
**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION**
Washington, D.C. 20549

Form 10-Q

(Mark One)

- QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934**

For the Quarterly Period Ended September 30, 2002

or

- TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _____ to _____

Commission file number 333-59348

MIDWEST GENERATION, LLC
(Exact name of registrant as specified in its charter)

Delaware

(State or other jurisdiction of
incorporation or organization)

33-0868558

(I.R.S. Employer Identification No.)

One Financial Place

440 South LaSalle Street, Suite 3500

Chicago, Illinois

(Address of principal executive offices)

60605

(Zip Code)

Registrant's telephone number, including area code: **(312) 583-6000**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES NO

Number of units outstanding of the registrant's Membership Interests as of November 11, 2002:
100 units (all units held by an affiliate of the registrant).

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PART I—FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

MIDWEST GENERATION, LLC

BALANCE SHEETS

(In thousands)

	<u>September 30, 2002</u>	<u>December 31, 2001</u>
	(Unaudited)	
Assets		
Current Assets		
Cash and cash equivalents	\$ 69,812	\$ 52,635
Accounts receivable, net of allowance of \$4,269 in 2002 and 2001	172,605	70,982
Due from affiliates	170,541	175,592
Fuel inventory	71,328	80,042
Spare parts inventory	18,068	17,718
Interest receivable from affiliate	28,040	58,885
Assets under price risk management	199	—
Other current assets	10,950	7,793
Total current assets	<u>541,543</u>	<u>463,647</u>
Property, Plant and Equipment	5,271,001	4,946,386
Less accumulated depreciation	432,877	304,466
Net property, plant and equipment	<u>4,838,124</u>	<u>4,641,920</u>
Notes Receivable From Affiliate	1,366,502	1,667,000
Total Assets	<u>\$6,746,169</u>	<u>\$6,772,567</u>

The accompanying notes are an integral part of these financial statements.

MIDWEST GENERATION, LLC
BALANCE SHEETS
(In thousands)

	<u>September 30,</u> <u>2002</u>	<u>December 31,</u> <u>2001</u>
	<u>(Unaudited)</u>	
Liabilities and Member's Equity		
Current Liabilities		
Accounts payable	\$ 10,476	\$ 17,192
Accrued liabilities	65,623	66,789
Due to affiliates	3,353	3,461
Interest payable	63,162	83,892
Interest payable to affiliates	3,017	41,233
Liabilities under price risk management	492	8,401
Current portion of lease financing	9,793	9,173
Total current liabilities	<u>155,916</u>	<u>230,141</u>
Subordinated revolving line of credit with affiliate	1,952,994	1,952,680
Subordinated long-term debt with affiliate	1,719,308	1,719,308
Lease financing, net of current portion	2,169,855	2,179,648
Deferred taxes	85,726	56,875
Deferred coal and transportation costs	62,289	78,150
Benefit plans and other	<u>97,000</u>	<u>92,232</u>
Total Liabilities	<u>6,243,088</u>	<u>6,309,034</u>
Commitments and Contingencies (Note 3)		
Member's Equity		
Membership interests, no par value; 100 units authorized, issued and outstanding	—	—
Additional paid-in capital	678,241	669,928
Accumulated deficit	(174,988)	(206,395)
Accumulated other comprehensive loss	<u>(172)</u>	<u>—</u>
Total Member's Equity	<u>503,081</u>	<u>463,533</u>
Total Liabilities and Member's Equity	<u>\$6,746,169</u>	<u>\$6,772,567</u>

The accompanying notes are an integral part of these financial statements.

MIDWEST GENERATION, LLC
STATEMENTS OF OPERATIONS
(In thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(Unaudited)		(Unaudited)	
Operating Revenues				
Energy revenues	\$ 181,733	\$ 146,463	\$ 417,010	\$ 387,118
Capacity revenues	344,654	340,318	546,051	524,923
Energy and capacity revenues from marketing affiliate	3,103	1,280	10,317	10,467
Loss from price risk management	—	(12,600)	(2,242)	(20,768)
Total operating revenues	<u>529,490</u>	<u>475,461</u>	<u>971,136</u>	<u>901,740</u>
Operating Expenses				
Fuel	146,951	109,194	319,719	309,036
Plant operations	70,082	95,111	258,330	293,996
Asset impairment charges	25,402	—	25,402	—
Depreciation and amortization	44,828	42,964	128,411	124,425
Administrative and general	5,868	7,241	18,981	18,273
Total operating expenses	<u>293,131</u>	<u>254,510</u>	<u>750,843</u>	<u>745,730</u>
Operating income	<u>236,359</u>	<u>220,951</u>	<u>220,293</u>	<u>156,010</u>
Other Income (Expense)				
Interest income and other	29,204	32,525	90,036	99,035
Interest expense	(86,169)	(96,284)	(254,604)	(299,036)
Total other expense	<u>(56,965)</u>	<u>(63,759)</u>	<u>(164,568)</u>	<u>(200,001)</u>
Income (loss) before income taxes	179,394	157,192	55,725	(43,991)
Provision (benefit) for income taxes	67,643	60,478	24,318	(16,789)
Net Income (Loss)	<u>\$ 111,751</u>	<u>\$ 96,714</u>	<u>\$ 31,407</u>	<u>\$ (27,202)</u>

The accompanying notes are an integral part of these financial statements.

MIDWEST GENERATION, LLC
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(In thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(Unaudited)		(Unaudited)	
Net Income (Loss)	\$111,751	\$ 96,714	\$ 31,407	\$(27,202)
Other comprehensive income (expense), net of tax:				
Unrealized gains (losses) on derivatives qualified as cash flow hedges:				
Cumulative effect of change in accounting for derivatives, net of income tax expense of \$15,870 . .	—	—	—	20,834
Other unrealized holding gains (losses) arising during period, net of income tax expense (benefit) of \$(225) and \$(121) for the three months and nine months ended September 30, 2002, respectively, and \$430 for the nine months ended September 30, 2001	(319)	—	(172)	611
Reclassification adjustments for gains included in net income (loss), net of income tax expense of \$8,741 and \$14,410 for the three months and nine months ended September 30, 2001, respectively	—	(12,393)	—	(20,432)
Comprehensive Income (Loss)	<u>\$111,432</u>	<u>\$ 84,321</u>	<u>\$ 31,235</u>	<u>\$(26,189)</u>

The accompanying notes are an integral part of these financial statements.

MIDWEST GENERATION, LLC
STATEMENTS OF CASH FLOWS
(In thousands)

	Nine Months Ended September 30,	
	2002	2001
	(Unaudited)	
Cash Flows From Operating Activities		
Net income (loss)	\$ 31,407	\$ (27,202)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation and amortization	128,411	124,425
Non-cash contribution of services	8,313	7,925
Asset impairment charges	25,402	—
Deferred taxes	28,851	(11,125)
Increase in accounts receivable	(101,623)	(88,930)
Decrease in due to/from affiliates	4,943	62,827
(Increase) decrease in inventory	8,364	(33,079)
(Increase) decrease in interest receivable from affiliate	30,845	(14,586)
Increase in other current assets	(3,157)	(7,744)
Increase (decrease) in accounts payable	(6,716)	16,243
Decrease in accrued liabilities	(8,802)	(74,266)
Increase (decrease) in interest payable	(58,946)	772
Decrease in other liabilities	(3,352)	(17,658)
Increase (decrease) in net liabilities under price risk management	(8,280)	19,567
Net cash provided by (used in) operating activities	75,660	(42,831)
Cash Flows From Financing Activities		
Borrowings from subordinated long-term debt with affiliate	60,000	264,352
Repayments of subordinated long-term debt with affiliate	(60,000)	(115,000)
Borrowings from subordinated revolving line of credit with affiliate	59,200	78,538
Repayments of subordinated revolving line of credit with affiliate	(58,886)	(90,258)
Repayment of capital lease obligation	(9,173)	(18,240)
Net cash provided by (used in) financing activities	(8,859)	119,392
Cash Flows From Investing Activities		
Capital expenditures	(350,122)	(42,053)
Repayment of loan from affiliate	300,498	—
Net cash used in investing activities	(49,624)	(42,053)
Net increase in cash and cash equivalents	17,177	34,508
Cash and cash equivalents at beginning of period	52,635	15,699
Cash and cash equivalents at end of period	\$ 69,812	\$ 50,207

The accompanying notes are an integral part of these financial statements.

MIDWEST GENERATION, LLC
NOTES TO FINANCIAL STATEMENTS

Note 1. General

In the opinion of management, all adjustments, including recurring accruals, have been made that are necessary to present fairly the financial position and results of operations for the periods covered by this report. The results of operations for the nine months ended September 30, 2002 are not necessarily indicative of the operating results for the full year.

Our significant accounting policies are described in Note 2 to our financial statements as of December 31, 2001, included in our 2001 Annual Report on Form 10-K filed with the Securities and Exchange Commission. We follow the same accounting policies for interim reporting purposes. This quarterly report should be read in connection with such financial statements.

Certain prior period amounts have been reclassified to conform to the current period financial statement presentation. These reclassifications had no effect on net income or member's equity.

Income Taxes

We are included in the consolidated federal and state income tax returns of Edison International and are party to a tax-allocation agreement with our parent Edison Mission Midwest Holdings. In accordance with the agreement and the tax-allocation procedures that have been in effect since our formation, our current tax liability or benefit is generally determined on a separate return basis, except for calculating consolidated state income taxes, for which we use the long-term state tax apportionment factors of the Edison International group. Also, while we are generally subject to separate return limitations for net losses, under the tax-allocation agreement we are permitted to transfer to Edison Mission Midwest Holdings, or its subsidiaries, net operating loss benefits which would not yet be realized in a separate return in exchange for a reduction in our intercompany account balances (including subordinated loans). Thus, during the fourth quarter of 2002, we expect to realize a portion of the tax receivable on our books through a reduction in amounts owed under our subordinated loan agreement with Edison Mission Overseas Co.

We account for income taxes using the asset-and-liability method, wherein deferred tax assets and liabilities are recognized for future tax consequences of temporary differences between the carrying amounts and the tax bases of assets and liabilities using enacted rates.

Current Developments

A number of significant developments have adversely affected independent power producers and subsidiaries of major integrated energy companies who sell a sizable portion of their generation into the wholesale energy market (sometimes referred to as merchant generators). These developments include depressed market prices in U.S. wholesale energy markets, significant declines in the credit ratings of most major market participants and the decline of liquidity in the energy markets as a result of tightening credit and increasing concern about the ability of counterparties to perform their obligations. In addition, many merchant generators and power trading firms have announced plans to improve their financial position through asset sales, cancellation or deferral of substantial new development, significant reductions and elimination of trading activities, decreases in capital expenditures, including cancellations of orders for new turbines, and reductions in operating costs.

Our Situation

Our plants have been largely unaffected by these developments because Exelon Generation is under contract with us to buy substantially all of the capacity of our units for the balance of 2002. However, as permitted by the power purchase agreements, Exelon Generation has advised us that it

will not purchase 2,684 MW of the capacity from our coal-fired units and 1,864 MW of capacity from our Collins Station and small peaking units for 2003 and 2004, and Exelon Generation has the further right to release an additional 3,043 MW for 2004. As a result, beginning in 2003, the portion of our generation to be sold into the wholesale markets will significantly increase, thereby increasing our merchant risk. See “Management’s Discussion and Analysis of Results of Operations and Financial Condition—Market Risk Exposures.”

As a result of these and other factors, Moody’s downgraded our credit rating and the credit ratings of our parent, Edison Mission Midwest Holdings, and our indirect parent, Edison Mission Energy on October 1, 2002 as shown in the following table:

<u>Rated Entities</u>	<u>Moody’s Rating prior to Downgrade</u>	<u>Moody’s Rating after Downgrade</u>
Edison Mission Energy senior unsecured debt	Baa3	Ba3
Edison Mission Midwest Holdings Co. bank facility	Baa2	Ba2
Midwest Generation, LLC	Baa3	Ba3

In addition, Standard & Poor’s has placed the credit rating of Edison Mission Midwest Holdings on CreditWatch with negative implications. See “Management’s Discussion and Analysis of Results of Operations and Financial Condition—Credit Ratings.”

Against this background, we have undertaken actions to reduce our commitments and expenditures, thereby improving our cash flow. These actions include:

- a reduction in our capital expenditure program by \$310 million for the years 2003-2005 due to suspension of work on two selective catalytic reduction systems (commonly referred to as SCRs) for our Powerton Station; and
- suspension, beginning in January 2003, of operations at Units 1 and 2 of our Will County plant and Units 4 and 5 of our Collins Station in order to reduce operating costs.

For a discussion of our current financial condition, see “Management’s Discussion and Analysis of Results of Operations and Financial Condition—Liquidity and Capital Resources.”

Note 2. Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) consisted of the following (in thousands):

	<u>Unrealized Losses on Cash Flow Hedges</u>	<u>Accumulated Other Comprehensive Loss</u>
Balance at December 31, 2001	\$ —	\$ —
Current period change	<u>(172)</u>	<u>(172)</u>
Balance at September 30, 2002 (unaudited)	<u><u>\$(172)</u></u>	<u><u>\$(172)</u></u>

Unrealized losses on cash flow hedges at September 30, 2002 include forward energy sales contracts that did not meet the normal sales and purchases exception under SFAS No. 133. These losses arise because current forecasts of future electricity prices are higher than our contract prices. As our hedged positions are realized, approximately \$1.1 million, after tax, of the net unrealized losses on cash flow hedges will be reclassified into earnings during the next twelve months. The maximum period over which a cash flow hedge is designated is through December 31, 2003.

Note 3. Commitments and Contingencies

Commercial Commitments

The following table summarizes our commercial commitments as of September 30, 2002.

<u>Commercial Commitments</u>	<u>2002</u>	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>Thereafter</u>	<u>Total</u>
				(in millions)			
Environmental improvements	<u>\$ 9.9</u>	<u>\$ 7.4</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$17.3</u>

Capital Expenditures

The Company's capital program has been reduced by \$310 million as a result of the suspension of work related to two Powerton Station SCRs. As a result of the decision to suspend work on this project, the Company recorded a pre-tax impairment charge of \$25.4 million during the third quarter ended September 30, 2002, due to the write-off of capitalized costs associated with these environmental improvements. This decision to reduce capital expenditures was made in light of current market conditions. See "Management's Discussion and Analysis of Results of Operations and Financial Condition—Market Risk Exposures" and "Management's Discussion and Analysis of Results of Operations and Financial Condition—Environmental Matters and Regulations."

On August 9, 2002, the Company exercised its option to purchase the Illinois peaker power units that were subject to a lease with a third-party lessor. As disclosed in "Management's Discussion and Analysis of Results of Operations and Financial Condition—Off-Balance Sheet Transactions" in the Company's 2001 Annual Report on Form 10-K, this operating lease was structured to maintain a minimum amount of equity (3% of the acquisition price) for the duration of the lease term in accordance with existing guidance for leases involving special purpose entities (sometimes referred to as synthetic leases). In order to fund the purchase, the Company received full payment of principal, interest and fees on its \$300 million note receivable from Edison Mission Energy, and then paid \$300 million plus outstanding lease obligations to the owner-lessor. These peaker units were recorded as assets and are being depreciated over their estimated useful lives of 15 years.

Power Purchase Agreements

Electric power generated at the Company's power generation plants is sold under three power purchase agreements with Exelon Generation, under which Exelon Generation purchases capacity and has the right to purchase energy generated by the power generation plants. The Company initially entered into agreements with Commonwealth Edison on December 15, 1999 which were assigned to Exelon Generation in January 2001. The power purchase agreements have a term of up to five years and provide for capacity and energy payments. Exelon Generation is obligated to make capacity payments for the power generation plants under contract and energy payments for the electricity produced by these plants and taken by Exelon Generation. The capacity payments provide the power generation plants revenue for fixed charges, and the energy payments compensate the power generation plants for variable costs of production.

In July 2002, under the power purchase agreement related to the Company's coal-fired generation units, Exelon Generation notified the Company of its exercise of its option to purchase 1,265 MW of capacity and energy during 2003 (of a possible total of 3,949 MW subject to option) from the option coal units. As a result, 2,684 MW of capacity of the Will County 1 and 2, Joliet 6 and 7, and Powerton 5 and 6 units will no longer be subject to the power purchase agreement after January 1, 2003. The notification received from Exelon Generation has no effect on its commitments to purchase capacity from these units for the balance of 2002. Exelon Generation continues to have a similar option, exercisable not later than 180 days prior to January 1, 2004, to retain or release for 2004 all or a

portion of the option coal units retained for 2003. It remains committed to purchase the capacity of certain committed units having 1,696 MW of capacity for both 2003 and 2004.

In October 2002, under the power purchase agreements related to the Company's Collins Station and peaking units, Exelon Generation notified the Company of its exercise of its option to terminate the existing power purchase agreements during 2003 with respect to (a) 1,614 MW of capacity and energy (of a possible total of 2,698 MW subject to the option to terminate) from the Collins Station, a natural gas and oil-fired electric generating station, and (b) 113 MW of capacity and energy (of a possible total of 807 MW subject to the option to terminate) from the natural gas and oil-fired peaking units, in accordance with the terms of each applicable power purchase agreement. As a result, 1,614 MW of capacity from the Collins Units 2, 4 and 5, and 113 MW of capacity from the Lombard 33 and Calumet 33 and 34 peaking units, will no longer be subject to a power purchase agreement after January 1, 2003. The notification received from Exelon Generation has no effect on its commitments to purchase capacity from these generating units for the balance of 2002. Exelon Generation continues to have a similar option to terminate, exercisable not later than 90 days prior to January 1, 2004, the power purchase agreements for 2004 with respect to all or a portion of the generating units not previously terminated for 2003 (1,084 MW from the Collins Station and 694 MW from the peaking units).

If Exelon Generation does not fully dispatch the power generation plants under contract, the Company may sell, subject to specified conditions, the excess energy at market prices to neighboring utilities, municipalities, third-party electric retailers, large consumers and power marketers on a spot basis. A bilateral trading infrastructure already exists with access to the Mid-America Interconnected Network and the East Central Area Reliability Council.

Chicago In-City Obligation

Pursuant to the acquisition documents for the purchase of generating assets from Commonwealth Edison, the Company committed to install one or more gas-fired electric generating units having an additional gross dependable capacity of 500 MW at or adjacent to an existing power plant site in Chicago (referred to as the In-City Obligation). The acquisition documents require that commercial operation of this project commence by December 15, 2003. Due to additional capacity for new gas-fired generation in the Mid-America Interconnected Network, generally referred to as the MAIN Region, and the improved reliability of power generation in the Chicago area, the Company is in discussions with Commonwealth Edison and the City of Chicago regarding alternatives to construction of 500 MW of capacity, which the Company does not believe is needed at this time. There can be no assurance that these discussions will result in an agreement to terminate the In-City Obligation. If the Company were to install this additional capacity, the Company estimates that the cost could be as much as \$320 million.

Environmental Matters

The Company is subject to environmental regulation by federal, state and local authorities in the United States. The Company believes that, as of the date of this report, it is in substantial compliance with environmental regulatory requirements and that maintaining compliance with current requirements will not materially affect its financial position or results of operations. However, possible future developments, such as the promulgation of more stringent environmental laws and regulations, and future proceedings which may be taken by environmental authorities, could affect the costs and the manner in which the Company conducts its business and could cause the Company to make substantial additional capital expenditures. There is no assurance that the Company would be able to recover these increased costs from its customers or that its financial position and results of operations would not be materially adversely affected.

Interconnection Agreements

The Company has entered into interconnection agreements with Commonwealth Edison to provide interconnection services necessary to connect its Illinois Plants with their transmission systems. Unless terminated earlier in accordance with the terms thereof, the interconnection agreements will terminate on a date mutually agreed to by both parties. This date may not exceed the retirement date of the Illinois Plants. The Company is required to compensate Commonwealth Edison for all reasonable costs associated with any modifications, additions or replacements made to the interconnection facilities or transmission systems in connection with any modification, addition or upgrade to its Illinois Plants.

Guaranty of Debt of Edison Mission Midwest Holdings and Pledge of Ownership Interests

The Company has guaranteed Edison Mission Midwest Holdings' (its parent) third-party debt in the amount of \$1.7 billion at September 30, 2002. The Company's parent also pledged the membership interests in the Company to the lenders in connection with the third-party debt arrangements.

Note 4. Supplemental Statements of Cash Flows Information

	Nine Months Ended September 30,	
	2002	2001
	(Unaudited) (in thousands)	
Cash paid for interest	\$313,550	\$298,264
Cash paid for income taxes	—	—

Note 5. Subsequent Events

The Company had a retirement health care and other benefits plan related to its union-represented employees that expired on June 15, 2002. In October 2002, the Company reached an agreement with its union-represented employees on a new retirement health care and other benefits plan which extends from January 1, 2003 through June 30, 2005. The Company will continue to provide benefits at the same level as those in the expired agreement until December 31, 2002.

As described in the Company's 2001 Annual Report on Form 10-K, it has been accounting for postretirement benefits obligations on the basis of a substantive plan under Statement of Financial Accounting Standards No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." A substantive plan means that the Company assumed for accounting purposes that it would provide for postretirement benefits to union-represented employees following conclusion of negotiations to replace the current benefits agreement, even though it had no legal obligation to do so. Under the new agreement, postretirement benefits will not be provided. Accordingly, the Company will treat this as a plan termination under SFAS No. 106 and will record a pre-tax gain of \$70.7 million during the fourth quarter of 2002.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

The following discussion contains forward-looking statements. These statements are based on our current plans and expectations and involve risks and uncertainties which could cause actual future activities and results of operations to be materially different from those set forth in the forward-looking statements. Important factors that could cause differences in our results of operations are set forth under “—Credit Ratings” and “—Market Risk Exposures” below, and under “—Risk Factors” in the Management’s Discussion and Analysis of Results of Operations and Financial Condition included in Item 7 of Midwest Generation, LLC’s Annual Report on Form 10-K for the year ended December 31, 2001.

The Management’s Discussion and Analysis of Results of Operations and Financial Condition of this Form 10-Q discusses material changes in the results of operations, financial condition and other developments of Midwest Generation, LLC since December 31, 2001, and as compared to the third quarter and nine months ended September 30, 2001. This discussion presumes that the reader has read or has access to the Management’s Discussion and Analysis of Results of Operations and Financial Condition included in Item 7 of Midwest Generation, LLC’s Annual Report on Form 10-K for the year ended December 31, 2001.

Unless otherwise indicated, the information presented in this section is with respect to Midwest Generation, LLC.

General

We are a special-purpose Delaware limited liability company formed on July 12, 1999 for the purpose of owning or leasing, making improvements to and operating the power generation assets we purchased from Commonwealth Edison. We are a wholly-owned subsidiary of Edison Mission Midwest Holdings Co., an indirect wholly-owned subsidiary of Edison Mission Energy and an indirect wholly-owned subsidiary of Edison International.

In connection with the acquisition of the power generation assets, we entered into three five-year power purchase agreements for the coal-fired stations, the Collins Station, and the peaker stations, with Commonwealth Edison. Subsequently, Commonwealth Edison, which we refer to as ComEd, assigned its rights and obligations under these power purchase agreements to Exelon Generation. We currently derive virtually all of our energy and capacity revenues from Exelon Generation under these power purchase agreements. For more information on these power purchase agreements, including committed capacity and energy purchases by Exelon Generation for 2003, see “—Market Risk Exposures.”

We have entered into a contract with a marketing affiliate for scheduling and related services and to market energy that has not been committed to be sold under the power purchase agreements with Exelon Generation and to engage in hedging activities. The marketing affiliate also purchases fuel, other than coal, and enters into fuel hedging arrangements on our behalf.

Under the terms of the power purchase agreements with Exelon Generation, we receive significantly higher capacity payments during June through September, the summer months. Accordingly, our operating results are substantially higher during these months and lower, including expected losses, during non-summer months.

Current Developments

A number of significant developments have adversely affected independent power producers and subsidiaries of major integrated energy companies who sell a sizable portion of their generation into the wholesale energy market (sometimes referred to as merchant generators). These developments include depressed market prices in U.S. wholesale energy markets, significant declines in the credit ratings of most major market participants and the decline of liquidity in the energy markets as a result

of tightening credit and increasing concern about the ability of counterparties to perform their obligations. In addition, many merchant generators and power trading firms have announced plans to improve their financial position through asset sales, cancellation or deferral of substantial new development, significant reductions and elimination of trading activities, decreases in capital expenditures, including cancellations of orders for new turbines, and reductions in operating costs.

Our Situation

Our plants have been largely unaffected by these developments because Exelon Generation is under contract with us to buy substantially all of the capacity of our units for the balance of 2002. However, as permitted by the power purchase agreements, Exelon Generation has advised us that it will not purchase 2,684 MW of the capacity from our coal-fired units and 1,864 MW of capacity from our Collins Station and small peaking units for 2003 and 2004, and Exelon Generation has the further right to release an additional 3,043 MW for 2004. As a result, beginning in 2003, the portion of our generation to be sold into the wholesale markets will significantly increase, thereby increasing our merchant risk. See “—Market Risk Exposures.”

As a result of these and other factors, Moody’s downgraded our credit rating and the credit ratings of our parent, Edison Mission Midwest Holdings, and our indirect parent, Edison Mission Energy on October 1, 2002 as shown in the following table:

<u>Rated Entities</u>	<u>Moody’s Rating prior to Downgrade</u>	<u>Moody’s Rating after Downgrade</u>
Edison Mission Energy senior unsecured debt	Baa3	Ba3
Edison Mission Midwest Holdings Co. bank facility .	Baa2	Ba2
Midwest Generation, LLC	Baa3	Ba3

In addition, Standard & Poor’s has placed the credit rating of Edison Mission Midwest Holdings on CreditWatch with negative implications. See “—Credit Ratings.”

Against this background, we have undertaken actions to reduce our commitments and expenditures, thereby improving our cash flow. These actions include:

- a reduction in our capital expenditure program by \$310 million for the years 2003-2005 due to suspension of work on two selective catalytic reduction systems (commonly referred to as SCRs) for our Powerton Station; and
- suspension, beginning in January 2003, of operations at Units 1 and 2 of our Will County plant and Units 4 and 5 of our Collins Station in order to reduce operating costs.

For a discussion of our current financial condition, see “—Liquidity and Capital Resources.”

Results of Operations

Operating Revenues

Operating revenues increased \$54.0 million and \$69.4 million in the third quarter and nine months ended September 30, 2002, respectively, compared to the corresponding periods of 2001. The third quarter increase was primarily due to higher energy revenue from increased generation and lower losses from price risk management. The increase during the nine months ended September 30, 2002 was due to higher capacity revenue, higher energy prices and lower losses from price risk management. For both of the first nine months of 2002 and 2001, 99% of our total capacity and energy revenues were derived under our three power purchase agreements with Exelon Generation.

Our coal stations generated 8,482 GWh and 20,885 GWh of electricity during the third quarter and nine months ended September 30, 2002, respectively, compared to generating 7,589 GWh and 20,732

GWh of electricity in the corresponding periods of 2001. The availability factors for the first nine months of 2002 and 2001 were 84.4% and 81.4%, respectively. The availability factor is determined by the number of megawatt hours we are available to generate electricity divided by the number of megawatt hours in the period. We are not available during periods of planned and unplanned maintenance. We generally refer to unplanned maintenance as a forced outage. We had forced outage rates of 6.2% and 9.9% during the nine months ended September 30, 2002 and 2001, respectively. The weighted average price for energy was \$16.87/MWh during the first nine months of 2002, compared to \$16.22/MWh in the corresponding period of 2001. The increase in the weighted average price for energy is due to scheduled price increases in our power purchase agreement.

Loss from price risk management activities decreased \$12.6 million and \$18.5 million in the third quarter and nine months ended September 30, 2002, respectively, compared to the corresponding periods of 2001. The 2001 losses were primarily related to the change in market value of futures contracts with respect to a portion of our anticipated fuel purchases that did not qualify for hedge accounting under SFAS No. 133.

Operating Expenses

Operating expenses increased \$38.6 million and \$5.1 million in the third quarter and nine months ended September 30, 2002, respectively, compared to the corresponding periods of 2001. Operating expenses consist of expenses for fuel, plant operations, depreciation and amortization and administrative and general expenses. The change in the components of operating expenses is discussed below.

Fuel expenses increased \$37.8 million and \$10.7 million in the third quarter and nine months ended September 30, 2002, respectively, compared to the corresponding periods of 2001. The increases were due to increased generation and increased coal prices offset by the consumption of natural gas in 2002 versus primarily fuel oil in 2001 at the Collins Station. We use natural gas as the fuel for the Collins Station unless fuel oil is less costly to generate electricity. During 2001, the cost to generate electricity was generally lower using fuel oil than natural gas.

Plant operations expenses decreased \$25.0 million and \$35.7 million in the third quarter and nine months ended September 30, 2002, respectively, compared to the corresponding periods of 2001. The decreases were primarily due to higher maintenance costs from planned outages in 2001 and costs of additional security related to a strike during the third quarter of 2001. In addition, we incurred lower rent expense on our Illinois peaker power units lease due to a decline in variable lease costs tied to changes in interest rates and from the termination of the lease in August 2002.

We recorded a \$25.4 million impairment charge during the third quarter ended September 30, 2002 for the write-off of capitalized costs associated with the suspension of capital improvements at our Powerton Station. For more information on this event, see “—Environmental Matters and Regulations.”

Depreciation and amortization expense increased \$1.9 million and \$4.0 million in the third quarter and nine months ended September 30, 2002, respectively, compared to the corresponding periods of 2001. The increase was primarily due to the \$300 million purchase of the Illinois peaker power units in August 2002 that were previously subject to a lease, in addition to other recurring capital expenditure additions. Depreciation expense primarily relates to the acquisition of the power generation assets we purchased from Commonwealth Edison that are being depreciated over periods ranging from 20 to 40 years and the Illinois peaker power units that are being depreciated over 15 years, effective August 2002. The amortization expense relates to the Powerton-Joliet facilities sale-leaseback and the Collins Station sale-leaseback which are being amortized over the term of the leases.

Administrative and general expenses decreased \$1.4 million in the third quarter and increased \$0.7 million in the nine months ended September 30, 2002, respectively, compared to the corresponding periods of 2001. The changes in administrative and general expenses were primarily due to changes in support costs charged from our parent as a contribution of services.

Other Income (Expense)

Interest and other income decreased \$3.3 million and \$9.0 million in the third quarter and nine months ended September 30, 2002, respectively, compared to the corresponding periods of 2001. The decreases consisted primarily of decreases in interest income from lower rates on our variable rate loans to Edison Mission Energy and due to repayment received from Edison Mission Energy in August 2002 on its \$300 million loan in connection with our purchase of the Illinois peaker power units.

Interest expense decreased \$10.1 million and \$44.4 million in the third quarter and nine months ended September 30, 2002, respectively, compared to the corresponding periods of 2001. Interest expense primarily relates to borrowings from Edison Mission Overseas Co., a wholly-owned subsidiary of our parent, under subordinated loan agreements, and interest expense related to the lease financings of the Collins, Powerton and Joliet Stations. The decreases were primarily due to lower rates on the subordinated loans that are tied to variable interest rates and on the variable component of the Collins lease financing.

Provision (Benefit) For Income Taxes

We had an effective income tax provision rate of 43.6% in the first nine months of 2002, compared to an effective tax benefit rate of 38.2% in the first nine months of 2001. The effective tax rates were different from the federal statutory rate of 35% due to state income taxes. The income tax benefit results from tax-allocation agreements with our parent, Edison Mission Midwest Holdings.

Net Income (Loss)

Net income was \$31.4 million in the nine months ended September 30, 2002, compared to a net loss of \$27.2 million for the corresponding period of 2001. Although we expect to generate cash flow from operations, we expect to incur annual losses after depreciation, amortization and interest expense for several years. Our future results of operations will depend primarily on revenues from the sale of energy, capacity and other related products, and the level of our operating expenses.

Liquidity and Capital Resources

At September 30, 2002, we had cash and cash equivalents of \$69.8 million compared to \$52.6 million at December 31, 2001. Net working capital was \$385.6 million at September 30, 2002 compared to \$233.5 million at December 31, 2001. Included in net working capital is \$169.9 million of income tax receivable included on our balance sheet in Due from Affiliates at both September 30, 2002 and December 31, 2001. Working capital is normally higher at September 30 as compared to December 31 as a result of the increased revenues during summer months.

Net cash provided by operating activities increased \$118.5 million in the first nine months of 2002, compared to the corresponding period of 2001. The increase in cash provided by operating activities is primarily due to our net income in 2002 versus net loss in 2001 and the timing of cash receipts and disbursements relating to working capital items.

Net cash used in financing activities was \$8.9 million in the first nine months of 2002, compared to net cash provided by financing activities of \$119.4 million in the corresponding period of 2001. Our increase in cash provided from operating activities in 2002 has allowed us to decrease our net

borrowings compared to 2001. The cash used in financing activities for the first nine months of 2002 is primarily due to the pay down of our capital lease obligations.

Net cash used in investing activities increased \$7.6 million in the first nine months of 2002, compared to the corresponding period of 2001. The net increase was primarily due to additional capital expenditures.

Our capital expenditures for the remainder of 2002 are estimated to be \$32.1 million. Our principal source of liquidity is cash on hand and future cash flow from operations. In addition, we have access to a \$150 million working capital facility through our parent. We believe that we will have adequate liquidity to meet our obligations as they become due in the next twelve months. However, conditions may change, including items that are beyond our control, which could result in a shortfall of cash available to meet our debt obligations.

We have the following maturities of long-term debt to our affiliate at September 30, 2002 (in millions):

<u>Amount</u>	<u>Due Date</u>
\$ 911.0	December 2003
808.3	December 2004
<u>\$1,719.3</u>	

We plan to refinance the \$911 million debt obligation prior to its expiration in December 2003. Completion of this refinancing is subject to a number of uncertainties, including the availability of credit from financial institutions in light of industry conditions. Accordingly, there is no assurance that we will be able to refinance this debt when it becomes due or that if we are able to complete a refinancing, that the amount and the terms will not be substantially different from those under our current credit facility.

Purchase of Equipment Under Lease

On August 9, 2002, we exercised our option to purchase the Illinois peaker power units that were subject to a lease with a third-party lessor. As disclosed in “Off-Balance Sheet Transactions” in our 2001 Annual Report on Form 10-K, this operating lease was structured to maintain a minimum amount of equity (3% of the acquisition price) for the duration of the lease term in accordance with existing guidance for leases involving special purpose entities (sometimes referred to as synthetic leases). In order to fund the purchase, we received full payment of principal, interest and fees on our \$300 million note receivable from Edison Mission Energy, and then paid \$300 million plus outstanding lease obligations to the owner-lessor. These peaker units were recorded as assets and are being depreciated over their estimated useful lives of 15 years.

Chicago In-City Obligation

Pursuant to the acquisition documents for the purchase of generating assets from Commonwealth Edison, we committed to install one or more gas-fired electric generating units having an additional gross dependable capacity of 500 MW at or adjacent to an existing power plant site in Chicago (referred to as the In-City Obligation). The acquisition documents require that commercial operation of this project commence by December 15, 2003. Due to additional capacity for new gas-fired generation in the Mid-America Interconnected Network, generally referred to as the MAIN Region, and the improved reliability of power generation in the Chicago area, we are in discussions with Commonwealth Edison and the City of Chicago regarding alternatives to construction of 500 MW of capacity, which we do not believe is needed at this time. There can be no assurance that these discussions will result in an agreement to terminate the In-City Obligation. If we were to install this additional capacity, we estimate that the cost could be as much as \$320 million.

Debt Service Coverage Ratio

Our parent company, Edison Mission Midwest Holdings, is the borrower under a \$1.869 billion credit facility with a group of commercial banks which we have guaranteed. The funds borrowed under this facility were used to fund our original acquisition and provide working capital to our operations. As part of the original acquisition, we entered into a sale-leaseback transaction for the Collins Station and then subsequently entered into sale-leaseback transactions for the Powerton and Joliet Stations in August 2000. In order to make a distribution from Edison Mission Midwest Holdings to Edison Mission Energy, we and Edison Mission Midwest Holdings must be in compliance with the covenants specified in these agreements, including maintaining a minimum credit rating. Due to the downgrade of the credit rating of Edison Mission Midwest Holdings, no distributions can currently be made by Edison Mission Midwest Holdings to Edison Mission Energy. See “—Credit Ratings.”

Edison Mission Midwest Holdings must also maintain a debt service coverage ratio for the prior twelve-month period of at least 1.50 to 1 as long as the power purchase agreements with Exelon Generation represent 50% or more of Edison Mission Midwest Holdings’ and its subsidiaries’ revenues. If the power purchase agreements with Exelon Generation represent less than 50% of Edison Mission Midwest Holdings’ and its subsidiaries’ revenues, it must maintain a debt service coverage ratio of at least 1.75 to 1. Failure to meet such historical debt service coverage ratio is an event of default under the credit agreement and Collins lease agreements, which, upon a vote by a majority of the lenders to accelerate the due date of the obligations of Edison Mission Midwest Holdings or associated with the Collins lease, may result in an event of default under the Powerton and Joliet leases. It is expected that more than 50% of our revenues will come from Exelon Generation in 2003. At September 30, 2002, Edison Mission Midwest Holdings met the historical financial performance measures.

There are no restrictions on our ability to make payments on the outstanding intercompany loans from our affiliate, Edison Mission Overseas (which is also a subsidiary of Edison Mission Midwest Holdings) or to make distributions directly to Edison Mission Midwest Holdings.

Credit Ratings

Downgrade of Us and Our Parent, Edison Mission Midwest Holdings

We have guaranteed the obligations of our parent, Edison Mission Midwest Holdings, under a \$1.869 billion credit facility. On October 1, 2002, Moody’s downgraded Edison Mission Midwest Holdings’ bank facility rating to Ba2 from Baa2 and our lessor bonds rating to Ba3 from Baa3. These ratings remain under review for possible further downgrade. Standard & Poor’s currently rates Edison Mission Midwest Holdings at “BBB–”. On July 25, 2002, Standard & Poor’s changed its outlook to negative from stable on its “BBB–” corporate credit ratings of Edison Mission Midwest Holdings. In addition, Standard & Poor’s changed its outlook to negative from stable on its “BBB–” ratings on the lessor bonds of the Powerton and Joliet leases. On October 10, 2002, Standard & Poor’s placed the “BBB–” corporate ratings of Edison Mission Midwest Holdings on CreditWatch with negative implications.

As a result of the Moody’s downgrade of Edison Mission Midwest Holdings below investment grade, provisions in the agreements binding on Edison Mission Midwest Holdings and us will limit the ability of Edison Mission Midwest Holdings to use excess cash flow to make distributions to Edison Mission Energy. There are no limitations on our ability to pay intercompany loans or distributions to Edison Mission Midwest Holdings or Edison Mission Overseas. The following table summarizes the provisions restricting cash distributions (sometimes referred to as cash traps) and the related changes in

the cost of borrowing by Edison Mission Midwest Holdings under the applicable financing agreements. The currently applicable provisions are those set forth in the same row as the Moody's rating "Ba2."

<u>S&P Rating</u>	<u>Moody's Rating</u>	<u>Cost of Borrowing Margin</u> (based on LIBOR)	<u>Cash Trap</u>
BBB– or higher	Baa3 or higher	150	No cash trap
BB+	Ba1	225	50% free cash trapped until six month debt service reserve is funded
BB	Ba2	275	100% of free cash trapped
BB–	Ba3	325	100% of free cash trapped
B+	B1	325	100% cash sweep by lenders to repay debt (i.e., 100% of free cash trapped and used to repay debt)

The increase in the cost of the borrowings of Edison Mission Midwest Holdings resulted in an increase in our cost of borrowing under our long-term debt with Edison Mission Overseas, as the terms and conditions of our loan agreement with Edison Mission Overseas mirrors the terms of Edison Mission Midwest Holdings' credit agreement. The annual increase in our interest and lease costs as a result of the downgrade is estimated to be \$33.5 million.

As a result of the downgrade of Edison Mission Midwest Holdings to Ba2, provisions in the agreements binding on Edison Mission Midwest Holdings and us require Edison Mission Midwest Holdings to deposit each quarter 100% of its defined excess cash flow into a cash flow recapture account held and maintained by the collateral agent. On October 31, 2002, Edison Mission Midwest Holdings deposited \$50.3 million into the cash flow recapture account in accordance with these provisions. Edison Mission Midwest Holdings will be required to make deposits into the cash flow recapture account at the end of each such quarter in an amount equal to the quarter's excess cash flow. The funds in the cash flow recapture account may be used only to meet debt service obligations of Edison Mission Midwest Holdings, which we have guaranteed, if funds are not otherwise available from working capital. The deposit of funds into this account limits the amount of funds that would otherwise be available by Edison Mission Midwest Holdings to lend to us to meet working capital requirements.

Downgrade of Edison Mission Energy

On October 1, 2002, Moody's downgraded Edison Mission Energy's senior unsecured rating to Ba3 (below investment grade) from Baa3 (investment grade). These ratings remain under review for possible further downgrade. These rating actions do not trigger any defaults under Edison Mission Energy's credit facilities; however, the changed ratings will increase the borrowing costs under some of their facilities. On October 10, 2002, Standard & Poor's placed the "BBB-" corporate rating of Edison Mission Energy on CreditWatch with negative implications.

As part of the sale-leaseback of the Powerton and Joliet Stations, we loaned the proceeds (\$1.367 billion) to Edison Mission Energy in exchange for promissory notes in the same aggregate amount. Debt service payments by Edison Mission Energy on the promissory notes are used by us to meet our payment obligations under these leases. Furthermore, Edison Mission Energy has guaranteed our lease obligations under these leases. Edison Mission Energy's obligations under the promissory notes payable to us are general obligations of Edison Mission Energy and are not contingent upon receiving distributions from our parent Edison Mission Midwest Holdings. Accordingly, Edison Mission Energy is still obligated to continue to make payments under the intercompany loans from us, notwithstanding Edison Mission Energy's inability to receive distributions from Edison Mission Midwest Holdings as a result of the downgrade. Since Edison Mission Midwest Holdings is restricted from making distributions to Edison Mission Energy, Edison Mission Energy needs to generate sufficient

cash flow from other subsidiaries or sources in excess of their interest and overhead costs to continue to make payments under the intercompany loans from us. There is no assurance that Edison Mission Energy will have sufficient cash flow to meet these obligations. If we do not receive payment on the intercompany loans from Edison Mission Energy, we may be unable to meet our lease obligations under the Powerton and Joliet leases. This would result in an event of default under the Powerton and Joliet leases and in a cross-default under the Collins Lease and credit agreement of Edison Mission Midwest Holdings, which we have guaranteed. These events would have a material adverse affect on us.

We have entered into a contract with a marketing affiliate, Edison Mission Marketing & Trading, for the sale of energy and capacity not contracted to Exelon Generation and for the purchase of fuel, which enables this marketing affiliate to engage in forward sales and hedging. Under this contract, we pay the marketing affiliate fees of \$0.02/MWh plus emission allowance fees. Edison Mission Energy has provided guarantees to support Edison Mission Marketing & Trading's operations, including contracts with third parties, for the marketing of our power pursuant to our marketing agreement. Following the Moody's downgrade of Edison Mission Energy's credit rating, Edison Mission Energy provided \$5.2 million (as of November 7, 2002) in letters of credit in response to requests for collateral by counter-parties and could be required to provide additional collateral in the future. It is likely that much of Edison Mission Marketing & Trading's transactions in the near future will be supported by letters of credit and cash collateral instead of guarantees by Edison Mission Energy. Depending on market conditions and the volume and duration of forward sales, there is no assurance that Edison Mission Energy will be able to provide credit support to Edison Mission Marketing & Trading in amounts sufficient to support all of our merchant activity.

Market Risk Exposures

Our primary market risk exposures arise from fluctuations in electricity prices, fuel prices, emission allowance prices, transmission rights and interest rates. We manage these risks in part by using derivative financial instruments in accordance with established policies and procedures. See "—Current Developments" and "—Credit Ratings" for a discussion of the market developments and their impact on our credit and the credit of our counter-parties.

Commodity Price Risk

Our merchant power plants expose us to commodity price risk, which represents the potential loss that can be caused by a change in the market value of a particular commodity. Commodity price risks are actively monitored to ensure compliance with our risk management policies through our marketing affiliate. Policies are in place which limit the amount of total net exposure we may enter into at any point in time. Procedures exist which allow for monitoring of all commitments and positions with regular reviews by a risk management committee. We perform a "value at risk" analysis in our daily business to measure, monitor and control our overall market risk exposure. The use of value at risk allows management to aggregate overall risk, compare risk on a consistent basis and identify the drivers of the risk. Value at risk measures the worst expected loss over a given time interval, under normal market conditions, at a given confidence level. Given the inherent limitations of value at risk and relying on a single risk measurement tool, we supplement this approach with the use of stress testing and worst-case scenario analysis, as well as stop loss limits and counter-party credit exposure limits.

As discussed further below, beginning in 2003, we will be selling a significant portion of our energy into wholesale energy markets. We intend to hedge a portion of our electric output that is not committed to be sold under long-term contracts, in order to provide more predictable earnings and cash flow. When appropriate, we manage the spread between electric prices and fuel prices, and use forward contracts, swaps, futures, or options contracts to achieve those objectives.

With the exception of revenue generated by the three power purchase agreements with Exelon Generation, our revenues and results of operations during the estimated useful lives of the power plants will depend upon prevailing market prices for capacity, energy, ancillary services, fuel oil, coal, natural gas, emission credits and associated transportation costs in the market area known as the MAIN Region and neighboring markets. Among the factors that influence the price of power in the MAIN Region are:

- prevailing market prices for fuel oil, coal and natural gas and associated transportation costs;
- the extent of additional supplies of capacity, energy and ancillary services from current competitors or new market entrants, including the development of new generation facilities;
- transmission congestion in and to the MAIN Region;
- the market structure rules to be established for the MAIN Region and contiguous areas;
- the cost of emission credits or allowances;
- the availability, reliability and operation of nuclear generating plants in the MAIN Region;
- weather conditions prevailing in the MAIN Region and surrounding areas from time to time; and
- the rate of growth in electricity usage as a result of factors such as regional economic conditions and the implementation of conservation programs.

Status of the Exelon Generation Contracts

Virtually all of our energy and capacity sales in the first nine months of 2002 were to Exelon Generation under the power purchase agreements, and we expect this to continue during the remainder of 2002. Under each of the power purchase agreements, Exelon Generation, upon notice by a given date, has the option in effect to terminate each agreement with respect to all or a portion of the units subject to it.

In July 2002, under the power purchase agreement related to our coal-fired generation units, Exelon Generation notified us of its exercise of its option to purchase 1,265 MW of capacity and energy during 2003 (of a possible total of 3,949 MW subject to option) from the option coal units. As a result, 2,684 MW of capacity of the Will County 1 and 2, Joliet 6 and 7, and Powerton 5 and 6 units will no longer be subject to the power purchase agreement after January 1, 2003. The notification received from Exelon Generation has no effect on its commitments to purchase capacity from these units for the balance of 2002. Exelon Generation continues to have a similar option, exercisable not later than 180 days prior to January 1, 2004, to retain or release for 2004 all or a portion of the option coal units retained for 2003. Exelon Generation remains committed to purchase the capacity of certain committed units having 1,696 MW of capacity for both 2003 and 2004.

The following table lists the committed coal units, the units for which Exelon Generation has exercised its call option for 2003, and the units which, as of January 1, 2003, will be released from the

terms of the power purchase agreement, along with related pricing information set forth in the power purchase agreement.

Coal-Fired Units

Unit Name	Unit Size (MW)	Summer(1) Capacity Charge (\$ per MW Month)		Non-Summer(1) Capacity Charge (\$ per MW Month)		Energy Prices (\$/MWhr)	
		2003	2002	2003	2002	2003	2002
Committed Units							
Waukegan Unit 7	328	11,000	12,000	1,375	1,500	17.0	16.0
Crawford Unit 8	326	11,000	12,000	1,375	1,500	17.0	16.0
Will County Unit 4	520	11,000	12,000	1,375	1,500	17.0	16.0
Joliet Unit 8	522	11,000	12,000	1,375	1,500	17.0	16.0
	<u>1,696</u>						
Option Units(2)							
Waukegan Unit 6	100	21,300	15,520	2,663	1,940	20.0	19.0
Waukegan Unit 8	361	21,300	15,520	2,663	1,940	20.0	16.0
Fisk Unit 19	326	21,300	15,520	2,663	1,940	20.0	19.0
Crawford Unit 7	216	21,300	15,520	2,663	1,940	20.0	19.0
Will County Unit 3	262	21,300	15,520	2,663	1,940	20.0	16.0
	<u>1,265</u>						
Released Units(3)							
Will County Unit 1	156	(3)	15,520	(3)	1,940	(3)	16.0
Will County Unit 2	154	(3)	15,520	(3)	1,940	(3)	19.0
Joliet Unit 6	314	(3)	15,520	(3)	1,940	(3)	19.0
Joliet Unit 7	522	(3)	15,520	(3)	1,940	(3)	19.0
Powerton Unit 5	769	(3)	15,520	(3)	1,940	(3)	16.0
Powerton Unit 6	769	(3)	15,520	(3)	1,940	(3)	16.0
	<u>2,684</u>						
	<u><u>5,645</u></u>						

- (1) “Summer” months are June, July, August and September, and “Non-Summer” months are the remaining months in the year.
- (2) Option units refer to those option units for which Exelon Generation has exercised its right to purchase capacity and energy during 2003 under the terms of the power purchase agreement.
- (3) Released units refer to those option units for which Exelon Generation has *not* exercised its right to purchase capacity and energy during 2003, and which are thus released from the terms of the power purchase agreement. After January 1, 2003, the price for energy and capacity from these units will be based upon either the terms of new bilateral contracts or prices received from forward and spot market sales.

In October 2002, under the power purchase agreements related to our Collins Station and peaking units, Exelon Generation notified us of its exercise of its option to terminate the existing power purchase agreements during 2003 with respect to (a) 1,614 MW of capacity and energy (of a possible total of 2,698 MW subject to the option to terminate) from the Collins Station, a natural gas and oil-fired electric generating station, and (b) 113 MW of capacity and energy (of a possible total of 807 MW subject to the option to terminate) from the natural gas and oil-fired peaking units, in accordance

with the terms of each applicable power purchase agreement. As a result, 1,614 MW of capacity from the Collins Units 2, 4 and 5, and 113 MW of capacity from the Lombard 33 and Calumet 33 and 34 peaking units, will no longer be subject to a power purchase agreement after January 1, 2003. The notification received from Exelon Generation has no effect on its commitments to purchase capacity from these generating units for the balance of 2002. Exelon Generation continues to have a similar option to terminate, exercisable not later than 90 days prior to January 1, 2004, the power purchase agreements for 2004 with respect to all or a portion of the generating units not previously terminated for 2003 (1,084 MW from the Collins Station and 694 MW from the peaking units).

The following table lists the generating units at the Collins Station and the peaking units as to which Exelon Generation has not exercised its option to terminate for 2003, the generating units and peaking units which, as of January 1, 2003, will, as a result of the exercise by Exelon Generation of its option to terminate, be released from the terms of the power purchase agreement, and the peaking units as to which Exelon Generation exercised its option to terminate effective as of January 1, 2002, along with related pricing information set forth in the respective power purchase agreements.

Collins Station and Peaking Units

<u>Generating Unit</u>	<u>Unit Size (MW)</u>	<u>Summer(1) Capacity Charge (\$ per MW Month)</u>		<u>Non-Summer(1) Capacity Charge (\$ per MW Month)</u>		<u>Energy Prices (\$/MWhr)</u>	
		<u>2003</u>	<u>2002</u>	<u>2003</u>	<u>2002</u>	<u>2003</u>	<u>2002</u>
Option Units							
Collins Unit 1	554	8,333	6,666	2,083	1,667	33	32
Collins Unit 3	530	8,333	6,666	2,083	1,667	33	32
	<u>1,084</u>						
Peaking Units	694	9,500	7,600	1,500	1,200	55-90	50-85
Released Units							
Collins Unit 2	554	(2)	6,666	(2)	1,667	(2)	32
Collins Unit 4	530	(2)	6,666	(2)	1,667	(2)	32
Collins Unit 5	530	(2)	6,666	(2)	1,667	(2)	32
	<u>1,614</u>						
Peaking Units	113	(2)	7,600	(2)	1,200	(2)	50
Peaking Units(3)	137	(3)	(3)	(3)	(3)	(3)	(3)

- (1) "Summer" months are June, July, August and September, and "Non-Summer" months are the remaining months in the year.
- (2) Generating and peaking units for which Exelon Generation has exercised its right to terminate the power purchase agreement with respect thereto, and which are thus released from the terms of the power purchase agreement. After January 1, 2003, the price for energy and capacity from these units will be based upon either the terms of new bilateral contracts or prices received from forward and spot market sales.
- (3) Peaking units for which Exelon Generation exercised its right to terminate the power purchase agreement effective as of January 1, 2002. The price for energy and capacity from these units has since that date been based on the terms of bilateral contracts or prices received from forward and spot market sales.

Under the Collins Station power purchase agreement, Exelon Generation has the right to purchase all of the energy produced by the Collins Station. Energy prices vary depending on the total annual number of megawatt hours of energy purchased and the market price of natural gas. When purchases exceed an annual threshold of 2.7 million MWh (reduced to 1.88 million MWh for 2002 by amendment), Exelon Generation purchases energy at market price and thus bears all subsequent risk of changes in the market price of natural gas used to produce the energy purchased. The Collins Station is capable of burning fuel oil in lieu of natural gas, which enables us to use fuel oil when it costs less than natural gas. We have in the past purchased and have in inventory stocks of fuel oil for this purpose. Our marketing affiliate has also entered into financial transactions that hedge the price risk of a portion of our anticipated fuel purchases in 2002, although these contracts do not qualify for hedge accounting under SFAS No. 133.

The energy and capacity from any units which do not remain subject to one of the power purchase agreements with Exelon Generation will be sold under terms, including price and quantity, to be negotiated by our marketing affiliate with customers through a combination of bilateral agreements, forward energy sales and spot market sales. Thus, we will be subject to the market risks related to the price of energy and capacity described above. We expect capacity prices for merchant energy sales will, in the near term, be substantially lower than those we currently receive under our existing agreements (with the possibility of minimal revenues due to the current oversupply conditions in this marketplace). We further expect that the lower revenues resulting from this difference will be offset in part by energy prices, which we believe will, in the near term, be higher for merchant energy sales than those we currently receive under our existing agreements, as indicated below in the table of forward-looking prices. We intend to manage price risk, in part, by accessing both the direct customer and over-the-counter markets described below as well as using derivative financial instruments in accordance with established policies and procedures.

During 2003, the primary markets available to us for wholesale sales of electricity are expected to be “direct customer” and “over-the-counter.” Direct customer transactions are bilateral sales to regional buyers that principally include investor-owned utilities, municipal utilities, rural electric cooperatives and retail energy suppliers. Transactions in the direct customer market include real-time, daily and longer term structured sales that meet the specific requirements of wholesale electricity consumers. Over-the-counter markets are generally accessed through third-party brokers and electronic exchanges, and include forward sales of electricity. The most liquid over-the-counter markets in the Midwest region are “Into Cinergy,” and, to a lesser extent, “Into ComEd.”

“Into Cinergy” and “Into ComEd” are bilateral markets for the sale or purchase of electrical energy for future delivery. The emergence of “Into Cinergy,” and “Into ComEd” as commercial hubs for the trading of physical power has not only facilitated transparency of wholesale power prices in the Midwest, but also aided in the development of risk management strategies that are utilized to mitigate commodity price volatility. Energy is traded in the form of physical delivery of megawatt-hours. Delivery is either made (1) into the receiving control area’s transmission system (i.e., Cinergy’s or ComEd’s transmission system) by the seller’s daily election of control area interface, or (2) by procuring energy generated from a source within the receiving control area. Almost all of our plants have busbar delivery that meets the “Into ComEd” delivery criteria. Performance of transactions in these markets is secured by liquidated damages and, in the case of less creditworthy counter-parties, credit support provisions such as letters of credit and cash margining arrangements.

The following table sets forth the forward month-end market prices for energy per megawatt hour for the calendar 2003 and calendar 2004 “strips,” which are defined as energy purchases for the entire calendar year, as publicly quoted for sales “Into ComEd” and “Into Cinergy” during the first nine months of 2002. As indicated above, these forward prices will continue to fluctuate as a result of a number of factors, including gas prices, electricity demand, which is also affected by economic growth, and the amount of existing and planned power plant capacity. The actual spot prices for electricity delivered into these markets may vary materially from the forward market prices.

Into ComEd*

<u>Date</u>	<u>2003</u>			<u>2004</u>		
	<u>On-Peak</u>	<u>Off-Peak</u>	<u>24-Hr</u>	<u>On-Peak</u>	<u>Off-Peak</u>	<u>24-Hr</u>
January 31, 2002	\$27.26	\$18.34	\$22.56	\$28.72	\$19.09	\$23.65
February 28, 2002	28.96	18.50	23.48	31.30	19.25	24.99
March 31, 2002	32.50	19.85	25.56	34.31	21.35	27.20
April 30, 2002	32.55	19.05	25.65	33.55	20.05	26.65
May 31, 2002	30.85	17.31	23.71	32.30	19.18	25.38
June 30, 2002	29.54	16.88	22.50	30.98	19.38	24.53
July 31, 2002	28.64	16.90	22.37	30.09	18.90	24.11
August 31, 2002	28.75	17.00	22.47	30.20	19.25	24.34
September 30, 2002	29.16	15.92	22.09	30.61	18.17	23.96

Into Cinergy**

<u>Date</u>	<u>2003</u>			<u>2004</u>		
	<u>On-Peak</u>	<u>Off-Peak</u>	<u>24-Hr</u>	<u>On-Peak</u>	<u>Off-Peak</u>	<u>24-Hr</u>
January 31, 2002	\$28.38	\$18.77	\$23.32	\$29.85	\$19.52	\$24.41
February 28, 2002	30.30	18.75	24.25	32.64	19.50	25.75
March 31, 2002	33.82	20.15	26.33	35.63	21.65	27.97
April 30, 2002	34.03	19.75	26.73	35.03	20.75	27.73
May 31, 2002	31.74	18.88	24.96	33.97	20.75	27.00
June 30, 2002	31.08	18.25	23.95	32.50	20.75	25.97
July 31, 2002	29.34	18.25	23.41	32.00	20.25	25.72
August 31, 2002	29.63	18.00	23.41	31.60	20.25	25.54
September 30, 2002	30.56	17.50	23.59	32.18	19.75	25.54

(1) On-peak refers to the hours of the day between 7:00 a.m. and 11:00 p.m. Monday through Friday. All other hours of the week are referred to as off-peak.

* Source: Prices were obtained by gathering publicly available broker quotes adjusted for historical basis differences between ComEd and Cinergy.

** Source: Prices were obtained by gathering publicly available broker quotes.

The average price that we derive from electricity sales is normally higher than a 24-hour price as we manage our generation to optimize the on-peak periods when power prices are higher.

We intend to hedge a portion of our merchant portfolio risk through our marketing affiliate. To the extent we do not do so, the unhedged portion will be subject to the risks and benefits of spot-market price movement. The extent to which we will hedge our market price risk through forward over-the-counter sales depends on several factors. First, we will evaluate over-the-counter market prices to determine whether sales at forward market prices are sufficiently attractive compared to assuming the risk associated with spot market sales. Second, our ability to enter into hedging transactions will depend upon our liquidity and upon the over-the-counter forward sales markets' having sufficient

liquidity to enable us to identify counter-parties who are able and willing to enter into hedging transactions with us. See “—Credit Risk.”

In addition to the prevailing market prices, our ability to derive profits from the sale of electricity from the released units will be affected by the cost of production, including costs incurred to comply with environmental regulations. The costs of production of the released units vary and, accordingly, depending on market conditions, the amount of generation that will be sold from the released units is expected to vary from unit to unit. In this regard, we plan to suspend operations of Will County Units 1 and 2 and Collins Station Units 4 and 5 at the end of 2002 until market conditions improve. If market conditions were to be depressed for an extended period of time, we would need to consider decommissioning these units, which would result in a charge against income.

Our ability to transmit energy to counter-party delivery points to consummate spot sales and hedging transactions may be affected by transmission constraints. Although the Federal Energy Regulatory Commission (FERC) and the relevant industry participants are working to minimize such issues, we cannot determine how quickly or how effectively such issues will be resolved.

A group of transmission-owning utilities have asked the FERC to permit them to join PJM, and the FERC granted those requests, with conditions, in an order issued on July 31, 2002. These companies include Commonwealth Edison and American Electric Power. As recently filed by Commonwealth Edison with FERC, Commonwealth Edison will join PJM either as an individual transmission owner, or as a member of an Independent Transmission Company (ITC). Furthermore, the Commonwealth Edison transmission system, to which our plants are directly interconnected, is expected to be fully integrated into the PJM market structure by December of 2003. National Grid is currently in discussions with American Electric Power, Commonwealth Edison and Dayton Power and Light to form an independent transmission company (ITC) that would operate under the PJM umbrella and oversight. We believe that Commonwealth Edison’s integration into the PJM market will improve our ability to sell electricity into a well-developed, stable, transparent, and liquid cash market without additional transmission charges. The expanded PJM market will be interconnected by numerous extra-high voltage transmission ties and will include (in addition to the existing market encompassed by PJM) the service territories of Commonwealth Edison, American Electric Power, Illinois Power, Virginia Power, and Dayton Power and Light. Furthermore, as a condition of approval of the requests to join PJM, the FERC is requiring PJM and its counterpart transmission entity in the Midwest (the Midwest ISO) to form a common, seamless energy market by October 2004, which would further expand the areas into which we may sell power without incurring multiple transmission charges. The companies are planning to begin the first phase of the integration process during the first quarter of 2003 by turning over their respective transmission service operations to PJM under the terms and conditions of the PJM Open Access Transmission Tariff. The first phase of this integration process is intended to eliminate rate-pancaking across the current PJM region and the new PJM West region, of which both Commonwealth Edison and American Electric Power will be a part.

Non-Trading Derivative Financial Instruments

The following table summarizes the fair values for outstanding financial instruments used for price risk management activities by instrument type (in thousands):

	September 30, 2002 <u>(Unaudited)</u>	December 31, 2001 <u> </u>
Commodity price:		
Forwards	\$(1,761)	\$ (126)
Futures	—	(8,401)

In assessing the fair value of our derivative financial instruments, we use a variety of methods and assumptions based on the market conditions and associated risks existing at each balance sheet date. The fair value of commodity price contracts takes into account quoted market prices, time value of money, volatility of the underlying commodities and other factors. The following table summarizes the maturities, the valuation method and the related fair value of our commodity risk management assets and liabilities as of September 30, 2002 (in thousands):

	<u>Total Fair Value</u>	<u>Maturity < 1 year</u>	<u>Maturity 1 to 3 years</u>	<u>Maturity 4 to 5 years</u>	<u>Maturity > 5 years</u>
			(Unaudited)		
Prices actively quoted	<u>\$(1,761)</u>	<u>\$(2,747)</u>	<u>\$ 986</u>	<u>\$ —</u>	<u>\$ —</u>

Credit Risk

As a result of Exelon Generation’s notification to release some of our units from the respective power purchase agreements in 2003, we will be selling a significant portion of our energy into wholesale energy markets and intend to hedge our merchant portfolio risk through our marketing affiliate.

In conducting price risk management activities, our marketing affiliate enters into contracts with a number of utilities, energy companies and financial institutions. Due to factors beyond our control, market liquidity has decreased significantly since the beginning of 2002, and a number of formerly significant trading parties have completely withdrawn from the market or substantially reduced their trading activities. The reduction in the credit quality of traditional trading parties increases our credit risk. In addition, the decrease in market liquidity may require us to rely more heavily on wholesale electricity sales to direct customers which may increase our credit risk. In the event a counter-party were to default on its trade obligation, we would be exposed to the risk of possible loss associated with reselling the contracted product at a lower price if the non-performing counter-party were unable to pay the resulting liquidated damages owed to us. Further, we would be exposed to the risk of non-payment of accounts receivable accrued for products delivered prior to the time such counter-party defaulted.

To manage credit risk, our marketing affiliate looks at the risk of a potential default by our counter-parties. Credit risk is measured by the loss that would occur if the counter-parties failed to perform pursuant to the terms of their contractual obligations. Our marketing affiliate has established controls to determine and monitor the creditworthiness of counter-parties and uses master netting agreements whenever possible to mitigate the exposure to counter-party risk. This may require counter-parties to pledge collateral when deemed necessary. Our marketing affiliate generally manages the credit in the portfolio based on credit ratings using published ratings of counter-parties to guide the process of setting credit levels, risk limits and contractual arrangements, including master netting agreements. Where external ratings are not available, our marketing affiliate conducts internal assessments of credit risks of counter-parties using publicly disclosed information, such as financial statements, regulatory filings and press releases. The credit quality of our marketing affiliate’s counter-parties is reviewed regularly by a risk management committee. Our marketing affiliate also monitors the concentration of credit risk from various positions, including contractual commitments. Credit concentration is determined on both an individual and group counter-party basis. In addition to continuously monitoring our credit exposure to counter-parties, our marketing affiliate also takes appropriate steps to limit or lower credit exposure.

Interest Rate Risk

Interest rate changes affect the cost of capital needed to operate the facilities and our lease costs under the Collins Station lease and our lease costs under the Illinois peaker power units lease prior to our purchase on August 9, 2002.

Off-Balance Sheet Transactions

For a discussion of Midwest Generation, LLC's off-balance sheet transactions, refer to "Off-Balance Sheet Transactions" on page 33 of Midwest Generation, LLC's Annual Report on Form 10-K for the fiscal year ended December 31, 2001.

On August 9, 2002, we exercised our option to purchase the Illinois peaker power units that were subject to a lease with a third-party lessor. This operating lease was structured to maintain a minimum amount of equity (3% of the acquisition price) for the duration of the lease term in accordance with existing guidance for leases involving special purpose entities (sometimes referred to as synthetic leases). In order to fund the purchase, we received full payment of principal, interest and fees on our \$300 million note receivable from Edison Mission Energy, and then paid \$300 million plus outstanding lease obligations to the owner-lessor. These peaker units were recorded as assets and are being depreciated over their estimated useful lives of 15 years.

Environmental Matters and Regulations

For a discussion of Midwest Generation, LLC's environmental matters, refer to "Environmental Matters and Regulations" on page 33 of Midwest Generation, LLC's Annual Report on Form 10-K for the fiscal year ended December 31, 2001 and the notes to the Financial Statements set forth therein. There have been no significant developments with regard to environmental matters that affect disclosures presented as of December 31, 2001, except as follows:

We anticipate that upgrades to our environmental controls to reduce nitrogen oxide (NOx) emissions will result in capital expenditures of \$9.9 million for the remainder of 2002 and \$14.0 million in 2003. Our capital program has been reduced by \$310 million for the years 2003-2005 due to the suspension of work related to the two Powerton Station SCRs. This decision to reduce capital expenditures was made in light of current market conditions. See "—Market Risk Exposures." We believe that given the amount of environmental control technology already installed, the remaining planned installations (excluding the Powerton SCRs), and the market forecast price of NOx credits, we will be able to comply with all NOx emission requirements in a cost effective manner.

Beginning with the 2003 ozone season (May 1 through September 30), we must comply with an average NOx emission rate of 0.25 lb NOx/mmBtu of heat input. This limitation is commonly referred to as the East St. Louis State Implementation Plan (SIP). This regulation is a State of Illinois requirement. Compliance with this standard will be met by averaging the emissions of all our power plants. Additional burner controls planned for installation at Powerton in the spring of 2003, along with over-compliance at our other plants, will facilitate compliance with this standard.

Beginning with the 2004 ozone season, an additional NOx emission regulation will go into effect. This federally mandated regulation, commonly referred to as the "NOx SIP Call" will cap NOx emissions within a 19-state region east of the Mississippi with a tonnage cap on NOx emissions. This program allows NOx trading similar to the current SO2 trading program already in effect. Our compliance plan is to rely upon a combination of strategies. We have already qualified for early reduction credits by reducing NOx emissions at various plants ahead of the imposed deadline. Additionally, the installation of emission control technology at select plants will ensure over-compliance at those individual plants with pending NOx emission limitations. Finally, NOx emission trading will be

utilized as needed to comply with any shortfall in emission credits anticipated with the deferral of the SCR projects at our Powerton Station.

Critical Accounting Policies

For a discussion of Midwest Generation, LLC's critical accounting policies, refer to "Critical Accounting Policies" on page 36 of Midwest Generation, LLC's Annual Report on Form 10-K for the fiscal year ended December 31, 2001.

New Accounting Standards

In August 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," which will be effective on January 1, 2003. The Statement requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is increased to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. We are studying the effects of the new standard.

In April 2002, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections" which supersedes previous guidance for reporting gains and losses from extinguishment of debt and accounting for leases, among other things. The portion of the Statement relating to the rescission of SFAS No. 4, "Reporting Gains and Losses from Extinguishment of Debt" requires that any gain or loss on extinguishment of debt that was classified as an extraordinary item that does not meet the unusual in nature and infrequent of occurrence criteria in APB Opinion No. 30, "Reporting the Results of Operations—Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions" shall be reclassified. The standard will be effective on January 1, 2003. We do not expect this standard to have a material impact on our financial statements.

In June 2002, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" which will be effective on January 1, 2003. The Statement requires that liabilities for costs associated with exit or disposal activities initiated after December 31, 2002 be recognized when incurred, rather than at the date of a commitment to an exit or disposal plan. We do not expect this standard to have a material impact on our financial statements.

Recent Developments

We had a retirement health care and other benefits plan related to our union-represented employees that expired on June 15, 2002. In October 2002, we reached an agreement with our union-represented employees on a new retirement health care and other benefits plan which extends from January 1, 2003 through June 30, 2005. We will continue to provide benefits at the same level as those in the expired agreement until December 31, 2002.

As described in our 2001 Annual Report on Form 10-K, we have been accounting for postretirement benefits obligations on the basis of a substantive plan under Statement of Financial Accounting Standards No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." A substantive plan means that we assumed for accounting purposes that we would provide for postretirement benefits to union-represented employees following conclusion of negotiations to replace the current benefits agreement, even though we had no legal obligation to do so. Under the

new agreement, postretirement benefits will not be provided. Accordingly, we will treat this as a plan termination under SFAS No. 106 and will record a pre-tax gain of \$70.7 million during the fourth quarter of 2002.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

For a discussion of market risk sensitive instruments, refer to “Market Risk Exposures” on page 29 in Item 7 of Midwest Generation, LLC’s Annual Report on Form 10-K for the fiscal year ended December 31, 2001. Refer to “Market Risk Exposures” in Item 2 for an update to that disclosure.

ITEM 4. CONTROLS AND PROCEDURES

Under the Sarbanes-Oxley Act of 2002 and implementing rules and regulations adopted by the Securities and Exchange Commission (SEC), Midwest Generation, LLC must maintain disclosure controls and procedures. The term “disclosure controls and procedures” is defined in the SEC’s regulations to mean, as applied to Midwest Generation, LLC, controls and other procedures that are designed to ensure that information required to be disclosed by Midwest Generation, LLC in reports filed with the SEC are recorded, processed, summarized, and reported, within the time frames specified in the SEC’s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by Midwest Generation, LLC in its SEC reports is accumulated and communicated to Midwest Generation, LLC’s management, including its Chief Executive Officer and its Chief Financial Officer, as appropriate to allow timely decisions regarding disclosure. The SEC’s regulations also require Midwest Generation, LLC to carry out evaluations, under the supervision and with the participation of Midwest Generation, LLC’s management, including its Chief Executive Officer and its Chief Financial Officer, of the effectiveness of the design and operation of Midwest Generation, LLC’s disclosure controls and procedures. These evaluations must be carried out within the 90-day period prior to the filing date of certain reports, including this Quarterly Report on Form 10-Q.

The Chief Executive Officer and the Chief Financial Officer of Midwest Generation, LLC have evaluated the effectiveness of the design and operation of Midwest Generation, LLC’s disclosure controls and procedures as of November 11, 2002. They have concluded that those disclosure controls and procedures, as of the evaluation date, were effective in ensuring that information required to be disclosed by Midwest Generation, LLC in its reports filed with the SEC was (1) accumulated and communicated to Midwest Generation, LLC’s management, as appropriate to allow timely decisions regarding disclosure, and (2) recorded, processed, summarized, and reported within the time frames specified in the SEC’s rules and forms.

The Chief Executive Officer and the Chief Financial Officer of Midwest Generation, LLC also have concluded that there were no significant changes in Midwest Generation, LLC’s internal controls or in other factors that could significantly affect those controls subsequent to the date of their evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

PART II—OTHER INFORMATION

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) Exhibits

<u>Exhibit No.</u>	<u>Description</u>
10.25	Tax-Allocation Agreement, effective January 1, 2002, by and between Midwest Generation, LLC and Edison Mission Midwest Holdings Co.
99.1	Statement Pursuant to 18 U.S.C. Section 1350.

(b) Reports on Form 8-K

The registrant filed the following report on Form 8-K during the quarter ended September 30, 2002:

<u>Date of Report</u>	<u>Dated Filed</u>	<u>Item(s) Reported</u>
July 2, 2002	July 2, 2002	5

