YEAR ENDING 2024

ANNUAL REPORT

OF

NorthWestern Energy

GAS UTILITY

Docket 2025.01.001

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

Gas 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:

Respondent is a wholly-owned, direct subsidiary of NorthWestern Energy Group, Inc. At December 31, 2024, NorthWestern Energy Group, Inc. owned 100% of the common stock of respondent.

Sch. 2	BOARD OF DIRECTORS	
	Director's Name & Address (City, State)	Remuneration
1		
2	See NorthWestern Corporation's Annual Report FERC Form No. 1 page	
3	105 for our Corporate Board of Directors.	
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Sch. 3

OFFICERS

Title	Department Supervised	Name
President and Chief Operating Officer	Executive	Brian Bird
Vice President,	Legal Services	Shannon Heim
General Counsel and Federal Government Affairs	Corporate Secretary	
	Risk Management	
	Contracts	
	Federal Governmental Affairs	
Vice President,	Asset and Project Management	Bleau LaFave
Asset Management & Business Development	Business Development and Strategic Support	
Vice President, Distribution	Distribution Operations - MT/SD/NE	Jason Merkel
	Construction	
	Substation Operations	
	Wildfire Operations	
Vice President, Transmission	Transmission Planning, Engineering, Construction,	Michael Cashell
	and Operations	
	Gas Transmission & Storage	
	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	
Vice President,	Brand, Advertising, and	Bobbi Schroeppel
Customer Care, Communications and	Customer Communications	
Human Resources	Customer Experience and Support	
	Customer Interaction	
	Community Connections	
	Revenue Cycle Management	
	Human Resources	
	Safety/Health/Environmental Services	
	DSM and Energy Efficiency	
	Sustainability	
Vice President & Chief Financial Officer	Tax, Internal Audit and Compliance	Crystal Lail
	Financial Planning & Analysis	
	Controller and Treasury Functions	
	Investor Relations and Corporate Finance	
	Flight Services	
	Regulatory Affairs	
	Governmental Affairs - Nebraska and South Dakota	
	Enterprise Risk and Business Continuity	
Vice President, Technology	Business Technology	Jeanne Vold
	Customer Systems & Solutions	
	Data & Analytics	
	Operation Technology	
	Security	

Reflects active officers as of December 31, 2024

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		**$ 180,078**	**100.00 %**
NorthWestern Corporation:			
Montana Utility Operations	Electric Utility Natural Gas Utility Natural Gas Pipeline (including Canadian Montana Pipeline Corp., Havre Pipeline Company, LLC Lodge Creek Pipelines, LLC and Willow Creek Gathering, LLC) Propane Utility		
Unregulated Operations		**$ —**	**— %**
Direct Subsidiaries:			
Clark Fork and Blackfoot, LLC	Former Milltown hydroelectric facility		
Total Corporation		**$ 180,078**	**100.00 %**

Sch. 5	CORPORATE ALLOCATIONS					
	Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
1						
2						
3						
4	Executive Department	Includes the following departments:	Overhead costs not charged directly are	$4,885,116	78.10 %	$1,369,656
5		CEO and Board of Directors	typically allocated based on a 3-factor formula			
6			consisting of gross plant, labor, and margin.			
7						
8	Legal Department	Includes the following departments:	Overhead costs not charged directly are	27,628,155	83.94 %	5,285,028
9		Chief Legal and Risk Management	typically allocated based on a 3-factor formula			
10			consisting of gross plant, labor, and margin.			
11						
12	Regulatory Affairs	Includes the following departments:	Overhead costs not charged directly are	1,526,618	65.08 %	819,042
13		Regulatory Affairs MT, SD & NE Public and Regulatory Affairs	typically allocated based on a 3-factor formula			
14			consisting of gross plant, labor, and margin.			
15						
16	Finance	Includes the following departments: CFO, Treasury, FP&A	Overhead costs not charged directly are	20,747,534	80.35 %	5,073,321
17		Tax , Investor Relations, Corporate Aircraft,	typically allocated based on a 3-factor formula			
18		and Compensation & Benefits	consisting of gross plant, labor, and margin.			
17						
18	Controller	Includes the following departments: Controller, Accounting	Overhead costs not charged directly are	5,805,939	80.07 %	1,445,158
17		Accounts Payable, Payroll, Financial Reporting & Regulatory Affairs Finance	typically allocated based on a 3-factor formula			
18			consisting of gross plant, labor, and margin.			
19						
20	Audit & Controls	Includes the following departments:	Overhead costs not charged directly are	1,016,574	79.00 %	270,229
21		Internal Audit and Enterprise Risk Management	typically allocated based on a 3-factor formula			
22			consisting of gross plant, labor, and margin.			
23						
24	Business Technology	Includes the following departments:	Overhead costs not charged directly are	22,500,547	79.32 %	5,864,517
25		Applications, Architecture, Governance	typically allocated based on a 3-factor formula			
26			consisting of gross plant, labor, and margin.			
27						
28	Corporate Facilities	Includes the following departments:	Overhead costs not charged directly are	82,179	31.27 %	180,603
29		Sioux Falls Facilities and Helena Building	typically allocated based on a 3-factor formula			
30			consisting of gross plant, labor, and margin.			
31						
32	Customer Care	Includes the following departments: Customer Care Combined, Customer Care SD&NE	Overhead costs not charged directly are	25,464,061	75.57 %	8,231,999
33		CC MT, CC - Assoc & Dispatch, Business Develop and Regulatory Support	typically allocated based on a 3-factor formula			
34		Human Resources, Print Services and Charitable Contributions	consisting of gross plant, labor, and margin.			
35						
36						
37						
38						
39						
40	**TOTAL**			$ 109,656,723	79.35 %	$ 28,539,553

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 Affiliates**					
3	NorthWestern Energy Group, Inc.	Board of Director Fees	Actual Expense	$ 1,400,076		$ 1,400,076
4	**Total Nonutility Affiliates**			$1,400,076		$1,400,076
6						
7						
8						
9	**Utility Affiliates**					
10	Havre Pipeline Company, LLC	Natural gas gathering,	Gathering rate based on cost,	2,158,465		
11		transmission, & compression	transmission & compression			
12			are at tariffed rates			
13	**Total Utility Affiliates**			$2,158,465		$0
14	**TOTAL AFFILIATE TRANSACTIONS**			$3,558,541		$1,400,076

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 Affiliates**					
3	NorthWestern Energy Group, Inc.	Labor and Benefits	Actual Expense	$ 49,800	4.40 %	$ 49,800
4						
5						
6	**Total Nonutility Affiliates**			$49,800		$49,800
8						
9						
10						
11	**Utility Affiliates**					
12						
13	Havre Pipeline Company, LLC	Administration Fee	Negotiated Contract Rate	511,733	15.20 %	511,733
14	Havre Pipeline Company, LLC	Labor Cost	Actual Expense	1,293,304	38.40 %	1,293,304
15	NorthWestern Energy Public Service Corporation	Labor Cost	Actual Expense	39,301,336	56.50 %	$ 39,301,336
16	**Total Utility Affiliates**			41,106,373		$ 41,106,373
17						
18	**TOTAL AFFILIATE TRANSACTIONS**			41,156,173		$ 41,156,173

Sch. 8	MONTANA UTILITY INCOME STATEMENT - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	400 Operating Revenues	$ 205,833,731	$ —	$ 205,833,731	$ 248,630,279	(17.21)%
3						
4	**Total Operating Revenues**	205,833,731	—	205,833,731	248,630,279	(17.21)%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expense	102,073,009	—	102,073,009	133,514,684	(23.55)%
9	402 Maintenance Expense	7,221,122	—	7,221,122	7,232,472	(0.16)%
10	403 Depreciation Expense	22,889,591	(846,505)	23,736,096	24,023,749	(1.20)%
11	404-405 Amort. & Depletion of Gas Plant	6,968,693	—	6,968,693	5,995,804	16.23 %
12	406 Amort. of Plant Acquisition Adj.	—	—	—	—	-
13	407.3 Regulatory Amortizations - Debit	12,209,714	—	12,209,714	25,959,491	(52.97)%
14	407.4 Regulatory Amortizations - Credit	(25,722,651)	—	(25,722,651)	(17,498,769)	(47.00)%
15	408.1 Taxes Other Than Income Taxes	37,214,543	—	37,214,543	34,311,635	8.46 %
16	409.1 Income Taxes-Federal	(1,488,129)	(9,689)	(1,478,440)	(6,900,414)	78.57 %
17	-Other	(536,151)	(3,340)	(532,811)	(2,368,490)	77.50 %
18	410.1 Deferred Income Taxes-Dr.	78,358,682	568,438	77,790,244	69,023,854	12.70 %
19	411.1 Deferred Income Taxes-Cr.	(81,356,333)	(319,650)	(81,036,683)	(63,482,434)	(27.65)%
20	411.4 Investment Tax Credit Adj.	—	—	—	—	-
21						
22	**Total Operating Expenses**	157,832,090	(610,746)	158,442,836	209,811,580	(24.48)%
23	**NET OPERATING INCOME**	$ 48,001,641	$ 610,746	$ 47,390,895	$ 38,818,699	22.08 %

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, in accordance with FERC requirements, 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.

Sch. 9	MONTANA REVENUES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	**Core Distribution Business Units**					
3	**(DBUs)**					
4	440 Residential	$ 110,207,495	$ —	$ 110,207,495	$ 136,047,920	(18.99)%
5	442.1 Commercial	59,932,123	—	59,932,123	73,713,246	(18.70)%
6	442.2 Industrial Firm	1,040,763	—	1,040,763	1,391,696	(25.22)%
7	445 Public Authorities	912,182	—	912,182	1,016,662	(10.28)%
8	448 Interdepartmental Sales	440,135	—	440,135	664,785	(33.79)%
9	491.2 CNG Station	—	—	—	—	-
10						
11	**Total Sales to Core DBUs**	172,532,698	—	172,532,698	212,834,309	(18.94)%
12						
13	447 Sales for Resale	861,133	—	861,133	3,072,317	(71.97)%
14						
15	**Total Sales of Natural Gas**	173,393,831	—	173,393,831	215,906,626	(19.69)%
16						
17	496.1 Provision for Rate Refunds	—	—	—	—	-
18						
19	**Total Revenue Net of Rate Refunds**	173,393,831	—	173,393,831	215,906,626	(19.69)%
20						
21	489.1 Gathering	738,021	—	738,021	1,041,174	
22	489.2 Transmission	30,244,568	—	30,244,568	29,524,320	2.44 %
23						
24	**Total Revenues From Transportation**	30,982,589	—	30,982,589	30,565,494	1.36 %
25						
26	Miscellaneous Revenues	1,457,311	—	1,457,311	2,158,160	(32.47)%
27						
28	**Total Other Operating Revenue**	1,457,311	—	1,457,311	2,158,160	(32.47)%
29	**TOTAL OPERATING REVENUE**	$ 205,833,731	$ —	$ 205,833,731	$ 248,630,279	(17.21)%
30						
31						
32						
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35						
36						

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Gas Raw Materials**					
2	**Gas Raw Materials-Operation**					
3	728 Liquefied Petroleum Gas	$ —	$ —	$ —	$ —	-
4	735 Miscellaneous Production Expenses	—	—	—	—	-
5	**Total Operation-Gas Raw Materials**	—	—	—	—	-
6						
7	**Gas Raw Materials-Maintenance**					
8	741 Structures & Improvements	—	—	—	—	-
9	**Total Maintenance-Gas Raw Materials**	—	—	—	—	-
10	**Total Gas Raw Materials**	—	—	—	—	-
11	**Production Expenses**					
12						
13	**Production & Gathering-Operation**					
14	750 Supervision & Engineering	100,595	—	100,595	129,609	(22.39)%
15	751 Maps & Records	—	—	—	—	-
16	752 Gas Wells Expenses	725,093	—	725,093	758,913	(4.46)%
17	753 Field Lines Expenses	16,512	—	16,512	8,050	105.12 %
18	754 Field Compressor Station Expense	2,224,018	—	2,224,018	3,018,122	(26.31)%
19	755 Field Comp. Station Fuel & Power	(33,838)	—	(33,838)	(141,175)	76.03 %
20	756 Field Meas. & Reg. Station Expense	101,741	—	101,741	128,942	(21.10)%
21	757 Dehydration Expense	6,497	—	6,497	15,650	(58.49)%
22	758 Gas Well Royalties	593,643	—	593,643	1,174,456	(49.45)%
23	759 Other Expenses	695,060	—	695,060	577,794	20.30 %
24	760 Rents	276,042	—	276,042	172,647	59.89 %
25	**Total Oper.-Production & Gathering**	4,705,363	—	4,705,363	5,843,008	(19.47)%
26						
27	**Production Maintenance**					
28	762 Maint. of Gathering Structures	—	—	—	—	-
29	763 Maint. of Producing Gas Wells	1,503	—	1,503	—	-
30	764 Maint. of Field Lines	136,756	—	136,756	78,088	75.13 %
31	765 Maint. of Field Compressor Stations	138,754	—	138,754	111,847	24.06 %
32	766 Maint. of Field Meas. & Reg. Stations	3,195	—	3,195	9,498	(66.36)%
33	767 Maint. of Purification Equipment	1,335	—	1,335	8,440	(84.18)%
34	769 Maint. of Other Equipment	2,833	—	2,833	948	198.84 %
35	**Total Maintenance - Production**	284,376	—	284,376	208,822	36.18 %
36	**TOTAL Natural Gas Production & Gathering**	4,989,739	—	4,989,739	6,051,830	(17.55)%
37						
38	**Other Gas Supply Expense-Operation**					
39	800 NG Wellhead Purchases	26,539,034	—	26,539,034	54,311,371	(51.14)%
40	803 NG Transmission Line Purchases	7,747,728	—	7,747,728	5,471,253	41.61 %
41	805 Other Gas Purchases	(1,361,873)	—	(1,361,873)	6,641,334	(120.51)%
42	805 Purchased Gas Cost Adjustments	—	—	—	—	-
43	805 Incremental Gas Cost Adjustments	—	—	—	—	-
44	805 Deferred Gas Cost Adjustments	—	—	—	—	-
45	806 Exchange Gas	—	—	—	—	-
46	807 Well Expenses-Purchased Gas	568,105	—	568,105	552,350	2.85 %
47	807 Purch. Gas Meas. Stations-Oper.	—	—	—	—	-
48	807 Purch. Gas Meas. Stations-Maint.	—	—	—	—	-
49	807 Purch. Gas Calculations Expenses	—	—	—	—	-
50	808 Other Purchased Gas Expenses	—	—	—	—	-
51	808 Gas Withdrawn from Storage -Dr.	7,364,746	—	7,364,746	7,655,987	(3.80)%
52	809 Gas Delivered to Storage -Cr.	—	—	—	—	-
53	810 Gas Used-Comp. Station Fuel-Cr.	—	—	—	—	-
54	811 Gas Used-Products Extraction-Cr.	—	—	—	—	-
55	812 Gas Used-Other Utility Oper.-Cr.	—	—	—	—	-
56	813 Other Gas Supply Expenses	—	—	—	—	-
57	**Total Other Gas Supply Expenses**	40,857,740	—	40,857,740	74,632,295	(45.25)%
58	**Total Production Expenses**	45,847,479	—	45,847,479	80,684,125	(43.18)%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Storage Expenses**					
2						
3	**Underground Storage-Operation**					
4	814 Supervision & Engineering	152,499	—	152,499	157,979	(3.47)%
5	815 Maps & Records	—	—	—	—	-
6	816 Wells	848,349	—	848,349	391,683	116.59 %
7	817 Lines	84,256	—	84,256	39,993	110.68 %
8	818 Compressor Station	556,786	—	556,786	505,090	10.24 %
9	819 Compressor Station Fuel & Power	—	—	—	—	-
10	820 Measuring & Regulating Station	27,507	—	27,507	21,264	29.36 %
11	821 Purification	101,863	—	101,863	68,384	48.96 %
12	823 Gas Losses	—	—	—	—	-
13	824 Other Expenses	110,120	—	110,120	111,279	(1.04)%
14	825 Storage Well Royalties	739	—	739	3,682	(79.93)%
15	826 Rents	—	—	—	—	-
16	**Total Operation-Underground Storage**	1,882,119	—	1,882,119	1,299,354	44.85 %
17						
18	**Underground Storage-Maintenance**					
19	830 Supervision & Engineering	(5,431)	—	(5,431)	67,128	(108.09)%
20	831 Structures & Improvements	98,021	—	98,021	198,765	(50.68)%
21	832 Reservoirs & Wells	21,139	—	21,139	13,336	58.51 %
22	833 Lines	21,764	—	21,764	38,991	(44.18)%
23	834 Compressor Station Equipment	145,373	—	145,373	76,756	89.40 %
24	835 Meas. & Reg. Station Equipment	5,685	—	5,685	6,728	(15.50)%
25	836 Purification Equipment	16,442	—	16,442	24,523	(32.95)%
26	837 Other Equipment	—	—	—	—	-
27	**Total Maintenance-Underground Storage**	302,993	—	302,993	426,227	(28.91)%
28	**Total Underground Storage Expenses**	2,185,112	—	2,185,112	1,725,580	26.63 %
29	**Transmission Expenses**					
30	**Transmission-Operation**					
31	850 Supervision & Engineering	3,748,870	—	3,748,870	3,250,603	15.33 %
32	851 System Control & Load Dispatching	763,505	—	763,505	690,499	10.57 %
33	853 Compressor Station Labor & Expense	717,360	—	717,360	841,231	(14.72)%
34	855 Other Fuel & Power for Comp. Stat.	—	—	—	—	-
35	856 Mains	1,191,378	—	1,191,378	925,997	28.66 %
36	857 Measuring & Regulating Station	776,306	—	776,306	681,819	13.86 %
37	858 Transmission & Comp.-By Others	—	—	—	—	-
38	859 Other Expenses	385,967	—	385,967	902,438	(57.23)%
39	860 Rents	—	—	—	—	-
40	**Total Operation-Transmission**	7,583,386	—	7,583,386	7,292,587	3.99 %
41	**Transmission-Maintenance**					
42	861 Supervision & Engineering	211,809	—	211,809	167,882	26.17 %
43	862 Structures & Improvements	171,046	—	171,046	168,832	1.31 %
44	863 Mains	729,013	—	729,013	808,375	(9.82)%
45	864 Compressor Station Equipment	432,259	—	432,259	909,364	(52.47)%
46	865 Meas. & Reg. Station Equipment	241,613	—	241,613	230,445	4.85 %
47	867 Other Equipment	—	—	—	—	-
48	**Total Maintenance-Transmission**	1,785,740	—	1,785,740	2,284,898	(21.85)%
49	**Total Transmission Expenses**	9,369,126	—	9,369,126	9,577,485	(2.18)%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Distribution Expenses**					
2	**Distribution-Operation**					
3	870 Supervision & Engineering	1,524,989	—	1,524,989	1,459,315	4.50 %
4	871 Load Dispatching	—	—	—	—	-
5	872 Compressor Station Labor & Expense	—	—	—	—	-
6	873 Compressor Station Fuel and Power	—	—	—	—	-
7	874 Mains and Services	4,058,675	—	4,058,675	3,510,436	15.62 %
8	875 Meas. & Reg. Station-General	149,794	—	149,794	137,698	8.78 %
9	876 Meas. & Reg. Station-Industrial	—	—	—	—	-
10	877 Meas. & Reg. Station-City Gate	—	—	—	8,415	(100.00)%
11	878 Meter & House Regulator	996,911	—	996,911	986,612	1.04 %
12	879 Customer Installations	1,188,263	—	1,188,263	1,193,582	(0.45)%
13	880 Other Expenses	579,377	—	579,377	539,751	7.34 %
14	881 Rents	4,845	—	4,845	4,024	20.40 %
15	**Total Operation-Distribution**	8,502,854	—	8,502,854	7,839,833	8.46 %
16	**Distribution-Maintenance**					
17	885 Supervision & Engineering	750,609	—	750,609	713,495	5.20 %
18	886 Structures & Improvements	—	—	—	—	-
19	887 Mains	563,402	—	563,402	487,648	15.53 %
20	889 Meas. & Reg. Station Exp.-General	44,127	—	44,127	17,426	153.23 %
21	890 Meas. & Reg. Station Exp.-Industrial	—	—	—	—	-
22	891 Meas. & Reg. Station Exp.-City Gate	—	—	—	—	-
23	892 Services	469,848	—	469,848	355,506	32.16 %
24	893 Meters & House Regulators	996,234	—	996,234	991,923	0.43 %
25	894 Other Equipment	—	—	—	—	-
26	**Total Maintenance-Distribution**	2,824,220	—	2,824,220	2,565,998	10.06 %
27	**Total Distribution Expenses**	11,327,074	—	11,327,074	10,405,831	8.85 %
28	**Customer Accounts Expenses**					
29	**Customer Accounts-Operation**					
30	901 Supervision	—	—	—	—	-
31	902 Meter Reading	418,885	—	418,885	507,232	(17.42)%
32	903 Customer Records & Collection	2,859,402	—	2,859,402	2,412,347	18.53 %
33	904 Uncollectible Accounts	364,257	—	364,257	579,231	(37.11)%
34	905 Miscellaneous Customer Accounts	—	—	—	—	-
35	**Total Customer Accounts Expenses**	3,642,544	—	3,642,544	3,498,810	4.11 %
36						
37	**Customer Service & Information Expenses**					
38	**Customer Service-Operation**					
39	907 Supervision	—	—	—	—	-
40	908 Customer Assistance	442,522	—	442,522	863,771	(48.77)%
41	909 Inform. & Instructional Advertising	422,786	—	422,786	392,932	7.60 %
42	910 Misc. Customer Service & Inform.	—	—	—	—	-
43	**Total Customer Service & Information Exp.**	865,308	—	865,308	1,256,703	(31.14)%
44						
45	**Sales Expenses**					
46	**Sales-Operation**					
47	911 Supervision	—	—	—	—	-
48	912 Demonstrating & Selling	—	—	—	—	-
49	913 Advertising	190,950	—	190,950	204,057	(6.42)%
50	916 Miscellaneous Sales	—	—	—	—	-
51	**Total Sales Expenses**	190,950	—	190,950	204,057	(6.42)%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Administrative & General Expenses**					
2	**Admin. & General - Operation**					
3	920 Administrative & General Salaries	10,136,568	—	10,136,568	9,036,000	12.18 %
4	921 Office Supplies & Expenses	4,890,281	—	4,890,281	4,460,989	9.62 %
5	922 Administrative Exp. Transferred-Cr.	(2,667,908)	—	(2,667,908)	(2,341,982)	(13.92)%
6	923 Outside Services Employed	1,513,665	—	1,513,665	1,526,310	(0.83)%
7	924 Property Insurance	826,103	—	826,103	729,434	13.25 %
8	925 Legal & Claim Department	5,548,059	—	5,548,059	3,696,158	50.10 %
9	926 Employee Pensions & Benefits	8,521,477	—	8,521,477	8,482,697	0.46 %
10	928 Regulatory Commission Expenses	46,221	—	46,221	190,235	(75.70)%
11	930 Miscellaneous General Expenses	4,776,920	—	4,776,920	5,589,466	(14.54)%
12	931 Rents	251,359	—	251,359	278,731	(9.82)%
13	**Total Operation-Admin. & General**	33,842,745	—	33,842,745	31,648,038	6.93 %
14	**Admin. & General - Maintenance**					
15	935 General Plant	2,023,793	—	2,023,793	1,746,527	15.88 %
16	**Total Admin. & General Expenses**	35,866,538	—	35,866,538	33,394,565	7.40 %
17	**TOTAL OPER. & MAINT. EXPENSES**	$ 109,294,131	$ —	$ 109,294,131	$ 140,747,156	(22.35)%
18						
19						
20						
21						
22						

Schedule 10C

Sch. 11	MONTANA TAXES OTHER THAN INCOME - NATURAL GAS (INCLUDES CMP)			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	1,962,862	2,036,073	(3.60)%
3	Property Taxes	33,328,513	30,149,636	10.54 %
4	Crow Tribe RR and Utility Tax	134,904	124,836	8.06 %
5	Blackfoot Possessory Tax	757,600	348,409	117.45 %
6	Consumer Counsel	103,915	193,110	(46.19)%
7	Public Service Commission	641,844	886,175	(27.57)%
8	Heavy Highway Use	341	586	(41.81)%
9	Gas Production Taxes	189,819	499,522	(62.00)%
10	Delaware Franchise Tax	78,388	55,061	42.37 %
11				
12				
13				
14	**Canadian Taxes**			
15	Ad Valorem	16,357	18,227	(10.26)%
16				
17				
18				
19				
20	**TOTAL TAXES OTHER THAN INCOME**	$ 37,214,543	$ 34,311,635	8.46 %

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	A EXCAVATION	Excavation Contractor	261,701
2	ABSOLUTAIRE, INC	HVAC Consulting	125,135
3	ACRT, INC	Consulting Services	336,354
4	AFFCO INC	Hydro Construction Services	2,830,609
5	ALERTWEST INC	Security Services	108,878
6	AMERICAN INNOVATIONS INC	Software Support Services	120,135
7	ANDRITZ HYDRO CORP	Hydro Upgrade Services	2,899,165
8	ARCADIS US INC	Engineering Services	1,675,886
9	ARCOS LLC	Call-out Services	163,709
10	ASCEND ANALYTICS LLC	Hydro Expert Analysis	378,526
11	ASPLUNDH TREE EXPERT LLC	Tree Trimming	7,629,399
12	ASSOCIATED UNDERWATER SERVICE	Inspection Services	143,767
13	AVEVA SOFTWARE, LLC	Computer Support Services	285,729
14	BART ENGINEERING COMPANY	Engineering Services	664,833
15	BASELOAD POWER GENERATION PARTS Total	Engineering Services	475,606
16	BEACON COMMUNICATIONS LLC	Software Maintenance	902,828
17	BIG HORN WIRELINE, LLC Total	Storage	534,597
18	BILLINGS FLYING SERVICE, INC.	Powerline Services	81,950
19	BISON ENGINEERING INC	Engineering Services	482,608
20	BLUE MOUNTAIN DIRECTIONAL DRI	Boring Services	1,750,357
21	BRY ENTERPRISE Total	Road Bore Services	476,671
22	BURK EXCAVATION AND UTILITIES	Construction	1,773,504
23	CATERPILLAR POWER GENERATION	Generation Services	11,452,834
24	CENTRON SERVICES INC	Customer Collection service	78,467
25	CHARLOTTE ST. ADVISORS, LLC Total	Tactical Planning Prof Services	622,725
26	CHAZNLINE, LLC Total	Heavy Haul Services	1,479,980
27	CN UTILITY CONSULTING INC	Utility Consulting Services	312,382
28	CONTINENTAL STEEL WORKS	Fabrication Services	3,601,852
29	CRIST, KROGH, BUTLER & NORD L	Legal Services	367,635
30	CROWLEY FLECK PLLP	Legal Services	218,196
31	CTA INC.	Energy Conservation Consultants	1,326,989
32	DAVEY RESOURCE GROUP, INC	Surveying Services	158,610
33	DAVEY TREE SURGERY COMPANY	Tree Trimming	5,880,940
34	DELOITTE & TOUCHE LLP	Audit Services	1,790,953
35	DEPT OF HEALTH & HUMAN SERVIC	Weatherization Program Services	2,018,371
36	DIETZEL ENTERPRISES INC	Construction	518,225
37	DJ&A P C CONSULTING ENGINEER	Surveying Services	183,117
38	DNV ENERGY SERVICES USA INC Total	Commercial Lighting program	6,169,892
39	DOBLE ENGINEERING CO	Maintenance Service	122,499
40	DORSEY & WHITNEY LLP	Legal Services	961,107
41	DOWL HKM	Geotechnical Services	136,916
42	E SOURCE COMPANIES LLC	Consulting Services	168,680
43	ELM LOCATING & UTILITY SERVIC	Locating Services and Excavation Notifications	6,153,175
44	ENERGY CONTRACT SERVICES LLC	Inspection Services	2,936,634
45	ENERGY SHARE OF MONTANA	USBC Services	485,307
46	EOCENE ENVIROMENTAL GROUP	Environmental Services	888,698
47	FAGEN, INC	Construction	28,333,410
48	FLYNN WRIGHT INC	Advertising Services	2,756,110
49	FOOTHILLS RIG SERVICE	Well Services	81,061
50	GARTNER INC	Information Technology Consulting	659,611
51	GE ENERGY MANAGEMENT SERVICES, LLC Total	E-Terra Source Upgrade Assist	833,420
52	GEI CONSULTANTS INC	Environmental Consultants	438,758
53	GENERAL ELECTRIC INTERNATIONA	Plant Operator Services	4,769,233
54	GEOSPATIAL INNOVATIONS INC	GSI Services & Maintenance	322,088
55	GREGG ENGINEERING	Informational Technology Simulation	107,345
56	GUY TABACCO CONSTRUCTION	Construction	198,991
57	H2E INC	Engineering Services	642,756
58	HARDY CONSTRUCTION CO	Construction	2,467,729

Sch. 12A	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
61	HDR ENGINEERING INC	Engineering Services	6,413,893
62	HEATH CONSULTANTS INC	Gas Leak Surveys	1,009,409
63	HIGHMARK MEDIA	Safety Training	107,265
64	HITACHI ENERGY USA INC Total	Engineering Consulting	871,100
65	INTEC SERVICES INC	Pole Inspection Services	3,015,168
66	ITRON INC	Meter Installation	27,189,449
67	J D POWER AND ASSOCIATES	Energy Study	136,030
68	J2 BUSINESS PRODUCTS	Copier Maintenance	219,056
69	JACKSON CONTRACTOR GROUP	Construction	151,022
70	JACKSON HOMES LLC	Construction	624,054
71	JARES FENCE COMPANY INC	Fence Materials/Installation	160,552
72	JEFFERY CONTRACTING LLC	Construction	879,895
73	KARV LLC	Boring Services	186,421
74	KELLERMEYER BERGENSONS SERVICES LLC Total	Cleaning Services	487,300
75	LEARJET INC	Repair Services	415,618
76	LOCKMER PLUMBING HEATING &	Gas Meter Relocations	233,098
77	M&D CONSTRUCTION INC	Construction	1,031,281
78	MERCER HUMAN RESOURCE CONSULT	HR Consulting	162,225
79	MERKEL ENGINEERING INC	Consulting Services	703,463
80	MICHAELS FENCE & SUPPLY CO	Installation Services	81,539
81	MICHELS CORPORATION	Construction	7,471,160
82	MINUTEMAN AVIATION INC.	Helicopter Charter Services	528,353
83	MONTANA FISH WILDLIFE & PARKS	Wildlife Monitoring Services	788,184
84	MOODY'S INVESTORS SERVICE	Debt Rating Services	302,000
85	MORRISON MAIERLE INC	Engineering Services	809,035
86	MOUNTAIN POWER CONSTRUCTION C	Electric Construction and Maintenance	21,935,062
87	MOUNTAIN WEST HOLDING COMPANY	Traffic Safety Services	511,641
88	NATIONAL CENTER FOR APPROPRIA	Conservation Program Consultants	872,857
89	NORTHWEST ENERGY EFFICIENCY	Energy Services	1,282,896
90	OPEN ACCESS TECHNOLOGY INT'L	Software Support Services	750,764
91	PINNACLE RESEARCH & CONSULTING	Consulting Services	323,974
92	PL-ENERSERV, LLC	Construction	260,908
93	POTEET CONSTRUCTION	Traffic Safety Services	202,291
94	POTELCO INC	Electric Construction and Maintenance	20,898,233
95	POWER SETTLEMENTS CONSULTING &	Consulting Services	213,271
96	POWERS HEATING LLC	Meter Installation	95,706
97	PRO PIPE CORPORATION	Welding Services	485,871
98	QUANTA UTILITY ENGINEERING	Engineering Services	7,765,723
99	RIVER DESIGN GROUP INC	Engineering Services	103,903
100	ROCKY MOUNTAIN CONTRACTORS INC	Electric Construction and Maintenance	25,575,881
101	ROD TABBERT CONSTRUCTION INC	Construction	209,810
102	SCENIC CITY ENTERPRISES INC	Construction	97,393
103	SCHNABEL ENGINEERING LLC	Consulting Services	248,095
104	SHAW PIPELINE SERVICES INC Total	Pipeline Service Reroute	592,702
105	SIDEWINDERS LLC	Generator Repair Services	2,025,172
106	SOLAR TURBINES INC Total	Commissioning New Controls	1,083,808
107	SPHERION STAFFING	Temporary Labor	164,548
108	STANDARD & POOR'S FINANCIAL S	Debt Rating Services	143,370
109	STATE LINE CONTRACTORS INC	Electric Construction and Maintenance	850,784
110	STINSON LEONARD STREET LLP	Legal Services	898,373
111	SULLIVAN BROS. CONSTRUCTION INC Total	Boring Services	276,521
112	TBC CONSTRUCTION LLC Total	Pipeline Service Reroute	1,447,439
113	TERRA REMOTE SENSING (USA) INC	Surveying Services	1,100,534
114	THE MOSAIC COMPANY	Training	728,521
115	THOMPSON HINE LLP	Benefits Audit Services	109,782
116	TIMBERLINE SECURITY & SERVICES	Security Services	487,630
117	TLC SEPTIC SERVICE	Excavation Contractor	397,401

Sch. 12B	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
121	TRADEMARK ELECTRIC INC	Construction	743,825
122	TROUTMAN SANDERS LLP	Legal Services	156,385
123	ULTIMATE LANDSCAPE REPAIR LLC	Landscape service	799,273
124	UNITED STATES GEOLOGICAL SURV	Environmental Consulting	235,800
125	UTILITIES UNDERGROUND LOCATION	Excavation Location Services	321,501
126	VAISALA INC	Wind Forecasting Services	163,944
127	VERTEX	Billing Services and Programming	2,862,854
128	VERTIV CORPORATION	Maintenance Service	272,931
129	WATER & ENVIRONMENTAL TECHNOL	Engineering Services	447,405
130	WATSON TRUCKING OF HAVRE LLC	Hauling Services	154,120
131	WILLIAMSON FENCING & SPR.,INC.	Fence Materials/Installation	273,083
132	WILLIS TOWERS WATSON US LLC	Compensation Services	328,960
133	ZACHA UNDERGROUND CONSTRUCTIO	Construction	138,780
134			
135			
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137			
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172			
	Total of Payments Set Forth Above		**$ 266,762,938**
	1/ This schedule includes payments for professional services over $75,000.		

Sch. 13	POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS			
	Description	Total Company	Montana	% Montana
1				
2				
3	There is one employee political action committee			
4	(PAC):			
5				
6	a. NorthWestern Energy Montana Employee PAC for			
7	Montana employees;			
8				
9				
10				
11				
12				
13				
14				
15				
16				
17	All of the money contributed by members is			
18	dedicated to support political candidates, state and			
19	local political party organizations, and ballot issues.			
20	No company funds may be spent in support of a			
21	political candidate. Nominal administrative costs			
22	for such things as duplicating, postage, and			
23	meeting expenses are paid by the company as			
24	provided by law. These costs are charged to			
25	shareholder expense.			
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40	**TOTAL Contributions**	$ —	$ —	— %

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	$ 427,325,878	$ 474,947,258	(10.03)%
8	Service cost	5,099,037	5,104,682	(0.11)%
9	Interest cost	20,725,219	23,535,206	(11.94)%
10	Plan participants' contributions	—	—	-
11	Amendments	—	—	-
12	Actuarial (gain) loss	(26,780,061)	2,235,431	>-300.00%
13	Settlements	(848,500)	(51,942,557)	98.37 %
14	Benefits paid	(20,718,964)	(26,554,142)	21.97 %
15	Benefit obligation at end of year	$ 404,802,609	$ 427,325,878	(5.27)%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 348,133,473	$ 388,693,381	(10.43)%
18	Actual return on plan assets	8,025,978	29,936,791	(73.19)%
19	Settlements	(848,500)	(51,942,557)	98.37 %
20	Employer contribution	8,122,500	8,000,000	1.53 %
21	Plan participants' contributions	—	—	-
22	Benefits paid	(20,718,964)	(26,554,142)	21.97 %
23	Fair value of plan assets at end of year	$ 342,714,487	$ 348,133,473	(1.56)%
24	**Funded Status**	$ (62,088,122)	$ (79,192,405)	21.60 %
26	Unrecognized net actuarial gain (loss)	—	—	-
27	Unrecognized prior service cost	—	—	-
29	Prepaid (accrued) benefit cost	$ (62,088,122)	$ (79,192,405)	21.60 %
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	5.60 %	5.00 %	12.00 %
32	Expected return on plan assets	6.65 %	6.44 %	3.26 %
33	Rate of compensation increase	4.00% Union & 4.00% Non-Union	4.00% Union & 4.00% Non-Union	— %
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	$ 5,099,037	$ 5,104,682	(0.11)%
36	Interest cost	20,725,219	23,535,206	(11.94)%
37	Expected return on plan assets	(22,585,531)	(23,448,483)	3.68 %
38	Settlement (gain) loss recognized	—	4,394,595	(100.00)%
39	Recognized net actuarial gain	33,810	228,222	(85.19)%
40	Net periodic benefit cost (SEC Basis)	$ 3,272,535	$ 9,814,222	(66.66)%
41	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
42	Pension Costs	$ 8,122,500	$ 8,000,000	1.53 %
43	Pension Costs Capitalized	2,317,926	3,791,146	(38.86)%
44	Accumulated Pension Asset (Liability) at Year End	$ (62,088,122)	$ (79,192,405)	21.60 %
45	**Number of Company Employees:**			
46	Covered by the Plan 1/	1,058	1,355	(21.92)%
47	Not Covered by the Plan 1/	1,124	1,073	4.75 %
48	Active 1/	349	387	(9.82)%
49	Retired	455	685	(33.58)%
50	Deferred Vested Terminated 1/	254	283	(10.25)%

1/ 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			0.00%
18	Actual return on plan assets			0.00%
19	Acquisition			0.00%
20	Employer contribution 1/	$ 14,659,033	$ 13,211,496	10.96 %
21	Plan participants' contributions			0.00%
22	Benefits paid			0.00%
23	Fair value of plan assets at end of year 1/			0.00%
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	$ —	$ —	0.00%
28				
29	**Weighted-average Assumptions as of Year End**	Not Applicable		
30	Discount rate		— %	0.00%
31	Expected return on plan assets		— %	0.00%
32	Rate of compensation increase		— %	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)	$ —	$ —	0.00%
41				
42	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
43	401(k) Plan Defined Contribution Costs	$ 11,611,162	$ 10,351,128	12.17 %
44	401(k) Plan Defined Contribution Costs Capitalized	2,936,990	2,626,496	11.82 %
45	Accumulated Pension Asset (Liability) at Year End	Not Applicable		
46	**Number of Company Employees:**	2/	2/	
47	Covered by the Plan - Eligible	1,590	1,571	1.21 %
48	Not Covered by the Plan			0.00%
49	Active - Participating	1,579	1,565	0.89 %
50	Retired			0.00%
51	Vested Former Employees, Retirees and Active-	431	424	1.65 %
52	Noncontributing			
	1/ This plan covers all NorthWestern Corporation employees.			
	2/ 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: 2022.07.078			
4	Order number: 7860y			
5	Amount recovered through rates	$ (390,861)	$ 475,268	(182.24)%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	5.45 %	4.90 %	11.22 %
8	Expected return on plan assets	5.84 %	5.62 %	3.91 %
9	Medical Cost Inflation Rate 3/	5.00% fixed rate annually	5.00% fixed rate annually	
10	Actuarial Cost Method	Projected Unit Credit Actuarial Cost Method, Allocated from the Date of Hire to Full Eligibility Date		
11	Rate of compensation increase	4.00% Union & 4.00% Non-Union	4.00% Union & 4.00% 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				

1/ Obtained from NorthWestern Energy-Montana's 2024 FASB 106 Valuation. Assumptions and data are as of December 31, 2024.

2/ Obtained from NorthWestern Energy-Montana's 2023 FASB 106 Valuation. Assumptions and data are as of December 31, 2023.

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/Dependents covered by the Plan			0.00%
7	**Montana 4/**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year	$ 10,598,133	$ 12,070,609	(12.20)%
10	Service cost	251,843	272,534	(7.59)%
11	Interest Cost	456,347	553,883	(17.61)%
12	Plan participants' contributions	1,109,234	1,383,742	(19.84)%
13	Amendments			-
14	Actuarial loss/(gain)	(1,803,657)	(820,734)	(119.76)%
15	Acquisition			-
16	Benefits paid	(2,272,247)	(2,861,901)	20.60 %
17	Benefit obligation at end of year	$ 8,339,653	$ 10,598,133	(21.31)%
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	$ 22,309,163	$ 20,055,071	11.24 %
20	Actual return on plan assets	3,177,129	3,334,030	(4.71)%
21	Acquisition			-
22	Employer contribution	448,847	398,221	12.71 %
23	Plan participants' contributions	1,109,234	1,383,742	(19.84)%
24	Benefits paid	(2,272,247)	(2,861,901)	20.60 %
25	Fair value of plan assets at end of year	$ 24,772,126	$ 22,309,163	11.04 %
26	**Funded Status**	$ 16,432,473	$ 11,711,030	40.32 %
27	Unrecognized net transition (asset)/obligation	—	—	-
28	Unrecognized net actuarial loss/(gain)	—	—	-
29	Unrecognized prior service cost	—	—	-
30	Prepaid (accrued) benefit cost	$ 16,432,473	$ 11,711,030	40.32 %
31	**Components of Net Periodic Benefit Costs**			
32	Service cost	$ 251,843	$ 272,534	(7.59)%
33	Interest cost	456,347	553,883	(17.61)%
34	Expected return on plan assets	(1,279,870)	(1,096,381)	(16.74)%
35	Amortization of transitional (asset)/obligation	—	—	-
36	Amortization of prior service cost	—	116,071	(100.00)%
37	Recognized net actuarial loss/(gain)	—	79,270	(100.00)%
38	Net periodic benefit cost	$ (571,680)	$ (74,623)	>-300.00%
39	**Accumulated Post Retirement Benefit Obligation**			
40	Amount Funded through VEBA	$ —	$ —	-
41	Amount Funded through 401(h)	—	—	-
42	Amount Funded through other - Company funds	448,847	398,221	12.71 %
43	TOTAL	$ 448,847	$ 398,221	12.71 %
44	Amount that was tax deductible - VEBA	$ —	$ —	-
45	Amount that was tax deductible - 401(h)	—	—	-
46	Amount that was tax deductible - Other	(390,861)	475,268	(182.24)%
47	TOTAL	$ (390,861)	$ 475,268	(182.24)%
48	**Montana Intrastate Costs:**			
49	Pension Costs	$ (390,861)	$ 475,268	(182.24)%
50	Pension Costs Capitalized	(111,770)	120,833	(192.50)%
51	Accumulated Pension Asset (Liability) at Year End	16,432,473	11,711,030	40.32 %
52	**Number of Montana Employees:**			
53	Covered by the Plan	1,030	1,151	(10.51)%
54	Not Covered by the Plan	1,664	1,655	0.54 %
55	Active	341	376	(9.31)%
56	Retired	633	718	(11.84)%
57	Spouses/Dependents covered by the Plan	56	57	(1.75)%
	4/ There are approximately $2,386,168 and $3,109,816 of additional OPEB liabilities outstanding at December 31, 2024 and 2023, respectively, for other company 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
1	Michael R. Cashell Vice President, Transmission	340,729	193,597	A	36,777 65,827 213,966 —	B C D E	850,896	782,566	8.7 %
2	Jeanne M. Vold Vice President, Technology	277,409	146,160	A	68,159 54,075 148,689 14,999 10,529	B C D E F	720,020	576,267	24.9 %
3	Bleau J. LaFave Vice President, Asset Management & Business Development	264,620	140,940	A	64,077 50,003 125,014 9,142 10,097 2,776 132	B C D E F G H	666,801	430,401	54.9 %
4	Jason Merkel Vice President, Distribution	273,656	166,518	A	35,188 51,002 127,518 7,169 3,213 183	B C D E G H	664,447	608,564	9.2 %
5	Jeffrey Berzina Controller	266,360	124,884	A	59,843 103,557	B D	554,644	468,217	18.5 %
6	Cynthia Fang Vice President, Regulatory	177,077	—	A	43,420 2,935 21,338 6,927 241,000	B G I J K	492,697	465,414	5.9 %
7	Michael L. Nieman Chief Audit & Compliance Officer	266,926	77,971	A	59,452 65,440 11,299	B D E	481,088	458,426	4.9 %
8	Travis E. Meyer Director, Corporate Development & Investor Relations Officer	244,167	80,014	A	57,247 69,009 5,318 7,921	B D E F	463,676	384,933	20.5 %
9	Emilie Ng Treasurer	224,448	52,878	A	58,597 53,748 9,044	B D E	398,715	346,041	15.2 %
10	Timothy P. Olson Counsel Corporate & Corporate Secretary Sr	218,324	64,009	A	54,519 52,969 264	B D H	390,085	358,774	8.7 %

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

1/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2024 Annual Incentive Compensation Plan. Amounts were earned in 2024 and paid in the first quarter of 2025. Based on company performance against plan, the incentive plan was funded at 116% of target. Salary and incentive in current rate recovery are based on historic test year costs, which are reviewed by the Montana Consumer Counsel, other parties, and MPSC staff in a general rate review. There is no specific recovery of these or most other expenses.

2/ 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> Defined Contribution Supplemental Executive Retirement Program

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

E> 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, 2024.

Actual Change in Pension Value

Mike Cashell	(13,466)
Jeanne Vold	14,999
Bleau LaFave	9,142
Jason Merkel	7,169
Jeff Berzina	—
Cynthia Fang	—
Michael Nieman	11,299
Travis Meyer	5,318
Emilie Ng	9,044
Timothy Olson	—

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

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

H> Value of non-cash taxable award and associated tax gross-up.

I> Value of PTO payout

J> Value of COBRA reimbursements

K> Severance Agreement

3/ Recovery of non-stock-based compensation is based on historic test year costs, which are reviewed by the Montana Consumer Counsel, other parties, and MPSC staff in a general rate review. There is no specific recovery of these or most other expenses.

Shareholders vote on executive compensation, and have consistently approved above 96%, most recently 98.9%.

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	Total Compensation Reported Last Year	% Increase Total Compensation
1	Brian B. Bird President & Chief Executive Officer	873,077	1,044,000 A	64,661 B 480,000 C 2,320,016 D 29,203 E 132 H	4,811,089	3,110,602	54.7 %
2	Crystal D. Lail Vice President, Chief Financial Officer	493,101	435,000 A	57,247 B 142,313 C 592,947 D 6,161 E 13,367 F	1,740,136	1,257,244	38.4 %
3	Shannon M. Heim General Counsel & Vice President, Federal Government Affairs	364,615	171,680 A	59,312 B 70,000 C 332,498 D — E 2,972 G	1,001,077	770,110	30.0 %
4	John D. Hines Vice President, Supply & Montana Government Affairs	341,065	193,597	37,311 B 66,077 C 214,745 D 71,969 E 5,123 F	929,887	784,041	18.6 %
5	Bobbi L. Schroeppel Vice President, Customer Care, Communications, & Human Resources	344,347	182,700 A	68,131 B 65,800 C 213,843 D 16,836 E 800 I	892,457	735,583	21.3 %

TOP FIVE 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
1	1/ Bonuses include the following:						
2							
3	A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2024 Annual						
4	Incentive Compensation Plan. Amounts were earned in 2024 and paid in the first quarter of 2025. Based on company						
5							
6	on historic test year costs, which are reviewed by the Montana Consumer Counsel, other parties, and MPSC staff in a general rate review.						
7	There is no specific recovery of these or most other expenses.						
8							
9	2/ All Other Compensation for named employees consists of the following:						
10	B> Employer contributions to benefits generally available to all employees on a nondiscriminatory basis - medical,						
11	dental, vision, employee assistance program, group term life, health savings account, wellness incentive,						
12	401(k) match, and non-elective 401(k) contribution, as applicable.						
13							
14	C> Defined Contribution Supplemental Executive Retirement Program						
15							
16	D> Values reflect the grant date fair value for performance stock awards. Executive stock based compensation is not included in rate recovery.						
17							
18	E> Change in pension value over previous year. The present value of accumulated benefits was calculated						
19	assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed						
20	payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements						
21	in our Annual Report on Form 10-K for the year ended December 31, 2024.						
22							
23	Actual Change in Pension Value						
24	Brian B. Bird	29,203					
25	Crystal D. Lail	6,161					
26	Shannon M. Heim	—					
27	John D. Hines	71,969					
28	Bobbi L. Schroeppel	16,836					
29							
30	F> Vacation sold back during the year at 75 percent of the rate of pay at the time of sellback.						
31							
32	G> Value of executive physical examination and associated tax gross-up.						
33							
34	H> Value of non-cash taxable award and associated tax gross-up.						
35							
36	I> Imputed income for facilities						
37							
38	3/ Stock-based compensation is paid by shareholders.						
39	Recovery of non-stock-based compensation is based on historic test year costs, which are reviewed by the Montana Consumer Counsel, other						
40	parties, and MPSC staff in a general rate review. There is no specific recovery of these or most other expenses.						
41							
42	Shareholders vote on proposed executive compensation on an annual basis during our shareholder meeting, and have consistently approved at						
43	above 96%, most recently 98.9%.						
44	Our Chief Executive Officer's compensation is 80% at-risk. Overall executive compensation is discussed in the Compensation Disclosure and						
45	Analysis section of our annual Proxy Statement.						
46							
47							

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	$ 6,769,324,100	$ 7,585,573,446	$ (816,249,346)	(10.76)%
4	101.1 Property Under Capital Leases	40,943,217	41,127,257	(184,040)	(0.45)%
5	103 Experimental Electric Plant Unclassified	4,798,750	4,798,750	—	— %
6	105 Plant Held for Future Use	4,191,929	4,140,227	51,702	1.25 %
7	107 Construction Work in Progress	125,080,799	358,401,452	$ (233,320,653)	(65.10)%
8	108 Accumulated Depreciation Reserve	(2,244,952,173)	(2,675,309,658)	$ 430,357,485	(16.09)%
9	108.1 Accumulated Depreciation - Capital Leases	(37,193,803)	(35,183,325)	$ (2,010,478)	5.71 %
10	111 Accumulated Amortization & Depletion Reserves	(116,083,491)	(106,740,672)	$ (9,342,819)	8.75 %
11	114 Electric Plant Acquisition Adjustments	451,564,554	481,574,396	(30,009,842)	(6.23)%
12	115 Accumulated Amortization-Electric Plant Acq. Adj.	(91,524,576)	(92,378,300)	853,724	(0.92)%
13	116 Utility Plant Adjustments	263,806,234	357,585,527	(93,779,293)	(26.23)%
14	117 Gas Stored Underground-Noncurrent	38,192,545	36,212,426	1,980,119	5.47 %
15	**Total Utility Plant**	5,208,148,085	5,959,801,526	(751,653,441)	(12.61)%
16	**Other Property and Investments**				
17	121 Nonutility Property	686,805	686,805	—	— %
18	122 Accumulated Depr. & Amort.-Nonutililty Property	(68,042)	(67,635)	(407)	0.60 %
19	123.1 Investments in Assoc Companies and Subsidiaries	(110,826,649)	(97,949,544)	(12,877,105)	13.15 %
20	124 Other Investments	14,135,821	13,050,811	1,085,010	8.31 %
21	128 Miscellaneous Special Funds	—	—	—	-
22	LT Portion of Derivative Assets - Hedges	—	—	—	-
23	**Total Other Property & Investments**	(96,072,065)	(84,279,563)	(11,792,502)	13.99 %
24	**Current and Accrued Assets**				
25	131 Cash	911,923	8,763,190	(7,851,267)	(89.59)%
26	134 Other Special Deposits	13,894,365	14,856,653	(962,288)	(6.48)%
27	135 Working Funds	17,500	22,850	(5,350)	(23.41)%
28	142 Customer Accounts Receivable	66,518,761	91,004,511	(24,485,750)	(26.91)%
29	143 Other Accounts Receivable	12,617,310	17,049,224	(4,431,914)	(25.99)%
30	144 Accumulated Provision for Uncollectible Accounts	(2,160,945)	(2,813,090)	652,145	(23.18)%
31	146 Accounts Receivable-Associated Companies	44,900,286	39,498,557	5,401,729	13.68 %
32	151 Fuel Stock	2,248,613	9,710,818	(7,462,205)	(76.84)%
33	154 Plant Materials and Operating Supplies	79,780,714	85,254,493	(5,473,779)	(6.42)%
34	164 Gas Stored - Current	6,743,589	18,814,211	(12,070,622)	(64.16)%
35	165 Prepayments	18,978,350	21,740,289	(2,761,939)	(12.70)%
36	172 Rents Receivable	64,160	73,787	(9,627)	(13.05)%
37	173 Accrued Utility Revenues	74,104,042	105,109,956	(31,005,914)	(29.50)%
38	174 Miscellaneous Current & Accrued Assets	1,025,532	876,037	149,495	17.06 %
39	**Total Current & Accrued Assets**	319,644,200	409,961,486	(90,317,286)	(22.03)%
40	**Deferred Debits**				
41	181 Unamortized Debt Expense	9,376,139	11,096,631	(1,720,492)	(15.50)%
42	182 Regulatory Assets	676,869,364	746,025,553	(69,156,189)	(9.27)%
43	183 Preliminary Survey and Investigation Charges	—	376,264	(376,264)	(100.00)%
44	184 Clearing Accounts	—	(2,520)	2,520	(100.00)%
45	186 Miscellaneous Deferred Debits	949,677	11,117,717	(10,168,040)	(91.46)%
46	189 Unamortized Loss on Reacquired Debt	16,960,804	20,027,942	(3,067,138)	(15.31)%
47	190 Accumulated Deferred Income Taxes	194,013,891	289,883,014	(95,869,123)	(33.07)%
48	191 Unrecovered Purchased Gas Costs	253,352	3,394,843	(3,141,491)	(92.54)%
49	**Total Deferred Debits**	898,423,227	1,081,919,444	(183,496,217)	(16.96)%
50	**TOTAL ASSETS and OTHER DEBITS**	$ 6,330,143,447	$ 7,367,402,893	$ (1,037,259,446)	(14.08)%

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	$ 1	$ 1	$ —	— %
4	211 Miscellaneous Paid-In Capital	2,044,999,693	1,981,122,792	63,876,901	3.22 %
5	216 Unappropriated Retained Earnings	349,075,632	809,312,954	(460,237,322)	(56.87)%
6	217 Reacquired Capital Stock	—	—	—	-
7	219 Accumulated Other Comprehensive Income	(5,383,393)	(5,513,000)	129,607	(2.35)%
8	**Total Proprietary Capital**	2,388,691,933	2,784,922,747	(396,230,814)	(14.23)%
9	**Long Term Debt**				
10	221 Bonds	2,074,660,000	2,479,660,000	(405,000,000)	(16.33)%
11	224 Other Long Term Debt	342,000,000	318,000,000	24,000,000	7.55 %
12	226 (Less) Unamortized Discount on Long Term Debt-Debit	—	6,538	(6,538)	(100.00)%
13	**Total Long Term Debt**	2,416,660,000	2,797,653,462	(380,993,462)	(13.62)%
14	**Other Noncurrent Liabilities**				
15	227 Obligations Under Capital Leases-Noncurrent	2,292,287	5,996,448	(3,704,161)	(61.77)%
16	228.2 Accumulated Provision for Injuries and Damages	5,427,888	6,745,658	(1,317,770)	(19.54)%
17	228.3 Accumulated Provision for Pensions and Benefits	(4,015,920)	4,631,028	(8,646,948)	(186.72)%
18	228.4 Accumulated Miscellaneous Operating Provisions	30,772,443	50,272,082	(19,499,639)	(38.79)%
19	229 Accumulated Provision for Rate Refunds	—	—	—	-
20	230 Asset Retirement Obligations	33,987,819	41,424,213	(7,436,394)	(17.95)%
21	**Total Other Noncurrent Liabilities**	68,464,517	109,069,429	(40,604,912)	(37.23)%
22	**Current and Accrued Liabilities**				
23	231 Notes Payable	—	—	—	-
24	232 Accounts Payable	90,053,114	131,709,370	(41,656,256)	(31.63)%
25	234 Accounts Payable to Associated Companies	212,852	2,288,407	(2,075,555)	(90.70)%
26	235 Customer Deposits	17,640,442	11,954,099	5,686,343	47.57 %
27	236 Taxes Accrued	76,941,004	75,980,842	960,162	1.26 %
28	237 Interest Accrued	24,578,517	24,775,303	(196,786)	(0.79)%
29	241 Tax Collections Payable	298,173	1,789,013	(1,490,840)	(83.33)%
30	242 Miscellaneous Current and Accrued Liabilities	57,585,069	73,408,627	(15,823,558)	(21.56)%
31	243 Obligations Under Capital Leases-Current	3,902,892	3,720,377	182,515	4.91 %
32	**Total Current and Accrued Liabilities**	271,212,063	325,626,038	(54,413,975)	(16.71)%
33	**Deferred Credits**				
34	252 Customer Advances for Construction	123,249,058	107,470,505	15,778,553	14.68 %
35	253 Other Deferred Credits	93,579,661	147,334,417	(53,754,756)	(36.48)%
36	254 Regulatory Liabilities	119,721,846	190,647,029	(70,925,183)	(37.20)%
37	255 Accumulated Deferred Investment Tax Credits	2,229,208	258,964	1,970,244	>300.00%
38	281-283 Accumulated Deferred Income Taxes	846,335,161	904,420,302	(58,085,141)	(6.42)%
39	**Total Deferred Credits**	1,185,114,934	1,350,131,217	(165,016,283)	(12.22)%
40	**TOTAL LIABILITIES and OTHER CREDITS**	$ 6,330,143,447	$ 7,367,402,893	$ (1,037,259,446)	(14.08)%
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	2/ On January 1, 2024, we completed the second and final phase of the holding company reorganization. NorthWestern Corporation (NW Corp) contributed the assets and liabilities of its				
48	South Dakota and Nebraska regulated utilities to NorthWestern Energy Public Service Corporation, (NWE Public Service), and then distributed its equity interest in NWE Public Service				
49	and certain other subsidiaries to NorthWestern Energy Group, Inc., resulting in NW Corp owning and operating the Montana regulated utility and NWE Public Service owning and operating				
50	the Nebraska and South Dakota utilities, each as a direct subsidiary of NorthWestern Energy Group, Inc. Due to this reorganization, the prior period information included in these statements may not be comparable to the current period				
51					

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Nature of Operations and Basis of Consolidation

NorthWestern Corporation (NW Corp), a direct wholly-owned subsidiary of NorthWestern Energy Group, Inc., doing business as NorthWestern Energy, provides electricity and / or natural gas to approximately 627,900 customers in Montana and Yellowstone National Park. We 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.

The following notes to the financials statements appear in Northwestern Corporation's annual report to the stockholders and are prepared in conformity with 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:

- Removal and decommissioning costs of generation, transmission and distribution assets are reflected in the Balance Sheets as a component of accumulated depreciation of $444.1 million and $523.7 million as of December 31,2024 and December 31,2023, 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 $263.8 million as of December 31,2024 and $357.6 million as of December 31,2023, 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 31,2024 and December 31,2023, 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 $0.7 million and $0.9 million as of December 31,2023 and December 31,2022, 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 $0.7 million and $0.9 million as of December 31,2024 and December 31,2023, 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.

Events occurring subsequent to December 31, 2023, have been evaluated as to their potential impact to the Financial Statements through the date of this report.

Holding Company Reorganization

On October 2, 2023, NW Corp and NorthWestern Energy Group, Inc. completed a merger transaction pursuant to which NorthWestern Energy Group, Inc. became the holding company parent of NW Corp. In this reorganization, shareholders of NW Corp (the predecessor publicly held parent company) became shareholders of NorthWestern Energy Group, Inc., maintaining the same number of shares and ownership percentage as held in NW Corp immediately prior to the reorganization. NW Corp became a wholly-owned subsidiary of NorthWestern Energy Group, Inc. The transaction was effected pursuant to a merger pursuant to Section 251(g) of the General Corporation Law of the State of Delaware, which provides for the formation of a holding company without a vote of the shareholders of the constituent corporation. As a result of the reorganization, NorthWestern Energy Group, Inc. became the successor issuer to NW Corp pursuant to Rule 12g-3(a) of the Securities Exchange Act of 1934, and as a result, NorthWestern Energy Group, Inc.'s common stock was deemed registered under Section 12(b) of the Securities Exchange Act of 1934.

Upon the conversion of all issued and outstanding NW Corp common stock into common stock in NorthWestern Energy Group, Inc., as described above, the common stock of NW Corp ceased to exist. The accounting for this common stock conversion is treated as a retirement of common stock for NW Corp as the shares cease to exist. As such, the amounts included in Common stock and Treasury stock were cleared into Paid-in capital. Subsequent to the reorganization, NW Corp has 100 shares of common stock issued and outstanding, which are held by NorthWestern Energy Group, Inc.

On January 1, 2024, we completed the second and final phase of the holding company reorganization. NW Corp contributed the assets and liabilities of its South Dakota and Nebraska regulated utilities to NorthWestern Energy Public Service Corporation (NWE Public Service), and then distributed its equity interest in NWE Public Service and certain other subsidiaries to NorthWestern Energy Group, Inc., resulting in NW Corp owning and operating the Montana regulated utility and NWE Public Service owning and operating the Nebraska and South Dakota utilities, each as a direct subsidiary of NorthWestern Energy Group, Inc.

(2) Discontinued Operations

On January 1, 2024, we completed the previously announced second and final phase of our holding company reorganization resulting in the distribution of our ownership in NWE Public Service, our former South Dakota electric and natural gas and Nebraska natural gas operating segments, and certain non-regulated subsidiaries, our former other operating segment, to NorthWestern Energy Group, Inc. As a result of this distribution, the historical assets and liabilities for these operating segments have been classified as assets and liabilities of discontinued operations and the historical results of operations are shown in discontinued operations, net of tax. Our Financial Statements for prior periods reflect this reclassification. The notes to our financial statements present information from continuing operations.

The carrying amounts of the major classes of assets and liabilities of discontinued operations included in our Consolidated Balance Sheet at December 31, 2023, were as follows:

	As of December 31, 2023
ASSETS	
Current Assets:	
Cash and cash equivalents	$ 253
Restricted cash	1,166
Accounts receivable, net	37,547
Inventories	31,717
Regulatory assets	5,681
Prepaid expenses and other	10,910
Total current assets	**87,274**
Property, plant, and equipment, net	1,067,606
Goodwill	93,779
Regulatory assets	93,933
Other noncurrent assets	21,555
Total Assets	**$ 1,364,147**
LIABILITIES	
Current Liabilities:	
Accounts payable	28,766
Accrued expenses	27,949
Regulatory liabilities	20,767
Total current liabilities	**77,482**
Long-term debt	532,148
Deferred income taxes	20,307
Noncurrent regulatory liabilities	106,307
Other noncurrent liabilities	57,206
Total Liabilities	**$ 793,450**

The reconciliation of the major classes of income and expense constituting pretax income from discontinued operations to the after-tax income from discontinued operations on the Condensed Consolidated Statements of Income were as follows:

	Year Ended December 31, 2023
Operating revenues	$ 285,942
Operating expenses	249,024
Operating Income	36,918
Interest expense, net	(22,221)
Other income, net	1,805
Income from discontinued operations before income tax	16,502
Income tax expense	11,880
Discontinued operations, net of tax	$ 28,382

(3) Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with GAAP 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 Consolidated 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, AROs, regulatory assets and liabilities, allowances for uncollectible accounts, our QF 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.

Restricted Cash

Restricted cash consists primarily of funds held in trust accounts to satisfy the requirements of certain stipulation agreements and insurance reserve requirements.

Accounts Receivable, Net

Accounts receivable are net of allowances for uncollectible accounts of $2.2 million and $2.5 million at December 31, 2024 and December 31, 2023, respectively. Receivables include unbilled revenues of $74.1 million and $84.1 million at December 31, 2024 and December 31, 2023, respectively.

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 Consolidated 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 (regulatory liabilities).

If we were required to terminate the application of these provisions to our regulated operations, all such deferred amounts would be recognized in the Consolidated Statements of Income at that time. This would result in a charge to earnings and accumulated other comprehensive loss (AOCL), 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 Consolidated 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 AOCL 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 Consolidated Statements of Cash Flows, depending on the underlying nature of the hedged items. As of December 31, 2024, the only derivative instruments we have qualify for the normal purchases and normal sales exception.

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.

Property, Plant and Equipment

Property, plant and equipment are 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 property, plant and equipment 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 interest expense, while the equity component is included in other income. This rate averaged 7.0% and 6.4% for 2024 and 2023, respectively. AFUDC capitalized totaled $25.5 million and $23.1 million for the years ended December 31, 2024 and 2023, respectively.

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 5 to 127 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 2024 and 2023.

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 noncurrent regulatory liabilities.

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 Consolidated Income Statements and provision for income taxes.

Under the Inflation Reduction Act of 2022 our production tax credits may be transferred to an unrelated entity. Our policy is to account for these transferable credits within income tax expense.

Environmental Costs

We record environmental costs when it is probable we are liable for the costs and we can reasonably estimate the liability. 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,	
	2024	2023
	(in thousands)	
Cash paid (received) for:		
Income taxes [1]	$ (4,769)	$ (827)
Interest [2]	100,853	105,238
Significant non-cash transactions:		
Capital expenditures included in trade accounts payable [3]	18,537	42,322

(1) Includes income tax refunds from discontinued operations of $845 as of December 31, 2023.

(1) Includes interest payments from discontinued operations of $20,778 as of December 31, 2023.

(2) Includes capital expenditures included in trade accounts payable of discontinued operations of $3,867 as of December 31, 2023.

The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the Consolidated Balance Sheets that sum to the total of the same such amounts shown in the Consolidated Statements of Cash Flows (in thousands):

	December 31,	
	2024	2023
Cash and cash equivalents	$ 1,934	$ 8,851
Restricted cash	13,894	14,857
Discontinued operations (Note 2)	—	1,419
Total cash, cash equivalents, and restricted cash shown in the Consolidated Statements of Cash Flows	$ 15,828	$ 25,127

Restricted cash consists primarily of funds held in trust accounts to satisfy the requirements of certain stipulation agreements and insurance reserve requirements.

Accounting Standards Issued

There were no accounting standards adopted in the current year that had a material impact to our financial condition, results of operations, and cash flows. 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.

(4) Regulatory Matters

Montana Rate Review

In July 2024, we filed a Montana electric and natural gas rate review with the Montana Public Service Commission (MPSC). In November 2024, the MPSC partially approved our requested interim rates effective December 1, 2024, subject to refund. Subsequently, we modified our request through rebuttal testimony. In March 2025, we filed a natural gas settlement with certain parties and a motion for revised interim natural gas rates. In April 2025, we filed a partial electric settlement with certain other parties and a motion for revised interim electric rates. Both settlements and motions for revised interim rates are subject to approval by the MPSC.

The partial electric settlement includes, among other things, agreement on base revenue increases (excluding base revenues associated with Yellowstone County Generating Station (YCGS)), allocated cost of service, rate design, updates to the amount of revenues associated with property taxes (excluding property taxes associated with YCGS), regulatory policy issues related to requested changes in regulatory mechanisms, and agreement to support a separate motion for revised electric interim rates. The partial electric settlement provides for the deferral and annual recovery of incremental operating costs related to wildfire mitigation and insurance expenses through the Wildfire Mitigation Balancing Account.

The natural gas settlement includes, among other things, agreement on base revenues, allocated cost of service, rate design, updates to the amount of revenues associated with property taxes, and agreement to support a separate motion for revised natural gas interim rates.

The details of our rebuttal request are set forth below:

Requested Revenue Increase (Decrease) Through Rebuttal Testimony (in millions)

	Electric	Natural Gas
Base Rates	$ 153.8	27.9
Power Cost & Credit Mechanism (PCCAM)(1)	(94.5)	n/a
Property Tax (tracker base adjustment)(1)	(1.3)	0.1
Total Revenue Increase Requested through Rebuttal Testimony	$ 58.0	$ 28.0

(1) These items are flow-through costs. PCCAM reflects our fuel and purchased power costs.

The details of our interim rates granted are set forth below:

Interim Revenue Increase (Decrease) Granted (in millions)

	Electric	Natural Gas
Base Rates	$ 18.4	$ 17.4
PCCAM(1)	(88.0)	n/a
Property Tax (tracker base adjustment)(1)(2)	7.4	0.2
Total Interim Revenue Granted	$ (62.2)	$ 17.6

(1) These items are flow-through costs. PCCAM reflects our fuel and purchased power costs.
(2) Our requested interim property tax base increase went into effect on January 1, 2025, as part of our 2024 property tax tracker filing.

The details of our settlement agreement and requested revised interim rates are set forth below:

Requested Revenue Increase (Decrease) through Settlement Agreements and Revised Interim Filing (in millions)

	Electric	Natural Gas
Base Rates:		
Base Rates (Settled)	$ 66.4	$ 18.0
Base Rates - YCGS (Non-settled)(1)(2)	43.9	n/a
Requested Base Rates for Revised Interim Filing	110.3	18.0
Pass-through items:		
Property Tax (tracker base adjustment) (Settled)(3)	(5.2)	0.1
Property Tax (tracker base adjustment) - YCGS (Non-settled)(1)(3)	4.0	n/a
PCCAM (Non-settled)(1)(2)(3)	(94.5)	n/a
Requested Pass-Through Rates for Revised Interim Filing	(95.7)	0.1
Total Requested Revenue Increase through Revised Interim Filing(4)	$ 14.6	$ 18.1

(1) These items were not included within the partial electric settlement and will be contested items that are expected to be determined in the MPSC's final order.
(2) Intervenor positions propose up to an $11.6 million reduction to this base rate revenue request and an additional $38.4 million decrease to the PCCAM base.
(3) These items are flow-through costs. PCCAM reflects our fuel and purchased power costs.
(4) Revised interim filing rates are requested to be effective May 1, 2025. If the revised interim rates are not approved, and a final order is not received by May 23, 2025, which is 270 days from acceptance of our filing, we intend to implement, as permitted by Montana statute, our rebuttal rates, which will be subject to refund, until a final order is received.

A hearing on the electric and natural gas rate review is scheduled for June 9, 2025. Interim rates will remain in effect on a refundable basis until the MPSC issues a final order.

(5) Regulatory Assets and Liabilities

We prepare our Consolidated Financial Statements in accordance with the provisions of ASC 980, as discussed in Note 3 - 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. Of these regulatory assets and liabilities, energy supply costs are the only items earning a rate of return. The remaining regulatory items have corresponding assets and liabilities that will be paid for or refunded in future periods.

	Note Reference	Remaining Amortization Period	December 31, 2024	December 31, 2023
			(in thousands)	
Flow-through income taxes	13	Plant Lives	$ 522,015	$ 483,949
Pension	15	See Note 15	56,719	73,823
Excess deferred income taxes	13	Plant Lives	39,040	44,657
Employee related benefits	15	See Note 15	17,877	21,926
Wildfire Mitigation		Undetermined	17,368	1,623
Deferred financing costs	12	See Note 12	16,961	18,540
State & local taxes & fees		1 Year	8,863	2,733
Supply costs		1 Year	1,132	3,895
Other		Various	15,098	22,811
Total Regulatory Assets			**$ 695,073**	**$ 673,957**
Removal cost	7	Plant Lives	$ 444,058	$ 435,470
Excess deferred income taxes	13	Plant Lives	108,154	117,870
State & local taxes & fees		1 Year	46	29,686
Supply costs		1 Year	5,093	924
Gas storage sales		16 years	6,205	6,625
Other		Various	1,977	905
Total Regulatory Liabilities			**$ 565,533**	**$ 591,480**

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 13 - Income Taxes for further discussion.

Pension and Employee Related Benefits

We recognize the unfunded portion of plan benefit obligations in the Consolidated 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 MPSC allows recovery of postretirement benefit costs on an accrual basis.

Deferred Financing Costs

Consistent with our historical regulatory treatment, a regulatory asset has been established to reflect the remaining deferred financing costs on long-term debt that has been replaced through the issuance of new debt. These amounts are amortized over the life of the new debt.

Enhanced Wildfire Mitigation Plan

We have developed an Enhanced Wildfire Mitigation Plan addressing five key areas: situational awareness, operational practices, system preparedness, vegetation management, and public communications outreach. Because of ever-increasing wildfire risk, our plan includes greater focus on situational awareness to monitor changing environmental conditions, operational practices that are more reactive to changing conditions, increased frequency of patrol and repairs, and more robust system hardening programs that target higher risk segments in our transmission and distribution systems. The MPSC has approved the deferral of incremental operating costs related to this Enhanced Wildfire Mitigation Plan.

Supply Costs

The MPSC has authorized the use of electric and natural gas supply cost trackers that enable us to track actual supply costs and either recover the under collection or refund the over collection to our customers. Accordingly, we have recorded a regulatory asset and liability to reflect the future recovery of under collections and refunding of over collections through the ratemaking process. We earn interest on natural gas supply costs under collected, or apply interest to an over collection, of 6.7 percent. For our electric supply tracker, the PCCAM, the interest rate we earn on supply costs under collected, or the interest rate we apply to an over collection, is based on the monthly interest rate for three month commercial paper as published by the Federal Reserve.

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, or refund the decrease, in rates, less the amount allocated to Federal Energy Regulatory Commission jurisdictional customers and net of the related income tax benefit.

Removal Cost

The anticipated costs of removing assets upon retirement are collected from customers in advance of removal activity as a component of depreciation expense. Our depreciation method, including cost of removal, is established by the respective regulatory commissions. Therefore, consistent with this regulated treatment, we reflect this accrual of removal costs for our regulated assets by increasing our regulatory liability. See Note 7 - Asset Retirement Obligations, for further information regarding this item.

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.

(6) Property, Plant and Equipment

The following table presents the major classifications of our property, plant and equipment (in thousands):

	December 31,	
	2024	2023
	(in thousands)	
Electric Plant	$ 4,888,326	$ 4,343,235
Natural Gas Plant	1,328,386	1,244,451
Plant acquisition adjustment[1]	656,319	656,319
Common and Other Plant	204,663	197,783
Construction work in process	133,740	352,377
Total property, plant and equipment	7,211,434	6,794,165
Less accumulated depreciation	(1,561,647)	(1,502,887)
Less accumulated amortization	(344,785)	(315,082)
Net property, plant and equipment	$ 5,305,002	$ 4,976,196

(1) The plant acquisition adjustment balance above includes our hydro generating assets acquired in 2014 and the inclusion of our interest in Colstrip Unit 4 in rate base in 2009. The acquisition adjustment is amortized on a straight-line basis over the estimated remaining useful life of each related asset in depreciation expense.

Net plant and equipment under finance lease were $3.0 million and $5.2 million as of December 31, 2024 and 2023, respectively, which is primarily comprised of 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 a 30% ownership interest in Colstrip Unit 4, a base-load electric generating plant, which is coal fired and operated by Talen Montana, LLC (Talen). Talen has a 30 percent ownership interest in Colstrip Unit 3. We have a reciprocating sharing agreement with Talen regarding the operation of Colstrip Units 3 and 4, in which each party receives 15 percent of the respective combined output and is responsible for 15 percent of the respective operating and construction costs, regardless of whether a particular cost is specified to Colstrip Unit 3 or 4. However, each party if responsible for its own fuel-related costs. Our interest in this plant is reflected in the Consolidated Balance Sheets on a pro rata basis and our share of operating expenses is reflected in the Consolidated Statements of Income. The participants each finance their own investment.

In January 2023 and July 2024, we entered into definitive agreements, the first with Avista and the second with Puget, to acquire their respective interests in Colstrip Units 3 & 4. In particular, we agreed to acquire a 15% (222 megawatts) interest from Avista and a 25% (370 megawatts) interest from Puget. Both agreements provide that the purchase price will be $0. These agreements are substantially similar and are both scheduled to close December 31, 2025, subject to the satisfaction of customary closing conditions and approvals contained within the agreements. Under the terms of the agreements, we will be responsible for operating costs starting on January 1, 2026; while Puget and Avista will remain responsible for their respective pre-closing share of environmental and pension liabilities attributed to events or conditions existing prior to the closing of the transaction and for any future decommission and demolition costs associated with the existing facilities that comprise their interests.

Acquisition of Avista and Puget's interests would result in our ownership of 55 percent of the facility with the ability to guide operating and maintenance investments. This would provide capacity to help us meet our obligation to provide reliable and cost effective power to our customers in Montana, while allowing opportunity for us to identify and plan for newer lower or no-carbon technologies in the future.

Either party may terminate the respective separate agreement if any requested regulatory approval is denied or if the closing has not occurred by December 31, 2025 or if any law or order would delay or impair closing.

Information relating to our ownership interest in this facility is as follows (in thousands):

	Colstrip Unit 4
December 31, 2024	
Ownership percentages	30.0 %
Plant in service	$ 330,888
Accumulated depreciation	137,153
December 31, 2023	
Ownership percentages	30.0 %
Plant in service	$ 323,793
Accumulated depreciation	127,381

(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 property, plant and equipment and other noncurrent liabilities. 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 asset retirement obligation (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 facility, 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,	
	2024	2023
Liability at January 1,	$ 34,808	$ 33,861
Accretion expense	1,626	1,575
Liabilities incurred	—	—
Liabilities settled	(1,923)	(1,151)
Revisions to cash flows	(299)	523
Liability at December 31,	$ 34,212	$ 34,808

During the twelve months ended December 31, 2024 our ARO liability decreased $1.9 million for partial settlement of the legal obligations at our jointly-owned coal-fired generation facility and natural gas pipeline segments. Additionally, during the twelve months ended December 31, 2024, our ARO liability decreased $0.3 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 Consolidated 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. The recorded amounts of costs collected from customers through depreciation rates are classified as a regulatory liability in recognition of the fact that we have collected these amounts that will be used in the future to fund asset retirement costs and do not represent legal retirement obligations. See Note 5 - Regulatory Assets and Liabilities for removal costs recorded as regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2024 and 2023.

(8) Goodwill

We completed our annual goodwill impairment test as of April 1, 2024, 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.

Goodwill by segment is as follows (in thousands):

	December 31,	
	2024	2023
Electric	$ 179,900	$ 179,900
Natural gas	83,900	83,900
Total Goodwill	$ 263,800	$ 263,800

(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 Consolidated Financial Statements at December 31, 2024 and 2023. 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 AOCL. We reclassify these gains from AOCL into interest expense 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 Consolidated Financial Statements (in thousands):

Cash Flow Hedges	Location of Amount Reclassified from AOCL to Income	Amount Reclassified from AOCL into Income during the Year Ended December 31, 2024	
Interest rate contracts	Interest Expense	$	612

A pre-tax loss of approximately $12.1 million is remaining in AOCL as of December 31, 2024, and we expect to reclassify approximately $0.6 million of pre-tax losses from AOCL into interest expense 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, accounts payable, and short-term borrowings, the carrying amount of each such item 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, 2024	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)		
Rabbi trust investments	14,136	—	—	—	14,136
Total	**$ 14,136**	**$ —**	**$ —**	**$ —**	**$ 14,136**
December 31, 2023					
Restricted cash equivalents	$ 14,857	$ —	$ —	$ —	$ 14,857
Rabbi trust investments	13,030	—	—	—	13,030
Total	**$ 27,887**	**$ —**	**$ —**	**$ —**	**$ 27,887**

Restricted cash equivalents represents 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, 2024		December 31, 2023	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt	$ 2,406,206	$ 2,104,381	$ 2,223,561	$ 2,000,767

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

On November 29, 2023 we amended our existing $425.0 million revolving credit facility (the Amended Facility) to address the holding company reorganization and extended the maturity date of the facility to November 29, 2028. The Amended Facility does not amortize and is unsecured. Borrowings may be made at interest rates equal to (a) SOFR, plus a credit spread adjustment of 10.0 basis points plus a margin of 100.0 to 175.0 basis points, or (b) a base rate, plus a margin of 0.0 to 75.0 basis points. After the completion of the holding company reorganization on January 1, 2024, we own and operate only the Montana regulated utility, and the base capacity of the Amended Facility automatically reduced to $400.0 million. The Amended Facility has uncommitted features that allow us to request one-year extensions to the maturity date and increase the size of the Amended Facility by an additional $100.0 million.

On January 24, 2025, we amended our existing $400.0 million Amended Facility to increase the capacity to $425.0 million. This amendment did not affect the maturity date or borrowing rates.

On January 2, 2024, we terminated our $100.0 million Additional Credit Facility. On January 4, 2024, we terminated our $25.0 Swingline Facility.

Commitment fees for the unsecured revolving lines of credit were $0.4 million and $0.5 million for the years ended December 31, 2024 and 2023.

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

	2024	2023
Unsecured revolving line of credit, expiring November 2028	400.0	425.0
Unsecured revolving line of credit, expiring November 2024	—	100.0
Unsecured revolving line of credit, expiring November 2025	—	25.0
	400.0	**550.0**
Amounts outstanding at December 31:		
SOFR borrowings	342.0	264.0
Letters of credit	—	—
	342.0	**264.0**
Net availability as of December 31(1)	**$ 58.0**	**$ 286.0**

(1) As discussed above, upon the completion of the holding company reorganization and termination of the Additional Credit Facility and Swingline facility in January 2024, our total consolidated capacity decreased to $400.0 million.

Our credit facilities include covenants that require us to meet certain financial tests, including a maximum debt to capitalization ratio not to exceed 65 percent. The facilities also contain 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 Montana First Mortgage Bonds would trigger a cross default on the Amended Facility; however, a default on the Amended Facility would not trigger a default on the Montana First Mortgage Bonds.

(12) Long-Term Debt and Finance Leases

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

	Due	December 31, 2024	December 31, 2023
Unsecured Debt:			
Unsecured Revolving Line of Credit	2028	$ 342,000	$ 264,000
Secured Debt:			
Mortgage bonds—			
Montana—1.00%	2024	—	100,000
Montana—5.01%	2025	161,000	161,000
Montana—3.11%	2025	75,000	75,000
Montana—3.99%	2028	35,000	35,000
Montana—3.21%	2030	100,000	100,000
Montana—5.57%	2031	175,000	—
Montana—5.57%	2033	239,000	239,000
Montana—5.71%	2039	55,000	55,000
Montana—4.15%	2042	60,000	60,000
Montana—4.85%	2043	15,000	15,000
Montana—4.176%	2044	450,000	450,000
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—4.30%	2052	40,000	40,000
Pollution control obligations—			
Montana—3.88%	2028	144,660	144,660
Other Long Term Debt:			
Discount on Notes and Bonds and Debt Issuance Costs, Net	—	(10,454)	(11,099)
Total Long-Term Debt		$ 2,406,206	$ 2,252,561
Less current maturities (including associated debt issuance costs)		(235,959)	(99,950)
Total Long-Term Debt, Net of Current Maturities		$ 2,170,247	$ 2,152,611
Finance Leases:			
Total Finance Leases	2026	$ 5,461	$ 8,799
Less current maturities		(3,596)	(3,338)
Total Long-Term Finance Leases		$ 1,865	$ 5,461

Secured Debt

First Mortgage Bonds and Pollution Control Obligations

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

On March 30, 2023, we issued and sold $239.0 million aggregate principal amount of Montana First Mortgage Bonds (the bonds) at a fixed interest rate of 5.57 percent maturing on March 30, 2033. These bonds were issued in transactions 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.

On June 29, 2023, the City of Forsyth, Rosebud County, Montana issued $144.7 million principal amount of Pollution Control Revenue Refunding Bonds (2023 Pollution Control Bonds) on our behalf. The 2023 Pollution Control Bonds were issued at a fixed interest rate of 3.88 percent maturing on July 1, 2028. The proceeds of the issuance were loaned to us pursuant to a Loan Agreement and were deposited directly with U.S. Bank Trust Company, National Association, as trustee, for the redemption of the 2.00 percent, $144.7 million City of Forsyth Pollution Control Revenue Refunding Bonds due on August 1, 2023 that had previously been issued on our behalf. Pursuant to the Loan Agreement, we are obligated to make payments in such amounts and at such times as will be sufficient to pay, when due, the principal and interest on the 2023 Pollution Control Bonds. Our obligations under the Loan Agreement are secured by delivery of a like amount of our Montana First Mortgage Bonds, which are secured by our Montana electric and natural gas assets. So long as we are making payments under the Loan Agreement, no payments under these mortgage bonds will be due. The 2023 Pollution Control Bonds were issued in a transaction exempt from the registration requirements of the Securities Act of 1933, as amended.

On May 28, 2024, we issued and sold $175.0 million aggregate principal amount of Montana First Mortgage Bonds at a fixed interest rate of 5.56 percent maturing on March 28, 2031. These bonds were issued in transactions exempt from the registration requirements of the Securities Act of 1933. Proceeds were used to redeem the $100.0 million of Montana First Mortgage Bonds due this year and for other general utility purposes. The bonds are secured by our electric and natural gas assets associated with its Montana utility operations.

On March 21, 2025, NW Corp issued and sold $400.0 million aggregate principal amount of Montana First Mortgage Bonds at a fixed interest rate of 5.07 percent maturing on March 21, 2030. These bonds were issued and sold to certain initial purchasers without being registered under the Securities Act of 1933, as amended (Securities Act), in reliance upon exemptions therefrom in compliance with Rule 144A under the Securities Act, or under Regulation S under the Securities Act for sales to non-U.S. persons. Proceeds will be used to repay outstanding borrowings under our NW Corp revolving credit facility, repay maturing Montana First Mortgage Bonds, and for general utility purposes.

On April 11, 2025, we redeemed all $161.0 million of NW Corp's 5.01 percent Montana First Mortgage Bonds due May 1, 2025.

As of December 31, 2024, we were in compliance with our financial debt covenants.

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt and finance leases, during the next five years are $239.6 million in 2025, $1.9 million in 2026, and $521.7 million in 2028.

(13) Income Taxes

Income tax expense (benefit) is comprised of the following (in thousands):

	Year Ended December 31, 2024	Year Ended December 31, 2023
Federal		
Current	$ 1,667	$ (1,016)
Deferred	13,602	17,581
Investment tax credits	1,970	(129)
State		
Current	61	(864)
Deferred	2,365	3,847
Income Tax Expense	$ 19,665	$ 19,419

Our effective tax rate typically differs from the federal statutory tax rate primarily due to production tax credits and 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 following table reconciles our effective income tax rate to the federal statutory rate:

	Year Ended December 31, 2024	Year Ended December 31, 2023
Federal statutory rate	21.0 %	21.0 %
State income tax, net of federal provisions	0.9	1.3
Flow-through repairs deductions	(9.6)	(11.5)
Gas repairs safe harbor method change	(2.2)	—
Amortization of excess deferred income taxes	(1.2)	(0.8)
Production tax credits	(1.1)	(1.4)
Prior year permanent return to accrual adjustments	(0.3)	—
Plant and depreciation of flow through items	3.3	2.8
Release of unrecognized tax benefits	—	(1.4)
Other, net	(1.0)	0.5
Effective tax rate	9.8 %	10.5 %

The table below summarizes the significant differences in income tax expense (benefit) based on the differences between our effective tax rate and the federal statutory rate (in thousands). All of our income from continuing operations is primarily from domestic operations.

	Year Ended December 31,	
	2024	2023
Income Before Income Taxes	$ 199,744	$ 185,168
Income tax calculated at federal statutory rate	41,946	38,885
Permanent or flow through adjustments:		
State income, net of federal provisions	1,719	2,367
Flow-through repairs deductions	(19,274)	(21,379)
Gas repairs safe harbor method change	(4,366)	—
Amortization of excess deferred income taxes	(2,465)	(1,479)
Production tax credits	(2,288)	(2,582)
Prior year permanent return to accrual adjustments	(567)	—
Plant and depreciation of flow through items	6,690	5,167
Release of unrecognized tax benefits	—	(2,680)
Other, net	(1,730)	1,120
	(22,281)	(19,466)
Income Tax Expense	$ 19,665	$ 19,419

We and our subsidiaries are included in NorthWestern Energy Group, Inc.'s consolidated federal and state income tax returns. In accordance with our tax sharing agreement with NorthWestern Energy Group, Inc., we compute our income taxes based upon the separate return method, where we are assumed to file a separate return with the taxing authority, thereby reporting our taxable income and paying the applicable tax to or receiving the appropriate refund from NorthWestern Energy Group, Inc.

In 2023, the Internal Revenue Service (IRS) issued a safe harbor method of accounting for the repair and maintenance of natural gas transmission and distribution property. For the year ending December 31, 2024, after completion of our impact analysis of the gas repairs safe harbor method change, we recorded an income tax benefit of approximately $4.4 million related to tax deductions for repair costs that were previously capitalized in the 2022 and prior tax years.

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

	December 31,	
	2024	2023
NOL carryforward	$ 89,816	82,351
Production tax credit	35,602	$ 33,279
Customer advances	32,455	28,300
Pension / postretirement benefits	10,369	16,352
Compensation accruals	9,857	8,319
Interest rate hedges	3,205	3,367
Unbilled revenue	3,126	7,222
Reserves and accruals	2,133	2,952
Environmental liability	2,131	2,222
Other, net	4,334	3,407
Deferred Tax Asset	**193,028**	**187,771**
Excess tax depreciation	(599,893)	(552,815)
Flow through depreciation	(119,674)	(108,413)
Goodwill amortization	(89,687)	(88,183)
Regulatory assets and other	(23,721)	(18,572)
Deferred Tax Liability	**(832,975)**	**(767,983)**
Deferred Tax Liability, net	**$ (639,947)**	**$ (580,212)**

As of December 31, 2024, our total federal net operation loss (NOL) carryforward was approximately $342.6 million. Our federal NOL carryforward does not expire. Our state NOL carryforward as of December 31, 2024 was approximately $335.3 million. If unused, our state NOL carryforwards will expire in 2033. We believe it is more likely than not that sufficient taxable income will be generated to utilize these NOL carryforwards.

At December 31, 2024, our total production tax credit carryforward was approximately $35.6 million. If unused, our production tax credit carryforwards will expire as follows: $1.2 million in 2035, $3.4 million in 2036, $3.5 million in 2037, $3.9 million in 2038, $4.4 million in 2039, $5.4 million in 2040, $4.4 million in 2041, $4.5 million in 2042, $2.6 million in 2043, and $2.3 million in 2044 . We believe it is more likely than not that sufficient taxable income will be generated to utilize these production tax credit carryforwards.

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):

	2024	2023
Unrecognized Tax Benefits at January 1	$ 5,179	$ 7,310
Gross increases - tax positions in prior period	—	—
Gross increases - tax positions in current period	—	—
Gross decreases - tax positions in current period	(1,569)	(2,131)
Lapse of statute of limitations	—	—
Unrecognized Tax Benefits at December 31	$ 3,610	$ 5,179

Our unrecognized tax benefits include approximately $1.4 million related to tax positions as of December 31, 2024 and 2023, that if recognized, would impact our annual effective tax rate. On April 14, 2023, the Internal Revenue Service (IRS) issued Revenue Procedure 2023-15, which provides a safe harbor method of accounting for gas repairs expenditures. During the year ended December 31, 2023, we adopted this method and decreased our total unrecognized tax benefits by $0.4 million and recognized an income tax benefit of approximately $2.7 million for previously unrecognized tax benefits. 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 and penalties related to uncertain tax positions in income tax expense. As of December 31, 2024, we have accrued $1.7 million for the payment of interest and penalties in the Consolidated Balance Sheets. As of December 31, 2023, we had $1.0 million accrued for the payment of interest and penalties.

Tax years 2021 and forward remain subject to examination by the IRS and state taxing authorities. During the first quarter of 2023 the IRS commenced and concluded a limited scope examination of our 2019 amended federal income tax return.

(14) 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, 2024			December 31, 2023		
	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount
Foreign currency translation adjustment	$ (4)	$ —	$ (4)	$ 2	$ —	$ 2
Reclassification of net income (loss) on derivative instruments	612	(160)	452	612	(160)	452
Postretirement medical liability adjustment	—	—	—	(331)	69	(262)
Other comprehensive (loss) income	$ 608	$ (160)	$ 448	$ 283	$ (91)	$ 192

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

	December 31, 2024	December 31, 2023
Foreign currency translation	$ 1,433	$ 1,437
Derivative instruments designated as cash flow hedges	(8,921)	(9,373)
Postretirement medical plans	(45)	280
Accumulated other comprehensive loss	$ (7,533)	$ (7,656)

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

		December 31, 2024 Year Ended			
	Affected Line Item in the Consolidated Statements of Income	Interest Rate Derivative Instruments Designated as Cash Flow Hedges	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (9,373)	$ 280	$ 1,437	$ (7,656)
Other comprehensive income before reclassifications		—	—	(4)	(4)
Amounts reclassified from AOCL	Interest Expense	452	—	—	452
Amounts reclassified from AOCL		—	—	—	—
Net current-period other comprehensive income (loss)		452	—	(4)	448
Distribution to Parent		$ —	$ (325)	$ —	$ (325)
Ending Balance		$ (8,921)	$ (45)	$ 1,433	$ (7,533)

	Affected Line Item in the Consolidated Statements of Income	December 31, 2023 Year Ended			
		Interest Rate Derivative Instruments Designated as Cash	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (9,825)	$ 542	$ 1,435	$ (7,848)
Other comprehensive loss before reclassifications		—	—	2	2
Amounts reclassified from AOCL	Interest Expense	452	—	—	452
Amounts reclassified from AOCL		—	(262)	—	(262)
Net current-period other comprehensive income (loss)		452	(262)	2	192
Ending Balance		$ (9,373)	$ 280	$ 1,437	$ (7,656)

(15) Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

We sponsor and/or contribute to pension, postretirement health care and life insurance benefit plans for eligible employees. The pension plan for our Montana employees is referred to as the NorthWestern Energy MT Plan (formerly known as the NorthWestern Energy Plan). 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 a liability in our Consolidated 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,	
	2024	2023	2024	2023
Change in benefit obligation:				
Obligation at beginning of period	$ 427,326	$ 474,947	$ 10,598	$ 12,070
Service cost	5,099	5,105	252	272
Interest cost	20,725	23,535	456	554
Actuarial (gain) loss	(26,780)	2,235	(1,804)	(820)
Settlements(1)	(848)	(51,942)	—	—
Benefits paid	(20,719)	(26,554)	(1,163)	(1,478)
Benefit Obligation at End of Period	$ 404,803	$ 427,326	$ 8,339	$ 10,598
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 348,134	$ 388,693	$ 22,309	$ 20,055
Return on plan assets	8,026	29,937	3,177	3,334
Employer contributions	8,122	8,000	449	398
Settlements(1)	(848)	(51,942)	—	—
Benefits paid	(20,719)	(26,554)	(1,163)	(1,478)
Fair value of plan assets at end of period	$ 342,715	$ 348,134	$ 24,772	$ 22,309
Funded Status	$ (62,088)	$ (79,192)	$ 16,433	$ 11,711
Amounts Recognized in the Balance Sheet Consist of:				
Noncurrent asset	—	—	16,943	12,378
Total Assets	—	—	16,943	12,378
Current liability	(10,000)	(10,000)	(510)	(667)
Noncurrent liability	(52,088)	(69,192)	—	—
Total Liabilities	(62,088)	(79,192)	(510)	(667)
Net amount recognized	$ (62,088)	$ (79,192)	$ 16,433	$ 11,711
Amounts Recognized in Regulatory Assets Consist of:				
Prior service credit	—	—	—	—
Net actuarial (loss) gain	(30,843)	(43,097)	3,716	15
Total	$ (30,843)	$ (43,097)	$ 3,716	$ 15

(1) In October 2023, we entered into a group annuity contract from an insurance company to provide for the payment of pension benefits to select NorthWestern Energy MT Pension Plan participants. We purchased the contract with $51.9 million of plan assets in 2023. A trailing premium of $0.8 million related to final data reconciliation was paid from plan assets in 2024, reflecting a final annuitized participant count of 276. The insurance company took over the payments of these benefits starting January 1, 2024. This transaction settled $51.9 million of our NorthWestern Energy MT Pension Plan obligation. As a result of this transaction, during the twelve months ended December 31, 2023, we recorded a non-cash, non-operating settlement charge of $4.4 million. This charge is recorded within other income, net on the Consolidated Statements of Income. As discussed within Note 5 – Regulatory Assets and Liabilities, the MPSC allows recovery of pension costs on a cash funding basis. As such, this charge was deferred as a regulatory asset on the Consolidated Balance Sheets, with a corresponding decrease to operating and maintenance expense on the Consolidated 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.

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,			
	2024		2023		2024		2023	
Components of Net Periodic Benefit Cost								
Service cost	$	5,099	$	5,105	$	252	$	272
Interest cost		20,725		23,535		456		554
Expected return on plan assets		(22,585)		(23,448)		(1,280)		(1,096)
Amortization of prior service cost (credit)		—		—		—		116
Recognized actuarial loss (gain)		33		228		—		79
Settlement loss recognized[1]		—		4,395		—		—
Net Periodic Benefit Cost (Credit)	$	3,272	$	9,815	$	(572)	$	(75)
Regulatory deferral of net periodic benefit cost[2]		4,850		(1,814)		—		—
Previously deferred costs recognized[2]		—		—		181		550
Net Periodic Benefit Cost Recognized	$	8,122	$	8,001	$	(391)	$	475

(1) Settlement losses are related to partial annuitization of the NorthWestern Energy MT Pension Plan effective October 24, 2023.
(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 Consolidated Statements of Income as those costs are recovered through customer rates.

For the years ended December 31, 2024 and 2023 Service costs were recorded in Operating, general, and administrative expense while non-service costs were recorded in Other income, net on the Consolidated Statements of Income.

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, 2024 and 2023. 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. During 2022, the plan's actuary conducted an experience study to review five years of plan experience and update these assumptions.

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 2024 decreased our projected benefit obligation by approximately $27.6 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 decreased our long term rate of return on assets assumption for NorthWestern Energy MT Pension Plan to 6.17 percent for 2025.

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

	Pension Benefits December 31,		Other Postretirement December 31,	
	2024	2023	2024	2023
Discount rate	5.60	5.00	5.45	4.90
Expected rate of return on assets	6.65	6.44	5.84	5.62
Long-term rate of increase in compensation levels (non-union)	4.00	4.00	4.00	4.00
Long-term rate of increase in compensation levels (union)	4.00	4.00	4.00	4.00
Interest crediting rate	6.00	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 Liability Hedging Fixed Income assets);
- Allocation to foreign equities increases the portfolio diversification and thereby decreases portfolio risk while providing for the potential for enhanced long-term returns;
- Private real estate and broad global opportunistic fixed income asset classes can provide diversification to both equity and liability hedging fixed income investments and that a moderate allocation to each can potentially improve the expected risk-adjusted return for the NorthWestern Energy Pension Plan investments over full market cycles;
- 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 Energy Health and Welfare	
	December 31,		December 31,	
	2024	2023	2024	2023
Fixed income securities	45.0 %	45.0 %	40.0 %	40.0 %
Non-U.S. fixed income securities	—	—	—	—
Opportunistic fixed income	11.0	11.0	—	—
Global equities	38.5	38.5	60.0	60.0
Private real estate	5.5	5.5	—	—

The actual allocation by plan is as follows:

	NorthWestern Energy Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,	
	2024	2023	2024	2023
Cash and cash equivalents	— %	— %	0.3 %	0.2 %
Fixed income securities(1)	43.7	45.3	32.2	35.1
Non-U.S. fixed income securities	—	—	—	—
Opportunistic fixed income	11.1	10.6	—	—
Global equities(1)	39.0	37.6	67.5	64.7
Private real estate	6.2	6.5	—	—
	100.0 %	100.0 %	100.0 %	100.0 %

(1) While the NorthWestern Energy Health and Welfare plan allocation of assets as of December 31, 2024, between Fixed income securities and Global equities is greater than 5 percent different from the target allocation, the plan Investment Manager has 60 days to correct this deviation from the plan.

Generally, the asset mix will be rebalanced to the target mix as individual portfolios approach their minimum or maximum levels. The guidelines allow for a transition to targets over time as assets are reallocated to newly-approved asset classes of opportunistic fixed income and private real estate. Debt securities consist of U.S. and international instruments including emerging markets and high yield instruments, as well as government, corporate, asset backed and mortgage backed securities. While the portfolio may invest in high yield securities, the average quality must be rated at least “investment grade" by rating agencies. Equity, real estate and fixed income portfolios may be comprised of both active and passive management strategies. 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. We also invest in global equities with exposure to developing and emerging markets. Equity investments may also be diversified across investment styles such as growth and value. Derivatives, options and futures are permitted for the purpose of reducing risk but may not be used for speculative purposes. Real estate investments will consist of global equity or debt interests in tangible property consisting of land, buildings, and other improvements in commercial and residential sectors.

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 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 or any affiliate's stock is not permitted; however, any holding in a diversified mutual fund or collective investment fund is permitted.

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 2024 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 costs for 2024 and 2023 were based on actual contributions to the plan. Annual contributions to each of the pension plans are as follows (in thousands):

	2024	2023
NorthWestern Energy Pension Plan	$ 8,122	$ 8,000

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

	Pension Benefits	Other Postretirement Benefits
2025	24,575	1,680
2026	25,611	986
2027	26,608	845
2028	27,326	841
2029	28,027	755
2030-2034	147,401	3,400

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 the plan. We also contribute various percentages of employees' gross compensation to the plan. Company contributions for the years ended December 31, 2024 and 2023 were $11.6 million, $10.3 million, respectively.

(16) Stock-Based Compensation

Our employees participate in the NorthWestern Energy Group, Inc. Amended and Restated Equity Compensation Plan (ECP), which includes restricted stock awards and performance share awards. The remaining vesting period for awards previously granted ranges from one to three 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.

Stock-based compensation expense is allocated to us based on the outstanding awards held by our employees and our allocation of labor costs. 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 certain performance goals are achieved 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 performance relative to the performance goals. Beginning in 2023, these awards contain service-, market-, and performance-based components. The service-based component of these awards, representing 30 percent of the award, vest at the end of the three-year performance period as long as the individual has remained employed over that term. The performance goals are independent of each other and equally weighted at 35 percent of the award, and are based on two metrics: (i) EPS growth level and average return on equity; and (ii) total shareholder return relative to a peer group. Performance unit awards issued prior to 2023 included both the market- and performance-based components discussed above.

Fair value is determined for each component of the performance unit awards. The fair value of the service-based component is estimated based upon the closing market price of NorthWestern Energy Group, Inc. common stock as of the grant date less the present value of expected dividends. The fair value of the performance-based component is estimated based upon the closing market price of NorthWestern Energy Group, Inc. common stock as of the grant date 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 market-based component 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:

	2024	2023
Risk-free interest rate	4.38 %	4.33 %
Expected life, in years	3	3
Expected volatility	12.5% to 29.0%	30.4% to 41.0%
Dividend yield	5.6 %	4.4 %

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 NorthWestern Energy Group, Inc.'s nonvested shares as of and changes during the year ended December 31, 2024, are as follows:

	Performance Unit Awards		
	Shares	Weighted-Average Grant-Date Fair Value	
Beginning nonvested grants	153,784	$	53.26
Granted	150,704		41.13
Vested	(60,830)		51.61
Forfeited	(11,732)		48.12
Remaining nonvested grants	231,926	$	46.07

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. Awards granted before 2022 are subject to a five-year performance and vesting period. The performance measure for these awards requires NorthWestern Energy Group, Inc. 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. Awards granted in 2022 no longer contain this performance measure, instead these awards will vest after five full calendar years if the employee remains employed during that service period. No retirement/retention restricted shares were granted during the year ended December 31, 2023. Once vested, the awards will be paid out in shares of NorthWestern Energy Group, Inc. 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 NorthWestern Energy Group, Inc.'s common stock as of the grant date less the present value of expected dividends.

A summary of NorthWestern Energy Group, Inc.'s nonvested shares as of and changes during the year ended December 31, 2024, are as follows:

	Shares	Weighted-Average Grant-Date Fair Value	
Beginning nonvested grants	60,779	$	47.91
Granted	—		—
Vested	—		—
Forfeited	(9,983)		60.73
Remaining nonvested grants	50,796	$	45.40

We recognized total stock-based compensation expense of $2.8 million and $3.0 million for the years ended December 31, 2024 and 2023, respectively, and related income tax benefit of $(0.6) million, $(0.8) million for the years ended December 31, 2024 and 2023, respectively. As of December 31, 2024, there was $6.6 million of unrecognized compensation cost related to the nonvested portion of the outstanding awards at Northwestern Energy Group, Inc. A portion of these cost is expected to be recognized over a weighted-average period of 2 years. The total fair value of NorthWestern Energy Group, Inc. shares vested was $3.1 million and $4.4 million, for the years ended December 31, 2024 and 2023 respectively.

(17) 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. We have 100 shares of common stock issued and outstanding.

Dividend Restrictions

Under various state regulatory agreements, debt agreements and the Federal Power Act, we have restrictions, including minimum equity ratios, that limit the amount of dividend distributions that can be made.

Pursuant to the MPSC regulatory agreement, if our secured credit ratings are above BBB- for S&P Global Ratings and Baa3 for Moody's Investor Services, we may declare or pay dividends as long as our common equity ratio is 40 percent or above. If our secured credit ratings are BBB- for S&P Global Ratings or Baa3 for Moody's Investor Services, we may declare or pay dividends as long as our common equity ratio is 43 percent or above. If our secured credit ratings fall below BBB- with S&P Global Ratings or Baa3 with Moody's Investor Services, we may not declare or pay dividends.

Our ability to pay dividends is also limited by the terms of various debt agreements, pursuant to which, we are required to maintain a debt to capitalization ratio of no more than 0.65 to 1.00.

As of December 31, 2024, approximately $784.6 million of our net assets were available for the payment of dividends under our most restrictive dividend restriction.

(18) Commitments and Contingencies

Qualifying Facilities Liability

Our QF liability primarily consists of unrecoverable costs associated with three contracts covered under the PURPA. These contracts require us to purchase minimum amounts of energy at prices ranging from $118 to $130 per MWH through 2029. As of December 31, 2024, our estimated gross contractual obligation related to these contracts was approximately $229.0 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $205.8 million through 2029. As contractual obligations are settled, the related purchases and sales are recorded within Fuel, purchased power and direct transmission expense and Electric revenues in our Consolidated Statements of Income. The present value of the remaining liability is recorded in Other noncurrent liabilities in our Consolidated Balance Sheets. The following summarizes the change in the liability (in thousands):

	December 31,	
	2024	2023
Beginning QF liability	$ 28,670	$ 49,728
Settlements[1]	(7,606)	(24,707)
Interest expense	2,434	3,649
Ending QF liability	$ 23,498	$ 28,670

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

	Gross Obligation	Recoverable Amounts	Net
2025	$ 60,360	$ 52,950	$ 7,410
2026	55,393	46,274	9,119
2027	56,665	46,668	9,997
2028	42,400	41,664	736
2029	14,134	18,231	(4,097)
Total[1]	$ 228,952	$ 205,787	$ 23,165

(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 Fuel, purchased power and direct transmission expense in the Consolidated Statements of Income and were approximately $189.5 million and $217.9 million for the years ended December 31, 2024 and 2023, respectively. As of December 31, 2024, our commitments under these contracts were $264.3 million in 2025, $312.2 million in 2026, $300.2 million in 2027, $298.9 million in 2028, $302.6 million in 2029, and $2.3 billion thereafter. These commitments are not reflected in our Consolidated 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 $19.1 million between 2024 and 2040. These commitments are not reflected in our Consolidated 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 is estimated to range between $6.2 million to $10.8 million. As of December 31, 2024, we had a reserve of approximately $8.1 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.

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

	December 31,	
	2024	2023
Liability at January 1,	$ 8,438	$ 8,858
Deductions	(416)	(1,084)
Charged to costs and expense	71	664
Liability at December 31,	$ 8,093	$ 8,438

We are permitted to recover the remediation costs related to certain environmental liabilities within rates. 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 for all remediation costs, we do not expect these costs to have a material effect on our consolidated financial position or results of operations.

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 (CO_2) and methane emissions from natural gas. These actions include legislative proposals, Executive, Congressional and EPA actions at the federal level, state level activity, investor activism and private party litigation relating to emissions. Coal-fired plants have come under particular scrutiny due to their level of emissions. We have joint ownership interests in one coal-fired electric generating plants, which is operated by Talen. We are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated.

EPA Rules - 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. Section 111(d) of the Clean Air Act (CAA) confers authority on EPA and the states to regulate emissions, including GHGs, from existing stationary sources. In April 2024, the EPA released final rules related to greenhouse gas (GHG) emission standards (GHG Rules) for existing coal-fired facilities and new coal and natural gas-fired facilities as well as final rules strengthening the MATS requirements (MATS Rules). In particular, the GHG Rules will (i) strengthen the current New Source Performance Standards for newly built fossil fuel-fired stationary combustion turbines (generally natural gas-fired); (ii) establish emission guidelines for states to follow in limiting carbon pollution from existing fossil fuel-fired steam generating electric generating units (including coal, oil and natural gas-fired units); and (iii) establish emission guidelines for large, frequently used existing fossil fuel-fired stationary combustion turbines (generally natural gas-fired). The MATS Rules will strengthen emission limits for acid gases, mercury, and other hazardous air pollutants from new and existing electric generating units. Compliance with the rules will require expensive upgrades at Colstrip Units 3 and 4 with proposed compliance dates that may not be achievable and / or require technology that is unproven, resulting in significant impacts to costs of the facilities. The final MATS and GHG Rules require compliance as early as 2027 and 2032, respectively.

Previous efforts by the EPA were met with extensive litigation, and this time is no different. We, along with many other utilities, electric cooperatives, organizations, and states, have petitioned for judicial review of the GHG and MATS Rules with the U.S. Court of Appeals for the D.C. Circuit. The United States Supreme Court denied the multiple stay requests related to the MATS Rule and the GHG Rule. The litigation on the merits continues for both the MATS and GHG rules in the D.C. Circuit Court of Appeals, and decisions are expected in 2025. On April 8, 2025, President Trump issued a proclamation, "Regulatory Relief for Certain Stationary Sources to Promote American Energy," exempting certain coal plants, including Colstrip Units 3 and 4, Big Stone Plant, and Coyote Plant, from compliance with the MATS Rule through July 8, 2029. If the MATS Rules and GHG Rules are fully implemented, it would result in additional material compliance costs. We will continue working with federal and state regulatory authorities, other utilities, and stakeholders to seek relief from the MATS and GHG regulations that, in our view, disproportionately impact customers in our region.

These GHG Rules and MATS Rules as well as future additional environmental requirements - federal or state - 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 or hazardous air pollutants may not be available within a timeframe consistent with the implementation of any such 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 state of Montana has developed and submitted to the EPA, for its approval, their respective State Implementation Plan (SIP) for Regional Haze compliance. While the state of Montana did not meet the EPA's July 31, 2021 submission deadline, it was submitted in 2022. The Montana SIP as drafted and submitted to EPA does not call for additional controls for our interest in Colstrip Unit 4. Until the SIP is finalized and approved by EPA, the potential remains that installation of additional emissions controls might be required at the Colstrip facility

Jointly Owned Plants - We have joint ownership in a generation plant located in Montana that is 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

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). On August 1, 2018, the Federal District Court granted our and Talen's motions to dismiss the State's Complaint as it pertains to the navigability of the riverbeds associated with four of our hydroelectric facilities near Great Falls. A bench trial before the Federal District Court commenced January 4, 2022, and concluded on January 18, 2022, which addressed the issue of navigability concerning our other six facilities. On August 25, 2023, the Federal District Court issued its Findings of Fact, Conclusions of Law, and Order (the "Order"), which found all but one of the segments of the riverbeds in dispute not navigable, and thus not owned by the State of Montana. The one segment found navigable, and thus owned by the State, was the segment on which the Black Eagle development was located. The State filed a motion to pursue an interlocutory appeal of the Order, and on January 2, 2024, the Federal District Court certified the Order for appeal to the 9th Circuit Court of Appeals.. Upon the State's motion, the Federal District Court certified the Order for interlocutory appeal to the 9th Circuit Court of Appeals. After briefing and oral argument, the 9th Circuit affirmed the Federal District Court's Order in full on March 4, 2025.

Following the mandate and remand, the District Court will resume jurisdiction to determine damages for the Sun River to Black Eagle Falls Segment of the Missouri River. If the Federal District Court calculates damages as the State District Court did in 2008, we do not anticipate the resulting annual rent for the Black Eagle segment would have a material impact to our financial position or results of operations. 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.

Yellowstone County Generating Station Air Permit

On October 21, 2021, the Montana Environmental Information Center and the Sierra Club filed a lawsuit in Montana State District Court, against the MDEQ and NorthWestern, alleging that the environmental analysis conducted by MDEQ prior to issuance of the YCGS air quality construction permit was inadequate. On April 4, 2023, the Montana District Court issued an order finding MDEQ's environmental analysis was deficient in not addressing exterior lighting and greenhouse gases and remanded it back to MDEQ to address the deficiencies and vacated the YCGS air quality permit pending that remand. As a result of the vacatur of the permit, we paused construction. On June 8, 2023, the Montana District Court granted our motion to stay the order vacating the air quality permit pending the outcome of our appeal to the Montana Supreme Court. We recommenced YCGS construction in June 2023 and placed the plant in service in October 2024. On January 3, 2025, the Montana Supreme Court ordered that the YCGS air quality permit be reinstated. The Court remanded the matter back to MDEQ for supplemental analysis regarding lighting and greenhouse gas emissions in Montana. YCGS is commercially operable with the reinstated air quality permit.

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 our opinion, the amount of ultimate liability with respect to these other actions will not materially affect our financial position, results of operations, or cash flows.

(19) Revenue from Contracts with Customers

Accounting Policy

Our revenues are primarily from tariff based sales. We provide gas and/or electricity to customers under these tariffs without a defined contractual term (at-will). As the revenue from these arrangements is equivalent to the electricity or gas supplied and billed in that period (including estimated billings), there will not be a shift in the timing or pattern of revenue recognition for such sales. We have also completed the evaluation of our other revenue streams, including those tied to longer term contractual commitments. These revenue streams have performance obligations that are satisfied at a point in time, and do not have a shift in the timing or pattern of revenue recognition.

Customers are billed monthly on a cycle basis. To match revenues with associated expenses, we accrue unbilled revenues for electric and natural gas services delivered to customers, but not yet billed at month-end.

Nature of Goods and Services

We currently provide retail electric and natural gas services to three primary customer classes. Our largest customer class consists of residential customers, which include single private dwellings and individual apartments. Our commercial customers consist primarily of main street businesses, and our industrial customers consist primarily of manufacturing and processing businesses that turn raw materials into products.

Electric Segment - Our regulated electric utility business primarily provides generation, transmission, and distribution services to our customers. We recognize revenue when electricity is delivered to the customer. Payments on our tariff based sales are generally due in 20-30 days after the billing date.

Natural Gas Segment - Our regulated natural gas utility business primarily provides production, storage, transmission, and distribution services to our customers. We recognize revenue when natural gas is delivered to the customer. Payments on our tariff based sales are generally due in 20-30 days after the billing date.

Disaggregation of Revenue

The following tables disaggregate our revenue for the twelve months ended by major source and customer class (in millions):

December 31, 2024	Electric	Natural Gas	Total
Residential	$ 398.8	$ 110.2	$ 509.0
Commercial	409.0	59.9	468.9
Industrial	46.6	1.0	47.6
Lighting, governmental, irrigation, and interdepartmental	30.0	1.3	31.3
Total Retail Revenues	**884.4**	**172.4**	**1,056.8**
Regulatory Amortization	21.2	14.9	36.1
Transmission	97.1	—	97.1
Wholesale and other	7.5	36.9	44.4
Total Revenues	**$ 1,010.2**	**$ 224.2**	**$ 1,234.4**

December 31, 2023	Electric	Natural Gas	Total
Residential	$ 408.3	$ 136.1	$ 544.4
Commercial	431.4	73.7	505.1
Industrial	46.0	—	46.0
Lighting, governmental, irrigation, and interdepartmental	30.0	1.7	31.7
Total Retail Revenues	**915.7**	**211.5**	**1,127.2**
Regulatory Amortization	(103.8)	(15.2)	(119.0)
Transmission	78.4	—	78.4
Wholesale and other	8.0	41.6	49.6
Total Revenues	**$ 898.3**	**$ 237.9**	**$ 1,136.2**

(20) Related Party Transactions and Shared Services

Our parent, NorthWestern Energy Group, Inc., is organized as a holding company. As part of a holding company we receive services and share costs with Northwestern Energy Group, Inc., and its other subsidiaries pursuant to an Intercompany Services Agreement (ISA) that became effective in 2023. The ISA was approved by the MPSC. We employ all or substantially all of the employees of NorthWestern Energy Group, Inc. and its subsidiaries and, in accordance with the ISA, will provide all employment related services to the parties to the ISA. Pursuant to the ISA, all rendered services are at cost. For the year ended December 31, 2024, the total amount of payroll related services provided to NorthWestern Energy Public Service Corporation, a direct wholly-owned subsidiary of NorthWestern Energy Group, Inc., was $39.3 million.

Additionally, pursuant to the ISA, when utility-related operating, administrative, and general costs are attributable to more than one entity within the holding company structure and are unable to be direct charged (Shared OA&G Costs), these costs will be allocated amongst the entities pursuant to a Cost Allocation Manual. The nature of these Shared OA&G Costs includes operations supervision and engineering, energy supply marketing, networking communications, information technology, human resources, accounting, legal, and other such administrative costs.

The services provided under the ISA are settled in cash amongst the parties each month.

Sch. 19	MONTANA PLANT IN SERVICE - NATURAL GAS (INCLUDES CMP)			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1	**Intangible Plant**			
2	2301 Organization	$ 12,873	$ 12,873	— %
3	2302 Franchises and Consents	114,169	114,169	— %
4	2303 Miscellaneous Intangible Plant	1,933,112	1,900,998	1.69 %
5	**Total Intangible Plant**	2,060,154	2,028,040	1.58 %
6				
7	**Production Plant**			
8	2325 Gas Leaseholds	74,914,875	74,904,745	0.01 %
9	2327 Field Compressor Structure	64,803	64,803	— %
10	2328 Field Mea & Reg Structure	642,881	642,881	— %
11	2330 Well Construction	4,844,695	4,825,284	0.40 %
12	2331 Well Equipment	5,399,939	5,274,776	2.37 %
13	2332 Field Lines	2,577,700	2,577,700	— %
14	2333 Field Compressor Equipment	1,555,808	1,555,808	— %
15	2334 Measuring & Regulating Equip.	2,197,688	2,197,688	— %
16	2337 Other Equipment	483,356	66,732	>300.00%
17	**Total Production Plant**	92,681,745	92,110,417	0.62 %
18				
19	**Underground Storage Plant**			
20	2350 Land and Land Rights	5,768,407	4,943,533	16.69 %
21	2351 Structures and Improvements	4,429,768	3,309,706	33.84 %
22	2352 Wells	18,185,730	10,672,122	70.40 %
23	2353 Lines	16,716,118	15,338,784	8.98 %
24	2354 Compressor Station Equipment	14,775,129	13,770,583	7.29 %
25	2355 Measuring & Regulating Equip.	3,007,867	2,984,352	0.79 %
26	2356 Purification Equipment	598,376	598,376	— %
27	2357 Other Equipment	1,312,306	1,312,306	— %
28	**Total Underground Storage Plant**	64,793,701	52,929,762	22.41 %
29				
30	**Transmission Plant**			
31	2365 Rights of Way	28,025,676	23,282,958	20.37 %
32	2366 Structures and Improvements	22,113,261	20,912,212	5.74 %
33	2367 Mains	400,938,324	375,007,167	6.91 %
34	2368 Compressor Station Equipment	65,558,209	63,312,513	3.55 %
35	2369 Meas. & Reg. Station Equipment	41,188,418	35,389,708	16.39 %
36	2370 Communication Equipment	—	—	-
37	2371 Other Equipment	953,371	858,893	11.00 %
38	**Total Transmission Plant**	558,777,259	518,763,451	7.71 %
39				
40	**Distribution Plant**			
41	2374 Land and Land Rights	1,306,037	1,305,740	0.02 %
42	2375 Structures and Improvements	386,387	537,594	(28.13)%
43	2376 Mains	271,825,555	256,290,131	6.06 %
44	2377 Compressor Station Equipment	—	—	-
45	2378 M&R Station Equip.-General	5,099,921	5,022,347	1.54 %
46	2379 M&R Station Equip.-City Gate	—	—	-
47	2380 Services	121,067,350	114,612,617	5.63 %
48	2381 Customers Meters and Regulators	103,397,479	97,719,689	5.81 %
49	2382 Meter Installations	—	—	-
50	2383 House Regulators	—	—	-
51	2384 House Regulator Installations	—	—	-
52	2385 M&R Station Equip.-Industrial	103,320	103,320	— %
53	2386 Other Prop. on Customers' Premises	—	—	-
54	2387 Other Equipment	207,277	86,720	139.02 %
55	**Total Distribution Plant**	503,393,326	475,678,158	5.83 %

Sch. 19	cont. MONTANA PLANT IN SERVICE - NATURAL GAS (INCLUDES CMP)			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1				
2	**General Plant**			
3	2389 Land and Land Rights	101,675	101,675	— %
4	2390 Structures and Improvements	2,450,951	2,480,751	(1.20)%
5	2391 Office Furniture and Equipment	196,013	196,013	— %
6	2392 Transportation Equipment	20,262,132	19,346,359	4.73 %
7	2393 Stores Equipment	204,272	205,609	(0.65)%
8	2394 Tools, Shop & Garage Equipment	7,850,782	7,464,771	5.17 %
9	2395 Laboratory Equipment	360,957	360,957	— %
10	2396 Power Operated Equipment	5,781,895	5,792,181	(0.18)%
11	2397 Communication Equipment	2,810,411	2,913,666	(3.54)%
12	2398 Miscellaneous Equipment	52,304	54,008	(3.16)%
13	2399 Other Tangible Property	—	—	-
14	**Total General Plant**	40,071,392	38,915,990	2.97 %
15	**Total Gas Plant in Service**	1,261,777,577	1,180,425,818	6.89 %
16				
17	4101 Gas Plant Allocated from Common	64,798,191	60,472,293	7.15 %
18	2105 Gas Plant Held for Future Use	29,866	29,866	— %
19	2107 Gas Construction Work in Progress	25,858,064	24,056,885	7.49 %
20	2117 Gas in Underground Storage	44,910,861	50,275,607	(10.67)%
21				
22				
23	**TOTAL GAS PLANT**	$ 1,397,374,559	$ 1,315,260,469	6.24 %
24				
25				
26	**CONSOLIDATED**	December 31,		
27	**PLANT IN SERVICE**	2024	2023	
28				
29	Montana Electric	$ 5,239,884,995	$ 4,702,506,244	
30	Yellowstone National Park	25,659,606	23,530,558	
31	Montana Natural Gas (Includes CMP)	1,261,777,577	1,180,425,818	
32	Common	210,314,290	193,279,118	
33	Townsend Propane	1,730,243	1,547,775	
34	South Dakota Electric	—	1,115,119,868	
35	South Dakota Natural Gas	—	262,937,110	
36	South Dakota Common	—	71,074,956	
37	Asset Retirement Obligation	29,957,389	35,151,999	
38	**TOTAL PLANT**	$ 6,769,324,100	$ 7,585,573,446	

Sch. 20	MONTANA DEPRECIATION SUMMARY - NATURAL GAS (INCLUDES CMP)				
	Functional Plant Class	Montana Plant Cost	This Year Montana	Last Year Montana	Current Avg. Rate
1	**Accumulated Depreciation**				
2					
3	Production and Gathering	$ 92,681,745	$ 58,577,603	$ 54,330,009	5.23 %
4					
5	Underground Storage	64,793,701	28,084,339	27,921,582	1.95 %
6					
7	Other Storage	—	—	—	— %
8					
9	Transmission	558,777,259	148,481,018	144,293,208	1.59 %
10					
11	Distribution	503,393,326	187,349,049	180,302,830	2.50 %
12					
13	General and Intangible	42,131,546	29,334,775	28,756,081	9.98 %
14					
15	Common	64,798,191	21,426,611	18,627,225	6.48 %
16					
17					
18	**Total Accum Depreciation**	$ 1,326,575,768	$ 473,253,395	$ 454,230,935	2.55 %
19					
20					
21					

		December 31,	
22	**Consolidated**		
23	**Accumulated Depreciation**	2024	2023
24			
25	Montana Electric	$ 1,813,548,024	$ 1,739,696,988
26	Yellowstone National Park	13,118,320	12,038,251
27	Montana Natural Gas (Includes CMP)	451,826,784	435,603,710
28	Common	63,662,277	53,580,007
29	Townsend Propane	1,164,154	1,127,273
30	South Dakota Electric	—	384,514,178
31	South Dakota Natural Gas	—	113,554,633
32	South Dakota Common	—	21,556,117
33	Acquisition Writedown	32,458,684	35,163,173
34	Basin Creek Capital Lease	37,193,802	35,183,325
35	FIN 47	(3,217,616)	2,093,317
36	CWIP-Capital Retirement Clearing	(11,524,962)	(16,877,317)
37	**Total Consolidated Accum Depreciation**	$ 2,398,229,467	$ 2,817,233,655

Sch. 21	MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED) - NATURAL GAS			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1				
2	154 Plant Materials & Operating Supplies			
3	Assigned and Allocated to:			
4	Operation & Maintenance	—	—	-
5	Construction	11,904,167	8,913,867	33.55 %
6	Storage Plant	$ 22,150	$ 23,454	(5.56)%
7	Transmission Plant	173,364	157,132	10.33 %
8	Distribution Plant	369,908	421,769	(12.30)%
9				-
10	**Total MT Materials and Supplies**	$ 12,469,589	$ 9,516,222	31.04 %
11				
12				
13	**Consolidated**	December 31,		
14	**Materials and Supplies**	2024	2023	
15				
16	Montana Natural Gas	$ 12,469,589	$ 9,516,222	
17	Montana Electric	67,311,125	56,282,931	
18	South Dakota	—	19,455,340	
19				
20	**Total Consolidated Materials and Supplies**	$ 79,780,714	$ 85,254,493	

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - NATURAL GAS			
	Commission Accepted - Most Recent	% Capital Structure	% Cost Rate	Weighted Cost
1				
2	Docket Number: D2022.07.078			
3	Order Number : 7860y			
4	Effective Date : November 1, 2023			
5				
6	Common Equity	48.02 %	9.55 %	4.59 %
7	Long Term Debt	51.98 %	4.01 %	2.08 %
8				
9	**TOTAL**	100.00 %		6.67 %
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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	$ 180,078,441	$ 194,131,555	(7.24)%
4	Noncash Charges (Credits) to Income:			
5	Depreciation and Depletion	147,975,406	179,874,970	(17.73)%
6	Amortization, Net	35,587,522	36,075,440	(1.35)%
7	Other Noncash Charges to Net Income, Net	7,046,126	10,610,312	(33.59)%
8	Deferred Income Taxes, Net	15,695,900	8,535,605	83.89 %
9	Investment Tax Credit Adjustments, Net	1,970,244	(129,483)	>300.00%
10	Change in Operating Receivables, Net	4,548,357	25,423,506	(82.11)%
11	Change in Materials, Supplies & Inventories, Net	(6,710,218)	(7,177,502)	6.51 %
12	Change in Operating Payables & Accrued Liabilities, Net	23,887,716	(68,659,030)	134.79 %
13	Allowance for Funds Used During Construction (AFUDC)	(17,537,612)	(17,612,998)	0.43 %
14	Change in Other Assets & Liabilities, Net	(30,228,854)	79,866,995	(137.85)%
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	(2,152,888)	(2,275,985)	5.41 %
17	Change in Regulatory Assets	9,340,746	36,795,341	(74.61)%
18	Change in Regulatory Liabilities	(35,364,509)	19,246,128	(283.75)%
19	**Net Cash Provided by Operating Activities**	334,136,377	494,704,854	(32.46)%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(484,972,274)	(566,864,445)	14.45 %
22	(Net of AFUDC)			
23	Investment in Equity Securities	(253,166)	(9,105,446)	97.22 %
24	Proceeds from Sale of Assets	—	—	-
25	**Net Cash Used in Investing Activities**	(485,225,440)	(575,969,891)	15.76 %
26	**Cash Flows from Financing Activities:**			
27	Proceeds from Issuance of:			
28	Issuance of Long-Term Debt	175,000,000	300,000,000	(41.67)%
29	Issuance of Notes Payable	—	—	-
30	Line of Credit Borrowings, Net	—	—	-
31	Proceeds From Issuance of Common Stock, Net	—	73,612,936	(100.00)%
32	Payments for Retirement of:			-
33	Repayments of Short Term Borrowings, Net	—	(92,403)	100.00 %
34	Repayments of Long Term Borrowings, Net	(100,000,000)	—	-
35	Line of Credit Borrowings (Repayments), Net	78,000,000	(132,000,000)	159.09 %
36	Dividends on Common Stock	(69,936,850)	(154,089,441)	54.61 %
37	Other Financing Activities:			
38	Distribution of Cash From NorthWestern Energy Group, Inc.	60,000,000	—	-
39	Debt Financing Costs	(792,992)	(4,109,961)	80.71 %
40	Treasury Stock Activity	—	731,249	(100.00)%
41	**Net Cash Used in Financing Activities**	142,270,158	84,052,380	69.26 %
42	**Net Increase/Decrease in Cash and Cash Equivalents**	(8,818,905)	2,787,343	>-300.00%
43	**Cash and Cash Equivalents at Beginning of Year**	23,642,693	20,855,350	13.37 %
44	**Cash and Cash Equivalents at End of Year**	$ 14,823,788	$ 23,642,693	(37.30)%
45				
46	This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory			
47	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity			
48	method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana			
49	Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4.			
50				
51	On January 1, 2024, we completed the second and final phase of the holding company reorganization. NorthWestern Corporation (NW Corp)			
52	contributed the assets and liabilities of its South Dakota and Nebraska regulated utilities to NorthWestern Energy Public Service Corporation, (NWE Public Service), and then distributed its equity interest in NWE Public Service and certain other subsidiaries to NorthWestern Energy Group, Inc.,			
53	resulting in NW Corp owning and operating the Montana regulated utility and NWE Public Service owning and operating the Nebraska and South Dakota			
54	utilities, each as a direct subsidiary of NorthWestern Energy Group, Inc. Due to this reorganization, the prior period information included in these			
55	statements may not be comparable to the current period.			
56				

Sch. 24	MONTANA LONG TERM DEBT 2024								
	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	4.18% Series($450M), Due 2044	11/14/14	11/15/44	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 %	2,581,777	3.44 %
12	4.11% Series($125M), Due 2045	06/23/15	07/01/45	125,000,000	124,273,156	125,000,000	4.11 %	5,530,890	4.42 %
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 %
15	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 %
16	3.21% Series($100M) Due 2030	05/15/20	05/15/30	100,000,000	99,516,844	100,000,000	3.21 %	3,270,011	3.27 %
17	5.57% Series($239M) Due 2033	03/30/23	03/30/33	239,000,000	238,912,135	239,000,000	5.57 %	13,429,877	5.62 %
18	5.56% Series($175M) Due 2031	03/28/24	03/28/31	175,000,000	174,207,008	175,000,000	5.56 %	9,813,279	5.61 %
19	**Total First Mortgage Bonds**			$ 1,930,000,000	$ 1,917,863,034	$ 1,930,000,000		$ 88,956,357	4.61 %
20									
21	**Pollution Control Bonds**								
22	3.875% Series ($144.7M), Due 2028	06/29/23	07/01/28	$ 144,660,000	$ 144,020,056	$ 144,660,000	3.875 %	$ 5,918,622	4.09 %
23									
24	**Total Pollution Control Bonds**			$ 144,660,000	$ 144,020,056	$ 144,660,000		$ 5,918,622	4.09 %
25									
26	**Other Long-Term Debt**								
27									
28									
29	**Total Other Long Term Debt**			$ —	$ —	$ —		$ —	
30									
31	**TOTAL LONG TERM DEBT**			$ 2,074,660,000	$ 2,061,883,090	$ 2,074,660,000		$ 94,874,979	4.57 %
32									
33									
34	This schedule does not reflect our obligations under capital lease which total $5,461,499								
35									
36									
37									
38									
39									
40									
41									
42									
43									
44									
45									
46									
47									
48									

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										
11										
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21										
22										
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24										
25										
26										
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	100	$ 0.01				N/A	N/A	
February	100	0.01				N/A	N/A	
March	100	0.01	N/A	N/A		N/A	N/A	
April	100	0.01				N/A	N/A	
May	100	0.01				N/A	N/A	
June	100	0.01	N/A	N/A		N/A	N/A	
July	100	0.01				N/A	N/A	
August	100	0.01				N/A	N/A	
September	100	0.01	N/A	N/A		N/A	N/A	
October	100	0.01				N/A	N/A	
November	100	0.01				N/A	N/A	
December	100	0.01	N/A	N/A		N/A	N/A	
TOTAL Year End	100	$ 0.01	N/A	N/A	N/A	N/A	N/A	N/A

1/ Monthly shares are actual shares outstanding at month-end.

Sch. 27	MONTANA EARNED RATE OF RETURN - GAS				
		Description	This Year	Last Year	% Change
1		**Rate Base**			
2	101	Plant in Service	$ 1,270,441,251	$ 1,177,508,387	7.89 %
3	108	Accumulated Depreciation	(457,993,485)	(443,286,924)	(3.32)%
4					
5	**Net Plant in Service**		$ 812,447,766	$ 734,221,463	10.65 %
6		Additions:			
7	154, 156	Materials & Supplies	$ 10,807,680	$ 17,519,140	(38.31)%
8	165	Prepayments			
9		Other Additions	42,343,592	41,791,590	1.32 %
10					
11	**Total Additions**		$ 53,151,272	$ 59,310,730	(10.39)%
12		Deductions:			
13	190	Accumulated Deferred Income Taxes	$ 31,504,232	$ 33,702,300	(6.52)%
14	252	Customer Advances for Construction	24,502,945	21,912,689	11.82 %
15	255	Accumulated Def. Investment Tax Credits			
16		Other Deductions	44,307,113	47,062,844	(5.86)%
17					
18	**Total Deductions**		$ 100,314,290	$ 102,677,833	(2.30)%
19	**Total Rate Base**		$ 765,284,748	$ 690,854,360	10.77 %
21	**Net Earnings**		$ 47,390,895	$ 38,818,699	22.08 %
22	**Rate of Return on Average Rate Base 1/**		5.622 %	5.033 %	11.70 %
23	**Rate of Return on Average Equity 1 & 2/**		7.087 %	6.607 %	7.27 %
24					
25		**Major Normalizing and**			
26		**Commission Ratemaking Adjustments**			
27		Rate Schedule Revenues 3/	$ 4,786,779	$ 766,416	>300.00%
28		Environmental True-up MGP Sites 4/	289,935	394,884	(26.58)%
29					
30		Non-Allowables:			
31		Advertising	277,213	322,806	(14.12)%
32		Dues, Contributions, Other	29,896	45,209	(33.87)%
33					
34		Gas Safe Harbor Method Change 5/	(4,366,137)		-
35		Uncertain Tax Position - Tax Benefit 6/		(4,046,589)	100.00 %
36		Associated Income Taxes 7/	(2,447,836)	1,143,289	>-300.00%
37	**Total Adjustments**		$ (1,430,150)	$ (1,373,985)	(4.09)%
38	**Revised Net Earnings**		$ 45,960,745	$ 37,444,714	22.74 %
39	**Adjusted Rate of Return on Average Rate Base**		6.006 %	5.420 %	10.81 %
40	**Adjusted Rate of Return on Average Equity 2/**		8.166 %	6.946 %	17.56 %

41
42 1/ These return percentages have been calculated by taking actual net earnings for the period after adjusting for the
43 non-routine items discussed below within Note 5 & 6.
44
45 2/ Return on Equity calculated using the capital structure approved in Docket No. D2022.7.78.
46
47 3/ Rate schedule revenues are adjusted to revenues on a normalized basis by converting to volumes based on normal
48 weather. The impact to our adjusted rate of returns due to interim rates, which are subject to refund, going into
49 effect on December 1, 2024, as approved in docket no. 2024.05.053, interim order no. 7968e, was $2,293,116. Absent
50 these interim rates, our adjusted rate of return on average rate base and average equity would have been
51 5.706% and 7.542%, respectively.
52
53 4/ Removal of expenses recorded in 2024 related to environmental costs not recovered from customers.
54
55 5/ In 2023, the Internal Revenue Service (IRS) issued a safe harbor method of accounting for the repair
56 and maintenance of natural gas transmission and distribution property. For the year ending
57 December 31, 2024, after completion of our impact analysis of the gas repairs safe harbor method change,
58 we had an income tax benefit related to the tax deductions for repair costs that were previously capitalized in
59 the 2022 and prior tax years.
60
61 6/ Benefit recorded from reversal of prior period Uncertain Tax Positions related to natural gas tax repairs due to
62 adoption of the safe harbor provisions in Revenue Procedure 2023-15. This amount was inadvertently excluded from our
63 2023 reported Schedule 27.
64
65 7/ Associated Income taxes include an interest synchronization adjustment based upon the approved
66 capital structure in Docket No. D2022.7.78.

Sch. 27	cont. MONTANA EARNED RATE OF RETURN - GAS			
	Description	This Year	Last Year	% Change
1				
2	**Detail - Other Additions**			
3	Gas Stored Underground	37,167,272	36,167,272	2.76 %
4	Cost of Refinancing Debt	5,626,832	6,174,499	(8.87)%
5	MPSC/MCC Taxes	(450,512)	(550,181)	18.12 %
6				
7	**Total Other Additions**	$ 42,343,592	$ 41,791,590	1.32 %
8				
9	**Detail - Other Deductions**			
10	Personal Injury and Property Damage	$ 1,859,313	$ 1,614,731	15.15 %
11	Storage Gas Sales 2000 & 2001	6,415,170	6,835,686	(6.15)%
12	Gross Cash Requirements	14,950,975	17,174,406	(12.95)%
13	Regulatory Liability (TCJA)	$ 20,756,611	$ 20,830,436	(0.35)%
14	Environmental Reserve	325,044	607,585	(46.50)%
15				
16	**Total Other Deductions**	$ 44,307,113	$ 47,062,844	(5.86)%
17				
18				
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Sch. 28	MONTANA COMPOSITE STATISTICS - NATURAL GAS (INCLUDES CMP)		
		Description	Amount
1			
2		**Plant (Intrastate Only)**	
3			
4	101	Plant in Service (Includes Allocation from Common)	$ 1,326,575,768
5	105	Plant Held for Future Use	29,866
6	107	Construction Work in Progress	25,858,064
7	117	Gas in Underground Storage	44,910,861
8	151-163	Materials & Supplies	12,469,589
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	473,253,395
11	252	Customer Advances	26,059,500
12	**NET BOOK COSTS**		910,531,253
13			
14		**Revenues & Expenses**	
15			
16	400	Operating Revenues	$ 205,833,731
17			
18	**Total Operating Revenues**		205,833,731
19			
20	401-402	Other Operating Expenses (including regulatory amortizations)	95,781,194
21	403-407	Depreciation, Depletion, & Amortization Expenses	30,704,789
22	408.1	Taxes Other than Income Taxes	37,214,543
23	409-411	Federal & State Income Taxes	(5,257,690)
24			
25	**Total Operating Expenses**		158,442,836
26	**Net Operating Income**		47,390,895
27			
28	415-421.1	Other Income	3,474,677
29	421.2-426.5	Other Deductions	542,401
30	**NET INCOME BEFORE INTEREST EXPENSE**		$ 50,323,171
31			
32		**Average Customers (Intrastate Only)**	
33		Residential	185,642
34		Commercial	26,171
35		Industrial	236
36		Other (including interdepartmental)	199
37	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		212,248
38			
39		**Other Statistics (Intrastate Only)**	
40		Average Annual Residential Use (Dkt)	74.1
41		Average Annual Residential Cost per (Dkt)	$ 8.02
42		Average Residential Monthly Bill	$ 49.47
43			
44		Plant in Service (Gross) per Customer	$ 6,250

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2020	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,000	486	77	1	564
2	Amsterdam	206	58	12	—	70
3	Anaconda	9,421	3,484	348	6	3,838
4	Augusta	316	204	53	1	258
5	Belfry	193	4	1	—	5
6	Belgrade	10,460	7,597	1,409	4	9,010
7	Big Mountain	—	330	38	—	368
8	Big Sandy	605	293	75	—	368
9	Big Timber	1,650	959	199	6	1,164
10	Bigfork	5,118	1,746	250	1	1,997
11	Billings	117,116	28	4	—	32
12	Bonner	1,690	80	32	1	113
13	Boulder	1,201	464	86	3	553
14	Bozeman	53,293	28,075	4,190	18	32,283
15	Browning	1,018	1,057	156	6	1,219
16	Buffalo	—	7	1	—	8
17	Butte	34,494	13,224	1,566	35	14,825
18	Cardwell	62	19	4	—	23
19	Carter	65	29	10	—	39
20	Chester	847	358	138	1	497
21	Chinook	1,185	715	150	5	870
22	Choteau	1,721	911	182	7	1,100
23	Churchill	1,030	461	47	—	508
24	Clancy	1,851	779	52	—	831
25	Clinton	1,018	383	18	1	402
26	Columbia Falls	5,308	3,810	421	5	4,236
27	Columbus	1,857	1,147	192	4	1,343
28	Conrad	2,318	1,132	228	10	1,370
29	Coram	572	128	30	—	158
30	Corbin	—	1	—	—	1
31	Corvallis	1,125	1,455	112	—	1,567
32	Cut Bank	3,056	46	12	1	59
33	Deer Lodge	2,938	1,661	227	5	1,893
34	Dillon	3,880	2,223	377	6	2,606
35	Drummond	272	205	53	2	260
36	East Glacier Park	354	141	47	1	189
37	East Helena	1,944	2,539	179	3	2,721
38	Elliston	227	108	15	—	123
39	Essex	44	111	20	1	132
40	Fairfield	759	425	88	4	517
41	Florence	821	1,446	110	1	1,557
42	Floweree	19	42	9	—	51
43	Fort Belknap	1,567	320	62	—	382
44	Fort Benton	1,449	658	169	1	828
45	Fort Harrison	—	—	13	58	71
46	Fort Shaw	256	113	13	—	126
47	Galata	—	2	—	—	2
48	Gallatin Gateway	967	217	55	—	272
49	Garneill	—	6	2	—	8
50	Garrison	115	22	8	—	30
51	Gildford	141	75	25	—	100
52	Grantsdale	—	17	1	—	18
53	Great Falls	60,442	1,004	87	2	1,093

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2020	Residential	Commercial	Industrial & Other	Total
1	Greycliff	89	45	6	—	51
2	Hall	51	63	17	—	80
3	Hamilton	4,659	4,563	766	7	5,336
4	Harlem	769	323	64	1	388
5	Harlowton	955	538	106	—	644
6	Havre	9,362	4,568	707	10	5,285
7	Helena	32,091	20,351	2,657	28	23,036
8	Hilger	154	29	3	2	188
9	Hingham	131	81	31	1	113
10	Hungry Horse	828	226	37	—	263
11	Inverness	77	36	12	—	48
12	Jefferson City	597	244	15	2	261
13	Joplin	159	96	25	—	121
14	Judith Gap	110	64	14	—	78
15	Kalispell	24,558	13,910	2,300	21	16,231
16	Kremlin	78	46	18	—	64
17	Laurel	7,222	28	2	—	30
18	Ledger	—	7	—	—	7
19	Lewistown	5,952	3,068	530	7	3,605
20	Livingston	8,040	4,505	645	14	5,164
21	Logan	72	40	6	—	46
22	Lohman	—	2	1	—	3
23	Lolo	4,399	1,825	105	—	1,930
24	Loma	65	44	18	—	62
25	Manhattan	2,086	996	136	2	1,134
26	Martin City	461	115	16	—	131
27	Marysville	82	1	—	—	1
28	Milltown	—	70	11	—	81
29	Missoula	73,489	32,571	4,108	49	36,728
30	Montana City	2,918	879	92	—	971
31	Moore	194	3	—	—	3
32	MT General Office	—	1	—	—	1
33	Philipsburg	841	474	103	1	578
34	Power	177	—	1	—	1
35	Ramsay	—	41	7	—	48
36	Red Lodge	2,257	2,297	316	9	2,622
37	Reedpoint	177	119	16	1	136
38	Roberts	304	189	23	—	212
39	Rocker	—	48	7	—	55
40	Rudyard	270	125	30	—	155
41	Ryegate	223	3	1	—	4
42	Shawmut	42	23	7	—	30
43	Shelby	3,169	9	5	—	14
44	Sheridan	694	481	79	—	560
45	Silver Star	46	22	5	—	27
46	Silverbow	—	3	4	2	9
47	Simms	361	159	16	—	175
48	Somers	1,049	440	22	—	462
49	Stevensville	2,002	1,984	294	5	2,283
50	Sun River	95	104	16	—	120
51	Three Forks	1,989	927	161	—	1,088
52	Turah	364	167	4	—	171
53	Twin Bridges	330	206	62	—	268

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2020	Residential	Commercial	Industrial & Other	Total
1	Valier	530	313	68	5	386
2	Vaughn	737	333	28	—	361
3	Victor	789	513	82	—	595
4	Walkerville	639	240	11	—	251
5	Warm Springs	—	13	2	—	15
6	West Glacier	221	107	44	3	154
7	Whitefish	7,751	5,243	535	5	5,783
8	Whitehall	1,006	710	116	1	1,833
9	Whitlash	4	1	1	—	2
10	Williamsburg	—	1	—	—	1
11	Willow Creek	230	101	15	—	116
12	Wolf Creek	25	51	19	2	72
13	Winifred	—	52	26	—	78
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48						
49	**Total**	541,961	185,642	26,227	378	212,247

1/ Customer populations represent an average of the 12 month period from 01/01/24 through 12/31/24.

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
4	Customer Care	154	151	153
5	Finance	56	64	60
6	Information Technology	102	95	99
7	Distribution	435	521	478
8	Asset Management	40	49	45
9	Transmission	322	261	292
10	Supply	132	126	129
11	Legal	22	10	16
12				
13				
14				
15				
16				
	TOTAL EMPLOYEES	1,263	1,277	1,270

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

Sch. 31	MONTANA CONSTRUCTION BUDGET 2025 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3	MT Distribution - Transformer Purchase New Connects	$ 13,722,000	$ 13,722,000
4	MT Distribution - Wildfire Line Device Upgrades	8,053,055	8,053,055
5	MT Transmission - Sub Maint. Autotransformer Upgrade	6,975,123	6,975,123
6	MT Transmission - Capacity Miller-Stevensville A Line	6,232,913	6,232,913
7	MT Transmission - TSR Wind Alkali Creek 161kv	5,405,763	5,405,763
8	MT Distribution - New Manhattan Substation	5,244,900	5,244,900
9	MT Distribution - Sub Capacity Hamilton North Sub	4,958,348	4,958,348
10	MT Transmission - Sub Broadview Cap Replace 500kv	4,450,763	4,450,763
11	MT Transmission - TSR WAPA Belt-Monarch 100kv	4,394,819	4,394,819
12	MT Transmission - Sub Maint. Clyde Park Sub Rebuild	4,271,764	4,271,764
13	MT Transmission - Capacity Great Falls Eastside-SE-Southside	3,327,340	3,327,340
14	MT Distribution - Sub Capacity GTF SW Sub Bank #2	3,110,146	3,110,146
15	MT Transmission - Sub Maint. Broadview	3,091,256	3,091,256
16	MT Distribution - Sub Capacity Belgrade West Bank #2	2,707,914	2,707,914
17	MT Distribution - Pole Replacements Helena	2,516,639	2,516,639
18	MT Transmission - Sub Capacity Broadview Bus	2,505,077	2,505,077
19	MT Transmission - Billings Wildfire Hardening	2,504,192	2,504,192
20	MT Transmission - Missoula Wildfire Hardening	2,490,789	2,490,789
21	MT Transmission - Butte Wildfire Hardening	2,457,449	2,457,449
22	MT Transmission - Sub Maint. Richardson Coulee	2,369,340	2,369,340
23	MT Distribution - Missoula Wildfire Hardening	2,343,439	2,343,439
24	MT Transmission - Sub Maint. Glengarry	2,183,455	2,183,455
25	MT Distribution - Helena Wildfire Hardening	2,168,607	2,168,607
26	MT Distribution - Sub Maint. Bozeman-E Gallatin Bank 3	2,165,409	2,165,409
27	MT Transmission - Sub Maint. Malta	2,077,306	2,077,306
28	MT Transmission - Sub Capacity TSR Three Rivers 230/161	2,075,387	2,075,387
29	MT Transmission - Sub Capacity GTF 230 Switchyard Expansion	2,072,200	2,072,200
30	MT Transmission - Capacity Great Falls Southside-MT Refining	2,049,519	2,049,519
31	MT Transmission - Great Falls Wildfire Hardening	1,998,748	1,998,748
32	MT Transmission - Havre Wildfire Hardening	1,996,132	1,996,132
33	MT Transmission - Bozeman Wildfire Hardening	1,995,911	1,995,911
34	MT Distribution - Wildfire PSPS Mobile Generators	1,853,084	1,853,084
35	MT Distribution - New Manhattan Substation Feeders	1,803,659	1,803,659
36	MT Distribution - Sub Capacity Missoula Russel St Transformer	1,781,525	1,781,525
37	MT Distribution - Pole Replacements Great Falls	1,747,496	1,747,496
38	MT Distribution - Sub Capacity Lolo Bank Upgrade	1,683,239	1,683,239
39	MT Transmission - Capacity Billings Broadview-Shorey	1,556,105	1,556,105
40	MT Transmission - Lewistown Wildfire Hardening	1,499,430	1,499,430
41	MT Transmission - Hamilton Wildfire Hardening	1,498,651	1,498,651
42	MT Transmission - Helena Wildfire Hardening	1,496,274	1,496,274
43	MT Distribution - Sub Capacity Ennis City Transf. Upgrade	1,481,164	1,481,164
44	MT Distribution - Pole Replacements Lewistown	1,393,334	1,393,334
45	MT Distribution - Bozeman Wildfire Hardening	1,381,997	1,381,997
46	MT Transmission - Sub Maint. SBRU Lewistown	1,240,893	1,240,893
47	MT Transmission - Pole Replacements Lewistown	1,227,967	1,227,967
48	MT Distribution - Wildfire Cutout Replacements	1,190,362	1,190,362
49	MT Distribution - Pole Replacements Butte	1,009,975	1,009,975
50	MT Transmission - Wildfire Reclosures Hamilton	1,000,000	1,000,000
51	MT Transmission - Wildfire Reclosures Livingston	1,000,000	1,000,000
52	MT Transmission - Wildfire Reclosures Havre	1,000,000	1,000,000
53			
54	All Other Projects < $1 Million Each and blankets	89,466,287	89,466,287
55	**Total Electric Utility Construction Budget**	**$ 230,227,145**	**$ 230,227,145**
56			
57	**Natural Gas Operations**		
58	MT Transmission - Capacity Helena Junction - Helena City Gate 1	$ 19,211,640	$ 19,211,640
59	MT Transmission - Butte City Gate 1 to City Gate 3 Replace	13,794,047	13,794,047
60	MT Transmission - Capacity North Helena Tie - Boulder Tap	9,356,089	9,356,089
61	MT Gas Storage - Dry Creek Compressors	6,087,038	6,087,038
62	MT Gas Storage - Dry Creek Additional Wells	5,202,628	5,202,628
63	MT Transmission - RIGTL Vaughn to Sun Prairie	4,355,397	4,355,397
64	MT Distribution - Butte Base Gas One Upgrades	3,411,019	3,411,019
65	MT Distribution - Gas Meters and Regulators New Connects	1,254,000	1,254,000
66	MT Transmission - Frenchtown City Gate 1 Upgrade	1,029,234	1,029,234
67	MT Gas Transmission - Missoula Landfill RNG	1,027,166	1,027,166
68			
69	All Other Projects < $1 Million Each and blankets	$ 30,006,074	$ 30,006,074
70	**Total Natural Gas Utility Construction Budget**	**$ 94,734,332**	**$ 94,734,332**
71			
72	**Common**		
73	MT Common - Distribution AMI Metering and Infrastructure	$ 11,278,506	$ 11,278,506
74	MT Common - Fleet Replacements	5,000,072	5,000,072
75	MT Common - Facilities Livingston Design and Construct	4,879,101	4,879,101
76	MT Common - Business Technology HRIS Solution	3,896,032	3,896,032
77	MT Common - Billings Mechanics Garage	2,382,800	2,382,800
78	MT Common - Business Technology Enterprise GIS	1,921,370	1,921,370
79	MT Common - Business Technology Microsoft Enterprise Platform	1,352,354	1,352,354
80	MT Common - Business Technology Digital Workforce Mgmt	1,012,449	1,012,449
81			
82	All Other Projects < $1 Million Each and blankets	11,647,024	11,647,024
83	(Includes BT, Communications, Facilities, Land, Customer Service)		
84	**Total Common Utility Construction Budget**	**$ 43,369,708**	**$ 43,369,708**
85			
86	**MT Generation**		
87	MT Generation - Hydro Black Eagle Spillway Upgrade for Ice	$ 9,156,445	$ 9,156,445
88	MT Generation - CU4 Plant Upgrades	8,796,195	8,796,195
89	MT Generation - DGGS Gas Gen 50k hour overhaul	6,859,039	6,859,039
90	MT Generation - DGGS Gas Gen 50k hour overhaul	6,821,530	6,821,530
91	MT Generation - DGGS PT 50k hour overhaul	4,174,313	4,174,313
92	MT Generation - DGGS PT 50k hour overhaul	4,099,545	4,099,545
93	MT Generation - Colstrip Land	3,004,390	3,004,390
94	MT Generation - Hydro Holter Unit 4 Turbine Upgrade	2,497,189	2,497,189
95	MT Generation - Hydro Hauser Unit 6 Turbine Upgrade	1,905,362	1,905,362
96	MT Generation - Hydro Thompson Falls Unit 6 Turbine Upgrade	1,857,131	1,857,131
97	MT Generation - Holter Unit 4 Generator Rewind	1,832,763	1,832,763
98	MT Generation - Hydro Hauser Unit 1 Turbine Upgrade	1,701,389	1,701,389
99	MT Generation - Hydro Holter Headgate Upgrade	1,451,408	1,451,408
100	MT Generation - Hydro Thompson Falls Unit 6 Generator Rewind	1,393,567	1,393,567
101	MT Generation - Hydro Thompson Falls Relicensing	1,266,989	1,266,989
102	MT Generation - Hydro Spare 20 MVA GSU	1,155,145	1,155,145
103			
104	All Other Projects < $1 Million Each and blankets	$ 7,797,126	$ 7,797,126
105	**Total MT Generation**	**65,769,526**	**65,769,526**
106	**TOTAL CONSTRUCTION BUDGET**	**$ 434,100,711**	**$ 434,100,711**

Sch. 32	MONTANA TRANSMISSION, DISTRIBUTION and STORAGE SYSTEMS -NATURAL GAS						
	Transmission System-Sales and Transportation						
		Peak Day of Month		Peak Day Volume (MMBTU's)		Monthly Volumes (MMBTU's)	
	Month	Total Company	Montana	Total Company	Montana	Total Company	Montana
1	January		12		387,540		6,867,109
2	February		15		288,859		6,864,856
3	March		5		229,249		5,512,851
4	April		17		193,271		4,485,281
5	May		1		204,475		3,274,864
6	June		18		233,135		2,558,663
7	July		28		210,382		2,337,271
8	August		6		162,818		2,556,382
9	September		30		134,698		2,638,617
10	October		30		193,262		3,168,879
11	November		19		207,857		4,638,644
12	December		12		239,845		6,181,127
13	TOTAL						51,084,544
14							
15							
16	Distribution System-Sales and Transportation						
17		Sales Volumes		Transportation Volumes		Monthly Volumes (MMBTU's)	
18	Month	Total Company	Montana	Total Company	Montana	Total Company	Montana
19	January		3,726,870		82,606		3,809,476
20	February		3,594,479		94,446		3,688,925
21	March		2,991,313		64,232		3,055,545
22	April		2,054,949		49,564		2,104,513
23	May		1,551,873		31,682		1,583,555
24	June		1,009,406		22,373		1,031,779
25	July		580,816		14,120		594,936
26	August		421,004		13,440		434,444
27	September		463,522		13,228		476,750
28	October		728,866		14,801		743,667
29	November		1,713,645		34,433		1,748,078
30	December		2,940,766		54,004		2,994,770
31	TOTAL		21,777,509		488,929		22,266,438
32							
33							
34	Storage System-Sales and Transportation						
35		Peak Day & Peak Day Vol.		Total Monthly Volumes (MMBTU's)			
36		Total Company	Montana	Total Montana		Energy Supply	
37	Month	1/	1/	Injection	Withdrawal	Injection	Withdrawal
38	January			24,614	3,505,907		2,189,331
39	February			6,187	2,801,907		1,886,396
40	March			12,903	2,137,133		1,666,515
41	April			1,883,697	141,922	311,343	
42	May			2,908,678	44,686	1,252,423	
43	June			3,383,945	22,600	2,483,310	
44	July			3,325,957	26,310	2,743,606	
45	August			2,107,254	28,557	1,323,584	
46	September			1,561,348	286,965	761,810	
47	October			1,073,438	632,996	279,130	
48	November			49,012	2,314,504		1,873,860
49	December			16,155	2,607,165		1,678,641
50	TOTAL			16,353,188	14,550,652	9,155,206	9,294,743
51							
52							
53	1/ Data is not accumulated on a daily basis. Therefore the peak day and peak day volumes are not available.						
54							
55							

Sch. 33	SOURCES OF MONTANA CORE NATURAL GAS SUPPLY				
	Supply Location	Last Year Volumes MMBTU	This Year Volumes MMBTU	Last Year Avg. Commodity Cost	This Year Avg. Commodity Cost
1					
2	Canadian Pipeline	18,793,872		$ 2.5275	
3	Havre Pipeline	712,039		1.9598	
4	Encana Pipeline	—		—	
	Colorado Interstate Pipeline	498,981		6.1851	
5	Company Owned Production 1/	3,706,987		0.4273	
6	Intra Montana Purchase	208,332		2.3133	
7	**TOTAL CORE SUPPLY LAST YEAR**	23,920,211		$ 2.4883	
8					
9	Canadian Pipeline		17,375,050		$ 1.3370
10	Havre Pipeline		635,013		1.0652
11	Encana Pipeline		—		—
12	Colorado Interstate Pipeline		428,000		5.4529
13	Company Owned Production 1/		3,485,674		0.1968
14	Intra Montana Purchase		251,931		1.0638
15	**TOTAL CORE SUPPLY THIS YEAR**		22,175,668		$ 1.5757
16					
17	1/ Average commodity cost for Company Owned Production reflects royalties and production taxes only.				
18					
19					

Sch. 34	MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS						
	Program Description (These are Natural Gas DSM Programs)	Current Year Expenditures	Previous Year Expenditures	% Change	Planned Savings (Mcf or Dkt)	Achieved Savings (Mcf or Dkt)	Difference
1							
2	2024 Natural Gas Business Partners Program	$ 2,098	$ —	— %	—	—	—
3	- Initiated 2005, 2024 weighted average program life = 0 years, 0 participants.						
4	*2024 Northwest Energy Efficiency Alliance (NEEA)	$ —	$ 1,284,200	100.00 %	—	19,345	19,345
5	- Initiated natural gas savings in 2006, program life = 15 years						
6	2024 Residential Natural Gas Existing Construction Program	$ 252,126	$ 215,662	16.91 %	—	10,755	10,755
7	- Reinitiated 2021, 2024 weighted average program life = 16 years, 466 participants.						
8	2024 Residential Natural Gas New Construction Program	$ 23,567	$ 9,435	149.80 %	—	372	372
9	- Reinitiated 2022, 2024 weighted average program life = 18 years, 21 participants.						
10	2024 Commercial Natural Gas Existing Construction Program	$ 39,256	$ 51,721	(24.10)%	—	1,475	1,475
11	- Reinitiated 2021, 2024 weighted average program life = 18 years, 9 participants.						
12	2024 General Expenses All Natural Gas DSM Programs	$ 11,143	$ 48,031	(76.80)%	—	—	—
13	-NA						
14							
15	A program participant is a Montana commercial or residential natural gas						
16	customer who installs eligible energy conservation measures and receives						
17	financial incentives/rebates either directly or indirectly.						
18							
19	*Note: 2024 NEEA expenditures are allocated to electric DSM but there are						
20	gas savings as a result of some NEEA initiatives.						
21	Participant has not been defined or counted for NEEA.						
22							
23	Units reported are in dekatherms ("Dkt"). No planned savings were in place.						
24							
25							
26							
27							
28	**TOTAL**	$ 328,190	$ 1,609,049	(79.60)%	—	31,947	31,947

Sch. 35	MONTANA CONSUMPTION AND REVENUES - NATURAL GAS						
		Operating Revenues 1/		Dkt Sold 1/		Average Customers	
	Description	Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	Sales of Natural Gas						
2							
3	Residential	$ 110,207,495	$ 136,047,920	13,748,373	14,008,018	185,642	183,810
4	Commercial	59,932,123	73,713,246	7,781,799	8,036,086	26,171	25,727
5	Industrial Firm	1,040,763	1,391,696	147,466	157,142	236	232
6	Public Authorities	912,182	1,016,662	133,745	121,485	142	135
7	Interdepartmental	440,135	664,785	63,058	75,077	56	55
8	Sales to Other Utilities	861,133	3,072,317	184,721	196,908	1	1
9	TOTAL SALES	$ 173,393,831	$ 215,906,626	22,059,162	22,594,716	212,248	209,960
10		Operating Revenues		Dkt Transported		Average Customers	
11		Current	Previous	Current	Previous	Current	Previous
12		Year	Year	Year	Year	Year	Year
13	Transportation of Gas						
14							
15	On System Transportation	$ 29,942,261	$ 29,202,361	28,326,069	28,513,167	265	274
16	Off System Transportation & Storage	—	—	—	—	—	—
17	Canadian Montana Pipeline	302,307	321,959	—	—	—	—
18	TOTAL TRANSPORTATION	$ 30,244,568	$ 29,524,320	28,326,069	28,513,167	265	274
30	1/ Revenue and Dkts include unbilled and Canadian Montana Pipeline.						

Sch. 36A	Natural Gas Universal System Benefits Programs					
	Program Description	Actual Expenditures	Contracted or Committed to Spend	Total Expenditures	Expected savings (dKt)	Most recent program evaluation
1	Local Conservation					
2	Audit Program	$ 794,771	$ —	$ 794,771	3,431	2012
3	NWE Promotion	$ 40,470	$ —	$ 40,470		
4	NWE Labor	$ 21,677	$ —	$ 21,677		
5	NWE Admin. Non-labor	$ 1,674	$ —	$ 1,674		
6	USB Interest & Svc Chg	$ (38,910)	$ —	$ (38,910)		
7	Low Income					
8	Bill Assistance	$ 776,839	$ —	$ 776,839		
9	Free Weatherization	$ —	$ —	$ —	4,716	2012
10	Energy Share	$ 224,276	$ —	$ 224,276		
11	NWE Promotion	$ 62,794	$ —	$ 62,794		
12	NWE Labor	$ 34,648	$ —	$ 34,648		
13	NWE Admin. Non-labor	$ 26,409	$ —	$ 26,409		
14	USB Interest & Svc Chg	$ (105,627)	$ —	$ (105,627)		
15	Total	$ 1,839,021	$ —	$ 1,839,021	8,147	
16	Number of customers that received low income rate discounts				6,192	
17	Average monthly bill discount amount ($/mo)				$ 20.91 (a)	
18	Average LIEAP-eligible household income				n/a	
19	Number of customers that received weatherization assistance				154	
20	Expected average annual bill savings from weatherization				31 dKt	
21	Number of residential HomeEnergy Checks and/or Surveys performed				902	
22						
23	(a) Average monthly bill discount is for the six (6) month time period that the natural gas low income rate discount is in effect.					
24	(a) Average monthly bill discount is for the six (6) month time period that the natural gas low income rate discount is in effect.					
25	Note: Order 6679e, allows NorthWestern to track on an annual basis its Natural Gas USB expenditures and revenues and adjust the Natural Gas USB Charge for any over or under collections.					

Sch. 36B	Montana Conservation & Demand Side Management Programs					
	Program Description (These are Natural Gas USB Programs)	Actual Current Year Expenditures	Contracted or Committed to Spend	Total Current Year Expenditures	Expected savings (Dkt)	Most recent program evaluation
1	Local Conservation					
2	Energy Audit Program	$ 794,771	$ —	$ 794,771	3,431	2012
3						
4	Market Transformation					
5	*Building Operator Certification (BOC)	$ —	$ —	$ —	1,767	2012
6						
7	Low Income					
8	Free Weatherization	$ —	$ —	$ —	4,716	2012
9						
10	*Note: BOC expenditures are allocated to electric USB					
11	but there are typically gas savings as a result of BOC.					
12						
13	Note: Order 6679e, allows NorthWestern to track on an annual basis its					
14	Natural Gas USB expenditures and revenues and adjust the Natural Gas					
15	USB Charge for any over or under collections.					
16						
17						
18						
19	Total	$ 794,771	$ —	$ 794,771	9,914	2012