COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account	Ref. Page No.	Balance at Beginning of Yr	Balance at End of Year
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200-201	$10,132,293,560	$10,577,759,885
3	Construction Work in Progress (107)	200-201	374,984,455	340,580,582
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		$10,507,278,015	$10,918,340,467
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200-201	5,085,719,106	5,303,941,597
6	Net Utility Plant (Enter Total of line 4 less 5)		$5,421,558,909	$5,614,398,870
7	Nuclear Fuel (120.1-102.4, 120.0)	202-203	316,081,624	350,143,089
8	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	325,469,620	340,595,962
9	Net Nuclear Fuel (Enter Total of line 7 less 8)		($9,387,996)	$9,547,127
10	Net Utility Plant (Enter Total of lines 6 and 9)		$5,412,170,913	$5,623,945,997
11	Utility Plant Adjustments (116)	122	0	0
12	Gas Stored Underground-Noncurrent (117)	220-Gas	0	0
13	OTHER PROPERTY AND INVESTMENTS			
14	Nonutility Property (121)	221	$15,067,221	$15,007,071
15	(Less) Accum. Prov. for Depr. and Amort. (122)	221	917,308	1,620,352
16	Investments in Associated Companies (123)	222-223	20,113,070	24,669,200
17	Investment in Subsidiary Companies (123.1)	224-225	668,037,531	761,190,933
18	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
19	Noncurrent Portion of Allowances	228-229	0	0
20	Other Investments (124)	222-223	6,686,897	6,652,188
21	Special Funds (125-128)		597,686,545	605,410,963
22	TOTAL Other Property and Investments (Total of lines 14 thru 17, 19 thru 21)		$1,306,673,956	$1,411,310,003
23	CURRENT AND ACCRUED ASSETS			
24	Cash (131)		$43,336,745	$13,865,089
25	Special Deposits (132-134)		0	5,319,313
26	Working Funds (135)		2,680,151	112,044
27	Temporary Cash Investments (136)	222-223	1,442,238	32,074,158
28	Notes Receivable (141)	226A	0	5,942,160
29	Customer Accounts Receivable (142)	226A	14,158,341	9,529,496
30	Other Accounts Receivable (143)	226A	29,806,056	36,451,751
31	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)	226A	8,451,343	9,909,700
32	Notes Receivable from Associated Companies (145)	226B	0	0
33	Accounts Receivable from Assoc. Companies (146)	226B	4,880,776	14,571,739
34	Fuel Stock (151)	227	41,031,275	48,732,160
35	Fuel Stock Expense Undistributed (152)	227	0	0
36	Residuals (Elec) and Extracted Products (Gas) (153)	227	0	0
37	Plant Material and Operating Supplies (154)	227	70,252,911	66,993,127
38	Merchandise (155)	227	0	0
39	Other Material and Supplies (156)	227	0	0
40	Nuclear Materials Held for Sale (157)	202,227	0	20

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS) (CONTINUED)

Line No.	Title of Account	Ref. Page No.	Balance at Beginning of Yr	Balance at End of Year
41	Allowances	228-229	22,269,745	15,594,075
42	(Less) Noncurrent Portion of Allowances		0	0
43	Stores Expenses Undistributed (163)	227	(560,136)	0
44	Gas Stored Underground - Current (164.1)	220-Gas	739,123,655	854,841,552
45	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)	220-Gas	0	0
46	Prepayments (165)		428,695,180	424,148,076
47	Advances for Gas (166-167)		0	0
48	Interest and Dividends Receivable (171)		6,967	16,134
49	Rents Receivable (172)		1,596,471	1,400,688
50	Accrued Utility Revenues (173)		0	117,567
51	Miscellaneous Current and Accrued Assets (174)	229	214,526,039	218,152,130
52	TOTAL Current and Accrued Assets (Enter Total of lines 23 thru 51)		$1,604,795,071	$1,737,951,579
53	DEFERRED DEBITS			
54	Unamortized Debt Expense (181)		$39,597,074	$40,859,776
55	Extraordinary Property Losses (182.1)	230B	0	0
56	Unrecovered Plant and Regulatory Study Costs (182.2)	230B	10,354,377	9,835,861
57	Other Regulatory Assets	232	1,073,523,034	1,643,359,877
58	Prelim. Survey and Investigation Charges (Electric) (183)	231	0	0
59	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)	231	0	0
60	Clearing Accounts (184)		(6,916,929)	559,640
61	Temporary Facilities (185)		0	0
62	Miscellaneous Deferred Debits (186)	233	30,782,731	42,494,243
63	Def. Losses from Disposition of Utility Plt. (187)	236	0	0
64	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
65	Unamortized Loss on Reacquired Debt (189)	237	51,048,225	71,384,788
66	Accumulated Deferred Income Taxes (190-192)	234-235	758,404,139	809,287,809
67	Unrecovered Purchased Gas Costs (191)		0	0
68	TOTAL Deferred Debits (Enter Total of lines 53 thru 67)		$1,956,792,651	$2,617,781,994
69	TOTAL Assets and other Debits (Enter Total of lines 10, 11, 12, 22, 52, and 68)		$10,280,432,591	$11,390,989,573

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account	Ref. Page No.	Balance at Beginning of Yr	Balance at End of Year
1	PROPRIETARY CAPTIAL			
2	Common Stock Issued (201)	250-251	$841,087,890	$841,087,890
3	Preferred Stock Issued (204)	250-251	44,159,900	44,159,900
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	386,028,613	386,028,613
7	Other Paid-In Capital (208-211)	253	336,732,838	600,860,948
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254	23,718,573	23,718,573
11	Retained Earnings (215, 215.1, 216)	118-119	299,689,261	383,259,128
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	220,948,792	224,488,555
13	(Less) Reacquired Capital Stock (217)	250-251	0	0
14	TOTAL Proprietary Capital (Enter Total of lines 2 thru 13)		$2,104,928,721	$2,456,166,461
15	LONG-TERM DEBT			
16	Bonds (221)	256-257	$1,482,700,000	$2,300,000,000
17	(Less) Reacquired Bonds (222)	256-257	0	0
18	Advances from Associated Companies (223)	256-257	894,541,239	865,895,379
19	Other Long-Term Debt (224)	256-257	1,679,052,149	1,095,436,983
20	Unamortized Premium on Long-Term Debt (225)		2,982,906	2,656,078
21	(Less) Unamortized Discount on Long-Term Debt-Dr. (226)		24,146,482	18,450,135
22	TOTAL Long-Term Debt (Enter Total of lines 16 thru 21)		$4,035,129,812	$4,245,538,305
23	OTHER NONCURRENT LIABILITIES			
24	Obligations Under Capital Leases - Noncurrent (227)		$57,703,424	$47,906,111
25	Accumulated Provision for Property Insurance (228.1)		0	0
26	Accumulated Provision for Injuries and Damages (228.2)		21,467,900	33,382,996
27	Accumulated Provision for Pensions and Benefits (228.3)		190,106,327	560,810,943
28	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
29	Accumulated Provision for Rate Refunds (229)		15,026,070	23,308,031
30	TOTAL Other Noncurrent Liabilities (Total of lines 24 thru 29)		$284,303,721	$665,408,081
31	CURRENT AND ACCRUED LIABILITIES			
32	Notes Payable (231)	260A	$0	$0
33	Accounts Payable (232)		186,049,674	240,279,436
34	Notes Payable to Associated Companies (233)	260B	237,361,641	38,218,389
35	Accounts Payable to Associated Companies (234)	260B	74,543,876	64,125,373
36	Customer Deposits (235)		23,329,595	29,580,152
37	Taxes Accrued (236)	262-263	202,338,954	267,907,444
38	Interest Accrued (237)		54,518,570	55,103,798
39	Dividends Declared (238)		0	0
40	Matured Long-Term Debt (239)		0	0

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (CONTINUED)

Line No.	Title of Account	Ref. Page No	Balance at Beginning of Yr	Balance at End of Year
41	Matured Interest (240)		0	0
42	Tax Collections Payable (241)		554,113	3,112,110
43	Miscellaneous Current and Accrued Liabilities (242)	268	124,914,680	106,257,888
44	Obligations Under Capital Leases-Current (243)		10,175,510	10,389,983
45	Fed. Inc. Tax Accrued - Prior Year (244)		0	0
46	Michigan Single Business Taxes Accrued for Prior Years (244.1)		0	0
47	Fed. Inc. Tax Accrued - Prior Year Adj (245)		0	0
48	Michigan Single Business Taxes Accrued for Prior Years-Adj. (245.1)		0	0
49	TOTAL Current and Accrued Liabilities (Total of lines 32 thru 48)		$913,786,613	$814,974,573
50	DEFERRED CREDITS			
51	Customer Advances for Construction (252)	268	$27,442,562	$33,503,806
52	Accumulated Deferred Investment Tax Credits (255)	266-267	73,057,767	69,229,339
53	Deferred Gains from Disposition of Utility Plant (256)	270	0	0
54	Other Deferred Credits (253)	269	505,802,112	577,565,519
55	Other Regulatory Liabilities	278	514,192,326	559,110,940
56	Unamortized Gain on Reacquired Debt (257)	237	0	0
57	Accumulated Deferred Income Taxes (281-284)	272-277	1,821,788,957	1,969,492,549
58	TOTAL Deferred Credits (Enter Total of lines 51 thru 57)		$2,942,283,724	$3,208,902,153
59	TOTAL Liabilities and Other Credits (Enter Total of lines 14, 22, 30, 49 and 58)		$10,280,432,591	$11,390,989,573

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another utility column (I, k, m, o) in a similar manner to a utility department. Spread the amount(s) over lines 02 thru 24 as appropriate. Include thses amounts in columns (c) and (d) totals.
2. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
3. Report data for lines 7, 9, and 10 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1, and 407.2.
4. Use pages 122-123 for important notes regarding the statement of income or any account therof.
5. Give concise explanations concerning unsettled rate proceedings where a contigency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenue or costs to which the contigency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover

Line No.	Account	Ref. Page No.	TOTAL Current Year	Previous Year
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	300-301	$4,632,102,099	$4,380,900,514
3	Operating Expenses			
4	Operation Expenses (401)	320-323	$3,309,484,576	$3,065,541,648
5	Maintenance Expenses (402)	320-323	$207,914,744	191,944,340
6	Depreciation Expense (403)	336-337	$285,083,864	316,200,884
7	Amort. & Depl. of Utility Plant (404-405)*	336-337	$18,960,791	18,588,748
8	Amort. of Utility Plant Acq. Adj. (406)	336-337	$6,158	6,158
9	Amort. of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)		$518,516	612,648
10	Amort. of Conversion Expenses (407)		$0	0
11	Regulatory Debits		$53,917,936	41,709,000
12	(Less) Regulatory Credits		$56,673,000	0
13	Taxes Other Than Income Taxes (408.1)	262-263	$192,730,731	180,642,257
14	Income Taxes - Federal (409.1)	262-263	(13,242,647)	(69,085,400)
15	- Other (409.1)	262-263	0	(402,839)
16	Provision for Deferred Inc. Taxes (410.1)	234,272-276	$318,269,093	402,223,442
17	(Less) Provision for Deferred Income Taxes - Cr.(411.1)	234,272-276	$178,530,658	197,807,849
18	Investment Tax Credit Adj. - Net (411.4)	266-267	(3,828,428)	(4,114,717)
19	(Less) Gains from Disp. of Utility Plant (411.7)	270A-B	$29,583	0
20	Losses from Disp. of Utility Plant (411.7)	235A-B	$172,591	0
21	(Less) Gains from Disposition of Allowances			9,549,027
22	Losses from Disposition of Allowances		$20,764	0
23	TOTAL Utility Operating Expenses (Total of lines 4 thru 22)		$4,134,775,448	$3,936,509,293
24	Net Utility Operating Income (Enter total of line 2 less 23) (Carry forward to page 117, line 25)		$497,326,651	$444,391,221

* Current year amount includes $549,030, last year includes $1,267,095 of ARO accretion expense.

STATEMENT OF INCOME FOR THE YEAR (CONTINUED)

amounts paid with respect to power and gas purchases.

6. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.

7. If any notes appearing in the report to stockholders are applicable to this Statement of Income, such as notes may be included on pages 122-123.

8. Enter on pages 122-123 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also give the approximate dollar effect of such changes.

9. Explain in a footnote if the previous year's figures are different from that reported in prior years.

10. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, lines 2 to 23, and report the information in the blank space on pages 122-123 or in a footnote.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year	No.
						1
$2,542,779,074	$2,543,909,804	$2,089,323,025	$1,836,990,710	$0	$0	2
						3
$1,604,259,577	$1,576,524,671	$1,705,224,999	$1,489,016,977	$0	$0	4
165,494,317	151,907,048	42,420,427	40,037,292	0	0	5
182,859,584	197,309,806	102,224,280	118,891,078	0	0	6
8,829,569	9,242,802	10,131,222	9,345,946	0	0	7
0	0	6,158	6,158	0	0	8
						9
518,516	555,801	0	56,847	0	0	
0	0	0	0	0	0	10
53,861,090	41,709,000	56,847	0	0	0	11
56,673,000	0	0	0	0	0	12
139,164,730	130,999,557	53,566,001	49,642,700	0	0	13
(20,432,643)	(25,889,074)	7,189,996	(43,196,326)	0	0	14
0	(293,879)	0	(108,960)	0	0	15
224,447,615	265,199,058	93,821,478	137,024,384	0	0	16
117,679,248	142,101,872	60,851,410	55,705,977	0	0	17
(2,964,770)	(3,032,223)	(863,658)	(1,082,494)	0	0	18
29,583	0	0	0			19
166,606	0	5,985	0			20
0	9,549,027		0			21
20,764	0		0			22
$2,181,843,123	$2,192,581,668	$1,952,932,325	$1,743,927,625	$0	$0	23
$360,935,951	$351,328,136	$136,390,700	$93,063,085	$0	$0	24

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	Account	Ref. Page No.	TOTAL Current Year	TOTAL Previous Year
25	Net Utility Operating Income (Carried forward from page 114)		$497,326,651	$444,391,221
26	Other Income and Deductions			
27	Other Income			
28	Nonutility Operating Income			
29	Revenues From Merchandising, Jobbing and Contract Work (415)	282	$44,803,444	$47,514,704
30	(Less) Costs & Exp. of Merchandising,Job & Contr. Work (416)	282	36,761,677	41,326,173
31	Revenues From Nonutility Operations (417)	282	1,854,296	5,542,723
32	(Less)Expenses of Nonutility Operations (417.1)	282	1,708,413	1,826,153
33	Nonoperating Rental Income (418)	282	497,946	638,895
34	Equity in Earnings of Subsidiary Companies (418.1)	119,282	2,128,290	19,999,799
35	Interest and Dividend Income (419)	282	5,723,645	6,755,013
36	Allowance for Other Funds Used During Construction (419.1)	282	(143,197)	3,034,218
37	Miscellaneous Nonoperating Income (421)	282	126,662,061	15,684,658
38	Gain on Disposition of Property (421.1)	280	1,554,447	2,791,010
39	TOTAL Other Income (Enter Total of lines 29 thru 38)		$144,610,842	$58,808,694
40	Other Income Deductions			
41	Loss on Disposition of Property (421.2)	280	$793,696	$1,196,123
42	Miscellaneous Amortization (425)	340	0	0
43	Miscellaneous Income Deductions (426.1-426.5)	340,341	37,206,265	75,340,876
44	TOTAL Other Income Deductions (Total of lines 41 thru 43)		$37,999,961	$76,536,999
45	Taxes Applic. to Other Income and Deductions			
46	Taxes Other Than Income Taxes (408.2)	262-263	$370,568	$787,320
47	Income Taxes - Federal (409.2)	262-263	27,336,288	(19,071,645)
48	Income Taxes - Other (409.2)	262-263	0	
49	Provision for Deferred Inc. Taxes (410.2)	234,272-276	13,476,850	12,427,085
50	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234,272-276	12,626,755	8,099,558
51	Investment Tax Credit Adj.- Net (411.5)	264-265	0	0
52	(Less) Investment Tax Credits (420)	264-265	0	0
53	TOTAL Taxes on Other Inc. & Ded. (Total of lines 46 thru 52)		$28,556,951	($13,956,798)
54	Net Other Income and Deductions (Total of lines 39, 44, & 53)		$78,053,930	($3,771,507)
55	Interest Charges			
56	Interest on Long-Term Debt (427)	257	$196,096,207	$154,634,127
57	Amortization of Debt Disc. and Expense (428)	256-257	8,884,323	18,643,930
58	Amortization of Loss on Reacquired Debt (428.1)		8,032,964	1,617,841
59	(Less) Amort. of Premium on Debt - Credit (429)	256-257	326,828	678,213
60	(Less) Amortization of Gain on Reacquired Debt - Credit (429.1)		0	0
61	Interest on Debt to Assoc. Companies (430)	257-340	68,229,491	66,623,601
62	Other Interest Expense (431)	340	10,474,488	12,523,728
63	(Less)Allow. for Borrowed Funds Used During Constr.-Cr. (432)		(4,916,369)	8,711,477
64	Net Interest Charges (Total of lines 56 thru 63)		$296,307,014	$244,653,537
65	Income Before Extraordinary Items (Total of lines 25, 54 and 64)		$279,073,567	$195,966,177
66	Extraordinary Items			
67	Extraordinary Income (434)	342	$0	$0
68	(Less) Extraordinary Deductions (435)	342	0	0
69	Net Extraordinary Items (Enter Total of line 67 less line 68)		$0	$0
70	Income Taxes - Federal and Other (409.3)	262-263	0	0
71	Extraordinary Items After Taxes (Total of line 69 less line 70)		$0	$0
72	Net Income (Enter Total of lines 65 and 71)		$279,073,567	$195,966,177

RECONCILIATION OF DEFERRED INCOME TAX EXPENSE

1. Report on this page the charges to accounts 410, 411 and 420 reported in the contra accounts 190, 281, 282, 283 and 284.
2. The charges to the subaccounts of 410 and 411 found on pages 114-117 should agree with the subaccount totals reported on this page. In the event the deferred income tax expenses reported on pages 114-117 do not directly reconcile with the amounts found on this page, then provide the additional information requested in instruction #3, on a separate page.

Line No.		Electric Utility	Gas Utility
1	Debits to Account 410 from:		
2			
3	Account 190	29,979,669	17,950,975
4	Account 281	0	0
5	Account 282	74,521,885	33,562,236
6	Account 283	119,946,061	42,308,267
7	Account 284	0	0
8			
9	Reconciling Adjustments	0	0
10	Total Account 410.1 (on pages 114-15 line 16)	224,447,615	93,821,478
11	Total Account 410.2 (on page 117 line 49)		
12			
13			
14	Credits to Account 411 from:		
15			
16	Account 190	35,658,597	34,337,525
17	Account 281	0	
18	Account 282	30,669,814	12,023,386
19	Account 283	51,350,837	14,490,499
20	Account 284	0	0
21	Reconciling Adjustments	0	0
22	Total Account 411.1 (on pages 114-15 line 17)	117,679,248	60,851,410
23	Total Account 411.2 (on page 117 line 50)		
24			
25	Net ITC Adjustment - Account 255		
26	ITC Utilized for the Year DR	0	0
27	ITC Amortized for the Year CR	(2,964,770)	(863,658)
28	ITC Adjustments:		
29	Adjust last year's estimate		
30	to actual per filed return	0	0
31			
32	Other (specify)	0	0
33	Net Reconciling Adjustments Account 411.4*	(2,964,770)	(863,658)
34	Net Reconciling Adjustments Account 411.5**		
35	Net Reconciling Adjustments Account 420***		

* on pages 114-115 line 18
** on page 117 line 51
*** on page 117 line 52

RECONCILIATION OF DEFERRED INCOME TAX EXPENSE (Continued)

3. (a) Provide a detailed reconciliation of the applicable deferred income tax expense subaccount(s) reported on pages 114-117 with the amount reported on this page.
(b) Identify all contra accounts (other than accounts 190 and 281-284).
(c) Identify the company's regulatory authority to utilize a contra account other than accounts 190 or 281-284 for the recording of deferred income tax expense(s).

Other Utility	Total Utility	Other Income	Total Company	Line No.
				1
				2
0	47,930,644	12,474,426	60,405,070	3
0	0	0	0	4
0	108,084,121	4,594	108,088,715	5
0	162,254,328	997,830	163,252,158	6
0	0	0	0	7
				8
0	0	0	0	9
0	318,269,093			10
		13,476,850		11
				12
				13
				14
				15
0	69,996,122	11,689,422	81,685,544	16
0	0	0	0	17
0	42,693,200	5,709	42,698,909	18
0	65,841,336	931,624	66,772,960	19
0	0	0	0	20
0	0	0	0	21
0	178,530,658			22
		12,626,755		23
				24
				25
0	0	0	0	26
0	(3,828,428)	0	(3,828,428)	27
				28
				29
0	0	0	0	30
				31
0	0	0	0	32
0	(3,828,428)	0		33
		0		34
		0		35

OPERATING LOSS CARRYFORWARD						
Fill in below when the company sustains an operating loss, loss carryback or carryforward whenever or wherever applicable.						
				Loss Utilized		
Line No.	Year (a)	Operating Loss (b)	Loss or Carryforward (F) or Carryback (B) (c)	Amount (d)	Year (e)	Balance Remaining (f)
1	2001	674,397,536	F	634,387,239	various	40,010,297
2	2003	142,656,967	F	130,791,795	various	11,865,172
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
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20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35	Total					51,875,469

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		154,183,046	102,038,144
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		276,945,277	175,966,378
17	Appropriations of Retained Earnings (Acct. 436)			
18	Excess Hydro Earnings		-3,416,411	(4,167,831)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-3,416,411	(4,167,831)
23	Dividends Declared-Preferred Stock (Account 437)			
24	4.50 Preferred		-1,679,180	(1,679,180)
25	4.16 Preferred		-284,756	(284,756)
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-1,963,936	(1,963,936)
30	Dividends Declared-Common Stock (Account 438)			
31			-190,000,000	(218,115,783)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-190,000,000	(218,115,783)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		1,411,474	100,426,074
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		237,159,450	154,183,046

Name of Respondent Consumers Energy Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2004/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39			100,000,000	100,000,000
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)		100,000,000	100,000,000
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		47,511,152	44,094,741
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		147,511,152	144,094,741
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		384,670,602	298,277,787
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		222,360,266	302,786,541
50	Equity in Earnings for Year (Credit) (Account 418.1)		2,128,290	19,999,799
51	(Less) Dividends Received (Debit)		1,411,475	30,450,000
52	Dissolved Subsidiaries - transferred to 216 (MGS, METCO, PARNALL HLDS)			(69,976,074)
53	Balance-End of Year (Total lines 49 thru 52)		223,077,081	222,360,266

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	279,073,567	195,966,177
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	301,265,236	375,850,343
5	Amortization of Capital Lease and Debt	25,765,240	28,223,851
6	Gain on Disposition of Property	-760,751	-1,594,887
7	Regulatory Return on Capital Expenditures	-112,935,000	
8	Deferred Income Taxes (Net)	86,032,939	192,544,906
9	Investment Tax Credit Adjustment (Net)	-3,828,428	-4,114,717
10	Net (Increase) Decrease in Receivables	-104,973,302	-30,622,953
11	Net (Increase) Decrease in Inventory	-128,719,154	-255,273,074
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	118,246,938	-68,365,239
14	Net (Increase) Decrease in Other Regulatory Assets	-12,873,447	-36,298,930
15	Net Increase (Decrease) in Other Regulatory Liabilities	44,974,480	56,060,009
16	(Less) Allowance for Other Funds Used During Construction	-143,197	3,034,218
17	(Less) Undistributed Earnings from Subsidiary Companies	716,816	-24,868,201
18	Bad Debt Expense	20,260,237	20,748,682
19	Cumulative Effect of Change in Accounting	739,887	
20	Prepayments	4,547,104	-385,592,858
21	Change in Other Assets and Liabilities	22,040,386	-86,862,200
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	538,282,313	22,503,093
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-429,747,385	-375,753,234
27	Gross Additions to Nuclear Fuel	-34,587,697	-24,160,227
28	Gross Additions to Common Utility Plant	-23,109,542	-84,244,375
29	Gross Additions to Nonutility Plant	-2,339	
30	(Less) Allowance for Other Funds Used During Construction		
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-487,446,963	-484,157,836
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	1,939,430	2,454,458
38	Cost to Retire Property	-73,250,302	-71,919,431
39	Investments in and Advances to Assoc. and Subsidiary Companies	-41,380,079	-34,622,413
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43	Miscellaneous Investments	15,667,253	20,507,345
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-584,470,661	-567,737,877
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	1,038,767,087	1,602,644,617
62	Preferred Stock		
63	Common Stock		
64	Contribution from Stockholder	250,000,000	
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,288,767,087	1,602,644,617
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-837,158,417	-760,520,000
74	Preferred Stock		
75	Common Stock		
76	Payment of Capital Leases	-9,918,822	-13,453,981
77			
78	Net Decrease in Short-Term Debt (c)	-199,143,252	-256,040,144
79			
80	Dividends on Preferred Stock	-2,446,778	-1,972,078
81	Dividends on Common Stock	-190,000,000	-218,115,783
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	50,099,818	352,542,631
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	3,911,470	-192,692,153
87			
88	Cash and Cash Equivalents at Beginning of Period	47,459,134	240,151,287
89			
90	Cash and Cash Equivalents at End of period	51,370,604	47,459,134

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Consumers Energy Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2004/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

Consumers Energy Company
Notes to Consolidated Financial Statements

The footnotes included herein are from Consumers Energy's annual report as of December 31, 2004, which are prepared on a consolidated basis as permitted by instruction 6 on page 122 of this report. These include the consolidated balances of the Midland Cogeneration Venture Limited Partnership and First Midland Limited Partnership (FMLP) as of December 31, 2004, in accordance with Revised FASB Interpretation 46. The financial statements on pages 110-121 of this report are prepared utilizing the equity method of accounting for the subsidiaries of Consumers Energy and reflect the line item classifications utilized in regulatory accounting. Accordingly, the footnotes have been presented on a consolidated basis as allowed by regulatory guidance. The FMLP's earnings for 2004 was $33 million. Summarized financial information of the MCV Partnership for 2004 follows:

Statements of Income

	In Millions
Years Ended December 31	2004
Operating revenue	$650
Operating expenses	574
Operating income	76
Other expense, net	99
Net Income	(23)

Balance Sheet

			In Millions
December 31	2004		2004
Assets		**Liabilities and Equity**	
Current assets	$ 367	Current liabilities	$ 226
Plant, net	1,425	Non-current liabilities	944
Other assets	188	Partners' equity	810
	$ 1,980		$ 1,980

1: Corporate Structure and Accounting Policies

Corporate Structure: Consumers, a subsidiary of CMS Energy, a holding company, is a combination electric and gas utility company that provides service to customers in Michigan's Lower Peninsula. Our customer base includes a mix of residential, commercial, and diversified industrial customers, the largest segment of which is the automotive industry.

Principles of Consolidation: The consolidated financial statements include Consumers, and all other entities in which we have a controlling financial interest or are the primary beneficiary, in accordance with Revised FASB Interpretation No. 46. The primary beneficiary of a variable interest entity is the party that absorbs or receives a majority of the entity's expected losses or expected residual returns or both as a result of holding variable interests, which are ownership, contractual, or other economic interests. In 2004, we consolidated the MCV Partnership and the FMLP in accordance with Revised FASB Interpretation No. 46. For additional details, see Note 13, Implementation of New Accounting Standards. These entities are reported as equity method investments in our consolidated financial statements for all periods prior to January 1, 2004. We use the equity method of accounting for investments in companies and partnerships that are not consolidated, where we have significant influence over operations and financial policies, but are not the primary beneficiary. Intercompany transactions and balances have been eliminated.

Use of Estimates: We prepare our consolidated financial statements in conformity with U.S. generally accepted accounting principles. We are required to make estimates using assumptions that may affect the reported amounts and disclosures. Actual results could differ from those estimates.

We are required to record estimated liabilities in the consolidated financial statements when it is probable that a loss will be incurred in the future as a result of a current event, and when the amount can be reasonably estimated. We have used this accounting principle to record estimated liabilities as discussed in Note 2, Contingencies.

Revenue Recognition Policy: We recognize revenues from deliveries of electricity and natural gas, and the storage of natural gas when services are provided. Sales taxes are recorded as liabilities and are not included in revenues.

Capitalized Interest: We are required to capitalize interest on certain qualifying assets that are undergoing activities to prepare them for their intended use. Capitalization of interest for the period is limited to the actual interest cost that is incurred. Our regulated businesses are permitted to capitalize an allowance for funds used during construction on regulated construction projects and to include such amounts in plant in service.

Cash Equivalents and Restricted Cash: All highly liquid investments with an original maturity of three months or less are considered cash equivalents.

At December 31, 2004, our restricted cash on hand was $21 million. Restricted cash dedicated for repayment of Securitization bonds is classified as a current asset as the payments on the related Securitization bonds occur within one year.

Financial Instruments: We account for investments in debt and equity securities using SFAS No. 115. Debt and equity securities classified as available-for-sale are reported at fair value determined from quoted market prices. Debt and equity securities classified as held-to-maturity are reported at cost. Unrealized gains or losses resulting from changes in fair value of certain available-for-sale debt and equity securities are reported, net of tax, in equity as part of accumulated other comprehensive income. Unrealized gains or losses are excluded from earnings unless the related changes in fair value are determined to be other than temporary.

Unrealized gains or losses on our nuclear decommissioning investments are reflected as regulatory liabilities on our Consolidated Balance Sheets. Realized gains or losses would not affect our earnings or cash flows.

For additional details regarding financial instruments, see Note 4, Financial and Derivative Instruments.

Gas Inventory: We use the weighted average cost method for valuing working gas and recoverable cushion gas in underground storage facilities

Generating Plant Fuel Stock Inventory: We use the weighted average cost method for valuing coal inventory and classify these costs as generating plant fuel stock on our Consolidated Balance Sheets. The MCV Partnership's natural gas inventory is also included in this category, stated at the lower of cost or market and valued using the last-in, first-out ("LIFO") method.

Impairment of Investments and Long-Lived Assets: We evaluate the potential impairment of our investments in projects and other long-lived assets, other than goodwill, based on various analyses, including the projection of undiscounted cash flows, whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. If the carrying amount of the investment or asset exceeds its estimated undiscounted future cash flows, an impairment loss is recognized, and the investment or asset is written down to its estimated fair value.

Maintenance and Depreciation: We charge property repairs and minor property replacements to maintenance expense. We also charge planned major maintenance activities to operating expense unless the cost represents the acquisition of additional components or the replacement of an existing component. We capitalize the cost of plant additions and replacements. We depreciate utility property using straight-line rates approved by the MPSC. The composite depreciation rates for our properties are:

Years Ended December 31	2004	2003	2002
Electric utility property	3.2%	3.1%	3.1%
Gas utility property	3.7%	4.6%	4.5%
Other property	8.4%	8.1%	7.2%

Nuclear Fuel Cost: We amortize nuclear fuel cost to fuel expense based on the quantity of heat produced for electric generation. For nuclear fuel used after April 6, 1983, we charge certain disposal costs to nuclear fuel expense, recover these costs through electric rates, and remit them to the DOE quarterly. We elected to defer payment for disposal of spent nuclear fuel burned before April 7, 1983. As of December 31, 2004, we have recorded a liability to the DOE of $141 million, including interest, which is payable upon the first delivery of spent nuclear fuel to the DOE. The amount of this liability, excluding a portion of interest, was recovered through electric rates. For additional details on disposal of spent nuclear fuel, see Note 2, Contingencies, "Other Electric Contingencies – Nuclear Matters."

Other Income and Other Expense: The following tables show the components of Other income and Other expense:

			In Millions
Years Ended December 31	2004	2003	2002
Other income			
Electric restructuring return	$ 6	$ 8	$ 4
Return on stranded costs	7	-	-
Return on security costs	2	-	-
All other	1	2	2
Total other income	$ 16	$ 10	$ 6

			In Millions
Years Ended December 31	2004	2003	2002
Other expense			
Loss on SERP investment	$ (1)	$ (1)	$ (3)

Loss on CMS Energy stock	-	(12)	(12)
Civic and political expenditures	(2)	(2)	(3)
Donations	(1)	-	-
All other	(3)	(4)	(7)
Total other expense	$ (7)	$ (19)	$ (25)

Property, Plant, and Equipment: We record property, plant, and equipment at original cost when placed into service. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost is charged to accumulated depreciation. The cost of removal, less salvage, is recorded as a regulatory liability. For additional details, see Note 6, Asset Retirement Obligations. An allowance for funds used during construction is capitalized on regulated construction projects. With respect to the retirement or disposal of non-regulated assets, the resulting gains or losses are recognized in income.

Property, plant, and equipment at December 31, 2004 and 2003, was as follows:

				In Millions
Years Ended December 31		Estimated Depreciable Life in Years (e)	2004	2003
Electric:				
	Generation	13-105	$ 3,433	$ 3,332
	Distribution	12-75	4,069	3,799
	Other	7-50	384	388
	Capital leases (a)		81	81
Gas:				
	Underground storage facilities (b)	30-65	255	232
	Transmission	15-75	367	342
	Distribution	40-75	2,057	1,976
	Other	7-50	290	300
	Capital leases (a)		26	25
Other:	MCV Facility	5-35	2,481	-
	Non-utility property	7-71	15	15
	Construction work-in-progress		353	375
	Other		27	-
Less accumulated depreciation, depletion, and amortization (c)			5,665	4,417
Net property, plant, and equipment (d)			$ 8,173	$ 6,448

(a) Capital leases presented in this table are gross amounts. Accumulated amortization of capital leases was $49 million at December 31, 2004 and $38 million at December 31, 2003.

(b) Includes unrecoverable base natural gas in underground storage of $26 million at December 31, 2004 and $23 million at December 31, 2003, which is not subject to depreciation.

(c) As of December 31, 2004, accumulated depreciation, depletion, and amortization is comprised of $4.601 billion from public utility plant, $1.063 billion related to the consolidation of the MCV Facility, and $1 million from our non-utility plant assets. As of December 31, 2003, accumulated depreciation, depletion, and amortization included $4.416 billion from our public utility plant and $1 million related to non-utility plant assets.

(d) Included in net property, plant and equipment are intangible assets primarily related to software development costs, consents, leasehold improvements, and rights of way. The estimated amortization life for software development costs is seven years. The estimated amortization life for leasehold improvements is over the life of the lease. Other intangible amortization lives range from 50 to 105 years. Intangible assets at December 31, 2004 and 2003 were as follows:

In Millions

Year Ended December 31, 2004	Gross Cost	Accumulated Amortization	Intangible Asset, Net
Software development	$ 179	$ 117	$ 62
Rights of way	93	28	65
Leasehold improvements	20	13	7
Franchises and consents	19	9	10
Other intangibles	18	14	4
Totals	$ 329	$ 181	$ 148

In Millions

Year Ended December 31, 2003	Gross Cost	Accumulated Amortization	Intangible Asset, Net
Software development	$ 178	$ 107	$ 71
Rights of way	89	25	64
Leasehold improvements	32	30	2
Franchises and consents	19	8	11
Other intangibles	18	14	4
Totals	$ 336	$ 184	$ 152

Pre-tax amortization expense related to these intangible assets was $19 million for the year ended December 31, 2004, $19 million for the year ended December 31, 2003, and $17 million for the year ended December 31, 2002. Intangible assets amortization is forecasted to range from $8 million to $19 million per year over the next five years.

(e) The following table illustrates the depreciable life for electric and gas structures and improvements:

Electric	Estimated Depreciable Life in Years	Gas	Estimated Depreciable Life in Years
Generation:		Underground storage facilities	45-50
Coal	39-43	Transmission	60
Nuclear	17-25	Distribution	50
Hydroelectric	55-71	Other	50

Other	32
Distribution	50-60
Other	40-42

Reclassifications: Certain prior year amounts have been reclassified for comparative purposes. These reclassifications did not affect consolidated net income for the years presented.

Related Party Transactions: We received income from related parties as follows:

		In Millions		
Type of Income	Related Party	2004	2003	2002
Gas sales, storage, transportation and other services (a)	MCV Partnership	$ -	$ 17	$ 27
Income from our investments in related party trusts (b)	Consumers' affiliated Trust Preferred Securities companies	1	2	-
Dividend income (b)	CMS Energy parent company	-	-	3

We recorded expense from related parties as follows:

		In Millions		
Type of Cost	Related Party	2004	2003	2002
Electric generating capacity and energy (a)	MCV Partnership	$ -	$455	$497
Electric generating capacity and energy	Affiliates of Enterprises	67	64	67
Interest expense on long-term debt (b)	Consumers' affiliated Trust Preferred Securities companies	44	45	-
Gas purchases	CMS ERM	1	27	127
Overhead expense (c)	CMS Energy parent company	-	8	18
Gas transportation (d)	Panhandle/Trunkline	-	1	22
Gas transportation	CMS Bay Area Pipeline, L.L.C.	4	4	4

(a) In 2004, we consolidated the MCV Partnership and the FMLP into our consolidated financial statements in accordance with Revised FASB Interpretation No. 46. For additional details, see Note 13, Implementation of New Accounting Standards.

(b) We issued Trust Preferred Securities through several Consumers' affiliated companies. As of December 31, 2003, we deconsolidated the trusts that hold the mandatorily redeemable Trust Preferred Securities. As a result of the deconsolidation, we now record on the Consolidated Statements of Income, Interest on Long-term debt – related parties to the trusts holding the Trust Preferred Securities. For additional information on Consumers' affiliated Trust Preferred Securities companies, see Note 13, Implementation of New Accounting Standards.

(c) We base our related party transactions on regulated prices, market prices, or competitive bidding.
In 2003, we paid overhead costs to CMS Energy based on an industry allocation methodology, such as the Massachusetts Formula. In 2004, we paid no overhead costs to CMS Energy.

(d) Panhandle was sold in June 2003.

We own 2.4 million shares of CMS Energy Common Stock with a fair value of $25 million at December 31, 2004. For additional details on our investment in CMS Energy Common Stock, see Note 4, Financial and Derivative Instruments.

Trade Receivables: We record our accounts receivable at fair value. Accounts deemed uncollectible are charged to operating expense.

Unamortized Debt Premium, Discount, and Expense: We capitalize premiums, discounts, and expenses incurred in connection with the issuance of long-term debt and amortize those costs ratably over the terms of the debt issues. Any refinancing costs are charged to expenses as incurred. For the regulated portions of our businesses, if we refinance debt, we capitalize any remaining unamortized premiums, discounts, and expenses and amortize them ratably over the terms of the newly issued debt.

Utility Regulation: We account for the effects of regulation based on the regulated utility accounting standard SFAS No. 71. As a result, the actions of regulators affect when we recognize revenues, expenses, assets, and liabilities.

We reflect the following regulatory assets and liabilities, which include both current and non-current amounts, on our Consolidated Balance Sheets. We expect to recover these costs through rates over periods of up to 14 years. We recognized an OPEB transition obligation in accordance with SFAS No. 106 and established a regulatory asset for the amount that we expect to recover in rates over the next eight years.

	In Millions	
December 31	2004	2003
Securitized costs (Note 3)	$ 604	$ 648
Postretirement benefits (Note 5)	530	181
Electric Restructuring Implementation Plan (Note 2)	88	91
Manufactured gas plant sites (Note 2)	65	67
Abandoned Midland project	10	10
Unamortized debt costs	71	51
Asset retirement obligation (Note 6)	83	49
Stranded costs (Note 2)	63	-
Section 10d(4) regulatory asset (Note 2)	141	-
Other	41	8
Total regulatory assets (a)	$ 1,696	$ 1,105
Cost of removal (Note 6)	$ 1,044	$ 983
Income taxes (Note 7)	357	312
Asset retirement obligation (Note 6)	168	168
Other	5	4
Total regulatory liabilities (a)	$ 1,574	$ 1,467

(a) At December 31, 2004, we classified $19 million of regulatory assets as current regulatory assets and we classified

$1.677 billion of regulatory assets as non-current regulatory assets. At December 31, 2003, we classified $19 million of regulatory assets as current regulatory assets and we classified $1.086 billion of regulatory assets as non-current regulatory assets. At December 31, 2004 and December 31, 2003, all of our regulatory liabilities represented non-current regulatory liabilities.

2: Contingencies

SEC and Other Investigations: As a result of round-trip trading transactions by CMS MST, CMS Energy's Board of Directors established a Special Committee to investigate matters surrounding the transactions and retained outside counsel to assist in the investigation. The Special Committee completed its investigation and reported its findings to the Board of Directors in October 2002. The Special Committee concluded, based on an extensive investigation, that the round-trip trades were undertaken to raise CMS MST's profile as an energy marketer with the goal of enhancing its ability to promote its services to new customers. The Special Committee found no effort to manipulate the price of CMS Energy Common Stock or affect energy prices. The Special Committee also made recommendations designed to prevent any recurrence of this practice. Previously, CMS Energy terminated its speculative trading business and revised its risk management policy. The Board of Directors adopted, and CMS Energy implemented the recommendations of the Special Committee.

CMS Energy is cooperating with an investigation by the DOJ concerning round-trip trading. CMS Energy is unable to predict the outcome of this matter and what effect, if any, this investigation will have on its business. In March 2004, the SEC approved a cease-and-desist order settling an administrative action against CMS Energy related to round-trip trading. The order did not assess a fine and CMS Energy neither admitted nor denied the order's findings. The settlement resolved the SEC investigation involving CMS Energy and CMS MST.

Securities Class Action Lawsuits: Beginning on May 17, 2002, a number of securities class action complaints were filed against CMS Energy, Consumers, and certain officers and directors of CMS Energy and its affiliates. The complaints were filed as purported class actions in the United States District Court for the Eastern District of Michigan, by shareholders who allege that they purchased CMS Energy's securities during a purported class period. These cases were later consolidated by the court. The plaintiffs generally seek unspecified damages based on allegations that the defendants violated United States securities laws and regulations by making allegedly false and misleading statements about CMS Energy's business and financial condition, particularly with respect to revenues and expenses recorded in connection with round trip trading by CMS MST. CMS Energy, Consumers, and the individual defendants filed motions to dismiss on June 21, 2004. The judge issued an opinion and order dated January 7, 2005, granting the motion to dismiss for Consumers and three of the individual defendants, but denying the motions to dismiss for CMS Energy and the 13 remaining individual defendants. CMS Energy and the individual defendants will defend themselves vigorously but cannot predict the outcome of this litigation.

ERISA Lawsuits: CMS Energy is a named defendant, along with Consumers, CMS MST, and certain named and unnamed officers and directors, in two lawsuits brought as purported class actions on behalf of participants and beneficiaries of the CMS Employees' Savings and Incentive Plan (the "Plan"). The two cases were filed in July 2002 in United States District Court for the Eastern District of Michigan and were later consolidated by the court. Plaintiffs allege breaches of fiduciary duties under ERISA and seek restitution on behalf of the Plan with respect to a decline in value of the shares of CMS Energy Common Stock held in the Plan. Plaintiffs also seek other equitable relief and legal fees. The judge issued an opinion and order dated December 27, 2004, conditionally granting plaintiffs' motion for class certification. A trial date has not been set, but is expected to be no earlier than late in 2005. CMS Energy and Consumers will defend themselves vigorously but cannot predict the outcome of this litigation.

ELECTRIC CONTINGENCIES

Electric Environmental Matters: Our operations are subject to environmental laws and regulations. Costs to operate our facilities in compliance with these laws and regulations generally have been recovered in customer rates.

Clean Air: The EPA and the state regulations require us to make significant capital expenditures estimated to be $802 million. As of December 31, 2004, we have incurred $525 million in capital expenditures to comply with the EPA regulations and anticipate that the remaining $277 million of capital expenditures will be made between 2005 and 2011.

The EPA has alleged that some utilities have incorrectly classified plant modifications as "routine maintenance" rather than seek modification permits from the EPA. We have received and responded to information requests from the EPA on this subject. We believe that we have properly interpreted the requirements of "routine maintenance." If our interpretation is found to be incorrect, we may be required to install additional pollution controls at some or all of our coal-fired electric plants and potentially pay fines. Additionally, the viability of certain plants remaining in operation could be called into question.

In addition to modifying the coal-fired electric plants, we expect to utilize nitrogen oxide emissions allowances for years 2005 through 2009, most of which have been purchased. The cost of the allowances is estimated to average $8 million per year for 2005-2006. The need for allowances will decrease after year 2006 with the installation of emissions control technology.

Cleanup and Solid Waste: Under the Michigan Natural Resources and Environmental Protection Act, we expect that we will ultimately incur investigation and remedial action costs at a number of sites. We believe that these costs will be recoverable in rates under current ratemaking policies.

We are a potentially responsible party at several contaminated sites administered under Superfund. Superfund liability is joint and several, meaning that many other creditworthy parties with substantial assets are potentially responsible with respect to the individual sites. Based on past experience, we estimate that our share of the total liability for the known Superfund sites will be between $1 million and $9 million. As of December 31, 2004, we have recorded a liability for the minimum amount of our estimated Superfund liability.

In October 1998, during routine maintenance activities, we identified PCB as a component in certain paint, grout, and sealant materials at the Ludington Pumped Storage facility. We removed and replaced part of the PCB material. We have proposed a plan to deal with the remaining materials and are awaiting a response from the EPA.

Litigation: In October 2003, a group of eight PURPA qualifying facilities selling power to us filed a lawsuit in Ingham County Circuit Court. The lawsuit alleges that we incorrectly calculated the energy charge payments made pursuant to power purchase agreements with qualifying facilities. In February 2004, the Ingham County Circuit Court judge deferred to the primary jurisdiction of the MPSC, dismissing the circuit court case without prejudice. In February 2005, the MPSC issued an order in the 2004 PSCR plan case concluding that we have been correctly administering the energy charge calculation methodology. The eight plaintiff qualifying facilities have appealed the dismissal of the circuit court case to the Michigan Court of Appeals. We cannot predict the outcome of this appeal.

ELECTRIC RESTRUCTURING MATTERS

Electric ROA: The MPSC approved revised tariffs that establish the rates, terms, and conditions under which retail customers are permitted to choose an electric supplier. These revised tariffs allow ROA customers, upon as little as 30 days notice to us, to return to our generation service at current tariff rates. If any class of customers' (residential, commercial, or industrial) ROA load reaches ten percent of our total load for that class of customers, then returning ROA customers for that class must give 60 days notice to return to our generation service at current tariff rates. However, we may not have capacity available to serve returning ROA customers that is sufficient or reasonably priced. As a result, we may be forced to purchase electricity on the spot market at higher prices than we can recover from our customers during the rate cap periods. We cannot predict the total amount of electric supply load that may be lost to alternative electric suppliers. As of March 2005, alternative electric suppliers are providing 900 MW of generation supply to ROA customers. This amount represents 12 percent of our distribution load and an increase of 23 percent compared to March 2004.

Electric Restructuring Proceedings: Below is a discussion of our electric restructuring proceedings.

The following chart summarizes our electric restructuring filings with the MPSC:

Proceeding	Year(s) Filed	Years Covered	Requested Amount	Status
Stranded Costs	2002-2004	2000-2003	$137 million (a)	The MPSC ruled that we experienced zero Stranded Costs for 2000 through 2001. The MPSC approved recovery of $63 million in Stranded Costs for 2002 through 2003.
Implementation Costs	1999-2004	1997-2003	$91 million (b)	The MPSC allowed $68 million for the years 1997-2001, plus $20 million for the cost of money through 2003. Implementation cost filings for 2002 and 2003 in the amount of $8 million, which includes the cost of money through 2003, are pending MPSC approval.
Section 10d(4) Regulatory Assets	2004	2000-2005	$628 million	Filed with the MPSC in October 2004.

(a) Amount includes the cost of money through the year in which we expected to receive recovery from the MPSC and assumes recovery of Clean Air Act costs through the Section 10d(4) Regulatory Asset case.

(b) Amount includes the cost of money through the year prior to the year filed.

Section 10d(4) Regulatory Assets: Section 10d(4) of the Customer Choice Act allows us to recover certain regulatory assets through deferred recovery of annual capital expenditures in excess of depreciation levels and certain other expenses incurred prior to and throughout the rate freeze and rate cap periods, including the cost of money. The section also allows deferred recovery of expenses incurred during the rate freeze and rate cap periods that result from changes in taxes, laws, or other state or federal governmental actions. In October 2004, we filed an application with the MPSC seeking recovery of $628 million of Section 10d(4) Regulatory Assets for the period June 2000 through December 2005 consisting of:

- capital expenditures in excess of depreciation,
- Clean Air Act costs,
- other expenses related to changes in law or governmental action incurred during the rate freeze and rate cap periods, and
- the associated cost of money through the period of collection.

Of the $628 million, $152 million relates to the cost of money.

As allowed by the Customer Choice Act, in January 2004, we began accruing and deferring for recovery the 2004 portion of our Section 10d(4) Regulatory Assets. In November 2004, the MPSC issued an order in Detroit Edison's general electric rate case which concluded that Detroit Edison's return of and on Clean Air Act costs incurred from June 2000 through December 2003 are recoverable under Section 10d(4). Based on the precedent set by this order, we recorded an additional regulatory asset in November 2004 for our return of and on Clean Air Act expenditures incurred from 2000 through 2003. Unless we receive an order from the MPSC to the contrary, we will continue to record additional accruals. However, certain aspects of Detroit Edison's electric rate case are different from our Section 10d(4) Regulatory Asset filing. In March 2005, the MPSC Staff filed testimony recommending the MPSC approve recovery of approximately $323 million. We cannot predict the amount, if any, the MPSC will approve as recoverable. At December 31, 2004, total Section 10d(4) Regulatory Assets totaled $141 million.

Transmission Sale: In May 2002, we sold our electric transmission system to MTH, a non-affiliated limited partnership whose general partner is a subsidiary of Trans-Elect, Inc. We are in arbitration with MTH regarding property tax items used in establishing the selling price of our electric transmission system. An unfavorable outcome could result in a reduction of sale proceeds previously recognized of approximately $2 million to $3 million.

ELECTRIC RATE MATTERS

Electric Rate Case: In December 2004, we filed an application with the MPSC to increase our retail electric base rates. The electric rate case filing requests an annual increase in revenues of approximately $320 million. The primary reasons for the request are increased system maintenance and improvement costs, Clean Air Act related expenditures, and employee pension costs. A final order from the MPSC on our electric rate case is expected in late 2005. If approved as requested, the rate increase would go into effect in January 2006 and would apply to all retail electric customers. We cannot predict the amount or timing of the rate increase, if any, which the MPSC will approve.

Power Supply Costs: To reduce the risk of high electric prices during peak demand periods and to achieve our reserve margin target, we employ a strategy of purchasing electric capacity and energy contracts for the physical delivery of electricity primarily in the summer months and to a lesser degree in the winter months. We have purchased capacity and energy contracts partially covering the estimated reserve margin requirements for 2005 through 2007. As a result, we have recognized an asset of $12 million for unexpired capacity and energy contracts as of December 31, 2004. The total premium costs of electric capacity and energy contracts for 2004 were approximately $12 million.

PSCR: The PSCR process assures recovery of all reasonable and prudent power supply costs actually incurred by us. In September 2004, we submitted our 2005 PSCR filing to the MPSC. The proposed PSCR charge would allow us to recover a portion of our increased power supply costs from commercial and industrial customers and, subject to the overall rate caps, from other customers. We self-implemented the proposed 2005 PSCR charge in January 2005. We estimate the increased recovery of power supply costs from commercial and industrial customers to be approximately $49 million in 2005. The revenues from the PSCR charges are subject to reconciliation at the end of the year after actual costs have been reviewed for reasonableness and prudence. We cannot predict the outcome of these PSCR proceedings.

OTHER ELECTRIC CONTINGENCIES

The Midland Cogeneration Venture: The MCV Partnership, which leases and operates the MCV Facility, contracted to sell electricity to Consumers for a 35-year period beginning in 1990 and to supply electricity and steam to Dow. We hold a 49 percent partnership interest in the MCV Partnership, and a 35 percent lessor interest in the MCV Facility.

In 2004, we consolidated the MCV Partnership and the FMLP into our consolidated financial statements in accordance with Revised FASB Interpretation No. 46. For additional details, see Note 13, Implementation of New Accounting Standards. Our consolidated retained earnings include undistributed earnings from the MCV Partnership of $237 million at December 31, 2004 and $245 million at December 31, 2003.

The cost that we incur under the MCV Partnership PPA exceeds the recovery amount allowed by the MPSC. We expense all cash underrecoveries directly to income. We estimate cash underrecoveries of capacity and fixed energy payments as follows:

	2005	2006	2007
Estimated cash underrecoveries	$56	$55	$39

After September 15, 2007, we expect to claim relief under the regulatory out provision in the PPA, limiting our capacity and fixed energy payments to the MCV Partnership to the amount collected from our customers. The MCV Partnership has indicated that it may take issue with our exercise of the regulatory out clause after September 15, 2007. We believe that the clause is valid and fully effective, but cannot assure that it will prevail in the event of a dispute. The MPSC's future actions on the capacity and fixed energy payments recoverable from customers subsequent to September 2007 may affect negatively the earnings of the MCV Partnership and the value of our investment in the MCV Partnership.

Further, under the PPA, variable energy payments to the MCV Partnership are based on the cost of coal burned at our coal plants and our operation and maintenance expenses. However, the MCV Partnership's costs of producing electricity are tied to the cost of natural gas. Because natural gas prices have increased substantially in recent years and the price the MCV Partnership can charge us for energy has not, the MCV Partnership's financial performance has been impacted negatively. Even with the approved RCP, if gas prices continue at present levels or increase, the economics of operating the MCV Facility may be adverse enough to require us to recognize an impairment.

In January 2005, the MPSC issued an order approving the RCP, with modifications. The RCP allows us to recover the same amount of capacity and fixed energy charges from customers as approved in prior MPSC orders. However, we are able to dispatch the MCV Facility on the basis of natural gas market prices, which will reduce the MCV Facility's annual production of electricity and, as a result, reduce the MCV Facility's consumption of natural gas by an estimated 30 to 40 bcf annually. This decrease in the quantity of high-priced natural gas consumed by the MCV Facility will benefit our ownership interest in the MCV Partnership.

The substantial MCV Facility fuel cost savings will be used first to offset fully the cost of replacement power. Second, $5 million annually will be used to fund a renewable energy program. Remaining savings will be split between the MCV Partnership and Consumers. Consumers' direct savings will be shared 50 percent with its customers in 2005 and 70 percent in 2006 and beyond. Consumers' direct savings from the RCP, after a portion is allocated to customers, will be used to offset our capacity and fixed energy underrecoveries expense. Since the MPSC has excluded these underrecoveries from the rate making process, we anticipate that our savings from the RCP will not affect our return on equity used in our base rate filings.

In January 2005, Consumers and the MCV Partnership's general partners accepted the terms of the order and implemented the RCP. The underlying agreement for the RCP between Consumers and the MCV Partnership extends through the term of the PPA. However, either party may terminate that agreement under certain conditions. In February 2005, a group of intervenors in the RCP case filed an application for rehearing of the MPSC order. The Attorney General also filed a claim of appeal with the Michigan Court of Appeals. We cannot predict the outcome of these appeals.

MCV Partnership Property Taxes: In January 2004, the Michigan Tax Tribunal issued its decision in the MCV Partnership's tax appeal against the City of Midland for tax years 1997 through 2000. The MCV Partnership estimates that the decision will result in a refund to the MCV Partnership of approximately $35 million in taxes plus $10 million of interest. The Michigan Tax Tribunal decision has been appealed to the Michigan Court of Appeals by the City of Midland and the MCV Partnership has filed a cross-appeal at the Michigan Court of Appeals. The MCV Partnership also has a pending case with the Michigan Tax Tribunal for tax years 2001 through 2004. The MCV Partnership cannot predict the outcome of these proceedings; therefore, the above refund (net of approximately $16 million of deferred expenses) has not been recognized in 2004 earnings.

Nuclear Plant Decommissioning: Decommissioning funding practices approved by the MPSC require us to file a report on the adequacy of funds for decommissioning at three-year intervals. We prepared and filed updated cost estimates for Big Rock and Palisades on March 31, 2004. Excluding additional costs for spent nuclear fuel storage, due to the DOE's failure to accept this spent nuclear fuel on schedule, these reports show a decommissioning cost of $361 million for Big Rock and $868 million for Palisades. Since Big Rock is currently in the process of being decommissioned, the estimated cost includes historical expenditures in nominal dollars and future costs in 2003 dollars, with all Palisades costs given in 2003 dollars.

In 1999, the MPSC orders for Big Rock and Palisades provided for fully funding the decommissioning trust funds for both sites. In December 2000, funding of the Big Rock trust fund stopped because the MPSC-authorized decommissioning surcharge collection period expired. The MPSC order set the annual decommissioning surcharge for Palisades at $6 million through 2007. Amounts collected from electric retail customers and deposited in trusts, including trust earnings, are credited to a regulatory liability and asset retirement obligation.

Big Rock: Excluding the additional nuclear fuel storage costs due to the DOE's failure to accept this spent fuel on schedule, we are currently projecting that the level of funds provided by the trust for Big Rock will fall short of the amount needed to complete the decommissioning by $26 million. At this time, we plan to provide the additional amounts needed from our corporate funds and, subsequent to the completion of radiological decommissioning work, seek recovery of such expenditures at the MPSC. We cannot predict how the MPSC will rule on our request. The following table shows our Big Rock decommissioning activities:

		In Millions
	Year-to-Date December 31, 2004	Cumulative Total-to-Date
Decommissioning expenditures (a)	$35	$298

Withdrawals from trust funds	36	279

(a) Includes site restoration expenditures.

These activities had no material impact on net income. At December 31, 2004, we have an investment in nuclear decommissioning trust funds of $52 million for Big Rock. In addition, at December 31, 2004, we have charged $8 million to our FERC jurisdictional depreciation reserve for the decommissioning of Big Rock.

Palisades: Excluding additional nuclear fuel storage costs due to the DOE's failure to accept this spent fuel on schedule, we concluded that the existing surcharge for Palisades needed to be increased to $25 million annually, beginning January 1, 2006, and continue through 2011, our current license expiration date. In June 2004, we filed an application with the MPSC seeking approval to increase the surcharge for recovery of decommissioning costs related to Palisades beginning in 2006. In September 2004, we announced that we will seek a 20-year license renewal for Palisades. In January 2005, we filed a settlement agreement with the MPSC that was agreed to by four of the six parties. The settlement agreement provides for the continuation of the existing $6 million annual decommissioning surcharge through 2011 and for the next periodic review to be filed in March 2007. We are seeking MPSC approval of the settlement, under a contested settlement proceeding, but cannot predict the outcome.

At December 31, 2004, we have an investment in the MPSC nuclear decommissioning trust funds of $513 million for Palisades. In addition, at December 31, 2004, we have a FERC decommissioning trust fund with a balance of $10 million. For additional details on decommissioning costs accounted for as asset retirement obligations, see Note 6, Asset Retirement Obligations.

Nuclear Matters: *DOE Litigation:* In 1997, a U.S. Court of Appeals decision confirmed that the DOE was to begin accepting deliveries of spent nuclear fuel for disposal by January 1998. Subsequent U.S. Court of Appeals litigation, in which we and other utilities participated, has not been successful in producing more specific relief for the DOE's failure to accept the spent nuclear fuel.

There are two court decisions that support the right of utilities to pursue damage claims in the United States Court of Claims against the DOE for failure to take delivery of spent nuclear fuel. Over 60 utilities have initiated litigation in the United States Court of Claims; we filed our complaint in December 2002. In July 2004, the DOE filed an amended answer and motion to dismiss the complaint. In October 2004, we filed a response to the DOE's motion and our motion for summary judgment on liability. Oral argument has been held, and the motions are now before the Court for a decision. If our litigation against the DOE is successful, we anticipate future recoveries from the DOE. We plan to use recoveries to pay the cost of spent nuclear fuel storage until the DOE takes possession as required by law. We can make no assurance that the litigation against the DOE will be successful.

In July 2002, Congress approved and the President signed a bill designating the site at Yucca Mountain, Nevada, for the development of a repository for the disposal of high-level radioactive waste and spent nuclear fuel. We expect that the DOE will submit an application to the NRC sometime in 2005 for a license to begin construction of the repository. The application and review process is estimated to take several years.

Insurance: We maintain nuclear insurance coverage on our nuclear plants. At Palisades, we maintain nuclear property insurance from NEIL totaling $2.750 billion and insurance that would partially cover the cost of replacement power during certain prolonged accidental outages. Because NEIL is a mutual insurance company, we could be subject to assessments of up to $27 million in any policy year if insured losses in excess of NEIL's maximum policyholders surplus occur at our, or any other member's, nuclear facility. NEIL's policies include coverage for acts of terrorism.

At Palisades, we maintain nuclear liability insurance for third-party bodily injury and off-site property damage resulting from a nuclear hazard for up to approximately $10.761 billion, the maximum insurance liability limits established by the Price-Anderson Act. The United States Congress enacted the Price-Anderson Act to provide financial liability protection for those parties who may be liable for a nuclear accident or incident. Part of the Price-Anderson Act's financial protection is a mandatory industry-wide program under which owners of nuclear generating facilities could be assessed if a nuclear incident occurs at any nuclear generating facility. The maximum assessment against us could be $101 million per occurrence, limited to maximum annual installment payments of $10 million.

We also maintain insurance under a program that covers tort claims for bodily injury to nuclear workers caused by nuclear hazards. The policy contains a $300 million nuclear industry aggregate limit. Under a previous insurance program providing coverage for claims brought by nuclear workers, we remain responsible for a maximum assessment of up to $6 million.

Big Rock remains insured for nuclear liability by a combination of insurance and a NRC indemnity totaling $544 million, and a nuclear property insurance policy from NEIL.

Insurance policy terms, limits, and conditions are subject to change during the year as we renew our policies.

GAS CONTINGENCIES

Gas Environmental Matters: We expect to incur investigation and remedial costs at a number of sites under the Michigan Natural Resources and Environmental Protection Act, a Michigan statute that covers environmental activities including remediation. These sites include 23 former manufactured gas plant facilities. We operated the facilities on these sites for some part of their operating lives. For some of these sites, we have no current ownership or may own only a portion of the original site. We have completed initial investigations at the 23 sites. We will continue to implement remediation plans for sites where we have received MDEQ remediation plan approval. We will also work toward resolving environmental issues at sites as studies are completed.

We have estimated our costs for investigation and remedial action at all 23 sites using the Gas Research Institute-Manufactured Gas Plant Probabilistic Cost Model. We expect our remaining costs to be between $37 million and $90 million. The range reflects multiple alternatives with various assumptions for resolving the environmental issues at each site. We base the estimates on discounted 2003 costs using a discount rate of three percent. The discount rate represents a 10-year average of U.S. Treasury bond rates reduced for increases in the consumer price index. We expect to fund most of these costs through insurance proceeds and MPSC-approved rates. As of December 31, 2004, we have recorded a liability of $38 million, net of $44 million of expenditures incurred to date, and a regulatory asset of $65 million. Any significant change in assumptions, such as an increase in the number of sites, different remediation techniques, nature and extent of contamination, and legal and regulatory requirements, could affect our estimate of remedial action costs.

In its November 2002 gas distribution rate order, the MPSC authorized us to continue to recover approximately $1 million of manufactured gas plant facilities environmental clean-up costs annually. This amount will continue to be offset by $2 million to reflect amounts recovered from all other sources. We defer and amortize, over a period of 10 years, manufactured gas plant facilities environmental clean-up costs above the amount currently included in rates. Additional amortization of the expense in our rates cannot begin until after a prudency review in a gas rate case.

GAS RATE MATTERS

Gas Cost Recovery: The GCR process is designed to allow us to recover all of our purchased natural gas costs if incurred under reasonable and prudent policies and practices. The MPSC reviews these costs for prudency in an annual reconciliation proceeding.

The following table summarizes our GCR reconciliation filings with the MPSC. Additional details related to these proceedings follow the table.

Gas Cost Recovery Reconciliation

GCR Year	Date Filed	Order Date	Net Over Recovery	Status
2001-2002	June 2002	May 2004	$3 million	$2 million has been refunded, $1 million is included in our 2003-2004 GCR reconciliation filing
2002-2003	June 2003	March 2004	$5 million	Net over-recovery includes interest accrued through March 2003, and an $11 million disallowance settlement agreement
2003-2004	June 2004	February 2005	$31 million	Filing includes the $1 million and the $5 million GCR net over-recovery above

Net over-recovery amounts included in the table above include refunds that we received from our suppliers which are required to be refunded to our customers.

GCR year 2003-2004: In February 2005, the MPSC approved a settlement agreement that resulted in a credit to our GCR customers for a $28 million over-recovery, plus $3 million interest, using a roll-in refund methodology. The roll-in methodology incorporates a GCR over/under-recovery in the next GCR plan year.

GCR plan for year 2004-2005: In December 2003, we filed an application with the MPSC seeking approval of a GCR plan for the 12-month period of April 2004 through March 2005. In June 2004, the MPSC issued a final Order in our GCR plan approving a settlement. The settlement included a quarterly mechanism for setting a GCR ceiling price. The current ceiling price is $6.57 per mcf. Actual gas costs and revenues will be subject to an annual reconciliation proceeding.

GCR plan for year 2005-2006: In December 2004, we filed an application with the MPSC seeking approval of a GCR plan for the 12-month period of April 2005 through March 2006. Our request proposes using a GCR factor consisting of:

- a base GCR factor of $6.98 per mcf, plus
a quarterly GCR ceiling price adjustment contingent upon future events.

The GCR factor can be adjusted monthly, provided it remains at or below the current ceiling price. The quarterly adjustment mechanism allows an increase in the GCR ceiling price to reflect a portion of cost increases if the average NYMEX price for a specified period is greater than that used in calculating the base GCR factor. Actual gas costs and revenues will be subject to an annual reconciliation proceeding.

2003 Gas Rate Case: In March 2003, we filed an application with the MPSC for a gas rate increase in the annual amount of $156 million. In December 2003, the MPSC granted an interim rate increase in the amount of $19 million annually. The MPSC also ordered an annual $34 million reduction in our annual depreciation expense and related taxes.

On October 14, 2004, the MPSC issued its Opinion and Order on final rate relief. In the order, the MPSC authorized us to place into effect surcharges that would increase annual gas revenues by $58 million. Further, the MPSC rescinded the $19 million annual interim rate increase. The final rate relief was contingent upon our agreement to:

- achieve a common equity level of at least $2.3 billion by year-end 2005 and propose a plan to improve the common equity level thereafter until our target capital structure is reached,
- make certain safety-related operation and maintenance, pension, retiree health-care, employee health-care, and storage working capital expenditures for which the surcharge is granted,
- refund surcharge revenues when our rate of return on common equity exceeds its authorized 11.4 percent rate,
- prepare and file annual reports that address certain issues identified in the order, and
- file a general rate case on or before the date that the surcharge expires (which is two years after the surcharge goes into effect).

On October 15, 2004, we agreed to these commitments.

2001 Gas Depreciation Case: In December 2003, we filed an update to our gas utility plant depreciation case originally filed in June 2001. On December 18, 2003, the MPSC ordered an annual $34 million reduction in our depreciation expense and related taxes in an interim rate order issued in our 2003 gas rate case.

In October and December 2004, the MPSC issued Opinions and Orders in our gas depreciation case. The October 2004 order requires us to file an application for new depreciation accrual rates for our natural gas utility plant on, or no earlier than three months prior to, the date we file our next natural gas general rate case. The MPSC also directed us to undertake a study to determine why our removal costs are in excess of those of other regulated Michigan natural gas utilities and file a report with the MPSC Staff on or before December 31, 2005.

In February 2005, we requested a delay in the filing date for the next depreciation case until after the MPSC considers the removal cost study, and after the MPSC issues an order in a pending case relating to asset retirement obligation accounting.

OTHER MATTERS

Collective Bargaining Agreements: Approximately 46 percent of our employees are represented by the Utility Workers of America Union. The Union represents Consumers' operating, maintenance, and construction employees and our call center employees. The collective bargaining agreement with the Union for our operating, maintenance, and construction employees will expire on June 1, 2005 and negotiations for a new agreement is underway currently. The collective bargaining agreement with the Union for our call center employees will expire on August l, 2005.

OTHER CONTINGENCIES

In addition to the matters disclosed within this Note, we are party to certain lawsuits and administrative proceedings before various courts and governmental agencies arising from the ordinary course of business. These lawsuits and proceedings may involve personal injury, property damage, contractual matters, environmental issues, federal and state taxes, rates, licensing, and other matters.

We have accrued estimated losses for certain contingencies discussed within this Note. Resolution of these contingencies is not expected to have a material adverse impact on our financial position, liquidity, or results of operations.

3: Financings and Capitalization

Long-term debt as of December 31 follows:

In Millions

	Interest Rate (%)	Maturity	2004	2003
			$	$
First mortgage bonds	4.250	2008	250	250
	4.800	2009	200	200
	4.400	2009	150	-
	4.000	2010	250	250
	5.000	2012	300	-
	5.375	2013	375	375
	6.000	2014	200	200
	5.000	2015	225	-
	5.500	2016	350	-
	7.375	2023	-	208
			2,300	1,483
Senior notes	6.000	2005	-	300
	6.500	2005	-	141
	6.250	2006	332	332
	6.375	2008	159	159
	6.875	2018	180	180
	6.500	2028	141	142
			812	1,254
Securitization bonds	5.188 (a)	2005-2015	398	426
FMLP Debt (b):				
Subordinated secured notes	11.750	2005	70	-
Subordinated secured notes	13.250	2006	75	-
Tax-exempt subordinated secured notes	6.875	2009	137	-
Tax-exempt subordinated secured notes	6.750	2009	14	-
			296	-
Nuclear fuel disposal liability		(c)	141	139
Tax-exempt pollution control revenue bonds	Various	2010-2018	126	126
Long-term bank debt (d)	Variable	2006	60	200
Other			1	4
			328	469

Total principal amounts outstanding	4,134	3,632
Current amounts	(118)	(28)
Net unamortized discount	(16)	(21)
Total Long-term debt	$ 4,000	$ 3,583

(a) Represents the weighted average interest rate at December 31, 2004 (5.097 percent at December 31, 2003).

(b) We consolidate the FMLP in accordance with Revised FASB Interpretation No. 46. The FMLP debt is essentially project debt secured by certain assets of the MCV Partnership and the FMLP. The debt is non-recourse to other assets of Consumers.

(c) Maturity date uncertain.

(d) Paid off in January 2005.

Financings: The following is a summary of significant long-term debt issuances and retirements during 2004:

	Principal (In millions)	Interest Rate (%)	Issue/Retirement Date	Maturity Date
Debt Issuances				
FMB	$ 150	4.400	August 2004	August 2009
FMB	300	5.000	August 2004	February 2012
FMB	350	5.500	August 2004	August 2016
FMB	225	5.000	December 2004	March 2015
Total debt issuances	$ 1,025			
Debt Retirements				
FMLP debt	$ 115	11.750	July 2004	July 2004
Long-term bank debt	140	Variable	August 2004	March 2009
Senior notes	141	6.500	September 2004	June 2018
Senior notes	300	6.000	September 2004	March 2005
FMB	208	7.375	December 2004	September 2023
Total debt retirements	$ 904			

Issuance costs associated with the issuances of FMBs totaled $7 million and are being amortized ratably over the lives of the related debt. Call premiums associated with the debt retirements totaled $20 million and are being amortized ratably over the lives of the newly issued debt.

Subsequent Financing Activities:

In January 2005, we issued $250 million of 5.15 percent FMBs due 2017. We used the net proceeds of $247 million to pay off our $60 million long-term bank loan, to redeem our $73 million 8.36 percent subordinated deferrable interest notes, and to redeem our $124 million 8.20 percent subordinated deferrable interest notes. The subordinated deferrable interest notes are classified as Long-term debt – related parties on our accompanying Consolidated Balance Sheets.

First Mortgage Bonds: We secure our FMBs by a mortgage and lien on substantially all of our property. Our ability to issue and sell securities is restricted by certain provisions in the first mortgage bond indenture, our articles of incorporation, and the need for regulatory approvals under federal law.

Securitization Bonds: Securitization bonds are collateralized by certain regulatory assets. The bondholders have no recourse to our other assets.. Through our rate structure, we bill customers for securitization surcharges to fund the payment of principal, interest, and other related expenses on the Securitization bonds. Securitization surcharges totaled $50 million annually in 2003 and 2004.

Long-Term Debt – Related Parties: We formed various statutory wholly-owned business trusts for the sole purpose of issuing preferred securities and lending the gross proceeds to ourselves. The sole assets of the trusts consist of the debentures described below. These debentures have terms similar to those of the mandatorily redeemable preferred securities the trusts issued. We determined that we do not hold the controlling financial interest in our trust preferred security structures. Accordingly, those entities were deconsolidated as of December 31, 2003 and are reflected in Long-term debt – related parties. The trust preferred securities were previously included in mezzanine equity.

The following is a summary of Long-term debt – related parties as of December 31:

			In Millions	
Debenture and related party	Interest Rate (%)	Maturity	2004	2003
Subordinated deferrable interest notes, Consumers Power Company Financing I (a)	8.36	2015	$ 73	$ 73
Subordinated deferrable interest notes, Consumers Energy Company Financing II (a)	8.20	2027	124	124
Subordinated debentures, Consumers Energy Company Financing III (b)	9.25	2029	180	180
Subordinated debentures, Consumers Energy Company Financing IV	9.00	2031	129	129
Total principal amounts outstanding			506	506
Current amounts			(180)	-
Total Long-term debt – related parties			$ 326	$ 506

(a) Redeemed in February 2005.
(b) Redeemed in January 2005 with available cash.

In the event of default, holders of the trust preferred securities would be entitled to exercise and enforce the trusts' creditor rights against us, which may include acceleration of the principal amount due on the debentures. We have issued certain guarantees with respect to payments on the preferred securities. These guarantees, when taken together with our obligations under the debentures, related indenture and trust documents, provide full and unconditional guarantees for the trusts' obligations under the preferred securities.

Debt Maturities: At December 31, 2004, the aggregate annual maturities for long-term debt for the next five years are:

In Millions

	Payments Due				
	2005	2006	2007	2008	2009
Long-term debt	$ 118	$ 478	$ 59	$ 504	$ 443

Regulatory Authorization for Financings: We have FERC authorization to issue or guarantee up to $1.1 billion of short-term securities and up to $1.1 billion of short-term FMBs as collateral for such short-term securities. We have FERC authorization to issue up to $1 billion of long-term securities for refinancing or refunding purposes, $1.5 billion of long-term securities for general corporate purposes, and $2.5 billion of long-term FMBs to be issued solely as collateral for other long-term securities.

Revolving Credit Facilities: The following secured revolving credit facilities with banks are available as of December 31, 2004:

In Millions

Company	Expiration Date	Amount of Facility	Amount Borrowed	Outstanding Letters-of-Credit	Amount Available
Consumers (a)		$ 500	$ -	$ 25	$ 475
The MCV Partnership	August 27, 2005	50	-	2	48

(a) This facility expires in August 2005 and may be extended annually at Consumers' option to July 31, 2007. The interest rate on borrowings under this facility is LIBOR plus 125 basis points. Annual fees for letters-of-credit are 125 basis points on the amount outstanding. A quarterly fee of 22.5 basis points is payable on the average daily unused balance.

Sale of Accounts Receivable: Under a revolving accounts receivable sales program, we currently sell certain accounts receivable to a wholly owned, consolidated, bankruptcy remote special purpose entity. In turn, the special purpose entity may sell an undivided interest in up to $325 million of the receivables. We sold $304 million of receivables at December 31, 2004 and we sold $297 million of receivables at December 31, 2003. These sold amounts are excluded from accounts receivable on our Consolidated Balance Sheets. We continue to service the receivables sold to the special purpose entity. The purchaser of the receivables has no recourse against our other assets for failure of a debtor to pay when due and the purchaser has no right to any receivables not sold. No gain or loss has been recorded on the receivables sold and we retain no interest in the receivables sold.

Certain cash flows under our accounts receivable sales program are shown in the following table:

In Millions

Years Ended December 31	2004	2003
Net cash flow as a result of accounts receivable financing	$ 7	$ (28)
Collections from customers	$ 4,541	$ 4,361

Dividend Restrictions: Under the provisions of our articles of incorporation, at December 31, 2004, we had $456 million of unrestricted retained earnings available to pay common stock dividends. However, covenants in our debt facilities cap common stock dividend payments at $300 million in a calendar year. In October 2004, the MPSC rescinded its December 2003 interim gas rate order, which included a $190 million annual dividend cap. For the year ended December 31, 2004, we paid $190 million in common stock dividends to CMS Energy.

Preferred Stock: Our Preferred Stock outstanding follows:

December 31	Series	Optional Redemption Price	Number of Shares 2004	Number of Shares 2003	In Millions 2004	In Millions 2003
Preferred Stock						
Cumulative $100 par value,						
Authorized 7,500,000 shares,						
with no mandatory redemption	$4.16	$103.25	68,451	68,451	$ 7	$ 7
	$4.50	$110.00	373,148	373,148	37	37
Total Preferred Stock					$ 44	$ 44

FASB Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others:* This Interpretation became effective January 2003. It describes the disclosure to be made by a guarantor about its obligations under certain guarantees that it has issued. At the inception of a guarantee, it requires a guarantor to recognize a liability for the fair value of the obligation undertaken in issuing the guarantee. The initial recognition and measurement provision of this Interpretation does not apply to some guarantee contracts, such as warranties, derivatives, or guarantees between either parent and subsidiaries or corporations under common control, although disclosure of these guarantees is required. For contracts that are within the recognition and measurement provision of this Interpretation, the provisions were to be applied to guarantees issued or modified after December 31, 2002.

The following table describes our guarantees at December 31, 2004:

					In Millions
Guarantee Description	Issue Date	Expiration Date	Maximum Obligation	Carrying Amount	Recourse Provision (a)
Standby letters of credit	Various	Various	$ 25	$ -	$ -
Surety bonds	Various	Various	6	-	-
Nuclear insurance retrospective premiums	Various	Various	134	-	-

(a) Recourse provision indicates the approximate recovery from third parties including assets held as collateral.

The following table provides additional information regarding our guarantees:

Guarantee Description	How Guarantee Arose	Events That Would Require Performance
Standby letters of credit	Normal operations of coal power plants	Noncompliance with environmental regulations and non-responsive to demands for corrective action
	Natural gas transportation	Nonperformance
	Self-insurance requirement	Nonperformance
	Nuclear plant closure	Nonperformance

Surety bonds	Normal operating activity, permits and license	Nonperformance
Nuclear insurance retrospective premiums	Normal operations of nuclear plants	Call by NEIL and Price-Anderson Act for nuclear incident

4: Financial and Derivative Instruments

Financial Instruments: The carrying amounts of cash, short-term investments, and current liabilities approximate their fair values because of their short-term nature. We estimate the fair values of long-term financial instruments based on quoted market prices or, in the absence of specific market prices, on quoted market prices of similar instruments or other valuation techniques.

The cost and fair value of our long-term financial instruments are as follows:

In Millions

December 31	2004			2003		
	Cost	Fair Value	Unrealized Gain (Loss)	Cost	Fair Value	Unrealized Gain (Loss)
Long-term debt (a)	$ 4,118	$ 4,232	$ (114)	$ 3,611	$ 3,711	$ (100)
Long-term debt - related parties (b)	506	518	(12)	506	518	(12)
Available-for-sale securities:						
Common stock of CMS Energy (c)	10	25	15	10	20	10
SERP:						
Equity securities	15	21	6	10	14	4
Debt securities (e)	9	9	-	7	7	-
Nuclear decommissioning investments (d):						
Equity securities	136	262	126	143	260	117
Debt securities (e)	291	302	11	288	304	16

(a) Includes current maturities of $118 million at December 31, 2004 and $28 million at December 31, 2003. Settlement of long-term debt is generally not expected until maturity.

(b) Includes current maturities of $180 million at December 31, 2004.

(c) At December 31, 2004, we held 2.4 million shares of CMS Energy Common Stock.

(d) Nuclear decommissioning investments include cash and equivalents and accrued income totaling $11 million at December 31, 2004 and $11 million at December 31, 2003. Unrealized gains and losses on nuclear decommissioning investments are reflected as regulatory liabilities.

(e) The fair value of available-for-sale debt securities by contractual maturity as of December 31, 2004 is as follows:

	In Millions
Due in one year or less	$ 31
Due after one year through five years	122
Due after five years through ten years	120
Due after ten years	38
Total	$ 311

Our held-to-maturity investments consist of debt securities held by the MCV Partnership totaling $139 million as of December 31, 2004. These securities represent funds restricted primarily for future lease payments and are classified as Other assets on our Consolidated Balance Sheets. These investments have original maturity dates of approximately one year or less and, because of their short maturities, their carrying amounts approximate their fair values.

Derivative Instruments: We are exposed to market risks including, but not limited to, changes in interest rates, commodity prices, and equity security prices. We manage these risks using established policies and procedures, under the direction of both an executive oversight committee consisting of senior management representatives and a risk committee consisting of business-unit managers. We may use various contracts to manage these risks including swaps, options, futures, and forward contracts.

We intend that any gains or losses on these contracts will be offset by an opposite movement in the value of the item at risk. We enter into all risk management contracts for purposes other than trading. These contracts contain credit risk if the counterparties, including financial institutions and energy marketers, fail to perform under the agreements. We minimize such risk through established credit policies that include performing financial credit reviews of our counterparties. Determination of our counterparties' credit quality is based upon a number of factors, including credit ratings, disclosed financial condition, and collateral requirements. Where contractual terms permit, we employ standard agreements that allow for netting of positive and negative exposures associated with a single counterparty. Based on these policies and our current exposures, we do not anticipate a material adverse effect on our financial position or earnings as a result of counterparty nonperformance.

Contracts used to manage market risks may be considered derivative instruments that are subject to derivative and hedge accounting pursuant to SFAS No. 133. If a contract is accounted for as a derivative instrument, it is recorded in the financial statements as an asset or a liability, at the fair value of the contract. The recorded fair value is then adjusted quarterly to reflect any change in the market value of the contract, a practice known as marking the contract to market. Changes in fair value (that is, gains or losses) are reported either in earnings or accumulated other comprehensive income, depending on whether the derivative qualifies for cash flow hedge accounting treatment.

For derivative instruments to qualify for hedge accounting, the hedging relationship must be formally documented at inception and be highly effective in achieving offsetting cash flows or offsetting changes in fair value attributable to the risk being hedged. If hedging a forecasted transaction, the forecasted transaction must be probable. If a derivative instrument, used as a cash flow hedge, is terminated early because it is probable that a forecasted transaction will not occur, any gain or loss as of such date is recognized immediately in earnings. If a derivative instrument, used as a cash flow hedge, is terminated early for other economic reasons, any gain or loss as of the termination date is deferred and recorded when the forecasted transaction affects earnings. The ineffective portion, if any, of all hedges is recognized in earnings.

We use a combination of quoted market prices, prices obtained from external sources, such as brokers, and mathematical valuation models to determine the fair value of those contracts requiring derivative accounting. In certain contracts, long-term commitments may extend beyond the period in which market quotations for such contracts are available. Mathematical models are developed to determine various inputs into the fair value calculation including price and other variables that may be required to calculate fair value. Realized cash returns on these commitments may vary, either positively or negatively, from the results estimated through application of the mathematical model. In connection with the market valuation of our derivative contracts, we maintain reserves, if necessary, for credit risks based on the financial condition of counterparties.

The majority of our contracts are not subject to derivative accounting under SFAS No. 133 because they qualify for the normal purchases and sales exception, or because there is not an active market for the commodity. Our electric capacity and energy contracts are not accounted for as derivatives due to the lack of an active energy market in the state of Michigan and the significant transportation costs that would be incurred to deliver the power under the contracts to the closest active energy market at the Cinergy hub in Ohio. Similarly, our coal purchase contracts are not accounted for as derivatives due to the lack of an active market for the coal that we purchase. If active markets for these commodities develop in the future, we may be required to account for these contracts as derivatives, and the resulting mark-to-market impact on earnings could be material to our financial statements..

The MISO is scheduled to begin the Midwest Energy Market on April 1, 2005, which will include day-ahead and real-time energy market information and centralized dispatch for market participants. At this time, we believe that the commencement of this market will not constitute the development of an active energy market in the state of Michigan. However, after having adequate experience with the Midwest Energy Market, we will reevaluate whether or not the activity level within this market leads to the conclusion that an active energy market exists.

Derivative accounting is required for certain contracts used to limit our exposure to commodity price risk. The following table reflects the fair value of all contracts requiring derivative accounting:

In Millions

December 31	2004			2003		
Derivative Instruments	Cost	Fair Value	Unrealized Gain (Loss)	Cost	Fair Value	Unrealized Gain (Loss)
Gas contracts	$ 2	$ -	$ (2)	$ 3	$ 2	$ (1)
Derivative contracts associated with Consumers' investment in the MCV Partnership:						
Prior to consolidation (a)	-	-	-	-	15	15
After consolidation:						
Gas fuel contracts	-	56	56	-	-	-
Gas fuel futures and swaps	-	64	64	-	-	-

(a) The amount associated with derivative contracts held by the MCV Partnership as of December 31, 2003 represents our proportionate share of the unrealized gain on those contracts accounted for as cash flow hedges included in Accumulated other comprehensive income. Our proportionate share of the total fair value of all derivative instruments held by the MCV Partnership as of December 31, 2003 was $51 million, and is included in Investments – Midland Cogeneration Venture Limited Partnership on our Consolidated Balance Sheets.

The fair value of our derivative contracts is included in Derivative instruments, Other assets, or Other liabilities on our Consolidated Balance Sheets.

Gas Contracts: Our gas utility business uses fixed-priced weather-based gas supply call options and fixed-priced gas supply call and put options to meet our regulatory obligation to provide gas to our customers at a reasonable and prudent cost. Unrealized gains and losses associated with these options are reported directly in earnings as part of Other income, and then directly offset in earnings and recorded on the balance sheet as a regulatory asset or liability as part of the GCR process. At December 31, 2004, we held fixed-priced weather-based gas supply call options and had sold fixed-priced gas supply put options.

Derivative Contracts Associated with Consumers' Investment in the MCV Partnership:
Gas Fuel Contracts: The MCV Partnership uses natural gas fuel contracts to buy gas as fuel for generation, and to manage gas fuel costs. The MCV Partnership believes that certain of its long-term natural gas contracts qualify as normal purchases under SFAS No. 133, and therefore, these contracts were not recognized at fair value on the balance sheet as of December 31, 2004. The MCV Partnership also held certain long-term gas contracts that did not qualify as normal purchases as of December 31, 2004, because these contracts contained volume optionality. Accordingly, these contracts were accounted for as derivatives, with changes in fair value recorded in earnings each quarter. The MCV Partnership expects future earnings volatility on these contracts, since gains and losses will be recorded each quarter. For the year ended December 31, 2004, we recorded a $19 million net loss associated with these gas contracts in Fuel for electric generation on our Consolidated Statements of Income. The fair value of these contracts will reverse over the remaining life of the contracts ranging from 2005 to 2007.

Due to the implementation of the RCP in January 2005, the MCV Partnership has determined that a significant portion of its gas fuel contracts no longer qualify as normal purchases because the contracted gas will not be consumed for electric production. Accordingly, these contracts will be treated as derivatives and will be marked-to-market through earnings each quarter, which could increase earnings volatility. Based on market prices for natural gas as of January 31, 2005, the accounting for the MCV Partnership's long-term gas contracts, including those affected by the implementation of the RCP, could result in an estimated $100 million (pretax before minority interest) gain recorded to earnings in the first quarter of 2005. This estimated gain will reverse in subsequent quarters as the contracts settle. For further details on the RCP, see Note 2, Contingencies, "Other Electric Contingencies – The Midland Cogeneration Venture." If there are further changes in the level of planned electric production or gas consumption, the MCV Partnership may be required to account for additional long-term gas contracts as derivatives, which could add to earnings volatility.

Gas Fuel Futures and Swaps: The MCV Partnership enters into natural gas futures contracts, option contracts, and over-the-counter swap transactions in order to hedge against unfavorable changes in the market price of natural gas in future months when gas is expected to be needed. These financial instruments are used principally to secure anticipated natural gas requirements necessary for projected electric and steam sales, and to lock in sales prices of natural gas previously obtained in order to optimize the MCV Partnership's existing gas supply, storage, and transportation arrangements. At December 31, 2004, the MCV Partnership held gas fuel futures and swaps.

The contracts that are used to secure anticipated natural gas requirements necessary for projected electric and steam sales qualify as cash flow hedges under SFAS No. 133. The MCV Partnership also engages in cost mitigation activities to offset the fixed charges the MCV Partnership incurs in operating the MCV Facility. These cost mitigation activities include the use of futures and options contracts to purchase and/or sell natural gas to maximize the use of the transportation and storage contracts when it is determined that they will not be needed for the MCV Facility operation. Although these cost mitigation activities do serve to offset the fixed monthly charges, these cost mitigation activities are not considered a normal course of business for the MCV Partnership and do not qualify as hedges. Therefore, the mark-to-market gains and losses from these cost mitigation activities are recorded in earnings each quarter.

As of December 31, 2004, we have recorded a cumulative net gain of $21 million, net of tax, in Accumulated other comprehensive income relating to our proportionate share of the contracts held by the MCV Partnership that qualify as cash flow hedges. This balance represents natural gas futures, options, and swaps with maturities ranging from January 2005 to December 2009, of which $11 million of this gain is expected to be reclassified as an increase to earnings during the next 12 months. In addition, for the year ended December 31, 2004, we recorded a net gain of $37 million in earnings from hedging activities related to natural gas requirements for the MCV Facility operations and a net gain of $2 million in earnings from the MCV Partnership's cost mitigation activities.

5: Retirement Benefits

We provide retirement benefits to our employees under a number of different plans, including:

- non-contributory, defined benefit Pension Plan,
- a cash balance pension plan for certain employees hired after June 30, 2003,
- benefits to certain management employees under SERP,
- a defined contribution 401(k) plan,
- benefits to a select group of management under EISP, and
- health care and life insurance benefits under OPEB.

Pension Plan: The Pension Plan includes funds for our employees and our non-utility affiliates, including Panhandle. The Pension Plan's assets are not distinguishable by company.

In June 2003, CMS Energy sold Panhandle to Southern Union Panhandle Corp. No portion of the Pension Plan assets were transferred with the sale and Panhandle employees are no longer eligible to accrue additional benefits. The Pension Plan retained pension payment obligations for Panhandle employees that were vested under the Pension Plan.

The sale of Panhandle resulted in a significant change in the makeup of the Pension Plan. A remeasurement of the obligation was required at the date of sale. The remeasurement further resulted in the following:

- an increase in OPEB expense of $4 million for 2003, and
- an additional charge to accumulated other comprehensive income of $31 million ($20 million after-tax) in 2003 as a result of the increase in the additional minimum pension liability. As a result of company contributions in 2003, the additional minimum pension liability was eliminated as of December 31, 2003.

In 2003, a substantial number of retiring employees elected a lump sum payment instead of receiving pension benefits as an annuity over time. Lump sum payments constitute a settlement under SFAS No. 88. A settlement loss must be recognized when the cost of all settlements paid during the year exceeds the sum of the service and interest costs for that year. We recorded a settlement loss of $48 million ($31 million after-tax) in December 2003.

SERP: SERP benefits are paid from a trust established in 1988. SERP is not a qualified plan under the Internal Revenue Code; SERP trust earnings are taxable and trust assets are included in consolidated assets. Trust assets were $30 million at December 31, 2004, and $22 million at December 31, 2003. The assets are classified as Other non-current assets. The Accumulated Benefit Obligation for SERP was $30 million at December 31, 2004 and $19 million at December 31, 2003.

401k: Employer matching contributions to the 401(k) plan are invested in CMS Energy common stock. The amount charged to expense for this plan was $8 million in 2002. The employer's match for the 401(k) plan was suspended on September 1, 2002 and was resumed on January 1, 2005.

The MCV Partnership sponsors a defined contribution retirement plan covering all employees. Under the terms of the plan, the MCV Partnership makes contributions of either 5 or 10 percent of an employee's eligible annual compensation dependent upon the employee's age. The MCV Partnership also sponsors a 401(k) savings plan for employees. Contributions and costs for this plan are based on matching an employee's savings up to a maximum level. Amounts contributed under these plans were $1 million in 2004.

EISP: We implemented an EISP in 2002 to provide flexibility in separation of employment by officers, a select group of management, or other highly compensated employees. Terms of the plan may include payment of a lump sum, payment of monthly benefits for life, payment of premium for continuation of health care, or any other legally permissible term deemed to be in our best interest to offer. As of December 31, 2004, the Accumulated Benefit Obligation of the EISP was $4 million.

OPEB: Retiree health care costs at December 31, 2004 are based on the assumption that costs would increase 7.5 percent in 2004. The rate of increase is expected to be 10 percent for 2005. The rate of increase is expected to slow to an estimated 5 percent by 2010 and thereafter.

The MCV Partnership sponsors defined cost postretirement health care plans that cover all full-time employees, except key management. Participants in the postretirement health care plans become eligible for the benefits if they retire on or after the attainment of age 65 or upon a qualified disability retirement, or if they have 10 or more years of service and retire at age 55 or older. The accumulated benefit obligation of the MCV Partnership's postretirement plans was $5 million at December 31, 2004. The MCV Partnership's net periodic postretirement health care cost for 2004 was less than $1 million.

The health care cost trend rate assumption affects the estimated costs recorded. A one-percentage point change in the assumed health care cost trend assumption would have the following effects:

	In Millions	
	One Percentage Point Increase	One percentage Point Decrease
Effect on total service and interest cost component	$ 12	$ (10)
Effect on postretirement benefit obligation	$ 149	$ (129)

We adopted SFAS No. 106, effective as of the beginning of 1992. We recorded a liability of $466 million for the accumulated transition obligation and a corresponding regulatory asset for anticipated recovery in utility rates. For additional details, see Note 1, Corporate Structure and Accounting Policies, "Utility Regulation." The MPSC authorized recovery of the electric utility portion of these costs in 1994 over 18 years and the gas utility portion in 1996 over 16 years.

The measurement date for all of Consumers' plans is November 30 for 2004, and December 31 for 2003 and 2002. We believe accelerating the measurement date on our benefit plans by one month is preferable as it improves control procedures and allows more time to review the completeness and accuracy of the actuarial measurements. As a result of the measurement date change in 2004, we recorded a $1 million cumulative effect of change in accounting, net of tax benefit, as a decrease to earnings. We also increased the amount of accrued benefit cost on our Consolidated Balance Sheets by $2 million. The effect of the measurement date change was immaterial. The measurement date for the MCV Partnership's plan is December 31, 2004.

Assumptions: The following table recaps the weighted-average assumptions used in our retirement benefits plans to determine the benefit obligation and net periodic benefit cost:

	Pension & SERP			OPEB		
	2004	2003	2002	2004	2003	2002
Discount rate	6.00%	6.25%	6.75%	6.00%	6.25%	6.75%
Expected long-term rate of return on						

plan assets (a)						
Union				8.75%	8.75%	8.75%
Non-Union				6.00%	6.00%	6.00%
Rate of compensation increase:						
Pension	3.50%	3.25%	3.50%			
SERP	5.50%	5.50%	5.50%			

(a) We determine our long-term rate of return by considering historical market returns, the current and future economic environment, the capital market principals of risk and return, and the expert opinions of individuals and firms with financial market knowledge. We use the asset allocation of the portfolio to forecast the future expected total return of the portfolio. The goal is to determine a long-term rate of return that can be incorporated into the planning of future cash flow requirements in conjunction with the change in the liability. The use of forecasted returns for various classes of assets used to construct an expected return model is reviewed periodically for reasonability and appropriateness.

Costs: The following table recaps the costs incurred in our retirement benefits plans:

	8.75%	8.75%	8.75%			In Millions
	Pension & SERP			OPEB		
Years Ended December 31	2004	2003	2002	2004	2003	2002
Service cost	$36	$39	$ 40	$18	$ 17	$ 16
Interest expense	77	75	86	54	61	63
Expected return on plan assets	(109)	(80)	(103)	(45)	(39)	(40)
Plan amendments	-	-	4	-	-	-
Settlement charge	-	48	-	-	-	-
Amortization of:						
Net loss	14	9	-	11	18	8
Prior service cost	6	7	8	(8)	(6)	(1)
Net periodic pension and postretirement benefit cost	$24	$98	$ 35	$30	$ 51	$ 46

Reconciliations: The following table reconciles the funding of our retirement benefits plans with our retirement benefits plans' liability:

						In Millions
	Pension Plan		SERP		OPEB	
Years Ended December 31	2004	2003	2004	2003	2004	2003
Benefit obligation at beginning of period	$ 1,189	$ 1,256	$ 22	$ 21	$ 812	$ 890
Service cost	35	38	1	1	18	17
Interest cost	74	74	3	1	54	61
Plan amendment	-	(19)	-	-	-	(44)
Employee Transfers	-	-	12	-	-	-
Actuarial loss	138	55	3	-	168	(72)
Benefits paid	(108)	(215)	(1)	(1)	(39)	(40)
Benefit obligation at end of period (a)	1,328	1,189	40	22	1,013	812
Plan assets at fair value at beginning of period	1,067	607	-	-	564	465

Actual return on plan assets	81	115	-	-	25	68
Company contribution	-	560	-	-	48	71
Actual benefits paid	(108)	(215)	-	-	(39)	(40)
Plan assets at fair value at end of period	1,040	1,067	-	-	598	564
Benefit obligation in excess of plan assets	(288)	(122)	(40)	(22)	(415)	(248)
Unrecognized net loss from experience different than assumed	642	501	6	3	347	164
Unrecognized prior service cost (benefit)	23	29	-	-	(99)	(107)
Net Balance Sheet Asset (Liability)	377	408	(34)	(19)	(167)	(191)
Additional VEBA Contributions or Non-Trust Benefit Payments					15	-
Additional minimum liability adjustment (b)	(419)	-	-	-	-	-
Total Net Balance Sheet Asset (Liability)	$ (42)	$ 408	$ (34)	$ (19)	$ (152)	$ (191)

(a) The Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law in December 2003. The Act establishes a prescription drug benefit under Medicare (Medicare Part D), and a federal subsidy, which is tax-exempt, to sponsors of retiree health care benefit plans that provide a benefit that is actuarially equivalent to Medicare Part D.

We believe our plan is actuarially equivalent to Medicare Part D and have incorporated, retroactively, the effects of the subsidy into our financial statements as of June 30, 2004, in accordance with FASB Staff Position, No. SFAS 106-2. We remeasured our obligation as of December 31, 2003 to incorporate the impact of the Act, which resulted in a reduction to the accumulated postretirement benefit obligation of $148 million. The remeasurement resulted in a reduction of OPEB cost of $23 million for 2004. The reduction of $23 million includes $7 million in capitalized OPEB costs. For additional details, see Note 13, Implementation of New Accounting Standards.

(b) The Pension Plan's Accumulated Benefit Obligation of $1.082 billion exceeded the value of the Pension Plan assets and net balance sheet asset at December 31, 2004. As a result, we recorded an additional minimum liability of $419 million. Consistent with MPSC guidance, Consumers recognized the cost of their additional minimum liability as a regulatory asset. Accordingly, Consumers' additional minimum liability includes an intangible asset of $21 million, and a regulatory asset of $372 million. The Accumulated Benefit Obligation for the Pension Plan was $1.019 billion at December 31, 2003.

Plan Assets: The following table recaps the categories of plan assets in our retirement benefits plans:

	Pension		OPEB	
	2004	2003	2004	2003
Asset Category:				
Fixed Income	34%	52%(b)	45%	51%
Equity Securities	61%	44%	54%	48%
CMS Energy Common Stock (a)	5%	4%	1%	1%

(a) At November 30, 2004, there were 4,892,000 shares of CMS Energy Common Stock in the Pension Plan assets with a fair value of $50 million, and 493,000 shares in the OPEB plan assets, with a fair value of $5 million. At December 31, 2003, there were 4,970,000 shares of CMS Energy Common Stock in the Pension Plan assets with a fair value of $42 million, and 414,000 shares in the OPEB plan assets, with a fair value of $4 million.

(b) The percentage of fixed income at December 31, 2003 is high because our December contribution of $329 million was deposited temporarily into fixed income securities.

We contributed $62 million to our OPEB plan in 2004. We plan to contribute $62 million to our OPEB plan in 2005. We did not contribute to our Pension Plan in 2004. We do not plan to contribute to our Pension Plan in 2005.

We have established a target asset allocation for our Pension Plan assets of 65 percent equity and 35 percent fixed income investments to maximize the long-term return on plan assets, while maintaining a prudent level of risk. The level of acceptable risk is a function of the liabilities of the plan. Equity investments are diversified mostly across the Standard & Poor's 500 Index, with a lesser allocation to the Standard & Poor's Mid Cap and Small Cap Indexes and a Foreign Equity Index Fund. Fixed income investments are diversified across investment grade instruments of both government and corporate issuers. Annual liability measurements, quarterly portfolio reviews, and periodic asset/liability studies are used to evaluate the need for adjustments to the portfolio allocation.

We have established union and non-union VEBA trusts to fund our future retiree health and life insurance benefits. These trusts are funded through the rate making process for Consumers, and through direct contributions from the non-utility subsidiaries. The equity portions of the union and non-union health care VEBA trusts are invested in a Standard & Poor's 500 Index fund. The fixed income portion of the union health care VEBA trust is invested in domestic investment grade taxable instruments. The fixed income portion of the non-union health care VEBA trust is invested in a diversified mix of domestic tax-exempt securities. The investment selections of each VEBA are influenced by the tax consequences, as well as the objective of generating asset returns that will meet the medical and life insurance costs of retirees.

Benefit Payments: The expected benefit payments for each of the next five years and the five-year period thereafter are as follows:

			In Millions
	Pension	SERP	OPEB(a)
2005	$113	$2	$53
2006	105	2	51
2007	96	2	53
2008	90	2	54
2009	89	2	56
2010-2014	423	13	322

(a) OPEB benefit payments are net of employee contributions and expected Medicare Part D subsidy payments.

6: Asset Retirement Obligations

SFAS No. 143: This standard became effective January 2003. It requires companies to record the fair value of the cost to remove assets at the end of their useful life, if there is a legal obligation to remove them. We have legal obligations to remove some of our assets, including our nuclear plants, at the end of their useful lives. As required by SFAS No. 71, we accounted for the implementation of this standard by recording regulatory assets and liabilities instead of a cumulative effect of a change in accounting principle.

The fair value of ARO liabilities has been calculated using an expected present value technique. This technique reflects assumptions such as costs, inflation, and profit margin that third parties would consider to assume the settlement of the obligation. Fair value, to the extent possible, should include a market risk premium for unforeseeable circumstances. No market risk premium was included in our ARO fair value estimate since a reasonable estimate could not be made. If a five percent market risk premium were assumed, our ARO liability would increase by $22 million.

If a reasonable estimate of fair value cannot be made in the period in which the ARO is incurred, such as for assets with indeterminate lives, the liability is to be recognized when a reasonable estimate of fair value can be made. Generally, gas transmission and electric and gas distribution assets have indeterminate lives. Retirement cash flows cannot be determined and there is a low probability of a retirement date. Therefore, no liability has been recorded for these assets. Also, no liability has been recorded for assets that have insignificant cumulative disposal costs, such as substation batteries. The measurement of the ARO liabilities for Palisades and Big Rock are based on decommissioning studies that largely utilize third-party cost estimates.

The following tables describe our assets that have legal obligations to be removed at the end of their useful life:

December 31, 2004 — In Millions

ARO Description	In Service Date	Long Lived Assets	Trust Fund
Palisades – decommission plant site	1972	Palisades nuclear plant	$523
Big Rock – decommission plant site	1962	Big Rock nuclear plant	52
JHCampbell intake/discharge water line	1980	Plant intake/discharge water line	-
Closure of coal ash disposal areas	Various	Generating plants coal ash areas	-
Closure of wells at gas storage fields	Various	Gas storage fields	-
Indoor gas services equipment relocations	Various	Gas meters located inside structures	-

In Millions

ARO Description	ARO Liability 1/1/03	Incurred	Settled	Accretion	Cash flow Revisions	ARO Liability 12/31/03
Palisades - decommission	$249	$ -	$ -	$19	$ -	$268
Big Rock - decommission	61	-	(40)	13	-	34
JHCampbell intake line	-	-	-	-	-	-
Coal ash disposal areas	51	-	(3)	5	-	53
Wells at gas storage fields	2	-	-	-	-	2
Indoor gas services relocations	1	-	-	-	-	1
Total	$364	$ -	$(43)	$37	$ -	$358

In Millions

ARO Description	ARO Liability 12/31/03	Incurred	Settled	Accretion	Cash flow Revisions	ARO Liability 12/31/04
Palisades - decommission	$268	$ -	$ -	$22	$60	$350
Big Rock – decommission	34	-	(40)	14	22	30
JHCampbell intake line	-	-	-	-	-	-
Coal ash disposal areas	53	-	(4)	5	-	54
Wells at gas storage fields	2	-	(1)	-	-	1
Indoor gas services relocations	1	-	-	-	-	1
Total	$358	$ -	$(45)	$41	$82	$436

The Palisades and Big Rock cash flow revisions resulted from new decommissioning reports filed with the MPSC in March 2004. The Palisades ARO also reflects a cash flow revision for the probability of operating license renewal; the renewal would extend the plant's operating license by twenty years. For additional details, see Note 2, Contingencies, "Other Electric Contingencies – Nuclear Plant Decommissioning."

On October 14, 2004 the MPSC issued a generic proceeding to review SFAS No. 143, *Accounting for Asset Retirement Obligations*, FERC Order No. 631, *Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations*, and their accounting and ratemaking issues. Utilities are required to respond to the Order by March 15, 2005. We consider the proceeding a clarification of accounting and reporting issues that relate to all Michigan utilities; we anticipate no financial impact.

7: Income Taxes

We file a consolidated federal income tax return with CMS Energy. Income taxes are generally allocated based on each company's separate taxable income. We had tax related receivables from CMS Energy of $4 million in 2004 and $46 million in 2003.

We practice deferred tax accounting for temporary differences in accordance with SFAS No. 109. We use ITC to reduce current income taxes payable, and defer and amortize ITC over the life of the related property. AMT paid generally becomes a tax credit that we can carry forward indefinitely to reduce regular tax liabilities in future periods when regular taxes paid exceed the tax calculated for AMT. At December 31, 2004, we had AMT credit carryforwards in the amount of $20 million that do not expire, and tax loss carryforwards in the amount of $69 million that expire in 2021 through 2023. In addition, at December 31, 2004, we had charitable contribution carryforwards in the amount of $13 million that expire in 2005 through 2008 and general business credit carryforwards in the amount of $4 million that primarily expire in 2005, for which a valuation allowance has been provided.

The significant components of income tax expense (benefit) consisted of:

In Millions

Years Ended December 31	2004	2003	2002
Current federal income taxes	$ 26	$ (58)	$ (97)
Current federal income tax benefit of operating loss	(11)	-	-

carryforwards			
Deferred federal income taxes	142	201	283
Deferred ITC, net	(5)	(6)	(6)
Income tax expense	$ 152	$ 137	$ 180

The principal components of our deferred tax assets (liabilities) recognized in the balance sheet are as follows:

	In Millions	
December 31	2004	2003
Property	$ (863)	$ (826)
Consolidated investments	(217)	(226)
Securitization costs	(176)	(186)
Gas inventories	(126)	(100)
Employee benefits	(79)	(90)
SFAS No. 109 regulatory liability	135	120
Nuclear decommissioning	63	59
Tax loss and credit carryforwards	52	42
Valuation allowance	(9)	(8)
Other, net	(150)	(51)
Net deferred tax liabilities	$(1,370)	$ (1,266)
Deferred tax liabilities	$ (2,102)	$ (1,967)
Deferred tax assets, net of valuation allowance	732	701
Net deferred tax liabilities	$ (1,370)	$ (1,266)

The actual income tax expense differs from the amount computed by applying the statutory federal tax rate of 35 percent to income before income taxes as follows:

			In Millions
Years Ended December 31	2004	2003	2002
Income before cumulative effect of change in accounting principle	$ 280	$ 196	$ 363
Income tax expense	152	137	180
Preferred securities distributions (Note 3)	-	-	(44)
Pretax income	432	333	499
Statutory federal income tax rate	x 35%	x 35%	x 35%
Expected income tax expense	151	117	174
Increase (decrease) in taxes from:			
Property differences not previously deferred	13	18	18
OPEB Medicare subsidy	(5)	-	-

Loss on investment in CMS Energy Common Stock	-	4	4
Sale of METC	-	-	(5)
ITC amortization/adjustments	(6)	(6)	(6)
Valuation allowance provision	1	8	-
Affiliated companies' dividends	-	-	(1)
Other, net	(2)	(4)	(4)
Actual income tax expense	$ 152	$ 137	$ 180
Effective tax rate	35.2%	41.1%	36.1%

8: Executive Incentive Compensation

We provide a Performance Incentive Stock Plan (the Plan) to key employees and non-employee Directors or consultants based on their contributions to the successful management of the company. On May 28, 2004, shareholders approved an amendment to the Plan, with an effective date of June 1, 2004. The amendment established a 5-year term for the Plan. The Plan includes the following type of awards:

- phantom shares,
- performance units,
- restricted stock,
- stock options,
- stock appreciation rights, and
- management stock purchases.

Phantom shares are valued at the fair market price of common stock when granted. They give the holder the right to receive the appreciation value of common stock on one or more valuation dates, according to a specified vesting schedule determined at time of grant. These shares are subject to forfeiture if employment terminates before vesting.

Performance units have an initial value established at the time of grant. Performance criteria are established at the time of grant and, depending upon the extent to which they are met, will determine the value of the payout, which may be in the form of cash, common stock, or a combination of both. These units are subject to forfeiture if employment terminates.

Restricted shares of common stock are outstanding shares with full voting and dividend rights. These awards vest 100 percent after three years and are subject to achievement of specified levels of total shareholder return including a comparison to a peer group of companies. Some awards vest based solely on continued employment. These awards are subject to forfeiture if employment terminates before vesting. Restricted shares vest fully if control of CMS Energy changes, as defined by the Plan.

Stock options give the holder the right to purchase common stock at a given price over an extended period of time. Stock appreciation rights give the holder the right to receive common stock appreciation, defined as the excess of the market price of the stock at the date of exercise over the grant date price. All stock options and stock appreciation rights are valued at fair market price when granted. All options and rights may be exercised upon grant, and expire up to 10 years and one month from the date of grant.

Management stock purchases are the election of select participants in the Officer's Incentive Compensation Plan to receive all or a portion of their incentive payments in the form of shares of restricted common stock or shares of restricted stock units. These participants may also receive awards of additional restricted common stock or restricted stock units provided the total value of these additional grants does not exceed $2.5 million for any fiscal year.

Under the revised Plan, shares awarded or subject to options, phantom shares and performance units may not exceed 6 million shares from June 2004 through May 2009, nor may such grants or awards to any participant exceed 250,000 shares in any fiscal year.

Shares for which payment or exercise is in cash, as well as shares or options that are forfeited, may be awarded or granted again under the Plan.

Awards of up to 5,482,690 shares of CMS Energy Common Stock may be issued as of December 31, 2004. All grants awarded under this Plan in 2004 were in the form of restricted stock.

The following table summarizes the restricted stock and stock options granted to our key employees under the Performance Incentive Stock Plan:

	Restricted Stock	Options	
CMS Energy Common Stock	Number of Shares	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2002	239,665	1,100,952	$ 30.93
Granted	163,890	490,600	$ 14.32
Exercised or Issued	(26,663)	(6,083)	$ 17.13
Forfeited or Expired	(56,172)	(65,080)	$ 32.03
Outstanding at December 31, 2002	320,720	1,520,389	$ 25.58
Granted	434,011	1,105,490	$6.35
Exercised or Issued	(22,812)	-	-
Forfeited or Expired	(69,372)	(31,667)	$26.25
Outstanding at December 31, 2003	662,547	2,594,212	$17.37
Granted	395,641	-	-
Exercised or Issued	(66,537)	(358,102)	$6.65
Forfeited or Expired	(128,449)	(151,218)	$29.98
Outstanding at December 31, 2004	863,202	2,084,892	$18.30

At December 31, 2004, 316,312 of the 863,202 shares of CMS Energy restricted common stock outstanding are subject to performance objectives. Compensation expense for restricted stock was $2 million in 2004, $4 million in 2003, and less than $1 million in 2002.

The following table summarizes our stock options outstanding at December 31, 2004:

Range of Exercise Prices	Number of Shares Outstanding and Exercisable	Weighted Average Remaining Life	Weighted Average Exercise Price

CMS Energy Common Stock:

\$6.35 - \$6.35	808,188	8.70 years	\$ 6.35
\$8.12 - \$8.12	213,850	7.67 years	\$ 8.12
\$17.00 - \$25.39	423,248	5.91 years	\$ 20.48
\$27.25 – \$39.06	551,689	4.60 years	\$34.09
\$43.38 - \$43.38	87,917	3.57 years	\$43.38
\$6.35 - \$43.38	2,084,892	6.72 years	\$18.30

In December 2002, we adopted the fair value based method of accounting for stock-based employee compensation, under SFAS No. 123, as amended by SFAS No. 148. We elected to adopt the prospective method recognition provisions of this Statement, which applies the recognition provisions to all awards granted, modified, or settled after the beginning of the fiscal year that the recognition provisions are first applied.

The following table summarizes the weighted average fair value of stock options granted:

Options Grant Date	2004 (a)	2003	2002 (b)
Fair value at grant date	-	\$3.04	\$3.79, \$1.40

(a) There were no stock option grants during 2004.
(b) For 2002, there were two stock option grants totaling 490,600 options.

The stock options fair value is estimated using the Black-Scholes model, a mathematical formula used to value options traded on securities exchanges. The following assumptions were used in the Black-Scholes model:

Years Ended December 31	2004 (a)	2003	2002 (b)
CMS Energy Common Stock Options			
Risk-free interest rate	-	3.23%	4.02%, 3.28%
Expected stock price volatility	-	53.10%	31.64%, 39.67%
Expected dividend rate	-	-	\$ .365, \$ .1825
Expected option life (years)	-	4.7	4.5

(a) There were no stock option grants during 2004.
For 2002, there were two stock option grants totaling 490,600 options.

We recorded \$3 million as stock-based employee compensation cost for 2003, and \$1 million for 2002. All stock options vest at date of grant.

9: Leases

We lease various assets, including vehicles, railcars, construction equipment, furniture, and buildings. We have both full-service and net leases. A net lease requires us to pay for taxes, maintenance, operating costs, and insurance. Most of our leases contain options at the end of the initial lease term to:

- purchase the asset at fair value, or

- renew the lease at fair rental value.

Our capital leases are comprised mainly of leased service vehicles and office furniture. As of December 31, 2004, capital lease obligations totaled $58 million. We are authorized by the MPSC to record both capital and operating lease payments as operating expense and recover the total cost from our customers. Capital lease expenses were $13 million in 2004, $17 million in 2003, and $20 million in 2002. In November 2003, we exercised our purchase option under the capital lease agreement for our main headquarters building in Jackson, Michigan. Operating lease charges were $13 million in 2004, $13 million in 2003, and $13 million in 2002.

In order to obtain permanent financing for the MCV Facility, the MCV Partnership entered into a sale and lease back agreement with a lessor group, which includes the FMLP, for substantially all of the MCV Partnership's fixed assets. In accordance with SFAS No. 98, the MCV Partnership accounts for the transaction as a financing arrangement. As of December 31, 2004, finance lease obligations totaled $286 million, which represents the third-party portion of the MCV Partnership's finance lease obligation. Charges under the MCV Partnership's finance lease obligation were $105 million in 2004. For additional details on transactions with the MCV Partnership and the FMLP, see Note 2, Contingencies, "Other Electric Contingencies – The Midland Cogeneration Venture."

Minimum annual rental commitments under our non-cancelable leases at December 31, 2004 were:

			In Millions
	Capital Leases	Finance Lease	Operating Leases
2005	$ 13	$ 19	$ 13
2006	13	18	12
2007	12	18	10
2008	10	19	10
2009	8	20	7
2010 and thereafter	15	192	28
Total minimum lease payments	71	286	$ 80
Less imputed interest	13	-	
Present value of net minimum lease payments	58	286	
Less current portion	10	19	
Non-current portion	$ 48	$ 267	

10: Summarized Financial Information of Significant Related Energy Supplier

Under Revised FASB Interpretation No. 46, we are the primary beneficiary of the MCV Partnership. We consolidated their assets, liabilities, and financial activities into our financial statements as of and for the year ended December 31, 2004. As of December 31, 2004, the MCV Partnership had total assets of $1.980 billion and a net loss of $24 million for the year. For 2003 and 2002, the MCV Partnership was accounted for as an equity method investment and their summarized financial information is shown below. Our 49 percent investment in the MCV Partnership was $419 million at December 31, 2003 and our share of net income was $29 million for the year ended December 31, 2003 and $65 million for the year ended December 31, 2002.

Under the PPA with the MCV Partnership discussed in Note 2, Contingencies, our 2003 obligation to purchase electric capacity from the MCV Partnership provided 15 percent of our owned and contracted electric generating capacity. Summarized financial information of the MCV Partnership for 2003 and 2002 follows:

Statements of Income

	In Millions	
Years Ended December 31	2003	2002
Operating revenue (a)	$584	$597
Operating expenses	416	409
Operating income	168	188
Other expense, net	108	114
Income before cumulative effect of accounting change	60	74
Cumulative effect of change in method of accounting for derivative options contracts (b)	-	58
Net Income	$ 60	$ 132

Balance Sheet

			In Millions
December 31	2003		2003
Assets		**Liabilities and Equity**	
Current assets (c)	$ 389	Current liabilities	$ 250
Plant, net	1,494	Non-current liabilities (d)	1,021
Other assets	187	Partners' equity (e)	799
	$ 2,070		$ 2,070

(a) Revenue from Consumers totaled $514 million in 2003 and $557 million in 2002.

(b) On April 1, 2002, the MCV Partnership implemented a new accounting standard for derivatives. As a result, the MCV Partnership began accounting for several natural gas contracts containing an option component at fair value. The MCV Partnership recorded a $58 million cumulative effect adjustment for the change in accounting principle as an increase to earnings. CMS Midland's 49 percent ownership share was $28 million ($18 million after-tax), which is reflected as a change in accounting principle on our Consolidated Statements of Income.

(c) Receivables from Consumers totaled $40 million for December 31, 2003.

(d) The FMLP is the sole beneficiary of a trust that is the lessor in a long-term direct finance lease with the MCV Partnership. CMS Holdings holds a 46.4 percent ownership interest in the FMLP. The MCV Partnership's lease obligations, assets, and operating revenues secure the FMLP's debt. The following table summarizes obligation and payment information regarding the direct finance lease:

		In Millions
December 31		2003
Balance Sheet:		
MCV Partnership:	Lease obligation	$ 894
FMLP:	Non-recourse debt	431
	Lease payment to service non-recourse debt (including interest)	158
CMS Holdings:	Share of interest portion of lease payment	37
	Share of principle portion of lease payment	36

		In Millions	
Years Ended December 31		2003	2002
Income Statement:			
FMLP:	Earnings	$ 32	$ 38

(e) CMS Midland's recorded investment in the MCV Partnership includes capitalized interest, which we are expensing over the life of our investment in the MCV Partnership. The financing agreements prohibit the MCV Partnership from distributing any cash to its owners until it meets certain financial test requirements. We do not anticipate receiving a cash distribution in the near future.

11: Jointly Owned Regulated Utility Facilities

We are required to provide only our share of financing for the jointly owned utility facilities. The direct expenses of the jointly owned plants are included in operating expenses. Operation, maintenance, and other expenses of these jointly owned utility facilities are shared in proportion to each participant's undivided ownership interest. The following table indicates the extent of our investment in jointly owned regulated utility facilities:

							In Millions
	Ownership Share	Net Investment		Accumulated Depreciation		Construction Work in Progress	
December 31	(percent)	2004	2003	2004	2003	2004	2003
Campbell Unit 3	93.3	$284	$299	$339	$328	$158	$113
Ludington	51.0	79	84	91	87	-	(1)
Distribution	Various	77	74	33	32	6	5

12: Reportable Segments

Our reportable segments are strategic business units organized and managed by the nature of the products and services each provides. We evaluate performance based upon the net income of each segment. We operate principally in two segments, electric utility and gas utility.

The electric utility segment consists of regulated activities associated with the generation and distribution of electricity in the state of Michigan. The gas utility segment consists of regulated activities associated with the transportation, storage, and distribution of natural gas in the state of Michigan.

Accounting policies of the segments are the same as we describe in the summary of significant accounting policies. Our financial statements reflect the assets, liabilities, revenues, and expenses directly related to the electric and gas segment where it is appropriate. We allocate accounts between the electric and gas segments where common accounts are attributable to both segments. The allocations are based on certain measures of business activities, such as revenue, labor dollars, customers, other operation and maintenance expense, construction expense, leased property, taxes or functional surveys. For example, customer receivables are allocated based on revenue. Pension provisions are allocated based on labor dollars.

We account for inter-segment sales and transfers at current market prices and eliminate them in consolidated net income available to common stockholder by segment. The "Other" segment includes our consolidated special purpose entity for the sale of trade receivables, the MCV Partnership and the FMLP.

The following table shows our financial information by reportable segment:

In Millions

Years Ended December 31	2004	2003	2002
Operating Revenues			
Electric	$ 2,586	$ 2,590	$ 2,648
Gas	2,081	1,845	1,519
Other	44	-	2
	$ 4,711	$ 4,435	$ 4,169
Earnings from Equity Method Investees			
Other (a)	$ 1	$ 42	$ 53
Depreciation, Depletion and Amortization			
Electric	$ 189	$ 247	$ 228
Gas	112	128	118
Other	90	2	2
	$ 391	$ 377	$ 348
Interest Charges			
Electric	$ 204	$ 164	$ 111
Gas	65	51	36
Other	97	30	21
	$ 366	$ 245	$ 168
Income Tax Expense			
Electric	$ 120	$ 90	$ 138
Gas	40	35	33
Other (b)	(8)	12	9
	$ 152	$ 137	$ 180
Net Income Available to Common Stockholder			
Electric	$ 222	$ 167	$ 264
Gas	71	38	46
Other	(16)	(11)	25
	$ 277	$ 194	$ 335
Investments in Equity Method Investees			
Electric	$ 3	$ 2	$ 2
Other (c)	16	659	643
	$ 19	$ 661	$ 645
Total Assets			
Electric (d)	$ 7,289	$ 6,831	$ 6,058
Gas (d)	3,187	2,983	2,586
Other	2,335	931	954
	$ 12,811	$10,745	$ 9,598
Capital Expenditures (e)			
Electric	$ 360	$ 310	$ 437
Gas	137	135	181
Other	21	-	-
	$ 518	$ 445	$ 618

(a) 2002 excludes $28 million benefit due to the change in accounting for derivative instruments.

(b) 2002 excludes $10 million tax expense due to the change in accounting for derivative instruments.

(c) As of December 31, 2003, the trusts that hold the mandatorily redeemable Trust Preferred Securities were deconsolidated. The trusts are now included on our Consolidated Balance Sheets as Investments –Other.

(d) Amounts include a portion of our other common assets attributable to both the electric and gas utility businesses.

(e) Amounts include electric restructuring implementation plan, purchase of nuclear fuel, and other assets. Amounts also include a portion of capital expenditures for plant and equipment attributable to both the electric and gas utility businesses.

13: Implementation of new accounting standards

FASB Interpretation No. 46, *Consolidation of Variable Interest Entities:* The FASB issued this Interpretation in January 2003. The objective of the Interpretation is to assist in determining when one party controls another entity in circumstances where a controlling financial interest cannot be properly identified based on voting interests. Entities with this characteristic are considered variable interest entities. The Interpretation requires the party with the controlling financial interest, known as the primary beneficiary, in a variable interest entity to consolidate the entity.

In December 2003, the FASB issued Revised FASB Interpretation No. 46. For entities that had not previously adopted FASB Interpretation No. 46, Revised FASB Interpretation No. 46 provided an implementation deferral until the first quarter of 2004. As of and for the quarter ended March 31, 2004, we adopted Revised FASB Interpretation No. 46 for all entities.

We determined that we are the primary beneficiary of both the MCV Partnership and the FMLP. We have a 49 percent partnership interest in the MCV Partnership and a 46.4 percent partnership interest in the FMLP. Consumers is the primary purchaser of power from the MCV Partnership through a long-term power purchase agreement. The FMLP holds a 75.5 percent lessor interest in the MCV Facility, which results in Consumers holding a 35 percent lessor interest in the MCV Facility. Collectively, these interests make us the primary beneficiary of these entities. As such, we consolidated their assets, liabilities, and activities into our financial statements as of and for the year ended December 31, 2004. These partnerships have third-party obligations totaling $582 million at December 31, 2004. Property, plant, and equipment serving as collateral for these obligations has a carrying value of $1.426 billion at December 31, 2004. The creditors of these partnerships do not have recourse to the general credit of Consumers.

We determined that we are not the primary beneficiary of our trust preferred security structures. Accordingly, those entities were deconsolidated as of December 31, 2003. Company Obligated Trust Preferred Securities totaling $490 million that were previously included in mezzanine equity, were eliminated due to deconsolidation. At December 31, 2004, we reflected Long-term debt – related parties of $326 million, current portion of Long-term debt – related parties of $180 million, and an investment in related parties of $16 million.

We are not required to restate prior periods for the impact of this accounting change.

FASB Staff Position, No. SFAS 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003*: The Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the Act) was signed into law in December 2003. The Act establishes a prescription drug benefit under Medicare (Medicare Part D) and a federal subsidy, which is exempt from federal taxation, to sponsors of retiree health care benefit plans that provide a benefit that is actuarially equivalent to Medicare Part D.

We believe our plan is actuarially equivalent to Medicare Part D and have incorporated retroactively the effects of the subsidy into our financial statements as of June 30, 2004, in accordance with FASB Staff Position, No. SFAS 106-2. We remeasured our obligation as of December 31, 2003 to incorporate the impact of the Act, which resulted in a reduction to the accumulated postretirement benefit obligation of $148 million. The remeasurement resulted in a total OPEB cost reduction of $23 million for 2004. Consumers capitalizes a portion of OPEB cost in accordance with regulatory accounting. As such, the remeasurement resulted in a net reduction of OPEB expense of $16 million for 2004.

EITF Issue No. 03-1, *The Meaning of Other-Than-Temporary Impairments*: The Issue addresses the definition of an other-than-temporary impairment of certain investments and provides additional disclosure requirements. The scope of EITF Issue No. 03-1 includes debt and equity securities accounted for under SFAS No. 115, debt and equity securities held by non-profit organizations under SFAS No. 124, and cost method investments under APB No. 18. We analyzed our in-scope investments under the guidance of this Issue and have provided additional disclosures.

FSP 109-1, Accounting and Disclosure Guidance for the Tax Deduction Provided to U.S. Based Manufacturers by the American Jobs Creation Act of 2004: The American Jobs Creation Act of 2004 provides for a deduction, starting in 2005, of a portion of the income from certain production activities, including the production of electricity. FSP 109-1 indicates that the deduction should be accounted for as a special deduction rather than a tax rate reduction under SFAS No. 109. We are currently studying this act for its impact on us; however, we do not anticipate a material amount of tax benefit from the domestic production activities deduction in the near future.

New Accounting Standards NOT YET EFFECTIVE

SFAS No. 123R, *Share-Based Payment*: The Statement requires companies to expense the grant date fair value of employee stock options and similar awards. The Statement also clarifies and expands SFAS No. 123's guidance in several areas, including measuring fair value, classifying an award as equity or as a liability, and attributing compensation cost to reporting periods.

In addition, this Statement amends SFAS No. 95, *Statement of Cash Flows*, to require that excess tax benefits related to the excess of the tax deductible amount over the compensation cost recognized be classified as a financing cash inflow rather than as a reduction of taxes paid in operating activities.

This Statement is effective for us as of the beginning of third quarter 2005. We adopted the fair value method of accounting for share-based awards effective December 2002, and therefore, expect this statement to have an insignificant impact on our results of operations when it becomes effective.

14: Quarterly financial and common stock information (unaudited)

	2004			
Quarters Ended	March 31	June 30	Sept. 30	Dec. 31
	In Millions			
Operating revenue (a)	$1,547	$923	$885	$1,356
Operating income (a)(d)	247	111	122	194
Income before cumulative effect of change in accounting Principle (d)	105	24	34	117
Cumulative effect of change in accounting (b)(c)	(1)	-	-	-

Net income (c)(d)	104	24	34	117
Preferred stock dividends	-	1	-	1
Net income available to common stockholder (c)(d)	104	23	34	116

(a) As of March 31, 2004, we determined that the MCV Partnership and the FMLP should be consolidated in accordance with revised FASB Interpretation No. 46. As such, we consolidated their financial activities into our financial statements as of and for the year ended December 31, 2004. For additional details, see Note 13, Implementation of New Accounting Standards.

(b) Net of tax.

(c) Quarterly data for March 31, 2004 differs from amounts previously reported as a result of accelerating the measurement date on our benefit plans by one month. For additional information, see Note 5, Retirement Benefits.

(d) Quarterly data for March 31, 2004 differs from amounts previously reported due to the remeasurement of our post retirement benefit obligation in accordance with FASB Staff Position, No. SFAS 106-2. For additional information, see Note 13, Implementation of New Accounting Standards.

	2003			
Quarters Ended	March 31	June 30	Sept. 30	Dec. 31
	In Millions			
Operating revenue	$1,442	$902	$879	$1,212
Operating income	233	139	115	96
Income (loss) before cumulative effect of change in accounting principle	110	52	44	(10)
Net income (loss)	110	52	44	(10)
Preferred stock dividends	-	1	-	1
Preferred securities distributions	11	11	11	(33)
Net income available to common stockholder	99	40	33	22

15: Income Taxes (Unconsolidated)

The significant components of income tax expense (benefit) consisted of:

	In Millions
Year Ended December 31	2004
Current federal income taxes	$ 14
Deferred income taxes	141
Deferred ITC, net	(4)
Income tax expense	$ 151

The actual income tax expense differs from the amount computed by applying the statutory federal tax rate of 35 percent to income before income taxes as follows:

	In Millions
Year Ended December 31	2004
Income before cumulative effect of change in accounting principle	$ 280
Income taxes	151
Pretax income	431
Statutory federal income tax rate	x 35%
Expected income tax expense	151
Increase (decrease) in taxes from:	
Differences not previously deferred	13
ITC amortization/adjustments	(4)
Tax exempt interest income	(3)
OPEB Medicare subsidy	(3)
Other, net	(1)
Actual income tax expense	$ 151