Nebraska Public Power District

COOPER NUCLEAR STATION
P.O. BOX 98, BROWNVILLE, NEBRASKA 68321
TELEPHONE (402)825-3811
FAX (402)825-5211

NSD940702

August 1, 1994

U. S. Nuclear Regulatory Commission
Attn: Mr. Ira Dinitz
Mail Stop 12-E-4
Washington, DC 20555

Subject: Licensee Guarantees of Payment of Deferred Premiums
Cooper Nuclear Station
NRC Dock No. 20-298. DPR-46

Gentlemen:

In accordance with the requirements of 10 CFR Part 140.21, relative to deferred insurance premiums, the Nebraska Public Power District submits the following information which, we believe, demonstrates our ability to obtain funds in the amount of $10 million for payment of such premiums within the specified three month period.

The Nebraska Public Power District has renewed a Credit Agreement, which is included as an enclosure, with the American National Bank and Trust Company of Chicago, which indicates that said bank will lend the District funds, not to exceed $5 million as specifically required to pay public liability claims arising from nuclear incidents. This Credit Agreement is valid through July 31, 1995, at which time the District will submit the appropriate documentation to verify the guarantee requirements for the following year.

Midwest Power Systems, under the terms of a power purchase contract, has acknowledged its responsibility to assume 50 percent of the retrospective premium requirements in an amount not to exceed $5 million in one year. Midwest Power Systems has chosen to utilize the type of guarantee defined in 10 CFR 140.21 (e). Therefore, as enclosures to this letter, we are submitting the following documents in support of 50 percent of the required $10 million premium.

1. Midwest Power Systems, Inc. 1993 Annual Report to the Securities and Exchange Commission - Form 10-K

2. Five Year Financial Forecast dated November, 1993 for Midwest Resources, the holding company of Midwest Power Systems.

We believe that the enclosed information is sufficient to demonstrate our ability to generate the necessary funds required by the deferred premium; however, should you

A001 Add: Ira Dinitz ltr Encl
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require additional information, please do not hesitate to contact me.

Sincerely,

G. R. Horn
Vice President - Nuclear

:jw

Enclosure

cc: U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

U. S. Nuclear Regulatory Commission w/o enclosure
Regional Office - Region IV
Arlington, TX

NRC Senior Resident Inspector
Cooper Nuclear Station w/o enclosure

CREDIT AGREEMENT

CREDIT AGREEMENT, dated as of August 1, 1994, between NEBRASKA PUBLIC POWER DISTRICT (herein called the "District") and AMERICAN NATIONAL BANK AND TRUST COMPANY OF CHICAGO (herein called the "Bank").

The District desires to provide for future borrowings, and the Bank is willing to commit to lend to the District, upon the terms and conditions herein set forth, the aggregate sum of up to $5,000,000, in such installments and at such times as hereinafter provided, to be evidenced by notes of the District therefor.

In consideration of the foregoing and the covenants and conditions herein contained, the parties thereto agree as follows:

1. Definitions. The following terms shall, for all purposes of this Credit Agreement, have the following meanings:

"Act" shall mean the Public Power and Irrigation District Law, constituting Article 6 of Chapter 70 of the Revised Statutes of Nebraska, as amended and supplemented.

"Electric Resolution" shall mean the resolution entitled "Electric System Revenue Bond Resolution" adopted by the Board of Directors of the District on August 22, 1968, as supplemented or amended in accordance with the terms thereof.

"Electric System Bonds" shall mean Electric System Revenue Bonds of the District authorized to be issued under the Electric Resolution.

"Electric System General Reserve Fund" shall mean the Electric System General Reserve Fund established in Section 502 of the Electric Resolution.

"Loans" shall mean the loans provided for in this Credit Agreement.

"Note or Notes" shall mean any note or notes, as the case may be, issued pursuant to this Credit Agreement by the District to evidence any Loan.

"Note Resolution" shall mean the resolution of the District entitled "Resolution Authorizing $5,000,000 Bank Credit of 1994," adopted July 8, 1994 authorizing the issuance of the Notes and authorizing the execution and delivery of this Credit Agreement, a true and correct copy of which resolution is annexed hereto as Annex A.

2. <u>Commitment to Lend</u>. The Bank hereby agrees, upon the terms and conditions herein set forth, to make one or more Loans to the District, in accordance with the provisions of this Credit Agreement, on or before July 31, 1995 in an aggregate principal up to, but not exceeding $5,000,000, each Loan to be in the principal amount of not less than $250,000.

3. <u>Borrowings</u>. The District shall give the Bank at least two (2) days prior notice of the date and amount of each borrowing hereunder. Each borrowing pursuant thereto shall take place at the principal office of the Bank at LaSalle and Washington Streets, Chicago, Illinois. Not later than 11:00 a.m. on the date of each borrowing, the Bank shall, subject to the terms of this Credit Agreement, make available to the District, Federal Reserve or other immediately available funds in the principal amount being borrowed, upon delivery to the Bank of a Note in such principal amount.

4. <u>The Notes</u>. Each Note shall be designated as "Electric System Note, Series NRC of 1994," shall be payable to the order of American National Bank and Trust Company of Chicago, shall be dated the date of its delivery, shall be payable one year from its date of issue (subject to optional prepayment as provided in Section 8 hereof), and shall bear interest (payable on the first day of each January, April, July and October) on the unpaid principal amount thereof from its date fluctuating at the rate per annum equal to 87% of the rate of interest announced or published publicly from time to time by the Bank as its base rate or equivalent rate of interest. Such interest rate shall be computed on the basis of a 365/366-day year.

The Notes shall be executed on behalf of the District by the manual signature of its Chairman, Vice Chairman, President, Treasurer or Assistant Treasurer and its corporate seal shall be affixed, imprinted, engraved or otherwise reproduced thereon and attested by the manual signature of its Secretary or any Assistant Secretary and shall be otherwise in substantially the form annexed hereto as Annex B.

5. <u>Commitment Fee</u>. The District shall pay to the Bank as a commitment fee contemporaneously with the execution of this Credit Agreement the sum of $5,000.

6. <u>Tax Indemnification</u>.

(i) The parties intend that the Bank shall receive in respect of the Notes amounts equal to the principal thereof and interest thereon as provided hereunder, when due, without deductions, penalties, charges, or withholdings as a result of the imposition of any federal income or similar federal tax imposed on the Bank as a holder of any of the notes (collectively "Taxes").

Any such Taxes shall be paid by the District. The District will pay the Bank the amounts necessary such that the net amount of the principal and interest received and retained by the Bank is not less than the amount payable under this Agreement had such Taxes not been imposed.

If, notwithstanding the previous two sentences, the Bank pays any such Taxes, the Bank will furnish to the District official tax receipts or evidence of payment of all such Taxes and the District will promptly reimburse the Bank therefor.

(ii) If the Internal Revenue Code of 1986, as amended, (the "Code"), or any other federal income tax law, rule, regulation, or governmental interpretation thereof hereafter enacted, adopted or issued, other than any such change mentioned in (iii) below, when affecting the Bank as a holder of the Notes or compliance by the Bank as a holder of the Notes with such,

(a) subjects the Bank to any tax, duty, charge, or withholding due on the principal of or interest on the Notes or changes the basis of taxation of payments to the Bank in respect of the principal of or interest on the Notes, including, without limitation, the effect of any limitation on the deductibility of interest on the funds obtained to purchase or carry the Notes; or

(b) imposes any other condition or circumstance the result of which is to increase the cost to the Bank of purchasing, funding or carrying the Notes, or reduces any amount receivable by the Bank in connection with the principal of or interest on the Notes or requires the Bank to make any payment calculated by reference to the amount of the Notes or interest received by it in an amount deemed material by the Bank;

then, within thirty days of demand by the Bank, the District shall pay the Bank an amount which will be equal, on an after-tax basis to the Bank (taking into account any taxes payable by the Bank on such amount), to (a) that portion of such increased cost incurred or (b) the amount or reduction in an amount received which the Bank determines is attributable to purchasing, funding or carrying the Notes to the extent of the principal amount thereof outstanding from time to time. The effect of any such increased cost which is imposed on the Bank generally may be allocated to the Notes on any reasonable basis in the discretion of the Bank.

(iii) If at any time or times while the Bank is the Holder of the Notes there is a change in the maximum marginal tax rate (the "Tax Rate") at which the Bank could be taxed for federal income tax purposes, the interest rate on the Notes shall be

decreased (in the case of a decrease in the Tax Rate) to an interest rate equal to the product of (i) the interest rate on the Notes in effect immediately prior to a change in the Tax Rate times (2) a fraction (expressed in decimals) the numerator of which is the number one (1) minus the applicable Tax Rate after such change and the denominator of which is the number one (1) minus the Tax Rate which had been in effect prior to such change in the Tax Rate.

(iv) Notwithstanding any of the other provisions of this Agreement, if the District has paid the additional amount specified in (ii) and (iii) above, the District shall not be obligated to pay or reimburse the Bank for any tax on the income of the Bank to the extent that such income tax is attributable to the inclusion in the gross income of the Bank for federal tax purposes of interest on the Notes as if such interest had been timely reported and timely paid.

7. Conditions Precedent to Loans. The Bank shall not be obligated to make any loan unless at the date specified for the making thereof the District delivers to the Bank:

(a) The opinion of the General Counsel to the District, dated as of such date, to the effect that:

(i) There is no litigation pending in any court, either State or Federal, questioning the creation, organization or existence of the District or the validity of this Credit Agreement or the Note being issued to evidence such Loan; and

(ii) The District has the power to borrow the amount being loaned; to execute and deliver this Credit Agreement; to evidence the Loans by its Notes to be made and delivered in accordance herewith, and to perform and observe all of the terms and conditions of this Credit Agreement on its part to be performed and observed; and

(b) A certificate of the Chairman, President, Treasurer or Assistant Treasurer of the District, dated as of such date, to the effect that the representations and warranties of the District contained in Section 15 of this Credit Agreement are true and correct as of such date; and

(c) A certificate of the Chairman or President or Treasurer or Assistant Treasurer of the District, dated as of such date, setting forth the aggregate amount of bonds and notes of the District that will be outstanding immediately after the issuance of the note then being issued and stating that no default has occurred in the payment of principal of or interest on any indebtedness for borrowed money

of the District which remains unsecured; and

(d) The opinion of Mudge Rose Guthrie Alexander & Ferdon, Bond Counsel to the District, dated as of such date, substantially in the form annexed thereto as Annex C;

(e) A certificate as to Arbitrage, dated as of such date, in accordance with the provisions of the Code; and

(f) Such additional certificates, instruments and other documents as the Bank or its counsel may deem necessary to effect good delivery of the Note being delivered on such date or evidence the due performance by the District of the conditions precedent hereunder.

8. Optional Prepayment. The District may prepay any Note as a whole or in part, at any time or from time to time, without penalty or premium, by paying to the Bank all or part of the principal amount of the Note to be prepaid, together with the unpaid interest accrued on the amount of principal so prepaid to the date of such prepayment. Each prepayment of a Note shall be made on such date and in such principal amount as shall be specified by the District in a written notice delivered to the Bank not less than 10 days prior thereto. Notice having been given as aforesaid, the principal amount of the Note stated in such notice or the whole thereof, as the case may be, shall become due and payable on the prepayment date stated in such notice, together with interest accrued and unpaid to the prepayment date on the principal amount then being paid; and the amount of principal and interest then due and payable shall be paid (i) in case the entire unpaid balance of the principal of any Note is to be paid, upon presentation and surrender of such Note to the District or its representative at the principal office of the Bank, and (ii) in case only part of the unpaid balance of principal of any Note is to be paid, upon presentation of such Note at the principal office of the Bank for notation thereon by the Bank of the amount of principal and interest on such Note then paid. If on the prepayment date moneys for the payment of the principal amount to be prepaid on such Note together with interest to the prepayment date on such principal amount, shall have been paid to the Bank as above provided and if notice of prepayment shall have been given to the Bank as above provided, then from and after the prepayment date interest on such principal amount of such Note shall cease to accrue. If said moneys shall not have been so paid on the prepayment date, such principal amount of such Note shall continue to bear interest until payment thereof at the rate provided for in Section 4 of this Credit Agreement.

9. Application of Note Proceeds. The proceeds of the Notes shall be used to pay amounts required to be paid by the District as a result of one or more nuclear incidents, as provided in the Price-Anderson Act, as amended (Pub. L. 94-197, as

amended and as compiled in 42 U.S.C. Section 2210 and pertinent subsections of 42 U.S.C. Section 2014, as amended) and certain regulations of the Nuclear Regulatory Commission (10 C.F.R. Part 140, as amended in particular by 42 Fed. Reg. 46-54 (January 3, 1977)) or any act or regulation supplemental thereto or amendatory thereof.

10. Payment. The obligation to pay the principal of and interest on the Notes and the other amounts payable hereunder is a special obligation of the District payable solely from such amounts in the Electric System General Reserve Fund as may be available therefor under the District's bond resolutions then outstanding; provided, however, that such obligation to pay the principal of and interest on the Notes and the other amounts payable hereunder from amounts in the Electric System General Reserve Fund shall be subject and subordinated in all respects to the pledge of the Revenues (as defined in the Electric Resolution), moneys, securities and funds created by the Electric Resolution and, provided, further, that the obligation to pay the principal of and interest on the Notes and the other amounts payable hereunder from amounts in the Electric System General Reserve Fund shall be subject and subordinated to any payments which shall at any time be required to be made from Electric System General Reserve Fund pursuant to Section 713 of the District's Power Supply System Revenue Bond Resolution, adopted by the Board of Directors of the District on September 29, 1972, as supplemented and amended in accordance with the terms thereof. The District shall duly and punctually pay or cause to be paid from the Electric System General Reserve Fund, in Federal Reserve or other immediately available funds, the principal of the Notes, the interest thereon and the other amounts payable hereunder at the dates and place and in the manner provided herein and in the Notes according to the true intent and meaning thereof. If the principal of the Notes becomes due and payable on a Saturday or Sunday or a day which is a Bank holiday, such payment shall be made on the next succeeding Bank business day and the extension of time for payment shall be included in computing interest in connection with such payment.

11. All of the Bank's rights and remedies under this Credit Agreement are cumulative and non-exclusive. The acceptance by the Bank of any partial payment made hereunder after the time when any of District's Loans become due and payable will not establish a custom, or waive any rights of the Bank to enforce prompt payment thereof. The Bank's failure to require strict performance by the District of any provision of this Credit Agreement shall not waive, affect or diminish any right of the Bank thereafter to demand strict compliance and performance therewith. Any waiver of an event of default hereunder shall not suspend, waive or affect any other event of default hereunder.

12. Rate Covenant. The District covenants and agrees with the Bank that so long as any credit shall be available hereunder or any Note or interest thereon is unpaid it shall comply for the benefit of the Bank with requirements of Section 712 of the Electric Resolution.

13. Negative Covenants of the District. The District, if and so long as credit shall be available hereunder or any Note or interest thereon is unpaid, will not alter, amend or repeal the Note Resolution, or take any action impairing the authority thereby or hereby given with respect to the issuance and payment of the Notes.

14. Tax Covenant. In order to maintain the exclusion from gross income for purposes of federal income taxation of interest on the Notes, the District shall comply with the provisions of the Code applicable to the Notes, including without limitation the provisions of the Code which prescribe yield and other limits within which the proceeds of the Notes and other amounts are to be invested and require that certain investment earnings on the foregoing be rebated on a periodic basis to the Treasury Department of the United States of America. The District shall not take any action or fail to take any action, which would cause the Notes to be "Arbitrage Bonds" within the meaning of Section 148(a) of the Code.

15. Representations and Warranties. The District represents and warrants that:

(a) The District has the power to borrow the amount provided for in this Credit Agreement; to execute and deliver this Credit Agreement; to evidence the Loans by its Notes to be made and delivered in accordance with the provisions hereof and to perform and observe all of the terms and conditions of this Credit Agreement on its part to be performed and observed;

(b) The making and performance by the District of this Credit Agreement will not violate any provision of the Act, or any bond or note resolution of the District, or any regulation, order or decree of any court, and will not result in a breach of any of the terms of the petition for creation, as amended, of the District or any agreement or instrument to which the District is a party or by which the District is bound; and

(c) The District, by adoption of the Note Resolution has duly authorized the borrowing of the amount provided for in this Credit Agreement, the execution and delivery of this Credit Agreement, and the making and delivery of the Notes to the Bank as herein provided; and to that end the District warrants that it will take all action and will do all things

which it is authorized by law to take and to do in order to fulfill all covenants on its part to be performed and to provide for and to assure payment of the Loans as herein provided.

16. Acceleration of Due Date Upon Default. If one or more of the following events of default shall occur and be continuing:

(a) Default shall occur and be continuing in the payment when due of any principal or interest on any Note;

(b) Any representation or warranty made herein or pursuant hereto shall prove to be untrue in any material respect;

(c) Default shall occur in the performance of any of the other covenants or agreements of the District contained herein, and the act or omission creating such default shall continue for a period of 30 days after written notice thereof shall have been given to the District; or

(d) Default shall be made in the payment of the principal of or interest on any Electric System Bonds when due, and as a result of such default, the maturity of such Bonds is accelerated;

then, and in any such event, the Bank shall have the right to declare the principal of and all interest then accrued on all Notes to be due and payable immediately, and upon such declaration the Notes and the interest accrued thereon shall become due and payable, anything in this Credit Agreement or in the Notes contained to the contrary notwithstanding.

17. Defeasance. If the District shall pay or cause to be paid, or there shall otherwise be paid, to the Bank the principal of and interest on the Notes at the times and in the manner stipulated herein, then the covenants, agreements and other obligations of the District hereunder shall thereupon cease, terminate and become void and be discharged and satisfied. If moneys sufficient to pay the principal amount of the Notes and interest thereon until maturity or a date fixed for repayment shall have been paid to the Bank for application to such purpose, the Notes and the interest thereon shall be deemed to have been paid within the meaning and with the effect expressed in this Section. Amounts so set aside and held may be invested in obligations of, or guaranteed by, the United States of America, provided, however, that said obligations shall mature not later than the maturity date of the Notes. All earnings from such investments shall be paid over to the District, as received, free and clear of any trust, lien or pledge.

18. Notices. All notices under this Credit Agreement shall be in writing and written notices shall be deemed to have been duly given if delivered or mailed by registered mail, in the case of the District, at Box 499, Columbus, Nebraska 68601,

Attention: President, and in the case of the Bank, at its principal office at LaSalle and Washington Streets, Chicago, Illinois 60690, Attention: Steven H. Abbey.

19. Counterparts. This Credit Agreement may be executed in any number of counterparts, and all such counterparts executed and delivered, each as an original, shall constitute but one and the same instrument.

IN WITNESS WHEREOF, the District and the Bank have caused this Credit Agreement to be duly signed on their respective behalf by their officers thereunto duly authorized, all as of the date and year first above written.

NEBRASKA PUBLIC POWER DISTRICT

[SEAL]

By Ronald D. Asche
Treasurer

Attest:

Ronda Travers
Assistant Secretary

AMERICAN NATIONAL BANK AND TRUST COMPANY OF CHICAGO

[SEAL]

"OFFICIAL SEAL"
BARBARA A. MULCAHY
NOTARY PUBLIC, STATE OF ILLINOIS
My Commission Expires 06/06/98

By
Vice President

Attest:

Barbara A. Mulcahy

ANNEX A

Resolution Authorizing $5,000,000 Bank Credit of 1994

Be it Resolved, by the Board of Directors of Nebraska Public Power District, as follows:

Section 1. Pursuant to the Public Power and Irrigation District Law, Article 6 of Chapter 70 of the Revised Statutes of Nebraska, as amended and supplemented (herein called the "Act"), Nebraska Public Power District (herein called the "District") shall be authorized to enter into a credit agreement (herein called the "Credit Agreement") for one or more loans in an aggregate principal amount up to, but not exceeding, $5,000,000 from American National Bank and Trust Company of Chicago (herein called the "Bank") in substantially the form submitted at this meeting, to which shall be annexed, as Annex A, a copy of this resolution adopted by the District. Each loan shall be made in the principal amount of not less than $250,000 on any date on or before July 31, 1995; provided that the District shall give the Bank two (2) days prior notice of the date and amount of each borrowing and shall be evidenced by an Electric System Note, Series NRC of 1994 (herein called a "Note"; all Notes made under the Credit Agreement are herein collectively called the "Notes") of the District in the aggregate principal amount of each loan, which Note shall be issued and delivered by the District to the Bank in the principal amount and on the date of the loan evidenced thereby. Each Note shall be payable to the order of the Bank from the sources set out in Section 10 of the Credit Agreement, shall be dated the date of its delivery, shall be payable one year from its date of issue (subject to optional prepayment as a whole or in part, at any time or from time to time, without penalty or premium, as provided in the Credit Agreement) and shall bear interest (payable on the first day of each January, April, July and October and upon maturity) on the unpaid principal amount thereof from its date fluctuating at the rate per annum equal to 87% of the rate of interest announced or published publicly from time to time by the Bank as its base rate or equivalent rate of interest. Interest is to be computed on the basis of a 365/366-day year. Each Note shall be in substantially the form set forth in Annex B to the Credit Agreement.

Section 2. The proceeds of the Notes shall be applied by the District to the purpose and in the manner provided in Section 9 of the Credit Agreement.

Section 3. The President, any Vice President, the Treasurer, and the Assistant Treasurer of the District are each hereby authorized to execute the Credit Agreement and the Secretary, or any Assistant Secretary, are each hereby authorized to affix the seal of the District on the Credit Agreement.

Section 4. The Chairman, Vice Chairman, President, Treasurer or Assistant Treasurer of the District are each hereby authorized to execute the Notes by manual signature and the Secretary or any Assistant Secretary are each hereby authorized to cause the seal of the District to be affixed, imprinted, engraved or otherwise reproduced on the Notes and to attest the same. Any of the foregoing officers are hereby authorized to deliver the executed Notes in accordance with the provisions of the Credit Agreement.

Section 5. The Chairman, Vice Chairman, President, Treasurer or Assistant Treasurer of the District and the Secretary or any Assistant Secretary are, and each of them hereby is authorized to do and perform all things and to execute all papers in the name of the District or otherwise, as they deem advisable, and to make all payments, necessary or convenient in their respective opinions, to the end that the District may carry out the objects of this resolution and its obligations under the terms of the Credit Agreement and of the Notes.

ANNEX B

(FORM OF NOTE)

NEBRASKA PUBLIC POWER DISTRICT

ELECTRIC SYSTEM NOTE, SERIES NRC OF 199_

No. $

FOR VALUE RECEIVED, the undersigned, NEBRASKA PUBLIC POWER DISTRICT (the "District"), a public corporation and political subdivision organized and existing under and by virtue of the laws of the State of Nebraska, hereby promises to pay to the order of American National Bank and Trust Company of Chicago (the "Bank") on ________________, 19__ upon presentation and surrender of this Note at the principal office of the Bank, the principal sum of _______________________ Dollars ($___________), in lawful money of the United States of America, and to pay interest (payable on ________________, 19__ and quarterly thereafter on the first day of each January, April, July and October and upon maturity) on said principal sum at said office in like money from the date hereof fluctuating at the rate per annum equal to 87% of the rate of interest announced or published publicly from time to time by the Bank as its base rate or equivalent rate of interest. Such interest shall be computed on the basis of a 365/366-day year.

This Note is a special obligation of the District and is one of a duly authorized issue of notes of the District (the "Notes") issued and to be issued under and pursuant to the Public Power and Irrigation District Law of Nebraska, as amended and supplemented (herein called the "Act"), and under and pursuant to a resolution of the District, adopted July 8, 1994, entitled Resolution Authorizing $5,000,000 Bank Credit of 1994 (the "Note Resolution"), and under and pursuant to a Credit Agreement (the "Credit Agreement"), dated as of August 1, 1994 by and between the District and the Bank.

The obligation to pay the principal of and interest on this Note is a special obligation of the District payable solely from such amounts in the Electric System General Reserve Fund (as defined in the Credit Agreement) as may be available therefor under the District's Bond resolutions then outstanding; provided, however, that such obligation to pay the principal of and interest on this Note from the Electric System General Reserve Fund is subject and subordinated in all respects to the pledge of the revenues, moneys, securities and funds created by the Electric Resolution (as defined in the Credit Agreement); and, provided, further, that the obligation to pay the principal of and interest on this Note from the Electric System General Reserve Fund is subject and subordinated to any payments which shall at any time be required to be made from the Electric System General Reserve Fund pursuant to Section 713 of the District's Power Supply

System Revenue Bond Resolution, adopted by the Board of Directors of the District on September 29, 1972, as supplemented and amended in accordance with the terms thereof.

This Note is subject to the terms and conditions contained in the Note Resolution and the Credit Agreement, copies of which are on file at the principal office of the District, and reference is made thereto for a complete statement of such terms and conditions.

The District shall have the right to prepay this Note as a whole or in part, at any time or from time to time, without penalty or premium, in accordance with the terms of the Credit Agreement. The prepayment date and the principal amount of the Note to be prepaid shall be specified by the District in a written notice to the Bank not less than 10 days prior to any prepayment. If on the prepayment date moneys for the payment of the principal amount of this Note to be prepaid, together with interest to the prepayment date on such principal amount, shall have been paid to the Bank as above provided, then from and after the prepayment date interest on such principal amount of this Note shall cease to accrue. If said moneys shall not have been so paid on the prepayment date, such principal amount of this Note shall continue to bear interest as provided above until payment thereof.

This Note is not an obligation of the State of Nebraska and the Act provides that the State of Nebraska shall never pledge its credit or funds, or any part thereof, for the payment or settlement of any indebtedness whatsoever of the District.

IN WITNESS WHEREOF, Nebraska Public Power District has caused this Note to be signed in its name and on its behalf by its President or Treasurer or Assistant Treasurer, and its official seal to be hereunto affixed and attested by its Secretary or any Assistant Secretary, as of _______ day of ________________, 19__.

NEBRASKA PUBLIC POWER DISTRICT

By____________________________
Treasurer

[SEAL]

Attest:

____
Assistant Secretary

ANNEX C

____________, 19__

Nebraska Public Power District
Columbus, Nebraska

American National Bank and
Trust Company of Chicago
Chicago, Illinois

Gentlemen:

We have examined the record of proceedings relating to the issuance of the $______________ Electric System Note, Series NRC of 1993, No. ____________, dated ____________, 19__ (the "Note"), of Nebraska Public Power District (the "District"), a body corporate and politic, constituting a public corporation and political subdivision of the State of Nebraska.

The Note is issued under and pursuant to Chapter 70, Article 6, of the Revised Statutes of the State of Nebraska, as amended (the "Act"), and under and pursuant to a Credit Agreement (the "Credit Agreement"), between the District and American National Bank and Trust Company of Chicago (the "Bank"), dated as of August 1, 1994, authorized by a resolution (the "Note Resolution") of the District adopted on July 8, 1994 and entitled "Resolution Authorizing $5,000,000 Bank Credit of 1994."

The Note is payable to the order of the Bank, matures on ___________, 19__ (subject to prepayment in accordance with the terms of the Credit Agreement), and bears interest (payable on ____________, 19__ and quarterly thereafter on the first day of January, April, July and October and upon maturity) from its date fluctuating at the rate per annum equal to 87% of the rate of interest announced or published publicly from time to time by the Bank as its base rate or equivalent rate of interest. Such interest rate shall be computed on the basis of a 365/366-day year.

The obligation to pay the principal of and interest on the Note is a special obligation of the District payable solely from such amounts in the Electric System General Reserve Fund (as defined in the Credit Agreement) as may be available therefor under the District's bond resolutions then outstanding; provided, however, that such obligation to pay the principal of and interest on the Note from the Electric System Reserve Fund is subject and subordinated in all respects to the pledge of the revenues, moneys, securities and funds created by the Electric Resolution (as defined in the Credit Agreement; and provided, further, that the obligation to pay the principal of and interest on the Note from the Electric System General Reserve Fund is subject and subordinated to any payments which shall at any time be required

to be made from the Electric System General Reserve Fund pursuant to Section 713 of the District's Power Supply System Revenue Bond Resolution, adopted by the Board of Directors of the District on September 9, 1972, as supplemented and amended in accordance with the terms thereof.

We are of the opinion that:

1. The District is duly created and validity existing under the provisions of the Act, with power to adopt the Note Resolution, to enter into the Credit Agreement, to issue the Note thereunder and to make and perform the covenants contained in the Credit Agreement.

2. The Note Resolution has been duly adopted by the District, is in full force and effect and is valid and binding on the District and enforceable in accordance with its terms, and the Credit Agreement has been duly authorized and executed by the District, is in full force and effect, is valid and binding upon the District and enforceable in accordance with its terms.

3. The Note has been duly authorized and issued by the District in accordance with law and in accordance with the Note Resolution and the Credit Agreement, and is a valid binding and direct obligation of the District enforceable in accordance with its terms and entitled to the benefit of the Act and of the Credit Agreement.

4. The Internal Revenue Code of 1986 as amended (the "Code") sets forth certain requirements which must be met subsequent to the issuance and delivery of the Note for interest thereon to be and remain excluded from gross income for purposes of federal income taxation. Noncompliance with such requirements may cause interest on the Note to be included in gross income retroactive to the date of issue of the Note. The District has covenanted to comply with such requirements.

In our opinion, under existing law, and assuming compliance with the aforementioned covenant, interest on the Note is excluded from gross income for federal and State of Nebraska income tax purposes. The Note is not a "specified private activity bond" within the meaning of Section 57(a) (5) of the Code and, therefore, the interest of the Note will not be treated as a preference item for purposes of computing the federal alternative minimum tax imposed by Section 55 of the Code. However, we note a portion of the interest on the Note owned by corporations may be subject to the federal alternative minimum tax, which is based in part on adjusted current earnings.

Except as stated in the preceding two paragraphs, we express no opinion as to any federal or state tax consequences of the ownership of, receipt of interest on, or disposition of the Note.

The opinions contained in paragraphs 2 and 3 above are qualified to the extent that the enforceability of the Note Resolution, the Credit Agreement and the Note, respectively, may be limited by any applicable bankruptcy, moratorium or similar laws relating to the enforcement of creditors' rights.

We have examined the Note, as executed, and, in our opinion, the form of said Note and its execution are regular and proper.

Very truly yours,

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

FORM 10-K

(Mark One)
[x] **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
[Fee Required]
For the fiscal year ended December 31, 1993

OR

[ ] **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
[No Fee Required]
For the transition period from ________ to ________

Commission file number 1-12582

MIDWEST POWER SYSTEMS INC.
(Exact name of registrant as specified in its charter)

IOWA	42-1375614
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
666 Grand Ave., P.O. Box 657, Des Moines, Iowa	50303
(Address of principal executive offices)	(Zip Code)
Registrant's telephone number, including area code	515-281-2900

Securities registered pursuant to Section 12(b) of the Act:

$1.7375 Cumulative Preferred Stock, Without Par Value
(Title of Class)

Securities registered pursuant to Section 12(g) of the Act:

$3.30 Cumulative Preferred Stock, Without Par Value
$3.75 Cumulative Preferred Stock, Without Par Value
$3.90 Cumulative Preferred Stock, Without Par Value
$4.20 Cumulative Preferred Stock, Without Par Value
$4.35 Cumulative Preferred Stock, Without Par Value
$4.40 Cumulative Preferred Stock, Without Par Value
$4.80 Cumulative Preferred Stock, Without Par Value
(Title of Class)

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 X No____

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K [X].

The aggregate market value of voting stock held by non-affiliates of the registrant was $0 as of March 22, 1994, when 1,000 shares of common stock, without par value, were outstanding.

MIDWEST POWER SYSTEMS INC.

1993 Form 10-K Annual Report

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PART I

ITEM 1. BUSINESS

(a) General Development of Business

Midwest Power Systems Inc. (MPS or Company), an Iowa corporation, is the wholly owned utility subsidiary of Midwest Resources Inc. (Midwest Resources or MWR). On July 22, 1992, Iowa Power Inc. (IPR) and Iowa Public Service Company (IPS) merged into and with MPS. IPS and IPR were previously the utility subsidiaries of Midwest Energy Company (MWE) and Iowa Resources Inc. (IOR), respectively. On November 7, 1990, IOR and MWE merged into Midwest Resources, a newly created holding company.

(b) Financial Information About Industry Segments

See Part IV, Item 14, "Exhibits, Financial Statement Schedules and Reports on Form 8-K", Note (3) of Notes to Consolidated Financial Statements for financial information about industry segments.

(c) Narrative Description of Business

GENERAL

MPS is an Iowa corporation which operates an electric division, Midwest Power, and a natural gas division, Midwest Gas. MPS is a regulated utility that holds franchises to operate in various municipalities and has territorial protection in other areas granted by state regulatory commissions. CBEC Railway Inc., an Iowa corporation formed in 1990, is a wholly owned subsidiary of MPS that was organized to own and operate rail facilities for the transportation of coal. CBEC Railway Inc. has not commenced operations.

CAPITAL EXPENDITURES AND FINANCING

The Company made gross utility property additions of $624 million during the period January 1, 1989, to December 31, 1993, of which $57 million was for Cooper capital improvements, $452 was for electric plant, $109 million was for gas plant and $6 million was for common plant. Utility property retirements during the same period amounted to $89 million, of which $64 million was applicable to electric plant, $23 million to gas plant and $2 million to common plant.

The Company's sources of capital are provided from funds generated internally and various external sources such as commercial paper, bank lines of credit, and other debt and equity securities.

On January 1, 1993, a new MPS indenture became effective. During 1993 the Company embarked on a plan to refinance and redeem a significant portion of the long-term debt issued by MPS' predecessor companies, IPS and IPR. As a result of the restructuring, the Company was able to eliminate the IPR indenture and only $11 million of long-term debt remains outstanding subject to the IPS indenture. No further bond issuances will be made under the IPS and IPR indentures. The MPS indenture is less restrictive than either of the two previous indentures. At December 31, 1993, approximately $981 million of additional general mortgage bonds could have been issued in compliance with the MPS indenture.

MPS currently has authority from the Federal Energy Regulatory Commission (FERC) to issue (i) before July 1995, short-term debt in the form of commercial paper, bank notes, and notes to MWR or affiliated companies of up to $250 million; (ii) $118 million of long-term debt in the form of general mortgage bonds and pollution control revenue bonds; and (iii) $15 million of preferred stock.

REGULATION

MWR is exempt from the Public Utility Holding Company Act of 1935. MWR's exemption is based upon its filing with the Securities and Exchange Commission (SEC) in November 1990, an Initial Statement by Holding Company Pursuant to Regulation 250.2 of the Public Utility Holding Company Act of 1935. MWR maintains its exemption by filing a Form U-3A-2 with the SEC each year.

MPS is a public utility within the meaning of the Federal Power Act and a natural gas company within the meaning of the Natural Gas Act. Therefore, it is subject to regulation by FERC in regard to numerous activities, including the issuance of securities, accounting policies and practices, sales for resale rates and the establishment and regulation of electric interconnections and transmission services. For the year ended December 31, 1993, approximately 11.7 percent of the total electric revenues were sales for resale and subject to FERC regulation. Natural gas revenues are not subject to FERC regulation.

MPS is subject to regulation by the Iowa Utilities Board (IUB) and the South Dakota Public Utilities Commission (SDPUC) as to electric and gas retail rates and service. Iowa law authorizes the IUB to suspend new rates for up to ten months beyond the date of initial filing. During the interim period of rate proceedings, statutory authority in Iowa allows for interim rate increases, subject to refund, starting no later than 90 days from the initial filing date. South Dakota law authorizes the SDPUC to suspend new rates for up to six months during the pendency of rate proceedings, however, the rates are permitted to be implemented after six months subject to refund pending a final order in the proceeding.

In addition, Iowa law requires that a certificate of convenience and necessity be obtained from the IUB prior to construction of a proposed electric generation station with a total capacity of 25 or more megawatts. Need for the station must be established and approval of the proposed site obtained before a certificate can be issued.

MPS' electric and gas operations are conducted under franchises (expiring in various years from 1994 to 2018), permits and licenses obtained from state and local authorities. Franchises for the largest communities served by the Company extend to the year 2000 and beyond.

MPS has entered into a long-term power purchase contract with Nebraska Public Power District under which it purchases one-half of the output of Cooper Nuclear Station (Cooper). Operations of Cooper are subject to regulation by the Nuclear Regulatory Commission (NRC). Refer to "Regulatory Environment" in "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in Part IV, Item 14, for discussion of recent NRC actions.

ENVIRONMENTAL MATTERS

The Company is subject to numerous legislative and regulatory environmental protection requirements involving air and water pollution, waste management, hazardous chemical use, noise abatement, land use and aesthetics.

Essentially all utility generating units are subject to the provisions of the Clean Air Act Amendments of 1990 which address continuous emission monitoring, permit requirements and fees and emission of toxic substances. The Company estimates capital costs of approximately $3 million and increased annual operations and maintenance expense of approximately $2 million for compliance with these provisions. By the year 2000, some Company coal-fired generating units will be required to install controls to reduce emissions of nitrogen oxides. The Company's present estimate of the costs of these controls is $33 million.

The United States Environmental Protection Agency and the Iowa Department of Natural Resources have determined that contaminated wastes remaining at certain decommissioned manufactured gas plant (MGP) facilities may pose a threat to the public health or the environment if such contaminants are in sufficient quantities and at such concentrations as to warrant remedial action. The Company could be involved in up to 22 such sites. The Company's present estimate of probable remediation costs at these sites is $15.5 million. The Company's current gas rates in Iowa provide recovery for MGP costs of $3.1 million on an annual basis.

As a user of polychlorinated biphenyls (PCBs), the Company is subject to governmental regulations pertaining to the use, handling and proper disposal of PCBs. The Company is aware of three PCB sites in which it may be involved. The Company anticipates recovery of any material expenditures from other responsible parties and through rates.

For further information relating to the Company's Environmental Matters, reference is made to Part IV, Item 14, Note (2)(b) of Notes to Consolidated Financial Statements.

EMPLOYEES

On February 14, 1994, the Company had 2,832 full-time employees and 76 part-time and temporary employees for a total of 2,908 employees. Of that total, 1,553 were union employees.

ELECTRIC OPERATIONS

Midwest Power has been engaged in the generation, purchase, transmission, distribution and sale of electric energy, serving 420,000 customers in 327 communities in Iowa and six communities in southeastern South Dakota.

Generation

Midwest Power's owned electric generating facilities are all located in Iowa. The net accredited generating capacity, along with the participation purchases and sales, net, and firm purchases and sales, net, are shown for summer 1993 accreditation.

Plant	Percent Ownership	Fuel	Accredited Generating Capability (kW)
Steam Electric Generating Plants:			
George Neal Station			
Unit No. 1	100.0	Coal	135,000
Unit No. 2	100.0	Coal	300,000
Unit No. 3	43.0	Coal	221,450
Unit No. 4	40.6	Coal	247,500
Ottumwa Unit	33.5	Coal	237,180
Louisa Unit	45.0	Coal	292,500
Council Bluffs Energy Center			
Unit No. 1	100.0	Coal	46,000
Unit No. 2	100.0	Coal	88,000
Unit No. 3	46.7	Coal	315,230
			1,882,860
Combustion Turbines:			
Parr - 2 units	100.0	Gas/Oil	27,100
Electrifarm - 3 units	100.0	Gas/Oil	186,100
River Hills Energy Center - 8 units	100.0	Gas/Oil	127,200
Sycamore Energy Center - 2 units	100.0	Gas/Oil	148,000
Pleasant Hill - 2 units	100.0	Oil	70,140
			558,540
Nuclear Capacity Purchase:			
Cooper Nuclear Station	(1)	Nuclear	389,000
Net Accredited Generating Capacity			2,830,400
Add: Participation Purchases and Sales, Net			(74,000)
Firm Purchases and Sales, Net			63,250
Adjusted Net Accredited Generating Capability			2,819,650

(1) Cooper Nuclear Station is owned by Nebraska Public Power District and the amount shown is Midwest Power's entitlement (50 percent) of Cooper's accredited capacity under a power purchase agreement extending to the year 2004. (Refer to Notes (1)(g) and (2)(a) of Notes to Consolidated Financial Statements included in Part IV, Item 14.)

The annual hourly peak demand occurs during the summer period, principally as a result of air conditioning use. Midwest Power's highest hourly peak demand in 1993 was 2,205 megawatts (MW) in August, 57 MW less than Midwest Power's record of 2,262 MW set in 1988 and 246 MW above the 1992 peak demand of 1,959 MW.

Midwest Power is interconnected with certain Iowa and neighboring utilities and is one of 43 utilities involved in an electric power pooling agreement known as the Mid-Continent Area Power Pool (MAPP). The purpose of MAPP is to coordinate the planning, construction and operation of generation and transmission facilities, including the purchase and sale of power and energy among members. In addition, Midwest Power and two other Iowa investor-owned utilities are partners in ENEREX, a general partnership. ENEREX coordinates the purchase and sale of electric energy among the partners and handles the daily unit commitment function.

The transmission lines of Midwest Power, operating from 34,500 to 345,000 volts, totaled 3,591 circuit miles at December 31, 1993.

In October 1992 the National Energy Policy Act (NEPA) was signed into law. NEPA, which allows all electric generators to transport wholesale power across utilities' transmission facilities, will promote competition in the wholesale electric market. The increasingly competitive environment brings with it an increase in risk. The Company is currently evaluating the law and its impact on Midwest Power. Refer to the "Regulatory Environment" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part IV, Item 14, of this filing.

Generation by coal, nuclear, oil and natural gas as a percent of Midwest Power's total net generation of electricity during each of the last three calendar years and the average cost to the Company of those fuels are as follows:

Year Ended	% of Generation Coal	Nuclear	Gas/Oil	All Fuels Average Cost (Mills per kWh)
1993	84	15	1	9.5
1992	75	24	1	9.1
1991	79	20	1	10.0

Fuel Supply

Midwest Power has contracts and commitments providing for the furnishing of coal in quantities which are adequate, in the opinion of management, absent circumstances not now foreseen. Costs of coal are subject to price adjustments under the existing contracts. All of the Company's wholesale sales (which are part of sales for resale) and retail sales of electricity are subject to energy adjustment clauses.

Approximately 50 percent of Midwest Power's coal needs for 1994 are expected to be met by coal delivered under its five major coal supply contracts. The balance will be met with coal purchased on the spot market.

Midwest Power's five major coal supply contracts under which deliveries are currently being received are as follows:

Year In Which Contract Expires	Contracted Annual Tonnage (1)
1994	292,000-439,000 (2)
1998	730,000-893,000
1999	760,000-921,000 (3)
2001	360,000-633,000 (3)
2003	621,000-887,000 (3)

(1) Company's share only where contract pertains to jointly owned unit.
(2) Option to extend for 2 years.
(3) Tonnage varies per specified annual contract amounts.

Midwest Power has contracts with rail shippers providing for the delivery of coal to its generating stations. Recently, utilities in the Midwest, including Midwest Power, have been experiencing delays in the delivery of coal from rail shippers. While the Company has been working with shippers, such delays, which have been caused by the 1993 summer floods, cold winter weather and other factors relating to the shippers' capabilities to deliver coal within specified delivery schedules have resulted in lower than normal stockpiles at certain of Midwest Power's generating facilities. The Company does not anticipate any adverse impact to its firm customers although it has reduced its activities in the bulk sales market.

Natural gas and oil are used for peak demand electric generation and for standby purposes. These sources are in adequate supply and available to meet the Company's needs.

Approximately 30 percent of the fuel in the core at Cooper Nuclear Station must be replaced every 18 months.

For additional information concerning electric operations, see "Unaudited Utility Statistics", in Part IV, Item 14, of this filing.

NATURAL GAS OPERATIONS

Midwest Gas has been engaged in the procurement, transportation, and distribution of natural gas for utilities and end-use customers primarily in the Midwest. With the implementation of FERC Orders 636, 636A and 636B (Order 636 or Orders) related to the regulation of natural gas interstate pipeline companies on November 1, 1993, Midwest Gas began operating in a more competitive environment. Midwest Gas now has complete responsibility for natural gas procurement, transportation and storage, a responsibility which had previously resided with Midwest Gas' interstate pipeline suppliers. These Orders directly impact the operations, revenues and costs of local distribution companies (LDCs), including Midwest Gas, and create new opportunities.

On August 31, 1993, Midwest Gas acquired the South Dakota distribution properties of Minnegasco, a division of Arkla, Inc., and Minnegasco acquired Midwest Gas' Minnesota distribution properties. Refer to "Midwest Gas Operations" in "Management's Discussion and Analysis of Financial Condition and Results of Operations", included in Part IV, Item 14, of this filing for more discussion of the exchange. As of December 31, 1993, Midwest Gas was distributing natural gas at retail to 342,000 customers in 204 communities in Iowa, 27 communities in South Dakota and 2 communities in Nebraska. Midwest Gas distributes the natural gas through 10,378 miles of distribution mains and services. During the 1993-94 heating season, the Midwest Gas firm peak day sendout was 539,000 MMBtu. Refer to "Unaudited Utility Statistics" in Part IV, Item 14, for additional information related to Midwest Gas' natural gas operations.

Refer to "Regulatory Environment" in "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in Part IV, Item 14, for further discussion of the impact of Order 636.

Fuel Supply and Capacity

With the implementation of FERC Order 636, Midwest Gas purchases the majority of its supplies either directly from producers or from third-party marketers. Midwest Gas uses a geographically diverse supply portfolio with varying terms to ensure system reliability. The term and geographic mix of contracted supplies are shown in the following table:

	Long-Term (More Than 1 Year)	Short-Term (Less Than 1 Year)	Spot Market (Daily/Monthly)	Total
Texas/Oklahoma	23%	4%	36%	63%
Canada	29%	4%	2%	35%
Other	-	-	2%	2%
Total	52%	8%	40%	100%

In preparation for the increased supply responsibilities under Order 636, Midwest Gas increased its natural gas inventory for the 1993-94 heating season. In the future, Midwest Gas will be able to more accurately determine its natural gas needs for operating under the rules of Order 636 via improved telemetering techniques and after it and other involved parties gain experience in the new environment.

Midwest Gas maintains contracts for transportation capacity from three pipelines: Northern Natural Gas Company (NNG), Natural Gas Pipeline Co. of America (Natural), and ANR Pipeline Company (ANR). Contracts with NNG provide delivery of 183,000 MMBtu per day of 12-month firm transport service and 131,100 MMBtu per day of seasonal firm transport service to meet winter peak demands. Contracts on a firm delivery basis with Natural are 60,700 MMBtu per day of firm transport service and 18,800 MMBtu per day of transportation and storage service during peak periods. Contracts with ANR provide for delivery of 6,600 MMBtu per day of firm transport service.

In addition, Midwest Gas also contracts for storage gas supplies. This storage gas is available primarily during the heating season and is delivered on either a firm or interruptible transportation contract. The following table shows the quantities of storage gas supplies available from each storage provider:

Storage Provider	Total Storage (MMBtu)	Maximum Daily Withdrawal (MMBtu)
NNG	6,000,000	139,000
Natural	3,048,500	36,700
ANR	359,900	4,800
Richfield	1,325,000	21,200

In order to meet peak day gas demand during winter months, two liquefied natural gas plants enable the liquefaction and storage of gas during off-peak months for use during the heating season and provide additional maximum daily delivery capacity of 69,600 MMBtu. In addition, 5 propane-air gas peak shaving plants, of which 4 are located in Iowa and 1 in South Dakota, have 81,300 MMBtu maximum daily delivery capacity.

Natural gas distribution facilities located in the Midwest experience significant seasonal demands. Sales during the spring and summer months are traditionally lower than the fall and winter heating season. These seasonal swings in demand result in additional availability of firm pipeline capacity during certain parts of the year. Midwest Gas has entered into numerous buy/sell arrangements which allow it to market its available firm capacity during these periods. FERC also established a "capacity brokering" mechanism under Order 636, which gives LDCs an opportunity to broker any unused capacities for various terms.

A purchased gas adjustment clause, which exists in all jurisdictions, permits rates charged to a majority of Midwest Gas' customers to be adjusted as natural gas transportation and supply costs change.

ITEM 2. PROPERTIES

Reference is made to Item 1 (c) "Electric Operations" and "Natural Gas Operations" of this filing concerning the properties of the Company.

It is the opinion of management that the principal depreciable utility properties owned by the Company are in good operating condition and well maintained.

The Mortgage and Deed of Trust of IPS as amended and supplemented constitutes a first mortgage lien on substantially all of the properties owned by the Company subject only to excepted encumbrances. The MPS General Mortgage Indenture and Deed of Trust dated January 1, 1993, constitutes a junior lien on all of the Company's electric properties located in Iowa subject to the IPS indenture and a first lien on all remaining and new electric properties in Iowa. It will become a first lien on all Iowa electric properties when the remaining $11 million of long-term debt outstanding issued under the IPS indenture is retired.

ITEM 3. LEGAL PROCEEDINGS

The Company and its subsidiaries have no material legal proceedings except for the following:

Environmental Matters

Reference is made to Item 1(c), "Environmental Matters," and to Part IV, Item 14, Note (2)(b) of Notes to Consolidated Financial Statements.

ITEM 4. RESULTS OF VOTES OF SECURITY HOLDERS

No matters were submitted to a vote of the Company's security holders during the fourth quarter of 1993.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Market Information and Dividends:

The Company's outstanding common stock is held entirely by its parent company, MWR, and is not publicly traded. The annual total of quarterly common stock cash dividends declared by the Company to MWR in 1993 and 1992 were $63,551,000 and $73,944,000, respectively.

ITEM 6. SELECTED FINANCIAL DATA

Reference is made to Part IV of this report.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Reference is made to Part IV of this report.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

For the information required by Item 8 for the Company, including the (i) Consolidated Statements of Income, (ii) Consolidated Statements of Cash Flows, (iii) Consolidated Balance Sheets, (iv) Consolidated Statements of Capitalization, (v) Consolidated Statements of Retained Earnings, (vi) Notes to Consolidated Financial Statements and (vii) Report of Independent Public Accountants, reference is made to Part IV of this report.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Information concerning the directors and executive officers of the Company is as follows:

(a) Identification

Name	Age	Present Position	Served in Present Position Since	Served as Director Since
Russell E. Christiansen	58	Chairman, President and Chief Executive Officer	1992	1992
Richard C. Engle	59	Executive Vice President, Midwest Power-Generation and Transmission and Director	1992	1992
Lynn K. Vorbrich	55	Executive Vice President, Midwest Power-Distribution and Director	1992	1992
Philip G. Lindner	50	Group Vice President-Administrative Services and Director	1992	1992
Beverly A. Wharton	40	Group Vice President, Midwest Gas and Director	1992	1992
John A. Rasmussen, Jr.	48	Vice President and General Counsel	1992	-
James R. Bull	52	Vice President	1992	-
James J. Howard	51	Vice President	1992	-
Lester A. Juon	55	Vice President	1992	-
Robert L. Lester	52	Vice President	1993	-
Paul J. Leighton	40	Secretary and Assistant Treasurer	1992	-
J. Sue Rozema	41	Treasurer and Assistant Secretary	1992	-
Larry M. Smith	38	Controller	1992	-

Each director and executive officer serves an annual term of office. Officers are elected annually by the Board of Directors. There are no family relationships between the foregoing executive officers and directors of the Company, nor any arrangements or understandings between any director or officer and any other person pursuant to which the director/officer was elected.

(b) Business Experience During the Last Five Years and Directorships

Russell E. Christiansen	Chairman and Chief Executive Officer of MWR since 1992, President since 1990 and Vice Chairman and Chief Operating Officer of MWR from 1990 to 1992. Chairman and Chief Executive Officer of MWE from 1986 to 1990 and President from 1985 to 1990. Chairman, President and Chief Executive Officer of MPS since 1992. Chairman and Chief Executive Officer of IPS from 1986 to 1992 and Chairman and Chief Executive Officer of IPR from 1990 to 1992. Director of Norwest Bank Iowa, N.A.
Richard C. Engle	Executive Vice President of MPS since 1992. President and Chief Operating Officer of IPS from 1990 to 1992, Senior Vice President and Chief Operating Officer from 1987 to 1990.
Lynn K. Vorbrich	Executive Vice President of MPS since 1992. President and Chief Operating Officer of IPR from 1989 to 1992. Executive Vice President of IPR from 1986 to 1989.
Philip G. Lindner	Group Vice President of MPS since 1992. Senior Vice President of IPR from 1990 to 1992. Vice President of IPR in 1989. Prior to joining IPR in 1989, Mr. Lindner served as Vice President and Chief Financial Officer for MacNeal Hospital from 1987 to 1989.
Beverly A. Wharton	Group Vice President of MPS since 1992. Senior Vice President of IPS from 1988 to 1992. Vice President from 1985 to 1988 and Secretary from 1984 to 1988.

Each of the officers not also serving as a director has been employed by the Company or one of its predecessors, IPS or IPR, for more than five years in various officer capacities except for Larry M. Smith. Mr. Smith has served as Controller of MPS since 1992. He was Controller of IPS from 1990 to 1992 and Controller of MWE in 1990. From 1985 to 1990 he was Manager of Corporate Accounting for MWE and was the acting Controller from 1988 to 1990.

ITEM 11. EXECUTIVE COMPENSATION

The following table sets forth the compensation for services in all capacities to MWR and its subsidiaries for the fiscal years ended December 31, 1993, 1992 and 1991, of those persons who were, at December 31, 1993, (i) the chief executive officer and (ii) the other four most highly compensated executive officers of the Company ("named executive officers"). Portions of the compensation shown in the following table is recovered from affiliate companies for services rendered to them by the named executive officers or through the sharing of costs through the MWR corporate allocation.

Summary Compensation Table

Annual Compensation

Name and Principal Position	Year	Salary($)	Other Annual Bonus($)(1)	All Other Compensation($)	
Russell E. Christiansen	1993	383,333	39,105	5,310	40,048(2)
Chairman, President and	1992	380,000	0	0	38,570
Chief Executive Officer	1991	360,000	60,000	0	29,980
Richard C. Engle	1993	225,000	23,017	0	25,238(3)
Executive Vice President	1992	224,000	0	4,583	24,201
	1991	212,000	31,800	0	18,583
Lynn K. Vorbrich	1993	228,446	23,422	0	17,586(4)
Executive Vice President	1992	232,061	0	4,510	16,947
	1991	211,492	31,800	0	14,978
Philip G. Lindner	1993	154,808	17,969	0	13,870(5)
Group Vice President	1992	155,446	0	3,413	9,923
	1991	142,662	19,200	0	11,744
Beverly A. Wharton	1993	152,500	14,875	0	12,598(6)
Group Vice President	1992	136,000	0	2,132	9,835
	1991	122,000	16,400	0	11,186

(1) Amounts shown for 1993 represent part of the estimated total incentive compensation award, which cannot be presently determined. The balance of the actual award will be paid in 1994 at such time as definitive corporate performance measures are calculated. See the Management Development Committee Report on Executive Compensation starting on page 15 for a discussion of the 1993 bonus.

(2) Consists of $15,000 as director fees, $22,050 for supplemental life insurance and a contribution by the Company of $2,998 to a defined contribution plan.

(3) Consists of $8,000 as director fees, $14,240 for supplemental life insurance and a contribution by the Company of $2,998 to a defined contribution plan.

(4) Consists of $8,000 as director fees, $8,000 for supplemental life insurance and a contribution by the Company of $1,586 to a defined contribution plan.

(5) Consists of $8,000 as director fees, $3,685 for supplemental life insurance and a contribution by the Company of $2,185 to a defined contribution plan.

(6) Consists of $8,000 as director fees, $1,600 for supplemental life insurance and a contribution by the Company of $2,998 to a defined contribution plan.

MANAGEMENT DEVELOPMENT COMMITTEE REPORT ON EXECUTIVE COMPENSATION

The Management Development Committee (Committee) of the MWR Board of Directors (Board of Directors) has furnished the following report on executive compensation. This committee, along with the MWR Board of Directors as a whole, determines compensation for officers of the parent company and affiliates. The term "Company" refers to MWR in this report.

The Management Development Committee is comprised of directors who are not current or former officers or employees of the Company or any of its subsidiaries. The Committee has the following responsibilities:

1. Review the performance of senior management, including the Chief Executive Officer.

2. Review compensation, benefits, pension plans and other forms of indirect compensation for officers and senior managerial employees.

3. Consider the needs for succession planning and adequacy of plans to assure continuity of the Company's management.

4. Review, approve and recommend to the Board of Directors and administer various incentive compensation plans, including annual and long-term plans.

The Company has a compensation policy which is designed to compensate management with salary, incentives and benefits at levels generally competitive with comparative utility companies and general industry. Comparative utility companies consist of those that are members of utility industry associations, some of which may also be included in the published industry index referenced in the shareholder return performance graph. Incentive plans and performance review processes are intended to encourage and reward outstanding performance. The compensation policy and the goals set for incentive plans are designed to benefit shareholders and customers as well as to attract and retain highly qualified and capable executives. In addition, the policy for establishing incentive compensation plans is intended to place a portion, ranging from approximately one-fourth to one-half, of total compensation at risk.

The Committee annually reviews executive compensation in December of each year for the purpose of determining base salaries for the next year. As part of its review, the Committee evaluates overall corporate performance, including earnings, comparative utility and general industry compensation levels and salary recommendations made by the Chief Executive Officer of the Company. The Committee then recommends base salaries to the Board of Directors. In January of each year, the Committee sets targets and goals for the annual and long term incentive compensation plans for that year. In the second and third quarters of each year, the Committee evaluates the attainment of targets and goals under these plans for the preceding year and determines the level of incentive awards, if any. Exceptional individual performance may be additionally rewarded under the noncash bonus award plan.

Base Salaries

The base salary for the named executive officers is determined by reference to the base salary paid to their respective peers at other comparable utility companies, industry and national surveys and performance judgments as to the past and expected future contributions of the individual executives. As a general

guideline, base salaries for the named executive officers are targeted at the utility industry average for comparative companies as determined through compensation surveys prepared by utility industry associations. In evaluating the performance of the named executive officers, the Committee considers their individual contributions in achieving operating and management efficiencies, applicable business unit performance and individual performance. The Committee also considers management's commitment to the long term growth of the Company by focusing on the strategic opportunities of the utility and nonutility businesses and developing plans to implement these strategies. Such strategic opportunities include those resulting from deregulation of certain aspects of the natural gas and electric utility businesses and the focusing of the nonutility businesses on the Company's core strengths.

In December 1992, the Committee reviewed with Mr. Christiansen the performance of each of the named executive officers during 1992 and the base salary adjustments recommended by Mr. Christiansen. In accordance with the recommendation of Mr. Christiansen, the Committee recommended to the Board of Directors that the named executive officers, including Mr. Christiansen, not receive a base salary adjustment for 1993 as a result of the Company not meeting its corporate performance goals for 1992, as discussed below under Annual Incentive Compensation, with the exception of Mrs. Wharton who received an adjustment due to a change in responsibilities and outstanding individual performance. The Board of Directors concurred with the recommendations of the Committee.

In October 1993, the Committee recommended to the Board of Directors that base salary adjustments for the named executive officers for 1994 be made effective November 1, 1993, in recognition of the Company's significantly improved financial performance through the end of the third quarter and the expected year end results. Individual adjustments ranging from two and seven-tenths percent to ten percent were determined using the criteria discussed above. The Committee independently reviewed the performance of Mr. Christiansen during 1993 and recommended to the Board of Directors that he receive a 1994 base salary adjustment of five percent in recognition of his contribution in leading the Company and its combined operations to greater operating and management efficiencies and significantly improved financial performance. The Board of Directors concurred with the recommendations of the Committee.

Annual Incentive Compensation

The Company adopted a Key Executive Annual Incentive Compensation Plan for key employees, including the named executive officers, effective in 1992. Individual awards under this plan are based on the achievement of specific individual, business unit and corporate performance goals which are revised annually. For Mr. Christiansen, seventy-five percent of his award is based on overall corporate goals and twenty-five percent on individual goals. For the other named executive officers with operations responsibilities, forty percent of their awards are based on achieving business unit goals, forty percent on overall corporate goals and twenty percent on individual goals. For the other named executive officers with staff responsibilities, sixty percent of their awards are based on overall corporate goals and forty percent on individual goals. Corporate performance goals consist of a shareholder measure of targeted earnings growth with a minimum earnings level to be achieved before any awards may be made and a customer measure of electric and gas rate performance as compared to other specific utility companies. Business unit goals consist of unit operations and maintenance cost measures and utility customer service measures, including service reliability and responsiveness to customer needs. Individual goals are developed by each of the other named executive officers and reviewed by the Chief Executive Officer. The achievement of the corporate performance and business unit goals is indexed on a sliding scale basis. As the goal is achieved and then exceeded, the index scales up. A target award of twenty-eight percent of annual base salary will be made to the other named executive officers upon achievement of one hundred percent of the established goals with a maximum award of forty-two percent if the established goals are exceeded as determined by the index. The Chief Executive Officer is eligible for a target award of thirty-five percent and a maximum award of fifty-two and one-half percent. Up to one-half of the award is paid in cash and the remainder in performance shares. Each performance share has a value equal to one share of the Company's Common Stock. The specific goals are not included herein because they are believed to represent confidential business information. No awards were made for 1992 performance since the corporate performance goals were not achieved. In December 1993,

annual incentive awards were made to Mr. Christiansen and the other named executive officers in the amounts shown on the Summary Compensation Table due to the achievement of the corporate performance and business unit goals. The amounts shown represent, in the case of Mr. Christiansen, fifty percent of the cash portion of the estimated total incentive award, and in the case of the other named executive officers, seventy-five percent of the cash portion of the estimated total incentive award. The balance of the cash portion of the award will be paid in 1994 and the deferred portion of the award will be credited to the respective participant's plan account after definitive corporate performance measures are calculated.

Long-Term Incentive Compensation

A Long-Term Incentive Compensation Plan was also adopted by the Company for the named executive officers, effective in 1992. Individual awards under this plan are based on the achievement of certain corporate performance goals during each three year performance cycle, with the first cycle consisting of the years 1990 through 1992 and the last cycle years 1994 through 1996. The two goals which must be met each year under the plan are the annual growth in corporate earnings per share and the return on shareholder equity. The target for each goal for the current year of the cycle is determined in January by the Committee. The earnings per share goal is weighted at seventy-five percent with the return on equity goal weighted at twenty-five percent. Target awards range from seven and one-half percent to twenty-five percent of annual base salary with maximum awards ranging from twelve and one-half percent to thirty-seven and one-half percent if the goals are exceeded. The Chief Executive Officer is eligible for awards at the twenty-five percent/thirty-seven and one-half percent levels. Cash awards are paid at the end of a performance cycle. The specific goals are not included herein because they are believed to represent confidential business information. No awards were made for the cycles ending December 31, 1992, or December 31, 1993, since the corporate performance goals for each cycle were not achieved.

Noncash Bonus Awards

The Company has adopted a noncash bonus award plan for certain officers of the Company. Individual awards are made in performance shares and paid in cash at the earlier of retirement, death, disability or involuntary termination without cause. Awards are made at the discretion of the Board of Directors upon recommendation by the Committee in recognition of exceptional performance. No awards were made under this plan for plan years 1992 or 1993.

RETIREMENT PLANS

The Midwest Power Systems Inc. Salaried Employees' Retirement Plan ("Midwest Power Retirement Plan") provides for payment of fixed pension benefits to persons who retire after a specified age and number of years of service, based on average annual salary during the five highest paid consecutive years out of the last ten years prior to retirement. For Messrs. Christiansen and Engle and Mrs. Wharton, benefits for service prior to January 1, 1992, are determined as provided by a predecessor retirement plan using the final average pay method, based on the employee's highest five years' earnings. Messrs. Christiansen, Engle, Vorbrich and Lindner and Mrs. Wharton are participants in the Midwest Power Retirement Plan and are credited with 34, 29, 21, 4 and 17 years of service, respectively.

The Company maintains an unfunded Supplemental Retirement Plan ("Supplemental Plan") to provide additional retirement benefits to certain officers, as determined by the Board of Directors. Messrs. Christiansen, Engle, Vorbrich and Lindner are participants in the Supplemental Plan. Part A of the Supplemental Plan provides retirement benefits up to sixty-five percent of a participant's highest annual salary during the five years prior to retirement reduced by the participant's Midwest Power Retirement Plan benefit. The percentage applied is based on years of credited service. A participant who elects early retirement is entitled to reduced benefits under the plan. A survivor benefit is payable to a surviving spouse. Part B of the plan provides that an additional one hundred-fifty percent of annual salary is to be paid out to participants at the rate of ten percent per year over fifteen years, except in the event of a participant's death, in which event the unpaid balance would be paid to the participant's beneficiary or estate. Benefits from the

Supplemental Plan will be paid out of general corporate funds. Deferred compensation is considered part of the salary covered by the Supplemental Plan.

The table below shows the estimated aggregate annual benefits payable (for the first 15 years of retirement) under the Supplemental Plan and the Midwest Power Retirement Plan. The amounts exclude Social Security and are based on a straight life annuity and retirement at age 65. Amounts shown are calculated on the basis of credited service. Federal law limits the amount of benefits payable to an individual through the Midwest Power Retirement Plan and benefits exceeding such limitation are payable under the Supplemental Plan.

Estimated Annual Benefit

Years of Service

Highest Annual Salary in Five Years Prior to Retirement	10	15	20	25 or More
$150,000	$ 90,000	$ 97,500	$105,000	$112,500
200,000	120,000	130,000	140,000	150,000
250,000	150,000	162,500	175,000	187,500
300,000	180,000	195,000	210,000	225,000
350,000	210,000	227,500	245,000	262,500
400,000	240,000	260,000	280,000	300,000
450,000	270,000	292,500	315,000	337,500
500,000	300,000	325,000	350,000	375,000

Mrs. Wharton is a participant in the Midwest Resources Inc. Supplemental Executive Retirement Plan ("Midwest Supplemental Plan"), a nonqualified plan for certain executives of the Company and its subsidiaries, as determined by the Board of Directors. The Midwest Supplemental Plan provides a participant, upon retirement at age 65 with thirty or more years of service, an annual retirement benefit equal to sixty percent of the participant's final average annual earnings which is defined as the average of salary plus bonus for the five highest consecutive years during the participant's employment with the Company. A participant who elects early retirement is entitled to reduced benefits under the plan. Payment of the retirement benefit will be made in the same manner as payments are elected by the participant under the Midwest Power Retirement Plan. This benefit will be reduced by the amount of the participant's regular retirement benefit. Benefits may be paid to surviving spouses depending on the payment method selected. Benefits to participants will be paid out of general corporate funds. Deferred compensation is considered part of the salary covered by the Midwest Supplemental Plan.

The table below shows the estimated aggregate benefits payable under the Midwest Supplemental Plan and the Midwest Power Retirement Plan. The amounts exclude Social Security and are based on normal retirement at age 65. Federal law limits the amount of benefits payable to an individual through the Midwest Power Retirement Plan and benefits exceeding such limitation are payable under the Midwest Supplemental Plan.

Estimated Annual Benefit

Years of Service

Highest Average Total Earnings	15	20	25	30 or More
$150,000	$ 67,500	$ 75,000	$ 82,500	$ 90,000
200,000	90,000	100,000	110,000	120,000
250,000	112,500	125,000	137,500	150,000
300,000	135,000	150,000	165,000	180,000
350,000	157,500	175,000	192,500	210,000
400,000	180,000	200,000	220,000	240,000
450,000	202,500	225,000	247,500	270,000
500,000	225,000	250,000	275,000	300,000

DIRECTORS' COMPENSATION

Directors each receive an annual fee of $8,000. No meeting fees are paid. In addition, Mr. Christiansen receives an annual amount of $7,000 from MWR as director fees for service on the MWR Board of Directors. Directors have the opportunity to make an election prior to the commencement of any year to defer a portion or all of their compensation received for service as a director pursuant to the Midwest Resources Inc. Board of Directors Deferred Compensation Plan. Amounts previously deferred under predecessor companies' defined compensation plans will be distributed in accordance with each such plan's respective provisions upon a director's termination of service as a director.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

MWR owns 100 percent of the 1,000 shares of MPS' common stock, without par value, which were outstanding on February 25, 1994.

The following table sets forth information concerning each class of MWR's and MPS' equity securities which were owned of record or beneficially held on February 25, 1994, by each of MPS' directors and nominees for election as directors, the chief executive officer and the four other most highly compensated executive officers and, as a group, by such persons and other executive officers. The number of shares owned by any director or nominee, or by all directors and executive officers of MPS as a group, did not exceed one percent of MWR shares outstanding on February 25, 1994.

Title of Class	Name of Director or Identity of Group	Amount and Nature of Beneficial Ownership (1)
Midwest Resources common stock, without par value	Russell E. Christiansen	11,761(2)
Midwest Resources common Stock, without par value	Richard C. Engle	8,288(3)
Midwest Resources common stock, without par value	Philip G. Lindner	1,266(4)
Midwest Resources common stock, without par value	Lynn K. Vorbrich	3,674(5)
Midwest Resources common stock, without par value	Beverly A. Wharton	3,248(6)
Midwest Resources common stock, without par value	13 directors and officers, as a group	61,888(7)

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(1) Beneficial ownership of each of the shares of Common Stock listed in the foregoing table is comprised of either sole voting power and sole investment power, unless otherwise noted.

(2) Includes 6,377 shares held in a defined contribution plan as of December 31, 1993, and 5,276 shares beneficially owned by Mr. Christiansen and his spouse.

(3) Includes 6,490 shares held in a defined contribution plan as of December 31, 1993, and 1,170 shares beneficially owned by Mr. Engle's spouse and 628 shares beneficially owned by Mr. Engle and his spouse.

(4) Includes 128 shares held in a defined contribution plan as of December 31, 1993, and 1,138 shares owned beneficially by Mr. Lindner and his spouse.

(5) Includes 1,465 shares held in a defined contribution plan as of December 31, 1993, and 242 shares beneficially owned by Mr. Vorbrich and his spouse.

(6) Includes 1,058 shares held in a defined contribution plan as of December 31, 1993, and 1,831 shares beneficially owned by Mrs. Wharton and her spouse and 359 shares beneficially owned in a custodial account for a minor child.

(7) Includes shares held in defined contribution plans as of December 31, 1993, and shares beneficially owned jointly with and individually by family members.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Reference is made to Part IV, Item 14, Note (15) of Notes to Consolidated Financial Statements for a summary of affiliated transactions.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a)1. **Financial Statements (included herein)**

(a)2. **Financial Statement Schedules (included herein)**

The following schedules should be read in conjunction with the aforementioned financial statements.

Other schedules are omitted because of the absence of conditions under which they are required or because the required information is given in the financial statements or notes thereto.

(a)3. **Exhibits**

See Exhibits Index on page 74.

(b) **Reports on Form 8-K**

None.

MIDWEST POWER SYSTEMS INC.
SELECTED CONSOLIDATED FINANCIAL DATA (1) and (2)

	1993	1992	1991	1990	1989
For the year ended December 31 (000)					
Operating revenues	$ 996,545	$ 923,180	$ 929,813	$ 876,943	$ 899,119
Operating income	132,397	112,971	137,646	135,814	141,174
Earnings on common stock (3)	83,503	46,944	72,082	75,072	82,474
As of December 31					
Total assets (000)	2,384,454	2,231,585	2,233,083	2,130,738	2,090,050
Capitalization ($ Millions-%)					
Common stock equity	$655-46%	$636-45%	$664-45%	$624-45%	$618-45%
Cumulative redeemable preferred stock	-	-	30-2%	30-2%	30-2%
Cumulative non-redeemable preferred stock	90- 6%	54-4%	54-4%	54-4%	54-4%
Long-term debt (excluding current maturities)	678-48%	727-51%	741-49%	666-49%	676-49%
Liability under power purchase contract (000)	$151,485	$146,150	$150,838	$159,293	$167,282

(1) In July 1992 Iowa Public Service Company and Iowa Power Inc. merged into and with Midwest Power Systems Inc. The data included in this statement is presented as if the companies were merged as of the earliest period shown and reflects the historical recorded amounts of the predecessor companies. Refer to Note (1)(a) of Notes to Consolidated Financial Statements.

(2) The Company exchanged its Minnesota gas properties for Minnegasco's South Dakota gas properties and cash during 1993. The Company sold certain other assets during 1989. The income from these transactions is reflected in earnings.

(3) Earnings per average common share and dividends on common stock per share are not applicable to MPS as a wholly-owned subsidiary.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion of the financial condition and results of operations of Midwest Power Systems Inc. (MPS or Company) is intended to provide readers of the financial statements included in this annual report with an understanding of material changes in the Company's financial condition and results of operations between the periods presented.

MPS is the principal subsidiary of Midwest Resources Inc. (MWR), a holding company formed in November 1990 through the merger of two utility holding companies. MPS maintains two operating divisions: Midwest Power and Midwest Gas.

The Company's results of operations are significantly influenced by weather conditions, general economic conditions in the Company's utility service territory and rate regulation. The Company is allowed current recovery from most of its customers for fuel and power purchased costs, including the fuel portion of Cooper Nuclear Station Power Purchased, through an energy adjustment clause and for gas purchased costs through a purchased gas adjustment clause. Thus, as the cost of fuel used to serve those customers fluctuates, revenues fluctuate accordingly, with no impact on earnings.

RESULTS OF OPERATIONS

Earnings:

Earnings on Common Stock (Earnings on Common) for 1993 was substantially improved compared to Earnings on Common for 1992. Earnings on Common for 1993 was $83.5 million compared to $46.9 million for 1992 and $72.1 million for 1991.

Two factors explain $34.5 million of the $36.6 million increase in Earnings on Common for 1993. Greatly improved weather conditions resulted in an increase of approximately $23 million compared to 1992, and an exchange of gas service territories produced an $11.5 million after-tax gain. Though still below normal, the 1993 weather resulted in greater use per customer than the unusually mild weather in 1992. On August 31, 1993, Midwest Gas and Minnegasco exchanged gas service territories. Minnegasco received the Midwest Gas Minnesota service territory, which serves over 79,000 customers, and Midwest Gas received the Minnegasco South Dakota service territory, which serves over 46,000 customers, and a $38 million cash payment.

A reduction in interest expense reflects the impact of the Company's debt refinancing activities and resulted in an improvement to Earnings on Common of $2.6 million. Also contributing to the increase in Earnings on Common compared to 1992 was a $1.5 million reduction of the 1992 Earnings on Common due to recognition of a loss on the sale of property. Continued realization of merger savings also helped to increase the 1993 earnings.

New federal income tax legislation which increased the rate by one percentage point retroactive to January 1, 1993, resulted in $1 million of additional income tax expense in the third quarter and income taxes recorded at the higher tax rate for the remainder of the year.

In July, the Company's utility service territory experienced record flooding. The flooding damaged five of the Company's substations and disrupted service at two others. Costs of restoring service lost during the flooding are reflected in the 1993 results. While revenues were reduced somewhat due to the flooding, the Company has not calculated a specific effect on revenues. Damage to the Company's utility

facilities totalled $5 million, most of which is expected to be covered by insurance. As a result there was not, and will not be, a significant impact on the Company's overall financial results.

Earnings on Common for 1992 decreased $25.2 million compared to Earnings on Common for 1991. The unusually mild weather during 1992 and warmer than normal weather in the summer of 1991 resulted in an $18.4 million reduction in Earnings on Common between the years. The loss recognition discussed above and an adjustment for previously deferred demand-side management costs accounted for $2.6 million of the decrease.

The following table provides a summary of the Earnings on Common contribution of each of the business segments discussed in the following pages.

Analysis of Earnings on Common	**1993**	**1992**	**1991**
		(In Millions)	
Midwest Power	$60.2	$39.9	$65.2
Midwest Gas	23.3	7.0	6.9
Earnings on Common	$83.5	$46.9	$72.1

Further details of the variations in Earnings on Common and changes in the line items on the Consolidated Statements of Income are discussed below.

Midwest Power Operations:

Weather conditions which were closer to normal in the Company's service territory accounted for nearly $20 million of the improvement in Earnings on Common for Midwest Power.

Revenues

Electric Revenue Increase (Decrease) from Prior Year	**1993**	**1992**
	(In Millions)	
Sales volumes	$ 36.8	$(27.2)
Rates	7.7	5.1
Cost per unit of energy	0.5	(2.7)
Sales for resale and other	(4.0)	10.9
Total revenue variance	$ 41.0	$(13.9)

Weather fluctuation in the Company's electric utility service territory was the primary cause of the variations in Electric Operating Revenues. As shown in the table above, improved sales volumes contributed $36.8 million to the $41.0 million increase in revenues for 1993 compared to 1992. Weather that was more favorable to the electric utility industry helped to increase use per customer. Temperatures, measured in cooling degree days, were 31.0 percent warmer than during the 1992 cooling season. Use per customer for residential customers, the highest margin customers, increased 8.4 percent, and total retail electric sales increased 7.3 percent in 1993. The unusually mild cooling season in 1992 and an above normal cooling season in 1991 resulted in a reduction of sales volumes in 1992 compared to 1991. Temperatures were 51.7 percent cooler in 1992 than those in the 1991 cooling season. As a result, sales to all retail customers decreased 3.3 percent due mostly to a decrease in sales to residential customers of 9.1 percent. The milder temperatures and some conservation due to demand-side management (DSM) programs resulted in a 9.9 percent decrease in the 1992 residential use per customer. As shown in the table, the decrease in retail sales volumes in 1992 reduced the Company's revenues by $27.2 million compared to 1991.

The impact of two rate cases settled during 1992 is reflected in the $7.7 million and the $5.1 million increases in revenues due to rate-related factors for 1993 and 1992, respectively.

An extended outage at Cooper Nuclear Station (Cooper) and increased retail sales volumes for the Company impacted the amount of energy available for sales for resale sales in 1993. (Cooper is a nuclear facility from which the Company purchases 50 percent of the energy output.) Sales for resale sales volumes in 1993 decreased 21.0 percent compared to 1992. Revenues from sales for resale sales decreased $8.5 million in 1993 compared to 1992 but remained above the 1991 amount. In 1992, sales for resale sales volumes increased 14.9 percent compared to 1991. The increase offset the 1992 decrease in retail sales and resulted in a 2.7 percent increase in total sales of electricity for 1992. The increase in sales for resale sales in 1992 was due to increased opportunities for sales for resale, increased availability of Company-generated energy due to lower retail sales and the impact of a bulk-power sales agreement effective in June 1991.

Expenses

Fuel for Generation increased $9.7 million, or 9.5 percent, in 1993 compared to 1992. Generation at Company-owned facilities increased 10.9 percent in order to meet the greater generation needs as a result of increased sales volumes. Fuel for Generation decreased 6.4 percent in 1992 due to a 5.8 percent decrease in the average fuel cost per kWh generated. Lower retail sales reduced the need for the Company's higher cost plants during 1992, which helped to decrease the overall cost of fuel.

Power Purchased decreased $4.2 million in 1993 but increased $11.0 million in 1992 due mostly to the use and replacement of a nuclear energy power reserve that is used during maintenance and refueling outages at Cooper.

Cooper Nuclear Station Power Purchased decreased 0.5 percent in 1993 because of a $6.4 million decrease in fuel costs and a $5.9 million increase in Cooper operations and maintenance costs. The decrease in fuel costs was due to the extended maintenance and refueling outage in 1993. In 1992, Cooper Nuclear Station Power Purchased increased $13.8 million, or 19.0 percent. This was due to an $11.4 million increase in operations and maintenance expenses and a $2.4 million increase in fuel costs. Since Cooper did not have a refueling outage in 1992, more fuel was used than in 1991. The fuel costs for Cooper are recovered in revenues through the energy adjustment clause.

Other Operating Expenses increased only 1.6 percent and 1.2 percent in 1993 and 1992, respectively, due in part to the impact of merger savings. In 1993, moderate increases in various general expenses contributed to the increase. A decrease in power production operating expenses helped to offset the increases in Other Operating Expenses. In 1992, the Company recorded a $1.1 million adjustment for DSM costs previously deferred. General increases in other operating expenses were partially offset by a decrease in costs related to the 1991 early retirement and severance plan.

A $3.8 million increase in Maintenance expenses for 1993 compared to 1992 was mostly attributable to the timing of generating plant maintenance and general plant maintenance. Maintenance expenses in 1992 increased $2.4 million due to an increase in overhead distribution and transmission costs, including tree trimming expenses.

Depreciation and Amortization increases were due to an increase in depreciable plant. General Taxes decreased $3.7 million in 1993 and increased $0.5 million in 1992 due mostly to the change in property assessment values.

Other, Net, for electric operations increased in 1993 due to the $2.5 million recognition of a loss on the sale of property in 1992, which also decreased Other, Net, compared to 1991. Allowance for funds used during construction (AFUDC) decreased $1.1 million for 1993 compared to 1992, due primarily to a reduced rate.

Midwest Gas Operations:

The $11.5 million after-tax gain resulting from the gas service territory exchange was the primary cause of the significant increase in Earnings on Common for the gas operations compared to 1992. The $11.5 million gain reflects the impact of settlement adjustments at year-end.

As a result of the exchange, 1993 results of operations were impacted by the change in number of customers, rates, expenses and other factors. The discussion of the various components of results of operations includes the impacts of the exchange. The reduced property and customer base will impact the Company's future results of operations through lower gas revenues and decreases in certain expenses. Revenues for the year 1992 were approximately $33 million and $56 million for the South Dakota and Minnesota service territories, respectively.

Revenues

Gas Revenue Increase (Decrease) from Prior Year	**1993**	**1992**
	(In Millions)	
Sales volumes	$ 17.4	$(12.2)
Rates	0.3	8.3
Cost per unit of gas purchased	6.4	12.4
Transportation and other	8.2	(1.0)
Total revenue variance	$ 32.3	$ 7.5

Unusually mild weather during the 1992 heating season had a major influence on the fluctuation in revenues between the years 1993, 1992 and 1991. Gas Operating Revenues in 1993 were $32.3 million greater than those reported in 1992. Temperatures, especially during the first quarter of 1993, were much more favorable to the gas operations. Measured in heating degree days, temperatures in 1993 were 13.7 percent colder than the unusually mild temperatures in 1992. Of the $17.4 million sales volumes increase reflected in the table, $20.7 million was due to a higher use per customer mostly as a result of the substantial increase in heating degree days. A decrease in customers partially offset the use per customer increase. Total retail sales of natural gas increased 5.9 percent compared to 1992. The mild temperatures in 1992 were 4.3 percent warmer than during 1991. As a result, use per customer remained below the 1991 levels and decreased revenues by $17.6 million. A growth in customers helped to offset that decrease and resulted in the $12.2 million net decrease due to sales volumes reflected in the table. Total retail sales of natural gas in 1992 decreased 5.4 percent compared to 1991.

An increase in the cost per unit of gas purchased resulted in $6.4 million and $12.4 million increases in revenues for 1993 and 1992, respectively, through the purchased gas adjustment clause. This component has no impact on Earnings on Common because it is offset by a corresponding cost per unit increase in Gas Purchased for Resale. An increase in overall rates due in part to interim and final rate increases in two gas rate cases yielded an $8.3 million increase in revenues in 1992 compared to 1991.

Expenses

Gas Purchased for Resale increased $23.6 million for 1993 compared to 1992 and $3.8 million for 1992 compared to 1991. The increase in the cost per unit of gas contributed to the increases for 1993 and 1992. The increase in natural gas sales volumes resulted in a further increase in 1993 Gas Purchased for Resale while the depressed 1992 sales volumes partially offset the increase due to the cost per unit of gas in 1992.

Other Operating Expenses increased $1.2 million and $4.0 million in 1993 and 1992, respectively. The most significant factor impacting Other Operating Expenses was the cost of manufactured gas plant (MGP) site remediation (refer to the "Environmental" section of Management's Discussion and Analysis). MGP site remediation expenses decreased $2.3 million in 1993 and increased $3.9 million in 1992. A majority of the fluctuation was due to the write-off of previously deferred MGP site remediation costs in 1992. The decrease in MGP site remediation costs in 1993 was offset by increases in expenses for gas distribution, customer accounts, and rent. Other factors contributing to the 1992 variation were increases in health insurance and pension expenses and a $0.7 million adjustment for DSM costs previously deferred. Partially offsetting the increases in 1992 were decreases in various other expenses, in part due to merger savings.

Maintenance expenses decreased $0.9 million and $0.3 million in 1993 and 1992, respectively, due primarily to decreases in gas distribution expense and, in 1992, an increase in new construction.

Other, Net, on the Consolidated Statements of Income includes the $18.5 million pretax gain related to the exchange of gas service territories, and Non-operating Income Taxes reflects the related income taxes. For 1992 Other, Net, reflects a $1.4 million recovery of MGP site remediation costs through a settlement with a third party during 1992.

LIQUIDITY AND CAPITAL RESOURCES

The Company has available to it a variety of sources of liquidity and capital resources, both internal and external. These resources provide funds required for current operations, debt retirement, dividends, construction expenditures and other capital requirements.

Material sources of liquidity at December 31, 1993, included current assets of $243 million and bank lines of credit of $167 million. The Company has authority from the Federal Energy Regulatory Commission (FERC) to issue before July 1995 short-term debt in the form of commercial paper and bank notes amounting to $250 million.

Consolidated cash capital expenditures, including Cooper capital improvements but excluding allowance for funds used during construction, were $164.0 million for 1993. Of the total, $141.6 million were for electric operations, $22.0 million were for gas operations and $0.4 million were for other. The Company's management annually reviews long-range capital expenditure needs. Based upon such a review, the Company has planned cash capital expenditures of $164 million for 1994. The Company expects that $137 million of the 1994 planned expenditures will be for electric operations and $27 million will be for gas operations. Planned cash capital expenditures for the years 1995 through 1998 are $744 million. The repowering project discussed below is not included in the planned cash capital expenditures. In addition, approximately $81 million is projected for long-term debt maturities and sinking fund requirements for the years 1994 through 1998.

The Company anticipates approximately 70 percent of capital requirements for 1994 through 1998 will be met with internal sources of capital. In 1994 the Company plans to issue long-term debt to meet a portion of the capital requirement needs and to replace short-term debt.

In a continuing effort to reduce costs and to take advantage of lower interest rates, the Company modified its capital structure during 1993. The most significant change was the refinancing and redemption of its long-term debt issued by its predecessor companies, Iowa Public Service Company (IPS) and Iowa Power Inc. (IPR). By refinancing a majority of its long-term debt, the Company was able to restructure the timing of its debt maturities and reduce the overall cost of debt. As of December 31, 1993, $629 million of the long-term debt issued by IPS and IPR had been replaced by new long-term debt. In addition, the Company used the cash proceeds from the gas service territory exchange to redeem $35.5 million of IPS and IPR first mortgage bonds. In November 1993 the Company issued $60 million of $1.7375 Series preferred stock to replace $13 million of first mortgage bonds and $23 million of higher cost preferred stock, as well as reduce short-term debt balances and provide for other general corporate purposes. The restructuring reduced the cost of debt by over $3 million in 1993 and extended the average life of long-term debt from 10.7 to 16.6 years. The new debt was issued under a single, modernized indenture which allows more flexibility for the Company's capital resources. As a result of the restructuring activities, the IPR indenture has been eliminated and one bond series for $11 million remains outstanding subject to the IPS indenture. The Company has all regulatory approval necessary to issue an additional $118 million of long-term debt and an additional $15 million of preferred stock.

As of December 31, 1993, the Company had approximately $1.055 billion of unbonded bondable property and $190 million of retired prior lien bonds, the combination of which entitles it to issue approximately $981 million of mortgage bonds under the MPS indenture.

The Company's access to external capital and its cost of capital are influenced by the credit ratings of its securities. The Company's credit ratings as of the end of January 1994 are shown in the table below. The ratings reflect only the views of such rating agencies, and each rating should be evaluated independently of any other rating. Generally, rating agencies base their ratings on information furnished to them by the issuing company and on investigation, studies and assumptions by the rating agencies. There is no assurance that any particular rating will continue for any given period of time or that it will not be changed or withdrawn entirely if in the judgment of the rating agency circumstances so warrant. Such ratings are not a recommendation to buy, sell or hold securities.

	Moody's Investors Service	Standard & Poor's
Mortgage Bonds	A2	A+
Preferred Stocks	a3	A
Commercial Paper	P-1	A1

The following is a summary of the meanings of the ratings shown above and the relative rank of the Company's rating within each agency's classification system.

Moody's top four mortgage bond ratings (Aaa, Aa, A and Baa) are generally considered "investment grade." Obligations which are rated "A" possess many favorable investment attributes and are considered as upper medium grade obligations. Factors giving security to principal and interest are considered adequate but elements may be present which suggest a susceptibility to impairment sometime in the future. A numerical modifier ranks the security within the category with a "1" indicating the high end, a "2" indicating the midrange and a "3" indicating the low end of the category. Standard & Poor's top four mortgage bond ratings (AAA, AA, A and BBB) are considered "investment grade". Debt rated "A" has a strong capacity to pay interest and repay principal although it is somewhat more susceptible to the adverse effects of changes in economic conditions than debt in higher rated categories. A plus (+) or

minus (-) sign may be used after Standard & Poor's ratings to designate the relative position of a credit within the rating category.

Ratings of preferred stocks are an indication of a company's ability to pay the preferred dividend and any sinking fund obligations on a timely basis. Moody's top four preferred stock ratings (aaa, aa, a and baa) are generally considered "investment grade". Moody's "a" rating is considered to be an upper medium grade preferred stock. Earnings and asset protection are expected to be maintained at adequate levels in the foreseeable future. Standard & Poor's top four preferred stock ratings (AAA, AA, A and BBB) are considered "investment grade". Standard & Poor's "A" rating indicates adequate earnings and asset protection.

Moody's top three commercial paper ratings (P-1, P-2 and P-3) are generally considered "investment grade". Issuers rated "P-1" have a superior ability for repayment of senior short-term debt obligations and repayment ability is often evidenced by a conservative structure, broad margins in earnings coverage of fixed financial charges and well established access to a range of financial markets and assured sources of alternate liquidity. Standard & Poor's commercial paper ratings are a current assessment of the likelihood of timely payment of debt having an original maturity less than 365 days. The top three Standard & Poor's commercial paper ratings (A1, A2 and A3) are considered "investment grade". Issues rated "A1" indicate that the degree of safety regarding timely payment is either overwhelming or very strong. Those issues determined to possess overwhelming safety are denoted with a plus (+) sign designation.

REGULATORY ENVIRONMENT

Legislation enacted in Iowa in 1990 requires electric and gas utilities to spend 2 percent and 1.5 percent, respectively, of their annual Iowa jurisdictional revenues on demand-side management (DSM) activities. The Company has filed a $22.7 million request with the Iowa Utilities Board (IUB) for the recovery of some of the costs incurred during the period July 1990 to December 1992, as well as lost revenues and other related components. Hearings in the case began in late January 1994. Once a final order is issued, the allowed recovery would occur over a four-year period. The filing includes $13.5 million of the deferred DSM costs, including carrying costs, on the Company's Consolidated Balance Sheet as of December 31, 1993. The Company will make periodic filings, as early as this year, for other DSM costs incurred and for future activities.

Other than the DSM filing, the Company currently has no rate case proceedings in progress. Electric services are being provided to customers in Iowa under the separate tariffs of IPS and IPR. The Company is working on the merging of electric tariffs and expects to file a future request with the IUB to establish one electric tariff for MPS in Iowa. In the rate filing, the Company will seek recovery of postretirement health care and life insurance costs on an accrual basis, which the IUB has ruled that it would permit if the Company externally funds these costs. On January 1, 1993, the Company adopted FAS 106, which is the accounting standard requiring accrual basis recognition of such postretirement benefit costs. The adoption of FAS 106 currently has a minimal impact on the Company's Earnings on Common since the Company is deferring most of the costs above the "pay-as-you-go" amount until recovery on an accrual basis is established in a rate proceeding. Refer to Note (14) for further discussion of the impact of FAS 106 on the Company.

The FERC issued orders, collectively Order 636, which have significantly changed the operations and regulatory requirements for interstate pipeline companies. These changes directly impact local distribution companies (LDCs), including Midwest Gas, by requiring LDCs to assume responsibility for the procurement, transportation and storage of natural gas. In preparation for the increased supply responsibilities under Order 636, the Company increased its natural gas inventory to ensure an adequate supply of natural gas to meet customer needs. On November 1, 1993, Order 636 became effective for two

of the interstate pipelines serving the Company, including its major supplier. Pipeline transition costs resulting from the implementation of Order 636 will be paid to pipelines over the next five years. The Company's Consolidated Balance Sheet as of December 31, 1993, includes a $42 million liability and regulatory asset recorded for the directly billed portion of its transition costs. Although the additional transition costs to be collected through pipeline demand and commodity rates have not been determined, they are not expected to exceed $32 million. Order 636 also mandates a change in the pipeline rate design. The mandated change will increase fixed charges paid to pipelines by Midwest Gas and would amount to a permanent increase in retail rates of approximately one percent. The Company anticipates that under current regulatory conditions it will recover costs related to Order 636 through the purchased gas adjustment clause. Midwest Gas will have other opportunities to reduce the cost of gas from: (1) pipeline cost of service reductions, (2) pipeline merchant service reductions, and (3) market-based cost of gas. These reductions are expected to offset a major portion of the gas cost increases. The Company continues to update assessments of the impacts of Order 636 as information becomes available. The actual impacts will depend to some degree on the outcome of the pipelines' experience from operating under new rules.

In 1992, the National Energy Policy Act (NEPA) was signed into law. This law promotes competition in the wholesale electric power market. The FERC has throughout 1993 taken action to establish rules and policies in compliance with provisions of the NEPA. The Company has been active in providing recommendations to the FERC in an effort to shape new transmission policies in ways that will best serve the interest of its customers and shareholders. The increasingly competitive environment brings with it an increase in risk and, according to rating agencies, possible changes in the utility securities markets. In 1993 the Company completed an analysis of the NEPA and, based on factors such as generating costs, concluded that it is in a good position to react to the increased competition and to take advantage of opportunities now available. However, until the Company has operated in the new environment for some time, the nature and extent of its impact on the Company cannot be determined.

The Nuclear Regulatory Commission (NRC) placed Cooper on its "Declining Trend Plant" list in late January, 1994. This action by the NRC is intended to identify plants with a declining safety performance record so that licensees may take appropriate remedial action on a timely basis to avoid a further decline. Nebraska Public Power District (NPPD) has developed a plan to address the NRC's concerns and is currently implementing the plan. The Company has increased its oversight functions at Cooper accordingly. Although the costs of implementing the NPPD plan has not been determined, the Company does not expect its share of such costs will have a material adverse impact upon the financial position or results of operations of the Company. The costs to be incurred by NPPD to remove Cooper from the "Declining Trend Plant" list may change as NPPD implements the plan and receives NRC comments on these actions over the upcoming year.

GENERATING CAPACITY

The Company has an agreement with the Department of Energy for a repowering project of the Company's Des Moines Energy Center to demonstrate a developing coal-burning technology believed to be substantially cleaner and more efficient than technologies now in use. As a result of the need for further component testing by the technology supplier, the Company and other involved parties have agreed to an extension for the repowering project.

The Company's current forecast of capacity requirements indicates that it will have capacity deficiencies for the remainder of the 1990s. These deficiencies are expected to be met by additional new non-base load facilities, opportune purchases of capacity or facilities or a combination thereof. The MWR Board of Directors approved a short-term capacity purchase and the construction of a combustion turbine at one of the Company's generating sites. The Company is in the process of obtaining the necessary

approvals to construct an 80-megawatt combustion turbine generator near Des Moines and plans to have it operational by June 1, 1994. Costs of constructing the generator are included in 1993 and planned 1994 capital expenditures. Any potential capacity option will be evaluated based on its cost and potential for minimizing the Company's long-term power supply costs.

The Company's current fuel mix for installed capacity is 66 percent coal, 20 percent oil and gas and 14 percent nuclear.

ENVIRONMENTAL

The Company is currently involved in a number of environmental issues including manufactured gas plant site remediation, polychlorinated biphenyls and provisions of the Clean Air Act Amendments of 1990. Please refer to Note (2)(b) for a discussion of the handling of these environmental issues.

SUPPLY CONTRACTS

The Company maintains contracts for delivery of capacity from each of the three pipelines serving its natural gas distribution system. The majority of the long-term contracts with natural gas pipelines have been renegotiated for three- to five-year terms. The Company has secured adequate supplies of natural gas for the 1993/1994 heating season. The Company estimates that its peak day requirements will be met with the following: 1) contracted third-party direct purchases, 2) stored gas, and 3) peak shaving facilities which are maintained to assure a reliable supply of gas during peak periods. In addition, the Company will displace a portion of these supplies with spot gas purchases if it is cost-effective to the customer. The above supply arrangements are expected to be viable options for meeting gas requirements for future extended periods.

The Company also maintains coal contracts requiring the purchase of three million tons per year. The contracts expire between 1994 and 2003. The Company estimates 50 percent of its coal requirements for 1994 will be met by coal purchased under these contracts and the remainder by coal purchased on the spot market.

MIDWEST POWER SYSTEMS INC.
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31		
	1993	1992	1991
		(In Thousands)	
OPERATING REVENUES			
Electric	$664,377	$623,360	$637,222
Gas	332,168	299,820	292,291
Other	-	-	300
Total	996,545	923,180	929,813
OPERATING EXPENSES			
Fuel for generation	111,138	101,468	108,400
Power purchased	32,268	36,434	25,466
Cooper Nuclear Station power purchased	85,987	86,455	72,659
Gas purchased for resale	224,337	200,780	196,979
Other operating expenses	159,812	156,901	151,678
Maintenance	57,077	54,233	52,140
Depreciation and amortization	89,805	86,190	82,475
General taxes	59,837	63,652	62,199
Current income taxes	36,890	19,894	35,873
Deferred income taxes	10,751	8,019	8,142
Investment tax credit	(3,754)	(3,817)	(3,844)
Total	864,148	810,209	792,167
OPERATING INCOME	132,397	112,971	137,646
OTHER INCOME			
Allowance for equity funds	-	1,213	124
Interest and dividend income	1,511	772	877
Non-operating income taxes	(7,868)	35	(176)
Other, net	18,921	(1,729)	(405)
Total	12,564	291	420
INCOME BEFORE FIXED CHARGES	144,961	113,262	138,066
FIXED CHARGES			
Interest on long-term debt	56,171	61,440	55,520
Other interest charges	3,122	2,230	8,002
Allowance for borrowed funds	(1,207)	(1,058)	(2,899)
Total	58,086	62,612	60,623
NET INCOME	86,875	50,650	77,443
Preferred stock dividends	3,372	3,706	5,361
EARNINGS ON COMMON STOCK	$ 83,503	$ 46,944	$ 72,082

The accompanying notes are an integral part of these statements.

MIDWEST POWER SYSTEMS INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31		
	1993	1992	1991
	(In Thousands)		
NET CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 86,875	$ 50,650	$ 77,443
Adjustments to reconcile net income to net cash provided:			
Depreciation and amortization	89,805	86,190	82,475
Amortization of advances for nuclear fuel and capital improvements	11,412	11,971	9,599
Net increase (decrease) in deferred income taxes and investment tax credit	(401)	2,939	2,955
Allowance for equity funds	-	(1,213)	(124)
Non-cash change in deferred assets	(3,197)	13,066	3,297
Gain on sale of assets	(18,485)	-	-
Amortization of unbilled revenues	-	-	(1,657)
Cash flows resulting from changes in working capital, net of effects from exchange of assets	24,254	574	15,592
Other	(5,855)	4,590	(9,025)
Net cash provided	184,408	168,767	180,555
NET CASH FLOWS FROM INVESTING ACTIVITIES			
Utility plant capital expenditures	(144,584)	(103,791)	(101,212)
Cooper Nuclear Station capital improvement advances	(3,540)	(10,855)	(14,297)
Other capital expenditures	(387)	(197)	292
Deferred demand side management expenditures	(16,671)	(7,934)	(7,476)
Allowance for equity funds	-	1,213	124
Proceeds from sale of assets	38,000	-	4,000
Net cash from investments	2,200	2,098	12
Net cash used	(124,982)	(119,466)	(118,557)
NET CASH FLOWS FROM FINANCING ACTIVITIES			
Dividends paid on common stock	(63,551)	(73,944)	(78,200)
Long-term debt proceeds, net of issuance cost	623,080	-	125,000
Retirement of long-term debt, net of reacquisition cost	(720,729)	(1,940)	(57,202)
Dividends paid on preferred stock	(3,372)	(3,706)	(5,361)
Reacquisition of preferred stock, net of reacquisition cost	(23,256)	(31,583)	(4)
Issuance of preferred stock, net of issuance expense	58,262	-	-
Contribution from parent	-	-	56,795
Net increase (decrease) in notes payable	71,700	58,100	(101,900)
Net cash used	(57,866)	(53,073)	(60,872)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	1,560	(3,772)	1,126
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	4,217	7,989	6,863
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 5,777	$ 4,217	$ 7,989

The accompanying notes are an integral part of these statements.

MIDWEST POWER SYSTEMS INC.
CONSOLIDATED BALANCE SHEETS

ASSETS

	As of December 31	
	1993	1992
	(In Thousands)	
UTILITY PLANT		
Electric	$2,293,770	$2,183,094
Gas	352,009	354,671
Plant acquisition adjustment	21,361	19,456
Gross plant, including construction work in progress of $87,736 and $33,416, respectively	2,667,140	2,557,221
Less accumulated depreciation and amortization	1,056,251	978,442
Utility plant, net	1,610,889	1,578,779
OTHER PROPERTY AND INVESTMENTS		
Property, net of accumulated depreciation and amortization	2,497	2,170
Investments	26,950	28,914
Total	29,447	31,084
POWER PURCHASE CONTRACT		
Productive capacity	151,485	146,150
Advances for capital improvements, net of accumulated amortization of $83,651 and $72,239, respectively	97,158	96,996
Total	248,643	243,146
CURRENT ASSETS		
Cash and cash equivalents	5,777	4,217
Receivables, less reserves of $875 and $1,151, respectively	128,090	133,414
Receivables from affiliated companies	37,579	37,654
Electric production fuel, at average cost	19,831	25,149
Natural gas and propane in storage, at average cost	28,466	18,367
Materials and supplies, at average cost	15,393	13,663
Prepayments and other	7,585	8,256
Total	242,721	240,720
DEFERRED CHARGES AND OTHER	252,754	137,856
TOTAL ASSETS	$2,384,454	$2,231,585

The accompanying notes are an integral part of these statements.

MIDWEST POWER SYSTEMS INC.
CONSOLIDATED BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

	As of December 31	
	1993	1992
	(In Thousands)	
CAPITALIZATION		
Common stock equity	$ 655,152	$ 635,823
Cumulative nonredeemable preferred stock	90,042	54,413
Long-term debt (excluding current maturities)	677,506	726,611
Total	1,422,700	1,416,847
POWER PURCHASE CONTRACT	140,655	138,085
CURRENT LIABILITIES		
Notes payable	129,800	58,100
Current portion of long-term debt	1,506	14,219
Current portion of power purchase contract	10,830	8,065
Accounts payable	75,678	69,171
Accounts payable to affiliated companies	2,696	5,125
Interest accrued	18,585	16,475
Taxes accrued	82,560	65,667
Other	21,002	19,388
Total	342,657	256,210
RESERVES, CREDITS AND OTHER LIABILITIES		
Deferred income taxes	331,568	314,541
Investment tax credit	65,374	70,283
Other	81,500	35,619
Total	478,442	420,443
TOTAL CAPITALIZATION AND LIABILITIES	$2,384,454	$2,231,585

The accompanying notes are an integral part of these statements.

MIDWEST POWER SYSTEMS INC.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

	As of December 31			
	1993		1992	
	(In Thousands)			
COMMON STOCK EQUITY				
Common stock, no par; 100,000,000 shares authorized;				
1,000 shares outstanding	$ 462,150		$ 462,274	
Retained earnings	193,002		173,549	
Total	655,152	46.1%	635,823	44.9%
PREFERRED STOCK; without par value; 10,000,000 shares authorized:				
Cumulative nonredeemable -				
$3.30 Series, 49,632 and 49,643 shares, respectively	4,963		4,964	
$3.75 Series, 38,320 shares	3,832		3,832	
$3.90 Series, 32,636 shares	3,263		3,263	
$4.20 Series, 47,369 shares	4,737		4,737	
$4.35 Series, 49,950 shares	4,995		4,995	
$4.40 Series, 50,000 shares	5,000		5,000	
$4.80 Series, 49,898 shares	4,990		4,990	
$1.7375 Series, 2,400,000 and zero shares, respectively	58,262		-	
$7.64 Series, zero and 66,135 shares, respectively	-		6,614	
$8.08 Series, zero and 48,786 shares, respectively	-		4,879	
$8.32 Series, zero and 71,525 shares, respectively	-		7,045	
$8.52 Series, zero and 40,944 shares, respectively	-		4,094	
Total	90,042	6.3%	54,413	3.8%
LONG-TERM DEBT				
Mortgage bonds:				
6 1/4% Series, due 1998	75,000		-	
6 3/4% Series, due 2000	75,000		-	
7 1/8% Series, due 2003	100,000		-	
7% Series, due 2003	100,000		-	
7 3/8% Series due, 2008	75,000		-	
8% Series due, 2022	50,000		-	
8 1/8% Series due, 2023	100,000		-	
8 1/4% Series, due 1996	-		80,000	
8 1/4% Series, due 1996	-		50,000	
8 3/8% Series, due 1997	-		50,000	
6 5/8% Series, due 1998	-		13,125	
9% Series, due 2000	-		25,000	
9% Series, due 2000	-		12,900	
7 5/8% Series, due 2001	-		13,350	
8% Series, due 2001	-		15,000	
7 3/8% Series, due 2002	-		17,000	
8.15% Series, due 2003	-		75,000	
8 2/10% Series, due 2003	-		50,000	
8 3/4% Series, due 2006	-		29,203	
9% Series, due 2006	-		25,000	
8% Series, due 2007	-		25,000	
8 1/4% Series, due 2007	-		29,400	
8 3/4% Series, due 2008	-		25,000	
10 1/2% Series, due 2018	-		70,000	

The accompanying notes are an integral part of these statements.

MIDWEST POWER SYSTEMS INC.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

	As of December 31			
	1993		1992	
	(In Thousands)			
LONG-TERM DEBT (CONTINUED)				
Pollution control revenue bonds:				
5.15% to 5.75% Series, due periodically through 2003	$ 8,276		$ 14,860	
4 4/10% Series, due 2013 (secured by first mortgage bonds)	11,000		11,000	
Louisa County, Iowa, floating 30-day municipal bond rate, due 2015	23,900		23,900	
5.95% Series, due 2023 (secured by general mortgage bonds)	29,030		-	
Floating weekly pollution control revenue bond rate, due 2023 (secured by general mortgage bonds)	28,295		-	
6 1/4% Series, due 1997 through 2006 (secured by first mortgage bonds)	-		18,000	
5 9/10% Series, due 1997 through 2007 (secured by first mortgage bonds)	-		18,000	
9 3/4% Series, due 1999 (secured by first mortgage bonds)	-		6,400	
6 1/2% Series, due 2003 (secured by first mortgage bonds)	-		9,900	
Notes:				
9% to 15% Series, due annually through 1996	44		79	
8 3/4% Series, due 2002	240		240	
6 4/10% Series, due 2003 through 2007	2,000		2,000	
9 1/2% Series, due annually through 2009	-		944	
9 7/8% Series, due monthly through 2011	-		13,480	
Obligation under capital lease	3,512		4,720	
Unamortized bond discount	(3,791)		(1,890)	
Total	677,506	47.6%	726,611	51.3%
TOTAL	$1,422,700	100.0%	$1,416,847	100.0%

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

	Year Ended December 31		
	1993	1992	1991
		(In Thousands)	
BEGINNING OF YEAR	$173,549	$201,408	$207,526
Earnings on common stock	83,503	46,944	72,082
Dividends on common stock	63,551	73,944	78,200
Loss on reacquisition of preferred stock	499	859	-
END OF YEAR	$193,002	$173,549	$201,408

The accompanying notes are an integral part of these statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

(a) Basis of Consolidation:

Midwest Power Systems Inc. (Company or MPS) is a wholly owned public utility subsidiary of Midwest Resources Inc. (MWR). The consolidated financial statements include the accounts of MPS and its wholly owned subsidiary, CBEC Railway Inc. MPS provides electric and gas utility services through its two operating divisions: Midwest Power and Midwest Gas. All significant intercompany transactions have been eliminated from the consolidated financial statements.

On July 22, 1992, Iowa Power Inc. (IPR) and Iowa Public Service Company (IPS), also wholly owned subsidiaries of MWR, merged with and into MPS. The Company accounted for the merger under a method which combines the assets, liabilities and ownership interest at their existing recorded amounts.

(b) Rate Regulation:

The Company's utility operations are subject to rate regulation by the Iowa Utilities Board (IUB), the South Dakota Public Utilities Commission and the Federal Energy Regulatory Commission (FERC). The financial statements of the Company are based on generally accepted accounting principles, which give recognition to the ratemaking and accounting practices of these agencies.

(c) Regulatory Assets:

MPS is subject to the provisions of Statement of Financial Accounting Standards 71 "Accounting for the Effects of Certain Types of Regulation." Regulatory assets represent probable future revenue to MPS associated with certain incurred costs as these costs are recovered through the ratemaking process. The following regulatory assets were reflected in the Consolidated Balance Sheets as of December 31 (in thousands):

	1993	1992
Deferred income taxes	$ 78,368	$ 63,166
FERC Order 636 transition costs	41,918	-
Debt refinancing costs	39,224	7,649
Energy efficiency costs	36,601	17,690
Environmental costs	15,502	14,001
Plant costs	12,805	15,240
Postretirement benefit costs	9,126	-
Nuclear plant outage costs	8,237	203
Other	10,733	12,056
Total	$252,514	$130,005

The Company uses an asset and liability approach for financial accounting and reporting for income taxes. Because of rate regulation, regulatory assets are also recorded. For additional information regarding deferred income taxes, FERC Order 636 transition costs, environmental costs and postretirement benefit costs see notes 13, 2(d), 2(b) and 14, respectively.

(d) **Revenue Recognition**

Revenues are recorded based on service rendered to the end of the month. Accrued unbilled revenues are $45,833,000 and $45,948,000 at December 31, 1993 and 1992, respectively, and are included in Receivables on the Consolidated Balance Sheets.

The majority of the Company's electric and gas revenues are subject to adjustment clauses. These clauses allow the Company to adjust the amounts charged for electric and gas service as the costs of gas purchases, fuel for generation or purchased power change. The costs recovered in revenues through use of the adjustment clauses are charged to expense in the same period.

(e) Depreciation and Amortization:

The Company's provisions for depreciation are based on straight-line composite rates. The average depreciation rates for the years ended December 31 were as follows:

	1993	1992	1991
Midwest Power	3.6%	3.6%	3.6%
Midwest Gas	3.8%	3.9%	3.9%

Utility plant is stated at original cost which includes overheads, administrative costs and an allowance for funds used during construction.

The cost of repairs and minor replacements is charged to maintenance expense. Property additions and major property replacements are charged to plant accounts. The cost of depreciable units of utility plant retired or disposed of in the normal course of business is eliminated from the utility plant accounts and such cost, plus net removal cost, is charged to accumulated depreciation.

(f) Consolidated Statements of Cash Flows:

The Company considers all cash and highly liquid debt instruments purchased with a remaining maturity of three months or less to be cash and cash equivalents for purposes of the Consolidated Statements of Cash Flows.

Cash paid for interest and income taxes for the years ended December 31 was as follows (in thousands):

	1993	1992	1991
Interest paid, net of amounts capitalized	$ 52,834	$ 60,711	$ 59,259
Income taxes paid	$ 32,629	$ 29,105	$ 31,858

Net cash provided (used) from changes in working capital amounts was as follows (in thousands):

	1993	1992	1991
Receivables	$ 5,324	$ (9,831)	$ (4,863)
Receivables from affiliated	75	18,465	12,126
Inventories	(6,511)	(6,248)	(160)
Prepayments and other current assets	671	(832)	(1,932)
Accounts payable	6,507	(8,129)	3,956
Accounts payable affiliates	(2,429)	2,451	1,642
Interest accrued	2,110	(40)	(611)
Taxes accrued	16,893	(3,625)	8,846
Other current liabilities	1,614	8,363	(3,412)
Total	$ 24,254	$ 574	$ 15,592

The Company entered into the following non-cash transactions: a 1993 exchange of MPS' Minnesota gas properties for Minnegasco's South Dakota gas properties recorded by the Company at $31,713,000, and $38,000,000 cash; and recognized liabilities of $55,318,000 and recorded the related regulatory and other assets.

(g) Accounting for Long-Term Power Purchase Contract:

Under a long-term power purchase contract with Nebraska Public Power District (NPPD), expiring in 2004, the Company purchases one-half of the output of the 778-megawatt Cooper Nuclear Station (Cooper). The Consolidated Balance Sheets include a liability for the Company's fixed obligation to pay 50 percent of NPPD's Nuclear Facility Revenue Bonds and other fixed liabilities. A like amount representing the Company's right to purchase power is shown as an asset.

The debt amortization component of the Company's payments to NPPD was $9,861,000, $5,854,000 and $8,455,000 and the net interest component was $5,678,000, $7,391,000 and $6,600,000 each for the years 1993, 1992 and 1991, respectively. Minimum payments of the power purchase contract obligation are $10,830,000, $12,180,000, $13,041,000, $13,652,000 and $14,313,000 for 1994, 1995, 1996, 1997 and 1998, :spectively.

Capital improvement costs for new property, including carrying costs, are being deferred, amortized and recovered in rates over the term of the NPPD contract. Capital improvement costs for property replacements, including carrying costs, are being deferred, amortized and recovered in rates over a five year period.

All costs the Company incurs in relation to its long-term power purchase contract with NPPD are included in Cooper Nuclear Station Power Purchased on the Consolidated Statements of Income.

(2) COMMITMENTS AND CONTINGENCIES:

(a) Long-Term Power Purchase Contract:

Payments to NPPD cover one-half of the fixed and operating costs of Cooper (excluding depreciation but including debt service) and the Company's share of nuclear fuel cost (including nuclear

fuel disposal) based on energy delivered. The debt service portion on a monthly basis is approximately $1.4 million for 1994 and is not contingent upon the plant being in service.

NPPD has filed a decommissioning plan with the Nuclear Regulatory Commission (NRC) and established an external trust for nuclear decommissioning funds. NPPD believes that the funding amount required by regulation understates the expected cost to decommission Cooper. Based on a site-specific study that includes decontamination, dismantling and site restoration costs, the Company's share of expected Cooper decommissioning costs is $158.3 million, in 1988 dollars. This site-specific estimate is being used as the basis for decommissioning funding. For purposes of developing a decommissioning funding plan, NPPD assumes decommissioning costs will escalate at an annual rate of six percent. Based on this assumption, the Company's share of expected decommissioning costs is $218.2 million in 1993 dollars. The funding plan assumes decommissioning will start in 2004, the currently anticipated plant shutdown date. During 1993, the Company contributed $8.9 million toward funding Cooper decommissioning. The decommissioning costs are being recognized over the expected service life of the plant and are included in the Company's service rates. As of December 31, 1993, the Company's share of funds set aside by NPPD in internal and external accounts for decommissioning was $27.3 million. In addition, the funding plan also assumes various funds and reserves currently held to satisfy NPPD Bond Resolution requirements will be available for plant decommissioning costs after the bonds are retired in early 2004.

The Company maintains financial protection against catastrophic loss associated with this obligation through a combination of insurance purchased by NPPD, insurance purchased directly by the Company, and the mandatory industry-wide loss funding mechanism afforded under the Price-Anderson Amendments Act of 1988. The coverage falls into three categories: nuclear liability, property coverage and workers compensation.

NPPD purchases nuclear liability insurance in the maximum available amount of $200 million. In accordance with the Price-Anderson Amendments Act of 1988, excess liability protection above that amount is provided by a mandatory industry-wide program under which the owners of nuclear generating facilities could be assessed for liability incurred due to a serious nuclear incident at any commercial nuclear reactor in the United States. Currently, the Company's maximum potential share of such an assessment is $39.6 million per incident, payable in installments not to exceed $5 million annually.

The property coverage provides for several items which include decontamination of the facility, disposal of the decontaminated material, business interruption, debt service, replacement power and premature decommissioning. NPPD purchases primary and excess property insurance for Cooper in the amount of $1.3 billion, and the Company purchases $700 million of excess property coverage directly from an industry-mutual insurance company. The combination of these coverages protects the Company for its 50 percent obligation in the event of a loss totalling $2.7 billion, which is the maximum amount of insurance coverage currently available to the Company. Additionally, the Company directly purchases extra expense/business interruption coverage to cover the cost of replacement power and/or other continuing costs in the event of a covered accidental outage at Cooper. The coverages purchased directly by the Company contain provisions for retrospective premium assessments should two or more full policy-limit losses occur in one policy year. Currently, the maximum retrospective amounts that could be assessed against the Company total $7 million.

The workers compensation coverage is an industry-wide policy with an aggregate limit of $200 million for the nuclear industry as a whole, in effect to cover tort claims of workers as a result of radiation

exposure on or after January 1, 1988. The Company's share of a maximum potential share of a retrospective assessment under this program is $1.5 million.

(b) **Environmental Matters:**

The United States Environmental Protection Agency (EPA) and the Iowa Department of Natural Resources (IDNR) have determined that contaminated wastes remaining at certain decommissioned manufactured gas plant (MGP) facilities may pose a threat to the public health or the environment if such contaminants are in sufficient quantities and at such concentrations as to warrant remedial action. The Company could be involved, as a potentially responsible party (PRP), in up to 22 such sites.

The Company and other PRPs have entered into a Consent Decree with the EPA for remediation at one site and have entered into an Administrative Order to conduct a removal action at a second site. The Company and IDNR have entered into Consent Orders to investigate and conduct response action at two additional sites. The Company proposes to conduct limited site investigations at most of the remaining sites. The outcome of the Company and environmental agency investigations will be an important factor with respect to any remedial action.

The Company's present estimate of probable remediation costs is $15.5 million. This estimate has been recorded as a liability and a regulatory asset for future recovery through the regulatory process. Beginning in September 1992, the Company's gas rates in Iowa provide recovery for MGP costs of $3.1 million on an annual basis. The Company is pursuing recovery of the response costs from other potentially responsible parties and its insurance carriers.

The estimate of probable remediation costs is established on a site specific basis. The costs are accumulated in a three-step process. First, a determination is made as to whether the Company has any potential legal liability for the site. If it does, the costs of performing a preliminary investigation are accrued. Once the investigation is completed and it is determined remedial action is required, the best estimate of remediation is accrued. If necessary, the estimate is revised when a consent order is issued. The estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action and changes in technology relating to remedial alternatives. The Company estimates it will take up to 15 years to resolve the MGP remediation issues.

As a user of polychlorinated biphenyls (PCBs), the Company is subject to governmental regulations pertaining to the use, handling and proper disposal of PCBs. The Company is involved as one of several parties in a cleanup at one site at which the cleanup activity began in 1986 and is anticipated to be complete within two years. The Company and other PRPs have made contributions to a trust fund that should be adequate to complete the cleanup required. The Company also entered into a Consent Decree and Consent Orders with the EPA and other PRPs at two other sites. Payments were made in 1993 to settle the Company's financial obligation at both sites. The likelihood of additional material expense from these sites is remote.

The Company's coal-fired generating units are minimally affected by the Phase I provisions of the Clean Air Act Amendments of 1990 (CAA). These generating units currently meet the new CAA sulfur dioxide emission rate standards by burning low-sulfur Wyoming coal. Additional emission rate reductions will not be required to achieve compliance. The Company estimates that sufficient emission allowances have been allocated on a system-wide basis for its units to operate at the capacity factors needed to meet system energy requirements. By the year 2000, some Company coal-fired generating units

will be required to install controls to reduce emissions of nitrogen oxides. The Company's present estimate of the costs of these controls is $33 million. Essentially all utility generating units are subject to CAA provisions which address continuous emission monitoring, permit requirements and fees, and emission of toxic substances. The Company estimates capital costs of approximately $3 million and increased annual operations and maintenance expense of approximately $2 million for compliance with these provisions.

It is management's opinion that the ultimate resolution of the environmental matters will not have a material adverse impact upon the financial position or results of operations of the Company.

(c) Capital Expenditures:

The Company's capital expenditures, including Cooper capital improvements, deferred demand side management expenditures and allowances for funds, are estimated to be $166,142,000 for 1994.

(d) Coal and Natural Gas Contract Commitments:

Midwest Power has entered into coal supply contracts for its fossil fueled generating stations. The contracts, with expiration dates ranging from 1994 through 2003, require minimum payments of $20,424,000, $19,447,000, $19,659,000, $19,439,000 and $19,679,000 for the years 1994, 1995, 1996, 1997 and 1998, respectively, and $43,864,000 for the years thereafter. The Company expects to supplement these coal contracts with spot market purchases to fulfill its future fossil fuel needs.

Midwest Gas has entered into various natural gas supply and transportation contracts with expiration dates ranging from 1994 through 2008. The minimum commitment under these contracts is $62,889,000, $49,610,000, $45,638,000, $34,585,000 and $7,319,000 for the years 1994, 1995, 1996, 1997 and 1998, respectively, and $17,680,000 for the years thereafter. During 1993, FERC Order 636 became effective, requiring interstate pipelines to restructure their services. The pipelines will recover the transition costs related to Order 636 from the local distribution companies. The Company has recorded a $41.9 million liability and regulatory asset for the transition costs related to its largest natural gas transportation provider.

(3) SEGMENTS OF BUSINESS:

For the year ended December 31	1993	1992	1991
Operating Revenues:		(In Thousands)	
Electric	$ 664,377	$ 623,360	$ 637,222
Gas	332,168	299,820	292,291
Other	-	-	300
	$ 996,545	$ 923,180	$ 929,813
Operating Expenses:			
Electric	$ 552,640	$ 526,070	$ 515,967
Gas	311,508	284,139	276,036
Other	-	-	164
	$ 864,148	$ 810,209	$ 792,167
Operating Income:			
Electric	$ 111,737	$ 97,290	$ 121,255
Gas	20,660	15,681	16,255
Other	-	-	136
	$ 132,397	$ 112,971	$ 137,646
Depreciation and Amortization Expense:			
Electric	$ 77,065	$ 74,305	$ 71,238
Gas	12,740	11,885	11,237
	$ 89,805	$ 86,190	$ 82,475
Capital Expenditures:			
Electric	$ 142,769	$ 99,308	$ 101,999
Gas	22,026	23,272	20,986
Other	387	197	(292)
	$ 165,182	$ 122,777	$ 122,693
Identifiable Assets as of December 31:			
Electric	$1,636,235	$1,589,990	$1,598,212
Gas	286,688	288,870	262,425
	1,922,923	1,878,860	1,860,637
Corporate assets	461,531	352,725	372,446
	$2,384,454	$2,231,585	$2,233,083

Identifiable assets are all assets that are used directly in the Company's operations of each segment. Corporate assets are principally investments, cash and cash equivalents, receivables, prepayments and deferred charges.

(4) FAIR VALUE OF FINANCIAL INSTRUMENTS:

The following table presents the carrying value and the estimated fair value of financial instruments included in the Consolidated Balance Sheets as of December 31 (in thousands):

	1993		1992	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt and current maturities	$678,151	$712,034	$736,950	$767,205
Preferred stock	90,042	79,003	54,413	38,779

The carrying amount of current assets and current liabilities approximates the fair value because of the short maturity of these financial instruments.

The fair value of investments is estimated based on the quoted market prices for those or similar investments, where available. Certain investments with carrying values of $26.9 million and $28.8 million as of December 31, 1993 and 1992, respectively, are excluded from the amounts shown because a reasonable estimate of fair value could not be made without incurring excessive costs. These investments consist primarily of the noncurrent portion of an investment representing all the issued preferred stock of an untraded company which is carried at $25.2 million and $27.4 million as of December 31, 1993 and 1992, respectively. The terms of this preferred stock provide that no dividends will be paid and require $2.2 million to be redeemed annually each February 1 through 2002, $3.9 million in 2003 and $3.8 million in 2004.

The fair values of long-term debt and preferred stock are estimated based on the quoted market prices of those or similar issues, where available. For those issues where no quoted market prices are available, the fair value is estimated based on current rates available to the Company for debt or preferred stock with similar remaining maturities.

(5) PREFERRED STOCK:

In 1992, the Company redeemed all 300,000 outstanding shares of the $7.35 Series Preferred Stock for the price of $105.201 per share. A $1.6 million loss on the reacquisition of the series was charged to Retained Earnings and Paid-in Capital.

On November 17, 1993, the Company issued 2,400,000 shares of $1.7375 Series No Par Value Preferred Stock with a stated value of $25 per share. Net proceeds from the issuance were $58.3 million.

On December 10, 1993, the Company redeemed all the outstanding shares of certain series of Cumulative Nonredeemable No Par Preferred Stock as follows: 66,135 shares of $7.64; 48,786 shares of $8.08; 71,525 shares of $8.32; and 40,944 shares of $8.52. The combined recorded value of the redeemed series was $22.6 million. The total cost of the transaction included a $623,000 premium, of which $124,000 was charged against Paid-in Capital and $499,000 was charged against Retained Earnings.

In addition to the transactions above, the Company redeemed 11, 482 and 44 shares of various series of preferred stock during 1993, 1992 and 1991, respectively.

The total outstanding preferred stock of $90.0 million may be redeemed at the option of the Company at prices which, in the aggregate, total $96.8 million. The aggregate total the holders of preferred stock are entitled to upon involuntary bankruptcy is $91.8 million plus accrued dividends. Annual dividend requirements for preferred stock outstanding at December 31, 1993, total $5,481,000.

(6) COMMON STOCK:

Common stock outstanding changed during the years ended December 31 as shown in the table below (in thousands):

	1993		1992		1991	
	Amount	Shares	Amount	Shares*	Amount	Shares*
Balance, beginning of year ...	$462,274	1,000	$462,948	1,000	$405,639	1,000
Changes due to:						
Contribution from parent	-	-	-	-	57,308	-
Gain (loss) on reacquisition of preferred stock	(124)	-	(674)	-	1	-
Balance, end of year	$462,150	1,000	$462,274	1,000	$462,948	1,000

* Shares are based upon the conversion of the total outstanding shares of common stock of IPR and IPS into 50 shares each of MPS plus 900 shares of MPS common stock outstanding at the time of the merger.

(7) SHORT-TERM BORROWING:

Interim financing of working capital needs and the construction program may be obtained from the sale of commercial paper or short-term borrowing from banks. The Company's short-term notes payable consisted of commercial paper borrowings of $129,800,000 and $58,100,000 at December 31, 1993 and 1992, respectively. The Company had bank lines of credit of $167,500,000 at December 31, 1993. These lines are used to support commercial paper and bank borrowings. The average interest rate on the commercial paper and bank borrowings was 3.25 percent for 1993 and 3.75 percent for 1992.

(8) LONG-TERM DEBT:

The Company's sinking fund requirements and maturities of long-term debt for 1994, 1995, 1996, 1997 and 1998 are $1,506,000, $998,000, $532,000, $2,522,000 and $75,124,000, respectively. Substantially all the Company's electric utility property is pledged.

(9) INVESTMENTS:

Investments include the following amounts as of December 31 (in thousands):

	1993	1992
Preferred stocks	$ 25,205	$ 27,392
Equity method investments	81	81
Other	1,664	1,441
Total	$ 26,950	$ 28,914

(10) CONCENTRATION OF CREDIT RISK:

Midwest Power provides electric service to 420,000 customers in 327 Iowa communities and six communities in southeastern South Dakota. Midwest Gas provides natural gas service to 342,000 customers in 204 Iowa, 27 South Dakota and two Nebraska communities. Midwest Power and Midwest Gas grant unsecured credit to customers, substantially all of whom are local businesses and residents.

(11) OTHER INCOME:

Included in Allowance for Equity Funds and Allowance for Borrowed Funds are allowances for funds used during construction and accrued on advances for capital improvements and other capital expenditures for the years ended December 31 as follows (in thousands).

	1993	1992	1991
Allowance for equity funds:			
Used during construction	$ -	$ 835	$ 37
Accrued on advances for capital improvements	-	409	65
Accrued on other capital expenditures	-	(31)	22
Allowance for borrowed funds:			
Used during construction	790	614	1,638
Accrued on advances for capital improvements	417	409	994
Accrued on other capital expenditures	-	35	267

(12) JOINTLY OWNED UTILITY PLANT:

Under joint plant ownership agreements with other utilities, the Company had undivided interests at December 31, 1993, in jointly owned generating plants as shown in the table below.

The dollar amounts below represent the Company's share in each jointly owned unit. Each participant has provided financing for its share of each unit. Operating Expenses on the Consolidated Statements of Income include the Company's share of the expenses of these units.

	Neal Unit No.3	Neal Unit No.4	Council Bluffs Unit No.3	Ottumwa Unit No.1	Louisa Unit No.1
	(Dollars in millions, except capital cost per kW)				
Utility plant in service	$ 67.1	$156.5	$168.6	$130.6	$270.9
Year placed in service	1975	1979	1978	1981	1983
Accumulated depreciation . .	$ 36.2	$ 68.9	$ 76.2	$ 50.7	$ 89.7
Unit capacity-MW	515	624	675	708	650
Percent ownership	43.0%	40.6%	46.7%	33.5%	45.0%
Capital cost per kW	$ 303	$ 618	$ 535	$ 551	$ 926

(13) INCOME TAX EXPENSE:

The Company adopted Financial Accounting Standard 109 "Accounting for Income Taxes" (FAS 109) in January 1993. The Company adopted FAS 109 on a restatement basis which resulted in a decrease to retained earnings of $10,807,000, as of the earliest period shown, with no material effect on net income during the periods presented. Because of rate regulation, additional net regulatory assets were also recorded on a restatement basis.

Income tax expense from continuing operations was as follows for the years ended December 31 (in thousands):

	1993	1992	1991
Current			
Federal	$40,297	$16,129	$28,792
State	11,859	4,993	8,600
	52,156	21,122	37,392
Deferred			
Federal	4,992	7,112	7,339
State	(484)	(356)	(540)
	4,508	6,756	6,799
Investment tax credit amortization	(4,909)	(3,817)	(3,844)
Total	$51,755	$24,061	$40,347

Included in Deferred Income Taxes and Prepayments and Other on the Consolidated Balance Sheets as of December 31 are deferred tax assets and deferred tax liabilities as follows (in thousands):

	1993	1992
Deferred Tax Assets		
Related to:		
Investment tax credits	$ 46,509	$ 48,257
Other	2,652	4,463
Total	$ 49,161	$ 52,720
Deferred Tax Liabilities		
Related to:		
Depreciable Property	$362,176	$356,555
Other	28,084	20,660
Total	$390,260	$377,215

The following table is a reconciliation between the effective income tax rate, before preferred stock dividends, indicated by the Consolidated Statements of Income and the statutory federal income tax rate for the years ended December 31:

	1993	1992	1991
Effective federal and state income tax rate	37%	32%	34%
State income tax, net of federal income tax benefit	(5)	(4)	(4)
Amortization of investment tax credit	4	5	3
Other	(1)	1	1
Statutory federal income tax rate	35%	34%	34%

MWR files a consolidated income tax return. The current and deferred income tax expenses reflected by MPS are the amounts that would have been recorded by the Company had it filed its own income tax return. The tax-related balances between MPS and MWR, as recorded by MPS, are a receivable of $1,076,000 and a payable of $2,712,000 at December 31, 1993 and 1992, respectively.

(14) RETIREMENT PLANS:

The following disclosures are the totals for MPS and nonutility affiliates, of which MPS represents approximately 96 percent of the payroll costs covered under these plans. No detailed segregation of the data is available by subsidiary. MPS data is shown in summary only.

The Company has non-contributory defined benefit pension plans covering substantially all employees. The benefit formulas are based on each employee's years of service and individual earnings.

The Company generally uses the aggregate actuarial cost method to determine annual funding requirements. Under this method, there is no unfunded prior service cost. The excess of the present value of projected benefits over plan assets is funded as a level percentage of covered payroll. The utility has been allowed to recover funding contributions in rates.

Net periodic pension cost includes the following components for the years ended December 31 (in thousands):

	1993	1992	1991
Service cost-benefit earned during the period	$ 7,857	$ 6,776	$ 6,445
Interest cost on projected benefit obligation	14,951	13,701	11,137
Decrease in pension costs from actual return on assets	(5,140)	(8,912)	(32,283)
Net amortization and deferral	(10,787)	(7,388)	17,732
Regulatory recognition of incurred cost	(1,114)	911	999
MPS and affiliates net periodic pension cost	$ 5,767	$ 5,088	$ 4,030
MPS net periodic pension cost	$ 5,418	$ 4,930	$ 3,262
Assumptions used were:			
Discount rate	7.25%	8.00%	8.50%
Rate of increase in compensation levels	5.50%	5.50%	5.50%
Expected long-term rate of return on assets	9.00%	9.00%	9.00%

The plan assets are stated at fair market value and are comprised of insurance contracts, federal government debt and corporate equity securities. The following table presents the plans' funding status and amounts recognized in the Company's Consolidated Balance Sheets as of December 31 (in thousands):

	1993	1992
Actuarial present value of benefit obligations:		
Vested benefit obligation	$(143,449)	$(121,547)
Nonvested benefit obligation	(12,016)	(7,156)
Accumulated benefit obligation	(155,465)	(128,703)
Provision for future pay increases	(64,249)	(50,728)
Projected benefit obligation	(219,714)	(179,431)
Plan assets at fair value	176,719	176,323
Projected benefit obligation greater than plan assets	(42,995)	(3,108)
Unrecognized prior service cost	14,100	12,998
Unrecognized net loss	38,180	2,825
Unrecognized net transition asset	(16,408)	(17,865)
Other	(10,102)	(3,473)
Pension liability recognized from total MPS and affiliate plans	$ (17,225)	$ (8,623)
Pension contribution in excess of cost included in Deferred Charges and Other in the MPS Consolidated Balance Sheets	$ 7,086	$ 8,353

In addition to defined benefit pension plans, the Company provides certain health care and life insurance benefits for retired employees. Under the current plan, substantially all of the Company's employees may become eligible for these benefits if they reach retirement age while working for the Company. However, the Company retains the right to change these benefits anytime at its discretion.

The Company adopted Financial Accounting Standard 106 "Employers Accounting for Postretirement Benefits Other Than Pensions" (FAS 106) in January 1993. For its Iowa utility operations, the Company is deferring the difference between the FAS 106 costs and the "pay-as-you-go" costs in anticipation of recovery of these costs in future rate proceedings. The IUB issued an order in January 1993, allowing recovery of externally funded FAS 106 costs. An IUB order allows utilities to defer the difference between the FAS 106 accrual and the "pay-as-you-go" method for up to three years. Therefore, the adoption of the standard has a minimal effect on current period earnings.

Net periodic postretirement benefit cost includes the following components for the year ended December 31 (in thousands):

	1993
Service cost earned during the period	$ 1,778
Interest cost	7,583
Decrease in benefit costs from actual return on plan assets	(462)
Amortization of unrecognized transition obligation	4,767
Other	287
Regulatory recognition of incurred cost	(9,126)
MPS and affiliates net periodic postretirement benefit cost	$ 4,827
MPS net periodic postretirement benefit cost	$ 4,661

The Company has established two external trust funds to meet its expected obligation. The trust funds' assets are comprised primarily of guaranteed investment accounts. A reconciliation of the funded status of the plan to the amounts realized as of December 31 is presented below (in thousands):

	1993
Accumulated postretirement benefit obligation:	
Retirees	$(68,797)
Active employees	(48,843)
Plan assets at fair value	10,082
Unrecognized transition obligation	90,579
Unrecognized net loss	16,979
Net postretirement benefit liability recognized in the Consolidated Balance Sheets of MWR and MPS	$ -

For purposes of calculating the postretirement benefit obligation it is assumed that health care costs for covered individuals prior to age 65 will increase by 14.0 percent in 1994, and that the rate of increase thereafter will decline to 5.5 percent over a ten-year period. Health care costs for covered individuals age 65 and older are assumed to increase by 11.0 percent in 1994, and the rate of increase thereafter will decline to 5.5 percent over a seven-year period. The weighted average discount rate used in determining the accumulated postretirement benefit obligation was 7.25 percent at December 31, 1993. The expected long-term rate of return on plan assets was 9.0 percent and 6.2 percent after taxes for the union plan and salaried plan, respectively.

If the assumed health care trend rate used to measure the expected cost of benefits covered by the plan was increased by one percent, the total service and interest cost would increase by $1,323,000 and the accumulated postretirement benefit obligation would increase by $11,119,000.

Recently introduced legislation has proposed national health care reform. The Company can not determine at this time what reforms will be made or their impact on the Company.

(15) AFFILIATED COMPANY TRANSACTIONS:

The companies identified as affiliates, other than the parent company, are wholly owned subsidiaries of MWR. The basis for these charges is provided for in service agreements between MPS and the parent company or its affiliates. In the opinion of management, the expenses between entities are fair and reasonable.

MPS' parent company incurs certain administrative and general expenses which are of general benefit to all of its subsidiaries, including treasury, legal, shareholder relations and accounting functions. MPS' share of such expenses was $6,807,000, $4,930,000 and $4,382,000 for 1993, 1992 and 1991, respectively.

MPS is reimbursed for charges incurred on behalf of its parent company and other affiliated companies. The amount of such expenses were $7,796,000, $6,810,000 and $5,529,000 for 1993, 1992 and 1991, respectively. The majority of these reimbursed expenses were for employee wages and benefits, insurance, building rental, computer costs, administrative services and travel expense.

MPS leases office facilities and other properties from affiliates and total lease payments were $599,000, $577,000 and $2,324,000 for 1993, 1992 and 1991, respectively. On December 31, 1991, MPS assumed ownership of the Sioux City office building which had previously been leased from an affiliate. As a result of the transfer, MPS assumed notes payable in the amount of $13,928,000.

MPS leases unit trains from an affiliate for the transportation of coal to MPS generating stations. Unit train costs, including maintenance, were $2,941,000, $2,933,000 and $3,825,000 for 1993, 1992, and 1991, respectively.

MPS leases other transportation equipment from an affiliate. MPS' lease costs were $235,000, $281,000 and $671,000 for 1993, 1992 and 1991, respectively.

MPS received interest income on cash invested with affiliates and interest expense was allocated to MPS from the parent. MPS recorded net affiliate company interest expense of $130,000 and $175,000 for 1992 and 1991, respectively.

MPS accepted assignment of accounts receivable owned by MWR to its diversified businesses subsidiary of $22,609,000 and $45,000,000 in 1992 and 1991, respectively. MPS collected $18,586,000 and $12,067,000 of the receivables during 1992 and 1991, respectively.

During 1993, MPS sold natural gas to an affiliate. MPS' cost of gas and margin related to these transactions were $505,000 and $58,000, respectively. MPS purchased natural gas from an affiliate during 1993. MPS' costs from these transactions were $198,000. In addition, MPS and an affiliate engaged in natural gas buy/sell transactions during 1993. MPS' transportation cost and margin related to these transactions were $398,000 and $197,000, respectively.

(16) UNAUDITED QUARTERLY OPERATING RESULTS:

	Operating Revenues	Operating Income	Earnings on Common Stock
		(In Thousands)	
1993			
1st Quarter	$ 296,254	$ 43,646	$ 27,128
2nd Quarter	212,152	24,915	9,534
3rd Quarter	233,982	38,953	34,876
4th Quarter	254,157	24,883	11,965
1992			
1st Quarter	$ 251,163	$ 32,650	$ 16,365
2nd Quarter	196,657	18,429	3,584
3rd Quarter	211,946	30,736	12,330
4th Quarter	263,414	31,156	14,665

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The Company's management is responsible for the presentation of the accompanying financial statements, which have been prepared in conformity with generally accepted accounting principles and include amounts based on informed estimates and judgments of management.

Management maintains internal accounting controls which it believes are adequate to provide reasonable assurance that assets are safeguarded, transactions are executed in accordance with management authorization and financial records are reliable for preparing the financial statements. Internal accounting controls are supported by written policies and procedures, a staff of internal auditors who conduct comprehensive internal audits and the selection and training of qualified personnel.

The Midwest Resources Inc. Board of Directors, through its Audit Committee comprised entirely of outside directors, meets periodically with management, internal auditors and the Company's independent public accountants to discuss auditing, internal control and financial reporting matters. To ensure their independence, both the internal auditors and independent public accountants have full and free access to the Audit Committee.

The independent public accountants, Arthur Andersen & Co., are engaged to audit the Company's financial statements in accordance with generally accepted auditing standards.

R. E. Christiansen
Chairman, President and Chief Executive Officer

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To Midwest Power Systems Inc.:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Midwest Power Systems Inc. (an Iowa corporation and wholly-owned subsidiary of Midwest Resources Inc.) and subsidiaries as of December 31, 1993 and 1992, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1993. These financial statements and the schedules referred to below are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedules based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Midwest Power Systems Inc. and subsidiaries as of December 31, 1993 and 1992, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1993, in conformity with generally accepted accounting principles.

As explained in Note 13 to the consolidated financial statements, the Company has given retroactive effect to the change in accounting for income taxes. As explained in Note 14 to the consolidated financial statements, effective January 1, 1993, the Company changed its method of accounting for postretirement benefits other than pensions.

Our audits were made for the purpose of forming an opinion on the basic financial statements taken as a whole. The schedules listed in the index of financial statement schedules (Item 14(a) 2) are presented for purposes of complying with the Securities and Exchange Commission's rules and are not part of the basic financial statements. These schedules have been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, fairly state in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

Chicago, Illinois
January 28, 1994

Arthur Andersen & Co.

UNAUDITED MIDWEST POWER STATISTICS

For the year ended December 31	1993	1992	1991	1990	1989
Revenues (000)					
Residential	$ 271,577	$ 244,295	$ 267,178	$ 253,937	$ 240,513
Small general service	149,283	150,319	152,870	145,547	150,256
Large general service	109,151	111,674	111,694	111,822	120,456
Other	56,590	30,839	32,434	30,341	32,661
Subtotal	586,601	537,127	564,176	541,647	543,886
Sales for resale	77,776	86,233	73,046	69,320	68,309
Total	$ 664,377	$ 623,360	$ 637,222	$ 610,967	$ 612,195
Sales (000 kWh)					
Residential	3,236,929	2,956,489	3,252,828	3,025,089	3,013,384
Small general service	2,598,178	2,617,781	2,667,210	2,489,279	2,354,375
Large general service	2,858,381	2,937,041	2,881,832	2,938,581	2,819,734
Other	811,688	347,371	354,719	356,787	370,361
Subtotal	9,505,176	8,858,682	9,156,589	8,809,736	8,557,854
Sales for resale	4,018,919	5,085,508	4,424,222	4,239,471	4,027,660
Total	13,524,095	13,944,190	13,580,811	13,049,207	12,585,514
Energy (000 kWh)					
Generated	10,819,740	9,753,806	9,814,754	9,306,590	8,444,290
Purchased	3,255,636	4,973,069	4,549,152	5,503,326	4,843,178
	14,075,376	14,726,875	14,363,906	14,809,916	13,287,468
Customers (year-end)					
Residential	363,305	360,048	356,076	353,490	350,464
Small general service	48,314	51,407	50,923	50,593	49,858
Large general service	671	759	769	751	759
Other	7,978	4,494	4,389	4,252	4,067
Subtotal	420,268	416,708	412,157	409,086	405,148
Sales for resale	54	79	85	84	88
Total	420,322	416,787	412,242	409,170	405,236
Average Annual Use Per Residential Customer					
Revenue	$751.04	$682.35	$753.09	$721.95	$689.35
KWh	8,952	8,258	9,169	8,600	8,637
Average number of residential customers	361,603	358,018	354,774	351,739	348,896
Revenues as a Percent of Total					
Residential	40.9%	39.2%	41.9%	41.6%	39.3%
Small general service	22.5	24.1	24.0	23.8	24.5
Large general service	16.4	17.9	17.5	18.3	19.7
Other	8.5	5.0	5.1	5.0	5.3
Subtotal	88.3	86.2	88.5	88.7	88.8
Sales for resale	11.7	13.8	11.5	11.3	11.2
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Sales as a Percent of Total					
Residential	23.9%	21.2%	24.0%	23.2%	23.9%
Small general service	19.2	18.8	19.6	19.1	18.7
Large general service	21.2	21.0	21.2	22.5	22.4
Other	6.0	2.5	2.6	2.7	3.0
Subtotal	70.3	63.5	67.4	67.5	68.0
Sales for resale	29.7	36.5	32.6	32.5	32.0
Total	100.0%	100.0%	100.0%	100.0%	100.0%

For the year ended December 31	1993	1992	1991	1990	1989
Revenues (000)					
Residential	$ 200,247	$ 183,262	$ 176,649	$ 158,653	$ 169,392
Small general service	91,127	81,689	78,233	70,749	78,493
Large general service	23,654	29,170	30,680	30,139	32,702
Sales for resale	5,346	-	-	-	-
Other	8,164	3,017	4,078	4,662	4,483
Subtotal	328,538	297,138	289,640	264,203	285,070
Gas Transported	3,630	2,682	2,651	1,414	1,492
Total	$ 332,168	$ 299,820	$ 292,291	$ 265,617	$ 286,562
Throughput (000 MMBtu)					
Sales					
Residential	36,129	33,161	34,750	31,413	34,621
Small general service	20,517	18,829	19,300	18,042	20,179
Large general service	6,118	8,303	9,187	9,493	11,594
Sales for resale	2,619	-	-	-	-
Other	1,559	463	1,014	490	478
Total sales	66,942	60,756	64,251	59,438	66,872
Gas transported	14,439	12,421	10,993	9,688	12,844
Total	81,381	73,177	75,244	69,126	79,716
Supply (000 MMBtu)					
Gas from peaking facilities					
LP gas	13	15	4	28	24
LNG gas	256	277	421	473	1,978
Natural gas purchased	78,945	69,062	75,887	65,291	67,750
Methane gas purchased	69	38	39	63	52
Total gas receipts	79,283	69,392	76,351	65,855	69,804
Less Company use, deliveries to LNG and storage	13,886	7,597	443	5,447	2,119
Supply available for retail sales	65,397	61,795	75,908	60,408	67,685
Sales for resale purchases	2,619	-	-	-	-
Total	68,016	61,795	75,908	60,408	67,685
Customers (year-end)					
Residential	306,507	334,789	327,313	321,119	312,446
Commercial	34,607	34,706	34,261	33,998	33,104
Industrial	750	906	940	944	1,044
Sales for resale	4	-	-	-	-
Subtotal	341,868	370,401	362,514	356,061	346,594
Gas Transported	84	72	59	56	47
Total	341,952	370,473	362,573	356,117	346,641
Average Annual Use Per Residential Customer					
Revenue	$ 614.58	$ 555.29	$ 546.16	$ 502.57	$546.53
MMBtu	111	100	107	100	112
Average number of residential customers	325,825	330,027	323,437	315,682	309,941

UNAUDITED MIDWEST GAS STATISTICS

For the year ended December 31	1993	1992	1991	1990	1989
Degree Days					
Actual	7,314	6,434	6,724	6,439	7,420
Normal	7,054	7,101	7,268	7,268	7,251
Percent colder (warmer) than normal	3.7	(9.4)	(7.5)	(11.4)	2.3
Revenues as a Percent of Total					
Residential	60.3%	61.1%	60.4%	59.7%	59.1%
Small general service	27.4	27.3	26.8	26.6	27.4
Large general service	7.1	9.7	10.5	11.4	11.4
Sales for resale	1.6	-	-	-	-
Other	2.5	1.0	1.4	1.8	1.6
Subtotal	98.9	99.1	99.1	99.5	99.5
Gas Transported	1.1	0.9	0.9	0.5	0.5
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Sales as a Percent of Total (Excluding Gas Transported)					
Residential	54.0%	54.6%	54.1%	52.8%	51.8%
Small general service	30.6	31.0	30.0	30.4	30.2
Large general service	9.2	13.7	14.3	16.0	17.3
Sales for resale	3.9	-	-	-	-
Other	2.3	0.7	1.6	0.8	0.7
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Cost per MMBtu	$ 3.35	$ 3.30	$ 3.07	$ 3.05	$ 2.97

SCHEDULE II

MIDWEST POWER SYSTEMS INC.
AMOUNTS RECEIVABLE FROM RELATED PARTIES,
UNDERWRITERS, PROMOTERS AND EMPLOYEES
OTHER THAN RELATED PARTIES
FOR THE YEAR ENDED DECEMBER 31, 1993
(In Thousands)

Column A	Column B	Column C	Column D		Column E	
	Balance at Beginning of Year	Additions	Deductions Amounts Collected	Deductions Amounts Written Off	Balance at End of Year Current	Balance at End of Year Not Current
Accounts Receivable						
Midwest Resources Inc.	$37,398	$ 4,018	$ 4,300	$ -	$37,116	$ -
Midwest Capital Group, Inc. . .	58	1,245	1,171	-	132	-
Other Related Parties	198	9,190	9,057	-	331	-
Total	$37,654	$14,453	$14,528	$ -	$37,579	$ -

MIDWEST POWER SYSTEMS INC.
AMOUNTS RECEIVABLE FROM RELATED PARTIES,
UNDERWRITERS, PROMOTERS AND EMPLOYEES
OTHER THAN RELATED PARTIES
FOR THE YEAR ENDED DECEMBER 31, 1992
(In Thousands)

Column A	Column B	Column C	Column D		Column E	
	Balance at Beginning of Year	Additions	Deductions Amounts Collected	Deductions Amounts Written Off	Balance at End of Year Current	Balance at End of Year Not Current
Accounts Receivable						
Midwest Resources Inc.	$33,662	$26,238 (1)	$22,502(2)	$ -	$37,398	$ -
Midwest Capital Group, Inc. . .	22,155	(21,595)(1)	502	-	58	-
Other Related Parties	302	2,167	2,271	-	198	-
Total	$56,119	$ 6,810	$25,275	$ -	$37,654	$ -

(1) Includes the transfer of $22,609 receivable from Midwest Capital Group, Inc. to Midwest Resources Inc.

(2) Includes $18,586 collected on the receivable transferred from Midwest Capital Group, Inc.

MIDWEST POWER SYSTEMS INC.
AMOUNTS RECEIVABLE FROM RELATED PARTIES,
UNDERWRITERS, PROMOTERS AND EMPLOYEES
OTHER THAN RELATED PARTIES
FOR THE YEAR ENDED DECEMBER 31, 1991
(In Thousands)

Column A	Column B	Column C	Column D		Column E	
	Balance at Beginning of Year	Additions	Deductions Amounts Collected	Deductions Amounts Written Off	Balance at End of Year Current	Balance at End of Year Not Current
Accounts Receivable						
Midwest Resources Inc.	$ 192	$48,148 (1)	$14,678 (2)	$ -	$33,662	$ -
Midwest Capital Group, Inc. .	67,731	(44,197)(1)	1,379 (3)	-	22,155	
Other Related Parties	322	1,578	1,598	-	302	-
Total	$68,245	$ 5,529	$17,655	$ -	$56,119	$ -

(1) Includes the transfer of $45,000 receivable from Midwest Capital Group, Inc. to Midwest Resources Inc.
(2) Includes $12,067 collected on the receivable transferred from Midwest Capital Group, Inc.
(3) Includes a non-cash settlement of $128 for the IPS corporate headquarters building.

MIDWEST POWER SYSTEMS INC.
CONSOLIDATED PROPERTY, PLANT AND EQUIPMENT
FOR THE YEAR ENDED DECEMBER 31, 1993
(In Thousands)

Column A	Column B	Column C	Column D	Column E	Column F
Classification	Balance at Beginning of Year	Additions at Cost	Retirements or Sale at Original Cost (Note 2)	Other Charges (Credits) (Note 3)	Balance at Close of Year
ELECTRIC PLANT:					
Electric plant in service					
Intangibles	$ 12,804	$ 671	$ 3	$ -	$ 13,472
Production					
Steam	912,377	1,784	1,663	(190)	912,308
Other	84,683	175	42	-	84,816
Transmission	273,698	5,071	1,390	63	277,442
Distribution	614,535	23,399	2,358	224	635,800
General plant	124,053	2,228	523	(1,278)	124,480
Completed, not unitized	103,913	33,832	(554)	-	138,299
Total electric plant in service	2,126,063	67,160	5,425	(1,181)	2,186,617
Electric plant in service under capital lease	10,544	-	198	-	10,346
Experimental plant	53	-	-	-	53
Plant held for future use	18,151	-	3,942	(651)	13,558
Construction work in progress	28,283	54,913	-	-	83,196
Total electric plant	2,183,094	122,073	9,565	(1,832)	2,293,770
GAS PLANT:					
Gas plant in service					
Intangibles	4,607	86	-	(109)	4,584
Production	6,744	144	7	(1,582)	5,299
Other storage	17,335	376	25	543	18,229
Distribution	258,823	12,844	1,067	(17,249)	253,351
General plant	51,526	2,428	1,398	2,681	55,237
Completed, not unitized	9,502	2,830	(10)	(2,574)	9,768
Total gas plant in service	348,537	18,708	2,487	(18,290)	346,468
Gas plant in service under capital lease	997	-	-	-	997
Plant acquisition adjustment	19,456	-	-	1,905	21,361
Plant held for future use	4	-	-	-	4
Construction work in progress	5,133	584	-	(1,177)	4,540
Total gas plant	374,127	19,292	2,487	(17,562)	373,370
Total utility plant	$2,557,221	$141,365	$ 12,052	$ (19,394)	$2,667,140
OTHER PHYSICAL PROPERTY	$ 2,174	$ 332	$ 4	$ -	$ 2,502

NOTES:
(1) See Notes (1e), (8) and (12) of Notes to Consolidated Financial Statements.
(2) The reserve for utility plant depreciation has been charged with the amount indicated on Schedule VI for the year ended December 31, 1993.
(3) Other Charges (Credits) includes the net effect of the gas property exchange.

SCHEDULE V

MIDWEST POWER SYSTEMS INC.
CONSOLIDATED PROPERTY, PLANT AND EQUIPMENT
FOR THE YEAR ENDED DECEMBER 31, 1992
(In Thousands)

Column A	Column B	Column C	Column D	Column E	Column F
Classification	Balance at Beginning of Year	Additions at Cost	Retirements or Sale at Original Cost (Note 2)	Other Charges (Credits) (Note 3)	Balance at Close of Year
ELECTRIC PLANT:					
Electric plant in service					
Intangibles	$ 6,434	$ 457	$ 1	$ 5,914	$ 12,804
Production					
Steam	909,470	3,153	696	450	912,377
Other	84,751	-	78	10	84,683
Transmission	271,666	5,257	3,226	1	273,698
Distribution	581,036	38,018	4,516	(3)	614,535
General plant	95,918	6,619	3,773	25,289	124,053
Completed, not unitized	78,216	27,674	1,390	(587)	103,913
Total electric plant in service	2,027,491	81,178	13,680	31,074	2,126,063
Electric plant in service under capital lease	10,449	-	41	136	10,544
Experimental plant	33	-	-	20	53
Plant held for future use	23,234	-	4,404	(679)	18,151
Construction work in progress	26,490	498	-	1,295	28,283
Total electric plant	2,087,697	81,676	18,125	31,846	2,183,094
GAS PLANT:					
Gas plant in service					
Intangibles	1,584	19	-	3,004	4,607
Production	6,743	1	-	-	6,744
Other storage	17,331	4	-	-	17,335
Distribution	242,927	17,266	1,378	8	258,823
General plant	23,685	1,466	86	26,461	51,526
Completed, not unitized	9,526	195	219	-	9,502
Total gas plant in service	301,796	18,951	1,683	29,473	348,537
Gas plant in service under capital lease	997	-	-	-	997
Plant acquisition adjustment	19,456	-	-	-	19,456
Plant held for future use	4	-	-	-	4
Construction work in progress	2,242	2,891	-	-	5,133
Total gas plant	324,495	21,842	1,683	29,473	374,127
COMMON PLANT:					
Common plant in service	61,619	(2,840)	(1,326)	(60,105)	-
Construction work in progress	932	400	-	(1,332)	-
Total common plant	62,551	(2,440)	(1,326)	(61,437)	-
Total utility plant	$2,474,743	$ 101,078	$ 18,482	$ (118)	$2,557,221
OTHER PHYSICAL PROPERTY	$ 2,565	$ 186	$ 416	$ (161)	$ 2,174

NOTES:
(1) See Notes (1e), (8) and (12) of Notes to Consolidated Financial Statements.
(2) The reserve for utility plant depreciation has been charged with the amount indicated on Schedule VI for the year ended December 31, 1992.
(3) Utility Plant previously classified as Common Plant was transferred to Electric Plant and Gas Plant during 1992.

MIDWEST POWER SYSTEMS INC.
CONSOLIDATED PROPERTY, PLANT AND EQUIPMENT
FOR THE YEAR ENDED DECEMBER 31, 1991
(In Thousands)

Column A	Column B	Column C	Column D	Column E	Column F
Classification	Balance at Beginning of Year	Additions at Cost	Retirements or Sale at Original Cost (Note 2)	Other Charges (Credits)	Balance at Close of Year
ELECTRIC PLANT:					
Electric plant in service					
Intangibles	$ 1,320	$ 1,287	$ 6	$ 3,833	$ 6,434
Production					
Steam	896,179	16,169	2,880	2	909,470
Other	49,931	34,842	22	-	84,751
Transmission	263,033	10,012	1,336	(43)	271,666
Distribution	549,890	35,729	4,562	(21)	581,036
General plant	97,797	9,554	7,637	(3,796)	95,918
Completed, not unitized	94,646	(18,048)	(1,618)	-	78,216
Total electric plant in service	1,952,796	89,545	14,825	(25)	2,027,491
Electric plant in service under capital lease	6,984	-	-	3,465	10,449
Experimental plant	33	-	-	-	33
Plant held for future use	23,358	-	124	-	23,234
Construction work in progress	37,840	(11,350)	-	-	26,490
Total electric plant	2,021,011	78,195	14,949	3,440	2,087,697
GAS PLANT:					
Gas plant in service					
Intangibles	1,326	259	2	1	1,584
Production	6,288	447	4	12	6,743
Other storage	16,208	1,224	77	(24)	17,331
Distribution	216,613	27,402	1,088	-	242,927
General plant	20,252	4,040	648	41	23,685
Completed, not unitized	19,846	(10,304)	16	-	9,526
Total gas plant in service	280,533	23,068	1,835	30	301,796
Gas plant in service under capital lease	997	-	-	-	997
Plant acquisition adjustment	19,456	-	-	-	19,456
Plant held for future use	4	-	-	-	4
Construction work in progress	6,503	(4,261)	-	-	2,242
Total gas plant	307,493	18,807	1,835	30	324,495
COMMON PLANT:					
Common plant in service	44,283	4,763	2,840	15,413 (3)	61,619
Common plant in service under capital lease	15,400	-	-	(15,400)(3)	-
Construction work in progress	2,783	(1,851)	-	-	932
Total common plant	62,466	2,912	2,840	13	62,551
Total utility plant	$2,390,970	$ 99,914	$ 19,624	$ 3,483	$2,474,743
OTHER PHYSICAL PROPERTY	$ 6,589	$ (219)	$ 4,323	$ 518	$ 2,565

NOTES:
(1) See Notes (1e), (8) and (12) of Notes to Consolidated Financial Statements.
(2) The reserve for utility plant depreciation has been charged with the amount indicated on Schedule VI for the year ended December 31, 1991. The difference represents the sale of land and other property not fully depreciated.
(3) MPS assumed ownership of property which was previously recorded as Property Under Capital Lease.

SCHEDULE VI

MIDWEST POWER SYSTEMS INC.
CONSOLIDATED ACCUMULATED DEPRECIATION, DEPLETION
AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT
FOR THE YEAR ENDED DECEMBER 31, 1993
(In Thousands)

Column A	Column B	Column C		Column D		Column E	Column F
				Retirements			
Description	Balance at Beginning of Year	Additions Charged to Income (Notes 1&2)	Additions Charged to Other Accounts (Note 3)	At Original Cost (Note 4)	Cost of Removal or Salvage, Net	Adjustments and Transfers (Note 5)	Balance at Close of Year
UTILITY PLANT:							
Electric plant	$873,194	$ 74,516	$ 4,469	$ 9,565	$ 3,314	$ (54)	$939,246
Gas plant	100,708	12,041	1,194	2,487	(95)	2,008	113,559
Plant acquisition adjustment	4,540	699	-	-	-	(1,793)	3,446
Total utility plant accumulated depreciation and amortization .	$ 978,442	$ 87,256	$ 5,663	$ 12,052	$ 3,219	$ 161	$1,056,251
OTHER PHYSICAL PROPERTY	$ 4	$ 1	$ -	$ -	$ -	$ -	$ 5

NOTES:

(1) See Footnote 1(e) of Notes to Consolidated Financial Statements for the basis of the provisions for depreciation.

(2) Depreciation and amortization as shown on the Consolidated Statements of Income and the Consolidated Statements of Cash Flows includes $2,548 of amortization of deferred charges.

(3) Represents provisions for depreciation of work equipment and other miscellaneous equipment of the Company which are charged to clearing accounts and apportioned therefrom, together with other expenses, to various accounts

(4) See Note (2) to Schedule V for the year ended December 31, 1993.

(5) Adjustments and Transfers includes the net effect of the gas property exchange.

MIDWEST POWER SYSTEMS INC.
CONSOLIDATED ACCUMULATED DEPRECIATION, DEPLETION
AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT
FOR THE YEAR ENDED DECEMBER 31, 1992
(In Thousands)

Column A	Column B	Column C		Column D		Column E	Column F
				Retirements			
Description	Balance at Beginning of Year	Additions Charged to Income (Notes 1&2)	Additions Charged to Other Accounts (Note 3)	At Original Cost (Note 4)	Cost of Removal or Salvage, Net	Adjustments and Transfers	Balance at Close of Year
UTILITY PLANT:							
Electric plant	$809,938	$ 70,832	$ 3,253	$ 18,125	$ 2,492	$ 9,788	$873,194
Gas plant	84,098	10,457	1,466	1,683	369	6,739	100,708
Plant acquisition adjustment	3,892	648	-	-	-	-	4,540
Common plant	15,551	2,599	100	(1,326)	(148)	(19,724)	-
Total utility plant accumulated depreciation and amortization	$913,479	$ 84,536	$ 4,819	$18,482	$ 2,713	$ (3,197)	$978,442
OTHER PHYSICAL PROPERTY	$ 4	$ -	$ -	$ -	$ -	$ -	$ 4

NOTES:

(1) See Footnote 1(e) of Notes to Consolidated Financial Statements for the basis of the provisions for depreciation.

(2) Depreciation and amortization as shown on the Consolidated Statements of Income and the Consolidated Statements of Cash Flows includes $1,654 of amortization of deferred charges.

(3) Represents provisions for depreciation of work equipment and other miscellaneous equipment of the Company which are charged to clearing accounts and apportioned therefrom, together with other expenses, to various accounts.

(4) See Note (2) to Schedule V for the year ended December 31, 1992.

SCHEDULE VI

MIDWEST POWER SYSTEMS INC.
CONSOLIDATED ACCUMULATED DEPRECIATION, DEPLETION
AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT
FOR THE YEAR ENDED DECEMBER 31, 1991
(In Thousands)

Column A	Column B	Column C		Column D		Column E	Column F
				Retirements			
Description	Balance at Beginning of Year	Additions Charged to Income (Notes 1&2)	Additions Charged to Other Accounts (Note 3)	At Original Cost (Note 4)	Cost of Removal or Salvage, Net	Adjustments and Transfers	Balance at Close of Year
UTILITY PLANT:							
Electric plant	$750,557	$68,195	$2,970	$14,918	$1,070	$4,204	$809,938
Gas plant	74,899	9,989	1,354	1,835	318	9	84,098
Plant acquisition adjustment	3,243	649	-	-	-	-	3,892
Common plant	15,889	2,023	376	2,840	(90)	13	15,551
Total utility plant accumulated depreciation and amortization	$844,588	$80,856	$ 4,700	$19,593	$1,298	$ 4,226	$913,479
OTHER PHYSICAL PROPERTY	$ 100	$ 1	$ -	$ 410	$ (91)	$ 222	$ 4

NOTES:

(1) See Footnote 1(e) of Notes to Consolidated Financial Statements for the basis of the provisions for depreciation.

(2) Depreciation and amortization as shown on the Consolidated Statements of Income and the Consolidated Statements of Cash Flows includes $1,618 of amortization of deferred charges.

(3) Represents provisions for depreciation of work equipment and other miscellaneous equipment of the Company which are charged to clearing accounts and apportioned therefrom, together with other expenses, to various accounts.

(4) See Note (2) to Schedule V for the year ended December 31, 1991.

MIDWEST POWER SYSTEMS INC.
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE THREE YEARS ENDED DECEMBER 31, 1993
(In Thousands)

Column A	Column B	Column C		Column D	Column E
		Additions		Deductions for Purposes for Which Reserves Were Created	
Description	Balance at Beginning of Year	Charged to Income	Charged to Other Accounts		Balance at End of Year
Reserves Deducted From Assets To Which They Apply:					
Reserve for uncollectable accounts:					
Year ended 1993	$1,151	$1,936	$ -	$2,212	$ 875
Year ended 1992	$1,069	$1,651	$ -	$1,569	$1,151
Year ended 1991	$1,145	$1,737	$ -	$1,813	$1,069

MIDWEST POWER SYSTEMS INC.
CONSOLIDATED SHORT-TERM BORROWINGS
FOR THE THREE YEARS ENDED DECEMBER 31, 1993
(In Thousands)

	Column A	Column B	Column C	Column D	Column E	Column F
	Category of Aggregate Short-term Borrowings	Balance at End of Year	Weighted Average Interest Rate (Note 1)	Maximum Amount Outstanding During the Year	Average Amount Outstanding During the Year (Note 2)	Weighted Average Interest Rate During the Year (Note 3)
Year Ended:						
1993	Commercial paper	$129,800	3.39%	$129,800	$ 72,129	3.25%
1992	Commercial paper	$ 58,100	3.78%	$ 68,300	$ 27,149	3.75%
1991	Commercial paper	-	-	$134,600	$104,327	6.15%

NOTES: (1) Weighted average interest rate on balance at the end of the year.

(2) The computation of the average amount outstanding during the year is based on the sum of the daily amounts outstanding divided by the number of days in the year.

(3) The computation of the weighted average interest rate is based on the sum of the annual interest on each transaction divided by the sum of the daily net amounts of commercial paper and notes outstanding.

(4) See Footnote (7) of Notes to Consolidated Financial Statements.

MIDWEST POWER SYSTEMS INC.
CONSOLIDATED SUPPLEMENTARY INCOME STATEMENT INFORMATION
FOR THE THREE YEARS ENDED DECEMBER 31, 1993
(In Thousands)

Column A	Column B		
	Charged to Cost And Expenses		
	Year Ended December 31		
	1993	1992	1991
Taxes, other than payroll and income taxes - Property	$52,369	$55,333	$52,625

NOTE: Maintenance and repairs is not set forth inasmuch as the information is included in the consolidated financial statements.

Depreciation and amortization of intangible assets, royalties and advertising are not set forth inasmuch as such items do not exceed one percent of total revenues as shown in the related Consolidated Statement of Income.

See Footnote (3) of Notes to Consolidated Financial Statements for additional supplementary income statement information by business segment.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

MIDWEST POWER SYSTEMS INC.

Date: March 25, 1994

By R. E. Christiansen
(R. E. Christiansen)
Chairman, President and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

Signature	Title	Date
R. E. Christiansen (R. E. Christiansen)	Chairman, President and Chief Executive Officer	March 25, 1994
P. G. Lindner (P. G. Lindner)	Group Vice President-Administrative Services and Director (Chief Financial and Accounting Officer)	March 25, 1994
R. C. Engle (R. C. Engle)	Director	March 25, 1994
L. K. Vorbrich (L. K. Vorbrich)	Director	March 25, 1994
B. A. Wharton (B. A. Wharton)	Director	March 25, 1994

EXHIBITS INDEX

Exhibits Filed Herewith		Sequential Page Nos.
4.4	Third Supplemental Indenture dated as of May 1, 1993, between MPS and Morgan Guaranty Trust Company of New York, Trustee.	76
4(a)-2	Twenty-Seventh Supplemental Indenture dated July2 2, 1992, between MPS and Chemical Bank, as trusteee under Iowa Public Service Company's Mortgage and Deed of Trust, Dated as of June 1, 1946.	94
10.6	Midwest Power Systems 1993 Key Executive Incentive Compensation Plan.	115
12	Computation of ratios of earnings to fixed charges and computation of ratios of earnings to fixed charges plus preferred dividend requirements.	127
21	Subsidiaries of MPS.	129
23	Consent of Independent Public Accountants.	130

Exhibits Incorporated by Reference

3.1 Articles of Incorporation of MPS, as amended (Filed as Annex B to MPS' Registration Statement, Registration No. 33-42866.)

3.2 Bylaws of MPS (Filed as Exhibit 3(b) to MPS' Registration Statement, Registration No. 33-42866.)

4.1 General Mortgage Indenture and Deed of Trust dated as of January 1, 1993, between MPS and Morgan Guaranty Trust Company of New York, Trustee. (Filed as Exhibit 4(b)-1 to the Company's Annual Report on Form 10-K for the year ended December 31, 1992, Commission File No. 0-20452.)

4.2 First Supplemental Indenture dated as of January 1, 1993, between MPS and Morgan Guaranty Trust Company of New York, Trustee. (Filed as Exhibit 4(b)-2 to the Company's Annual Report on Form 10-K for the year ended December 31, 1992, Commission File No. 0-20452.)

4.3 Second Supplemental Indenture dated as of January 15, 1993, between MPS and Morgan Guaranty Trust Company of New York, Trustee. (Filed as Exhibit 4(b)-3 to the Company's Annual Report on Form 10-K for the year ended December 31, 1992, Commission File No. 0-20452.)

4(a) Mortgage and Deed of Trust dated as of June 1, 1946 (physically filed in IPS' Registration Statement No. 2-6418 under the Securities Act of 1933 as Exhibit B-2).

4(a)-1 Twenty-Third Supplemental Indenture dated as of December 1, 1983 (physically filed in IPS' 10-K for fiscal year ended December 31, 1984, File Number 1-5131, under the Securities Act of 1934 as Exhibit 4(a)-23).

10.1 Power Sales Contract between IPR and Nebraska Public Power District, dated September 22, 1967. (Filed as Exhibit 4-C-2 to IPR's Registration Statement, Registration No. 2-27681.)

10.2 Amendments No. 1 and 2 to Power Sales Contract between IPR and Nebraska Public Power District. (Filed as Exhibit 4-C-2-a to IPR's Registration Statement, Registration No. 2-35624.)

10.3 Amendment No. 3 dated August 31, 1970, to the Power Sales Contract between IPR and Nebraska Public Power District, dated September 22, 1967. (Filed as Exhibit 5-C-2-b to IPR's Registration Statement, Registration No. 2-42191.)

10.4 Amendment No. 4 dated March 28, 1974, to the Power Sales Contract between IPR and Nebraska Public Power District, dated September 22, 1967. (Filed as Exhibit 5-C-2-c to IPR's Registration Statement, Registration No. 2-42191.)

10.5 Amended and Restated Agreement and Plan of Merger among Midwest Power Systems Inc., Iowa Public Service Company and Iowa Power Inc. (Filed as Annex A to Midwest Power Systems Inc.'s Registration Statement, Registration No. 33-42866)

Note: Pursuant to (b)(4)(iii)(A) of Item 601 of Regulation S-K, the Company has not filed as an exhibit to this Form 10-K every instrument with respect to long-term not being rgistered debt if the total amount of securities authorized thereunder does not exceed 10 percent of total assets of the Company but hereby agrees to furnish to the Commission on request any such instruments.

MIDWEST RESOURCES

666 GRAND AVENUE, PO BOX 9244
DES MOINES, IOWA 50306-9244
515-242-4300

FIVE YEAR FORECAST

RELEASED NOVEMBER 1993

Profile

Midwest Resources is the largest utility holding company in the state of Iowa, serving one-third of the state's electric and natural gas customers in urban, small town and rural areas. Midwest Power Systems, the utility subsidiary, serves 418,000 electric customers in Iowa and South Dakota and 337,000 natural gas customers in Iowa, South Dakota and Nebraska. The Company has additional holdings in nonregulated businesses. Midwest Resources has $2.5 billion in assets and nearly $900 million in annual revenues. The Company has 54,000 shareholders in all 50 states and 22 countries. Midwest Resources and its predecessors have paid dividends continuously since 1909.

Midwest Resources Financial Forecast

($ in millions)

	Projected 1993	Forecast 1994	Forecast 1995	Forecast 1996	Forecast 1997	Forecast 1998	Total 1994 - 1998
Capital Requirements							
Midwest Power Systems	$ 165	$ 167	$ 196	$ 189	$ 184	$ 189	$ 925
Midwest Capital Group	15	12	10	13	18	27	80
Maturities and Sinking Funds	22	8	7	40	9	78	142
Less: AFUDC	(1)	(3)	(4)	(3)	(4)	(3)	(17)
Subtotal Capital Requirements	$ 201	$ 184	$ 209	$ 239	$ 207	$ 291	$ 1,130
Refinanced Long-Term Debt	$ 675						
Total Capital Requirements	$ 876	$ 184	$ 209	$ 239	$ 207	$ 291	$ 1,130
Internal Sources of Capital							
Depreciation and Amortization	$ 116	$ 118	$ 117	$ 122	$ 122	$ 123	$ 602
Demand-Side Mgmt Amortization	0	4	7	13	16	18	58
Deferred Tax Items - Net	(10)	(10)	(5)	(1)	(1)	(4)	(21)
Other	25	17	32	24	31	40	144
Subtotal Internal Sources of Capital	$ 131	$ 129	$ 151	$ 158	$ 168	$ 177	$ 783
Percent of Total Capital Requirements		70%	72%	66%	81%	61%	69%
External Sources of Capital							
Long-Term Debt Financing	$ 632	$ 85	$ 40	$ 30	$ 35	$ 100	$ 290
Common Equity Financing	0	40	0	30	0	0	70
Short-Term Financing	113	(70)	18	21	4	14	(13)
Subtotal External Sources of Capital	$ 745	$ 55	$ 58	$ 81	$ 39	$ 114	$ 347
Percent of Total Capital Requirements		30%	28%	34%	19%	39%	31%
Total Sources of Capital	$ 876	$ 184	$ 209	$ 239	$ 207	$ 291	$ 1,130
Capitalization Ratios - Year-End							
Long-Term Debt	49%	49%	49%	48%	48%	48%	
Preferred Stock	5%	5%	5%	5%	5%	5%	
Common Equity	46%	46%	46%	47%	47%	47%	

Midwest Power Systems
Financial Forecast

($ in millions)

	Projected 1993	Forecast 1994	1995	1996	1997	1998	Total 1994 - 1998
Capital Requirements							
Midwest Power							
Capital Expenditures	$ 129	$ 129	$ 152	$ 149	$ 141	$ 145	$ 716
Demand-Side Mgmt Expenditures	10	10	13	13	15	15	66
Less: AFUDC	(2)	(2)	(4)	(3)	(4)	(3)	(16)
Subtotal Midwest Power	$ 137	$ 137	$ 161	$ 159	$ 152	$ 157	$ 766
Midwest Gas							
Capital Expenditures	$ 24	$ 23	$ 26	$ 21	$ 21	$ 21	$ 112
Demand-Side Mgmt Expenditures	3	4	5	6	7	8	30
Less: AFUDC	0	0	0	0	0	0	0
Subtotal Midwest Gas	$ 27	$ 27	$ 31	$ 27	$ 28	$ 29	$ 142
Midwest Power Systems							
Maturities and Sinking Funds	$ 14	$ 2	$ 1	$ 1	$ 3	$ 78	$ 85
Subtotal Midwest Power Systems	$ 14	$ 2	$ 1	$ 1	$ 3	$ 78	$ 85
Refinanced Long-Term Debt	$ 675						
Total Capital Requirements	$ 853	$ 166	$ 193	$ 187	$ 183	$ 264	$ 993
Internal Sources of Capital							
Depreciation and Amortization	$ 107	$ 110	$ 111	$ 116	$ 115	$ 116	$ 568
Demand-Side Mgmt Amortization	0	4	7	13	16	18	58
Deferred Tax Items - Net	1	0	(1)	0	(1)	(2)	(3)
Other	23	13	19	13	14	17	76
Subtotal Internal Sources of Capital	$ 131	$ 127	$ 137	$ 142	$ 144	$ 149	$ 699
Percent of Total Capital Requirements		77%	71%	76%	79%	56%	70%
External Sources of Capital							
Long-Term Debt Financing	$ 632	$ 85	$ 40	$ 30	$ 35	$ 100	$ 290
Common Equity Financing	0	40	0	30	0	0	70
Short-Term Financing	90	(86)	16	(15)	4	15	(66)
Subtotal External Sources of Capital	$ 722	$ 39	$ 56	$ 45	$ 39	$ 115	$ 294
Percent of Total Capital Requirements		23%	29%	24%	21%	44%	30%
Total Sources of Capital	$ 853	$ 166	$ 193	$ 187	$ 183	$ 264	$ 993
Capitalization Ratios - Year-End							
Long-Term Debt	47%	50%	50%	50%	50%	50%	
Preferred Stock	6%	5%	5%	5%	5%	5%	
Common Equity	47%	45%	45%	45%	45%	45%	
Pre-Tax Interest Coverage	3.2	3.2	3.3	3.1	3.1	3.2	

Midwest Power Systems
Operating Forecast

	Projected 1993	Forecast 1994	1995	1996	1997	1998	Compound Growth 1993 - 1998
Midwest Power (1)							
MWh Sales (in thousands) (2)							
Retail Sales	9,664	9,938	10,163	10,344	10,530	10,740	2.1%
Sales for Resale	3,934	4,952	4,465	4,504	4,620	4,278	1.7%
Total Sales	13,598	14,890	14,628	14,848	15,150	15,018	2.0%
Electric Generating Capability (MW)	2,836	2,938	2,938	2,938	2,938	2,938	
Capacity Purchases	359	357	378	258	251	251	
Capacity Sales	433	459	429	304	306	306	
Peak Demand	2,205	2,312	2,398	2,405	2,425	2,455	
Reserve Margin	25.3%	22.7%	20.4%	20.2%	18.9%	17.4%	
Fuel Sources							
Coal		78%	81%	81%	78%	80%	
Nuclear (3)		21%	18%	18%	21%	19%	
Oil/Gas		1%	1%	1%	1%	1%	
Total		100%	100%	100%	100%	100%	
Midwest Gas (1)							
MMCF Sales (2)							
Retail Sales	61,578	61,704	62,977	63,614	64,502	65,125	1.1%
Transportation Sales	13,407	13,960	14,538	15,122	15,706	16,290	4.0%
Total Sales	74,985	75,664	77,515	78,736	80,208	81,415	1.7%

Notes:

(1) Midwest Power Systems has two divisions: Midwest Power (electric) and Midwest Gas (natural gas).

(2) Legislation enacted in Iowa in 1990 requires electric and gas utilities to spend 2.0 percent and 1.5 percent, respectively, of their annual revenues on demand-side management programs. The impact of these programs has been reflected in the sales forecasts.

(3) The Company has a long-term power purchase contract with the Nebraska Public Power District for one-half the capacity of the Cooper Nuclear Station. The station went into service in 1974 and has generated significant amounts of energy for the Company since that time.

Key Assumptions

- Projected 1993 is based on actual results through June 1993 plus estimates for the last six months of the year.

- Electric peak load growth of 1.5% is forecasted for 1994-1998.

- The forecast assumes the addition of an 80 MW combustion turbine generator at the Pleasant Hill Energy Center in 1994. An application for regulatory approval of the unit was filed in October 1993.

- The forecast reflects the change in Midwest Gas sales due to the exchange of service territories with Minnegasco, which was finalized August 31, 1993.

- Rate increases for the period 1994-1998 are anticipated to be less than the rate of inflation.

- The inflation rate for operations and maintenance, excluding fuel, is projected to average 2.4% per annum.

- Projected 1993 Internal Generation, excluding the $675 million of redeemed debt, would be 65% of Capital Requirements for Midwest Resources and 74% for Midwest Power Systems.

Company Contacts

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(515) 281-2250

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Administrator-Finance
(515) 242-4380

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50306-9244