YEAR ENDING 2025

ANNUAL REPORT
OF

NorthWestern Energy
(Townsend Propane)

GAS UTILITY

Docket 2026.01.001

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

Propane 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, 2025, NorthWestern Energy Group, Inc. owned 100% of the common stock of respondent.

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

Sch. 3	OFFICERS		
	Title	Department Supervised	Name
1			
2	President and Chief Operating Officer	Executive	Brian Bird
3			
4	Vice President,	Legal Services	Shannon Heim
5	General Counsel and Federal Government Affairs	Corporate Secretary	
6		Risk Management	
7		Contracts	
8		Federal Governmental Affairs	
9			
10	Vice President,	Asset and Project Management	Bleau LaFave
11	Asset Management & Business Development	Business Development and Strategic Support	
12			
13	Vice President, Distribution	Distribution Operations - MT/SD/NE	Jason Merkel
14		Construction	
15		Substation Operations	
16		Wildfire Operations	
17			
18	Vice President, Transmission	Transmission Planning, Engineering, Construction,	Michael Cashell
19		and Operations	
20		Gas Transmission & Storage	
21		Transmission Policy, Services, and Operations	
22		Transmission Market Strategy	
23		Grid Real Time and Scada Operations	
24		FERC and NERC Compliance	
25		Support Services	
26			
27	Vice President,	Thermal and Wind Generation	John Hines
28	Supply and Montana Government Affairs	Hydro Operations	
29		Environmental and Lands Permitting & Compliance	
30		Long Term Resources	
31		Energy Supply Marketing Operations	
32		Montana Government Affairs	
33			
34	Vice President,	Brand, Advertising, and	Bobbi Schroeppel
35	Customer Care, Communications and	Customer Communications	
36	Human Resources	Customer Experience and Support	
37		Customer Interaction	
38		Community Connections	
39		Revenue Cycle Management	
40		Human Resources	
41		Safety/Health/Environmental Services	
42		DSM and Energy Efficiency	
43		Sustainability	
44			
45	Vice President & Chief Financial Officer	Tax, Internal Audit and Compliance	Crystal Lail
46		Financial Planning & Analysis	
47		Controller and Treasury Functions	
48		Investor Relations and Corporate Finance	
49		Flight Services	
50		Regulatory Affairs	
51		Governmental Affairs - Nebraska and South Dakota	
52		Enterprise Risk and Business Continuity	
53			
54	Vice President, Technology	Business Technology	Jeanne Vold
55		Customer Systems & Solutions	
56		Data & Analytics	
57		Operation Technology	
58		Security	
59			

Reflects active officers as of December 31, 2025

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		**$ 154,952**	**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		**$ 154,952**	**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	$5,996,926	78.63%	$1,629,400
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	31,052,792	81.89%	6,865,976
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	1,349,920	67.23%	658,052
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	22,599,623	81.22%	5,225,196
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	5,656,560	80.47%	1,372,659
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	968,407	79.47%	250,177
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	25,526,987	79.42%	6,616,048
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	336,885	84.91%	59,851
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	26,071,732	75.00%	8,689,743
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**			$ 119,559,832	79.22%	$ 31,367,102

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	$ 887,982		$ 887,982
4	**Total Nonutility Affiliates**			$887,982		$887,982
6						
7						
8						
9	**Utility Affiliates**					
10	Havre Pipeline Company, LLC	Natural gas gathering,	Gathering rate based on cost,	2,054,668		
11		transmission, & compression	transmission & compression			
12			are at tariffed rates			
13	**Total Utility Affiliates**			$2,054,668		$0
14	**TOTAL AFFILIATE TRANSACTIONS**			$2,942,650		$887,982

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.	Admin Fee	Negotiated Contract Rate	$ 49,947	0.50 %	$ 49,947
4						
5						
6	**Total Nonutility Affiliates**			$49,947		$49,947
7						
8						
9						
10	**Utility Affiliates**					
11						
12	Havre Pipeline Company, LLC	Administration Fee	Negotiated Contract Rate	505,046	14.60 %	505,046
13	Havre Pipeline Company, LLC	Labor Cost	Actual Expense	1,262,655	36.50 %	1,262,655
14	NorthWestern Cut Bank Gas, LLC	Labor Cost	Actual Expense	430,301	77.90 %	$ 430,301
15	NorthWestern Cut Bank Gas, LLC	Gas Supply Purchases	Actual Expense	340,599	96.10 %	340,599
16	NorthWestern Great Falls Gas, LLC	Labor Cost	Actual Expense	3,245,870	77.50 %	$ 3,245,870
17	NorthWestern Great Falls Gas, LLC	Transmission Services	Actual Expense	5,298,605	62.80 %	5,298,605
18	NorthWestern Energy Public Service Corporation	Labor Cost	Actual Expense	39,286,974	53.20 %	$ 39,286,974
19	**Total Utility Affiliates**			50,370,050		$ 50,370,050
20						
21	**TOTAL AFFILIATE TRANSACTIONS**			50,419,997		$ 50,419,997

Sch. 8	MONTANA UTILITY INCOME STATEMENT - PROPANE					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	400 Operating Revenues	$ 859,464	$ —	$ 859,464	$ 996,032	(13.71)%
3						
4	**Total Operating Revenues**	859,464	—	859,464	996,032	(13.71)%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expense	731,943	—	731,943	818,602	(10.59)%
9	402 Maintenance Expense	1,035	—	1,035	18,912	(94.53)%
10	403 Depreciation Expense	54,173	—	54,173	46,089	17.54 %
11	407.3 Regulatory Debits	—	—	—	—	-
12	408.1 Taxes Other Than Income Taxes	49,002	—	49,002	45,347	8.06 %
13	409.1 Income Taxes-Federal	11,968		11,968	14,474	(17.31)%
14	-Other	4,123		4,123	4,988	(17.34)%
15	410.1 Deferred Income Taxes-Dr.	(6,865)	—	(6,865)	(16,191)	57.60 %
16	411.1 Deferred Income Taxes-Cr.	—	—	—	—	-
17						
18	**Total Operating Expenses**	845,379	—	845,379	932,221	(9.32)%
19	**NET OPERATING INCOME**	$ 14,085	$ —	$ 14,085	$ 63,811	(77.93)%

This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1.

Sch. 9	MONTANA REVENUES - PROPANE					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1						
2	**Sales to Ultimate Consumers**					
3						
4	480 Residential	$ 485,123	$ —	$ 485,123	$ 556,691	(12.86)%
5	481 Commercial & Industrial-Small	374,341	—	$ 374,341	439,341	(14.79)%
6						
7	**Total Sales to Ultimate Consumers**	859,464	—	859,464	996,032	(13.71)%
8						
9	483 Sales for Resale	—	—	—	—	-
10						
11	**Total Sales of Propane**	859,464	—	859,464	996,032	(13.71)%
12						
13	449.1 Provision for Rate Refunds	—	—	—	—	-
14						
15	**Total Revenue Net of Rate Refunds**	859,464	—	859,464	996,032	(13.71)%
16						
17	Miscellaneous Revenues	—	—	—	—	-
18						
19	**Total Other Operating Revenue**	—	—	—	—	-
20	**TOTAL OPERATING REVENUE**	$ 859,464	$ —	$ 859,464	$ 996,032	(13.71)%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - PROPANE					
	Account Number & Title	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year Montana	Last Year Montana	% Change
1	**Supply Expenses**					
2	**Other Propane Supply Expense-Operation**					
3	804 Purchases	$ —	$ —	$ —	$ —	-
4	805 Other Propane Purchases	(28,322)	—	(28,322)	79,393	(135.67)%
5	807 Purchased Propane Expense	—	—	—	—	-
6	808 Propane Withdrawn from Storage	625,442	—	625,442	652,602	(4.16)%
7	809 Propane Delivered to Storage	—	—	—	—	-
8	**Total Supply Expenses**	597,120	—	597,120	731,995	(18.43)%
9	**Storage Expenses**					
10	**Other Storage-Operation**					
11	840 Operation Supervision & Engineering	—	—	—	—	-
12	841 Operation Labor & Expenses	—	—	—	—	-
13	842.3 Gas Losses	33,452	—	33,452	33,078	1.13 %
14	**Total Operation-Other Storage**	33,452	—	33,452	33,078	1.13 %
15						
16	**Other Storage-Maintenance**					
17	847 Maintenance Storage Expenses	—	—	—	—	-
18	**Total Maintenance-Other Storage**	—	—	—	—	-
19	**Total Storage Expenses**	33,452	—	33,452	33,078	1.13 %
20	**Distribution Expenses**					
21	**Distribution-Operation**					
22	870 Supervision & Engineering	—	—	—	—	-
23	874 Mains & Service	2,171	—	2,171	675	221.63 %
24	878 Meter & House Regulators	63,511	—	63,511	38,608	64.50 %
25	879 Customer Installation	2,485	—	2,485	1,105	124.89 %
26	880 Other	16,179	—	16,179	2,021	>300.00%
27	**Total Operation-Distribution**	84,346	—	84,346	42,409	98.89 %
28	**Distribution-Maintenance**					
29	885 Maintenance Superv. & Eng.	—	—	—	—	-
30	887 Maintenance of Mains	—	—	—	18,463	(100.00)%
31	892 Maint. of Services	70	—	70	130	(46.15)%
32	893 Maint. of Meters & House Regulators	548	—	548	319	71.79 %
33	894 Maintenance of Other Equipment	417	—	417	—	-
34	**Total Maintenance-Distribution**	1,035	—	1,035	18,912	(94.53)%
35	**Total Distribution Expenses**	85,381	—	85,381	61,321	39.24 %
36						
37	**Customer Accounts Expenses**					
38	**Customer Accounts-Operation**					
39	901 Supervision	—	—	—	—	-
40	902 Meter Reading	—	—	—	—	-
41	903 Customer Records & Collection Expense	—	—	—	102	(100.00)%
42	**Total Customer Accounts Expenses**	—	—	—	102	(100.00)%
43	**Administrative & General Expenses**					
44	**Admin. & General - Operation**					
45	920 Salaries	—	—	—	—	-
46	921 Office Supplies & Expenses	—	—	—	—	-
47	923 Outside Services	—	—	—	—	-
48	925 Injuries & Damages	—	—	—	—	-
49	926 Employee Pensions and Benefits	17,025	—	17,025	11,018	54.52 %
50	928 Regulatory Commission Expense	—	—	—	—	-
51	**Total Operation-Admin. & General**	17,025	—	17,025	11,018	54.52 %
52	**Admin. & General - Maintenance**					
53	935 General Plant	—	—	—	—	-
54	935.1 Computer Hardware	—	—	—	—	-
55	935.2 Computer Software	—	—	—	—	-
56	935.3 Communication Equipment	—	—	—	—	-
57	**Total Admin. & General Expenses**	17,025	—	17,025	11,018	54.52 %
58						
59	**TOTAL OPER. & MAINT. EXPENSES**	$ 732,978	$ —	$ 732,978	$ 837,514	(12.48)%

Sch. 11	MONTANA TAXES OTHER THAN INCOME - PROPANE			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	$ 4,123	$ 2,720	51.58 %
3	Real Estate & Personal Property	42,816	40,236	6.41 %
4	Consumer Counsel	258	299	(13.71)%
5	Public Service Commission	1,805	2,092	(13.72)%
6				
7	**TOTAL TAXES OTHER THAN INCOME**	$ 49,002	$ 45,347	8.06 %

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	A EXCAVATION	Excavation Contractor	232,921
2	ACOUSTIBLOK INC	Construction	176,975
3	ACUREN GROUP INC	Construction	245,008
4	AFFCO INC	Hydro Construction Services	1,238,843
5	ALERTWEST INC	Security Services	278,077
6	AMERICAN INNOVATIONS INC	Software Support Services	128,186
7	ANDRITZ HYDRO CORP	Hydro Upgrade Services	3,125,510
8	ARCOS LLC	Call-out Services	163,709
9	ASCEND ANALYTICS LLC	Hydro Expert Analysis	368,610
10	ASPLUNDH TREE EXPERT LLC	Tree Trimming	8,775,273
11	ASSOCIATED UNDERWATER SERVICE	Inspection Services	125,717
12	AUTOMOTIVE RENTALS INC	Fleet Management	5,081,036
13	AVEVA SOFTWARE, LLC	Computer Support Services	235,063
14	BALLARD SPAHR LLC	Legal Services	159,336
15	BART ENGINEERING COMPANY	Engineering Services	787,757
16	BASELOAD POWER GENERATION PARTS Total	Engineering Services	392,759
17	BEACON COMMUNICATIONS LLC	Software Maintenance	814,035
18	BIG HORN WIRELINE, LLC Total	Storage	438,447
19	BISON ENGINEERING INC	Engineering Services	257,382
20	BLUE MOUNTAIN DIRECTIONAL DRI	Boring Services	1,310,679
21	BRY ENTERPRISE Total	Road Bore Services	181,607
22	BURK EXCAVATION AND UTILITIES	Construction	906,475
23	CAPITAL CITY DRILLING INC	Drilling Services	97,425
24	CATERPILLAR POWER GENERATION	Generation Services	8,006,347
25	CHAZNLINE, LLC Total	Heavy Haul Services	1,533,707
26	CLEAN POWER RESEARCH LLC	Power Research	352,609
27	CONTINENTAL STEEL WORKS	Fabrication Services	1,282,469
28	CORMETECH INC	Construction	206,788
29	CRIST, KROGH, BUTLER & NORD L	Legal Services	270,942
30	CROWLEY FLECK PLLP	Legal Services	94,855
31	CTA INC.	Energy Conservation Consultants	1,347,587
32	CUDD PRESSURE CONTROL INC	Boring Services	762,263
33	DAVEY TREE SURGERY COMPANY	Tree Trimming	7,081,834
34	DELOITTE & TOUCHE LLP	Audit Services	235,432
35	DEPT OF HEALTH & HUMAN SERVIC	Weatherization Program Services	3,313,294
36	DIETZEL ENTERPRISES INC	Construction	136,640
37	DJ&A P C CONSULTING ENGINEER	Surveying Services	83,443
38	DNV ENERGY SERVICES USA INC Total	Commercial Lighting program	8,593,160
39	DOBLE ENGINEERING CO	Maintenance Service	107,124
40	DORSEY & WHITNEY LLP	Legal Services	311,834
41	DOUBLE G WELDING & PIPELINE SERVICE	Construction	82,559
42	DOWL HKM	Geotechnical Services	413,176
43	DYNAMIC RISK USA INC	Consulting Services	99,999
44	E SOURCE COMPANIES LLC	Consulting Services	183,616
45	EIS HOLDINGS	Consulting Services	340,444
46	ELM LOCATING & UTILITY SERVIC	Locating Services and Excavation Notifications	5,511,678
47	ENERGY CONTRACT SERVICES LLC	Inspection Services	1,972,755
48	ENERGY SHARE OF MONTANA	USBC Services	1,301,400
49	ENR GENERAL MACHINING CO	Construction	1,011,148
50	EOCENE ENVIROMENTAL GROUP	Environmental Services	1,320,198
51	FAGEN, INC	Construction	454,534
52	FLYNN WRIGHT INC	Advertising Services	1,869,840
53	GARTNER INC	Information Technology Consulting	827,569
54	GE ENERGY MANAGEMENT SERVICES, LLC Total	E-Terra Source Upgrade Assist	904,874
55	GE VERNOVA INTERNATIONAL HOLDING IN	Construction	1,046,650
56	GEI CONSULTANTS INC	Environmental Consultants	781,231
57	GENERAL ELECTRIC INTERNATIONA	Plant Operator Services	1,029,248
58	GEOSPATIAL INNOVATIONS INC	GSI Services & Maintenance	215,284

Sch. 12A	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
59	GREGG ENGINEERING	Informational Technology Simulation	110,820
60	GROOME INDUSTRIAL SERVICE GROUP LLC	Consulting Services	217,400
61	GUY TABACCO CONSTRUCTION	Construction	142,875
62	H2E INC	Engineering Services	491,590
63	HARDY CONSTRUCTION CO	Construction	3,691,706
64	HDR ENGINEERING INC	Engineering Services	3,130,944
65	HEATH CONSULTANTS INC	Gas Leak Surveys	1,060,094
66	HIGHMARK MEDIA	Safety Training	97,645
67	HITACHI ENERGY USA INC Total	Engineering Consulting	758,341
68	INTEC SERVICES INC	Pole Inspection Services	3,101,775
69	ITRON INC	Meter Installation	10,129,193
70	J D POWER AND ASSOCIATES	Energy Study	137,790
71	JARES FENCE COMPANY INC	Fence Materials/Installation	157,661
72	JEFFERY CONTRACTING LLC	Construction	723,771
73	JW WILLIAMS INC	Engineering Services	292,638
74	K & K ROOFING AND EXCAVATION INC Total	Roofing and Insulation	112,010
75	KARV LLC	Boring Services	78,220
76	KELLERMEYER BERGENSONS SERVICES LLC Total	Cleaning Services	374,951
77	LEARJET INC	Repair Services	377,566
78	LOCKMER PLUMBING HEATING &	Gas Meter Relocations	232,305
79	LOENBRO LLC	Construction	1,813,826
80	M&D CONSTRUCTION INC	Construction	414,204
81	MAINTENANCE ASSISTANCE PROGRAMS LLC	Maintenance Service	479,436
82	MERCER HUMAN RESOURCE CONSULT	HR Consulting	232,751
83	MERKEL ENGINEERING INC	Consulting Services	1,539,878
84	MICHELS CORPORATION	Construction	11,004,598
85	MINUTEMAN AVIATION INC.	Helicopter Charter Services	472,914
86	MONTANA FISH WILDLIFE & PARKS	Wildlife Monitoring Services	857,575
87	MOODY'S INVESTORS SERVICE	Debt Rating Services	241,000
88	MORRISON MAIERLE INC	Engineering Services	991,442
89	MOSAIC CONSULTING GROUP LLC	Consulting Services	273,850
90	MOUNTAIN POWER CONSTRUCTION C	Electric Construction and Maintenance	21,667,312
91	MOUNTAIN WEST HOLDING COMPANY	Traffic Safety Services	854,757
92	NATIONAL CENTER FOR APPROPRIA	Conservation Program Consultants	1,183,540
93	NORTHWEST ENERGY EFFICIENCY	Energy Services	1,736,404
94	OPEN ACCESS TECHNOLOGY INT'L	Software Support Services	765,437
95	PAR PACIFIC	USBC Services	533,231
96	PLUS COMMUNICATIONS LLC	Consulting Services	300,000
97	POTEET CONSTRUCTION	Traffic Safety Services	200,242
98	POTELCO INC	Electric Construction and Maintenance	21,655,011
99	POWERS HEATING LLC	Meter Installation	89,391
100	PRO PIPE CORPORATION	Welding Services	184,832
101	QUANTA UTILITY ENGINEERING	Engineering Services	7,795,757
102	RIVER CITY ENGINEERING LLC	Engineering Services	145,037
103	ROCKWELL AUTOMATION INC	Consulting Services	122,841
104	ROCKY MOUNTAIN CONTRACTORS INC	Electric Construction and Maintenance	28,232,853
105	ROD TABBERT CONSTRUCTION INC	Construction	398,688
106	S & H WEED CONTROL LLC	Weed Control Services	99,782
107	SCENIC CITY ENTERPRISES INC	Construction	125,648
108	SCHNABEL ENGINEERING LLC	Consulting Services	171,490
109	SHAW PIPELINE SERVICES INC Total	Pipeline Service Reroute	1,235,869
110	SIDEWINDERS LLC	Generator Repair Services	3,087,344
111	STANDARD & POOR'S FINANCIAL S	Debt Rating Services	788,000
112	STATE LINE CONTRACTORS INC	Electric Construction and Maintenance	140,758
113	STINSON LEONARD STREET LLP	Legal Services	508,347
114	SUPERIOR CONCRETE PRODUCTS LLC	Construction	476,431
115	TBC CONSTRUCTION LLC Total	Pipeline Service Reroute	2,059,500

Sch. 12B	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
116	TERRA REMOTE SENSING (USA) INC	Surveying Services	2,100,624
117	THE MOSAIC COMPANY	Training	211,201
118	THOMPSON HINE LLP	Benefits Audit Services	151,648
119	TIMBERLINE SECURITY & SERVICES	Security Services	368,299
120	TLC SEPTIC SERVICE	Excavation Contractor	417,591
121	TRADEMARK ELECTRIC INC	Construction	425,735
122	TROUTMAN SANDERS LLP	Legal Services	326,925
123	TW RIDLEY LLC	Construction	787,298
124	ULTIMATE LANDSCAPE REPAIR LLC	Landscape service	887,321
125	UNITED STATES GEOLOGICAL SURV	Environmental Consulting	245,270
126	UTILITIES UNDERGROUND LOCATION	Excavation Location Services	379,585
127	VAISALA INC	Wind Forecasting Services	157,113
128	VERTEX	Billing Services and Programming	3,011,373
129	VERTIV CORPORATION	Maintenance Service	98,097
130	WATER & ENVIRONMENTAL TECHNOL	Engineering Services	814,961
131	WATSON TRUCKING OF HAVRE LLC	Hauling Services	118,770
132	WESTERN LOW VOLTAGE INC	Construction	79,350
133	WESTERN WEATHER GROUP INC	Consulting Services	260,937
134	WILLIAMSON FENCING & SPR.,INC.	Fence Materials/Installation	609,672
135	WILLIS TOWERS WATSON US LLC	Compensation Services	170,289
136	ZACHA UNDERGROUND CONSTRUCTIO	Construction	116,727
137			
138			
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167			
	Total of Payments Set Forth Above		**$ 228,645,418**
	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	$ 404,802,609	$ 427,325,878	(5.27)%
8	Service cost	4,206,812	5,099,037	(17.50)%
9	Interest cost	17,715,567	20,725,219	(14.52)%
10	Plan participants' contributions	—	—	-
11	Amendments	—	—	-
12	Actuarial (gain) loss	(13,120,068)	(26,780,061)	51.01 %
13	Settlements	(221,423,000)	(848,500)	>-300.00%
14	Benefits paid	(18,577,517)	(20,718,964)	10.34 %
15	Benefit obligation at end of year	$ 173,604,403	$ 404,802,609	(57.11)%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 342,714,487	$ 348,133,473	(1.56)%
18	Actual return on plan assets	34,105,827	8,025,978	>300.00%
19	Settlements	(221,423,000)	(848,500)	>-300.00%
20	Employer contribution	10,000,000	8,122,500	23.11 %
21	Plan participants' contributions	—	—	-
22	Benefits paid	(18,577,517)	(20,718,964)	10.34 %
23	Fair value of plan assets at end of year	$ 146,819,797	$ 342,714,487	(57.16)%
24	**Funded Status**	$ (26,784,606)	$ (62,088,122)	56.86 %
26	Unrecognized net actuarial gain (loss)	—	—	-
27	Unrecognized prior service cost	—	—	-
29	Prepaid (accrued) benefit cost	$ (26,784,606)	$ (62,088,122)	56.86 %
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	5.65 %	5.60 %	0.89 %
32	Expected return on plan assets	6.17 %	6.65 %	(7.22)%
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	$ 4,206,812	$ 5,099,037	(17.50)%
36	Interest cost	17,715,567	20,725,219	(14.52)%
37	Expected return on plan assets	(16,580,550)	(22,585,531)	26.59 %
38	Settlement (gain) loss recognized	1,167,706	—	-
39	Recognized net actuarial gain	—	33,810	(100.00)%
40	Net periodic benefit cost (SEC Basis)	$ 6,509,535	$ 3,272,535	98.91 %
41	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
42	Pension Costs	$ 10,000,000	$ 8,122,500	23.11 %
43	Pension Costs Capitalized	3,136,359	2,317,926	35.31 %
44	Accumulated Pension Asset (Liability) at Year End	$ (26,784,606)	$ (62,088,122)	56.86 %
45	**Number of Company Employees:**			
46	Covered by the Plan 1/	538	1,058	(49.15)%
47	Not Covered by the Plan 1/	1,213	1,124	7.92 %
48	Active 1/	299	349	(14.33)%
49	Retired	9	455	(98.02)%
50	Deferred Vested Terminated 1/	230	254	(9.45)%
	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/	$ 15,487,511	$ 14,659,033	5.65%
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	$ 12,263,109	$ 11,611,162	5.61%
44	401(k) Plan Defined Contribution Costs Capitalized	3,684,153	2,936,990	25.44%
45	Accumulated Pension Asset (Liability) at Year End	Not Applicable		
46	**Number of Company Employees:**	2/	2/	
47	Covered by the Plan - Eligible	1,671	1,590	5.09%
48	Not Covered by the Plan			0.00%
49	Active - Participating	1,668	1,579	5.64%
50	Retired			0.00%
51	Vested Former Employees, Retirees and Active-	430	431	(0.23)%
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	$ (784,863)	$ (390,861)	(100.80)%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	5.05 %	5.45 %	(7.34)%
8	Expected return on plan assets	5.80 %	5.84 %	(0.68)%
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 2025 FASB 106 Valuation. Assumptions and data are as of December 31, 2025.

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

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	$ 8,339,653	$ 10,598,133	(21.31)%
10	Service cost	209,646	251,843	(16.76)%
11	Interest Cost	423,034	456,347	(7.30)%
12	Plan participants' contributions	913,202	1,109,234	(17.67)%
13	Amendments			-
14	Actuarial loss/(gain)	(1,406,825)	(1,803,657)	22.00 %
15	Acquisition			-
16	Benefits paid	(1,320,310)	(2,272,247)	41.89 %
17	Benefit obligation at end of year	$ 7,158,400	$ 8,339,653	(14.16)%
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	$ 24,772,126	$ 22,309,163	11.04 %
20	Actual return on plan assets	3,648,358	3,177,129	14.83 %
21	Acquisition			-
22	Employer contribution	(121,497)	448,847	(127.07)%
23	Plan participants' contributions	913,202	1,109,234	(17.67)%
24	Benefits paid	(1,320,310)	(2,272,247)	41.89 %
25	Fair value of plan assets at end of year	$ 27,891,879	$ 16,432,473	69.74 %
26	**Funded Status**	$ 20,733,479	$ 16,432,473	26.17 %
27	Unrecognized net transition (asset)/obligation	—	—	-
28	Unrecognized net actuarial loss/(gain)	—	—	-
29	Unrecognized prior service cost	—	—	-
30	Prepaid (accrued) benefit cost	$ 20,733,479	$ 16,432,473	26.17 %
31	**Components of Net Periodic Benefit Costs**			
32	Service cost	$ 209,646	$ 251,843	(16.76)%
33	Interest cost	423,034	456,347	(7.30)%
34	Expected return on plan assets	(1,417,543)	(1,279,870)	(10.76)%
35	Amortization of transitional (asset)/obligation	—	—	-
36	Amortization of prior service cost	—	—	-
37	Recognized net actuarial loss/(gain)	(133,087)	—	-
38	Net periodic benefit cost	$ (917,950)	$ (571,680)	(60.57)%
39	**Accumulated Post Retirement Benefit Obligation**			
40	Amount Funded through VEBA	$ —	$ —	-
41	Amount Funded through 401(h)	—	—	-
42	Amount Funded through other - Company funds	(121,497)	448,847	(127.07)%
43	TOTAL	$ (121,497)	$ 448,847	(127.07)%
44	Amount that was tax deductible - VEBA	$ —	$ —	-
45	Amount that was tax deductible - 401(h)	—	—	-
46	Amount that was tax deductible - Other	(784,863)	(390,861)	(100.80)%
47	TOTAL	$ (784,863)	$ (390,861)	(100.80)%
48	**Montana Intrastate Costs:**			
49	Pension Costs	$ (784,863)	$ (390,861)	(100.80)%
50	Pension Costs Capitalized	(239,114)	(111,770)	(113.93)%
51	Accumulated Pension Asset (Liability) at Year End	20,733,479	16,432,473	26.17 %
52	**Number of Montana Employees:**			
53	Covered by the Plan	952	1,030	(7.57)%
54	Not Covered by the Plan	1,746	1,664	4.93 %
55	Active	303	341	(11.14)%
56	Retired	603	633	(4.74)%
57	Spouses/Dependents covered by the Plan	46	56	(17.86)%
	4/ There are approximately $2,034,665 and $2,386,168 of additional OPEB liabilities outstanding at December 31, 2025 and 2024, 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	353,151	128,237 A	37,767 B 69,000 C 224,303 D 96,399 E	908,857	850,896	6.8 %
2	Jason Merkel Vice President, Distribution	298,432	108,576 A	35,812 B 58,000 C 159,534 D 102,948 E 197 G	763,499	664,447	14.9 %
3	Bleau J. LaFave Vice President, Asset Management & Business Development	289,627	106,920 A	69,344 B 54,000 C 148,463 D 36,847 E	705,201	666,801	5.8 %
4	Jeanne M. Vold Vice President, Technology	286,615	104,076 A	68,997 B 56,000 C 153,972 D 31,522 E 3,665 F	704,847	720,020	(2.1)%
5	Jeffrey Berzina Controller	275,310	90,617 A	63,234 B 121,151 D	550,312	554,644	(0.8)%
6	Travis E. Meyer Director, Corporate Development & Investor Relations Officer	261,303	64,546 A	63,918 B 76,473 D 26,805 E	493,045	463,676	6.3 %
7	John P. Kasperick Director, Financial Planning & Analysis	220,494	35,576 A	31,385 B 53,891 D 88,037 E	429,383	345,342	24.3 %
8	Emilie T. Ng Treasurer	233,554	37,707 A	62,989 B 57,015 D 21,383 E 71 G	412,719	398,715	3.5 %
9	Michael L. Nieman Chief Compliance Officer	218,013	34,744 A	57,198 B 43,019 D 44,248 E	397,222	481,088	(17.4)%
10	Timothy P. Olson Counsel Corporate & Corporate Secretary Sr	226,015	45,601 A	59,111 B 55,163 D 284 G	386,174	390,085	(1.0)%

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	1/ Bonuses include the following:						
2							
3	A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2025 Annual						
4	Incentive Compensation Plan. Amounts were earned in 2025 and paid in the first quarter of 2026. Based on company						
5	performance against plan, the incentive plan was funded at 80% of target. Salary and incentive in current rate recovery are based						
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							
11	B> Employer contributions to benefits generally available to all employees on a nondiscriminatory basis - medical,						
12	dental, vision, employee assistance program, group term life, health savings account, wellness incentive,						
13	401(k) match, and non-elective 401(k) contribution, as applicable.						
14							
15	C> Defined Contribution Supplemental Executive Retirement Program						
16							
17	D> Values reflect the grant date fair value for performance stock awards. Executive stock based compensation is not included in rate recovery.						
18							
19	E> Change in pension value over previous year. The present value of accumulated benefits was calculated						
20	assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed						
21	payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements						
22	in our Annual Report on Form 10-K for the year ended December 31, 2025.						
23							
24	Actual Change in Pension Value						
25	Mike Cashell	96,399					
26	Jason Merkel	102,948					
27	Bleau LaFave	36,847					
28	Jeanne Vold	31,522					
29	Jeff Berzina	—					
30	Travis Meyer	26,805					
31	John Kasperick	88,037					
32	Emilie Ng	21,383					
33	Michael Nieman	44,248					
34	Timothy Olson	—					
35							
36	F> Value of executive physical examination and associated tax gross-up.						
37							
38	G> Value of non-cash taxable award and associated tax gross-up.						
39							
40	3/ Stock-based compensation is paid by shareholders.						
41	Recovery of non-stock-based compensation is based on historic test year costs, which are reviewed by the Montana Consumer Counsel, other						
42	parties, and MPSC staff in a general rate review. There is no specific recovery of these or most other expenses.						
43							
44	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	921,263	743,400 A	67,108 B 540,000 C 2,700,022 D 41,647 E 3,305 F	5,016,745	4,811,089	4.3%
2	Crystal D. Lail Vice President, Chief Financial Officer	511,813	309,750 A	58,519 B 150,000 C 624,967 D 41,881 E	1,696,930	1,740,136	(2.5)%
3	Shannon M. Heim General Counsel & Vice President, Federal Government Affairs	378,741	152,810 A	60,939 B 74,000 C 351,549 D	1,018,039	1,001,077	1.7%
4	John D. Hines Vice President, Supply & Montana Government Affairs	353,151	128,237 A	38,445 B 69,000 C 224,303 D 126,134 E 2,194 F	941,464	929,887	1.2%
5	Bobbi L. Schroeppel Vice President, Customer Care, Communications, & Human Resources	358,269	130,095 A	69,820 B 70,000 C 227,520 D 50,672 E 2,384 F 33 G	908,793	892,457	1.8%

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/ Bonuses include the following:

A> Non-Equity Incentive Plan Compensation includes amounts paid under the NorthWestern Energy 2025 Annual Incentive Compensation Plan. Amounts were earned in 2025 and paid in the first quarter of 2026. Based on company performance against plan, the incentive plan was funded at 80% 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. 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, 2025.

Actual Change in Pension Value

Brian B. Bird	41,647
Crystal D. Lail	41,881
Shannon M. Heim	—
John D. Hines	126,134
Bobbi L. Schroeppel	50,672

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

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

3/ Stock-based compensation is paid by shareholders.

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 proposed executive compensation on an annual basis during our shareholder meeting, and have consistently approved at above 96%, most recently 98.3%.

Our Chief Executive Officer's compensation is 80% at-risk. Overall executive compensation is discussed in the Compensation Disclosure and Analysis section of our annual Proxy Statement.

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	$ 7,107,874,759	$ 6,769,324,100	$ 338,550,659	5.00 %
4	101.1 Property Under Capital Leases	41,532,618	40,943,217	589,401	1.44 %
5	103 Experimental Electric Plant Unclassified	2,882,883	4,798,750	(1,915,867)	(39.92)%
6	105 Plant Held for Future Use	3,959,559	4,191,929	(232,370)	(5.54)%
7	107 Construction Work in Progress	137,797,710	125,080,799	$ 12,716,911	10.17 %
8	108 Accumulated Depreciation Reserve	(2,347,587,855)	(2,244,952,173)	$ (102,635,682)	4.57 %
9	108.1 Accumulated Depreciation - Capital Leases	(39,204,279)	(37,193,803)	$ (2,010,476)	5.41 %
10	111 Accumulated Amortization & Depletion Reserves	(125,509,386)	(116,083,491)	$ (9,425,895)	8.12 %
11	114 Electric Plant Acquisition Adjustments	451,564,554	451,564,554	—	— %
12	115 Accumulated Amortization-Electric Plant Acq. Adj.	(100,574,102)	(91,524,576)	(9,049,526)	9.89 %
13	116 Utility Plant Adjustments	273,855,612	263,806,234	10,049,378	3.81 %
14	117 Gas Stored Underground-Noncurrent	38,206,206	38,192,545	13,661	0.04 %
15	**Total Utility Plant**	5,444,798,279	5,208,148,085	236,650,194	4.54 %
16	**Other Property and Investments**				
17	121 Nonutility Property	686,805	686,805	—	— %
18	122 Accumulated Depr. & Amort.-Nonutililty Property	(71,615)	(68,042)	(3,573)	5.25 %
19	123.1 Investments in Assoc Companies and Subsidiaries 2/	(80,051,388)	(110,826,649)	30,775,261	(27.77)%
20	124 Other Investments	14,672,278	14,135,821	536,457	3.80 %
21	128 Miscellaneous Special Funds	—	—	—	-
22	LT Portion of Derivative Assets - Hedges	—	—	—	-
23	**Total Other Property & Investments**	(64,763,920)	(96,072,065)	31,308,145	(32.59)%
24	**Current and Accrued Assets**				
25	131 Cash	2,953,972	911,923	2,042,049	223.93 %
26	134 Other Special Deposits	10,786,659	13,894,365	(3,107,706)	(22.37)%
27	135 Working Funds	16,200	17,500	(1,300)	(7.43)%
28	142 Customer Accounts Receivable	70,662,006	66,518,761	4,143,245	6.23 %
29	143 Other Accounts Receivable	18,674,312	12,617,310	6,057,002	48.01 %
30	144 Accumulated Provision for Uncollectible Accounts	(2,397,030)	(2,160,945)	(236,085)	10.93 %
31	146 Accounts Receivable-Associated Companies	55,580,399	44,900,286	10,680,113	23.79 %
32	151 Fuel Stock	2,255,915	2,248,613	7,302	0.32 %
33	154 Plant Materials and Operating Supplies	84,079,524	79,780,714	4,298,810	5.39 %
34	164 Gas Stored - Current	6,320,240	6,743,589	(423,349)	(6.28)%
35	165 Prepayments	20,684,324	18,978,350	1,705,974	8.99 %
36	172 Rents Receivable	56,198	64,160	(7,962)	(12.41)%
37	173 Accrued Utility Revenues	73,565,824	74,104,042	(538,218)	(0.73)%
38	174 Miscellaneous Current & Accrued Assets	358,632	1,025,532	(666,900)	(65.03)%
39	**Total Current & Accrued Assets**	343,597,175	319,644,200	23,952,975	7.49 %
40	**Deferred Debits**				
41	181 Unamortized Debt Expense	11,834,207	9,376,139	2,458,068	26.22 %
42	182 Regulatory Assets	738,810,317	676,869,364	61,940,953	9.15 %
43	183 Preliminary Survey and Investigation Charges	—	—	—	-
44	184 Clearing Accounts	(193,253)	—	(193,253)	-
45	186 Miscellaneous Deferred Debits	625,907	949,677	(323,770)	(34.09)%
46	189 Unamortized Loss on Reacquired Debt	15,873,179	16,960,804	(1,087,625)	(6.41)%
47	190 Accumulated Deferred Income Taxes	186,067,513	194,013,891	(7,946,378)	(4.10)%
48	191 Unrecovered Purchased Gas Costs	(1,204,021)	253,352	(1,457,373)	>-300.00%
49	**Total Deferred Debits**	951,813,849	898,423,227	53,390,622	5.94 %
50	**TOTAL ASSETS and OTHER DEBITS**	$ 6,675,445,383	$ 6,330,143,447	$ 345,301,936	5.45 %

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	2,050,821,868	2,044,999,693	5,822,175	0.28 %
5	216 Unappropriated Retained Earnings	363,027,291	349,075,632	13,951,659	4.00 %
6	217 Reacquired Capital Stock	—	—	—	-
7	219 Accumulated Other Comprehensive Income	(4,912,586)	(5,383,393)	470,807	(8.75)%
8	**Total Proprietary Capital**	2,408,936,574	2,388,691,933	20,244,641	0.85 %
9	**Long Term Debt**				
10	221 Bonds	2,338,660,000	2,074,660,000	264,000,000	12.72 %
11	224 Other Long Term Debt	362,000,000	342,000,000	20,000,000	5.85 %
12	225 Unamortized Premium on Long-Term Debt	1,998,623	—	1,998,623	-
13	226 (Less) Unamortized Discount on Long Term Debt-Debit	—	—	—	-
14	**Total Long Term Debt**	2,702,658,623	2,416,660,000	285,998,623	11.83 %
15	**Other Noncurrent Liabilities**				
16	227 Obligations Under Capital Leases-Noncurrent	868,750	2,292,287	(1,423,537)	(62.10)%
17	228.2 Accumulated Provision for Injuries and Damages	4,158,309	5,427,888	(1,269,579)	(23.39)%
18	228.3 Accumulated Provision for Pensions and Benefits	9,044,273	(4,015,920)	13,060,193	>-300.00%
19	228.4 Accumulated Miscellaneous Operating Provisions	22,098,420	30,772,443	(8,674,023)	(28.19)%
20	229 Accumulated Provision for Rate Refunds	—	—	—	-
21	230 Asset Retirement Obligations	32,554,134	33,987,819	(1,433,685)	(4.22)%
22	**Total Other Noncurrent Liabilities**	68,723,886	68,464,517	259,369	0.38 %
23	**Current and Accrued Liabilities**				
24	231 Notes Payable	—	—	—	-
25	232 Accounts Payable	100,446,379	90,053,114	10,393,265	11.54 %
26	234 Accounts Payable to Associated Companies	572,376	212,852	359,524	168.91 %
27	235 Customer Deposits	17,508,366	17,640,442	(132,076)	(0.75)%
28	236 Taxes Accrued	85,139,232	76,941,004	8,198,228	10.66 %
29	237 Interest Accrued	29,793,801	24,578,517	5,215,284	21.22 %
30	241 Tax Collections Payable	312,293	298,173	14,120	4.74 %
31	242 Miscellaneous Current and Accrued Liabilities	62,569,436	57,585,069	4,984,367	8.66 %
32	243 Obligations Under Capital Leases-Current	2,319,559	3,902,892	(1,583,333)	(40.57)%
33	**Total Current and Accrued Liabilities**	298,661,442	271,212,063	27,449,379	10.12 %
34	**Deferred Credits**				
35	252 Customer Advances for Construction	138,076,346	123,249,058	14,827,288	12.03 %
36	253 Other Deferred Credits	45,627,055	93,579,661	(47,952,606)	(51.24)%
37	254 Regulatory Liabilities	117,697,851	119,721,846	(2,023,995)	(1.69)%
38	255 Accumulated Deferred Investment Tax Credits	3,374,953	2,229,208	1,145,745	51.40 %
39	281-283 Accumulated Deferred Income Taxes	891,688,653	846,335,161	45,353,492	5.36 %
40	**Total Deferred Credits**	1,196,464,858	1,185,114,934	11,349,924	0.96 %
41	**TOTAL LIABILITIES and OTHER CREDITS**	$ 6,675,445,383	$ 6,330,143,447	$ 345,301,936	5.45 %
42					
43	1/ This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory				
44	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the				
45	equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian				
46	Montana Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4.				
47					
48	2/ The following table presents our Investment in Assoc Companies and Subsidiaries (123.1) balances:				
49		2025	2024		
50	Colstrip Unit 4 Basis Adjustment 3/	$ (118,636,301)	$ (122,389,179)		
51	Havre Pipeline Company, LLC	13,027,925	11,562,530		
52	NorthWestern Great Falls Gas, LLC	23,794,545	—		
53	NorthWestern Cut Bank Gas, LLC	1,762,443	—		
54		$ (80,051,388)	$ (110,826,649)		
55					
56	3/ This balance represents the FERC and MPSC basis difference in the Colstrip Unit 4 plant.				
57					

NOTES TO 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 690,100 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 NW Corp (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. Events occurring subsequent to December 31, 2025, have been evaluated as to their potential impact to the Consolidated Financial Statements through the date of issuance.

The following notes to the financials statements appear in NorthWestern Corporation's annual report to the shareholders 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. 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 $462.2 million and $444.1 million as of December 31, 2025 and December 31, 2024, 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 $273.9 million as of December 31, 2025 and $263.8 million as of December 31, 2024, 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, 2025 and December 31, 2024, 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 $1.3 million and $0.7 million as of December 31, 2025 and December 31, 2024, 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 $1.3 million and $0.7 million as of December 31, 2025 and December 31, 2024, 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.

Holding Company Reorganization

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, with a total value of $570.7 million, 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.

NorthWestern Energy Group, Inc. Pending Merger with Black Hills Corporation

On August 18, 2025, NorthWestern Energy Group, Inc. entered into a Merger Agreement with Black Hills and River Merger Sub Inc., a direct wholly owned subsidiary of Black Hills (Merger Sub). The Merger Agreement provides for an all-stock merger of equals between NorthWestern Energy Group, Inc. and Black Hills upon the terms and subject to the conditions set forth therein. The Merger Agreement provides for Merger Sub to merge with and into NorthWestern Energy Group, Inc. (Merger), with NorthWestern Energy Group, Inc. continuing as the surviving entity and a direct wholly owned subsidiary of Black Hills, which would assume the new corporate name of Bright Horizon Energy Corporation as the resulting parent company of the combined corporate group. The completion of the Merger is subject to the satisfaction or waiver of certain conditions to closing. We anticipate the transaction closing in the second half of 2026, subject to the satisfaction or waiver of certain closing conditions.

(2) 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

We recognize 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.

Accounts Receivable, Net

Accounts receivable are net of allowances for uncollectible accounts of $2.5 million and $2.2 million at December 31, 2025 and December 31, 2024, respectively. Receivables include unbilled revenues of $75.7 million and $74.1 million at December 31, 2025 and December 31, 2024, respectively.

Inventories

Inventories are stated at the lower of average cost or net realizable value.

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 (NPNS) 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, 2025, the only derivative instruments we have qualify for the NPNS exception.

Revenues and expenses on contracts that are designated as NPNS 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. NPNS 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 NPNS 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 7.2% and 7.0% for 2025 and 2024, respectively. AFUDC capitalized totaled $13.0 million and $25.5 million for the years ended December 31, 2025 and 2024, 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 2025 and 2024.

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. 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, 2025	Year Ended December 31, 2024
	(in thousands)	
Cash (received) paid for:		
Federal income tax	$ —	$ 57
Montana state income tax	—	(4,826)
Total Income taxes	$ —	$ (4,769)
Interest	107,073	100,853
Significant non-cash transactions:		
Capital expenditures included in trade accounts payable	30,080	18,537

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, 2025	December 31, 2024
Cash and cash equivalents	$ 4,201	$ 1,934
Restricted cash	10,787	13,894
Total cash, cash equivalents, and restricted cash shown in the Consolidated Statements of Cash Flows	$ 14,988	$ 15,828

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

Accounting Standards Issued

In December 2023, the Financial Accounting Standards Board issued Accounting Standards Update 2023-09, *Improvements to Income Tax Disclosures*, which expands income tax disclosures. The expanded disclosures require the disclosure of prescribed categories presented in the income tax rate reconciliation and additional disclosures on income tax expense and taxes paid, net of refunds received, for federal, state, and foreign jurisdictions. We early adopted this standard for the year ended December 31, 2025, and used the retrospective method of adoption, with no material impact on our Consolidated Financial Statements.

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

(3) Acquisition of Energy West Operations

In July 2024, we entered into an Asset Purchase Agreement with Hope Utilities to acquire its Energy West natural gas distribution system and operations serving approximately 33,000 customers located in Great Falls, Cut Bank, and West Yellowstone, Montana. In May 2025, the Montana Public Service Commission (MPSC) approved this acquisition and on July 1, 2025, we completed this acquisition for approximately $35.9 million in cash. Upon the completion of the acquisition, we transferred the utility operations to our two wholly-owned subsidiaries, NorthWestern Great Falls Gas LLC and NorthWestern Cut Bank Gas LLC.

The assets acquired and liabilities assumed were measured at estimated fair value in accordance with the accounting guidance under the Business Combinations Topic in the Financial Accounting Standards Board Accounting Standards Codification. These assets and liabilities are subject to rate-setting provisions that provide for revenues derived from costs, including a return on investment of assets less liabilities included in rate base. As such, the fair values of these assets and liabilities equal their carrying values.

The excess of the purchase price over the fair value of the assets acquired and liabilities assumed has been reflected as $10.0 million of goodwill within the Gas segment. Goodwill resulting from the acquisition is largely attributable to efficiency opportunities. The goodwill recognized in connection with the acquisition will be deductible for income tax purposes.

(4) Regulatory Matters

Montana Rate Review

In July 2024, we filed a Montana electric and natural gas rate review with the MPSC requesting an annual increase to electric and natural gas utility rates. In December 2025, the MPSC issued a final order approving the natural gas settlement agreement and partial electric settlement agreement. Among other things, the approved partial electric settlement agreement 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 details of this final order are set forth below:

Returns, Capital Structure & Revenue Increase Resulting From Final Order ($ in millions)

	Electric	Natural Gas
Return on Equity (ROE)	9.65 %	9.60 %
Equity Capital Structure	47.84 %	47.84 %
Base Rates	$ 105.5	$ 18.0
Power Cost and Credit Adjustment Mechanism (PCCAM)[(1)(2)]	(94.5)	n/a
Property Tax (tracker base adjustment)[(1)]	(1.8)	0.1
Total Revenue Increase Through Final Order	$ 9.2	$ 18.1

(1) These items are flow-through costs. PCCAM reflects our fuel and purchased power costs.
(2) This PCCAM reduction of $94.5 million represents the reduction in revenue at the previously approved 2021 PCCAM base of $208.3 million using the 2023 Montana rate review test period loads.

The final order provides for an update to the PCCAM by adjusting the base costs from $208.3 million to $119.0 million. It also suspended the 90/10 cost sharing mechanism of the PCCAM on a temporary basis pending further review by the MPSC. Within this final order, the MPSC disallowed a portion of the capital costs related to the construction of Yellow Stone County Generating Station. As a result, in the fourth quarter of 2025 we recorded a $30.9 million non-cash charge for the regulatory disallowance within Operating, administrative, and general on the Consolidated Statements of Income and a corresponding reduction to Property, plant, and equipment, net on the Consolidated Balance Sheets. As of December 31, 2025, we have deferred $7.7 million of base rate revenues collected that will be refunded to customers.

In January 2026, we filed a Motion for Reconsideration (Motion) as it relates to this final order. Among other things, our Motion requests that the MPSC reconsider their prudence conclusions regarding the capital costs associated with the construction of YCGS and clarification as to the effective date of the PCCAM sharing mechanism suspension, which we have requested an effective date of July 1, 2025, to align with the PCCAM tracker year. Any subsequent modifications by the MPSC to their final order would be reflected in our 2026 results.

Colstrip Acquisitions and Requests for Cost Recovery

In January 2023, we entered into a definitive agreement with Avista Corporation (Avista) to acquire their respective interests in Colstrip Units 3 and 4 for $0 and completed this acquisition on January 1, 2026. Accordingly, we are responsible for the associated operating costs beginning on January 1, 2026, which we will not collect through utility base rates, until requested in a future Montana rate review. 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 decommissioning and demolition costs associated with the existing facilities that comprise their interests.

The 222 megawatts of generation capacity from Colstrip Units 3 and 4 acquired from Avista (Avista Interests) on January 1, 2026, was identified as a key element in our strategy to achieve resource adequacy for customers, as outlined in our 2023 Montana Integrated Resource Plan. Noting the costs associated with operating this resource are not currently reflected in utility customer rates, in August 2025, we filed a temporary PCCAM tariff waiver request with the MPSC that would provide a near-term cost-recovery mechanism expected to largely offset approximately $18.0 million in annual incremental operating and maintenance costs associated with the Avista Interests. This waiver requested that the MPSC allow us to keep 100 percent of the net revenue associated with certain designated power sales contracts up to the amount of the operating and maintenance expenses we incur associated with our Avista Interests. Furthermore, the waiver request indicated that any net revenues from the designated contracts exceeding the operating and maintenance expenses associated with our Avista Interests would continue to flow back to retail customers. In January 2026, the MPSC approved our PCCAM tariff waiver request on an interim basis with final approval or denial subject to the ongoing PCCAM docket process.

(5) Regulatory Assets and Liabilities

We prepare our Consolidated Financial Statements in accordance with the provisions of ASC 980, as discussed in Note 2 - Significant Accounting Policies. Pursuant to this guidance, certain expenses and credits, normally reflected in income as incurred, are deferred and recognized when included in rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded based on management's assessment that it is probable that a cost will be recovered or that an obligation has been incurred. Accordingly, we have recorded the following major classifications of regulatory assets and liabilities that will be recognized in expenses and revenues in future periods when the matching revenues are collected or refunded. 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, 2025	December 31, 2024
			(in thousands)	
Flow-through income taxes	13	Plant Lives	$ 557,832	$ 522,015
Supply costs		1 Year	39,966	1,132
Excess deferred income taxes	13	Plant Lives	36,550	39,040
Wildfire Mitigation		Undetermined	29,433	17,368
Pension	15	See Note 15	21,416	56,719
State & local taxes & fees		1 Year	20,367	8,863
Employee related benefits	15	See Note 15	16,548	17,877
Deferred financing costs	12	See Note 12	15,873	16,961
Environmental clean-up	18	Undetermined	2,674	—
Other		Various	18,273	15,098
Total Regulatory Assets			**$ 758,932**	**$ 695,073**
Removal cost	7	Plant Lives	$ 462,221	$ 444,058
Excess deferred income taxes	13	Plant Lives	103,157	108,154
Rates subject to refund	4	1 Year	7,660	—
Gas storage sales		14 years	5,784	6,205
Supply costs		1 Year	1,715	5,093
Employee related benefits	15	See Note 15	798	—
State & local taxes & fees		1 Year	607	46
Other		Various	2,166	1,977
Total Regulatory Liabilities			**$ 584,108**	**$ 565,533**

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.

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.

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.

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.

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.

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.

Environmental Clean-Up

Environmental clean-up costs are the estimated costs of investigating and cleaning up contaminated sites we own. We discuss the specific sites and clean-up requirements further in Note 18 - Commitments and Contingencies. Environmental clean-up costs are typically recoverable in customer rates when they are actually incurred. When cost projections become known and measurable, we coordinate with the appropriate regulatory authority to determine a recovery period.

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, 2025	December 31, 2024
	(in thousands)	
Electric Plant	$ 5,119,202	$ 4,888,326
Natural Gas Plant	1,490,780	1,328,386
Plant acquisition adjustment(1)	656,319	656,319
Common and Other Plant	209,030	204,663
Construction work in process	151,143	133,740
Total property, plant and equipment	7,626,474	7,211,434
Less accumulated depreciation	(1,672,982)	(1,561,647)
Less accumulated amortization	(369,964)	(344,785)
Net property, plant and equipment	$ 5,583,528	$ 5,305,002

(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 $1.0 million and $3.0 million as of December 31, 2025 and 2024, respectively, which is 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.

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

	Colstrip Unit 4
December 31, 2025	
Ownership percentages	30.0 %
Plant in service	$ 339,677
Accumulated depreciation	147,749
December 31, 2024	
Ownership percentages	30.0 %
Plant in service	$ 330,888
Accumulated depreciation	137,153

On January 1, 2026, we acquired a 15 percent ownership interest in Colstrip Units 3 & 4 from Avista. With this acquisition we will own 15 percent of Colstrip Unit 3 and 45 percent of Unit 4. See Note 4 - Regulatory Matters for further discussion regarding these acquisitions.

(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,	
	2025	2024
Liability at January 1,	$ 34,212	$ 34,808
Accretion expense	1,560	1,626
Liabilities incurred	371	—
Liabilities settled	(3,578)	(1,923)
Revisions to cash flows	594	(299)
Liability at December 31,	$ 33,159	$ 34,212

During the twelve months ended December 31, 2025 our ARO liability decreased $3.6 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, 2025, our ARO liability increased $1.0 million related to changes in both the timing and amount of retirement cost estimates and liabilities incurred.

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, 2025 and 2024.

(8) Goodwill

We completed our annual goodwill impairment test as of April 1, 2025, 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.

For the year ended December 31, 2025, goodwill increased $10.0 million. See Note 3 - Acquisition of Energy West Operations for additional information.

Goodwill by segment is as follows (in thousands):

	December 31,	
	2025	2024
Electric	$ 179,890	$ 179,890
Natural gas	93,966	83,917
Total Goodwill	$ 273,856	$ 263,807

(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: 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, 2025 and 2024. 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, 2025
Interest rate contracts	Interest Expense	$ 612

A pre-tax loss of approximately $11.6 million is remaining in AOCL as of December 31, 2025, 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, 2025	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	14,673	—	—	—	14,673
Total	**$ 14,673**	**$ —**	**$ —**	**$ —**	**$ 14,673**
December 31, 2024					
Rabbi trust investments	14,136	—	—	—	14,136
Total	**$ 14,136**	**$ —**	**$ —**	**$ —**	**$ 14,136**

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, 2025		December 31, 2024	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt	$ 2,690,083	$ 2,449,267	$ 2,406,206	$ 2,104,381

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 January 24, 2025, we amended our existing $400.0 million revolving credit facility (Amended Facility) to increase the capacity to $425.0 million. The Amended Facility has a maturity date of November 29, 2028 and this 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. 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 $75.0 million.

Commitment fees for the unsecured revolving lines of credit were $0.3 million and $0.4 million for the years ended December 31, 2025 and 2024.

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

	2025	2024
Unsecured revolving line of credit, expiring November 2028	**$ 425.0**	**$ 400.0**
Amounts outstanding at December 31:		
SOFR borrowings	362.0	342.0
Letters of credit	—	—
	362.0	**342.0**
Net availability as of December 31	**$ 63.0**	**$ 58.0**

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, 2025	December 31, 2024
Unsecured Debt:			
Unsecured Revolving Line of Credit	2028	$ 362,000	$ 342,000
Secured Debt:			
Mortgage bonds—			
Montana—5.01%	2025	—	161,000
Montana—3.11%	2025	—	75,000
Montana—3.99%	2028	35,000	35,000
Montana—5.073%	2030	500,000	—
Montana—3.21%	2030	100,000	100,000
Montana—5.57%	2031	175,000	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		(10,577)	(10,454)
Total Long-Term Debt		$ 2,690,083	$ 2,406,206
Less current maturities (including associated debt issuance costs)		—	(235,959)
Total Long-Term Debt, Net of Current Maturities		$ 2,690,083	$ 2,170,247
Finance Leases:			
Total Finance Leases	2026	$ 1,865	$ 5,461
Less current maturities		(1,865)	(3,596)
Total Long-Term Finance Leases		$ —	$ 1,865

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 our electric and natural gas assets.

On March 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, and November 7, 2025, we issued and sold $400.0 million and $100.0 million, respectively, 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. The proceeds from the March 2025 issuance were utilized to redeem our $161.0 million of 5.01 percent Montana First Mortgage Bonds due May 1, 2025 and $75.0 million of 3.11 percent Montana First Mortgage Bonds due July 1, 2025, and for general utility purposes. The proceeds from the November 2025 issuance, which included $2.1 million of debt premium, were used for general utility purposes.

As of December 31, 2025, 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 $1.9 million in 2026, $541.7 million in 2028, and $600.0 million in 2030.

(13) Income Taxes

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

	Year Ended December 31,	
	2025	2024
Federal		
Current	$ 65	$ 1,667
Deferred	13,387	13,602
Investment tax credits	1,146	1,970
State		
Current	(776)	61
Deferred	(649)	2,365
Income Tax Expense	$ 13,173	$ 19,665

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

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

	Year Ended December 31,			
	2025		2024	
	(in dollars)	(in percent)	(in dollars)	(in percent)
Income before income taxes	$ 168,125		$ 199,744	
Income tax calculated at federal statutory rate	35,306	21.0 %	41,946	21.0 %
State income tax, net of federal provision(1)	(919)	(0.5)	1,719	0.9
Tax Credits				
Production tax credits	(1,650)	(1.0)	(2,288)	(1.1)
Other	(129)	(0.1)	(130)	(0.1)
Impact of utility ratemaking on income taxes				
Flow-through repairs deductions	(27,128)	(16.1)	(19,274)	(9.6)
Amortization of excess deferred income taxes	(2,692)	(1.6)	(2,465)	(1.2)
AFUDC, net	(1,170)	(0.7)	(2,417)	(1.2)
Plant and depreciation of flow through items	13,071	7.8	6,690	3.3
Gas repairs safe harbor method change	—	—	(4,366)	(2.2)
Changes in Unrecognized Tax Benefits				
Release of unrecognized tax benefits	(353)	(0.2)	—	—
Interest and penalties	(1,734)	(1.0)	766	0.4
Nontaxable and nondeductible items	881	0.5	232	0.1
Other	(310)	(0.3)	(748)	(0.5)
	(22,133)	(13.2)	(22,281)	(11.2)
Income Tax Expense and Effective Tax Rate	$ 13,173	7.8 %	$ 19,665	9.8 %

(1) For all years presented, the state of Montana comprises the majority of the domestic state income taxes, net of federal provisions.

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,	
	2025	2024
NOL carryforward	$ 84,771	89,816
Production tax credit	36,575	$ 35,602
Customer advances	36,406	32,455
Compensation accruals	10,126	9,857
Unbilled revenue	6,048	3,126
Interest rate hedges	3,044	3,205
Environmental liability	2,790	2,131
Reserves and accruals	1,277	2,133
Pension / postretirement benefits	—	10,369
Other	5,814	4,334
Deferred Tax Asset	**186,851**	**193,028**
Excess tax depreciation	(627,465)	(599,893)
Flow through depreciation	(129,905)	(119,674)
Goodwill amortization	(92,009)	(89,687)
Pension / postretirement benefits	(656)	—
Regulatory assets and other	(32,516)	(23,721)
Deferred Tax Liability	**(882,551)**	**(832,975)**
Deferred Tax Liability, net	**$ (695,700)**	**$ (639,947)**

As of December 31, 2025, our total federal net operation loss (NOL) carryforward was approximately $327.1 million. Our federal NOL carryforward does not expire. Our state NOL carryforward as of December 31, 2025 was approximately $301.6 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, 2025, our total production tax credit carryforward was approximately $36.6 million. If unused, our production tax credit carryforwards will expire as follows: $0.5 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, $2.3 million in 2044, and $1.7 million in 2045. 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):

	2025	2024
Unrecognized Tax Benefits at January 1	$ 3,610	$ 5,179
Gross increases - tax positions in prior period	—	—
Gross increases - tax positions in current period	—	—
Gross decreases - tax positions in current period	—	(1,569)
Lapse of statute of limitations	(3,610)	—
Unrecognized Tax Benefits at December 31	$ —	$ 3,610

During the years ending December 31, 2025 and 2024, due to the expiration of the statute of limitations we decreased our unrecognized tax benefits by $3.6 million and $1.6 million, respectively.

Our policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2025, we have no accrual for the payment of interest and penalties in the Consolidated Balance Sheets. As of December 31, 2024, we had $1.7 million accrued for the payment of interest and penalties.

Tax years 2022 and forward remain subject to examination by the IRS and state taxing authorities.

(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,					
	2025			2024		
	Before-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount	Before-Tax Amount	Tax Expense	Net-of-Tax Amount
Foreign currency translation adjustment	$ 18	$ —	$ 18	$ (4)	$ —	$ (4)
Reclassification of net income (loss) on derivative instruments	612	(160)	452	612	(160)	452
Postretirement medical liability adjustment	—	—	—	—	—	—
Other comprehensive income (loss)	$ 630	$ (160)	$ 470	$ 608	$ (160)	$ 448

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

	December 31,	
	2025	2024
Foreign currency translation	$ 1,451	$ 1,433
Derivative instruments designated as cash flow hedges	(8,469)	(8,921)
Postretirement medical plans	(45)	(45)
Accumulated other comprehensive loss	$ (7,063)	$ (7,533)

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

		December 31, 2025			
		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		$ (8,921)	$ (45)	$ 1,433	$ (7,533)
Other comprehensive income before reclassifications		—	—	18	18
Amounts reclassified from AOCL	Interest Expense	452	—	—	452
Net current-period other comprehensive income (loss)		452	—	18	470
Ending Balance		$ (8,469)	$ (45)	$ 1,451	$ (7,063)

	Affected Line Item in the Consolidated Statements of Income	December 31, 2024 Year Ended			
		Interest Rate Derivative Instruments Designated as Cash	Postretirement Medical Plans	Foreign Currency Translation	Total
Beginning balance		$ (9,373)	$ 280	$ 1,437	$ (7,656)
Other comprehensive loss 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)

(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. 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,	
	2025	2024	2025	2024
Change in benefit obligation:				
Obligation at beginning of period	$ 404,803	$ 427,326	$ 8,339	$ 10,598
Service cost	4,207	5,099	210	252
Interest cost	17,716	20,725	423	456
Actuarial (gain) loss	(13,121)	(26,780)	(1,407)	(1,804)
Settlements(1)	(221,423)	(848)	—	—
Benefits paid	(18,578)	(20,719)	(407)	(1,163)
Benefit Obligation at End of Period	$ 173,604	$ 404,803	$ 7,158	$ 8,339
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 342,715	$ 348,134	$ 24,772	$ 22,309
Return on plan assets	34,106	8,026	3,648	3,177
Employer contributions	10,000	8,122	(121)	449
Settlements(1)	(221,423)	(848)	—	—
Benefits paid	(18,578)	(20,719)	(407)	(1,163)
Fair value of plan assets at end of period	$ 146,820	$ 342,715	$ 27,892	$ 24,772
Funded Status	$ (26,784)	$ (62,088)	$ 20,734	$ 16,433
Amounts Recognized in the Balance Sheet Consist of:				
Noncurrent asset	—	—	21,216	16,943
Total Assets	—	—	21,216	16,943
Current liability	(11,500)	(10,000)	(482)	(510)
Noncurrent liability	(15,284)	(52,088)	—	—
Total Liabilities	(26,784)	(62,088)	(482)	(510)
Net amount recognized	$ (26,784)	$ (62,088)	$ 20,734	$ 16,433
Amounts Recognized in Regulatory Assets Consist of:				
Prior service credit	—	—	—	—
Net actuarial gain (loss)	970	(30,843)	7,221	3,716
Total	$ 970	$ (30,843)	$ 7,221	$ 3,716

(1) In August 2025, we entered into a group annuity contract with an insurance company to provide for the payment of pension benefits to select pension plan participants. We purchased the contract with $221.4 million of plan assets, representing 92 percent of the settled benefit obligation. The insurance company took over the payments of these benefits starting November 1, 2025. As a result of this transaction, during the twelve months ended December 31, 2025, we recorded a non-cash, non-operating settlement charge of $1.2 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 generally due to discount rate assumptions and actual asset returns compared with expected amounts. In the case of the NorthWestern Energy MT Pension Plan the actuarial gain/loss is mainly related to demographic changes as a result of the annuitization mentioned above.

Net Periodic Cost (Credit)

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

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2025	2024	2025	2024
Components of Net Periodic Benefit Cost				
Service cost	$ 4,207	$ 5,099	$ 210	$ 252
Interest cost	17,716	20,725	423	456
Expected return on plan assets	(16,581)	(22,585)	(1,418)	(1,280)
Recognized actuarial loss (gain)	—	33	(133)	—
Settlement loss recognized(1)	1,168	—	—	—
Net Periodic Benefit Cost (Credit)	$ 6,510	$ 3,272	$ (918)	$ (572)
Regulatory deferral of net periodic benefit cost(2)	3,490	4,850	—	—
Previously deferred costs recognized(2)	—	—	133	181
Net Periodic Benefit Cost (Credit) Recognized	$ 10,000	$ 8,122	$ (785)	$ (391)

(1) Settlement losses are related to partial annuitizations of the pension plan.
(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, 2025 and 2024 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, 2025 and 2024. 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 2025 decreased our projected benefit obligation by approximately $1.2 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 the pension plan to 6.3 percent for 2026.

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

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2025	2024	2025	2024
Discount rate	5.65	5.60	5.05	5.45
Expected rate of return on assets	6.17	6.65	5.80	5.84
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 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 a moderate allocation to each can potentially improve the expected risk-adjusted return for the NorthWestern Energy MT 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 3 - 8.5 percent, is as follows:

	NorthWestern Energy MT Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,	
	2025	2024	2025	2024
Fixed income securities	45.0 %	45.0 %	40.0 %	40.0 %
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 MT Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,	
	2025	2024	2025	2024
Cash and cash equivalents(1)	4.7 %	— %	0.4 %	0.3 %
Fixed income securities(2)	37.9	43.7	30.8	32.2
Opportunistic fixed income	9.1	11.1	—	—
Global equities(2)	33.3	39.0	68.8	67.5
Private real estate(2)	15.0	6.2	—	—
	100.0 %	100.0 %	100.0 %	100.0 %

(1) Includes a substantial required cash allocation for the NorthWestern Energy MT Pension Plan related to a new overlay strategy designed to mitigate interest rate risk. Cash and cash equivalents, for purposes of this strategy, would be considered fixed income securities as it relates to target investment allocations.
(2) While some of the actual asset allocations above differ from established target allocations as of December 31, 2025, the plan Investment Manager has 60 days to initiate action to rebalance portfolios, when allocations fall out of acceptable ranges. While target allocations are the goal, both plan liquidity needs and investment liquidity terms (particularly as they pertain to the pension plan annuitization mentioned above) may cause temporary imbalances to occur.

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.

The following tables set forth, both by level within the fair value hierarchy and by net asset value (NAV) as a practical expedient, the assets (in thousands) that were accounted for on a recurring basis:

	December 31, 2025					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value[(1)]	Total Investments Measured at NAV (Common Collective Trusts)	Total Investments
Pension Plan						
Cash and cash equivalents	$ —	$ —	$ —	$ —	$ 6,927	$ 6,927
Fixed income securities	—	13,541	—	13,541	41,968	55,509
Opportunistic fixed income	—	—	—	—	13,383	13,383
Global equities	—	—	—	—	48,922	48,922
Private real estate	—	—	—	—	22,079	22,079
Total investments	$ —	$ 13,541	$ —	$ 13,541	$ 133,279	$ 146,820
Other Postretirement Benefits Plan						
Cash and cash equivalents	$ —	$ —	$ —	$ —	$ 103	$ 103
Fixed income securities	5,940	—	—	5,940	2,653	8,593
Global equities	3,808	—	—	3,808	15,388	19,196
Total investments	$ 9,748	$ —	$ —	$ 9,748	$ 18,144	$ 27,892

	December 31, 2024					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value[(1)]	Total Investments Measured at NAV (Common Collective Trusts)	Total Investments
Pension Plan						
Cash and cash equivalents	$ —	$ —	$ —	$ —	$ 104	$ 104
Fixed income securities	—	—	—	—	149,567	149,567
Opportunistic fixed income	—	—	—	—	38,163	38,163
Global equities	—	—	—	—	133,692	133,692
Private real estate	—	—	—	—	21,189	21,189
Total investments	$ —	$ —	$ —	$ —	$ 342,715	$ 342,715
Other Postretirement Benefits Plan						
Cash and cash equivalents	$ —	$ —	$ —	$ —	$ 72	$ 72
Fixed income securities	5,504	—	—	5,504	2,475	7,979
Global equities	3,093	—	—	3,093	13,628	16,721
Total investments	$ 8,597	$ —	$ —	$ 8,597	$ 16,175	$ 24,772

(1) See Note 11 - Fair Value Measurements for further information on fair value measurement inputs and methods.

The following are descriptions of the methods and assumptions used to value investments held by pension and other postretirement trusts.

- Common/Collective Trusts: The majority of our plan assets are held by common collective trusts (CCTs). In accordance with our investment policy, these pooled investment funds must have an adequate asset base relative to their asset class, be invested in a diversified manner and have a minimum of three years of verified investment performance experience or have a portfolio manager with a minimum of three years of verified investment experience in a similar investment strategy. The fund must have management and/or oversight by an investment advisor registered with the SEC. Investments in a collective investment vehicle are valued by multiplying the investee company's NAV per share by the number of units or shares owned at the valuation date. NAV 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 direct holding of NorthWestern Energy Group stock is not permitted; however, any holding in a diversified mutual fund or collective investment fund is permitted.

- Registered Investment Companies: Investments in mutual funds, categorized as global equities above, sponsored by a registered investment company are valued based on exchange listed prices. Where the value is a quoted price in an active market, the investment is classified within Level 1 of the fair value hierarchy.
- Fixed Income Securities: Certain fixed income securities are valued at the closing price reported in the active market in which the security is traded. Other fixed income securities are valued based on yields currently available on comparable securities of issuers with similar credit ratings. When quoted prices are not available for identical or similar securities, the bonds are valued for the trustee by a pricing vendor on the basis of bid or mid evaluations in accordance to the region's market convention, using factors which include but are not limited to market quotes, yields, maturities and the bond's terms and conditions. Pricing vendors use proprietary methods to arrive at the evaluated price, which represents the price a dealer would pay for the security.
- Derivative Financial Instruments: Futures contracts that are publicly traded in active markets are valued at closing prices as of the last business day of the year. Fixed income futures and options are marked to market daily.

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 2026 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 2025 and 2024 were based on actual contributions to the plan. Annual contributions to each of the pension plans are as follows (in thousands):

	2025	2024
NorthWestern Energy Pension Plan	$ 10,000	$ 8,122

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

	Pension Benefits	Other Postretirement Benefits
2026	11,120	992
2027	5,825	846
2028	6,743	816
2029	7,679	701
2030	8,441	707
2031-2035	54,046	2,832

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, 2025 and 2024 were $12.3 million and $11.6 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. Stock-based compensation expense is allocated to us based on the outstanding awards held by our employees and our allocation of labor costs. We account for our share-based compensation arrangements by recognizing compensation costs for all share-based awards over the respective service period for employee services received in exchange for an award of equity or equity-based compensation. The compensation cost is based on the fair value of the grant on the date it was awarded.

We recognized total stock-based compensation expense of $4.8 million and $2.8 million for the years ended December 31, 2025 and 2024, respectively, and related income tax benefit of $1.3 million and $0.6 million for the years ended December 31, 2025 and 2024, 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, 2025, approximately $615.9 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 a contract covered under the PURPA. This contract requires us to purchase minimum amounts of energy at prices ranging from $124 to $130 per MWH through 2029. As of December 31, 2025, our estimated gross contractual obligation related to this contract was approximately $168.6 million through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $152.8 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,	
	2025	2024
Beginning QF liability	$ 23,498	$ 28,670
Settlements	(10,206)	(7,606)
Interest expense	1,585	2,434
Ending QF liability	$ 14,877	$ 23,498

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

	Gross Obligation	Recoverable Amounts	Net
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)	$ 168,592	$ 152,837	$ 15,755

(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 $166.2 million and $189.5 million for the years ended December 31, 2025 and 2024, respectively. As of December 31, 2025, our commitments under these contracts were $347.6 million in 2026, $289.4 million in 2027, $287.0 million in 2028, $291.4 million in 2029, $287.5 million in 2030, and $2.0 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 $18.1 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 $7.8 million to $15.4 million. As of December 31, 2025, we had a reserve of approximately $10.6 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,	
	2025	2024
Liability at January 1,	$ 8,093	$ 8,438
Additions	2,638	—
Deductions	(696)	(416)
Charged to costs and expense	561	71
Liability at December 31,	$ 10,596	$ 8,093

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.

In connection with the acquisition of the Energy West operations we recognized an additional $2.6 million reserve for remediation costs associated with a site in Great Falls, Montana that was identified during the acquisition. The MPSC has previously approved the recovery of costs related to this site, and as such, the costs associated with this reserve have been deferred as a regulatory asset on the Consolidated Balance Sheets. If approval to recover costs from retail customers is subsequently denied, our Asset Purchase Agreement with Hope Utilities includes provisions that allow us to seek recovery from them.

Global Climate Change - National and international actions have been initiated to address global climate change and the contribution of 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 a joint ownership interests in the Colstrip Units 3 & 4 coal-fired electric generating plant, 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. Historically, Section 111(d) of the Clean Air Act (CAA) has been interpreted to confer authority on EPA in coordination with the states to regulate emissions, including GHG emissions, from existing stationary sources. On April 25, 2024, the EPA released final rules related to 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). As finalized, compliance with the rules would 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.

On June 11, 2025, the EPA issued a Notice of Proposed Rulemaking proposing significant changes to the federal regulatory framework for both GHG emissions and hazardous air pollutants from power plants. If either the lead or alternative proposal is adopted, our additional material compliance costs would be eliminated. On February 19, 2026, the EPA rescinded the 2024 MATS Rules, restoring the rule to the 2012 MATS standards.

On February 12, 2026, the EPA released a final rule titled Rescission of the Greenhouse Gas Endangerment Finding and Motor Vehicle Greenhouse Gas Emission Standards Under the Clean Air Act. This action reflects a further shift in federal policy regarding the regulation of GHG emissions under the CAA and may have implications for the scope of the EPA's authority to regulate GHG emissions from stationary sources, including power plants. The legal and practical effects of this final rule, including the potential for judicial review or subsequent regulatory action, remain uncertain.

Notwithstanding these developments, existing and future federal, state, or regional environmental requirements - including potential revisions to GHG emissions standards, or other air quality regulations 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, a State Implementation Plans (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 this SIP is finalized and approved by EPA, the potential remains that installation of additional emissions controls might be required at the Colstrip Units 3 & 4 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

We are subject to various 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 thousands):

December 31, 2025	**Electric**	**Natural Gas**	**Total**
Residential	$ 406,643	$ 120,830	$ 527,473
Commercial	408,530	68,722	477,252
Industrial	43,128	2,439	45,567
Lighting, governmental, irrigation, and interdepartmental	31,031	2,223	33,254
Total Retail Revenues	**889,332**	**194,214**	**1,083,546**
Regulatory Amortization	59,200	5,336	64,536
Transmission	111,024	—	111,024
Transportation, wholesale and other	5,559	42,732	48,291
Total Revenues	**$ 1,065,115**	**$ 242,282**	**$ 1,307,397**

December 31, 2024	Electric	Natural Gas	Total
Residential	$ 398,790	$ 110,215	$ 509,005
Commercial	408,977	59,925	468,902
Industrial	46,638	1,041	47,679
Lighting, governmental, irrigation, and interdepartmental	29,537	1,352	30,889
Total Retail Revenues	**883,942**	**172,533**	**1,056,475**
Regulatory Amortization	21,140	14,622	35,762
Transmission	96,999	—	96,999
Transportation, wholesale and other	8,153	37,058	45,211
Total Revenues	**$ 1,010,234**	**$ 224,213**	**$ 1,234,447**

(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. 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 for each of the years ended December 31, 2025 and 2024.

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 - PROPANE			
	Account Number & Title	This Year Utility	Last Year Utility	% Change
1	**Local Storage Plant**			
2	3360 Land and Land Rights	$ 64,954	$ 64,954	— %
3	3363 Other Equipment	422,571	422,571	— %
4	**Total Local Storage Plant**	487,525	487,525	— %
5				
6	**Distribution Plant**			
7	3376 Mains	490,965	490,965	— %
8	3380 Services	493,602	493,602	— %
9	3381 Customers Meters and Regulators	33,429	33,429	— %
10	3382 Meter Installations	—	—	-
11	3389 Other Equipment	224,722	224,722	— %
12	**Total Distribution Plant**	1,242,718	1,242,718	— %
13	**Total Propane Plant in Service**	1,730,243	1,730,243	— %
14				
15	3107 Construction Work in Progress	—	—	-
16	3117 Gas in Underground Storage	38,934	25,273	54.05 %
17				
18				
19	**TOTAL PROPANE PLANT**	$ 1,769,177	$ 1,755,516	0.78 %
20				
21				
22	**CONSOLIDATED**	December 31,		
23	**PLANT IN SERVICE**	2025	2024	
24				
25	Montana Electric	$ 5,474,640,678	$ 5,239,884,995	
26	Yellowstone National Park	30,103,814	25,659,606	
27	Montana Natural Gas (Includes CMP)	1,358,494,423	1,261,777,577	
28	Common	212,354,056	210,314,290	
29	Townsend Propane	1,730,243	1,730,243	
30	South Dakota Electric	—	—	
31	South Dakota Natural Gas	—	—	
32	South Dakota Common	—	—	
33	Asset Retirement Obligation	30,551,545	29,957,389	
34	**TOTAL PLANT**	$ 7,107,874,759	$ 6,769,324,100	

Sch. 20	MONTANA DEPRECIATION SUMMARY - PROPANE				
	Functional Plant Class	Plant Cost	This Year	Last Year	Current Avg. Rate
1	**Accumulated Depreciation**				
2					
3	Local Storage Plant	$ 487,525	$ 319,264	$ 309,967	1.91 %
4					
5	Distribution	1,242,718	898,638	854,187	3.61 %
6					
7					
8	**Total Accumulated Depreciation**	$ 1,730,243	$ 1,217,902	$ 1,164,154	3.13 %
9					
10					
11					
12					

13	**Consolidated**	December 31,	
14	**Accumulated Depreciation**	2025	2024
15			
16	Montana Electric	$ 1,912,899,778	$ 1,813,548,024
17	Yellowstone National Park	14,948,369	13,118,320
18	Montana Natural Gas (Includes CMP)	463,061,074	451,826,784
19	Common	66,614,017	63,662,277
20	Townsend Propane	1,217,902	1,164,154
21	South Dakota Electric		—
22	South Dakota Natural Gas		—
23	South Dakota Common		—
24	Acquisition Writedown	29,754,194	32,458,684
25	Basin Creek Capital Lease	39,204,279	37,193,802
26	FIN 47	(2,577,463)	(3,217,616)
27	CWIP-Capital Retirement Clearing	(12,820,630)	(11,524,962)
28	**Total Consolidated Accum Depreciation**	$ 2,512,301,520	$ 2,398,229,467

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - PROPANE			
	Commission Accepted - Most Recent	% Capital Structure	% Cost Rate	Weighted Cost
2	Docket Number: 2016.9.68			
3	Order Number : 7522g			
4	Effective Date : September 1, 2017			
6	Common Equity	46.79 %	9.55 %	4.47 %
7	Long Term Debt	53.21 %	4.67 %	2.49 %
9	**TOTAL**	100.00 %		6.96 %
12	NorthWestern Corporation uses the Natural Gas Capital Structure as a proxy for Propane			

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	$ 154,951,659	$ 180,078,441	(13.95)%
4	Noncash Charges (Credits) to Income:			
5	Depreciation and Depletion	166,425,327	147,975,406	12.47 %
6	Amortization, Net	36,523,029	35,587,522	2.63 %
7	Other Noncash Charges to Net Income, Net	9,626,137	7,046,126	36.62 %
8	Regulatory disallowance of certain YCGS capital costs	30,895,449	—	-
9	Deferred Income Taxes, Net	13,852,745	15,695,900	(11.74)%
10	Investment Tax Credit Adjustments, Net	1,145,745	1,970,244	(41.85)%
11	Change in Operating Receivables, Net	(20,644,278)	4,548,357	>-300.00%
12	Change in Materials, Supplies & Inventories, Net	(3,882,762)	(6,710,218)	42.14 %
13	Change in Operating Payables & Accrued Liabilities, Net	17,472,870	23,887,716	(26.85)%
14	Allowance for Funds Used During Construction (AFUDC)	(8,690,963)	(17,537,612)	50.44 %
15	Change in Other Assets & Liabilities, Net	(47,592,965)	(30,228,854)	(57.44)%
16	Other Operating Activities:			
17	Undistributed Earnings from Subsidiary Companies	(1,673,575)	(2,152,888)	22.26 %
18	Change in Regulatory Assets	(23,273,474)	9,340,746	>-300.00%
19	Change in Regulatory Liabilities	(2,023,995)	(35,364,509)	94.28 %
20	**Net Cash Provided by Operating Activities**	323,110,949	334,136,377	(3.30)%
21	**Cash Inflows/Outflows From Investment Activities:**			
22	Construction/Acquisition of Property, Plant and Equipment	(426,100,959)	(484,972,274)	12.14 %
23	(Net of AFUDC)			
24	Investment in Equity Securities	—	(253,166)	100.00 %
25	Investment in and Advances to Assoc. and Subsidiary Companies	(39,211,228)	—	-
26	Proceeds from Sale of Assets	—	—	-
27	**Net Cash Used in Investing Activities**	(465,312,187)	(485,225,440)	4.10 %
28	**Cash Flows from Financing Activities:**			
29	Proceeds from Issuance of:			
30	Issuance of Long-Term Debt	502,077,000	175,000,000	186.90 %
31	Issuance of Notes Payable	—	—	-
32	Line of Credit Borrowings, Net	—	—	-
33	Proceeds From Issuance of Common Stock, Net	—	—	-
34	Payments for Retirement of:			-
35	Repayments of Short Term Borrowings, Net	—	—	-
36	Repayments of Long Term Borrowings, Net	(236,000,000)	(100,000,000)	(136.00)%
37	Line of Credit Borrowings, Net	20,000,000	78,000,000	(74.36)%
38	Dividend Distribtuion to NorthWestern Energy Group, Inc.	(141,000,000)	(69,936,850)	(101.61)%
39	Other Financing Activities:			
40	Distribution of Cash From NorthWestern Energy Group, Inc.	—	60,000,000	(100.00)%
41	Debt Financing Costs	(3,942,719)	(792,992)	>-300.00%
42	Treasury Stock Activity	—	—	-
43	**Net Cash Used in Financing Activities**	141,134,281	142,270,158	(0.80)%
44	**Net Increase/Decrease in Cash and Cash Equivalents**	(1,066,957)	(8,818,905)	87.90 %
45	**Cash and Cash Equivalents at Beginning of Year**	14,823,788	23,642,693	(37.30)%
46	**Cash and Cash Equivalents at End of Year**	$ 13,756,831	$ 14,823,788	(7.20)%
47				
48	This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory			
49	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity			
50	method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana			
51	Pipeline Corporation and the adjustment to a regulated basis for Colstrip Unit 4.			
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Sch. 24	MONTANA LONG TERM DEBT 2025								
	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 %
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 %
12	4.11% Series($125M), Due 2045	06/23/15	07/01/45	125,000,000	124,273,156	125,000,000	4.11 %	5,369,022	4.30 %
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	99,492,810	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	99,402,238	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	238,848,631	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 %	9,843,554	5.62 %
19	5.07% Series($400M) Due 2030	03/21/25	03/21/30	400,000,000	396,804,374	400,000,000	5.07 %	20,790,889	5.20 %
20	5.07% Series($100M) Due 2030	11/07/25	03/21/30	100,000,000	101,329,392	100,000,000	5.07 %	$ 5,020,346	5.02 %
21	**Total First Mortgage Bonds**			$ 2,194,000,000	$ 2,181,282,751	$2,194,000,000		$ 103,468,380	4.72 %
22									
23	**Pollution Control Bonds**								
24	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 %
25									
26	**Total Pollution Control Bonds**			$ 144,660,000	$ 144,020,056	$ 144,660,000		$ 5,918,622	4.09 %
27									
28	**Other Long-Term Debt**								
29									
30									
31	**Total Other Long Term Debt**			$ —	$ —	$ —		$ —	
32									
33	**TOTAL LONG TERM DEBT**			$ 2,338,660,000	$ 2,325,302,807	$2,338,660,000		$ 109,387,002	4.68 %
34									
35									
36	This schedule does not reflect our obligations under capital lease which total $1,865,229								
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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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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
3	January	100	$ 0.01				N/A	N/A	
5	February	100	0.01				N/A	N/A	
7	March	100	0.01	N/A	N/A		N/A	N/A	
9	April	100	0.01				N/A	N/A	
11	May	100	0.01				N/A	N/A	
13	June	100	0.01	N/A	N/A		N/A	N/A	
15	July	100	0.01				N/A	N/A	
17	August	100	0.01				N/A	N/A	
19	September	100	0.01	N/A	N/A		N/A	N/A	
21	October	100	0.01				N/A	N/A	
23	November	100	0.01				N/A	N/A	
25	December	100	0.01	N/A	N/A		N/A	N/A	
27	**TOTAL Year End**	100	$ 0.01	N/A	N/A	N/A	N/A	N/A	N/A

30 1/ Monthly shares are actual shares outstanding at month-end.

Sch. 27	MONTANA EARNED RATE OF RETURN - PROPANE			
	Description	This Year	Last Year	% Change
1	**Rate Base**			
2	101 Plant in Service	$ 1,730,244	$ 1,639,010	5.57 %
3	108 Accumulated Depreciation	(1,191,028)	(1,145,714)	(3.96)%
4				
5	**Net Plant in Service**	$ 539,216	$ 493,296	9.31 %
6	Additions:			
7	Propane on Hand	$ 32,104	$ 35,213	(8.83)%
8				
9	**Total Additions**	$ 32,104	$ 35,213	(8.83)%
10	Deductions:			
11	190 Accumulated Deferred Income Taxes	$ 54,076	$ 63,232	(14.48)%
12	Reg Liab (TCJA)	39,292	42,546	
13	**Total Deductions**	$ 93,368	$ 105,778	(11.73)%
14	**Total Rate Base**	$ 477,952	$ 422,731	13.06 %
15	**Net Earnings**	$ 14,085	$ 63,811	(77.93)%
16	**Rate of Return on Average Rate Base**	2.947 %	15.095 %	(80.48)%
17	**Rate of Return on Average Equity**	Not applicable	Not applicable	
18				
19	**Major Normalizing and**			
20	**Commission Ratemaking Adjustments**			
21				
22				
23		None		
24				
25				
26				
27				
28				
29	**Total Adjustments**			
30	**Revised Net Earnings**			
31	**Adjusted Rate of Return on Average Rate Base**			
32	**Adjusted Rate of Return on Average Equity**			
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				

Sch. 28	MONTANA COMPOSITE STATISTICS - PROPANE		
		Description	Amount
1			
2		**Plant**	
3			
4	101	Plant in Service	$ 1,730,243
5	107	Construction Work in Progress	
6	117	Gas in Underground Storage	38,934
7	108, 111	Depreciation & Amortization Reserves	1,217,902
8			
9	**NET BOOK COSTS**		551,275
10			
11		**Revenues & Expenses**	
12			
13	400	Operating Revenues	859,464
14			
15	**Total Operating Revenues**		859,464
16			
17	401-402	Operation & Maintenance Expenses	732,978
18	403-407	Depreciation Expense	54,173
19	408.1	Taxes Other than Income Taxes	49,002
20	409-411	Federal & State Income Taxes	9,226
21			
22	**Total Operating Expenses**		845,379
23	**Net Operating Income**		14,085
24			
25	415-421.1	Other Income	—
26	421.2-426.5	Other Deductions	—
27	**NET INCOME BEFORE INTEREST EXPENSE**		$ 14,085
28			
29		**Average Customers**	
30		Residential	551
31		Commercial / Industrial	76
32			
33	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		627
34			
35		**Other Statistics**	
36		Average Annual Residential Use (Dkt)	40.0
37		Average Annual Residential Cost per (Dkt)	$ 22.03
38		Average Residential Monthly Bill	$ 73.37
39			
40		Plant in Service (Gross) per Customer	$ 2,760

Sch. 29	Montana Customer Information- Propane, 1/					
	City	Population Census 2020	Residential	Commercial	Industrial & Other	Total
1	Townsend	1,787	551	76	—	627
2						
3						
4						
5						
6						
7						
8						
9	**Total**	1,787	551	76	—	627
10						
11						
12	1/ Customer populations represent an average of the 12 month period from 01/01/25 through 12/31/25.					

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
4	Customer Care	151	167	159
5	Finance	64	63	64
6	Information Technology	95	98	97
7	Distribution	520	560	540
8	Asset Management	50	50	50
9	Transmission	260	272	266
10	Supply	126	131	129
11	Legal	10	12	11
12				
13				
14				
15				
16				
	TOTAL EMPLOYEES	1,276	1,353	1,315

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

Sch. 31	MONTANA CONSTRUCTION BUDGET 2026 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3	MT Transmission - Mill Creek-Garrison #2 Line Upgrade	$ 22,297,708	$ 22,297,708
4	MT Distribution - Transformer Purchase New Connects	15,008,950	15,008,950
5	MT Transmission - Substation Autotransformer Upgrade	7,924,298	7,924,298
6	MT Distribution - Wildfire Line Device Upgrades	7,745,133	7,745,133
7	MT Transmission - TSR King Hills-Two Dot Wind	7,719,591	7,719,591
8	MT Transmission - TSR Great Falls 230-Highwood 100kv	7,226,783	7,226,783
9	MT Transmission - Great Falls 230 Substation Switchyard Expansion	5,694,860	5,694,860
10	MT Transmission - TSR Three Rivers 230/161kv Substation Bank	5,093,184	5,093,184
11	MT Transmission - Substation Broadview Bus	4,941,493	4,941,493
12	MT Transmission - TSR Big Timber Wind-BT Auto 161kv	4,818,516	4,818,516
13	MT Distribution - Deer Lodge Compressor Substation Rebuild	4,565,920	4,565,920
14	MT Transmission - TSR Big Timber Wind-Alkali Creek 161kv	4,143,085	4,143,085
15	MT Transmission - Billings Wildfire Hardening	3,601,618	3,601,618
16	MT Transmission - Substation Ovando Cap and Pin	3,132,123	3,132,123
17	MT Transmission - Great Falls Wildfire Hardening	3,095,352	3,095,352
18	MT Transmission - Butte Wildfire Hardening	2,961,822	2,961,822
19	MT Distribution - Anaconda Substation Transformer Upgrade	2,951,122	2,951,122
20	MT Transmission - Missoula Wildfire Hardening	2,946,434	2,946,434
21	MT Transmission - GTF Southside-MT Refining Capacity	2,655,922	2,655,922
22	MT Distribution - Missoula Wildfire Hardening	2,600,000	2,600,000
23	MT Transmission - Trident Belgrade 161kv Upgrade	2,524,819	2,524,819
24	MT Transmission - Lewistown Wildfire Hardening	2,319,053	2,319,053
25	MT Distribution - Bozeman Southside Substataion Upgrades	2,311,640	2,311,640
26	MT Transmission - Substation Broadview Cap Replace	1,990,931	1,990,931
27	MT Distribution - Pole Replacements Butte	1,939,855	1,939,855
28	MT Distribution - Pole Replacements Helena	1,864,073	1,864,073
29	MT Transmission - Substation Ovando Breakers and Foundation	1,857,411	1,857,411
30	MT Distribution - Deer Lodge 4.16kv Substation Cutover	1,846,249	1,846,249
31	MT Transmission - Substation Broadview Upgrade	1,842,081	1,842,081
32	MT Distribution - Bozeman Wildfire Hardening	1,800,070	1,800,070
33	MT Distribution - Helena Wildfire Hardening	1,800,000	1,800,000
34	MT Distribution - Overhead Section Reliability	1,796,371	1,796,371
35	MT Transmission - Billings Broadview-Shorey Road Capacity	1,791,896	1,791,896
36	MT Distribution - Pole Replacements Great Falls	1,778,053	1,778,053
37	MT Distribution - Butte Wildfire Hardening	1,756,921	1,756,921
38	MT Transmission - Pole Replacements Great Falls	1,747,368	1,747,368
39	MT Distribution - Helena YS Pipeline Substation Upgrade	1,738,506	1,738,506
40	MT Distribution - Glasgow WS Bank #1 Substation Upgrade	1,731,486	1,731,486
41	MT Distribution - Two Dot Substation Transformer Upgrade	1,657,428	1,657,428
42	MT Transmission - Wildfire Predicitive Services Technology	1,648,391	1,648,391
43	MT Distribution - Charlos Heights Substation Transformer Upgrade	1,609,462	1,609,462
44	MT Distribution - Cutbank Pump Bank 1 Substation Upgrade	1,585,607	1,585,607
45	MT Distribution - Livingston Cutover	1,578,025	1,578,025
46	MT Distirubion - Electric Meters New Connects	1,500,895	1,500,895
47	MT Distribution - Denton Substation Transformer Upgrade	1,485,106	1,485,106
48	MT Distribution - Willow Creek Transformer Substation Upgrade	1,472,192	1,472,192
49	MT Transmission - Miller Creek-Stevi B line capacity	1,355,127	1,355,127
50	MT Transmission - Butte MRI Reroute	1,323,669	1,323,669
51	MT Distribution - Great Falls Wildfire Hardening	1,299,974	1,299,974
52	MT Distribution - Deer Lodge 4.16kv Cutover	1,295,077	1,295,077
53	MT Distribution - Wildfire Cutout Replacements	1,240,062	1,240,062
54	MT Transmission - Pole Replacements Helena	1,224,144	1,224,144
55	MT Distribution - Helena Golf Course Substation Upgrade	1,194,483	1,194,483
56	MT Distribution - Pole Replacements Bozeman	1,167,898	1,167,898
57	MT Distribution - Pole Replacements Billings	1,144,577	1,144,577
58	MT Distribution - Underground Cable Replacements Bozeman	1,131,304	1,131,304
59	MT Transmission - Helena Wildfire Hardening	1,120,519	1,120,519
60	MT Transmission - Miller Creek-Stevi A line capacity	1,100,880	1,100,880
61	MT Distribution - Livingston Wildfire Hardening	1,097,467	1,097,467
62	MT Distribution - Circuit Test/Treat Pole	1,096,499	1,096,499
63	MT Transmission - Substation Painted Robe Upgrade	1,087,604	1,087,604
64			
65	All Other Projects < $1 Million Each and blankets	84,825,223	84,825,223
66	**Total Electric Utility Construction Budget**	**$ 270,802,310**	**$ 270,802,310**
67			
68	**Natural Gas Operations**		
69	MT Gas Storage - Dry Creek Additional Wells	$ 13,054,776	$ 13,054,776
70	MT Transmission - Bear Paw Compressor Station	10,020,005	10,020,005
71	MT Transmission - Helena-Three Forks Pipeline	8,660,914	8,660,914
72	MT Gas Storage - Dry Creek Compressors	5,167,256	5,167,256
73	MT Transmission - RIGTL Vaughn to Sun Prairie Compliance	4,721,629	4,721,629
74	MT Distribution - Butte Base Gas One Upgrades	3,885,174	3,885,174
75	MT Transmission - Lewistown Tap Replacement	3,498,007	3,498,007
76	MT Gas Storage - Six Shooter Storage Field	2,401,511	2,401,511
77	MT Distribution - Bozeman Base Gas One Upgrades	1,593,960	1,593,960
78	MT Transmission - Cenex Tap Rebuild	1,458,882	1,458,882
79	MT Distirubion - Gas Meters/Regulators New Connects	1,345,630	1,345,630
80	MT Transmission - Silver City to Helena Junction	1,290,933	1,290,933
81	MT Transmission - Methane Reduction Program	1,243,386	1,243,386
82	MT Transmission - Bozeman City Gate 1 and Tap	1,123,865	1,123,865
83	MT Distribution - Helena Base Gas One Upgrades	1,011,150	1,011,150
84			
85	All Other Projects < $1 Million Each and blankets	$ 30,551,807	$ 30,551,807
86	**Total Natural Gas Utility Construction Budget**	**$ 91,028,885**	**$ 91,028,885**
87			
88	**Common**		
89	MT Common - Business Technology Digital Workforce Mgmt	$ 9,824,839	$ 9,824,839
90	MT Common - Fleet Replacements	5,000,000	5,000,000
91	MT Common - Telecom PLTE Networking	4,805,221	4,805,221
92	MT Common - Distribution AMI Metering and Infrastructure	4,476,635	4,476,635
93	MT Common - Business Technology Enterprise GIS	3,956,543	3,956,543
94	MT Common - Facilities Kalispell Garage Addition	3,100,215	3,100,215
95	MT Common - Power Operated Equipment Replacements	1,100,000	1,100,000
96	MT Common - Facilities Helena Building Improvements	1,069,651	1,069,651
97			
98	All Other Projects < $1 Million Each and blankets	11,532,545	11,532,545
99	(Includes BT, Communications, Facilities, Land, Customer Service)		
100	**Total Common Utility Construction Budget**	**$ 44,865,649**	**$ 44,865,649**
101			
102	**MT Generation**		
103	MT Generation - DGGS PT80400 50k hour overhaul	4,400,299	4,400,299
104	MT Generation - Hydro Thompson Falls Unit 6 Turbine Upgrade	4,177,156	4,177,156
105	MT Generation - CU4 Plant Upgrades Avista	4,151,389	4,151,389
106	MT Generation - CU4 Plant Upgrades	4,114,044	4,114,044
107	MT Generation - Hydro Holter Unit 4 Turbine Upgrade	4,089,333	4,089,333
108	MT Generation - Hydro Hauser Unit 6 Turbine Upgrade	3,574,557	3,574,557
109	MT Generation - Hydro Thompson Falls Unit 6 Generator Rewind	3,353,231	3,353,231
110	MT Generation - Hydro Black Eagle Spillway Upgrade Phase 2	1,976,925	1,976,925
111	MT Generation - Hydro Holter Unit 4 Generator Rewind	1,939,594	1,939,594
112	MT Generation - Hydro Black Eagle Spillway Upgrade for Ice	1,856,260	1,856,260
113	MT Generation - Hydro Black Headgate Operator Upgrade	1,382,174	1,382,174
114	MT Generation - Hydro Thompson Falls Relicensing	1,358,200	1,358,200
115	MT Generation - Hydro Spare 20 MVA GSU	1,152,198	1,152,198
116			
117	All Other Projects < $1 Million Each and blankets	$ 10,455,735	$ 10,455,735
118	**Total MT Generation**	**47,981,095**	**47,981,095**
119	**TOTAL CONSTRUCTION BUDGET**	**$ 454,677,939**	**$ 454,677,939**

Sch. 33	MONTANA SOURCES OF PROPANE SUPPLY				
		Dekatherm Volumes		Avg. Commodity Cost ($/Dkt)	
		2025 Year	2024 Year	2025 Year	2024 Year
1	**Name of Supplier**				
2	AmeriGas				
3	Superior Propane				
4	Farstad Oil, Inc.				
5	Gibson Energy, LLC/Midstream	54,008	50,875	$ 12.4283	$ 13.0870
6	Madison River Propane				
7	**Total Propane Supply Volumes**	54,008	50,875	$ 12.4283	$ 13.0870

Sch. 35	MONTANA CONSUMPTION AND REVENUES - PROPANE						
		Operating Revenues		**Dkt Sold**		**Average Customers**	
		2025 Year	2024 Year	2025 Year	2024 Year	2025 Year	2024 Year
1	**Sales of Propane**						
2							
3	Residential	$ 485,123	$ 556,691	22,020	22,568	551	544
4	Commercial / Industrial	374,341	439,341	27,355	27,425	76	77
5							
6							
7	**TOTAL SALES**	$ 859,464	$ 996,032	49,375	49,993	$ 627	$ 621