BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN RE:	)	
	)	**Docket No. NG07-**
NORTHWESTERN Corporation	)	
d/b/a NorthWestern Energy	)	

AFFIDAVIT OF KENDALL KLIEWER

STATE OF SOUTH DAKOTA)
COUNTY OF MINNEHAHA) **SS**

Kendall Kliewer , being first duly sworn, deposes and says:

(1) He is the Vice President and Controller of NorthWestern Corporation (dba NorthWestern Energy), and in such capacity serves as its Chief Accounting Officer;

(2) As such Chief Accounting Officer, he has responsibility for all accounting records of NorthWestern Energy;

(3) He has reviewed all cost statements, working papers, and other supporting data submitted as part of this filing or maintained by NorthWestern Energy, and such cost statements, working papers, and other supporting data accurately set forth the books of NorthWestern Energy.

Kendall Kliewer

Subscribed and sworn to me this 1st day of May, 2007.

(SEAL)

NANCY THOMPSON
NOTARY PUBLIC
SOUTH DAKOTA

Nancy Thompson
Notary Public, South Dakota
My Commission Expires: 3/20/12

Line No.	ASSETS AND OTHER DEBITS	FERC Form 1	Non-Jurisdictional*	Jurisdictional
	(a)	(b)	(c)	(d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	2,497,287,113	1,961,877,212	535,409,901
3	Construction Work in Progress (107)	3,240,549	2,235,212	1,005,337
4	TOTAL Utility Plant	2,500,527,662	1,964,112,424	536,415,238
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 11	(1,221,309,452)	(960,010,057)	(261,299,395)
6	Net Utility Plant	1,279,218,210	1,004,102,367	275,115,843
7	Utility Plant Adjustment - Goodwill (116)	435,075,587	320,184,552	114,891,035
8	Gas Stored Underground - Noncurrent (117)	32,141,968	32,141,968	0
9	OTHER PROPERTY AND INVESTMENTS			
10	Nonutility Property (121)	5,357,845	5,357,845	0
11	(Less) Accum. Prov. For Depr. Amort. Depl. (122)	(1,473,243)	(1,473,243)	0
12	Investment in Associated Companies (123)	0	0	0
13	Investment in Subsidiary Companies (123.1)	123,892,253	123,892,253	0
14	Other Investments (124)	1,541,359	496,045	1,045,314
15	Special Funds (125-128)	0	0	0
16	LT Portion of Derivative Assets - Hedges	0	0	0
17	TOTAL Other Property and Investments	129,318,214	128,272,900	1,045,314
18	CURRENT AND ACCRUED ASSETS			
19	Cash (131)	1,808,086	1,713,405	94,681
20	Other Special Deposits (134)	2,965,707	2,965,707	0
21	Working Funds (135)	42,010	37,105	4,905
22	Temporary Cash Investments (136)	0	0	0
23	Notes Receivable (141)	49,909	49,909	0
24	Customer Accounts Receivable (142)	65,175,722	49,218,356	15,957,366
25	Other Accounts Receivable (143)	18,816,200	18,547,911	268,289
26	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)	(3,239,842)	(2,601,603)	(638,239)
27	Accounts Receivable from Assoc. Companies (146)	15,337,813	15,337,813	0
28	Fuel Stock (151)	3,313,948	1,013,302	2,300,646
29	Plant Material and Operating Supplies (154)	17,902,740	13,588,756	4,313,984
30	Merchandise (155)	0	0	0
31	Other Materials and Supplies (156)	0	0	0
32	Stores Expenses Undistributed (163)	0	0	0
33	Gas Stored Underground - Current (164.1)	39,240,016	35,433,413	3,806,603
34	Prepayments (165)	9,964,222	5,333,115	4,631,107
35	Interest and Dividends Receivable (171)	0	0	0
36	Rents Receivable (172)	61,624	61,024	600
37	Accrued Utility Revenues (173)	68,858,563	50,384,582	18,473,981
38	Miscellaneous Current and Accrued Assets (174)	1,161,258	1,161,258	0
39	Derivative Instrument Assets (175)	0	0	0
40	(Less) Long-Term Portion of Derivative Instrument Asset	0	0	0
41	Derivative Instrument Assets - Hedges (176)	0	0	0
42	(Less) Long-Term Portion of Derivative Instrument Asset	0	0	0
43	TOTAL Current and Accrued Assets	241,457,976	192,244,053	49,213,923
44	DEFERRED DEBITS			
45	Unamortized Debt Expenses (181)	17,255,590	14,700,121	2,555,469
46	Other Regulatory Assets (182.3-182.9)	148,502,899	131,713,975	16,788,924
47	Prelim. Survey and Investigation Charges (Electric) (183	0	0	0
48	Clearing Accounts (184)	43,321	(78)	43,399
49	Temporary Facilties (185)	78	78	0
50	Miscellaneous Deferred Debits (186)	21,279,929	21,274,139	5,790
51	Unamortized Loss on Reacquired Debt (189)	4,637,192	4,393,629	243,563
52	Accumulated Deferred Income Taxes (190)	45,646,258	33,465,232	12,181,026
53	Unrecovered Purchased Gas Costs (191)	5,612,870	451,510	5,161,360
54	TOTAL Deferred Debits	242,978,137	205,998,606	36,979,531
55	**TOTAL Assets and other Debits**	**2,360,190,092**	**1,882,944,446**	**477,245,646**
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58	*Non-Jurisdictional primarily consists of Montana operations.			
59				

Line No.	LIABILITIES AND OTHER CREDITS	FERC Form 1	Non-Jurisdictional*	Jurisdictional
	(a)	(b)	(c)	(d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	359,624	359,624	0
3	Preferred Stock Issued (204)		0	0
4	Premium on Capital Stock (207)	0	0	0
5	Other Paid-in Capital (208 - 211)	727,327,890	609,305,463	118,022,427
6	(Less) Discount on Captal Stock (213)	0	0	0
7	(Less) Capital Stock Expense (214)	0	0	0
8	Retained Earnings (215, 215.1, 216)	775,850,846	759,733,878	16,116,968
9	Unappropriated Undistributed Subsidiary Earnings (216.1 to 216.4)	(765,153,042)	(765,153,042)	0
10	(Less) Reacquired Capital Stock (217)	(9,885,098)	(9,885,098)	0
11	Accumulated Other Comprehensive Income (219)	14,271,357	14,271,357	0
12	TOTAL Proprietary Capital	742,771,577	608,632,182	134,139,395
13	LONG-TERM DEBT			
14	Bonds (221)	621,920,000	481,570,000	140,350,000
15	Advances from Associated Companies (223)	0	0	0
16	Other Long-Term Debt (224)	50,000,000	0	50,000,000
17	(Less) Unamoritzed Discount on Long-Term Debt-Debit (226)	(71,051)	(71,051)	0
18	TOTAL Long-Term Debt	671,848,949	481,498,949	190,350,000
19	OTHER NONCURRENT LIABILITIES			
20	Obligations Under Capital Leases (227)	39,323,563	39,315,743	7,820
21	Accumulated Provision for Property Insurance (228.1)	(70,841)	(70,841)	0
22	Accumulated Provision for Injuries and Damages (228.2)	8,617,963	7,392,253	1,225,710
23	Accumulated Provision for Pensions and Benefits (228.3)	52,570,168	51,899,463	670,705
24	Accumulated Miscellaneous Operating Provisions (228.4)	180,640,922	155,767,681	24,873,241
25	Asset Retirement Obligations (230)	3,801,012	2,418,877	1,382,135
26	LT Portion of Derivative Instrument Liabilities - Hedges (245)	0	0	0
27	TOTAL Other Noncurrent Liabilities	284,882,787	256,723,176	28,159,611
28	CURRENT AND ACCRUED LIABILITIES			
29	Notes Payable (231)	0	0	0
30	Accounts Payable (232)	88,243,950	68,657,457	19,586,493
31	Notes Payable to Associated Companies (233)	0	0	0
32	Accounts Payable to Associated Companies (234)	44,495,305	44,495,305	0
33	Customer Deposits (235)	7,641,259	6,939,594	701,665
34	Taxes Accrued (236)	129,888,541	118,299,470	11,589,071
35	Interest Accrued (237)	11,091,501	8,774,683	2,316,818
36	Dividends Declared (238)	0	0	0
37	Tax Collections Payable (241)	1,429,703	6,965	1,422,738
38	Miscellaneous Current and Accrued Liabilities (242)	60,141,335	50,821,990	9,319,345
39	Obligations Under Capital Leases (243)	1,414,661	1,406,841	7,820
40	Derivative Instrument Liabilities (244)	4,331,833	533,563	3,798,270
41	(Less) Long-Term Portion of Derivative Instrument Liabilities	0	0	0
42	Derivative Instrument Liabilities - Hedges (245)	0	0	0
43	(Less) Long-Term Portion of Derivative Liabilities - Hedges	0	0	0
44	TOTAL Current and Accrued Liabilities	348,678,088	299,935,868	48,742,220
45	DEFERRED CREDITS			
46	Customer Advances for Construction (252)	33,501,677	33,501,677	0
47	Other Deferred Credits (253)	87,874,078	69,205,223	18,668,855
48	Other Regulatory Liabilities (254)	26,296,808	16,481,067	9,815,741
49	Accumulated Deferred Investment Tax Credits (255)	4,028,288	0	4,028,288
50	Unamortized Gain on Reacquired Debt (257)	0	0	0
51	Accumulated Deferred Income Taxes (281)	0	0	0
52	Accumulated Deferred Income Taxes (282)	109,939,850	68,034,203	41,905,647
53	Accumulated Deferred Income Taxes (283)	50,367,990	48,932,101	1,435,889
54	TOTAL Deferred Credits	312,008,691	236,154,271	75,854,420
55	**TOTAL Liabilities and Other Credits**	**2,360,190,092**	**1,882,944,446**	**477,245,646**
56				
57				
58	*Non-Jurisdictional primarily consists of Montana operations.			
59				

NorthWestern Corporation, dba NorthWestern Energy
SD Natural Gas Income Statement
December 31, 2006 Test Year

SOUTH DAKOTA UTILITY INCOME STATEMENT - NATURAL GAS

Line No.	Account No.	Account Description	This Year Cons. Utility	Non Jurisdictional Adjustments	This Year South Dakota
	(a)	(b)	(c)	(d)	(e)
1	400	Operating Revenues	$ 356,064,030	$ 300,765,645	$ 55,298,385
2					
3		**Total Operating Revenues**	356,064,030	300,765,645	55,298,385
4					
5		OPERATING EXPENSES			
6	401	Operation Expense	283,252,044	232,253,018	50,999,026
7	402	Maintenance Expense	5,273,406	4,599,000	674,406
8	403	Depreciation Expense	14,637,740	12,308,553	2,329,187
9	404-405	Amort. & Depletion of Gas Plant	2,214,571	1,820,424	394,147
10	406	Amort. of Plant Acquisition Adj.	(2,288,552)	(2,288,552)	0
11	407.3	Regulatory Amortizations - Debit	7,641,238	7,641,238	0
12	407.4	Regulatory Amortizations - Credit	(3,740,866)	(3,878,714)	137,848
13	408.1	Taxes Other Than Income Taxes	24,109,226	21,939,646	2,169,580
14	409.1	Income Taxes-Federal	9,888,871	10,978,692	(1,089,821)
15		Other	1,452,425	1,451,896	529
16	410.1	Deferred Income Taxes-Dr.	0	0	0
17	411.1	Deferred Income Taxes-Cr.	(6,302,795)	(5,727,128)	(575,667)
18	411.4	Investment Tax Credit Adj.	(41,347)	(18,606)	(22,741)
19					
20		**Total Operating Expenses**	336,095,961	281,079,467	55,016,494
21		**NET OPERATING INCOME**	$ 19,968,069	$ 19,686,178	$ 281,891
22					

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

Line No.	Account	FERC Form 1	Non-Jurisdictional*	Jurisdictional
	(a)	(b)	(c)	(d)
	UNAPPROPRIATED RETAINED EARNINGS (ACCOUNT 216)			
1	Balance - Beginning of the year	785,732,060	781,340,125	4,391,935
2	Charges (identified by prescribed retained earnings account)			
3	Adjustments to Retained Earnings (Account 439)			
4	Collapse of Subsidiary into Utility	(1,231,521)	(1,231,521)	0
5	TOTAL Credits to Retained Earnings (Account 439)	(1,231,521)	(1,231,521)	0
6				
7	Investment True-up			
8				
9	TOTAL Debits to Retained Earnings (account 439)	0	0	0
10	Balance Transferred from Income (Account 433 less Account 418.1)	35,441,553	23,716,520	11,725,033
11	Appropriations of Retained Earnings (Account 436)			
12				
13	TOTAL Appropriations of Retained Earnings (Account 436)	0	0	0
14	Dividends Declared - Preferred Stock (Account 437)	0	0	0
15				
16	TOTAL Dividends Declared - Preferred Stock (Account 437)	0	0	0
17	Dividends Declared - Common Stock (Account 438)			
18	Dividends Declared - Common Stock	44,091,245	44,091,245	0
19				
20	TOTAL Dividends Declared - Common Stock (Account 438)	44,091,245	44,091,245	0
21	Transfers from Account 216.1, Unappropriated Undistrib Subsidiary Earnings	0	0	0
22	Balance - End of Period (Total 1, 9, 15, 16, 22, 29, 36, 37)	775,850,847	759,733,879	16,116,968
23				
24	APPROPRIATED RETAINED EARNINGS (Account 215)			
25				
26	TOTAL Appropriated Retained Earnings (Account 215)	0	0	0
27				
28	APPROP. RETAINED EARRINGS - AMORT. Reserve, Federal (Account 215.1)			
29	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct 215.1)			
30	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)	0	0	0
31	**TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38,47) (216.1)**	**775,850,847**	**759,733,879**	**16,116,968**
32	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
33	Report only on an Annual Basis, no Quarterly			
34	Balance-Beginning of Year (Debit or Credit)	(768,843,176)	(768,843,176)	0
35	Equity in Earnings for Year (Credit) (Account 418.1)	2,458,612	2,458,612	0
36	(Less) Dividends Received (debit)			
37	Collapse of Subsidiary into Utility	1,231,521	1,231,521	0
38	**Balance-End of Year (Total lines 49 thru 52)**	**(765,153,043)**	**(765,153,043)**	**0**
39				
40				
41	*Non-Jurisdictional primarily consists of Montana operations.			
42				

NOTES TO FINANCIAL STATEMENTS

(1) Nature of Operations

We are one of the largest providers of electricity and natural gas in the Upper Midwest and Northwest, serving approximately 640,000 customers in Montana, South Dakota and Nebraska under the trade name "NorthWestern Energy." We have generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska since 1923 and have distributed electricity and 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 Federal Energy Regulatory (FERC) as set forth in its applicable Uniform System of Accounts. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that may affect the reported amounts of assets, liabilities, revenues and expenses during the reporting period. Actual results could differ from those estimates.

(2) Pending Merger with Babcock & Brown Infrastructure Limited

On April 25, 2006, we entered into an Agreement and Plan of Merger (Merger Agreement) with Babcock & Brown Infrastructure Limited (BBI), an infrastructure investment company listed on the Australian Stock Exchange, under which BBI will acquire NorthWestern Corporation in an all-cash transaction at $37 per share. The Merger Agreement has been unanimously approved by both companies' Boards of Directors. Our shareholders approved the Merger Agreement at our August 2, 2006 annual meeting.

The transaction is conditioned upon a number of federal and state regulatory approvals or reviews, and satisfaction of other customary closing conditions. We have received approvals or clearances from the following:

- Committee on Foreign Investments in the United States (CFIUS) in July 2006;
- United States Federal Trade Commission and the United States Department of Justice under the Hart-Scott-Rodino Antitrust Improvement Act of 1976 in October 2006;
- Nebraska Public Service Commission (NPSC) in October 2006;
- FERC in October 2006;
- Federal Communications Commission in February 2007.

Due to existing statutory language in South Dakota, we submitted a filing to the South Dakota Public Utilities Commission (SDPUC) to determine if it has jurisdiction over the sale and, if so, for transaction approval. In July, the SDPUC filed a notice with FERC that it intended to intervene and file a protest in the federal proceedings. In October, we reached a settlement agreement under which the SDPUC will not oppose approval of the transaction by FERC, which includes the following provisions:

- We and BBI will not seek rate recovery of costs associated with the transaction;
- The majority of our future Board of Directors will be U.S. citizens with at least one South Dakota resident and at least one independent member who will have substantial utility or financial experience. In addition, the independent member(s) shall serve as chair of the Audit Committee and the Governance Committee;

- We will apply ring fencing provisions of the 2004 Stipulation and Settlement Agreement between us, the Montana Public Service Commission (MPSC) and the Montana Consumer Counsel (MCC) for the benefit of the SDPUC and South Dakota ratepayers;

- We will not borrow money secured by South Dakota regulated utility assets to upstream funds to either BBI or its affiliates without prior approval of the SDPUC; and

- We will maintain our corporate headquarters in Sioux Falls, South Dakota until the later of June 30, 2010 or three years following the effective date of the merger. We will continue to maintain senior management personnel in both South Dakota and Montana.

In December, the SDPUC determined that current state law does not allow them to exercise jurisdiction over the proposed sale.

We must still obtain the approval of the MPSC. We and the intervenors submitted testimony and additional information to the MPSC. The MPSC held a technical hearing from March 14, 2007 through March 16, 2007 and has set a schedule for post-hearing briefs, which requires BBI and us to file a brief on April 6, 2007, the intervenors to file a response on April 27, 2007, and BBI and us to file a reply on May 7, 2007. We anticipate receiving the MPSC's decision during the first half of 2007.

The Merger Agreement contains certain covenants whereby NorthWestern is required to continue to operate in the ordinary course of business and must obtain BBI's consent prior to making certain new investments or divestitures, issuing new debt or common stock or making dividend changes, among other provisions. In addition, the Merger Agreement also contains certain termination rights for both NorthWestern and BBI in which under specified circumstances NorthWestern may be required to pay BBI a termination fee of $50 million and BBI may be required to pay NorthWestern a business interruption fee of $70 million.

The merger will be accounted for as a purchase under GAAP. Under the purchase method of accounting, the assets and liabilities of NorthWestern will be recorded, as of the completion of the transaction, at their respective fair values, and we will record as a utility plant adjustment the excess, if any, of the purchase price over the fair value of our identifiable assets, including intangibles.

During the year ended December 31, 2006, we recorded $13.8 million in pre-tax charges for advisor and professional fees related to the transaction which are included in other deductions on our statement of income. These costs included payment of $8.6 million in transaction fees to our strategic advisor during 2006. Under the terms of this agreement, we will also be required to pay an additional $8.6 million upon closing.

In addition, in November 2006, the remaining shares available under our 2005 Long-Term Incentive Plan were granted in accordance with the terms of the Merger Agreement. These service-based restricted share awards vest over the next five years, however these shares will vest immediately upon closing of the transaction with BBI. If the transaction is completed in 2007 as anticipated, stock-based compensation expense will be approximately $14 million. Upon closing, NorthWestern's common stock will cease to be publicly traded.

(3) Significant Accounting Policies

Financial Statement Presentation and Basis of Accounting

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. 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 5). The other significant differences consist of the following:

- Comparative statements of net income per share are not presented;

- Removal costs of transmission and distribution assets are reflected in the balance sheets as a component of accumulated depreciation of $153.4 million and $142.6 million as of December 31, 2006 and 2005, respectively, in accordance with regulatory treatment as compared to regulatory liabilities for GAAP purposes (see Note 7);

- Goodwill resulting from our emergence from bankruptcy and fresh-start reporting is reflected in the balance sheets as a utility plant adjustment of $435.1 million as of December 31, 2006 and 2005 respectively, in accordance with regulatory treatment, as compared to goodwill for GAAP purposes (see Note 8);

- The write-down of plant values associated with the 2002 acquisition of the Montana operations is reflected in the balance sheets as a component of accumulated depreciation of $192.8 million for both December 31, 2006 and 2005, 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 materials and supplies 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 GAAP presentation reflects current and long-term debt on separate lines; and

- Accumulated deferred tax assets and liabilities are classified in the balance sheets as gross deferred debits and credits, respectively, while GAAP presentation reflects either a net deferred tax asset or liability.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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, uncollectible accounts, environmental costs, unbilled revenues and actuarially determined benefit costs. We revise the recorded estimates when we get better information or when we can determine actual amounts. Those revisions can affect operating results.

Revenue Recognition

For our South Dakota and Nebraska operations, as prescribed by the respective regulatory authorities, electric and natural gas utility revenues are based on billings rendered to customers. For our Montana operations, as prescribed by the MPSC, operating revenues are recorded monthly on the basis of consumption or services rendered. 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 Montana 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.

Inventories

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

	December 31,			
	2006		2005	
Fuel Stock	$	3,314	$	2,762
Materials and supplies		17,903		14,002
Gas stored underground (including the non-current portion reflected in utility plant)		71,382		55,147
	$	92,599	$	71,911

The storage gas amount as of December 31, 2005 includes $11.7 million related to deferred gas storage arrangements.

Regulation of Utility Operations

Our regulated operations are subject to the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulations* (SFAS No. 71). Accounting under SFAS No. 71 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 jurisdiction 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 on the balance sheet 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 all or a separable portion of our operations becomes no longer subject to the provisions of SFAS No. 71, an evaluation of future recovery of the related regulatory assets and liabilities would be necessary. In addition, we would determine any impairment to the carrying costs of deregulated plant and inventory assets.

Derivative Financial Instruments

We are exposed to market risk, including changes in interest rates and the impact of market fluctuations in the price of electricity and natural gas commodities as discussed further in Note 9. In order to manage these risks, we use both derivative and non-derivative contracts that may provide for settlement in cash or by delivery of a commodity, including:

- Forward contracts, which commit us to purchase or sell energy commodities in the future,
- Option contracts, which convey the right to buy or sell a commodity at a predetermined price, and
- Swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined contractual (notional) quantity.

SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133), as amended, requires that all derivatives be recognized in the balance sheet, either as assets or liabilities, at fair value, unless they meet the normal purchase and normal sales criteria. 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.

For contracts in which we are hedging 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 applied the normal purchases and normal sales scope exception, as provided by SFAS No. 133 and interpreted by Derivatives Implementation Guidance Issue C15, to certain contracts involving the purchase and sale of gas and electricity at fixed prices in future periods. 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.

Property, Plant and Equipment

Property, plant and equipment are stated at original cost, including contracted services, direct labor and material, allowance for funds used during construction (AFUDC), and indirect charges for engineering, supervision and similar overhead items. All expenditures for maintenance and repairs of utility property, plant and equipment are charged to the appropriate maintenance expense accounts. A betterment or replacement of a unit of property is accounted for as an addition and retirement of utility plant. At the time of such a retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal. Also included in plant and equipment are assets under capital lease, which are stated at the present value of minimum lease payments. Plant and equipment under capital lease were $44.8 million and $6.0 million as of December 31, 2006 and December 31, 2005, respectively.

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. We determine the rate used to compute AFUDC in accordance with a formula established by the FERC. This rate averaged 8.8% and 8.7% for Montana for 2006 and 2005, respectively, and 8.9% and 8.7% for South Dakota for 2006 and 2005, respectively. Interest capitalized totaled $1.0 million for the year ended December 31, 2006 and $1.3 million for the year ended December 31, 2005 for Montana and South Dakota combined.

We may require contributions in aid of construction from customers when we extend service. Amounts used from these contributions to fund capital additions were $8.7 million for the year ended December 31, 2006 and $8.9 million for the year ended December 31, 2005.

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 3.4% for both 2006 and 2005.

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.

Stock-based Compensation

Under our equity-based incentive plans, we have granted restricted stock awards to all employees and members of the Board of Directors (Board). We discuss these awards in further detail in Note 18. We adopted SFAS No. 123R, *Share-Based Payment* (SFAS No. 123R), upon emergence from bankruptcy, which was prior to the required effective date of January 1, 2006. SFAS No. 123R requires companies to recognize compensation expense for all equity-based compensation awards issued to employees that are expected to vest. Under SFAS 123R we recognize the fair value of compensation cost ratably or in tranches (depending if the award has cliff or graded vesting) over the period during which an employee is required to provide service in exchange for the award. As forfeitures of restricted stock grants occur, the compensation cost recognized to date is reversed.

Income Taxes

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 costs which are deferred for book purposes but expensed currently for tax purposes, and net operating loss carry forwards.

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 statement of operations 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.

We record estimated remediation costs, excluding inflationary increases and probable reductions for insurance coverage and rate recovery. The 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 July 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). FIN 48 is an interpretation of FASB Statement No. 109, *Accounting for Income Taxes*, and it seeks to reduce the diversity in practice associated with certain aspects of measurement and recognition in accounting for income taxes by prescribing a recognition threshold and measurement process for recording in the financial statements uncertain tax positions taken or expected to be taken in a tax return. Additionally, FIN 48 provides guidance on the derecognition, classification, accounting in interim periods and expanded disclosure with respect to the uncertainty in income taxes. FIN 48 is effective for us as of January 1, 2007. We are currently in the process of reviewing our uncertain tax positions to determine the impact to our financial statements. FIN 48 provides that a tax position that meets the more-likely-than-not threshold shall initially and subsequently be measured 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. Based on our preliminary assessment, we expect to increase our net deferred tax assets by $70 million to $90 million with a corresponding decrease to utility plant adjustments.

In September 2006, the FASB issued SFAS No. 157 *Fair Value Measurements* (SFAS No. 157), which defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. The provisions of SFAS No. 157 are effective as of the beginning of our 2008 fiscal year. We are currently evaluating the impact, if any, adopting SFAS No. 157 will have on our financial statements.

Accounting Standards Adopted

In September 2006, the FASB issued SFAS No. 158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans -- an amendment of FASB Statements No. 87, 88, 106, and 132(R)* (SFAS No. 158). SFAS No. 158 requires that we recognize the overfunded or underfunded status of our defined benefit and retiree medical plans (our Plans) as an asset or liability in our 2006 year-end balance sheet. Upon our emergence from bankruptcy in November 2004, we recognized a liability for the underfunded status of our Plans, therefore the amount recognized upon adoption of SFAS No. 158 as of December 31, 2006 represents adjustments to our discount rate assumption, our actual 2006 return on plan assets, and other factors. This resulted in a reduction to the liability recognized for our Plans of approximately $23.3 million. As we recover certain of these costs in rates, $23.0 million of this adjustment is reflected as a change in regulatory assets. We discuss our employee benefit plans in more detail in Note 17.

(4) Emergence from Bankruptcy

On September 14, 2003 (the Petition Date), we filed a voluntary petition for relief under the provisions of Chapter 11 of the Federal Bankruptcy Code (the Bankruptcy Code) in the United States Bankruptcy Court for the District of Delaware (Bankruptcy Court). On October 19, 2004, the Bankruptcy Court entered an order confirming our Plan of Reorganization (Plan), which became effective on November 1, 2004.

Plan of Reorganization

The consummation of the Plan resulted in, among other things, a new capital structure, the satisfaction or disposition of various types of claims against the Predecessor Company, the assumption or rejection of certain contracts, and the establishment of a new board of directors.

In accordance with the Plan, we issued 31.1 million shares of new common stock to settle claims of debt holders. We also established a reserve of approximately 4.4 million shares of common stock upon emergence to be used to resolve various outstanding litigation matters and distributed pro rata to holders of allowed trade vendor and general unsecured claims in excess of $20,000. As of December 31, 2006, approximately 1.3 million shares have been distributed from this reserve in settlement of claims.

Remaining disputed unsecured claims, when allowed, will receive shares out of the reserve set aside upon emergence.

Reorganization Items

The results of operations have been impacted by Reorganization Items, including continued costs incurred related to our reorganization since we filed for protection under Chapter 11 and the impact of fresh-start reporting. The following table provides detail of the charges incurred (in thousands):

		2005
Reorganization Items		
Professional fees (923)	$	5,490
Interest earned on accumulated cash (419)		—
Miscellaneous non-operating income – effects of the Plan and fresh-start reporting adjustments (421)		2,039
Total Reorganization Items	$	7,529

The 2005 amount included in effects of the Plan is primarily due to a loss on the reestablishment of a liability that was removed upon emergence from bankruptcy.

(5) Equity Investments

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

	December 31,			
		2006		2005
Canadian Montana Pipeline Corporation	$	1,845	$	1,814
Clark Fork & Blackfoot, LLC		(6,274)		(5,752)
Natural Gas Funding Trust		1,379		999
NorthWestern Services, LLC		21,365		18,641
NorthWestern Investments, LLC		103,273		(69,354)
Risk Partners Assurance, Ltd.		2,304		2,167
Total Investments in Subsidiary Companies	$	123,892	$	(51,485)

(6) Property, Plant and Equipment

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

	December 31,		
	2006		2005
Land and improvements	$ 40,878	$	40,215
Building and improvements	137,971		134,587
Storage, distribution, and transmission	1,963,586		1,861,870
Generation	143,138		136,908
Construction work in process	3,241		30,102
Other equipment	211,714		163,688
	2,500,528		2,367,370
Less accumulated depreciation	(1,221,310)		(1,159,645)
	$ 1,279,218	$	1,207,725

We have an electric default supply capacity and energy sale agreement with the owners of a natural gas fired peaking plant that began operating during 2006. In accordance with the agreement, we provide the natural gas necessary to meet demand, and purchase all of the net electrical capacity and output.

In our assessment of this contract, we determined that it fits the criteria of a capital lease as set forth in Emerging Issues Task Force 01-8, *Determining Whether an Arrangement Contains a Lease*. Accordingly, during 2006 we recorded an increase to property, plant and equipment and a capital lease obligation of approximately $40.2 million, which represents the present value of future cash payments for the base capacity and facility charges under the contract.

(7) Asset Retirement Obligations

We have identified asset retirement obligations, or ARO, 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, however, 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. Accordingly, the recorded amounts of estimated future removal costs are considered regulatory liabilities pursuant to SFAS No. 71, *Accounting for the Effects of Certain Types of Regulations* (SFAS No. 71). These amounts do not represent SFAS No. 143 legal retirement obligations. As of December 31, 2006 and 2005, we have recognized accrued removal costs of $153.4 million and $142.6 million, respectively, which are classified as accumulated depreciation. In addition, for our generation properties, we have accrued decommissioning costs since the generating units were first put into service in the amount of $13.3 million and $12.8 million as of December 31, 2006 and 2005, respectively, which are classified as accumulated depreciation.

In connection with the adoption of FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47), we have recorded a conditional asset retirement obligation of $3.8 million and $3.2 million, as of December 31, 2006 and 2005, respectively, which increases our property, plant and equipment and other regulatory assets. This is primarily related to Department of Transportation requirements to cut, purge and cap retired natural gas pipeline segments. The initial recording of the obligation had no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset pursuant to SFAS No. 71. We measure the liability at fair value when incurred and capitalize a corresponding amount as part of the book value of the related assets. 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 change in our conditional ARO during the year ended December 31, 2006, is as follows (in thousands):

Liability at January 1, 2006	$ 3,233
Accretion expense	254
Liabilities incurred	58
Liabilities settled	(57)
Revisions to cash flows	313
Liability at December 31, 2006	$ 3,801

(8) Utility Plant Adjustments

We review our acquisition and utility plant adjustments for impairment annually during the fourth quarter, or more frequently if changes in circumstances or the occurrence of events suggest an impairment exists. Our utility plant adjustment is $435.1 million as of December 31, 2006 and 2005.

(9) Risk Management and Hedging Activities

We are exposed to market risk, including changes in interest rates and the impact of market fluctuations in the price of electricity and natural gas commodities. We employ established policies and procedures to manage our risk associated with these market fluctuations using various commodity and financial derivative and non-derivative instruments, including forward contracts, swaps and options.

Interest Rates

During 2005, we implemented a risk management strategy of utilizing interest rate swaps to manage our interest rate exposures associated with anticipated refinancing transactions of approximately $380 million. These swaps were designated as cash-flow hedges under SFAS No. 133, with the effective portion of gains and losses, net of associated deferred income tax effects, recorded in accumulated other comprehensive income in our Balance Sheets. We reclassify gains and losses on the hedges from accumulated other comprehensive income (AOCI) into interest expense in our Statements of Income during the periods in which the interest payments being hedged occur.

During the first quarter of 2006, based on a review of our capital structure and cash flow, and approval by our Board of Directors, we decided not to refinance $60 million included in the interest rate swap that was being carried on our revolver. As the refinancing transaction and associated interest payments will not occur, the market value included in AOCI of $3.8 million was recognized in Miscellaneous Nonoperating Income. This forward starting interest rate swap was settled during the second quarter of 2006, and we received an aggregate payment of approximately $3.9 million, which is reflected in investing activities on the statement of cash flows.

In association with the refinancing transactions completed during the second and third quarters of 2006, we settled $170.2 million and $150 million of forward starting interest rate swap agreements, and received aggregate settlement payments of approximately $6.3 million and $8.3 million, respectively. These amounts are being amortized as a reduction to interest expense over the term of the underlying debt as the hedged interest payments are made, which is 17 years and 10 years, respectively. The cash proceeds related to these hedges are reflected in operating activities on the statement of cash flows. As of December 31, 2006 we have no further interest rate swaps outstanding.

Commodity Prices

During the second quarter of 2005, we implemented a risk management strategy of utilizing put options in conjunction with our forward fixed price sales to manage our commodity price risk exposure associated with our lease of a 30% share of the Colstrip Unit 4 generation facility. These transactions were designated as cash-flow hedges of forecasted electric sales of approximately 120,000 MWh in each of the third and fourth quarters of 2006 under the provisions of SFAS No. 133, with unrealized gains and losses being recorded in accumulated other comprehensive income in our Balance Sheets. Due to changes in forward prices for electricity during the fourth quarter of 2005, we utilized unit-contingent forward sales to lock in the remaining output during the third and fourth quarters of 2006, and as a result we undesignated the put options as a hedge of the cash flow variability. During the first quarter of 2006 the put options were sold and we recognized a $1.3 million reduction to cost of sales, reflecting the change in market value since they were undesignated. These cash proceeds are reflected in investing activities on the statement of cash flows. During the third and fourth quarters of 2006, we reclassified unrealized losses of approximately $0.9 million into earnings related to the change in market value prior to the hedges being undesignated. As of December 31, 2006 we have no put options outstanding.

(10) 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, 2006	December 31, 2005
Accounts Receivable from Associated Companies:		
Netexit, Inc.	$ -	$ 181,796
Clark Fork & Blackfoot, LLC	5,588	3,827
Nekota Resources, Inc.	7,299	5,443
NorthWestern Energy Marketing, LLC	2,433	2,334
NorthWestern Services, LLC	-	2,998
Risk Partners Assurance, Ltd.	18	18
	$ 15,338	$ 196,416
Accounts Payable to Associated Companies:		
Blue Dot Services, LLC	$ -	$ 1,192
Canadian Montana Pipeline Corporation	1,743	1,668
Montana Megawatts I, LLC	-	2,017
Natural Gas Funding Trust	216	26
NorCom Advanced Technologies Inc.	-	85
NorthWestern Investments, LLC	6,770	1,002
NorthWestern Services, LLC	35,766	-
	$ 44,495	$ 5,990

(11) Long-Term Debt and Capital Leases

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

	Due	December 31, 2006	December 31, 2005
Unsecured Debt:			
Senior Unsecured Revolver	2009	$50,000	$81,000
Secured Debt:			
Mortgage bonds—			
South Dakota—7.00%	2023	55,000	55,000
Montana—7.30%	2006		150,000
Montana—6.04%	2016	150,000	
Montana—8.25%	2007	365	365
South Dakota & Montana—5.875%	2014	225,000	225,000
Pollution control obligations—			
South Dakota—5.85%	2023	7,550	7,550
South Dakota—5.90%	2023	13,800	13,800
Montana—6.125%	2023		90,205
Montana—5.90%	2023		80,000
Montana—4.65%	2023	170,205	
Discount on Notes and Bonds	—	(71)	(1,898)
		$ 671,849	$ 701,022

Unsecured Revolving Line of Credit

On June 30, 2005, we entered into an amended and restated credit agreement that replaced our existing $225 million secured credit facility with an unsecured $200 million senior revolving line of credit with lower borrowing costs. The unsecured revolving line of credit will mature on November 1, 2009 and does not amortize. The facility bears interest at a variable rate based upon a grid which is tied to our credit rating from Fitch, Moody's, and S&P. The 'spread' or 'margin' ranges from 0.625% to 1.75% over the

London Interbank Offered Rate (LIBOR). The facility currently bears interest at a rate of approximately 6.475%, which is 1.125% over LIBOR. As of December 31, 2006, we had $15.3 million in letters of credit and $50 million of borrowings outstanding under the unsecured revolving line of credit. The weighted average interest rate on the outstanding revolver borrowings was 6.475% as of December 31, 2006.

Commitment fees for the unsecured revolving line of credit were $0.3 million and $0.1 million for the years ended December 31, 2006 and 2005, respectively. Commitment fees for the revolving tranche of the old credit facility were approximately $0.2 million for the first six months of 2005.

The credit facility includes covenants, which require us to meet certain financial tests, including a minimum interest coverage ratio and a minimum debt to capitalization ratio. The amended and restated line of credit also contains covenants which, among other things, limit our ability to incur additional indebtedness, create liens, engage in any consolidation or merger or otherwise liquidate or dissolve, dispose of property, make restricted payments, make loans or advances, and enter into transactions with affiliates. Many of these restrictive covenants will fall away upon the line of credit being rated "investment grade" by two of the three major credit rating agencies consisting of Fitch, Moody's and S&P. We have received a waiver of change in control covenants to allow for the BBI transaction. As of December 31, 2006, we are in compliance with all of the covenants under the amended and restated line of credit.

Secured Debt

The South Dakota Mortgage Bonds are two series of general obligation bonds we issued under our South Dakota indenture, and the South Dakota Pollution Control Obligations are three obligations 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.

Refinancing Transactions

During the second quarter of 2006, we issued $170.2 million of Montana Pollution Control Obligations (PCOs) at a fixed interest rate of 4.65%, and used the proceeds to redeem our 6.125%, $90.2 million and 5.90%, $80.0 million Montana pollution control obligations due in 2023. Consistent with our historical regulatory treatment, the remaining deferred financing costs of approximately $3.8 million were recorded as an unamortized debt expense and will be amortized over the remaining life of the debt. The new PCOs will mature on August 1, 2023, and are secured by our Montana electric and natural gas assets. This transaction will reduce our annual interest on long-term debt by approximately $2.4 million.

During the third quarter of 2006, we issued $150 million of Montana First Mortgage Bonds at a fixed interest rate of 6.04% and used the proceeds to redeem our 7.30%, $150 million Montana first mortgage bonds due December 1, 2006. Consistent with our historical regulatory treatment, the remaining deferred financing costs and prepayment penalty of $0.8 million were recorded as an unamortized debt expense and will be amortized over the remaining life of the debt. The new first mortgage bonds will mature September 1, 2016, and are secured by our Montana electric and natural gas assets. This transaction will reduce our annual interest on long-term debt by approximately $1.9 million.

Maturities of Long-Term Debt

The aggregate minimum principal maturities of long-term debt, during the next five years are $7.7 million in 2007, $7.8 million in 2008, $57.1 million in 2009, $7.3 million in 2010 and $7.8 million in 2011.

(12) Comprehensive Income (Loss)

The Financial Accounting Standards Board defines comprehensive income as all changes to the equity of a business enterprise during a period, except for those resulting from transactions with owners. For example, dividend distributions are excepted. Comprehensive income consists of net income and other comprehensive income (OCI). Net income may include such items as income from continuing operations, discontinued operations, extraordinary items, and cumulative effects of changes in accounting principles. OCI may include foreign currency translations, adjustments of minimum pension liability, and unrealized gains and losses on certain investments in debt and equity securities. Due to our emergence from bankruptcy we made adjustments for fresh-start reporting in accordance with SOP 90-7. These adjustments resulted in removal of items recorded in accumulated OCI of $6.0 million. Comprehensive income (loss) is calculated as follows (in thousands):

	December 31, 2006	December 31, 2005
Net income	$ 37,900	$ 59,467
Other comprehensive income:		
Reclassification of net gains on hedging instruments from OCI to net income	(3,443)	—
Net unrealized gain on derivative instruments qualifying as hedges, net of tax of $3,045 in 2005	12,588	4,885
Foreign currency translation adjustment		56
Total other comprehensive income	9,145	4,941
Total comprehensive income	$ 47,045	$ 64,408

The after tax components of accumulated other comprehensive income were as follows (in thousands):

	December 31, 2006	December 31, 2005
Balance at end of period,		
Unrealized gain on derivative instruments qualifying as hedges	$ 14,030	$ 4,885
Adjustment to initially apply SFAS No. 158	162	—
Foreign currency translation adjustment	79	79
Accumulated other comprehensive income	$ 14,271	$ 4,964

(13) Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of SFAS No. 107, *Disclosures About Fair Value of Financial Instruments*. The estimated fair-value amounts have been determined using available market information and appropriate valuation methodologies. However, considerable judgment is necessarily 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.

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

- The carrying amounts of cash and working funds, special deposits, and investments approximate fair value due to the short maturity of the instruments.

- Fair values for debt were determined 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, which is based on market prices.

The fair-value estimates presented herein are based on pertinent information available to us as of December 31, 2006 and December 31, 2005. Although we are not aware of any factors that would significantly affect the estimated fair-value amounts, such amounts have not been comprehensively revalued for purposes of these financial statements since that date, and current estimates of fair value may differ significantly from the amounts presented herein.

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

	December 31, 2006		December 31, 2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Assets:				
Cash and working funds	$ 1,850	$ 1,850	$ 284	$ 284
Special deposits	2,966	2,966	2,831	2,831
Investments	1,541	1,541	1,846	1,846
Liabilities:				
Long-term debt (including current portion)	671,849	674,131	701,022	703,363

(14) Income Taxes

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

	December 31, 2006	December 31, 2005
Excess tax depreciation	$ (96,967)	$ (120,652)
Regulatory assets	(20,392)	(33,594)
Regulatory liabilities	1,264	(839)
Unbilled revenue	2,980	3,971
Unamortized investment tax credit	2,169	2,458
Compensation accruals	3,680	1,605
Reserves and accruals	21,540	31,084
Goodwill amortization	(42,155)	(33,395)
Net operating loss carryforward (NOL)	13,338	43,012
AMT credit carryforward	3,186	3,186
Capital loss carryforward	6,376	—
Valuation allowance	(10,256)	(10,461)
Other, net	575	(2,489)
	$ (114,662)	$ (116,114)

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 their deferred tax assets. We have a valuation allowance of $10.3 million as of December 31, 2006 against capital loss carryforwards and certain state NOL carryforwards as we do not believe these assets will be realized.

At December 31, 2006 we estimate our total federal NOL carryforward to be approximately $418.1 million. If unused, $246.0 million will expire in the year 2023, and $172.0 million will expire in the year 2025. Our state NOL carryforward as of December 31, 2006 is estimated to be approximately $549.6

million. If unused, $378.9 million will expire in 2010, $33.8 million will expire in 2011, and $136.8 million will expire in 2012. Management believes it is more likely than not that sufficient taxable income will be generated to utilize these NOL carryforwards except as noted above.

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.

Due to our NOL carryforward, years 2000 and forward remain subject to examination by the IRS.

(15) Jointly Owned Plants

We have an ownership interest in three electric generating plants, all of which are coal fired and operated by other utility 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 (S.D.)	Neal #4 (Iowa)	Coyote I (N.D.)
December 31, 2006			
Ownership percentages	23.4%	8.7%	10.0%
Plant in service	$ 52,948	$ 29,930	$ 42,797
Accumulated depreciation	34,588	19,309	24,393
December 31, 2005			
Ownership percentages	23.4%	8.7%	10.0%
Plant in service	$ 53,022	$ 28,870	$ 42,542
Accumulated depreciation	33,188	18,541	23,468

(16) Operating Leases

We lease a generation facility, vehicles, office equipment, an airplane and office and warehouse facilities under various long-term operating leases. At December 31, 2006, future minimum lease payments for the next five years under non-cancelable lease agreements are as follows (in thousands):

2007	$ 34,457
2008	33,386
2009	32,668
2010	32,334
2011	14,520

Lease and rental expense incurred was $30.9 million and $31.0 million for the years ended December 31, 2006 and 2005, respectively.

In January 2005, we exercised an option to extend the term of our Colstrip Unit 4 generation facility lease an additional eight years. By extending the lease term, our annual lease payment remained at $32.2 million through 2010 and decreased to $14.5 million for the remainder of the lease. Beginning in 2005 our lease expense was reduced to $22.1 million annually based on a straight-line calculation over the full term of the lease. We finalized the purchase of the owner participant interest of a portion of this facility, representing approximately 79 megawatts of our leased interest, in March 2007, reducing the annual lease payments to $20.8 million annually through 2010, and $9.3 million annually through 2018.

(17) 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 employees, which includes two cash balance pension plans. The plan for our South Dakota and Nebraska employees is referred to as the NorthWestern Corporation pension plan, and the plan for our Montana employees is referred to as the NorthWestern Energy pension plan. Pension costs in Montana and other postretirement benefit costs in South Dakota are included in rates on a pay as you go basis for regulatory purposes. In 2005, we applied for and received an accounting order from the MPSC to utilize a five-year average of funding cost in our costs of service, therefore we maintain a regulatory asset and amortize it based on our five-year average funding requirement in Montana. Pension costs in South Dakota and other postretirement benefit costs in Montana are included in rates on an accrual basis for regulatory purposes. (See Note 19, Regulatory Assets and Liabilities, for the regulatory assets related to our pension and other postretirement benefit plans.) The prior service costs are amortized on a straight-line basis over the average remaining service period of active participants. Actuarial gains and losses in excess of 10% of the greater of the benefit obligation or the market-related value of assets are normally amortized over the average remaining service period of active participants. However as a result of fresh-start reporting, we adjusted our qualified pension and other postretirement benefit plans to their projected benefit obligation by recognizing all previously unamortized actuarial gains and losses upon emergence. The generation of any future amounts subsequent to emergence will be amortized under the same method as discussed above.

Adoption of SFAS 158

As discussed in Note 3, we adopted SFAS No. 158 as of December 31, 2006, which requires that we recognize the overfunded or underfunded status of our defined benefit and retiree medical plans (our Plans) as an asset or liability in our 2006 year-end balance sheet. Upon our emergence from bankruptcy in November 2004, we recognized a liability for the underfunded status of our Plans, therefore the amount recognized upon adoption of SFAS No. 158 as of December 31, 2006 represents adjustments to our discount rate assumption, our actual 2006 return on plan assets, and other factors. In addition, as we account for the effects of regulation under SFAS No. 71, for those plans which are able to recover the costs from our customers, the change is reflected as an adjustment to regulatory assets rather than other comprehensive income.

The following table illustrates the impact of adoption of SFAS No. 158 on the financial statements as of December 31, 2006 (in thousands):

	Before Application of SFAS No. 158	Adjustments	After Application of SFAS No. 158
Regulatory asset	$ 139,159	$ (23,037)	$ 116,122
Total assets	139,159	(23,037)	116,122
Pension liability	107,700	(21,237)	86,463
Other postretirement liability	39,736	(2,063)	37,673
Deferred tax liability	120,752	(101)	120,651
Total liabilities	268,188	(23,401)	244,787
Accumulated other comprehensive income	14,109	162	14,271
Total shareholder's equity	$ 14,109	$ 162	$ 14,271