YEAR ENDING 2011

ANNUAL REPORT

OF

NorthWestern Energy

(Townsend Propane)

GAS UTILITY

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:	Kendall G. Kliewer
	Telephone Number for Report Inquiries:	(406) 497-2759
	Address for Correspondence Concerning Report:	40 East Broadway Street Butte, MT 59701

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

N/A

Sch. 2	BOARD OF DIRECTORS	
	Director's Name & Address (City, State)	Remuneration
1		
2	See Northwestern Corporation's Annual Report on Form 10-K	
3	to the SEC for the Corporate Board of Directors.	
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Sch. 3	OFFICERS	
Title	**Department Supervised**	**Name**
President & Chief Executive Officer	Executive	Robert Rowe
Vice President,	Tax, Internal Audit, Credit	Brian Bird
Chief Financial Officer and Treasurer	Financial Planning and Analysis	
	Controller and Treasury Functions	
	Investor Relations and Business Development	
	Cash Management and Financial Applications	
	Business Technology	
	Energy Risk Management	
	Flight Services, Executive Compensation	
Vice President,	Legal Services	Heather Grahame
General Counsel	Corporate Secretary	
	Records Management	
	Risk Management	
Vice President,	Distribution Operations - MT/SD/NE	Curt Pohl
Distribution Operations	Construction, Asset Management	
	Organizational Development & Labor Relations	
	Distribution Infrastructure	
	Safety/Health/Environmental Services	
	Support Services	
Vice President,	Electric Transmission Engineering & Planning	Michael Cashell
Transmission	Gas Transmission & Storage	
	Transmission Services	
	Systems Operations Control Center	
	Transmission Business Development, Performance,	
	and Analysis	
	FERC Compliance	
	Mountain States Transmission Intertie Project	
Vice President,	Production & Generation Operations	John Hines
Supply	Energy Supply Planning, Regulatory, &	
	Marketing	
	Energy Supply Long-Term Growth	
Vice President,	Government & Regulatory Affairs	Patrick Corcoran
Government & Regulatory Affairs		
Vice President,	Corporate Communications	Bobbi Schroeppel
Customer Care, Communications &	Account and Analysis	
Human Resources	Infrastructure Systems and Support	
	Customer Care	
	Key Accounts/Customer Education	
	Human Resources	
Chief Audit & Compliance Officer	Internal Audit	Michael Nieman
	Enterprise Risk	
Vice President, Controller	Financial Reporting	Kendall Kliewer
	Accounting	
	Accounts Payable/Payroll	
	Compensation and Benefits	

Reflects active officers as of December 31, 2011.

Sch. 4	CORPORATE STRUCTURE		
Subsidiary/Company Name	**Line of Business**	**Earnings (000)**	**% of Total**
Regulated Operations (Jurisdictional & Non-Jurisdictional)		$ 92,851	100.32%
NorthWestern Corporation:			
Montana Utility Operations	Electric Utility Natural Gas Utility Natural Gas Pipeline (including CMP) Propane Utility Natural Gas Funding Trust - (Bond Transition Financing) 1/		
South Dakota Utility Operations	Electric Utility Natural Gas Utility		
Nebraska Utility Operations	Natural Gas Utility		
Unregulated Operations		$ (295)	-0.32%
Direct Subsidiaries:			
NorthWestern Services, LLC	Nonregulated natural gas marketing, property management		
Clark Fork and Blackfoot, LLC	Former Milltown hydroelectric facility		
NorthWestern Investments, LLC	Holds non-utility assets		
Risk Partners Assurance, Ltd.	Captive insurance company		
Mountain States Transmission Intertie, LLC	Will hold new transmission infrastructure assets		
Indirect Subsidiaries:			
Montana Generation, LLC	Non-regulated energy marketing		
Total Corporation		$ 92,556	100.00%

1/ While the Natural Gas Funding Trust (the Trust) is regulated by the MPSC and information pertaining to the Trust is reported to the MPSC on a semi-annual basis, it is reflected on the equity basis in this presentation.

Sch. 5

CORPORATE ALLOCATIONS

Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
Controller	Includes the following departments: Controller, Accounting Accounts Payable, Payroll, Financial Reporting and Compensation & Benefits	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	$32,144,468	84.73%	$5,792,496
Customer Care	Includes the following departments: Customer Care Combined, Customer Care SD&NE CC MT, Business Develop, Corp Communications & Contributions, Human Resources and Print Services	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	20,511,137	76.34%	6,357,423
Legal Department	Includes the following departments: Chief Legal, Record Services, Risk Management	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	12,746,518	85.79%	2,111,024
Finance	Includes the following departments: CFO, Treasury, FP&A Tax , Investor Relations, Corporate Aircraft, Business Technology Applications, Security, Data Center, Project Management & Asset Control and Capital Related Exp.	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	14,103,644	74.14%	4,920,407
Regulatory and Gov't Affairs	Includes the following departments: Regulatory Affairs, Load Research, Government Affairs, Regulatory Support Services, Community Relations and Public Affairs	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	3,858,396	83.59%	757,460
Executive Department	Includes the following departments: CEO and Board of Directors	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	2,979,188	71.19%	1,205,667
Audit & Controls	Includes the following departments: Internal Audit and Enterprise Risk Management	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	750,134	73.00%	277,447
Distribution	Includes the following departments: Sioux Falls Facilities and Mail Services	Overhead costs not charged directly are typically allocated based on a 3-factor formula consisting of gross plant, labor, and margin.	528,871	73.00%	195,610
TOTAL			$87,622,356	80.21%	$21,617,534

Sch. 6	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Utility	% of Total Affil. Rev.	Charges to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4						
5						
6						
7						
8						
9	**Total Nonutility Subsidiaries**			$0		$0
10	**Total Nonutility Subsidiaries Revenues**			$0		
11						
12						
13	**Utility Subsidiaries**					
14	Canadian-Montana Pipeline Corporation	Transportation	Tariff Rates	$29,400	20.2%	$29,400
15	**Total Utility Subsidiaries**			$29,400		$29,400
16	**Total Utility Subsidiaries Revenues**			$2,473,186		
17	**TOTAL AFFILIATE TRANSACTIONS**			$29,400		$29,400

Sch. 7	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Affiliate	% of Total Affil. Exp.	Revenues to MT Utility
1						
2	**Nonutility Subsidiaries**					
3						
4						
5						
6						
7						
8						
9	**Total Nonutility Subsidiaries**			$0		$0
10	**Total Nonutility Subsidiaries Expenses**			$344		
11						
12						
13	**Utility Subsidiaries**					
14	Natural Gas Funding Trust	Metering and billing services	Negotiated Contract Rate	$1,000,000	94.9%	$1,000,000
15	**Total Utility Subsidiaries**			$1,000,000		$1,000,000
16	**Total Utility Subsidiaries Expenses**			$1,065,228		
17	**TOTAL AFFILIATE TRANSACTIONS**			$1,000,000		$1,000,000

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	$ 928,549	$ -	$ 928,549	$ 792,969	17.10%
3						
4	**Total Operating Revenues**	928,549	-	928,549	792,969	17.10%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expense	807,999	-	807,999	679,294	18.95%
9	402 Maintenance Expense	29,243	-	29,243	29,592	-1.18%
10	403 Depreciation Expense	43,275	-	43,275	42,986	0.67%
11	407.3 Regulatory Debits	-	-	-	-	-
12	408.1 Taxes Other Than Income Taxes	52,822	-	52,822	55,669	-5.11%
13	409.1 Income Taxes-Federal			-	-	-
14	-Other			-	-	-
15	410.1 Deferred Income Taxes-Dr.	1,263	-	1,263	(9,595)	113.16%
16	411.1 Deferred Income Taxes-Cr.	-	-	-	-	-
17						
18	**Total Operating Expenses**	934,602	-	934,602	797,946	17.13%
19	**NET OPERATING INCOME**	(6,053)	$ -	$ (6,053)	$ (4,977)	-21.62%

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

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	440 Residential	$ 632,290	$ -	$ 632,290	$ 543,386	16.36%
5	442 Commercial & Industrial-Small	296,259	-	296,259	249,583	18.70%
6						
7	**Total Sales to Ultimate Consumers**	928,549	-	928,549	792,969	17.10%
8	447 Sales for Resale					
9						
10	**Total Sales of Propane**	928,549	-	928,549	792,969	17.10%
11	449.1 Provision for Rate Refunds					
12						
13	**Total Revenue Net of Rate Refunds**	928,549	-	928,549	792,969	17.10%
14						
15	**Other Operating Revenues**					
16						
17	**Total Other Operating Revenue**	-	-	-	-	-
18	**TOTAL OPERATING REVENUE**	$ 928,549	$ -	$ 928,549	$ 792,969	17.10%

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	(1,649)	-	(1,649)	(33,154)	95.03%
5	807 Purchased Propane Expense	-	-	-	-	-
6	808 Propane Withdrawn from Storage	716,103	-	716,103	604,723	18.42%
7	809 Propane Delivered to Storage	-	-	-	-	-
8	**Total Supply Expenses**	714,454	-	714,454	571,569	25.00%
9	**Storage Expenses**					
10	**Other Storage-Operation**					
11	840 Operation Supervision & Engineering	-	-	-	-	-
12	841 Operation Labor & Expenses	-	-	-	-	-
13	842 Rents	15,393	-	15,393	12,572	22.44%
14	**Total Operation-Other Storage**	15,393	-	15,393	12,572	22.44%
15						
16	**Other Storage-Maintenance**					
17	847 Maintenance Storage Expenses	-	-	-	-	-
18	**Total Maintenance-Other Storage**	-	-	-	-	-
19	**Total Storage Expenses**	15,393	-	15,393	12,572	22.44%
20	**Distribution Expenses**					
21	**Distribution-Operation**					
22	870 Supervision & Engineering	-	-	-	-	-
23	874 Mains & Service	12,331	-	12,331	14,195	-13.13%
24	878 Meter & House Regulators	22,475	-	22,475	22,159	1.43%
25	879 Customer Installation	5,451	-	5,451	7,354	-25.87%
26	880 Other	1,573	-	1,573	1,097	43.37%
27	**Total Operation-Distribution**	41,830	-	41,830	44,805	-6.64%
28	**Distribution-Maintenance**					
29	885 Maintenance Superv. & Eng.	-	-	-	-	-
30	887 Maintenance of Mains	27,793	-	27,793	29,592	-6.08%
31	892 Maint. of Services	135	-	135	-	-
32	893 Maint. of Meters & House Regulators	1,311	-	1,311	-	-
33	894 Maintenance of Other Equipment	3	-	3	-	-
34	**Total Maintenance-Distribution**	29,242	-	29,242	29,592	-1.18%
35	**Total Distribution Expenses**	71,072	-	71,072	74,397	-4.47%
36						
37	**Customer Accounts Expenses**					
38	**Customer Accounts-Operation**					
39	901 Supervision	-	-	-	-	-
40	902 Meter Reading	1,260	-	1,260	1,082	16.46%
41	903 Customer Records & Collection Expense	365	-	365	230	58.69%
42	**Total Customer Accounts Expenses**	1,625	-	1,625	1,312	23.86%
43	**Administrative & General Expenses**					
44	**Admin. & General - Operation**					
45	920 Salaries	660	-	660	603	9.48%
46	921 Office Supplies & Expenses	244	-	244	13	>300.00%
47	923 Outside Services	33,794	-	33,794	48,420	-30.21%
48	925 Injuries & Damages	-	-	-	-	-
49	926 Employee Pensions and Benefits	-	-	-	-	-
50	928 Regulatory Commission Expense	-	-	-	-	-
51	**Total Operation-Admin. & General**	34,698	-	34,698	49,036	-29.24%
52	**Admin. & General - Maintenance**					
53	935 General Plant	-	-	-	-	-
54	**Total Admin. & General Expenses**	34,698	-	34,698	49,036	-29.24%
55						
56	**TOTAL OPER. & MAINT. EXPENSES**	$ 837,242	$ -	$ 837,242	$ 708,886	18.11%

Sch. 11	MONTANA TAXES OTHER THAN INCOME - PROPANE			
	Description	This Year	Last Year	% Change
1				
2	Taxes associated with Payroll/Labor	$1,861	$2,240	-16.92%
3	Real Estate & Personal Property	48,732	51,320	-5.04%
4	Consumer Counsel	279	392	-28.83%
5	Public Service Commission	1,950	1,717	13.57%
6				
7				
8	**TOTAL TAXES OTHER THAN INCOME**	$52,822	$55,669	-5.11%

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
1	ACE ELECTRIC INC	Construction	88,790
2	AEVENIA INC	Construction	918,179
3	AFTEC LLC	Construction	202,591
4	ALME CONSTRUCTION, INC.	Welding Services	254,135
5	ALSTOM GRID INC	Software Support Services	257,996
6	APPALACHIAN PIPELINE CONTRACTORS	Pipeline Contractor	2,308,677
7	ARCADIS	Engineering Services	1,063,448
8	AREA STEEL	Construction	163,328
9	ASPLUNDH TREE EXPERT CO	Tree Trimming	3,453,442
10	ASSOCIATED ARBORISTS	Vegetation Management	1,796,451
11	AUTOMOTIVE RENTALS INC	Fleet Management	8,114,301
12	B & B CONTRACTING INC	Construction	459,179
13	BALHOFF & WILLIAMS LLC	Legal Services	307,143
14	BART ENGINEERING COMPANY	Engineering Services	254,976
15	BENEDICT CONSULTING PLLC	Energy Management System Consulting	231,524
16	BGL ASSET SERVICES LLC	Inspection and Remediation Services	154,285
17	BIG SKY WATER HAULING LLC	Water Hauling Services	114,708
18	BILL BALTRUSCH CONSTRUCTION INC	Asphalt Services	121,062
19	BILL FIELD TRUCKING INC	Hauling Services	582,874
20	BROWN COUNTY LANDFILL	Landfill Services	244,113
21	BROWNING, KALECZYC, BERRY & HOVAN	Legal Services	275,071
22	CARDINAL UTILITY CONSTRUCTION	Construction	97,168
23	CAUTHEN FORBES & WILLIAMS	Governmental Affairs Consultant	91,112
24	CENTRAL AIR SERVICE INC	Aerial Pilot Services	329,048
25	CENTRAL COPTERS INC	Flight Services	137,845
26	CENTRON SERVICES INC	Collection Services	94,291
27	CESSNA AIRCRAFT COMPANY	Aircraft Maintenance	185,496
28	CHARLES RIVER ASSOCIATES	Expert Witness	120,000
29	COMPLETE CAREER CENTER INC	Temporary Employment Services	99,788
30	CONSTRUCTION BUSINESS ASSOCIATES	Process Management Services	79,471
31	CONTINENTAL STEEL WORKS	Fabrication Services	761,866
32	CON-WAY TRANSPORTION SERVICES	Freight Services	165,700
33	COP CONSTRUCTION LLC	Construction	93,868
34	CRIST KROGH & NORD LLC	Legal Services	175,723
35	CROWLEY FLECK	Legal Services	610,345
36	DAKOTA HIGH VOLTAGE TESTING	Electric System Testing and Maintenance	117,714
37	DAVEY TREE SURGERY COMPANY	Tree Trimming	1,712,585
38	DAVIS WRIGHT TREMAINE LLP	Legal Services	507,673
39	DELOITTE & TOUCHE LLP	Audit Services	1,570,892
40	DELOITTE TAX LLP	Tax Consultants	305,300
41	DENTON LOUIS PEOPLES	Board of Director Fees	76,768
42	DEPT OF HEALTH & HUMAN SERVICES	Weatherization Program Services	1,823,754
43	DEWILD GRANT RECKERT & ASSOCIATES	Engineering Services	611,016
44	DHC INC	Boring Services	82,185
45	DICKSTEIN SHAPIRO LLP	Legal Services	984,055
46	DISTRIBUTION CONSTRUCTION CO	Gas Pipeline Construction	1,433,023
47	DJ&A P C CONSULTING ENGINEERS	Engineering Services	120,101
48	DNV RENEWABLES (USA) INC	Renewable Energy Consultants	179,444
49	EDISON ELECTRIC INSTITUTE	Membership Dues	422,399
50	EDM INTERNATIONAL INC	Anchor Rod Inspection Services	487,959
51	EIDEBAILLY	Audit Services	99,573
52	ELM LOCATING & UTILITY SERVICE	Locating Services and Excavation Notifications	1,980,917
53	EMC CORPORATION HEADQUARTERS	Software Support Services	419,266
54	ENERGY CONTRACT SERVICES INC	Construction	178,110
55	ENERGY SHARE OF MONTANA	USBC Services	772,123
56	EXPRESS SERVICES INC	Temporary Employment Services	80,506
57	FALLS CONSTRUCTION COMPANY	Construction	106,508
58	FISHNET SECURITY	Software Support Services	983,614
59	FLEMING & O'LEARY PLLP	Legal Services	82,639
60	GARLINGTON, LOHN & ROBINSON	Legal Services	99,053
61	GARTNER INC	Information Technology Consulting	119,055
62	GD & J INC	Well and Compressor Maintenance	120,329
63	GE ELECTRIC INTERNATIONAL INC	Energy Consulting Services	80,120
64	GEOTEK ENGINEERING & TESTING	Geotechnical Exploration Services	102,834

Sch. 12A	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
65	GREATER GALLATIN CONTRACTORS	Landscape Repair Services	114,346
66	H & H CONTRACTING INC	Concrete and Asphalt Services	624,369
67	H and H ASPHALT & MAINTENANCE	Asphalt Services	80,509
68	HAIDER CONSTRUCTION INC	Backhoe Services	305,253
69	HAROLD K SCHOLZ CO	Construction	700,706
70	HARTINGTON TELECOMMUNICATIONS	Boring Services	87,144
71	HDR ENGINEERING INC	Engineering Services	456,192
72	HEALTH FITNESS CORPORATION	Employee Wellness Program Management	332,350
73	HEATH CONSULTANTS INC	Gas Leak Surveys	647,449
74	HIGH MARK MEDIA	Marketing Services	171,090
75	HKG ARCHITECTS INC	Architectural Services	153,568
76	HUFF CONSTRUCTION INC	Construction	1,420,485
77	IMS CONSTRUCTION INC	Construction	99,394
78	INDEPENDENT INSPECTION COMPANY	Electric Line Inspection	2,153,813
79	INDEPENDENT POWER SYSTEMS INC	Installation of Renewal Energy Systems	181,348
80	INTELLIGENT ACCESS SYSTEMS OF NC	Access System Installation	97,250
81	INTERGRAPH CORPORATION	Software Consultants	616,975
82	JACOBSEN TREE EXPERTS	Tree Trimming	813,912
83	JAMCS CORPORATION	Construction	81,698
84	JAMES TALCOTT CONSTRUCTION INC	Construction	170,586
85	JONES DAY	Legal Services	169,022
86	JORDAN CONTRACTING INC	Construction	287,131
87	JSSI JET SUPPORT SERVICES INC	Flight Services	163,561
88	K & K ROOFING AND EXCAVATION INC	Roofing Contractor	94,289
89	KELLY SERVICES INC	Engineering Services	97,401
90	KEMA SERVICES INC	USB and DSM Programs and Services	8,616,533
91	KM CONSTRUCTION CO INC	Construction	114,865
92	KNIFE RIVER	Construction	98,476
93	KRONEBUSCH ELECTRIC INC	Construction	110,790
94	LANDS ENERGY CONSULTING	Energy Consultants	122,160
95	LARSON DIGGING INC	Construction	83,593
96	LC STAFFING SERVICE	Temporary Employment Services	103,553
97	LEONARD,STREET & DEINARD	Legal Services	91,495
98	LOCKMER PLUMBING HEATING & UTILITIES	Gas Meter Relocations	202,455
99	MAPPCOR	Electric Reliability Services	286,095
100	MCKINSTRY ESSENTION	Conservation Program Consultants	90,437
101	MERCER HUMAN RESOURCE CONSULTI	Actuarial and Consulting Services	122,551
102	MERIDIAN IT INC	Information Technology Services	393,402
103	MICROSOFT LICENSING GP	Computer Licensing	577,975
104	MICROSOFT SERVICES	Computer Maintenance	78,897
105	MONTANANS FOR COMMON SENSE PROPERTY RIGHTS	Political Action Committee	175,000
106	MOODY'S INVESTORS SERVICE	Debt Rating Services	209,500
107	MOUNTAIN WEST HOLDING COMPANY	Construction	261,527
108	NATIONAL CENTER FOR APPROPRIATE TECHNOLOGY	Conservation Program Consultants	1,629,842
109	NATURAL GAS SERVICES INC	Gas Servicemen	99,665
110	NEWMECH COMPANIES INC	Construction	2,903,219
111	NORTHWEST ENERGY EFFICIENCY ALLIANCE	Energy Services	1,658,146
112	OPEN ACCESS TECHNOLOGY INT'L INC	Software Support Services	303,836
113	P2 ENERGY SOLUTIONS INC	Computer System Implementation	99,980
114	PAR ELECTRIC CONTRACTORS INC	Electric Construction and Maintenance	7,608,858
115	PARADIGM ENTERPRISES INC	Construction	172,098
116	PARISI WESTERN PLUMBING & HEATING INC	Construction	107,222
117	PAULSEN MARKETING	Advertising	977,061
118	PERKINS COIE	Legal Services	613,637
119	PHILIP MASLOWE	Board of Director Fees	89,128
120	PICEK CONSTRUCTION CO INC	Construction	180,369
121	POWER ENGINEERS INCORPORATED	Engineering Services	1,968,626
122	POWERPLAN CONSULTANTS INC	Software Implementation Support Services	2,123,784
123	PRAIRIE POTHOLE CONSULTING	Land Survey Services	105,197
124	PRATT & WHITNEY POWER SYSTEMS	Construction	10,172,067
125	PRICEWATERHOUSECOOPERS LLP	Software Implementation Support Services	496,611
126	PROFESSIONAL MAILING & MARKETING	Mailing Services	3,001,254
127	RML INCORPORATED	Boring Services	242,782
128	ROCKY MOUNTAIN CONTRACTORS INC	Electric Construction and Maintenance	21,130,418
129	ROD TABBERT CONSTRUCTION INC	Construction	508,217

Sch. 12B	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES 1/		
	Name of Recipient	Nature of Service	Total
130	ROS CONSULTING LLC	Engineering Services	152,657
131	ROUNDS BROTHERS TRENCHING	Boring Services	247,698
132	SAP INDUSTRIES INC	Software Support Services	1,449,889
133	SCENIC CITY ENTERPRISES INC	Construction	111,384
134	SCHAEFFER CONSTRUCTION	Construction	149,300
135	SCHOENFELDER CONSTRUCTION INC	Construction	80,282
136	SHUMAKER TRUCKING & EXCAVATING	Excavation Contractor	1,294,197
137	SMARTPROS LEGAL & ETHICS LTD	Leadership Training and Surveys	117,709
138	SOLAR PLEXUS	USB and DSM Programs and Services	96,000
139	SOUTH DAKOTA ELECTRIC UTILITY COMPANIES	Membership Dues	88,300
140	SPHERION CORPORATION	Temporary Employment Services	223,012
141	STANDARD & POOR'S FINANCIAL SERVICES	Debt Rating Services	115,196
142	STATE LINE CONTRACTORS INC	Electric Construction and Maintenance	537,896
143	STENSON MANAGEMENT CONSULTING	Effective Leadership Consultant	120,002
144	STONE & WEBSTER INC	Power Generation Development	1,117,608
145	SULLIVAN, TABARACCI & RHOADES, PC	Legal Services	172,779
146	SUMMIT ROOFING INC	Roofing Contractor	105,453
147	SWANK ENTERPRISES	Construction	121,268
148	T&R ELECTRIC	Transformer Repair	145,700
149	TENDRIL NETWORKS INC	Software Support Services	305,455
150	TERRA CONTRACTING LLC	Construction	1,931,702
151	TERRACON	Engineering Services	114,223
152	TETRA TECH	Environmental Services	195,175
153	THE BOLDT COMPANY	Power Plant Construction	2,166,454
154	THE ELECTRIC COMPANY OF SOUTH DAKOTA	Construction	75,933
155	THE ENERGY AUTHORITY INC	Scheduling and Dispatching	271,016
156	THE L E MYERS CO	Storm Damage Restoration	1,923,720
157	THE LIBERTY CONSULTING GROUP	Professional Services	200,199
158	TODD BRUESKE CONSTRUCTION	Construction	305,119
159	TONY LASLOVICH CONSTRUCTION	Construction	91,034
160	TOWER SYSTEMS INC	Construction	280,289
161	TOWERS WATSON	Rate Case and Compensation Support	144,698
162	TRADEMARK ELECTRIC INC	Construction	701,166
163	UTILITIES UNDERGROUND LOCATION CENTER	Locating Services and Excavation Notifications	117,035
164	UTILITY DATA CONTRACTORS INC	Data Entry and Mapping Services	413,523
165	VAN NESS FELDMAN	Legal Services	328,012
166	VARSITY CONTRACTORS INC	Janitorial Services	285,808
167	VERTEX	Billing Services	4,154,198
168	WASHINGTON FORESTRY CONSULTANT	Forestry Consultants	391,439
169	WASHINGTON WEB ARCHITECTS INC	Website Architects	76,275
170	WESTERN AREA POWER ADMINISTRATION	Electric System Impact Studies	78,000
171	WILLIAMSON FENCING INC	Construction	197,631
172	WINSTON & STRAWN LLP	Legal Services	662,180
173	XEROX CAPITAL SERVICES LLC	Copy Machine Maintenance	85,032
174			
175			
176			
177	**Total of Payments Set Forth Above**		**$ 140,060,312**

1/ This schedule includes payments for professional services over $75,000.

Sch. 13	POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS			
	Description	Total Company	Montana	% Montana
	There are three employee political action committees (PAC)s:			
	a. Employees of NorthWestern Corporation (NorthWestern Energy) PAC;			
	b. NorthWestern Energy Employees PAC; and			
	c. NorthWestern Public Service Employees PAC.			
	All of the money contributed by members is dedicated to support political candidates. No company funds may be spent in support of a political candidate. Nominal administrative costs for such things as duplicating, postage, and meeting expenses are paid by the company as provided by law. These costs are charged to shareholder expense.			
	During 2011, NorthWestern Energy contributed $175,000 to the following PAC:			
	Montanans for Common Sense Property Tax Laws	$175,000.00	$175,000.00	100.00%
	TOTAL Contributions	$ 175,000.00	$ 175,000.00	100.00%

Sch. 14	**Pension Costs** 1/			
1	Plan Name: NorthWestern Energy Pension Plan			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Projected Unit Credit	IRS Code:		
4	Annual Contribution by Employer: Variable	Is the Plan Over Funded? No		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year	$ 421,133,381	$ 363,518,169	15.85%
8	Service cost	9,187,089	8,454,335	8.67%
9	Interest cost	21,718,105	21,336,658	1.79%
10	Plan participants' contributions	-	-	-
11	Amendments	-	-	-
12	Actuarial (gain) loss	43,905,803	45,364,176	-3.21%
13	Acquisition	-	-	-
14	Benefits paid	(18,014,681)	(17,539,957)	-2.71%
15	Benefit obligation at end of year	$ 477,929,697	$ 421,133,381	13.49%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 377,834,016	$ 343,464,773	10.01%
18	Actual return on plan assets	12,782,224	42,909,200	-70.21%
19	Acquisition	-	-	-
20	Employer contribution	10,500,000	9,000,000	16.67%
21	Plan participants' contributions	-	-	-
22	Benefits paid	(18,014,681)	(17,539,957)	-2.71%
23	Fair value of plan assets at end of year	$ 383,101,559	$ 377,834,016	1.39%
24	**Funded Status**	$ (94,828,138)	$ (43,299,365)	-119.01%
26	Unrecognized net actuarial gain (loss)	-	-	-
27	Unrecognized prior service cost	-	-	-
29	Prepaid (accrued) benefit cost	$ (94,828,138)	$ (43,299,365)	-119.01%
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	4.55%	5.25%	-13.33%
32	Expected return on plan assets	7.25%	7.75%	-6.45%
33	Rate of compensation increase	3.50% Union & 3.55% Non-Union	3.50% Union & 3.55% Non-Union	
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	$ 9,187,089	$ 8,454,335	8.67%
36	Interest cost	21,718,105	21,336,658	1.79%
37	Expected return on plan assets	(26,958,867)	(26,275,609)	-2.60%
38	Amortization of prior service cost	246,361	246,361	
39	Recognized net actuarial gain	2,515,966	140,169	>300.00%
40	Net periodic benefit cost (SEC Basis)	$ 6,708,654	$ 3,901,914	71.93%
41	**Montana Intrastate Costs: (MPSC Regulatory Basis)**	-	-	
42	Pension Costs	$ 29,410,000	$ 29,410,000	
43	Pension Costs Capitalized	6,021,422	5,372,685	12.07%
44	Accumulated Pension Asset (Liability) at Year End	$ (94,828,138)	$ (43,299,365)	-119.01%
45	**Number of Company Employees:**			
46	Covered by the Plan	3,149	3,181	-1.01%
47	Not Covered by the Plan 2/	213	130	63.85%
48	Active	972	1,032	-5.81%
49	Retired	1,358	1,296	4.78%
50	Deferred Vested Terminated	819	853	-3.99%

1/ NorthWestern Corporation has a separate pension plan covering South Dakota and Nebraska employees that is not reflected above.
2/This plan was closed to new entrants effective 10/03/08. Last year count is updated to be consistent with current year.

Sch. 14a	Pension Costs			
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			
8	Service cost			
9	Interest cost			
10	Plan participants' contributions	Not Applicable		
11	Amendments			
12	Actuarial loss			
13	Acquisition			
14	Benefits paid			
15	Benefit obligation at end of year	$ -	$ -	
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$ 220,342,829	$ 192,194,493	-12.77%
18	Actual return on plan assets			
19	Acquisition			
20	Employer contribution 2/	$ 6,720,175	$ 5,980,199	12.37%
21	Plan participants' contributions			
22	Benefits paid			
23	Fair value of plan assets at end of year 2/	$ 218,194,855	$ 220,342,829	-0.97%
24	**Funded Status**	Not Applicable		
25	Unrecognized net actuarial loss			
26	Unrecognized prior service cost			
27	Prepaid (accrued) benefit cost	$ -	$ -	
28				
29	**Weighted-average Assumptions as of Year End**	Not Applicable		
30	Discount rate			
31	Expected return on plan assets			
32	Rate of compensation increase			
33				
34	**Components of Net Periodic Benefit Costs**	Not Applicable		
35	Service cost			
36	Interest cost			
37	Expected return on plan assets			
38	Amortization of prior service cost			
39	Recognized net actuarial loss			
40	Net periodic benefit cost (SEC Basis)	$ -	$ -	
41				
42	**Montana Intrastate Costs: (MPSC Regulatory Basis)**			
43	401(k) Plan Defined Contribution Costs	$ 4,598,308	$ 3,980,161	15.53%
44	401(k) Plan Defined Contribution Costs Capitalized	941,461	727,105	29.48%
45	Accumulated Pension Asset (Liability) at Year End	Not Applicable		
46	**Number of Company Employees:**	3/	3/	
47	Covered by the Plan - Eligible	1,388	1,352	2.66%
48	Not Covered by the Plan			
49	Active - Participating	1,347	1,304	3.30%
50	Retired			
51	Vested Former Employees, Retirees and Active-	259	251	3.19%
52	Noncontributing			

2/ This plan covers all NorthWestern Corporation employees.

3/ Represents total company 401(k) plan participants.

Sch. 15	Other Post Employment Benefits (OPEBS)			
	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number: D2009.9.129			
4	Order number: 7046h			
5	Amount recovered through rates	$350,602	$1,161,304	-69.81%
6	**Weighted-average Assumptions as of Year End**	1/	2/	
7	Discount rate	3.75%	4.50%	-16.67%
8	Expected return on plan assets	7.25%	7.75%	-6.45%
9	Medical Cost Inflation Rate 3/	8.75%,4.5%:17	9.00%,4.5%:18	
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	3.50% Union & 3.55% Non-Union	3.50% Union & 3.55% 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 2010 FASB 106 Valuation. Assumptions and data are as of December 31, 2011.

2/ Obtained from NorthWestern Energy-Montana's 2009 FASB 106 Valuation. Assumptions and data are as of December 31, 2010.

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			
3	Not Covered by the Plan			
4	Active			
5	Retired			
6	Spouses/Dependants covered by the Plan			
7	**Montana 4/**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year	$26,467,645	$22,862,746	15.77%
10	Service cost	358,150	403,973	-11.34%
11	Interest Cost	970,483	1,363,908	-28.85%
12	Plan participants' contributions	1,089,753	-	-
13	Amendments	(464,242)	-	-
14	Actuarial loss/(gain)	(2,711,685)	4,341,706	-162.46%
15	Acquisition	-	-	-
16	Benefits paid	(3,289,421)	(2,504,688)	-31.33%
17	Benefit obligation at end of year	$22,420,683	$26,467,645	-15.29%
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	$17,201,034	$15,298,244	12.44%
20	Actual return on plan assets	339,995	1,902,790	-82.13%
21	Acquisition	-	-	-
22	Employer contribution	160,918	2,504,688	-93.58%
23	Plan participants' contributions	-	-	-
24	Benefits paid	(2,199,668)	(2,504,688)	12.18%
25	Fair value of plan assets at end of year	$15,502,279	$17,201,034	-9.88%
26	**Funded Status**	($6,918,404)	($9,266,611)	25.34%
27	Unrecognized net transition (asset)/obligation	-	-	-
28	Unrecognized net actuarial loss/(gain)	-	-	-
29	Unrecognized prior service cost	-	-	-
30	Prepaid (accrued) benefit cost	($6,918,404)	($9,266,611)	25.34%
31	**Components of Net Periodic Benefit Costs**			
32	Service cost	$358,150	$403,973	-11.34%
33	Interest cost	970,483	1,363,908	-28.85%
34	Expected return on plan assets	(1,185,450)	(1,185,614)	0.01%
35	Amortization of transitional (asset)/obligation	-	-	-
36	Amortization of prior service cost	(2,148,915)	($2,102,491)	-2.21%
37	Recognized net actuarial loss/(gain)	657,715	982,909	-33.08%
38	Net periodic benefit cost	($1,348,017)	($537,315)	-150.88%
39	**Accumulated Post Retirement Benefit Obligation**		-	
40	Amount Funded through VEBA	$ -	$ -	-
41	Amount Funded through 401(h)	-	-	-
42	Amount Funded through other - Company funds	160,918	2,504,688	-93.58%
43	TOTAL	$160,918	$2,504,688	-93.58%
44	Amount that was tax deductible - VEBA	$ -	$ -	-
45	Amount that was tax deductible - 401(h)	-	-	-
46	Amount that was tax deductible - Other	350,602	1,161,304	-69.81%
47	TOTAL	$350,602	$1,161,304	-69.81%
48	**Montana Intrastate Costs:**			
49	Pension Costs	$350,602	$1,161,304	-69.81%
50	Pension Costs Capitalized	71,782	212,150	-66.16%
51	Accumulated Pension Asset (Liability) at Year End	(6,918,404)	(9,266,611)	25.34%
52	**Number of Montana Employees:**		-	
53	Covered by the Plan	2,085	2,137	-2.43%
54	Not Covered by the Plan	192	153	25.49%
55	Active	1,014	1,080	-6.11%
56	Retired	961	948	1.37%
57	Spouses/Dependants covered by the Plan	110	109	0.92%

4/ There is approximately an additional $10,006,342 and $9,502,819 in other company OPEBS liabilities outstanding at December 31, 2011 and 2010, respectively for other supplemental retirement agreements in addition to what is reflected for Montana above.

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

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	Patrick R. Corcoran Vice President, Government & Regulatory Affairs	198,940	60,710 A	16,118 B 62,804 C 133,755 D	472,327	456,779	3%
2	Michael R. Cashell Vice President, Transmission	174,693	48,581 A	25,520 B 40,147 C 120,374 D	409,315	339,632	21%
3	William T. Rhoads General Manager, Generation	153,946	24,475 A	20,146 B 22,341 C 110,134 D 6,927 E 15,009 F	352,977	N/A	
4	Kendall G. Kliewer Vice President and Controller	224,444	0 A	40,844 B 70,856 C 6,384 D	342,528	393,990	-13%
5	John D. Hines Vice President, Supply	176,555	48,581 A	14,112 B 41,417 C 46,167 D	326,832	274,085	19%
6	Michael L. Nieman Chief Audit and Compliance Officer	192,217	46,554 A	41,179 B 34,793 C 2,684 D 5,598 E	323,025	326,244	-1%
7	John S. Fitzpatrick Executive Director State/Local Community Relations	171,017	28,953 A	20,685 B 19,087 C 50,033 D 4,446 F 6,720 G	300,941	286,439	5%
8	Daniel L. Rausch Director, Investor Relations & Business Development	168,094	35,653 A	35,162 B 25,027 C 3,768 D 3,782 F	271,486	264,152	3%
9	Wayne M. Hitt Director, Tax	153,085	32,702 A	34,248 B 22,341 C 5,913 D 8,500 H 625 I	257,414	N/A	
10	Michael Andrew McLain Corporate Counsel	107,500	19,630 A	18,990 B 105,114 H	251,234	N/A	

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	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 2011 Employee Incentive Compensation Plan. Amounts were earned in 2011 and paid in the first quarter of 2012. Based on company performance against plan, the incentive plan was funded at 101% of target. Individual awards varied from the funded level based on individual performance.

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

B> Employer contributions to benefits - medical, dental, vision, employee assistance program, group term life, Health Savings Account, non-cash awards and related tax liability gross up, 401(k) match and non-elective 401(k) contribution.

C> Values reflect the grant date fair value for restricted stock awards.

D>Change in pension value over previous year. The present value of accumulated benefits was calculated assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2011.

E> Vacation sold back during the year.

F> Merit pay or bonus.

G> Vehicle allowance.

H> Payments and imputed income for reimbursements related to relocation/commuting.

I> Imputed income related to use of facilities at Hebgen.

SCHEDULE 17

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

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	Total Compensation	Total Compensation Reported Last Year	% Increase Total Compensation
1	Robert C. Rowe President & Chief Executive Officer	510,101	415,110 A	18,903 B 474,785 C 49,812 D	1,468,711	1,231,916	19%
2	Brian B. Bird Vice President, Chief Financial Officer & Treasurer	334,634	170,199 A	40,012 B 216,755 C 9,531 D	771,131	735,084	5%
3	Heather Grahame Vice President, General Counsel	304,510	123,902 A	42,152 B 146,691 C 7,642 E	624,897	465,271	34%
4	Curtis T. Pohl Vice President, Distribution	239,748	97,551 A	42,303 B 115,486 C 6,848 D 7,222 F	509,158	436,999	17%
5	Bobbi Schroeppel Vice President, Customer Care, Communications & Human Resources	211,692	64,601 A	40,793 B 66,813 C 5,503 D	389,402	374,244	4%

TOP FIVE MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses 1/	Other 2/	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 2011 Employee Incentive Compensation Plan. Amounts were earned in 2011 and paid in the first quarter of 2012. Based on company performance against plan, the incentive plan was funded at 101% of target.

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

B> Employer contributions to benefits - medical, dental, vision, employee assistance program, group term life, Health Savings Account, 401(k) match, and non-elective 401(k) contribution.

C> Values reflect the grant date fair value for restricted stock awards.

D> Change in pension value over previous year. The present value of accumulated benefits was calculated assuming benefits commence at age 65 and using the discount rate, mortality assumption and assumed payment form consistent with those disclosed in the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2011.

E> Payments and imputed income for reimbursements related to relocation.

F> Vacation sold back during the year.

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	$3,479,352,079	$3,357,302,141	$122,049,938	3.64%
4	101.1 Property Under Capital Leases	40,209,537	40,209,537	-	0.00%
5	105 Plant Held for Future Use	4,900	4,900	-	0.00%
6	107 Construction Work in Progress	72,580,805	34,704,153	$37,876,652	109.14%
7	108 Accumulated Depreciation Reserve	(1,481,407,150)	(1,402,535,010)	($78,872,140)	5.62%
8	108.1 Accumulated Depreciation - Capital Leases	(11,057,582)	(9,047,108)	($2,010,474)	22.22%
9	111 Accumulated Amortization & Depletion Reserves	(23,574,461)	(20,095,364)	($3,479,097)	17.31%
10	114 Electric Plant Acquisition Adjustments	-	-	-	-
11	115 Accumulated Amortization-Electric Plant Acq. Adj.	-	-	-	-
12	116 Utility Plant Adjustments	355,128,500	355,128,500	-	0.00%
13	117 Gas Stored Underground-Noncurrent	32,119,408	32,118,564	844	0.00%
14	**Total Utility Plant**	2,463,356,036	2,387,790,313	75,565,723	3.16%
15	**Other Property and Investments**				
16	121 Nonutility Property	9,974,240	8,264,780	1,709,460	20.68%
17	122 Accumulated Depr. & Amort.-Nonutility Property	(503,814)	(450,593)	(53,221)	11.81%
18	123.1 Investments in Assoc Companies and Subsidiaries	(152,003,379)	(67,099,183)	(84,904,196)	126.54%
19	124 Other Investments	8,556,077	5,937,333	2,618,744	44.11%
20	128 Miscellaneous Special Funds	-	-	-	-
21	LT Portion of Derivative Assets - Hedges	-	-	-	-
22	**Total Other Property & Investments**	(133,976,876)	(53,347,663)	(80,629,213)	151.14%
23	**Current and Accrued Assets**				
24	131 Cash	5,888,517	6,191,524	(303,007)	-4.89%
25	134 Other Special Deposits	3,998,525	3,330,081	668,444	20.07%
26	135 Working Funds	39,300	40,567	(1,267)	-3.12%
27	136 Temporary Cash Investments	-	-	-	-
28	141 Notes Receivable	-	-	-	-
29	142 Customer Accounts Receivable	71,822,880	71,029,517	793,363	1.12%
30	143 Other Accounts Receivable	8,031,487	11,066,640	(3,035,153)	-27.43%
31	144 Accumulated Provision for Uncollectible Accounts	(2,929,624)	(2,874,902)	(54,722)	1.90%
32	145 Notes Receivable-Associated Companies	-	-	-	-
33	146 Accounts Receivable-Associated Companies	4,851,585	12,435,690	(7,584,105)	-60.99%
34	151 Fuel Stock	7,281,127	5,993,574	1,287,553	21.48%
35	154 Plant Materials and Operating Supplies	22,407,788	20,603,835	1,803,953	8.76%
36	164 Gas Stored - Current	29,819,575	24,080,873	5,738,702	23.83%
37	165 Prepayments	8,675,982	5,427,163	3,248,819	59.86%
38	171 Interest and Dividends Receivable	-	-	-	-
40	172 Rents Receivable	76,604	54,930	21,674	39.46%
41	173 Accrued Utility Revenues	71,118,239	69,393,581	1,724,658	2.49%
42	174 Miscellaneous Current & Accrued Assets	350,081	305,033	45,048	14.77%
43	175 Derivative Instrument Assets (175)	-	8,500	(8,500)	-100.00%
44	(Less) Long-Term Portion of Derivative Instrument Assets	-	-	-	-
45	176 LT Portion of Derivative Assets - Hedges	-	-	-	-
46	(less) LT Portion of Derivative Assets - Hedges	-	-	-	-
47	**Total Current & Accrued Assets**	231,432,066	227,086,606	4,345,460	1.91%
48	**Deferred Debits**				
49	181 Unamortized Debt Expense	11,307,102	12,256,091	(948,989)	-7.74%
50	182 Regulatory Assets	329,875,457	249,597,474	80,277,983	32.16%
51	183 Preliminary Survey and Investigation Charges	825,634	2,344,107	(1,518,473)	-64.78%
52	184 Clearing Accounts	13,354	2,710	10,644	>300.00%
53	185 Temporary Facilities	-	78	(78)	-100.00%
54	186 Miscellaneous Deferred Debits	1,883,035	2,834,279	(951,244)	-33.56%
55	189 Unamortized Loss on Reacquired Debt	15,413,238	16,882,134	(1,468,896)	-8.70%
56	190 Accumulated Deferred Income Taxes	164,228,720	97,507,302	66,721,418	68.43%
57	191 Unrecovered Purchased Gas Costs	3,554,323	1,633,876	1,920,447	117.54%
58	**Total Deferred Debits**	527,100,863	383,058,051	144,042,812	37.60%
59	**TOTAL ASSETS and OTHER DEBITS**	$ 3,087,912,089	$ 2,944,587,307	$ 143,324,782	4.87%

Sch. 18	cont. BALANCE SHEET 1/				
	Account Title	This Year	This Year	Variance	% Change
1	**Liabilities and Other Credits**				
2	**Proprietary Capital**				
3	201 Common Stock Issued	$ 398,411	$ 397,993	$ 418	0.11%
4	204 Preferred Stock Issued	-	-	-	-
5	207 Premium on Capital Stock	-	-	-	-
6	211 Miscellaneous Paid-In Capital	816,700,362	813,878,068	2,822,294	0.35%
7	213 Discount on Capital Stock	-	-	-	-
8	214 Capital Stock Expense	-	-	-	-
9	215 Appropriated Retained Earnings	-	-	-	-
10	216 Unappropriated Retained Earnings	128,631,093	87,984,357	40,646,736	46.20%
12	217 Reacquired Capital Stock	(90,272,890)	(90,427,113)	154,223	-0.17%
13	219 Accumulated Other Comprehensive Income	3,655,967	8,513,655	(4,857,688)	-57.06%
14	**Total Proprietary Capital**	859,112,943	820,346,960	38,765,983	4.73%
15	**Long Term Debt**				
16	221 Bonds	905,205,000	905,205,000	-	0.00%
17	223 Advances in Associated Companies	-	-	-	-
18	224 Other Long Term Debt	-	153,000,000	(153,000,000)	-100.00%
19	226 (Less) Unamortized Discount on Long Term Debt-Debit	155,738	179,838	(24,100)	-13.40%
20	**Total Long Term Debt**	905,049,262	1,058,025,162	(152,975,900)	-14.46%
21	**Other Noncurrent Liabilities**				
22	227 Obligations Under Capital Leases-Noncurrent	32,917,879	34,288,045	(1,370,166)	-4.00%
23	228.1 Accumulated Provision for Property Insurance	-	-	-	-
24	228.2 Accumulated Provision for Injuries and Damages	10,003,210	12,380,125	(2,376,915)	-19.20%
25	228.3 Accumulated Provision for Pensions and Benefits	26,150,621	28,680,305	(2,529,684)	-8.82%
26	228.4 Accumulated Miscellaneous Operating Provisions	214,313,846	206,905,197	7,408,649	3.58%
27	229 Accumulated Provision for Rate Refunds	11,432,481	3,541,702	7,890,779	222.80%
28	230 Asset Retirement Obligations	6,291,623	7,180,922	(889,299)	-12.38%
29	**Total Other Noncurrent Liabilities**	301,109,660	292,976,296	8,133,364	2.78%
30	**Current and Accrued Liabilities**				
31	231 Notes Payable	166,933,493	-	166,933,493	-
32	232 Accounts Payable	80,813,254	84,151,450	(3,338,196)	-3.97%
33	233 Notes Payable to Associated Companies	-	-	-	-
34	234 Accounts Payable to Associated Companies	70,978	61,584	9,394	15.25%
35	235 Customer Deposits	13,088,340	9,784,498	3,303,842	33.77%
36	236 Taxes Accrued	33,058,019	130,979,557	(97,921,538)	-74.76%
37	237 Interest Accrued	15,318,941	15,284,739	34,202	0.22%
39	238 Dividends Declared	-	-	-	-
40	241 Tax Collections Payable	1,198,760	1,222,070	(23,310)	-1.91%
41	242 Miscellaneous Current and Accrued Liabilities	47,775,316	48,679,642	(904,326)	-1.86%
42	243 Obligations Under Capital Leases-Current	1,370,168	1,275,845	94,323	7.39%
43	244 Derivative Instrument Liabilities	20,312,243	29,720,807	(9,408,564)	-31.66%
44	245 Derivative Instrument Liabilities - Hedges	-	-	-	-
45	**Total Current and Accrued Liabilities**	379,939,512	321,160,192	58,779,320	18.30%
46	**Deferred Credits**				
47	252 Customer Advances for Construction	41,020,091	43,787,528	(2,767,437)	-6.32%
48	253 Other Deferred Credits	137,947,782	79,080,915	58,866,867	74.44%
49	254 Regulatory Liabilities	28,352,270	22,765,216	5,587,054	24.54%
50	255 Accumulated Deferred Investment Tax Credits	1,572,445	1,996,006	(423,561)	-21.22%
51	257 Unamortized Gain on Reacquired Debt	-	-	-	-
52	281-283 Accumulated Deferred Income Taxes	433,808,124	304,449,032	129,359,092	42.49%
53	**Total Deferred Credits**	642,700,712	452,078,697	190,622,015	42.17%
54	**TOTAL LIABILITIES and OTHER CREDITS**	$ 3,087,912,089	$ 2,944,587,307	$ 143,324,782	4.87%
55					
56	1/ This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory				
57	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the				
58	equity method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian				
59	Montana Pipeline Corp.				
60					
61					
62					
63					
64					Schedule 18A

NOTES TO FINANCIAL STATEMENTS

(1) Nature of Operations

NorthWestern Corporation, doing business as NorthWestern Energy, provides electricity and natural gas to approximately 668,300 customers in Montana, South Dakota and Nebraska. We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have generated and distributed electricity and distributed natural gas in Montana since 2002.

The Financial Statements for the periods included herein have been prepared by NorthWestern Corporation (NorthWestern, we or us), pursuant to the rules and regulations of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. 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, 2011, have been evaluated as to their potential impact to the Financial Statements through the date of issuance, February 15, 2012.

(2) Significant Accounting Policies

Financial Statement Presentation

The financial statements are presented on the basis of the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (GAAP). This report differs from GAAP due to FERC requiring the presentation of subsidiaries on the equity method of accounting, which differs from Statement of Financial Accounting Standards No. 94 "Consolidation of All Majority-Owned Subsidiaries" (SFAS No. 94). SFAS No. 94 requires that all majority-owned subsidiaries be consolidated (see Note 3). The other significant differences consist of the following:

- Earnings per share is not presented;
- Removal and decommissioning costs of generation, transmission and distribution assets are reflected in the Balance Sheets as a component of accumulated depreciation of $251.2 million and $237.5 million as of December 31, 2011 and December 31, 2010, respectively, in accordance with regulatory treatment as compared to regulatory liabilities for GAAP purposes (see Note 5);
- Goodwill is reflected in the Balance Sheets as a utility plant adjustment of $355.1 million as of December 31, 2011 and December 31, 2010, respectively, in accordance with regulatory treatment, as compared to goodwill for GAAP purposes (see Note 6);
- 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, 2011 and December 31, 2010, 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;
- 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 separately presented for GAAP reporting;

- 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 either a net deferred tax asset or liability separately classified as current or non-current; and

- Regulatory assets and liabilities are reflected in the Balance Sheets as non-current items, while current and non-current amounts are separately presented for GAAP.

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 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, asset retirement obligations, uncollectible accounts, our QF obligation, environmental costs, unbilled revenues and actuarially determined benefit costs. 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

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

Cash Equivalents

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

Accounts Receivable, Net

Accounts receivable are net of allowances for uncollectible accounts of $2.9 million and $2.9 million at December 31, 2011 and December 31, 2010, respectively. Unbilled revenues were $71.1 million and $69.4 million at December 31, 2011 and December 31, 2010, respectively.

Inventories

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

	December 31, 2011	December 31, 2010
Fuel stock	$ 7,281	$ 5,994
Materials and supplies	22,408	20,604
Gas stored underground (including the non-current portion reflected in utility plant)	61,939	56,199
	$ 91,628	$ 82,797

Regulation of Utility Operations

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

Our Financial Statements reflect the effects of the different rate making principles followed by the jurisdictions regulating us. The economic effects of regulation can result in regulated companies recording costs that have been, or are expected 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 Statement of Income at that time. This would result in a charge to earnings, net of applicable income taxes, which could be material. In addition, we would determine any impairment to the carrying costs of deregulated plant and inventory assets.

Derivative Financial Instruments

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

Revenues and expenses on contracts that qualify are designated as normal purchases and normal sales and are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but on an accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time, and price is not tied to an unrelated underlying derivative. As part of our regulated electric and gas operations, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the exceptions, the fair value of the related contract would be reflected as an asset or liability and immediately recognized through earnings. See Note 7, Risk Management and Hedging Activities for further discussion of our derivative activity.

Utility Plant

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

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to net interest charges, while the equity component is included in other income. We determine the rate used to compute AFUDC in accordance with a formula established by the FERC. This rate averaged 7.9% and 8.2% for Montana for 2011 and 2010, respectively, and 7.8% and 8.2% for South Dakota for 2011 and 2010, respectively. AFUDC capitalized totaled $3.1 million for the year ended December 31, 2011 and $11.0 million for the year ended December 31, 2010 for Montana and South Dakota combined.

We capitalize preliminary survey and investigation charges related to the determination of the feasibility of transmission or generation utility projects in deferred debits. Upon commencement of construction, these costs are transferred to construction work in process, and upon completion, these costs will be transferred to utility plant. As of December 31, 2011 and 2010, we have capitalized preliminary survey and investigation costs of approximately $21.8 million and $19.0 million, respectively. Capitalized costs are charged to operating expense if the development of the project is no longer feasible.

We may require contributions in aid of construction from customers when we extend service. Amounts used from these contributions to fund capital additions were $2.0 million and $1.9 million for the years ended December 31, 2011 and 2010, 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 three to 40 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 3.3% and 3.2% for 2011 and 2010, respectively.

Depreciation rates include a provision for our share of the estimated costs to decommission three coal-fired generating plants at the end of the useful life of each plant. The annual provision for such costs is included in depreciation expense, while the accumulated provisions are included in accumulated depreciation.

Income Taxes

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

Environmental Costs

We record environmental costs when it is probable we are liable for the costs and we can reasonably estimate the liability. We may defer costs as a regulatory asset if we have prior regulatory authorization for recovery of these costs from customers in future rates. Otherwise, we expense the costs. If an environmental expense is related to facilities we currently use, such as pollution control equipment, then we 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. We treat any future costs of restoring sites where operation may extend indefinitely as a capitalized cost of plant retirement. The depreciation expense levels we can recover in rates include a provision for these estimated removal costs.

Emission Allowances

We have sulfur dioxide (SO2) emission allowances and each allowance permits a generating unit to emit one ton of SO2 during or after a specified year. We have approximately 3,200 excess SO2 emission allowances per year for years 2017 through 2031, however these allowances have no carrying value in our Financial Statements and the market for these years is presently illiquid. These emission allowances are not subject to regulatory jurisdiction. When excess SO2 emission allowances are sold, we reflect the gain in operating income and cash received is reflected as an investing activity.

Accounting Standards Issued

In May 2011, the Financial Accounting Standards Board (FASB) issued accounting guidance related to fair value measurement, which amends current guidance to achieve common fair value measurement and disclosure requirements in GAAP and International Financial Reporting Standards. The amendments generally represent clarification of how the concepts of highest and best use and valuation premise in a fair value measurement are relevant only when measuring the fair value of nonfinancial assets and are not relevant when measuring the fair value of financial assets or of liabilities. In addition, the guidance expanded the disclosures for the unobservable inputs for Level 3 fair value measurements, requiring quantitative information to be disclosed related to (1) the valuation processes used, (2) the sensitivity of the fair value measurement to changes in unobservable inputs and the interrelationships between those unobservable inputs, and (3) use of a nonfinancial asset in a way that differs from the asset's highest and best use. The new guidance will be effective for us beginning January 1, 2012. Other than requiring additional disclosures, we do not anticipate material impacts on our financial statements upon adoption.

In June 2011, the FASB issued an accounting pronouncement that provides new guidance on the presentation of comprehensive income in financial statements eliminating the option to present the components of other comprehensive income as part of the statement of stockholders' equity. It requires an entity to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In December 2011, the FASB issued revised guidance deferring the effective date of the specific requirement to present items that are reclassified out of accumulated other comprehensive income to net income alongside their respective components of net income and other comprehensive income. All other provisions of this guidance, which are to be applied retrospectively, are effective for us beginning January 1, 2012. This guidance concerns disclosure only and will not have a material effect on our financial statements.

In September 2011, the FASB issued new guidance for the testing of goodwill impairment. This guidance provides an entity the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying value. If, after assessing the totality of events or circumstances, an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is unnecessary. However, if an entity concludes otherwise, then it is required to perform the first step of the two-step impairment test currently required by calculating the fair value of the reporting unit and comparing the fair value with the carrying amount of the reporting unit. If the carrying amount of a reporting unit exceeds its fair value, then the entity is required to perform the second step of the goodwill impairment test to measure the amount of the impairment loss, if any. An entity has the option to bypass the qualitative assessment for any reporting unit in any period and proceed directly to performing the first step of the two-step goodwill impairment test. An entity may resume performing the qualitative assessment in any subsequent period. The guidance is effective for annual and interim goodwill impairment tests performed for us beginning January 1, 2012. We are evaluating the impact that the adoption of this standard will have on accounting policies as they relate to goodwill impairment testing in future periods.

Accounting Standards Adopted

There have been no new accounting pronouncements or changes in accounting pronouncements adopted during the year ended December 31, 2011 that are of significance, or potential significance, to us.

(3) **Equity Investments**

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

	December 31, 2011	December 31, 2010
Clark Fork & Blackfoot, LLC	$ -	$ (7,272)
Colstrip Unit 4 Basis Adjustment	(165,531)	(164,952)
Mountain States Transmission Intertie, LLC	18,296	14,616
Natural Gas Funding Trust	2,466	1,661
NorthWestern Services, LLC	(10,049)	(10,401)
NorthWestern Investments, LLC	-	96,369
Risk Partners Assurance, Ltd.	2,815	2,880
Total Investments in Subsidiary Companies	$ (152,003)	$ (67,099)

(4) **Utility Plant**

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

	December 31, 2011	December 31, 2010
Land and improvements	$ 58,635	$ 57,195
Building and improvements	161,349	152,310
Storage, distribution, and transmission	2,394,539	2,271,440
Generation	682,070	706,384
Construction work in process	72,581	34,704
Other equipment	222,973	210,188
	3,592,147	3,432,221
Less accumulated depreciation	(1,516,039)	(1,431,677)
	$ 2,076,108	$ 2,000,544

Plant and equipment under capital lease were $29.8 million and $31.9 million as of December 31, 2011 and December 31, 2010, respectively, which included $29.2 million and $31.1 million as of December 31, 2011 and 2010, respectively, related to a long-term power supply contract with the owners of a natural gas fired peaking plant, which has been accounted for as an obligation under capital lease.

Jointly Owned Electric Generating Plant

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

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

	Big Stone (SD)		Neal #4 (IA)		Coyote (ND)		Colstrip Unit 4 (MT)
December 31, 2011							
Ownership percentages		23.4%		8.7%		10.0%	30.0%
Plant in service	$	58,383	$	29,991	$	45,066	$ 287,462
Accumulated depreciation		39,246		23,046		29,740	59,586
December 31, 2010							
Ownership percentages		23.4%		8.7%		10.0%	30.0%
Plant in service	$	58,283	$	29,897	$	45,050	$ 284,770
Accumulated depreciation		40,201		22,443		30,114	54,402

(5) Asset Retirement Obligations

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 have identified asset retirement obligations (ARO), which are 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.

Our regulated utility operations have, previously recognized removal costs of transmission and distribution assets as a component of depreciation in accordance with regulatory treatment. 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. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. These amounts do not represent legal retirement obligations. As of December 31, 2011 and December 31, 2010, we have recognized accrued removal costs of $235.3 million and $222.1 million, respectively, which are classified as accumulated depreciation. In addition, for our generation properties, we have accrued non-ARO decommissioning costs since the generating units were first put into service in the amount of $15.9 million and $15.4 million as of December 31, 2011 and December 31, 2010, respectively, which are classified as accumulated depreciation.

The liabilities associated with conditional AROs are adjusted on an ongoing basis due to the passage of new laws and regulations and revisions to either the timing or amount of estimates of undiscounted cash flows and estimates of cost escalation factors. Our conditional AROs are primarily related to Department of Transportation requirements to cut, purge and cap retired natural gas pipeline segments. 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 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.

The following table presents the change in our gross conditional ARO (in thousands):

	December 31,	
	2011	2010
Liability at January 1,	$ 7,181	$ 6,688
Accretion expense	493	518
Liabilities incurred	486	76
Liabilities settled	(1,970)	(35)
Revisions to cash flows	102	(66)
Liability at December 31,	$ 6,292	$ 7,181

(6) Utility Plant Adjustments

Utility plant adjustments are not amortized; rather, they are evaluated for impairment at least annually. We evaluated our utility plant adjustments during the fourth quarters of 2011 and 2010 and determined that it was not impaired.

(7) 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 large portion of our electric and natural gas supply requirements within the Montana market. 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, such as fixed-price forward purchase and sales contracts. The objective of these transactions is to fix the price for a portion of anticipated energy purchases to supply our customers. 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 seasonal fluctuations in market prices. While individual contracts may be above or below market value, the overall portfolio approach is intended to provide price stability for consumers; therefore, these commodity costs are included in our cost tracking mechanisms and are recoverable from customers subject to prudence reviews by the applicable state regulatory commissions. We do not maintain a trading portfolio, and our derivative transactions are only used for risk management purposes. In addition, we may use interest rate swaps to manage our interest rate exposures associated with new debt issuances or to manage our exposure to fluctuations in interest rates on variable rate debt.

Accounting for Derivative Instruments

We evaluate new and existing transactions and agreements to determine whether they are derivatives. The permitted accounting treatments include: normal purchase normal sale; 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 normal purchase and normal sale scope exception (NPNS) to most of 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 amounts recorded in the Financial Statements at December 31, 2011 and 2010. 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.

Mark-to-Market Accounting

Certain contracts for the purchase of natural gas associated with our gas utility operations do not qualify for NPNS. These are typically forward purchase contracts for natural gas where we lock in a fixed price, settle the contracts financially and do not take physical delivery of the natural gas. We use the mark-to-market method of accounting for these derivative contracts as we do not elect hedge accounting. Upon settlement of these contracts, associated proceeds or costs are refunded to or collected from our customers consistent with regulatory requirements; therefore, we record a regulatory asset or liability based on changes in market value.

The following table represents the fair value and location of derivative instruments subject to mark-to-market accounting (in thousands). For more information on the determination of fair value see Note 9 - Fair Value Measurements.

		December 31,	
Mark-to-Market Transactions	**Balance Sheet Location**	**2011**	**2010**
Natural gas net derivative liability	Current and Accrued Liabilities	$ 20,312	$ 29,712

The following table represents the net change in fair value for these derivatives (in thousands):

	Unrealized gain (loss) recognized in Regulatory Assets	
	December 31,	
Derivatives Subject to Regulatory Deferral	**2011**	**2010**
Natural gas	$ 9,400	$ (6,051)

Credit Risk

We are exposed to credit risk primarily through buying and selling electricity and natural gas to serve customers. 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 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.

The following table presents, as of December 31, 2011, the aggregate fair value of forward purchase contracts that do not qualify for NPNS that contain credit risk-related contingent features. If the credit risk-related contingent features underlying these agreements were triggered as of December 31, 2011, the collateral posting requirements would be as follows (in thousands):

Contracts with Contingent Feature	Fair Value Liability	Posted Collateral	Contingent Collateral
Credit rating	$ 8,790	$ —	$ 8,790

Interest Rate Swaps Designated as Cash Flow Hedges

If we enter into contracts to hedge the variability of cash flows related to forecasted transactions that qualify as cash flow hedges, the changes in the fair value of such derivative instruments are reported in other comprehensive income. The relationship between the hedging instrument and the hedged item must be documented to include the risk management objective and strategy and, at inception and on an ongoing basis, the effectiveness of the hedge in offsetting the changes in the cash flows of the item being hedged. Gains or losses accumulated in other comprehensive income are reclassified to earnings in the periods in which earnings are affected by the variability of the cash flows of the related hedged item. Any ineffective portion of all hedges would be recognized in current-period earnings. Cash flows related to these contracts are classified in the same category as the transaction being hedged.

We have used interest rate swaps designated as cash flow hedges to manage our interest rate exposures associated with new debt issuances. These swaps were designated as cash-flow hedges with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in AOCI. We reclassify these gains from AOCI into interest on long-term debt during the periods in which the hedged interest payments occur. The following table shows the effect of these derivative instruments on the Financial Statements (in thousands):

Cash Flow Hedges	Amount of Gain Remaining in AOCI as of December 31, 2011	Location of Gain Reclassified from AOCI to Income	Amount of Gain Reclassified from AOCI into Income during the Year Ended December 31, 2011
Interest rate contracts	$ 8,087	Interest on long-term debt	$ 1,188

We expect to reclassify approximately $1.2 million of pre-tax gains on these cash-flow hedges from AOCI into interest on long-term debt during the next twelve months. These gains relate to swaps previously terminated, and we have no current interest rate swaps outstanding.

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(8) Related Party Transactions

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

	December 31, 2011	December 31, 2010
Accounts Receivable from Associated Companies:		
Clark Fork & Blackfoot, LLC	$ -	$ 7,273
Mountain States Transmission Intertie, LLC	2,650	2,096
NorthWestern Investments, LLC	-	157
NorthWestern Services, LLC	2,184	2,892
Risk Partners Assurance, Ltd.	18	18
	$ 4,852	$ 12,436
Accounts Payable to Associated Companies:		
Natural Gas Funding Trust	$ 71	$ 62

(9) 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.

A fair value 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 has been established by the applicable accounting guidance. 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. 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. Normal purchases and sales transactions are not included in the fair values by source table as they are not recorded at fair value. There were no transfers between levels for the periods presented. See Note 7 - Risk Management and Hedging Activities for further discussion.

December 31, 2011	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)		
Other Special Deposits	$ 3,999	$ —	$ —	$ —	$ 3,999
Rabbi trust investments	8,049	—	—	—	8,049
Derivative liability (1)	—	(20,312)	—	—	(20,312)
Total	**$ 12,048**	**$ (20,312)**	**$ —**	**$ —**	**$ (8,264)**
December 31, 2010					
Other Special Deposits	$ 3,330	$ —	$ —	$ —	$ 3,330
Rabbi trust investments	5,495	—	—	—	5,495
Derivative asset (1)	—	1,620	—	—	1,620
Derivative liability (1)	—	(31,332)	—	—	(31,332)
Net derivative position	—	(29,712)	—	—	(29,712)
Total	**$ 8,825**	**$ (29,712)**	**$ —**	**$ —**	**$ (20,887)**

(1) The changes in the fair value of these derivatives are deferred as a regulatory asset or liability until the contracts are settled. Upon settlement, associated proceeds or costs are passed through the applicable cost tracking mechanism to customers.

We present our derivative assets and liabilities on a net basis in the Balance Sheets. The table above disaggregates our net derivative assets and liabilities on a gross contract-by-contract basis as required and classifies each individual asset or liability within the appropriate level in the fair value hierarchy, regardless of whether a particular contract is eligible for netting against other contracts. These gross balances are intended solely to provide information on sources of inputs to fair value and do not represent our actual credit exposure or net economic exposure. Increases and decreases in the gross components presented in each of the levels in this table also do not indicate changes in the level of derivative activities. Rather, the primary factors affecting the gross amounts are commodity prices.

Other special deposits represent amounts held in money market mutual funds. Rabbi trust assets 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. Fair value for the commodity derivatives was determined using internal models based on quoted forward commodity prices. We consider nonperformance risk in our valuation of derivative instruments by analyzing the credit standing of our counterparties and considering any counterparty credit enhancements (e.g., collateral). The fair value measurement of liabilities also reflects the nonperformance risk of the reporting entity, as applicable. Therefore, we have factored the impact of our credit standing as well as any potential credit enhancements into the fair value measurement of both derivative assets and derivative liabilities. Consideration of our own credit risk did not have a material impact on our fair value measurements.

Financial Instruments

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

	December 31, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liabilities:				
Long-term debt (including current portion)	$ 905,049	$ 1,066,681	$ 1,058,025	$ 1,126,336

Notes payable consist of commercial paper and is not included in the table above as carrying value approximates fair value. 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.

(10) Notes Payable

On February 8, 2011, we entered into a commercial paper program under which we may issue unsecured commercial paper notes on a private placement basis up to a maximum aggregate amount outstanding at any time of $250 million to provide an additional financing source for our short-term liquidity needs. The maturities of the commercial paper issuances will vary, but may not exceed 270 days from the date of issue. Commercial paper issuances are supported by available capacity under our unsecured revolving credit facility. See Note 11 - Long-Term Debt, for more information on our unsecured revolving credit facility. As of December 31, 2011, we had $166.9 million in commercial paper outstanding. Commercial paper borrowings and related interest rates for the year ended December 31, 2011 were as follows (dollars in millions):

Amount outstanding as of December 31, 2011	$166.9
Weighted average interest rate as of December 31, 2011	0.57%
Daily average amount outstanding during 2011	$83.4
Weighted average interest rate during 2011	0.42%
Maximum month-end balance during 2011	$166.9

(11) Long-Term Debt

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

	Due	December 31, 2011	December 31, 2010
Unsecured Debt:			
Unsecured Revolving Line of Credit	2016	$ —	$ 153,000
Secured Debt:			
Mortgage bonds—			
South Dakota—6.05%	2018	55,000	55,000
South Dakota—5.01%	2025	64,000	64,000
Montana—6.04%	2016	150,000	150,000
Montana—6.34%	2019	250,000	250,000
Montana—5.71%	2039	55,000	55,000
Montana—5.01%	2025	161,000	161,000
Pollution control obligations—			
Montana—4.65%	2023	170,205	170,205
Other Long Term Debt:			
Discount on Notes and Bonds	—	(156)	(180)
		$ 905,049	$ 1,058,025

Unsecured Revolving Line of Credit

On June 30, 2011, we amended and restated our unsecured revolving credit facility scheduled to expire on June 30, 2012. We extended the term to June 30, 2016, and increases the aggregate principal amount available under the facility by $50 million to $300 million. The facility also has an accordion feature that allows us to increase the size up to $350 million with the consent of the lenders. The amended facility does not amortize and borrowings bear interest based on a credit ratings grid. The 'spread' or 'margin' ranges from 0.88% to 1.75% over the LIBOR. Based on our unsecured credit ratings on the closing date of the agreement, the applicable spread was 1.25%. A total of eight banks participate in the new facility, with no one bank providing more than 17% of the total availability. While no direct borrowings were outstanding as of December 31, 2011, letters of credit of $3.0 million were outstanding. Commitment fees for the unsecured revolving line of credit were $0.7 million and $0.8 million for the years ended December 31, 2011 and 2010, respectively.

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

Secured Debt

First Mortgage Bonds and Pollution Control Obligations

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

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

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt and capital leases, during the next five years are zero in 2012 through 2015 and $150.0 in 2016.

As of December 31, 2011, we are in compliance with our financial debt covenants.

(12) Income Taxes

Our effective tax rate differs from the federal tax rate of 35% primarily due to repairs and state tax bonus depreciation deductions. 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. We recognized federal repairs related tax benefits of $13.4 million and $9.7 million for 2011 and 2010, respectively.

We recognized a state tax bonus depreciation related benefit of $7.6 million for 2011, related to DGGS and other qualifying additions. Based on guidance issued by the IRS, we believe DGGS qualifies for a 50% bonus depreciation deduction in 2011. By comparison, we recognized a state tax bonus depreciation related benefit of $2.3 million in the fourth quarter of 2010, after the Small Business Jobs Act of 2010 was signed into law. This act provides a bonus depreciation deduction ranging from 50%-100% for qualified property acquired or constructed and placed into service during 2010 through 2012. We expect to recognize additional bonus depreciation related benefits through 2012.

In addition, we maintain a valuation allowance against certain state net operating loss (NOL) carryforwards based on our forecast of taxable income and our estimate that a portion of these NOL carryforwards will more likely than not expire before we can use them. During the first six months of 2011, we recognized a $2.4 million favorable state NOL carryforward utilization benefit due to 2010 taxable income being higher than our original estimate.

During 2011, we replaced the fixed asset module of our existing financial system with a new fixed asset software system commonly used in the utility industry and are in process of implementing the income tax module of this software to gain more utility specific functionality. This software is specialized to the utility industry and provides us a more integrated process of reconciling our temporary and permanent tax differences to our financial statements. We expect to complete the implementation of the income tax module during the first quarter of 2012. During the fourth quarter of 2011, we determined the calculation of certain differences associated primarily with plant-related basis differences had been overstated and therefore recognized a cumulative tax benefit adjustment of approximately $3.9 million. The adjustment related to prior periods and is not material to previously issued or current period financial statements.

The IRS issued guidance during the third quarter of 2011 providing a safe harbor method for determining the tax treatment of repairs costs for electric transmission and distribution property. We are evaluating whether or not we want to elect the safe harbor method, which may result in a change in related repairs deductions and unrecognized tax benefits. We expect to complete our evaluation by the third quarter of 2012.

Deferred income taxes relate primarily to the difference between book and tax methods of depreciating property, amortizing tax-deductible goodwill, the difference in the recognition of revenues and expenses for book and tax purposes, certain natural gas and electric costs which are deferred for book purposes but expensed currently for tax purposes, and NOL carry forwards. We have elected under Internal Revenue Code 46(f)(2) to defer investment tax credit benefits and amortize them against expense and customer billing rates over the book life of the underlying plant.

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

	December 31,	
	2011	2010
NOL carryforward	$ 51,941	$ 84,309
Pension / postretirement benefits	41,898	—
QF obligations	20,596	—
Customer advances	16,157	17,247
Property taxes	—	16,037
Environmental liability	9,670	8,425
AMT credit carryforward	6,897	7,067
Unbilled revenue	6,297	10,403
Compensation accruals	7,269	4,267
Reserves and accruals	4,378	(49,047)
Regulatory liability	1,098	550
Other, net	1,862	(1,098)
Valuation allowance	(3,834)	(653)
Deferred Tax Asset	**164,229**	**97,507**
Excess tax depreciation	(273,001)	(185,628)
Goodwill amortization	(96,233)	(77,193)
Flow through depreciation	(49,740)	(34,395)
Regulatory assets	(14,323)	(9,234)
Property taxes	(511)	—
Other, net	—	2,001
Deferred Tax Liability	**(433,808)**	**(304,449)**
Deferred Tax Liability, net	**$ (269,579)**	**$ (206,942)**

A valuation allowance is recorded when a company believes that it will not generate sufficient taxable income of the appropriate character to realize the value of its deferred tax assets. We have a valuation allowance against certain state NOL carryforwards as we do not believe these assets will be realized. For the year ended December 31, 2011, we increased our valuation allowance by approximately $0.3 million against certain state NOL carryforwards as we believe they will expire before we can use them due to decreased forecasts of state taxable income during the carryforward period.

At December 31, 2011 we estimate our total federal NOL carryforward to be approximately $457.2 million. If unused, our federal NOL carryforwards will expire as follows: $180.6 million in 2025; $4.0 million in 2026; $1.0 million in 2027; $95.5 million in 2028; $23.8 million in 2029; $3.2 million in 2030; and $149.1 million in 2031. We estimate our state NOL carryforward as of December 31, 2011 is approximately $429.4 million. If unused, our state NOL carryforwards will expire as follows: $211.5 million in 2012; $3.0 million in 2013; $0.8 million in 2014; $74.0 million in 2015; $18.6 million in 2016; $2.5 million in 2017; and $119.0 million in 2018. We believe it is more likely than not that sufficient taxable income will be generated to utilize these NOL carryforwards except as noted above.

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):

	2011	2010
Unrecognized Tax Benefits at January 1	$ 120,859	$ 122,844
Gross increases - tax positions in prior period	—	—
Gross decreases - tax positions in prior period	(15,774)	(5,707)
Gross increases - tax positions in current period	26,864	6,202
Gross decreases - tax positions in current period	—	(2,480)
Unrecognized Tax Benefits at December 31	$ 131,949	$ 120,859

Our unrecognized tax benefits include approximately $79.2 million and $80.4 million related to tax positions as of December 31, 2011 and 2010, respectively that if recognized, would impact our annual effective tax rate. We do not anticipate total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitations within the next twelve months.

Our policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. During the years ended December 31, 2011 and 2010, we have not recognized expense for interest or penalties, and do not have any amounts accrued at December 31, 2011 and 2010, respectively, for the payment of interest and penalties.

Our federal tax returns from 2000 forward remain subject to examination by the Internal Revenue Service.

(13) Accumulated Other Comprehensive Income

The following table displays the components of AOCI, which is included in proprietary capital on the Balance Sheets (in thousands).

	Net Unrealized Gains on Hedging Instruments	Pension and Other Benefits	Other	Total
Balances December 31, 2009	$ 10,465	$ (1,024)	$ 284	$ 9,725
Reclassification of net gains on hedging instruments from OCI to net income	(1,188)	—	—	(1,188)
Pension and postretirement medical liability adjustment, net of tax of $75	—	(134)	—	(134)
Foreign currency translation	—	—	111	111
Balances December 31, 2010	9,277	(1,158)	395	8,514
Reclassification of net gains on hedging instruments from OCI to net income, net of taxes of $458	(4,302)	—	—	(4,302)
Pension and postretirement medical liability adjustment, net of tax of $155	—	(581)	—	(581)
Foreign currency translation	—	—	25	25
Balance at December 31, 2011	$ 4,975	$ (1,739)	$ 420	$ 3,656

(14) Operating Leases

We lease vehicles, office equipment and facilities under various long-term operating leases. At December 31, 2011 future minimum lease payments for the next five years under non-cancelable lease agreements are as follows (in thousands):

2012	$	1,951
2013		1,021
2014		451
2015		181
2016		67

Lease and rental expense incurred was $2.2 million and $2.0 million for the years ended December 31, 2011 and 2010, respectively.

(15) Employee Benefit Plans

Pension and Other Postretirement Benefit Plans

We sponsor and/or contribute to pension and postretirement health care and life insurance benefit plans for eligible employees, which includes two cash balance pension plans. The plan for our South Dakota and Nebraska employees is referred to as the NorthWestern pension plan, and the plan for our Montana employees is referred to as the NorthWestern Energy pension 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% 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 Plan's funded status is recognized as an asset or liability in our financial statements. See Note 17 - 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 and a statement of the funded status (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2011	2010	2011	2010
Change in Benefit Obligation:				
Obligation at beginning of period	$ 478,790	$ 415,278	$ 35,968	$ 32,347
Service cost	10,199	9,361	437	483
Interest cost	24,394	24,090	1,348	1,803
Plan amendments	—	—	(464)	—
Actuarial loss (gain)	44,586	51,730	(2,056)	4,758
Benefits paid	(21,433)	(21,669)	(2,806)	(3,423)
Benefit obligation at end of period	$ 536,536	$ 478,790	$ 32,427	$ 35,968
Change in Fair Value of Plan Assets:				
Fair value of plan assets at beginning of period	$ 428,152	$ 391,429	$ 17,201	$ 15,298
Return on plan assets	14,218	48,392	340	1,903
Employer contributions	11,700	10,000	767	3,423
Benefits paid	(21,433)	(21,669)	(2,806)	(3,423)
Fair value of plan assets at end of period	$ 432,637	$ 428,152	$ 15,502	$ 17,201
Funded Status	$ (103,899)	$ (50,638)	$ (16,925)	$ (18,767)
Unrecognized net actuarial (gain) loss	—	—	—	—
Unrecognized prior service cost	—	—	—	—
Accrued benefit cost	$ (103,899)	$ (50,638)	$ (16,925)	$ (18,767)
Amounts recognized in the balance sheet consist of:				
Current liability	—	—	(1,075)	(1,078)
Noncurrent liability	(103,899)	(50,638)	(15,850)	(17,689)
Net amount recognized	$ (103,899)	$ (50,638)	$ (16,925)	$ (18,767)
Amounts recognized in regulatory assets consist of:				
Prior service (cost) credit	(1,241)	(1,487)	23,545	25,230
Net actuarial loss	(130,062)	(71,749)	(10,025)	(12,549)
Amounts recognized in AOCI consist of:				
Prior service cost	—	—	(1,604)	(1,755)
Net actuarial gain	—	—	(1,051)	(395)
Total	$ (131,303)	$ (73,236)	$ 10,865	$ 10,531

The total projected benefit obligation and fair value of plan assets for the pension plans with projected benefit obligations in excess of plan assets were as follows (in millions):

	Pension Benefits	
	December 31,	
	2011	2010
Projected benefit obligation	$ 536.5	$ 478.8
Accumulated benefit obligation	533.5	475.7
Fair value of plan assets	432.6	428.2

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,	
	2011	2010	2011	2010
Components of Net Periodic Benefit Cost				
Service cost	$ 10,199	$ 9,361	$ 437	$ 483
Interest cost	24,394	24,090	1,348	1,803
Expected return on plan assets	(30,462)	(29,839)	(1,185)	(1,186)
Amortization of prior service cost (credit)	246	246	(1,998)	(1,952)
Recognized actuarial loss	2,516	140	658	984
Net Periodic Benefit Cost (Credit)	$ 6,893	$ 3,998	$ (740)	$ 132

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.

We estimate amortizations from regulatory assets into net periodic benefit cost during 2012 will be as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
Prior service cost (credit)	$ 246	$ (1,998)
Accumulated gain	7,596	720

Actuarial Assumptions

The measurement dates used to determine pension and other postretirement benefit measurements for the plans are December 31, 2011 and 2010. 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.

For 2011 and 2010, we set the discount rate using a yield curve analysis, which projects benefit cash flows into the future and then discounts those cash flows to the measurement date using a yield curve. This is done by constructing a hypothetical bond portfolio whose cash flow from coupons and maturities matches the year-by-year, projected benefit cash flow from our plans.

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. Considering this information and future expectations for asset returns, we reduced our expected long-term rate of return on assets assumption from 7.25% to 7.00% for 2012.

The health care cost trend rates are established through a review of actual recent cost trends and projected future trends. Our retiree medical trend assumptions are the best estimate of expected inflationary increases to our healthcare costs. Due to the relative size of our retiree population (under 800 members), the assumptions used are based upon both nationally expected trends and our specific expected trends. Our average increase remains consistent with the nationally expected trends.

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

	Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,	
	2011	2010	2011	2010
Discount rate	4.40-4.55%	5.00-5.25%	3.50-4.30%	4.00-5.00%
Expected rate of return on assets	7.25	7.75	7.25	7.75
Long-term rate of increase in compensation levels (nonunion)	3.58	3.58	3.58	3.58
Long-term rate of increase in compensation levels (union)	3.50	3.50	3.50	3.50

The postretirement benefit obligation is calculated assuming that health care costs increased by 9.0% in 2011 and the rate of increase in the per capita cost of covered health care benefits thereafter was assumed to decrease gradually by 0.25% per year to an ultimate trend of 4.5% by the year 2029.

With our 2009 plan amendment to cap the company contribution toward the premium cost, 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, and the Prudent Man Rule of the Employee Retirement Income Security Act of 1974. 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 fully invested as long-term cash holdings reduce long-term rates of return;
- 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 overall funded status;
- Allocation to foreign equities increases the portfolio diversification and thereby decreases portfolio risk while providing for the potential for enhanced long-term returns;
- Active management can reduce portfolio risk and potentially add value through security selection strategies;
- A portion of plan assets should be allocated to passive, indexed management funds to provide for greater diversification and lower cost; and
- It is appropriate to retain more than one investment manager, provided that such managers offer asset class or style diversification.

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

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

	Pension Benefits		Other Benefits	
	December 31,		December 31,	
	2011	2010	2011	2010
Domestic debt securities	40.0%	40.0%	40.0%	40.0%
International debt securities	10.0	10.0	—	—
Domestic equity securities	40.0	40.0	50.0	50.0
International equity securities	10.0	10.0	10.0	10.0

The actual allocation by plan is as follows:

	NorthWestern Energy Pension		NorthWestern Pension		NorthWestern Energy Health and Welfare	
	December 31,		December 31,		December 31,	
	2011	2010	2011	2010	2011	2010
Cash and cash equivalents	—%	—%	—%	—%	2.0%	—%
Domestic debt securities	39.5	37.5	38.4	37.0	39.4	39.1
International debt securities	10.6	10.2	11.2	10.5	—	—
Domestic equity securities	40.3	41.9	40.9	41.8	49.8	50.7
International equity securities	9.6	10.4	9.5	10.7	8.8	10.2
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

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

Our plan assets are primarily invested in common collective trusts (CCTs), which are invested in equity and fixed income securities. In accordance with our investment policy, these pooled investment funds must have an adequate asset base relative to their asset class and be invested in a diversified manner and have a minimum of three years of verified investment performance experience or verified portfolio manager investment experience in a particular investment strategy and have management and oversight by an investment advisor registered with the SEC. Investments in a collective investment vehicle are valued by multiplying the investee company's net asset value per share with the number of units or shares owned at the valuation date. Net asset value per share is determined by the trustee. Investments held by the CCT, including collateral invested for securities on loan, are valued on the basis of valuations furnished by a pricing service approved by the CCT's investment manager, which determines valuations using methods based on quoted closing market prices on national securities exchanges, or at fair value as determined in good faith by the CCT's investment manager if applicable. The funds do not contain any redemption restrictions. The direct holding of NorthWestern Corporation stock is not permitted; however, any holding in a diversified mutual fund or collective investment fund is permitted. In addition, the NorthWestern Corporation pension plan assets also include a participating group annuity contract in the John Hancock General Investment Account, which consists primarily of fixed-income securities. The participating group annuity contract is valued based on discounted cash flows of current yields of similar contracts with comparable duration based on the underlying fixed income investments.

The fair value of our plan assets at December 31, 2011 by asset category are as follows (in thousands):

Asset Category	Total	Quoted Market Prices in Active Markets for Identical Assets Level 1	Significant Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Pension Plan Assets				
Cash and cash equivalents	$ 313	$ —	$ 313	$ —
Equity securities: (1)				
US small/mid cap growth	14,922	—	14,922	—
US small/mid cap value	15,290	—	15,290	—
US large cap growth	43,786	—	43,786	—
US large cap value	46,248	—	46,248	—
US large cap passive	54,477	—	54,477	—
Non-US core	41,270	—	41,270	—
Fixed income securities:(2)				
US core opportunistic	80,702	—	80,702	—
US passive	41,630	—	41,630	—
Long duration	6,998	—	6,998	—
Long duration investment grade	13,058	—	13,058	—
Long duration passive	5,441	—	5,441	—
Non-US passive	46,023	—	46,023	—
Active long corporate	12,730	—	12,730	—
Participating group annuity contract	9,749	—	9,749	—
	$ 432,637	$ —	$ 432,637	$ —
Other Postretirement Benefit Plan Assets				
Cash and cash equivalents	$ 270	$ —	$ 270	$ —
Equity securities: (1)				
US small/mid cap growth	643	—	643	—
US small/mid cap value	636	—	636	—
S&P 500 index	5,671	—	5,671	—
US large cap growth	180	—	180	—
US large cap value	192	—	192	—
US large cap passive	227	—	227	—
Non-US core	1,379	—	1,379	—
Fixed income securities: (2)				
Passive bond market	1,156	—	1,156	—
US core opportunistic	4,603	—	4,603	—
US passive	185	—	185	—
Long duration	25	—	25	—
Long duration investment grade	61	—	61	—
Long duration passive	26	—	26	—
Non-US passive	191	—	191	—
Active long corporate	57	—	57	—
	$ 15,502	$ —	$ 15,502	$ —

The fair value of our plan assets at December 31, 2010 by asset category are as follows (in thousands):

Asset Category	Total	Quoted Market Prices in Active Markets for Identical Assets Level 1	Significant Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Pension Plan Assets				
Cash and cash equivalents	$ 47	$ —	$ 47	$ —
Equity securities: (1)				
US small/mid cap growth	15,768	—	15,768	—
US small/mid cap value	16,124	—	16,124	—
US large cap growth	48,012	—	48,012	—
US large cap value	46,668	—	46,668	—
US large cap passive	52,688	—	52,688	—
Non-US core	44,751	—	44,751	—
Fixed income securities:(2)				
US core opportunistic	65,449	—	65,449	—
US passive	35,596	—	35,596	—
Long duration	49,083	—	49,083	—
Non-US passive	43,653	—	43,653	—
Participating group annuity contract	10,313	—	10,313	—
	$ 428,152	**$ —**	**$ 428,152**	**$ —**
Other Postretirement Benefit Plan Assets				
Cash and cash equivalents	$ 4	—	$ 4	—
Equity securities: (1)				
US small/mid cap growth	806	—	806	—
US small/mid cap value	829	—	829	—
S&P 500 index	6,029	—	6,029	—
US large cap growth	346	—	346	—
US large cap value	334	—	334	—
US large cap passive	378	—	378	—
Non-US core	1,758	—	1,758	—
Fixed income securities: (2)				
Passive bond market	1,073	—	1,073	—
US core opportunistic	4,683	—	4,683	—
US passive	272	—	272	—
Long duration	377	—	377	—
Non-US passive	312	—	312	—
	$ 17,201	$ —	$ 17,201	$ —

(1) This category consists of active and passive managed equity funds, which are invested in multiple strategies to diversify risks and reduce volatility.

(2) This category consists of investment grade bonds of issuers from diverse industries, debt securities issued by international, national, state and local governments, and asset-backed securities. This includes both active and passive managed funds.

For further discussion of the three levels of the fair value hierarchy see Note 9 - Fair Value Measurements.

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), which was signed into law on December 23, 2008, 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.

Based on the assumptions allowed under the PPA, WRERA, Treasury guidance and IRS guidance, we estimate that we will not have a minimum annual required contribution for 2012. We do expect to contribute approximately $11.7 million to our pension plans during 2012. Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact these funding requirements.

Due to the regulatory treatment of pension costs in Montana, expense is calculated using the average of our actual and estimated funding amounts from 2005 through 2012, therefore changes in our funding estimates creates increased volatility to earnings. Annual contributions to each of the pension plans are as follows (in thousands):

	2011	2010
NorthWestern Energy Pension Plan (MT)	$ 10,500	$ 9,000
NorthWestern Pension Plan (SD)	1,200	1,000
	$ 11,700	$ 10,000

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

	Pension Benefits	Other Postretirement Benefits
2012	$ 23,858	$ 3,664
2013	25,357	3,662
2014	26,334	3,581
2015	27,755	3,495
2016	29,330	3,334
2017-2021	165,725	12,470

Defined Contribution Plan

Our defined contribution plan permits employees to defer receipt of compensation as provided in Section 401(k) of the Internal Revenue Code. Under the plan, employees may elect to direct a percentage of their gross compensation to be contributed to the plan. We contribute various percentage amounts of the employee's gross compensation contributed to the plan. Matching contributions for the year ended December 31, 2011 and 2010 were $6.7 million and $6.0 million, respectively.

(16) Stock-Based Compensation

We grant stock-based awards through our 2005 Long-Term Incentive Plan (LTIP), which includes restricted stock awards and performance share awards. As of December 31, 2011, there were 1,006,952 shares of common stock remaining available for grants. The remaining vesting period for awards previously granted ranges from one to five years if the service and/or performance requirements are met. Nonvested shares do not receive dividend distributions. The long-term incentive plan provides for accelerated vesting in the event of a change in control.

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

Restricted Stock and Performance Share Awards

Performance share awards were granted under the 2005 LTIP during 2011 and 2010. With these awards, shares will vest if, at the end of the three-year performance period, we have achieved certain performance goals and the individual remains employed by us. The exact number of shares issued will vary from 0% to 200% of the target award, depending on actual company performance relative to the performance goals. These awards contain both a market and performance based component. The performance goals for these awards are independent of each other and equally weighted, and are based on two metrics: (i) cumulative net income and return on equity growth; and (ii) total shareholder return (TSR) relative to a peer group.

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

	2011	2010
Risk-free interest rate	1.40%	1.38%
Expected life, in years	3	3
Expected volatility	25.6% to 47.0%	27.2% to 51.6%
Dividend yield	4.9%	5.4%

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

A summary of nonvested shares as of December 31, 2011, and changes during the year ended December 31, 2011 are as follows:

	Performance Share Awards		Restricted Stock Awards	
	Shares	Weighted-Average Grant-Date Fair Value	Shares	Weighted-Average Grant-Date Fair Value
Beginning nonvested grants	179,939	$ 20.41	15,888	$ 30.84
Granted	108,679	20.48	2,000	29.34
Vested	(73,397)	21.48	(15,888)	30.32
Forfeited	(10,508)	20.30	—	—
Remaining nonvested grants	204,713	$ 20.07	2,000	$ 25.44

We recognized compensation expense of $2.1 million and $1.6 million for the years ended December 31, 2011 and 2010, respectively, and a related income tax benefit of $1.6 million and $0.2 million for the years ended December 31, 2011 and 2010, respectively. As of December 31, 2011, we had $2.0 million of unrecognized compensation cost related to the nonvested portion of outstanding awards, which is reflected as other paid-in capital in our Balance Sheets. The cost is expected to be recognized over a weighted-average period of 1.7 years. The total fair value of shares vested was $2.9 million and $1.4 million for the years ended December 31, 2011and 2010, respectively.

Retirement/Retention Restricted Share Awards

In December 2011, an executive retirement / retention program was established that provides for the annual grant of restricted share units. These awards are subject to a five-year performance and vesting period. The performance measure for these awards requires net income for the calendar year of at least three of the five full calendar years during the performance period to exceed net income for the calendar year the awards are granted. Once vested, the awards will be paid out in shares of common stock in five equal annual installments after a recipient has separated from service. The fair value of these awards is measured based upon the closing market price of our common stock as of the date of grant less the present value of expected dividends. There were 8,596 restricted share awards granted during 2011, with a weighted-average grant date fair value of $28.00.

Director's Deferred Compensation

Nonemployee directors may elect to defer up to 100% of any qualified compensation that would be otherwise payable to him or her, subject to compliance with our 2005 Deferred Compensation Plan for Nonemployee Directors and Section 409A of the Internal Revenue Code. The deferred compensation may be invested in NorthWestern stock or in designated investment funds. Compensation deferred in a particular month is recorded as a deferred stock unit (DSU) on the first of the following month based on the closing price of NorthWestern stock or the designated investment fund. The DSUs are marked-to-market on a quarterly basis with an adjustment to director's compensation expense. Based on the election of the nonemployee director, following separation from service on the Board, other than on account of death, he or she shall be paid a distribution either in a lump sum or in approximately equal installments over a designated number of years (not to exceed 10 years). During the years ended December 31, 2011 and 2010, DSUs issued to members of our Board totaled 31,032 and 36,831, respectively. Total compensation expense attributable to the DSUs during the years ended December 31, 2011 and 2010 was approximately $2.3 million and $1.3 million, respectively.

(17) Regulatory Assets and Liabilities

We prepare our financial statements in accordance with the provisions of ASC 980, as discussed in Note 2 - Significant Accounting Policies. Pursuant to this guidance, certain expenses and credits, normally reflected in income as incurred, are deferred and recognized when included in rates and recovered from or refunded to the customers. Regulatory assets and liabilities are recorded based on management's assessment that it is probable that a cost will be recovered or that an obligation has been incurred. Accordingly, we have recorded the following major classifications of regulatory assets and liabilities that will be recognized in expenses and revenues in future periods when the matching revenues are collected or refunded. These regulatory items have corresponding assets and liabilities that will be paid for or refunded in future periods. Because these costs are recovered as paid, they do not earn a return. We have specific orders to cover approximately 98% of our regulatory assets and 100% of our regulatory liabilities.

	Note Reference	Remaining Amortization Period	December 31, 2011	December 31, 2010
			(in thousands)	
Pension	13	Undetermined	$ 128,844	$ 94,500
Postretirement benefits	13	Undetermined	6,434	9,104
Distribution infrastructure projects	16	6 Years	4,883	—
Environmental clean-up	18	Various	16,998	15,438
Energy supply derivatives	6	1 Year	20,312	29,721
Income taxes	10	Plant Lives	124,967	71,374
Other	—	Various	27,437	29,460
Total regulatory assets			**$ 329,875**	**$ 249,597**
Gas storage sales		28 Years	11,672	12,092
Unbilled revenue		1 Year	10,597	8,203
Environmental clean-up		1 Year	1,733	467
State & local taxes & fees		1 Year	2,578	805
Other		Various	1,772	1,198
Total regulatory liabilities			**$ 28,352**	**$ 22,765**

Pension and Postretirement Benefits

We recognize the unfunded portion of plan benefit obligations in the Balance Sheets, which is remeasured at each year end, with a corresponding adjustment to regulatory assets/liabilities as the costs associated with these plans are recovered in rates. The portion of the regulatory asset related to our Montana pension plan will amortize as cash funding amounts exceed accrual expense under GAAP. The South Dakota Public Utilities Commission (SDPUC) allows recovery of pension costs on an accrual basis. The Montana Public Service Commission (MPSC) allows recovery of postretirement benefit costs on an accrual basis.

Montana Distribution System Infrastructure Project (DSIP)

In March 2011, we requested and received MPSC approval of an accounting order to defer certain incremental operating and maintenance expenses. The accounting order allows us to defer up to $16.9 million of expenses incurred during 2011 and 2012 as a regulatory asset and amortize these expenses associated with the phase-in portion of the DSIP over five years beginning in 2013. See Note 18 - Regulatory Matters, for further information regarding this item.

Environmental clean-up

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

Income Taxes

Tax assets primarily reflect the effects of plant related temporary differences such as flow-through of depreciation, repairs related deductions, removal costs, capitalized interest and contributions in aid of construction that we will recover or refund in future rates. We amortize these amounts as temporary differences reverse.

Unbilled Revenue

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

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

Under Montana law, we are allowed to track the increases in the actual level of state and local taxes and fees and recover these amounts. The MPSC has authorized recovery of approximately 60% of the estimated increase in our local taxes and fees (primarily property taxes) as compared to the related amount included in rates during our last general rate case.

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.

(18) Regulatory Matters

Dave Gates Generating Station at Mill Creek (DGGS)

Our regulatory filings seeking approval of rates related to DGGS are based on approximately 80% of our revenues related to the facility being subject to the jurisdiction of the Montana Public Service Commission (MPSC) and approximately 20% being subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). Intervenors in both jurisdictions have been challenging our proposed allocation methodology. In March 2012, the MPSC issued a final order in review of our previously submitted required compliance filing. The MPSC found that the total project costs incurred were prudent and established final rates. As a result of the lower than estimated construction costs and impact of the flow-through of accelerated state tax depreciation, the final rates are lower than our 2011 interim rates. The amount we over collected of approximately $6.2 million will be refunded to customers over a one-year period beginning in May 2012. The MPSC's final order approves using our proposed cost allocation methodology on a temporary basis, and requires us to complete a study of the relative contribution of retail and wholesale customers to regulation capacity needs. The results of this study may be used in determining future cost allocations between retail and wholesale customers.

Based on the MPSC's final order we recognized revenue of approximately $2.7 million during the three months ended March 31, 2012 that we had previously deferred pending outcome of the allocation uncertainty.

A FERC hearing regarding DGGS rates is scheduled for June 11, 2012 and an initial decision is scheduled to be issued on September 24, 2012. We continue to bill customers interim rates which have been effective since January 1, 2011. These interim rates are subject to refund plus interest pending final resolution at FERC.

Through March 31, 2012, we have deferred revenue of approximately $1.9 million associated with DGGS due to lower than estimated construction costs, our current estimate of operating expenses as compared to amounts included in our interim rate requests, and uncertainty related to the FERC's ultimate treatment of our cost allocation methodology. This uncertainty could result in an inability to fully recover our costs, as well as requiring us to refund more interim revenues than our current estimate.

Wind Generation

In February 2012, the MPSC approved our application for pre-approval to purchase a wind project in Judith Basin County in Montana to be developed and constructed by Spion Kop Wind, LLC, a wholly-owned subsidiary of Compass Wind, LLC (Compass) that would provide approximately 40 MW of capacity, with an estimated cost for the total project of approximately $86 million. The approval includes an authorized rate of return of 7.4%, which was computed using a 10% return on equity, a 5% estimated cost of debt and a capital structure consisting of 52% debt and 48% equity. The approval also includes a performance condition that would reduce our revenue requirement if the average production failed to meet a minimum threshold for the first three years. We do not believe this performance condition will have a significant impact. Construction has commenced and commercial operation is projected to begin by December 31, 2012. Both the energy and associated renewable energy credits would be placed into our electric supply portfolio to meet future customer loads and renewable portfolio standards obligations.

Battle Creek Filing

In March 2012, we submitted an application with the MPSC to place our majority interest in the Battle Creek Field natural gas production fields and gathering system acquired in 2010 in regulated natural gas rate base. The application reflects a joint stipulation between us and the Montana Consumer Counsel (MCC) of a 10% return on equity and a capital structure consisting of 52% debt and 48% equity. Since November 2010, the cost of service for the natural gas produced, including a return on our investment has been included in our natural gas supply tracker on an interim basis. Pending MPSC approval, the corresponding amounts included in the natural gas supply tracker are subject to refund and through March 31, 2012, we have deferred revenue of approximately $1.8 million based on the difference between our cost of service and current natural gas market prices.

Montana Electric and Natural Gas Tracker Filings

Each year we submit electric and natural gas tracker filings for recovery of supply costs for the 12-month period ended June 30 and for the projected supply costs for the next 12-month period. The MPSC reviews such filings and makes its cost recovery determination based on whether or not our electric and natural gas supply procurement activities were prudent. During March 2012, the MPSC found that our natural gas supply costs through the period ended June 30, 2011 were prudently incurred. During April 2012, the MPSC found that our electric supply costs through the period ended June 30, 2011 were prudently incurred.

(19) Commitments and Contingencies

Qualifying Facilities Liability

Our QF liability primarily consists of unrecoverable costs associated with three contracts covered under the PURPA. The QFs require us to purchase minimum amounts of energy at prices ranging from $78 to $136 per MWH through 2029. Our estimated gross contractual obligation related to the QFs is approximately $1.3 billion through 2029. A portion of the costs incurred to purchase this energy is recoverable through rates, totaling approximately $1.0 billion through 2029. The present value of the remaining QF liability is recorded in our Balance Sheets. The following summarizes the change in the QF liability (in thousands):

	December 31, 2011	December 31, 2010
Beginning QF liability	$ 177,322	$ 165,839
Unrecovered amount	(6,043)	(1,198)
Interest expense	12,908	12,681
Ending QF liability	$ 184,187	$ 177,322

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

	Gross Obligation	Recoverable Amounts	Net
2012	$ 67,111	$ 54,904	$ 12,207
2013	69,816	55,462	14,354
2014	72,354	56,025	16,329
2015	74,135	56,598	17,537
2016	75,945	57,188	18,757
Thereafter	909,322	683,404	225,918
Total	$ 1,268,683	$ 963,581	$ 305,102

Long Term Supply and Capacity Purchase Obligations

We have entered into various commitments, largely purchased power, coal and natural gas supply and natural gas transportation contracts. These commitments range from 20 to 25 years. Costs incurred under these contracts were approximately $390.3 million and $417.28 million for the years ended December 31, 2011 and 2010, respectively. As of December 31, 2011, our commitments under these contracts are $298.9 million in 2012, $262.9 million in 2013, $191.3 million in 2014, $116.9 million in 2015, $117.6 million in 2016, and $819.1 million thereafter. These commitments are not reflected in our Financial Statements.

Environmental Liabilities

The operation of electric generating, transmission and distribution facilities, and gas gathering, 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 and wildlife. We monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are promulgated, 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, the majority of our environmental reserve relates to the remediation of former manufactured gas plant sites owned by us. 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 become fixed and reliably determinable.

Our liability for environmental remediation obligations is estimated to range between $28.3 to $37.5 million, primarily for manufactured gas plants discussed below. As of December 31, 2011, we have a reserve of approximately $31.4 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. Over time, as specific laws are implemented and we gain experience in operating under them, a portion of the costs related to such laws will become determinable, and we may seek authorization to recover such costs in rates or seek insurance reimbursement as applicable; therefore, although we cannot guarantee regulatory recovery, we do not expect these costs to have a material effect on our financial position or ongoing operations.

Manufactured Gas Plants - Approximately $26.0 million of our environmental reserve accrual is related to manufactured gas plants. A formerly operated manufactured gas plant located in Aberdeen, South Dakota, has been identified on the Federal Comprehensive Environmental Response, Compensation, and Liability Information System list as contaminated with coal tar residue. We are currently investigating, characterizing, and initiating remedial actions at the Aberdeen site pursuant to work plans approved by the South Dakota Department of Environment and Natural Resources. Our current reserve for remediation costs at this site is approximately $12.0 million, and we estimate that approximately $9.2 million of this amount will be incurred during the next five years.

We also own sites in North Platte, Kearney and Grand Island, Nebraska on which former manufactured gas facilities were located. During 2005, the Nebraska Department of Environmental Quality (NDEQ) conducted Phase II investigations of soil and groundwater at our Kearney and Grand Island sites. During 2006, the NDEQ released to us the Phase II Limited Subsurface Assessments performed by the NDEQ's environmental consulting firm for Kearney and Grand Island. In February 2011, NDEQ completed an Abbreviated Preliminary Assessment and Site Investigation Report for Grand Island, which recommended additional ground water testing. Our reserve estimate includes assumptions for additional ground water testing. At present, we cannot determine with a reasonable degree of certainty the nature and timing of any risk-based remedial action at our Nebraska locations.

In addition, we own or have responsibility for sites in Butte, Missoula and Helena, Montana on which former manufactured gas plants were located. An investigation conducted at the Missoula site did not require remediation activities, but required preparation of a groundwater monitoring plan. The Butte and Helena sites were placed into the Montana Department of Environmental Quality (MDEQ) voluntary remediation program for cleanup due to excess regulated pollutants in the groundwater. Voluntary soil and coal tar removals were conducted in the past at the Butte and Helena locations in accordance with MDEQ requirements. We have conducted additional groundwater monitoring at the Butte and Missoula sites and, at this time, we believe natural attenuation should address the conditions at these sites; however, additional groundwater monitoring will be necessary. Monitoring of groundwater at the Helena site is ongoing and will be necessary for an extended time. At this time, we cannot estimate with a reasonable degree of certainty the nature and timing of risk-based remedial action at the Helena site or if any additional actions beyond monitored natural attenuation will be required.

Global Climate Change - There are national and international efforts to adopt measures related to global climate change and the contribution of emissions of GHG including, most significantly, carbon dioxide. These efforts include legislative proposals and EPA regulations at the federal level, actions at the state level, and private party litigation relating to GHG emissions. Coal-fired plants have come under particular scrutiny due to their level of GHG emissions. We have joint ownership interests in four electric generating plants, all of which are coal fired and operated by other companies. We have undivided interests in these facilities and are responsible for our proportionate share of the capital and operating costs while being entitled to our proportionate share of the power generated.

While numerous bills have been introduced that address climate change from different perspectives, including through direct regulation of GHG emissions, the establishment of cap and trade programs and the establishment of Federal renewable portfolio standards, Congress has not passed any federal climate change legislation and we cannot predict when or if Congress will pass such legislation and in what form. In the absence of such legislation, the EPA is regulating GHG emissions under its existing authority pursuant to the Clean Air Act. For example, the EPA promulgated regulations requiring major sources in the United States to begin collecting and reporting information regarding their GHG emissions. Certain of our facilities began collecting such data on January 1, 2010 and submitted their first annual reports to the EPA in September 2011. For petroleum and natural gas facilities, data collection began on January 1, 2011, with the first annual report due on March 31, 2012.

In June 2010, the EPA also adopted rules that make certain "stationary sources," such as power plants, subject to permitting requirements for their GHG emissions. Sources that emit more than 100,000 tons of greenhouse gases per year are now required to obtain permits for those emissions even if they are not otherwise required to obtain a new or modified permit. Such permits may require the installation and operation of "best available control technology" to control GHG emissions.

Also, in December 2010, the EPA entered into an agreement to settle litigation brought by states and environmental groups whereby the EPA agreed to issue New Source Performance Standards for GHG emissions from certain new and modified electric generating units and "emissions guidelines" for existing units over the next two years. Pursuant to this settlement agreement, the EPA agreed to issue proposed rules in 2011. The EPA, however, did not meet this deadline for issuing the proposed rules.

On June 20, 2011, the U.S. Supreme Court issued a decision that bars state and private parties from bringing federal common law nuisance actions against electrical utility companies based on their alleged contribution to climate change. The Supreme Court's decision did not, however, address state law claims. This decision is expected to affect other pending federal climate change litigation. Although we are not a defendant in any of these proceedings, additional litigation in federal and state courts over these issues is continuing.

Physical impacts of climate change may present potential risks for severe weather, such as floods and tornadoes, in the locations where we operate or have interests. Furthermore, requirements to reduce GHG emissions from stationary sources could cause us to incur material costs of compliance, increase our costs of procuring electricity in the marketplace or curtail the demand for fossil fuels such as oil and gas. In addition, we believe future legislation and regulations that affect GHG emissions from power plants are likely, although technology to efficiently capture, remove and/or sequester such emissions may not be available within a timeframe consistent with the implementation of such requirements. We cannot predict with any certainty whether these risks will have a material impact on our operations.

Coal Combustion Residuals (CCRs) - In June 2010, the EPA proposed two approaches to regulating the disposal and management of CCRs under the Resource Conservation and Recovery Act (RCRA). CCRs include fly ash, bottom ash and scrubber wastes. Under one approach, the EPA would regulate CCRs as a hazardous waste under Subtitle C of RCRA. This approach would have significant impacts on coal-fired plants, and would require plants to retrofit their operations to comply with hazardous waste requirements from the generation of CCRs and associated waste waters through transportation and disposal. This could also have a negative impact on the beneficial use of CCRs and the current markets associated with such use. The second approach would regulate CCRs as a solid waste under Subtitle D of RCRA. This approach would only affect disposal, most significantly any wet disposal, of CCRs. EPA has not yet issued a final CCR rule. We cannot predict at this time the final requirements of any CCR regulations and what impact, if any, they would have on us, but the costs of complying with any such requirements could be significant.

Water Intakes - Section 316(b) of the Federal Clean Water Act requires that the location, design, construction and capacity of any cooling water intake structure reflect the "best available technology" for minimizing environmental impacts. Permits required for existing facilities are to be developed by the individual states using their best professional judgment until the EPA takes action to address several court decisions that rejected portions of previous rules and confirmed that EPA has discretion to consider costs relative to benefits in developing cooling water intake structure regulations. In March 2011, EPA proposed a rule to address impingement and entrainment of aquatic organisms at existing cooling water intake structures. EPA has not yet issued a final rule; however, it is under a consent decree to do so by July 2012. When a final rule is issued and implemented, additional capital and/or increased operating costs may be incurred. The costs of complying with any such final water intake standards are not currently determinable, but could be significant.

Clean Air Act Rules and Associated Emission Control Equipment Expenditures

EPA has proposed or issued a number of rules under different provisions of the Clean Air Act that could require the installation of emission control equipment at the generation plants where we have joint ownership.

The Clean Air Visibility Rule was issued by the EPA in June 2005, to address regional haze in national parks and wilderness areas across the United States. The Clean Air Visibility Rule requires the installation and operation of Best Available Retrofit Technology (BART) to achieve emissions reductions from designated sources (including certain electric generating units) that are deemed to cause or contribute to visibility impairment in such 'Class I' areas.

In December 2011, the EPA issued a final rule relating to Mercury and Air Toxics Standards (MATS), which was formerly the proposed Maximum Achievable Control Technology standards for hazardous air pollutant emissions from new and existing electric generating units. Among other things, these MATS standards set stringent emission limits for acid gases, mercury, and other hazardous air pollutants. Facilities that are subject to the MATS must come into compliance within three years after the effective date of the rule (or by 2015) unless a one year extension is granted on a case-by-case basis. Numerous challenges to the MATS standards have been filed with the EPA and in Federal court and we cannot predict the outcome of such challenges. In the meantime, we are assessing the impact of the new MATS standards on our facilities, including the costs of compliance. As discussed below, we expect that these costs could be significant.

On July 7, 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) to reduce emissions from electric generating units that interfere with the ability of downwind states to achieve ambient air quality standards. Under the CSAPR, significant reductions in emissions of nitrogen oxide (NOx) and SO2 emissions reductions would be required beginning in 2012. The CSAPR was to become effective on January 1, 2012; however, on December 30, 2011, a Federal court ordered that CSAPR be stayed until a hearing could be held on the numerous legal challenges brought against EPA regarding the rule. It is currently expected that a hearing will be held in April 2012 and a decision on CSAPR will be issued sometime thereafter. The Federal court that stayed the CSAPR ordered that the Clean Air Interstate Rule remain in effect while the CSAPR is stayed. Regardless of the outcome of the stay hearing, CSAPR only applies to power plants within the eastern half of the United States, and, thus is only applicable to one plant in which we have an ownership interest, the Neal 4 plant located in Iowa. We do not expect CSAPR to affect any of the other plants in which we have an ownership interest.

We have joint ownership in generation plants located in South Dakota, North Dakota, Iowa and Montana that are or may become subject to various regulations that have been issued or proposed under the Clean Air Act, as discussed below.

South Dakota. The South Dakota Department of Environment and Natural Resources (DENR) determined that the Big Stone Plant, of which we have a 23.4% ownership, is subject to the Regional Haze Rule. South Dakota DENR submitted its revised State Implementation Plan (SIP) and associated implementation rules to the EPA on September 19, 2011. Under the SIP, the Big Stone plant must install and operate a new BART compliant air quality control system (AQCS) to reduce sulfur dioxide, nitrogen oxides, and particulate emissions as expeditiously as practicable, but no later than five years after the EPA's approval of South Dakota's SIP. We expect EPA approval of the SIP in the first half of 2012, however such approval cannot be guaranteed and we cannot predict the timing of any such approval with certainty. We will not incur any significant costs until the EPA approves the SIP or issues a federal implementation plan in its place. Although studies and evaluations are continuing, the current project cost for the AQCS is estimated to be approximately $490 million (our share is 23.4%).

Our incremental capital expenditure projections include amounts related to our share of the BART technologies at Big Stone based on current estimates. We could, however, face additional capital or financing costs. We will seek to recover any such costs through the regulatory process. The SDPUC has historically allowed timely recovery of the costs of environmental improvements; however, there is no precedent on a project of this size.

Based on the finalized MATS standards, it appears that Big Stone would meet the requirements by installing the AQCS system and using mercury control technology such as activated carbon injection. Mercury emissions monitoring equipment is already installed at Big Stone, but its operation has been put on hold pending additional regulatory direction.

North Dakota. The North Dakota Regional Haze SIP requires the Coyote generating facility, of which we have 10.0% ownership, to reduce its NOx emissions. On February 23, 2010, the North Dakota Department of Health (NDDOH) issued a construction permit to Coyote Station requiring installation of control equipment to limit its NOx emissions to 0.5 pounds per million Btu as calculated on a 12-month rolling average basis. The control equipment must be installed by July 1, 2018 and compliance with the limit must begin on July 1, 2019. Subsequent to issuance of the construction permit, the NDDOH entered into further negotiations with the EPA on regional haze plan implementation. As part of those negotiations, Coyote agreed to accept a NOx emission limit of 0.5 pounds per million Btu as calculated on a 30-day rolling average basis, including periods of start-up and shutdown, beginning on July 1, 2018. The current estimate of the total cost of the project is approximately $6 million (our share is 10.0%). The EPA is under a consent decree to take final action on North Dakota's revised regional haze implementation plan in the first half of 2012.

Iowa. The Neal 4 generating facility, of which we have an 8.7% ownership, is installing a scrubber, a baghouse and a selective non-catalytic reduction system to comply with national ambient air quality standards, the proposed CSAPR and MATS standards. These improvements are also expected to result in compliance with the regional haze provisions of the Clean Air Act. Capital expenditures for such equipment are currently estimated to be approximately $270 million (our share is 8.7%). The plant began incurring such costs in 2011 and the costs will be spread over the next three years. Our incremental capital expenditure projections include amounts related to our share of the emission control equipment at Neal 4 based on current estimates. We could, however, face additional capital or financing costs. We will seek to recover any such costs through the regulatory process.

Montana. Colstrip Unit 4, a coal fired generating facility in which we have a 30% interest, is currently controlling emissions of mercury under regulations issued by the State of Montana, which is more strict than the Federal standard, and has been since January 2010. The owners do not believe additional equipment will be necessary to meet the MATS standards for mercury. Additionally, the Colstrip facility anticipates meeting the expected MATS for acid gases without additional costs. However, Colstrip may have to install additional controls to further reduce particulate matter to meet MATS using particulate matter as a surrogate for non-mercury metals. The Colstrip owners are continuing to determine what may be required and while it is not possible to predict costs at this time, the costs of additional controls could be significant. In November 2010, Colstrip Unit 4 received a request from the EPA to provide further analysis regarding why Colstrip Unit 4 is not a BART eligible unit under the regional haze rule. The plant operator completed a high level analysis of various control options to reduce emissions of SO2 and particulate matter and submitted that analysis to EPA in January 2011. The analysis shows that these units are well controlled, any incremental reductions would not be cost effective and further analysis is not warranted. The plant operator also concluded that further analysis for NOx was not justified as controls at Colstrip Unit 4 were installed and the EPA previously agreed that such controls would satisfy BART for NOx control. The plant operator informed us that the EPA verbally indicated that it does not agree with all of the plant operator's conclusions and will be requesting additional information. The EPA is under a consent decree to take final action on Montana's regional haze implementation plan no later than June 29, 2012. The costs of complying with any final regional haze standards in Montana are not currently determinable, but could be significant.

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

Colstrip Energy Limited Partnership

In December 2006 and June 2007, the MPSC issued orders relating to certain QF long-term rates for the period July 1, 2003, through June 30, 2006. Colstrip Energy Limited Partnership (CELP) is a QF with which we have a power purchase agreement through June 2024. Under the terms of the power purchase agreement with CELP, energy and capacity rates were fixed through June 30, 2004 (with a small portion to be set by the MPSC's determination of rates in the annual avoided cost filing), and beginning July 1, 2004 through the end of the contract, energy and capacity rates are to be determined each year pursuant to a formula, with the rates to be used in that formula derived from the annual MPSC QF rate review.

CELP initially appealed the MPSC's orders and then, in July 2007, filed a complaint against NorthWestern and the MPSC in Montana district court, which contested the MPSC's orders. CELP disputed inputs into the underlying rates used in the formula, which initially are calculated by us and reviewed by the MPSC on an annual basis, to calculate energy and capacity payments for the contract years 2004-2005 and 2005-2006. CELP claimed that NorthWestern breached the power purchase agreement causing damages, which

CELP asserted to be approximately $23 million for contract years 2004-2005 and 2005-2006. The parties stipulated that NorthWestern would not implement the final derived rates resulting from the MPSC orders, pending an ultimate decision on CELP's complaint.

On June 30, 2008, the Montana district court granted both a motion by the MPSC to bifurcate, having the effect of separating the issues between contract/tort claims against us and the administrative appeal of the MPSC's orders and a motion by us to refer the claims against us to arbitration. The order also stayed the appellate decision pending a decision in the arbitration proceedings. Arbitration was held in June 2009 and the arbitration panel entered its interim award in August 2009, holding that although NorthWestern failed to use certain data inputs required by the power purchase agreement, CELP was entitled to neither damages for contract years 2004-2005 or 2005-2006, nor to recalculation of the underlying MPSC filings for those years, effectively finalizing CELP's contract rates for those years. We requested clarification from the arbitration panel as to its intent regarding the applicable rates.

On November 2, 2009, we received the final award from the arbitration panel which confirmed that the filed rates for 2004-2005 and 2005-2006 are not required to be recalculated. In affirming its interim award, the arbitration panel also denied CELP's request for attorney fees, holding that each party would be responsible for its own fees.

On June 15, 2010, the Montana district court confirmed the final arbitration panel award and denied CELP's motion to vacate, modify or correct the award. CELP appealed the decision to the Montana Supreme Court (MSC). In May 2011, the MSC affirmed the Montana district court's order and the arbitration award.

Meanwhile, on October 31, 2010, NorthWestern filed with the MPSC, consistent with the direction of the arbitration panel, for a determination of the inputs that will be used to calculate contract rates for periods subsequent to June 30, 2006. The MPSC has not yet ruled on our filing. On June 30, 2011, CELP submitted another demand for arbitration, seeking clarification from the same panel regarding the panel's intent as to the implementation of its award in Contract Years 17 (July 2005 - June 2006) and 18 (July 2006 - June 2007). The parties initially agreed to submit the matter without witnesses but following simultaneous submission of briefs in February 2012 and a hearing on March 1, 2012, the arbitration panel has requested further proceedings, including witness testimony at a hearing scheduled for July 30 through August 1, 2012. Based on our current assumptions (including current discount rates), if CELP prevailed entirely, we could be required to increase our QF liability by approximately $20 million. If we prevailed entirely, we could reduce our QF liability by up to $42 million. Due to the uncertainty around resolution of this matter, we currently are unable to predict its outcome. In addition, settlement discussions concerning these claims are ongoing.

Other Legal Proceedings

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

(20) Common Stock

We have 250,000,000 shares authorized consisting of 200,000,000 shares of common stock with a $0.01 par value and 50,000,000 shares of preferred stock with a $0.01 par value. Of these shares, 2,265,957 shares of common stock are reserved for the incentive plan awards. For further detail of grants under this plan see Note 16 - Stock-Based Compensation.

Repurchase of Common Stock

Shares tendered by employees to us to satisfy the employees' tax withholding obligations in connection with the vesting of restricted stock awards totaled 2,750 and 14,453 during the years ended December 31, 2011 and 2010, respectively, and are reflected in treasury stock. These shares were credited to treasury stock based on their fair market value on the vesting date.

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	0.00%
3	3363 Other Equipment	381,748	381,748	0.00%
4	**Total Local Storage Plant**	446,702	446,702	0.00%
5				
6	**Distribution Plant**			
7	3376 Mains	490,965	490,965	0.00%
8	3380 Services	493,066	490,818	0.46%
9	3381 Customers Meters and Regulators	33,429	33,180	0.75%
10	3382 Meter Installations		-	-
11	3389 Other Equipment	51,888	51,888	0.00%
12	**Total Distribution Plant**	1,069,348	1,066,851	0.23%
13	**Total Propane Plant in Service**	1,516,050	1,513,553	0.16%
14				
15	3107 Construction Work in Progress	-	-	-
16	3117 Gas in Underground Storage	23,095	22,251	3.79%
17				
18				
19	**TOTAL PROPANE PLANT**	$1,539,145	$1,535,804	0.22%
20				
21				

22	**CONSOLIDATED**	December 31,	
23	**PLANT IN SERVICE**	2011	2010
24			
25	Montana Electric	$ 2,167,521,871	$ 2,101,023,875
26	Yellowstone National Park	13,176,795	12,583,248
27	Montana Natural Gas (Includes CMP)	562,889,531	542,836,569
28	Common	79,977,860	73,833,445
29	Townsend Propane	1,516,050	1,513,553
30	South Dakota Electric	460,538,538	439,875,046
31	South Dakota Natural Gas	150,503,744	143,991,901
32	South Dakota Common	39,317,330	36,351,969
33	Asset Retirement Obligation	3,910,360	5,292,535
34	**TOTAL PLANT**	$ 3,479,352,079	$ 3,357,302,141

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	$381,748	$215,163	$206,421	2.29%
4					
5	Distribution	1,066,851	433,802	399,269	3.24%
6					
7					
8	**Total Accumulated Depreciation**	$1,448,599	$648,965	$605,690	
9					
10					
11					
12					

13	**Consolidated**	December 31,	
14	**Accumulated Depreciation**	2011	2010
15			
16	Montana Electric	$838,458,857	$777,672,624
17	Yellowstone National Park	8,644,902	8,375,865
18	Montana Natural Gas (Includes CMP)	228,357,798	217,491,781
19	Common	33,478,642	30,397,468
20	Townsend Propane	648,965	605,690
21	South Dakota Electric	249,041,748	236,785,039
22	South Dakota Natural Gas	64,714,374	60,954,155
23	South Dakota Common	11,240,646	9,067,229
24	Acquisition Writedown	73,854,295	81,444,433
25	Basin Creek Capital Lease	11,057,582	9,047,108
26	FIN 47	1,092,090	847,866
27	CWIP-Capital Retirement Clearing	-4,550,706	-1,011,776
28	**Total Consolidated Accum Depreciation**	$1,516,039,193	$1,431,677,482

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - PROPANE			
	Commission Accepted - Most Recent 1/	% Capital Structure	% Cost Rate	Weighted Cost
	Docket Number: 2009.9.129			
	Order Number : 7046h			
	Common Equity	48.00%	10.25%	4.92%
	Long Term Debt	52.00%	5.76%	3.00%
	TOTAL	100.00%		7.92%

1/ Docket 2009.9.129, Order 7046h specifies the authorized capital structure and associated costs for the regulated gas utility effective December 9, 2010.

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	$ 92,555,872	$ 77,376,457	19.62%
4	Noncash Charges (Credits) to Income:			
5	Depreciation	102,754,939	92,961,250	10.54%
6	Amortization, Net	(1,872,457)	(1,235,471)	-51.56%
7	Other Noncash Charges to Net Income, Net	8,895,186	7,893,929	12.68%
8	Deferred Income Taxes, Net	59,551,081	46,745,340	27.39%
9	Investment Tax Credit Adjustments, Net	(423,561)	(426,790)	0.76%
10	Change in Operating Receivables, Net	9,880,617	(3,911,111)	>300.00%
11	Change in Materials, Supplies & Inventories, Net	(8,830,208)	(3,405,097)	-159.32%
12	Change in Operating Payables & Accrued Liabilities, Net	(10,725,579)	(11,109,804)	3.46%
13	Allowance for Funds Used During Construction (AFUDC)	(1,876,583)	(6,564,191)	71.41%
14	Change in Other Assets & Liabilities, Net	1,734,801	28,781,987	-93.97%
15	Other Operating Activities:			
16	Undistributed Earnings from Subsidiary Companies	(510,094)	(3,729,609)	86.32%
17	Change in Regulatory Assets	(29,541,321)	(2,852,473)	>-300.00%
18	Change in Regulatory Liabilities	5,587,054	(7,724,029)	172.33%
19	**Net Cash Provided by Operating Activities**	227,179,747	212,800,388	6.76%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(188,730,360)	(240,745,782)	21.61%
22	(Net of AFUDC)			
23	Proceeds from Sale of Assets	209,396	68,883	203.99%
24	**Net Cash Used in Investing Activities**	(188,520,964)	(240,676,899)	21.67%
25	**Cash Flows from Financing Activities:**			
26	Proceeds from Issuance of:			
27	Credit Facilities Borrowings	80,000,000	225,000,000	-64.44%
28	Issuance of Short Term Borrowings, Net	166,933,493	695,000,000	-75.98%
29	Payments for Retirement of:			0.00%
30	Credit Facilities Repayments	(233,000,000)	(608,000,000)	61.68%
31	Long-Term Debt	-	(225,000,000)	100.00%
32	Capital Lease Obligations, Net	(11,079)	(29,342)	62.24%
33	Dividends on Common Stock	(51,909,137)	(48,996,981)	-5.94%
34	Other Financing Activities:			
35	Debt Financing Costs	(1,130,557)	(8,020,160)	85.90%
36	Treasury Stock Activity	154,223	(184,595)	183.55%
37	**Net Cash (Used in)/Provided by Financing Activities**	(38,963,057)	29,768,922	-230.89%
38	**Net (Decrease)/Increase in Cash and Cash Equivalents**	(304,274)	1,892,411	-116.08%
39	**Cash and Cash Equivalents at Beginning of Year**	6,232,091	4,339,680	43.61%
40	**Cash and Cash Equivalents at End of Year**	$ 5,927,817	$ 6,232,091	-4.88%
41				
42	This financial statement is presented on the basis of the accounting requirements of the Federal Energy Regulatory			
43	Commission (FERC) as set forth in its applicable Uniform System of Accounts. As such, subsidiaries are presented using the equity			
44	method of accounting. The amounts presented are consistent with the presentation in FERC Form 1, plus Canadian Montana			
45	Pipeline Corporation.			
46				

Sch. 24	MONTANA LONG TERM DEBT								
	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**								
3	6.34% Series, Due 2019	03/26/09	04/01/19	250,000,000	247,657,313	249,878,562	6.340%	$16,514,170	6.61%
4	5.71% Series, Due 2039	10/15/09	10/15/39	55,000,000	54,450,000	55,000,000	5.710%	$3,158,845	5.74%
5	6.04% Series, Due 2016	09/13/06	09/01/16	$150,000,000	$148,302,298	$149,965,700	6.040%	$9,308,114	6.21%
6	5.01% Series, Due 2025	05/27/10	05/01/25	161,000,000	160,075,635	$161,000,000	5.010%	$8,585,842	5.33%
7	**Total First Mortgage Bonds**			$616,000,000	$610,485,246	$615,844,262		$37,566,971	6.10%
8									
9	**Pollution Control Bonds**								
10	4.65% Series, Due 2023	04/27/06	08/01/23	$170,205,000	$164,451,956	$170,205,000	4.650%	$8,467,855	4.98%
11									
12	**Total Pollution Control Bonds**			$170,205,000	$164,451,956	$170,205,000		$8,467,855	4.98%
13									
14									
15	**TOTAL LONG TERM DEBT**			$786,205,000	$774,937,202	$786,049,262		$46,034,826	5.86%

Total Capital Leases does not include the Fleet Lease amounts due within 1 year of $7,382. It also does not include amounts associated with the Basin Creek contract, which totals $34,280,665.

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										
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30										
31										
32	TOTAL									

Sch. 26 — **COMMON STOCK**

	Avg. Number of Shares Outstanding 1/	Book Value Per Share	Earnings Per Share	Dividends Per Share (Declared)	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio
January	36,232,229	$23.02				$29.46	$28.18	
February	36,246,630	23.33				29.97	27.38	
March	36,252,743	23.19	$0.90	$0.36		30.57	28.23	
April	36,257,086	23.34				32.62	29.37	
May	36,258,870	23.42				33.24	31.84	
June	36,260,406	23.14	0.30	0.36		33.14	31.50	
July	36,260,887	23.31				34.11	31.27	
August	36,263,167	23.48				34.17	28.68	
September	36,264,686	23.14	0.41	0.36		34.11	30.96	
October	36,265,149	23.31				35.51	30.44	
November	36,272,547	23.60				35.05	32.23	
December	36,278,206	23.68	0.94	0.36		36.61	33.38	
TOTAL Year End	36,258,463	$23.68	$2.55	$1.44	43.53%	$35.79		14.0

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for the twelve months ended December 31, 2011.

Sch. 27	MONTANA EARNED RATE OF RETURN - PROPANE				
		Description	This Year	Last Year	% Change
1		**Rate Base**			
2	101	Plant in Service	$1,514,514	$1,509,708	0.32%
3	108	Accumulated Depreciation	(627,328)	(584,546)	-7.32%
4					
5	**Net Plant in Service**		$887,186	$925,162	-4.10%
6		Additions:			
7		Other Additions	$32,160	$32,342	-0.56%
8					
9	**Total Additions**		$32,160	$32,342	-0.56%
10		Deductions:			
11	190	Accumulated Deferred Income Taxes	$25,546	$72,994	-65.00%
12					
13	**Total Deductions**		$25,546	$72,994	-65.00%
14	**Total Rate Base**		$893,800	$884,510	1.05%
15	**Net Earnings**		($6,051)	($4,976)	-21.59%
16	**Rate of Return on Average Rate Base**		-0.677%	-0.563%	-20.33%
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		**Detail - Other Additions**			
35		Propane on Hand	$32,160	$32,342	-0.56%
36					
37	**Total Other Additions**		$32,160	$32,342	-0.56%
38					
39		**Detail - Other Deductions**			
40					
41	**Total Other Deductions**		-	-	-
42					
43					
44					
45					
46					

Sch. 28	MONTANA COMPOSITE STATISTICS - PROPANE		
		Description	Amount
1			
2		**Plant**	
3			
4	101	Plant in Service	$1,516,050
5	107	Construction Work in Progress	
6	117	Gas in Underground Storage	23,095
7	108, 111	Depreciation & Amortization Reserves	648,965
8			
9	**NET BOOK COSTS**		890,180
10			
11		**Revenues & Expenses**	
12			
13	400	Operating Revenues	928,549
14			
15	**Total Operating Revenues**		928,549
16			
17	401-402	Operation & Maintenance Expenses	837,242
18	403-407	Depreciation Expense	43,275
19	408.1	Taxes Other than Income Taxes	52,822
20	409-411	Federal & State Income Taxes	1,263
21			
22	**Total Operating Expenses**		934,602
23	**Net Operating Income**		(6,053)
24			
25	415-421.1	Other Income	-
26	421.2-426.5	Other Deductions	-
27	**NET INCOME BEFORE INTEREST EXPENSE**		$ (6,053)
28			
29		**Average Customers**	
30		Residential	507
31		Commercial / Industrial	71
32			
33	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		578
34			
35		**Other Statistics**	
36		Average Annual Residential Use (Dkt)	56.6
37		Average Annual Residential Cost per (Dkt)	$22.04
38		Average Residential Monthly Bill	$103.93
39			
40		Plant in Service (Gross) per Customer	$2,623

Sch. 29	Montana Customer Information- Propane, 1/					
	City	Population Census 2010	Residential	Commercial	Industrial & Other	Total
1	Townsend	1,878	507	71	-	578
2						
3						
4						
5						
6						
7						
8						
9	**Total**	1,878	507	71	-	578
10						
11						
12	1/ Customer populations represent an average of the 12 month period from 01/01/11 through 12/31/11.					

Sch. 30	MONTANA EMPLOYEE COUNTS 1/			
	Department	Year Beginning	Year End	Average
1				
2	**Utility Operations**			
3	Executive	2	2	2
4	Customer Care	104	109	107
5	Finance	118	123	121
6	Regulatory Affairs	27	27	27
7	Distribution	555	549	552
8	Transmission	182	201	192
9	Supply	20	32	26
10	Legal	12	12	12
11				
12				
13				
14				
15				
16				
17				
18	**TOTAL EMPLOYEES**	1,020	1,055	1,038

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

Sch. 31	MONTANA CONSTRUCTION BUDGET 2012 (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3	MT Elec Distribution - Elec Distribution Infrastructure Plan	$12,200,000	$12,200,000
4	MT Elec Distribution - Livingston-Big Timber Substation	1,082,086	1,082,086
5	MT Elec Distribution - Bozeman-Westside Substation	1,133,614	1,133,614
6	MT Elec Trans - South Butte Auto Transformer Sub	4,428,003	4,428,003
7	MT Elec Trans - Jack Rabbit-Big Sky 161KV line	7,795,256	7,795,256
8	SD Elec Trans - Reconductor Line 30 Siebrecht to Redfield	5,160,939	
9			
10	All Other Projects < $1 Million Each MT	46,857,793	46,857,793
11	All Other Projects < $1 Million Each SD	20,112,179	
12	**Total Electric Utility Construction Budget**	$98,769,870	$73,496,752
13			
14	**Natural Gas Operations**		
15	MT Gas Retail - Gas Distribution Infrastructure Plan	6,000,000	6,000,000
16	MT Gas Trans - Pipeline Integrity Mgmt - Bozeman HCA's	3,044,607	3,044,607
17	MT Gas Trans - Pipeline Integrity Mgmt - Other HCA projects	2,976,705	2,976,705
18			
19	All Other Projects < $1 Million Each MT	14,374,931	14,374,931
20	All Other Projects < $1 Million Each SD NE	4,088,655	
21	**Total Natural Gas Utility Construction Budget**	30,484,898	26,396,243
22			
23	**Common**		
24	Fleet and Equipment Purchases	6,000,000	4,703,000
25	BT CIS Upgrade and Consolidation	4,134,929	3,307,962
26	Communications - MT Mobile Radio replacement	2,644,139	2,644,139
27	SD Aberdeen Facility	1,462,500	
28	IT AM-FM GIS system	1,166,784	1,166,784
29	Communications - SD Mobile Radio replacement	1,394,071	
30			
31	All Other Projects < $1 Million Each MT	2,990,629	2,990,629
32	(Includes IT, Communications, Facilities, Cust Serv)		
33	All Other Projects < $1 Million Each SD NE	1,029,940	
34			
35	**Total Common Utility Construction Budget**	20,822,992	14,812,514
36			
37	MT CU4 capital additions - PPL invoice	4,965,000	4,965,000
38			
39	SD Big Stone, Neal 4, Coyote partner capital	4,438,506	
40	SD Internal Generation - RICE NESHAP Compliance	1,127,006	
41			
42	All Other Projects < $1 Million Each MT	250,000	250,000
43	All Other Projects < $1 Million Each SD	641,728	
44	**Total Colstrip Unit 4 and MT/SD Generation**	11,422,240	5,215,000
45	**TOTAL CONSTRUCTION BUDGET**	$161,500,000	$119,920,509

Sch. 33	MONTANA SOURCES OF PROPANE SUPPLY				
		Dekatherm Volumes		Avg. Commodity Cost	
		2011 Year	2010 Year	2011 Year	2010 Year
1	**Name of Supplier**				
2					
3	AmeriGas	44,545	20,127	$16.1018	$15.2106
4	Gibson Energy, LLC		25,702		$11.7366
5					
6	**Total Propane Supply Volumes**	44,545	45,829	$16.1018	$13.2623

Sch. 35	MONTANA CONSUMPTION AND REVENUES - PROPANE						
		Operating Revenues		Dkt Sold		Average Customers	
		2011 Year	2010 Year	2011 Year	2010 Year	2011 Year	2010 Year
1	**Sales of Propane**						
2							
3	Residential	$632,290	$543,386	28,687	30,640	507	508
4	Commercial / Industrial	296,259	249,583	13,602	14,252	71	70
5							
6							
7	**TOTAL SALES**	$928,549	$792,969	42,289	44,892	578	578