 years, 7 participants.				565	1,007	442
2021 Northwest Energy Efficiency Alliance (NEEA)**	$ 1,282,896	$ 1,282,896	0.00%	-	-	-
- Initiated electric savings in 2006, program life is 15 years				5,253	9,366	4,113
2021 E+ Commercial Electric New Construction Program	$ 606,812	$ 533,328	13.78%	-	-	-
- Initiated 2005, 2021 weighted average program life = 13 years, 42 participants.				2,837	5,058	2,221
2021 E+ Commercial Electric Savings Program	$ 643,227	$ 379,038	69.70%	-	-	-
- Initiated 2005, 2021 weighted average program life = 14 years, 47 participants.				2,871	5,118	2,247
2021 General Expenses All Electric DSM Programs	$4,783	$57,027	-91.61%	-	-	-
- N/A				-	-	-
A program participant is a Montana residential and/or commercial electric customer who installs eligible energy conservation measures and receives financial incentives/rebates either directly or indirectly.						
* Number of participants cannot be counted for the Manufacturer Buydown portion of the E+ Residential Lighting Program.						
**Note: 2021 NEEA expeditures are allocated to electric DSM but there are gas savings as a result of some NEEA initiatives. Participant has not been defined or counted for NEEA.						
Units reported are in megawatts ("MW") and megawatt-hours ("MWh")						
COVID-19 impacted 2021 DSM activities.						
TOTAL	$ 8,408,860	$ 8,494,565	-1.01%	0.08	0.14	0.06
				37,169	66,269	29,100

Sch. 35a	Electric Universal System Benefits Programs						
	Program Description	Actual Expenditures	Contracted or Committed to Spend	Total Allocations & Expenditures [a]	Expected savings [b]		Most recent program evaluation
1	Local Conservation				MWh	MW	
2	E+ Residential Audit/Sm. Comm Audit	$ -	$ 366,187	$ 366,187	405	0.065	2012
3	E+ Business Partners / Irrigation Projects	$ 21,785	$ -	$ 21,785	195	0.022	2012
4	NWE Promotion	$ 83,041	$ -	$ 83,041			
5	NWE Labor	$ 35,828	$ -	$ 35,828			
6	* Non LC/LI to cover LC Admin	$ 981					
7	NWE Admin. Non-labor	$ 117	$ -	$ 117			
8	USB Interest & Svc Chg	$ (16)	$ -	$ (16)			
9	Market Transformation						
10	Motor Management Training	$ -	$ 15,000	$ 15,000			
11	Energy Star Homes	$ 67,529	$ 60,593	$ 128,122			
12	Building Operator Certification	$ 29,100	$ 6,000	$ 35,100	237	0.000	2012
13	Regional Mkt Tansformation	$ 31,400	$ 1,254,140	$ 1,285,540			
14	NWE Promotion	$ 7,778	$ -	$ 7,778			
15	NWE Labor	$ 24,050	$ -	$ 24,050			
16	* Non LC/LI to cover LC Admin	$ 627	$ -	$ 627			
17	NWE Admin. Non-labor	$ 47	$ -	$ 47			
18	USB Interest & Svc Chg	$ (31)	$ -	$ (31)			
19	Renewable Resources						
20	Generation/Education	$ 582,757	$ 959,280	$ 1,542,037	696	0.529	2012
21	Green Power Product Offering	$ 23,733	$ 61,268	$ 85,000			
22	NWE Promotion	$ 16	$ -	$ 16			
23	NWE Labor	$ 82,029	$ -	$ 82,029			
24	* Non LC/LI to cover LC Admin	$ 1,122	$ -	$ 1,122			
25	NWE Admin. Non-labor	$ 51	$ -	$ 51			
26	USB Interest & Svc Chg	$ (33)	$ -	$ (33)			
27	Research & Development						
28	R&D/ Infrastructure	$ 123,725	$ 154,980	$ 278,705			
29	NWE Promotion	$ 266	$ -	$ 266			
30	NWE Labor	$ 28,831	$ -	$ 28,831			
31	* Non LC/LI to cover LC Admin	$ 259	$ -	$ 259			
32	NWE Admin. Non-labor	$ 12	$ -	$ 12			
33	USB Interest & Svc Chg	$ (8)	$ -	$ (8)			
34	Low Income						
35	Bill Assistance	$ 2,283,036	$ -	$ 2,283,036			
36	Free Weatherization	$ 166,603	$ 4,260,259	$ 4,426,862	139	0.000	2012
37	Elec Wx Incentives	$ 16,189	$ -	$ 16,189			
38	Fuel Switch Analyses	$ 100	$ -	$ 100			
39	Energy Share	$ 513,169	$ 628,389	$ 1,141,558			
40	NWE Promotion	$ 803	$ -	$ 803			
41	NWE Labor	$ 27,040	$ -	$ 27,040			
42	NWE Admin. Non-labor	$ 347	$ -	$ 347			
43	USB Interest & Svc Chg	$ (225)	$ -	$ (225)			
44	Large Customer Self Directed						
45	Self-Directed Energy Reduction	$ 2,707,212	$ 1,204,790	3,912,002			
46	Self-Directed to Low Income	$ 177,693	$ -	177,693			
47	NWE Reallocate to Free Weatherization	$ 279,717	$ -	279,717			
48	NWE Reallocate to Energy Share	$ 252,076	$ -	252,076			
49	NWE Labor	$ 6,616	$ -	6,616			
50	* NWE Reallocate to LC Admin	$ (2,989)	$ -	(2,989)			
51	Admin. Non-labor	$ -	$ -	0			
52	USB Interest & Svc Chg	$ (138)	$ -	(138)			
53	Total	$ 7,572,245	$ 8,970,886	$ 16,543,131	1,671	0.617	
54	Number of customers that received low income rate discounts				10,458		
55	Average monthly bill discount amount ($/mo)				$ 18.19		
56	Average LIEAP-eligible household income				n/a		
57	Number of customers that received weatherization assistance				252 [b]		
58	Expected average annual bill savings from weatherization				551	Kwh	
59	Number of residential audits performed on-site				- [b]		
60	Number of residential audits performed (mail in survey)				3,265 [b]		
61	Number of residential virtual assessments performed				848 [b]		
62	[a] Total expenditures are reported for the combination of 2018 - 2021 electric USB funds spent in 2021. Total allocations are reported for the combination of 2019 - 2021 electric USB funds expected to be spent in 2022						
63	(b) 2021 Total savings and number of customers are reported. Due to COVID-19, 2019, 2020, nor 2021 electric USB funds were spent on the E+ Audit or E+ Free Weatherization and Fuel Switch programs.						
64	COVID-19 impacted 2021 USB revenues and activities. COVID-19 resulted in activities planned for 2021 being postponed and funds carried forward to 2022 as allowed by statute and with extensions of time granted by the Department of Revenue as allowed by Administrative Rules (ARM) of Montana.						

Sch. 35b	Montana Conservation & Demand Side Management Programs					
	Program Description (These are Electric USB Programs)	Actual Current Year Expenditures	Contracted or Committed to Spend	Total Allocations & Expenditures [(a)]	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2	E+ Energy Audit for the Home or Business	$ -	$ 366,187	$ 366,187	0.07	2012
3					405	
4	E+ Electric Business Partners Program / Irrigation	$ 21,785	$ -	$ 21,785	0.02	2012
5					195	
6	Market Transformation					
7	Motor Management Training	$ -	$ 15,000	$ 15,000	-	2012
8					-	
9	Energy Star Homes	$ 67,529	$ 60,593	$ 128,122	-	2012
10					-	
11	Building Operator Certification	$ 29,100	$ 6,000	$ 35,100	-	2012
12					237	
13	Regional Market Transformation	$ 31,400	$ 1,254,140	$ 1,285,540	-	2012
14					-	
15	Renewables					
16	Generation/Education	$ 582,757	$ 959,280	$ 1,542,037	0.53	2012
17					696	
18	Green Power Product	$ 23,733	$ 61,268	$ 85,000	-	2012
19					-	
20	Research & Development					
21	R&D / Infrastructure	$ 123,725	$ 154,980	$ 278,705	-	2012
22					-	
23	Low Income					
24	Free Weatherization	$ 446,320	$ 4,260,259	$ 4,706,579	-	2012
25					139	
26	Elec Wx Incentives	$ 16,189	$ -	$ 16,189	-	2012
27					-	
28	Fuel Switch	$ 100	$ -	$ 100	-	2012
29					-	
30	Total	$ 1,342,638	$ 7,137,707	$ 8,480,344	0.62	2012
31					1,671	
32	[(a)] Total expenditures are reported for the combination of 2018 - 2021 electric USB funds spent in 2021. Total allocations are reported for the combination of 2018 - 2021 electric USB funds expected to be spent in 2022.					
33	COVID-19 impacted 2021 USB revenues and activities. COVID-19 resulted in activities planned for 2021 being postponed and funds carried forward to 2022 as allowed by statute and with extensions of time granted by the Department of Revenue as allowed by Administrative Rules (ARM) of Montana.					

Sch. 36	MONTANA CONSUMPTION AND REVENUES - ELECTRIC (EXCLUDES YNP)						
		Operating Revenues 1/		MWH Sold		Average Customers	
		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	**Sales of Electricity**						
2							
3	Residential	$ 331,121,441	$320,367,451	2,727,001	2,634,242	311,771	307,247
4	Commercial & Industrial	400,766,603	383,857,060	6,241,777	6,173,711	73,231	71,720
5	Public Street & Highway Lighting	14,778,361	15,671,385	37,520	50,945	3,640	3,713
6	Sales to Other Utilities	31,170,157	16,720,587	957,499	947,437	21	20
7	Interdepartmental	858,550	880,014	7,525	7,634	342	343
8							
9	**TOTAL SALES**	$778,695,112	$737,496,497	9,971,322	9,813,969	389,005	383,043
10							
11	1/ Revenue and MWHs include unbilled.						
12							
13							
14							
15							
16							