CASE NUMBER:

99-449

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

November 4, 1999

James B. Gainer
Legal Division
The Union Light Heat & Power Co
139 E. Fourth Street
Cincinnati, OH. 45202

RE: Case No. 99-449
THE UNION LIGHT, HEAT AND POWER COMPANY
(Integrated Resource Plan)

This letter is to acknowledge receipt of initial application in the above case. The application was date-stamped received November 1, 1999 and has been assigned Case No. 99-449. In all future correspondence or filings in connection with this case, please reference the above case number.

If you need further assistance, please contact my staff at 502/564-3940.

Sincerely,

Stephanie Bell

Stephanie Bell
Secretary of the Commission

SB/jc

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the 1999 Electric Long-Term Forecast Report of The Union Light, Heat and Power Company	)))	Case No. 99-449

MOTION TO PROTECT THE CONFIDENTIALITY OF INFORMATION CONTAINED IN UNION LIGHT, HEAT AND POWER COMPANY'S LONG-TERM FORECAST REPORT

The Union Light, Heat and Power Company (ULH&P) hereby moves this honorable Commission for leave to file certain portions of its Long-Term Forecast Report under seal. The portions of the Long-Term Forecast Report for which ULH&P requests confidentiality and the reasons why confidential treatment is necessary, are set forth in the attached Memorandum in Support.

Respectfully submitted

John J. Finnigan

John J. Finnigan, Jr. 86657
Senior Counsel
James B. Gainer 87288
Associate General Counsel
The Union Light, Heat and Power Company
107 Brent Spence Square
Covington, Kentucky 41011
(513) 287-3601

Attorneys for The Union Light, Heat and Power Company

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED NOV - 1 1999 PUBLIC SERVICE COMMISSION

In the Matter of the 1999 Electric Long-Term Forecast Report of The Union Light, Heat and Power Company	)))	Case No. 99-449

MEMORANDUM IN SUPPORT OF THE UNION LIGHT, HEAT AND POWER COMPANY's MOTION TO PROTECT THE CONFIDENTIALITY OF INFORMATION CONTAINED IN THE UNION LIGHT, HEAT AND POWER COMPANY's LONG-TERM FORECAST REPORT

The Union Light, Heat and Power Company (ULH&P) respectfully requests that the Kentucky Public Service Commission (Commission) grant its Motion to Protect the Confidentiality of Information Contained in ULH&P's Long-Term Forecast Report.

ULH&P is a Kentucky corporation with its principal office in Covington, Kentucky. ULH&P has the corporate power and authority, among others, to engage, and it is engaged, in the business of supplying electric utility service to the public in the Commonwealth of Kentucky. Accordingly, ULH&P is a public utility within the meaning of that term as used in K.R.S 278.010. As such ULH&P is subject to the jurisdiction of the Commission in the manner and to the extent provided by the laws of the Commonwealth of Kentucky. As of October 24, 1994, ULH&P's parent company, The Cincinnati Gas & Electric Company, became a wholly owned subsidiary of Cinergy Corp.

ULH&P owns, operates, manages and controls plants, properties and equipment used and useful for the production, transmission, distribution and furnishing of electric utility service to the public in the Commonwealth of Kentucky. ULH&P directly supplies electric energy to over 119,000 customers located in Northern Kentucky. ULH&P also sells electric energy for resale to municipal utilities, rural electric membership corporations and to other public utilities which in turn supply electric utility service to numerous customers in areas not served directly by ULH&P. Such sales for resale, and the rates charged therefor, are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) and are not the subject of this Motion.

As of the date of this Motion, ULH&P owns an electric transmission system and an electric distribution system in several communities in Kenton, Campbell, Boone, Grant and Pendleton counties in Northern Kentucky.

807 KAR 5:001, Section 7 allows ULH&P to seek leave of the Commission to file information contained in its Long-Term Forecast Report that ULH&P considers to be proprietary trade secret information, or otherwise confidential, in a redacted and non-redacted form under seal. This rule also establishes a procedure for presenting to the Commission that information which is confidential, and therefore should be protected. ULH&P is filing a redacted version of the 1999 Cinergy Long-Term Forecast

concurrently with this Motion. ULH&P is filing the three unredacted versions, under seal, as an exhibit to this Petition. ULH&P shall mark as confidential, trade secret, or proprietary, each redacted page of ULH&P's Long-Term Forecast.

ULH&P considers the redacted information to be proprietary, confidential, and trade secrets, as that term is used in 807 KAR 5:001, Section 7. The redacted version of the 1999 Cinergy Long-Term Forecast does not include the Confidential Information. The affidavit of Douglas F. Esamann, attached hereto as Exhibit A, describes the information for which ULH&P requests confidential treatment, and the reasons therefor. ULH&P reserves the right to file additional evidence, including affidavits of specific vendors, at a later time if such is necessary.

Three unredacted versions of ULH&P's Long-Term Forecast are filed herewith, under seal, as Exhibit B.

ULH&P respectfully requests that the Commission pursuant to 807 KAR 5:001, Section 7 grant its Motion to Protect the Confidentiality of Information Contained in ULH&P's Long-Term Forecast Report by making a determination that the Confidential Information is confidential, proprietary and a trade secret.

Respectfully submitted

John J. Finnigan, Jr. 86657
Senior Counsel
James B. Gainer 87288
Associate General Counsel
The Union Light, Heat and Power Company
107 Brent Spence Square
Covington, Kentucky 41011
(513) 287-3601

Attorneys for The Union Light, Heat and Power Company

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the 1999 Electric Long-Term Forecast Report of The Union Light, Heat and Power Company	)))	Case No. 99-449

NOV - 1 1999

AFFIDAVIT OF DOUGLAS F. ESAMANN

COMES NOW Douglas F. Esamann, being duly sworn, deposes and says:

1. My name is Douglas F. Esamann. I am employed by Cinergy Services, Inc. (Cinergy Services) as a Vice President. I perform the same function for Cinergy Corp.'s subsidiaries PSI Energy, Inc. (PSI) and The Cincinnati Gas & Electric Company (CG&E), parent company of The Union Light, Heat and Power Company (ULH&P).

2. This Affidavit is being filed with the Kentucky Public Service Commission (Commission) in support of ULH&P's Petition for a Determination that Certain Information Contained in the 1999 Cinergy IRP is Confidential Pursuant to 807 KAR 5:001, Section 7.

3. In developing the 1999 Cinergy Integrated Resource Plan (IRP), Cinergy Services, PSI, CG&E and ULH&P used certain confidential and proprietary information and data. Some of this data, as described below, is the confidential information of third parties who have taken reasonable steps to protect their confidential information, such as limiting the release of such information subject to confidentiality

agreements. Some of the data is the confidential information of Cinergy Services, PSI, CG&E and ULH&P.

4. A part of the data for which ULH&P seeks confidential treatment in the Petition is data supplied by New Energy Associates, L.L.C. (New Energy). In developing the 1999 Cinergy IRP, Cinergy used New Energy's state-of-the-art PROSCREEN II® and PROMOD IV® models, subject to a Licensing Agreement among Cinergy Services, PSI, CG&E and New Energy. This Licensing Agreement contains confidentiality provisions to protect New Energy's data.

5. In developing the 1999 Cinergy IRP, a forecast was used of potential market value for sulfur dioxide emission allowances developed by ICF Resources, Inc. CG&E agreed with ICF Resources, Inc. to keep such information confidential.

6. In developing the 1999 Cinergy IRP, a forecast was also used of sulfur dioxide emission allowance prices developed by Energy Ventures Analysis, Inc. (EVA). CG&E agreed with EVA to keep such information confidential.

7. In developing the 1999 Cinergy IRP, certain data developed by the Electric Power Research Institute (EPRI) was used which EPRI considers to be confidential and proprietary. CG&E agreed not to publish or make available to others such information without EPRI's prior written consent.

8. In developing the 1999 Cinergy IRP, certain data, including NO_x allowance prices, developed by Resource Data International, Inc. (RDI) was used, which RDI considers to be confidential and proprietary. CG&E agreed not to publish or make available to others such information without RDI's prior written consent.

9. In developing the 1999 Cinergy IRP, Services (Basic U.S. Economic Service, U.S. Economic Forecast Dataport, Limited Utility Cost Information Service, U. S. Energy Service) and certain data developed by DRI/McGraw-Hill (DRI) was used, which DRI considers to be confidential and proprietary. CG&E agreed not to publish or make available to others such information without DRI's prior written consent.

10. The other data for which ULH&P seeks confidential treatment in the Petition are the fuel price forecast, which was developed by Cinergy Services, the 1999 Cinergy SO_2 and NO_x compliance supply curves and plans, the Cinergy developed Energy Market Forecast (EMF), and certain other cost and unit performance information which is contained in the New Energy Confidential Data (ULH&P's Confidential Information).

ULH&P's Confidential Information provides actual or potential independent economic value for ULH&P and its ratepayers and should be treated as confidential. If fuel suppliers knew Cinergy Services' forecasted fuel prices, by station, such fuel suppliers would have an advantage in negotiating future fuel prices, to the detriment of ULH&P and its ratepayers. Furthermore, if competitors of ULH&P knew of such forecast, they would have an advantage in competing for new business against ULH&P.

11. The 1999 Cinergy SO_2 and NO_x compliance supply curves detail the expected marginal cost per ton of sulfur dioxide and nitrous oxide to comply with the Clean Air Act Amendments of 1990 and the NO_x SIP Call on the Cinergy System. Such information clearly has actual and potential independent economic value for ULH&P and its customers. If vendors knew the projected cost of compliance on the Cinergy System, they would have an unfair advantage over ULH&P with respect to the potential sales or purchase of SO_2 and NO_x emission allowances.

12. The 1999 Cinergy SO_2 and NO_x compliance plans detail the equipment and fuel switches necessary to comply with the Clean Air Act Amendments of 1990 and the NO_x SIP Call on the Cinergy System. Such information clearly has actual and potential independent economic value for ULH&P and its customers. If vendors knew the equipment and types of coal to be procured by the Cinergy System, they would have an unfair advantage over ULH&P in the pricing of such items.

13. The Cinergy-developed EMF details Cinergy's forecast of the future wholesale market price for energy. Such information clearly has actual and potential independent economic value for ULH&P and its

customers. If other sellers or purchasers of power knew Cinergy's market forecast, they would have an unfair advantage over ULH&P in the market.

14. Cinergy Services, PSI, CG&E and ULH&P have taken, and will continue to take, all reasonable steps in order to protect the ULH&P Confidential Information, including, but not limited to, only sharing such information internally on a need to know basis, and not releasing such information outside of the companies without appropriate confidentiality protection.

FURTHER AFFIANT SAITH NOT.

Douglas F. Esamann

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF BOONE)

Subscribed and sworn to before me this 25th day of October, 1999.

Notary Public

My Commission Expires:
May 3, 2003

My County of Residence:
Boone

CERTIFICATE OF SERVICE

A copy of the foregoing Integrated Resource Plan has been served by hand delivery or ordinary United States Mail, postage prepaid, to the following intervenors in ULH&P's last integrated resource plan review proceeding this 1st day of November, 1999:

Hon. Ann Louise Cheuvront
Assistant Attorney General
Kentucky Office of the Attorney General
1024 Capital Center Drive
Frankfort, KY 40602-2000

David Brown Kinloch
Soft Energy Associates
414 South Wenzel Street
Louisville, KY 40204

Hon. Carl Melcher
Northern Kentucky Legal Services
302 Greenup Street
Covington, KY 41011

Clint Hamm
Northern Kentucky Community Action Commission
13 West Seventh Street
Covington, KY 41012-0931

One copy of this Report will be kept at ULH&P's office at 7200 Industrial Rd., Florence, KY for public inspection during office hours. A copy of the Report will be provided to any person, upon request, at cost, to cover expenses incurred.

John J. Finnigan, Jr.
Senior Counsel

CINERGY®

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NOV - 1 1999
PUBLIC SERVICE COMMISSION

PSI Energy, Inc.
The Cincinnati Gas & Electric Company
The Union Light, Heat & Power Company

Case No. 99-449

1999

INTEGRATED RESOURCE PLAN

VOLUME I

November 1, 1999

By: Cinergy Services
Douglas F. Esamann, Vice President
139 East Fourth Street
P.O. Box 960
Cincinnati, Ohio 45201-0960

ULH&P ■ The Energy Service Company

The Union Light, Heat and Power Company
107 Brent Spence Square ·Covington, Kentucky 41012-0032

November 1, 1999

Hon. Don Mills, Executive Director
Public Service Commission of Kentucky
730 Schenkel Lane
Frankfort, KY 40602

RE: Cinergy 1999 Integrated Resource Plan

Dear Mr. Mills:

Pursuant to 807 KAR 5:058, and on behalf of The Union, Light, Heat & Power Company (ULH&P), Cinergy Services (Cinergy) submits ten (10) bound and one (1) unbound copies of the Cinergy 1999 Integrated Resource Plan (IRP) to the Public Service Commission of Kentucky. Please note that the 11 copies have been redacted to protect the confidentiality of certain information. Concurrently with the filing of this Cinergy 1999 IRP, ULH&P has filed a petition with the Commission requesting confidential treatment of such information.

The Cinergy IRP contains chapters generally covering areas such as: Objectives and Process, Load Forecast, Demand-Side Management, Supply-Side Resources, Clean Air Act Compliance Planning, Electric Transmission Forecast, and Selection and Implementation of the Plan. In addition, an Executive Summary, which provides a synopsis of the entire report, has been included. For your convenience, following "Attachment B" is a Kentucky Index which lists the Chapter(s) and Section(s) of the report that are responsive to each of the Kentucky regulations. To comply with the codes of conduct in FERC Order 889, items related to transmission and distribution were prepared independently, and have been compiled in a separate volume. A Kentucky specific Appendix is also included to address areas specific to Kentucky IRP regulations. All together, including the state specific appendix and the transmission information volume, each copy of the 1999 IRP consists of three volumes.

Please note that Jim Gainer, Legal Department, Room 25ATII, 139 East Fourth Street, Cincinnati, OH 45202, (513) 287-2633, is the Attorney of Record for this forecast.

Specific questions regarding the contents of this report should be directed to Diane L. Jenner, Asset Planning and Analysis, at the offices of Cinergy located at 1000 E. Main St., Plainfield, IN 46168.

Yours truly,

Douglas F. Esamann

Douglas F. Esamann, Vice President
Cinergy Services

ATTACHMENT "A"

Cinergy

1999 INTEGRATED RESOURCE PLAN

CERTIFICATE OF SERVICE

The undersigned states that he is a Vice President of Cinergy Services; that he is duly authorized in such capacity to execute and file this Integrated Resource Plan on behalf of The Union Light, Heat & Power Co., PSI Energy, Inc., and The Cincinnati Gas & Electric Company.

A copy of the attached "Notice of Filing" has been made by depositing the same in the United States mail, First Class postage prepaid to the following intervenors in ULH&P's last integrated resource plan review proceeding:

Hon. Ann Louise Cheuvront
Assistant Attorney General
Kentucky Office of the
Attorney General
1024 Capital Center Drive
Frankfort, KY 40602-2000

David Brown Kinloch
Soft Energy Associates
414 South Wenzel Street
Louisville, KY 40204

Hon. Carl Melcher
Northern Kentucky Legal
Services
302 Greenup Street
Covington, KY 41011

Clint Hamm
Northern Kentucky Community
Action Commission
13 West Seventh Street
Covington, KY 41012-0931

One copy of this Report will be kept at the principal business office of ULH&P (7200 Industrial Rd., Florence, KY) for public inspection during office hours. A copy of the Report will be provided to any person, upon request, at cost, to cover expenses incurred.

Douglas F. Esamann, Vice President

November 1, 1999
Date

ATTACHMENT "B"

NOTICE OF FILING

Please take notice that, pursuant to 807 KAR 5:058, Section 2, Part(2), The Union Light, Heat & Power Company ("ULH&P") has, this 1st day of October, 1999, filed a copy of the 1999 Cinergy Integrated Resource Plan ("IRP") with the Public Service Commission of Kentucky ("PSCKy").

This IRP contains Cinergy's assessment of various demand-side and supply-side resources to cost effectively meet jurisdictional customer electricity service needs.

A copy of the IRP, as filed, will be available for review at the offices of ULH&P, 7200 Industrial Rd., Florence, Kentucky, during normal business hours. A copy of this IRP will be provided, at cost, to cover expenses incurred, upon request.

KENTUCKY INDEX TO 1999 CINERGY IRP REPORT

Section 1. General Provisions
  No response required

Section 2. Filing Schedule
  No response required

Section 3. Waiver
  No response required

Section 4. Format
  (1) No response required
  (2) Kentucky Appendix

Section 5. Plan Summary
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  (2) Chapter 1, Sections B, C, D, E, F, G, H, I
  (3) Chapter 1, Section D
  (4) Chapter 1, Sections E, F, G, H, I
    Transmission Volume, Chapter 7, Section B
  (5) Chapter 1, Section I
  (6) Chapter 1, Section I

Section 6. Significant Changes
  Kentucky Appendix

Section 7. Load Forecasts
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  (2)(a) Kentucky Appendix
    (b) Kentucky Appendix
    (c) Kentucky Appendix
    (d) Chapter 3, Section G
    (e) Chapter 3, Section G
    (f) Chapter 3, Section G
    (g) Chapter 3, Section G
    (h) No response required
  (3) Chapter 3, Section G
  (4)(a) Chapter 3, Section G
    (b) Chapter 3, Section G
    (c) Chapter 3, Section G
    (d) Chapter 4, Sections A, B, C, F, G
      Kentucky Appendix
    (e) Kentucky Appendix
  (5)(a)(1) Chapter 3, Section G
      Kentucky Appendix
    (2) Chapter 3, Section G
      Kentucky Appendix

(b) (1) Chapter 3, Section G
(2) Chapter 3, Section G
(6) No response required
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(2) (a) Chapter 5, Sections B, F
Transmission Volume, Chapter 7, Section C
(b) Chapter 4, Sections A, B
(c) Chapter 5, Section F
Chapter 8, Section H
(d) Chapter 5, Sections C, E, F, G
(3) (a) Transmission Volume, Kentucky Appendix
(b) (1) Chapter 5, Figure 5-1
Chapter 8, Figures 8-5, 8-12, 8-13
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Chapter 8, Figure 8-5
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Chapter 8, Figure 8-5
(8) Chapter 5, Figures 5-1, 5-2
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(9) Chapter 5, Figure 5-1
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(10) Chapter 5, Figure 5-5
(11) Chapter 8, Figure 8-5
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(b) Kentucky Appendix

(c) General Appendix
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(e) General Appendix
(f) Kentucky Appendix
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(d) Chapter 5, Sections C, E, F, G

(e) (1) Chapter 4 Sections A, E, F
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(4) (a) Chapter 8, Figures 8-7, 8-9 through 8-11

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(g) Chapter 2, Section B
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No response required

Section 11. Procedures for Review of the Integrated Resource Plan
(1) No response required
(2) No response required
(3) No response required
(4) Kentucky Appendix

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PREFACE

Throughout this report, the Figures associated with each chapter or section of the appendix are located at the end of that chapter or section of the appendix for convenience.

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1. EXECUTIVE SUMMARY

A. SYSTEM DESCRIPTION

In the franchised service territories of its U.S. operating companies Cinergy serves the energy needs of 1.4 million electric customers and approximately 470,000 gas customers. Its service area spans 25,000 square miles in North Central, Central, and Southern Indiana, Southwestern Ohio, and Northern Kentucky.

The Cincinnati Gas and Electric Company (CG&E) and its utility subsidiaries operate in contiguous territories, providing electric service to approximately 748,000 customers and gas service to about 470,000 customers in an area covering some 3,000 square miles in Southwestern Ohio and adjacent areas in Kentucky and Indiana. The population of CG&E's service territory (including its utility subsidiaries) is estimated at 1.96 million and includes the cities of Cincinnati and Middletown, Ohio, and Covington and Newport, Kentucky.

The Union Light, Heat and Power Company (ULH&P), a wholly owned subsidiary of CG&E, provides electric and gas service in the Northern Kentucky area contiguous to the Southwestern Ohio area served by CG&E. ULH&P serves approximately 119,000 customers in its 500 square mile service territory. ULH&P owns an electric transmission system and an electric distribution system in several communities in Kenton, Campbell, Boone, Grant, and Pendleton counties of Northern Kentucky. ULH&P also owns a gas distribution system which serves either all or parts of Kenton, Campbell, Boone, Grant, Gallatin, and Pendleton counties in Northern Kentucky.

PSI Energy (PSI) is Indiana's largest electric utility, serving approximately 689,000 electric customers in 69 of Indiana's 92 counties covering North Central, Central, and Southern Indiana. Its service area spans 22,000 square miles with a population estimated at 2.5 million. It includes the cities of Bloomington, Terre Haute, and Lafayette, and suburban areas of Indianapolis, Louisville, and Cincinnati.

CG&E has a total installed net summer generation capability of 5,082 megawatts (MW), which includes 4,184 MW of coal-fired steam capacity and 898 MW of combustion turbine (CT) peaking capacity. The coal-fired generation is comprised of eighteen units located at seven stations. Eight of the CTs are oil-fired and ten are natural gas-fired. This includes the six newest, located at the

Woodsdale Generating Station, which are natural-gas fired with propane as a back-up fuel. Seven of the coal-fired steam units supplying capacity and energy to CG&E are jointly owned with Columbus Southern Power Company (CSP) and The Dayton Power and Light Company (DP&L). Four of the coal-fired steam units supplying capacity and energy to CG&E are commonly owned with DP&L.

PSI has a total installed net summer generation capability of 5,882 MW (excluding the ownership interests of Indiana Municipal Power Agency (IMPA) (156 MW) and Wabash Valley Power Association, Inc. (WVPA) (156 MW) in Gibson Generating Station Unit No. 5). This capacity consists of 5,535 MW of coal-fired, syngas-fired, or oil-fired steam capacity, 45 MW of hydroelectric capacity and 302 MW of peaking capacity. The steam capacity is comprised of twenty coal-fired units, one syngas-fired unit and one oil-fired unit located at six stations. The hydroelectric generation is a run-of-river facility comprised of three units. The peaking capacity consists of seven oil-fired diesels located at two stations, eight oil-fired CT units located at two stations, and one gas-fired CT with oil backup, which is the newest peaking unit, Cayuga 4.

The combined PSI/CG&E transmission system has extensive 345 kilovolt (kV), 230 kV, and 138 kV transmission lines and substations, including numerous strong interconnections with neighboring transmission providers. The primary purpose of the transmission system is to deliver bulk power into and/or across PSI's and CG&E's franchised service areas. The higher transmission voltages then generally are reduced to 138 kV and 69 kV to deliver the power to the numerous distribution substations or directly to large customers within the franchised service territories. Because of the numerous interconnections PSI and CG&E have with neighboring transmission providers, the combined CG&E/PSI transmission system increases electric system reliability and decreases costs to the customer by permitting the exchange of power and energy with other areas.

As of December 1998, the transmission system of CG&E and its subsidiary companies consisted of approximately 390 circuit miles of 345 kV lines (including CG&E's share of jointly-owned transmission) and 645 circuit miles of 138 kV lines. Portions of the 345 kV transmission system are jointly owned with CSP and/or DP&L. CG&E is interconnected with six other transmission providers (including PSI).

PSI, IMPA, and WVPA own the Joint Transmission System (JTS) in Indiana. The three co-owners have rights to use the JTS. As of December 1998, PSI's wholly and jointly owned share of transmission included approximately 857 circuit miles of 345 kV lines, 780 circuit miles of 230 kV lines and 1634 circuit miles of 138 kV lines. PSI is interconnected with nine other transmission providers (including CG&E).

B. PLANNING OBJECTIVES AND CRITERIA

An integrated resource planning process generally encompasses an assessment of a variety of supply-side, demand-side, and emission compliance alternatives leading to the formation of a diversified, long-term "least cost" portfolio of options intended to satisfy the electricity demands of customers located within a franchised service territory. The purpose of this Integrated Resource Plan (IRP) is to outline a strategy to furnish electric energy services in a reliable, efficient, and economic manner while factoring in environmental considerations. Another important aspect of the process is the preservation of options for the future, which also increases flexibility. The major objectives of the IRP presented in this filing are:

- Provide adequate, reliable, and economical service to customers while meeting all environmental requirements
- Maintain the flexibility and ability to alter the plan in the future as circumstances change
- Choose a near-term plan that is robust over a wide variety of possible futures
- Minimize risks

The reliability constraints utilized for this IRP are those currently approved by Public Utilities Commission of Ohio (PUCO), the Indiana Utility Regulatory Commission (IURC), and the Kentucky Public Service Commission (KyPSC), as listed below:

1. Minimum reserve margin of seventeen percent (17%);
2. Annual loss of load hours (LOLH) less than 175; and
3. Expected unserved energy (EUE) less than 0.18 percent.

C. PLANNING PROCESS

The advances in wholesale market competition, retail customer choice proposals, and various other proposed regulatory reforms have forced the electric utility business planning horizon to shrink. The analyses performed to prepare this IRP, or strategy, covered the period 1999-2019. Most of the planning model runs and sensitivity analyses were performed over the first ten year period, 1999-2008 (modeling period), with the primary focus being on the first five years, 1999-2003 (focus period). This technique was used in order to focus on the near-term while recognizing the fact that course corrections may be made along the way.

At the time the analysis for this IRP was begun, restructuring legislation in Ohio had not been enacted into law. As a result, the load level in this IRP reflects Cinergy continuing to serve its existing franchised service territory load throughout the forecast period.

The major Business Case or Base Case assumption concerning new laws and regulations is that no compliance changes beyond the NO_x SIP call will be required to be implemented throughout the modeling period (1999-2008). Risks associated with potential changes to environmental regulations are discussed further in Chapter 8, Section E. Risks associated with other changes to the Base Case assumptions are addressed through sensitivity analysis and qualitative reasoning in various sections of Chapters 5, 6, and 8.

The process utilized to develop the IRP consisted of two major components. One was organizational/structural, while the other was analytical.

The organizational process involved the formation of an IRP Team with representatives from key functional areas of Cinergy. The Team approach facilitated the high level of communication necessary across the functional areas required to develop an IRP. The Team also was responsible for examining the IRP requirements contained within the Indiana, Kentucky, and Ohio rules and conducting the necessary analyses to comply with them. In addition, it was important to select the best way to conduct the integration while incorporating interrelationships with other planning areas, e.g., fuel planning & procurement and, to the extent allowable considering the codes of conduct in FERC Order 889, transmission/distribution planning.

The analytical process involved the following specific steps:

1. Develop planning objectives and assumptions.

2. Prepare the franchised service territory electric load forecast(s).
3. Identify and screen potential electric demand-side resource options.
4. Identify, screen, and perform sensitivity analysis around the cost-effectiveness of potential electric supply-side resource options.
5. Identify, screen, and perform sensitivity analysis around the cost-effectiveness of potential emission compliance options.
6. Integrate the demand-side, supply-side, and emission compliance options.
7. Perform final sensitivity analyses on the integrated resource alternatives, and select the plan.
8. Determine the best way to implement the chosen plan.

The resource plan, or strategy, presented herein represents merely one possible outcome based upon a snapshot in time along the dynamic continuum of the business planning process.

D. LOAD FORECAST

The electric energy and peak demand forecasts of the franchised service territories within the Cinergy System in general, and of CG&E and its subsidiary companies (including ULH&P) and of PSI in particular, are prepared each year as part of the planning process. For this 1999 report, the forecast for the Cinergy System represents the sum of the individual forecasts for the CG&E (and subsidiaries) and PSI franchised service territories.

The general structure associated with the development of the Cinergy forecast involves three major components: a national economic forecast, economic forecasts for the CG&E and PSI service areas, and, finally, the electric load forecasts.

The national economic forecast provides information on the prospective growth of the national economy. This involves projections for numerous national economic and demographic concepts such as population, employment, industrial production, inflation, wage rates, and income. The national economic forecast was obtained from Data Resources, Inc. (DRI), a national economic consulting firm.

The forecast of the national economy is employed in conjunction with local economic data and a series of service area economic models to develop economic forecasts for each of the service areas in the Cinergy System. In turn, the service area economic forecasts are used along with energy and peak models to produce the electric load forecasts for CG&E and PSI.

1. Service Area Economic Forecast

The service area of the Cinergy system contains the CG&E and PSI service territories.

For CG&E and PSI, the forecast of local economic activity is produced by an internally developed and maintained regional economic model. This model incorporates the relative impacts of national and local events on the economy of Cinergy's service area.

With regard to the CG&E and PSI forecasts for employment, the commercial and governmental sectors are expected to continue to account for the bulk of local employment growth. Manufacturing employment is projected to remain relatively level, declining slightly.

2. Electric Energy And Peak Load Forecasts

The Cinergy projection of loads is the sum of the CG&E and PSI load projections.

Energy sales projections are prepared for the residential, commercial, industrial, and other sectors. Those components plus losses are aggregated to produce a forecast of net energy.

Table 1-1 provides information on the Cinergy System annual growth rates (before implementation of any new, or incremental, demand-side management programs) in energy for the major customer classes as well as net energy and peak demand.

TABLE 1-1

Cinergy System

ELECTRIC ENERGY AND PEAK LOAD

FORECAST: ANNUAL GROWTH RATES

	1999 - 2019
Residential MWH	1.2%
Commercial MWH	1.0%
Industrial MWH	2.1%
Net Energy MWH	1.4%
Summer Peak MW	1.4%
Winter Peak MW	1.3%

The forecast of net energy is graphically depicted on Figure 1-1, and the summer and winter peak forecasts are shown on Figure 1-2. These forecasts of energy and peak demand provide the starting point for the development of the Integrated Resource Plan.

E. DEMAND-SIDE MANAGEMENT RESOURCES

Cinergy, its customer representatives, and its regulators have begun taking steps to prepare for a competitive utility industry, not by abandoning energy efficiency, conservation, and demand reduction, but by shifting from ratepayer-subsidized Demand Side Management (DSM) programs to market-based, customer-driven energy-efficiency related products and services. Since the 1996 IRP was filed in Ohio on October 1, 1996, several key developments have changed the DSM portfolios of both CG&E and PSI.

CG&E - OHIO

On December 19, 1996, the Public Utilities Commission of Ohio (PUCO) issued an order in Case No. 95-203-EL-FOR, et al. The primary issues in that proceeding dealt with the role of DSM in the coming competitive environment. In its Order in the Case, the PUCO held that the fundamental assumption that validates DSM, namely the inherent cost sharing linkage among all customers of a utility, will be no longer valid in an open access, customer choice environment. The PUCO found that this calls into question the sustainability of cost transfers between participants and non-participants as the industry moves toward customer choice at the retail level.

In an effort to "...balance the probable future of an open access environment and the inherent delinkage of DSM cost sharing discussed above, with the potential for future DSM initiatives to produce avoided cost savings..."[1], the changes described below were made by the PUCO.

First, the Total Resource Cost (TRC) cost effectiveness test was revised to include only:

- Avoided environmental costs based on the internal cost to the utility of same;
- Avoided capacity costs that will occur over the next five years (in fact, the PUCO found that a five-year period, rather than the traditional 20-year period, is now more reasonable for analysis of costs and benefits for both the supply- and demand-side resources);

[1] Order in Ohio Case 95-203-EL-FOR, et al., p. 19.

- Fuel costs, but only after a demonstration that fuel cost savings resulted in benefits to all customers or the particular customer class.[2]

Second, the PUCO expressed concerns about the potential for stranded investment resulting from the company's investment in DSM, and concluded that steps should be taken immediately to minimize the risk.

Finally, the PUCO reaffirmed its commitment to the Collaborative process and ordered that up to one-half of the annual $4.8 million currently collected in rates for DSM should be allocated to community-beneficial energy conservation programs approved by the Collaborative and directed that the Collaborative should focus on programs which benefit difficult-to-reach segments of the residential market such as low-income customers. The PUCO's order also allows the costs associated with programs that do not pass cost-effectiveness tests to be included in this amount as long as they are recommended by the Collaborative and approved by the PUCO. It further ordered that the balance of the $4.8 million be allocated to reduce deferrals attributable to CG&E's prior DSM programs.

[2] Id. at 20.

The former Ohio Collaborative has been reorganized to respond to the changes brought about by the PUCO's December 1996 Order. In the place of the Ohio Collaborative, a new organization has been formed called the Cinergy/Community Energy Partnership (CCEP). The CCEP installed a new Board and developed the following new charter:

> *"The purpose of the Cinergy/Community Energy Partnership is to give Cinergy guidance and make recommendations on cost-effective programs that will benefit all residential customers, especially low income, and help the community become more energy efficient. The focus should be on the disadvantaged members of the community through weatherization assistance and help with PIPP* [Percentage of Income Payment Plan]."

Consistent with its new charter, the CCEP discontinued all programs that were not focused on the residential class. Since the CCEP Board does not recommend funding of the following programs through amounts already recovered in rates, and CG&E recognizes the need to minimize the risks associated with its growing deferral balance, the following programs will no longer be offered:

- Industrial Competitiveness Center

- Commercial/Industrial Energy Audit
- Commercial/Industrial Lighting Rebate
- Commercial/Industrial Lighting Technical Assistance
- Commercial/Industrial Adjustable Speed Drives
- Commercial/Industrial Premium Efficiency Motor
- Commercial/Industrial Customized Efficiency Audit
- Thermal Energy Storage

The following programs are currently offered:

- Electric Weatherization
- Energy Decisions Workshops
- Energy Efficient Refrigerator Replacement
- Energy-Recycle Education Awareness Program
- Energy Maintenance Services
- General Use Program
- Homebuyers' Workshop
- Home Energy House Call
- Internet Audit Tool
- Learn and Earn Program
- New Home Efficient Refrigerators
- New Home Owners' Training
- Non-Profit Energy Management Pilot Program (NEMP)
- Ohio Energy Project (formerly Ohio NEED)

ULH&P - KENTUCKY

As described in the April 1997 filing, the Kentucky Collaborative has continually considered the proper role of DSM as the industry moves toward retail competition. As a result, the Collaborative has focused on innovative low cost approaches for influencing the market, such as educational programs and collaborations with groups such as homebuilders' associations. As described in the previous IRP, the Commercial and Industrial (C&I) Work Team reviewed the C&I DSM program and decided not to request funding for their continuation beyond 1998. The primary reasons included: the lack of participation in the programs; the uncertainty that non-participants would realize projected benefits in a competitive environment; the belief that changes in the electric industry were driving the development of alternative approaches to conservation and/or load shape improvement that might be more sustainable than non-participant subsidized rebate programs. These include the development of innovative tariff options designed to influence the improvement of customers' load shapes and the growth of the competitive Energy Service Company (ESCo) market.

In October 1998, ULH&P, the Office of the Kentucky Attorney General (AG), and the Northern Kentucky

Community Action Commission (CAC), with the consensus of the Kentucky Collaborative, filed a request with the Kentucky Public Service Commission (KyPSC) for the continued funding of the following programs in Case No. 95-312:

- Residential Conservation and Energy Education
- Residential Energy Conservation Rates
- Residential Home Energy House Call
- Residential Comprehensive Energy Education Program
- Residential New Construction/Renovation Program

On November 23, 1998, the KyPSC approved the proposed DSM Riders, which were implemented in the first billing cycle of January 1999.

Since DSM costs are recovered contemporaneously in Kentucky, there are no issues related to outstanding deferral balances.

PSI Energy - INDIANA

In mid-1996, PSI began working with representatives from the Office of Utility Consumer Counselor (OUCC), the Citizen's Action Coalition of Indiana, Inc. (CAC), and the PSI-Industrial Group (PSI-IG) to develop a settlement agreement (Settlement Agreement or Agreement) that would:

1) Begin to move from traditional, ratepayer-subsidized DSM to market-based, customer-driven energy efficiency products and services; and 2) provide for recovery of PSI's DSM-related deferral balance.

The Indiana Utility Regulatory Commission (IURC) approved a Settlement Agreement on December 18, 1996 (Cause No. 40229). The Agreement provided ratepayer-subsidized incentives only for those market segments that the parties believed would not be priority targets for the "non-regulated" energy services companies, specifically residential and small to medium-sized commercial and industrial customers. In keeping with the terms of the Agreement, PSI discontinued all but the Low Income and Smart $aver® programs. The Smart $aver® program was changed in that its participant eligibility requirements were modified to include only the new construction residential market. While the Low Income and the Smart $aver® programs continue to be delivered by PSI, the four prescriptive incentive programs listed below were developed and implemented during the first quarter of 1997. The last three on the list were available only to commercial and industrial customers with peak electric demand below 500 kW.

- Residential Audit

- Residential Low-Income Program
- Lighting Incentive Plan
- Energy Efficient Cooling Systems
- Energy Efficient Motors

This is truly a transition strategy, wherein the traditional providers and energy service companies are primarily responsible for promotion and delivery of the programs to the market, and PSI is primarily responsible for administration of the program and processing of incentives.

The DSM Settlement Agreement is currently being renegotiated for the post-1999 period. The programs and impacts represented in this filing reflect Cinergy/PSI's best estimate regarding the outcome of those negotiations.

Cinergy DSM Program Screening

The DSM programs screened during this IRP process were those anticipated to be included in PSI's DSM Settlement Agreement, which is currently being negotiated. Cinergy does not rely on the impacts of any of the DSM programs currently being offered by CG&E and ULH&P, so they were not screened for inclusion in this IRP. All of the programs screened met the requirements of the Agreements or Orders under which they are administered and proceeded to the integration/optimization process.

The programs screened for this IRP were based upon those selected in the previous IRPs from a wide universe of potential DSM measures that was more than sufficient to achieve at least a 1% annual reduction in the level of forecasted retail energy sales and peak demand.

F. SUPPLY-SIDE RESOURCES

A wide variety of supply-side resource options were considered in the screening process. These generally included existing or potential purchases from other utilities, non-utility generation, and new utility-built generating units (conventional, advanced technologies, and renewables).

Potential equipment repairs, replacement of components, and efficiency changes at existing generating units are evaluated individually for their cost-effectiveness annually during the budgeting process. However, due to modeling limitations, the large number and wide ranging impacts of these individual changes made it impossible to include these numerous smaller-scale changes within the context of the IRP integration process. The routine economic evaluation of these smaller-scale changes generally is consistent with that utilized in the overall IRP process. As a result, the outcome and validity of this IRP have not been affected by this approach.

Because customers make cogeneration decisions based on their particular economic situations, neither PSI nor CG&E currently attempt to forecast specific megawatt levels of cogeneration activity in their respective service areas. However, as contracts are signed, the resulting energy and capacity supply will be reflected in future plans.

Over one hundred supply-side technologies from the Electric Power Research Institute (EPRI) Technical Assessment Guide Supply-Side Technologies (TAG-Supply™) and other sources were screened using a set of relative dollar per kilowatt-year versus capacity factor screening curves. Sensitivity analyses were performed to determine what data input and/or assumption changes would be necessary to make a technology that is not economical under base case conditions become economical. The surviving options, which were available during the 1999-2008 modeling period in the final base case integration process, were 165 MW and 214 MW Combustion Turbines (CT), and 256 MW and 378 MW Combined Cycle Units (CC) (summer ratings). These units could represent potential non-utility generating units, purchases, repowering of existing Cinergy units, or utility-constructed units. The remaining bids from the Cinergy 1999 Resource Bidding Program also were incorporated as supply-side resources.

G. CLEAN AIR ACT COMPLIANCE

SO_2

Cinergy used a market-based planning process to evaluate options for compliance with the Clean Air Act Amendments (CAAA) of 1990 in order to develop a plan that, when integrated into the resource planning process, meets the requirements of the CAAA in a reliable, cost-effective manner. This iteration of the compliance planning process focused primarily on Phase II (2000 and beyond) compliance. Both of the Cinergy Operating Companies previously had developed, filed and received approval of, and implemented, strategies for complying with the Phase I (1995 through 1999) requirements. Coal and emission allowance prices currently projected for the balance of Phase I support continuation of these strategies.

The Phase II CAAA SO_2 planning was conducted in three phases which involved: 1) a technical feasibility screening of compliance options; 2) an economic screening of compliance options; and 3) integration of the options passing through the screenings into the resource plan, thereby producing an integrated resource/CAAA compliance plan. A wide range of alternatives were considered including the use of higher sulfur Indiana and Ohio coals and scrubber technologies as well as fuel switches to lower sulfur coals. Through the screening processes and various sensitivity analyses (which were performed using proprietary models developed by The NorthBridge Group), the most feasible technologies, from a technical and economic perspective, were identified for inclusion into the integration process.

The SO_2 compliance alternatives surviving the screening process and passed to the integration process included Powder River Basin (PBR) coal (an extremely low-sulfur Western coal), Midwestern (Illinois Basin) Medium Sulfur Coal (MMSC) and Northern Appalachian Medium Sulfur (NAMSC) at several PSI units. At the CG&E units, fuel switches to Northern Appalachian Medium Sulfur and Central Appalachian Low Sulfur (CALSC) coals were included in the integration process.

To verify the cost and performance characteristics of units burning low-sulfur coals, additional test burns still need to be performed. In addition, issues regarding the joint-ownership of several Cinergy units need to be considered. Therefore, the results of this analysis should be considered preliminary.

NO_x

On September 24, 1998, USEPA Administrator, Carol Browner, signed the "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for purposes of Reducing Regional Transport of Ozone" or State Implementation Plan (SIP) call for revision under Section 110 of the Clean Air Act. The final rule was published in the Federal Register on October 27, 1998. States are directed to respond to the call by submitting revised SIPs by September 24, 1999, and source reductions to meet the NO_x emission budget per state are to be met by May 1, 2003.

The NO_x SIP Call establishes NO_x budgets for each of the 23 affected jurisdictions that will apply during the summer ozone season (May 1 through September 30) beginning in 2003. States are directed to revise their SIPs by reducing NO_x emissions from a number of sources including electric utilities. The electric utility NO_x emission rate is based upon 0.15 lb./MMBtu, but would be administered by USEPA through a regional cap and trade program similar to the Acid Rain Program for SO_2.

The United States Court of Appeals has recently (May 25, 1999) stayed indefinitely the implementation of USEPA's NO_x SIP Call pending the Court's resolution of the various other NO_x emission and ozone related regulatory and litigation activities.

Even though the stay of the SIP Call has been granted, Cinergy continues to study the compliance options available to comply with future NO_x emission reductions. The level of reductions and timing for compliance are unknown and likely to remain uncertain until next spring. However, given that USEPA's previous compliance date would have been extremely difficult to meet and still retain Cinergy's system reliability, it is still prudent to be prepared to cost effectively meet USEPA's emission reduction goals.

A large number of potential NO_x reduction projects were considered. They include Combustion Controls, such as Low NO_x burners and combustion tuning, and post

Combustion NO_x Controls, such as Selective Non-catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). Sensitivity analyses were performed to evaluate a number of emerging technologies.

Cinergy used a marginal cost based model that ranks each potential NO_x reduction project using the potential NO_x tons removed, the capital cost, and the O&M costs (both fixed and variable). After ranking the projects from lowest to highest marginal cost per ton of NO_x reduced, the model continues to select projects until enough tons have been removed so that estimated emissions are less than the expected allocation.

The compliance plan that was developed assumes that trading will be permitted across the entire Cinergy system. This decision ultimately rests with the individual States when they develop their State Implementation Plans (SIP). It is assumed that because of the stringency of EPA's NO_x SIP Call and the lack of a fluid market, that trading will comprise a relatively small amount of overall compliance. The Cinergy compliance plan therefore assumes that compliance will be accomplished on system. However the plan is structured to utilize trading should allowance prices fall below the highest marginal cost reduction projects.

Several of Cinergy's generating units are located close to areas in non-attainment with the current one-hour ozone standard. These areas include Cincinnati and Louisville. In addition, USEPA is implementing a new, more restrictive 8-hour ozone standard. This new standard is expected to create many additional non-attainment areas. In preparation of the SIPs, states have the ability to target specific areas for reductions. As a result, Cinergy could be required to make specific reductions in these areas. These reductions may not result in the lowest cost plan based on marginal cost per ton removed.

H. ELECTRIC TRANSMISSION FORECAST

In compliance with the codes of conduct in FERC Order 889, the relevant transmission information is located in the Transmission Volume or this report, which was prepared independently.

I. SELECTION AND IMPLEMENTATION OF THE PLAN

Once the screening processes were completed, the demand-side, supply-side, and compliance options were integrated into a set of resource plans, or strategies, using a consistent method of evaluation. PROSCREEN II® was the model utilized in this final integration process. From the optimized plans, four significantly different types of plans were selected. The sensitivity analysis methodology used in this IRP performs more detailed analysis at the front-end, or screening stage, and less detailed analysis at the back-end, or final integration stage. The sensitivity addressed at the integration stage was a lower load level sensitivity. Environmental risks and regulatory impacts were considered also.

Based upon both the quantitative and qualitative results of the screening analyses, sensitivity analyses, and environmental considerations, the plan selected to be the 1999 IRP is shown in Figure 1-3. The details of the plan including yearly capacity, purchases, capacity additions, retirements/derates, cogeneration, load, DSM, interruptible load, firm sales and reserve margins for Cinergy, PSI, and CG&E are shown in Figure 1-4.

The relative value for the 1998 Present Value Total Cost obtained from the PROVIEW™ output for the 1999 IRP is $29,869,692,000. The effective after-tax discount rate used was 7.62%. This plan had the lowest Present Value Total Cost.

This plan contains the DSM bundle (described in Chapter 4). The supply-side resources consist of purchases for 1999-2002, a combination of purchases and CTs in 2003, and a number of Combustion Turbines in 2004-2006. From 2009 to 2014, the plan contains 800 MW of Fuel Cell capacity. In 2011, 378 MW of CC capacity is added, and, from 2015 to 2018, one CT each year is added.

The IRP includes the projected SO_2 and NO_x compliance options described in Chapter 6. Any shortfalls between the yearly allowance allocation from the USEPA and the actual SO_2 and NO_x emitted will be supplied by Cinergy's allowance banks or by allowance purchases from the market.

It should be noted that, for the CG&E units that are jointly owned by Columbus Southern Power and Dayton Power & Light, the impacts on the co-owners must be considered and a decision made jointly as to how to meet compliance requirements. The results of this IRP reflect only the preliminary economic analysis performed by Cinergy, from a Cinergy perspective.

In making decisions concerning what steps to take to begin the implementation of the 1999 IRP, careful consideration must be given to the rapidly changing environment in which utilities operate. Some of the key issues or uncertainties are:

- Regulatory Climate - USEPA finalized new NAAQS for ozone and fine particulate matter in July 1997 and in September 1998 finalized the ozone transport SIP Call requiring NO_x emission reductions. However, implementation of all three regulations have been delayed by the courts and future requirements for emission reductions and deadlines are uncertain. The potential exists for additional regulation to be imposed on utilities in the form of CO_2 legislation, carbon taxes and energy taxes, regional haze, and air-toxics measures, to name a few.
- Customer Choice/Competition - Wholesale competition is a current reality. Many state commissions and legislatures (including Ohio & Indiana) either have been investigating restructuring the utility industry to allow direct access or retail wheeling or have already enacted such changes (see Amended Substitute Senate Bill Number 3 as passed by the 123rd General Assembly of Ohio, and signed by the Governor of Ohio on

July 6, 1999). These factors heighten the uncertainty surrounding the load level that should be included in a utility's plan.

- Wholesale Customer Uncertainties - With wholesale transmission access, wholesale customers now have more choices concerning their power supplier(s), which adds uncertainty as to what level of load Cinergy should be using in its planning.
- Technological and Market Advances - Technological advances could affect the types of resources needed for the future. The heightened level of competition also could ultimately result in the "commoditization" of electricity.

All of the uncertainties outlined above underscore the need to remain flexible in the implementation of the plan. Future investments must be approached cautiously to maintain or enhance the opportunity to react, respond, and adjust to change as it occurs, while still preserving as many options as reasonably possible.

Cinergy has not yet contracted for the purchases shown in the plan for the summers of 2000-2003. Decisions concerning whether to exercise the 100 MW call option purchased in the 1996 RFP will be made prior to the

Option Exercise Date each Spring based on the economics at the time. The purchases will be comprised of a combination of forward or option or unit power contracts secured prior to the time required and spot purchases from the market on either a weekly or daily basis. The decision as to the actual types of purchases that Cinergy will make depends on the relative prices of the alternatives available at that time. In addition, the uncertainties enumerated above suggest that smaller purchases than what is shown in the plan may be required. As a result, the Operations and Power Marketing and Trading departments, which are constantly monitoring both the Cinergy system and the regional marketplace, in consultation with Asset Planning and Analysis and the Operating Committee, will use their judgment to make decisions concerning the proper timing, type, and quantity of purchases required based on the need projections and applicable conditions at the time.

The CTs shown in the plan beginning in 2003 will continue to be studied to determine whether the need is of the magnitude indicated (see discussion of uncertainties above) and to determine the most economical ways of serving whatever need exists. As stated previously, the purchases, CTs, CC, and Fuel Cells in the plan represent "placeholders" for capacity and energy needs on the system. These needs can be fulfilled by purchases from the market, cogeneration, repowering, or other capacity that may be economical at the time decisions to acquire new capacity are required.

To comply with Phase II sulfur dioxide emission requirements, Cinergy's current strategy, as described in detail in Chapter 6, includes a combination of switching to lower-sulfur coals and using an emission allowance banking strategy. This cost-effective strategy will allow Cinergy to meet Phase II sulfur dioxide reduction requirements while maintaining optimal flexibility. Cinergy intends to use an emission allowance banking strategy to the extent a viable emission allowance market exists. However, the availability and economic value of emission allowances over the long term is still uncertain. In the event the market price for emission allowances or lower-sulfur coal increases substantially from the current forecast, Cinergy could be forced to implement high capital cost compliance options. Fuel switches generally can be implemented in two years or less. Therefore, the implementation of a number of these fuel switches has not been finalized at this time.

The NO_x compliance strategy is also detailed in Chapter 6. Even though the stay of the SIP Call has been granted, Cinergy continues to study the compliance options available to comply with future NO_x emission reductions. The level of reductions and timing for compliance are unknown and likely to remain uncertain until next spring. However, given that USEPA's previous compliance date would have been extremely difficult to meet and still retain Cinergy's system reliability, it is still prudent to be prepared to cost effectively meet USEPA's emission reduction goals. Whenever possible, Cinergy plans to implement the NO_x compliance controls during regularly scheduled unit outages.

Cinergy will be closely monitoring the SO_2 and NO_x emission allowance markets to determine whether the SO_2 and NO_x compliance plans continue to be economic. These compliance strategies will be adjusted as needed to ensure that the most economical plans are implemented.

The 1999 IRP is consistent with the overall planning objectives. Cinergy provides for the reliability of the system while maintaining flexibility and the preservation of options in order to be positioned to react to the future.

Figur -1

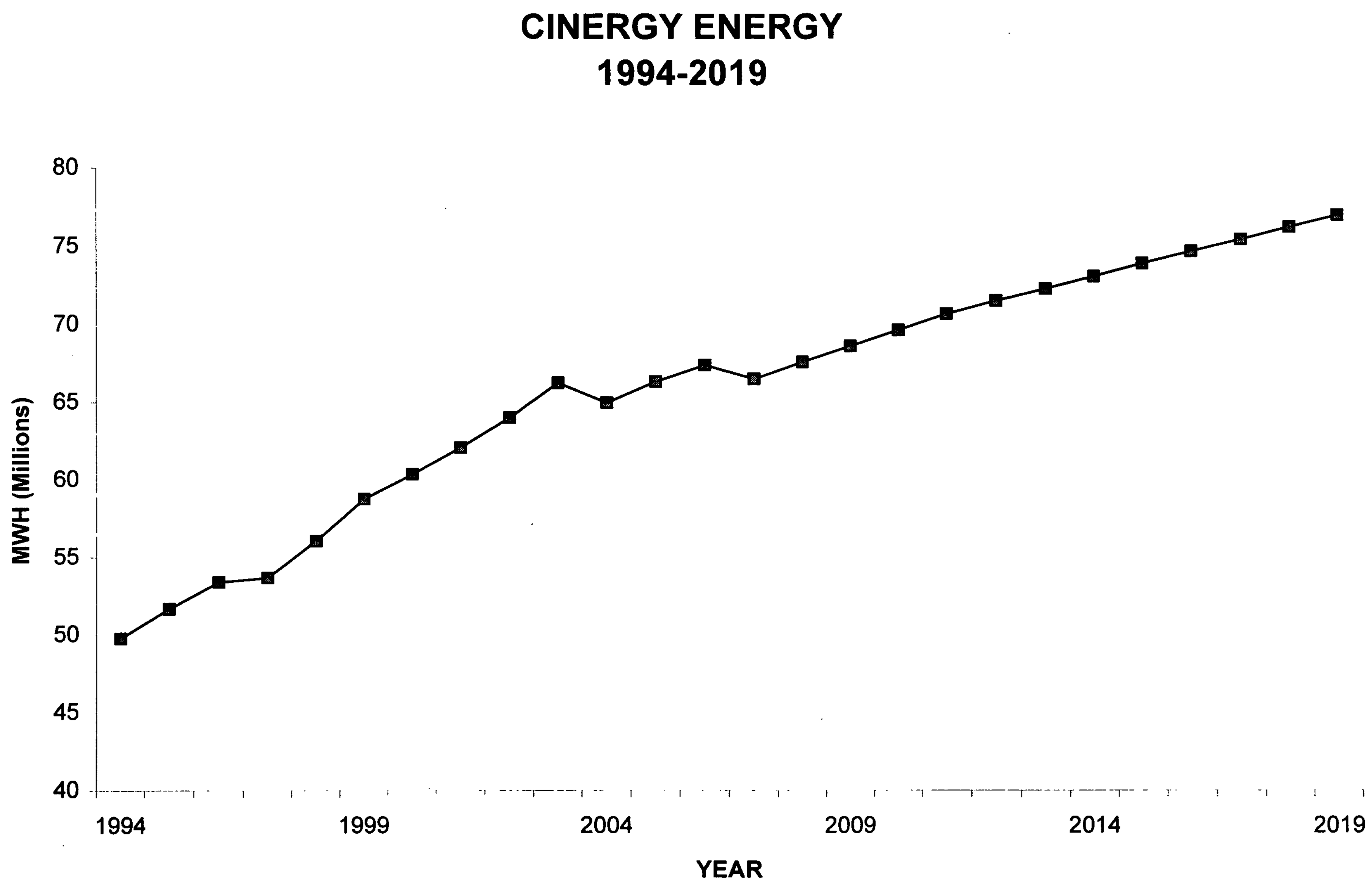
CINERGY ENERGY
1994-2019
MWH (Millions)
80
75
70
65
60
55
50
45
40
1994
1999
2004
2009
2014
2019
YEAR

Figure 1-2

CINERGY SUMMER AND WINTER PEAKS
1994-2019

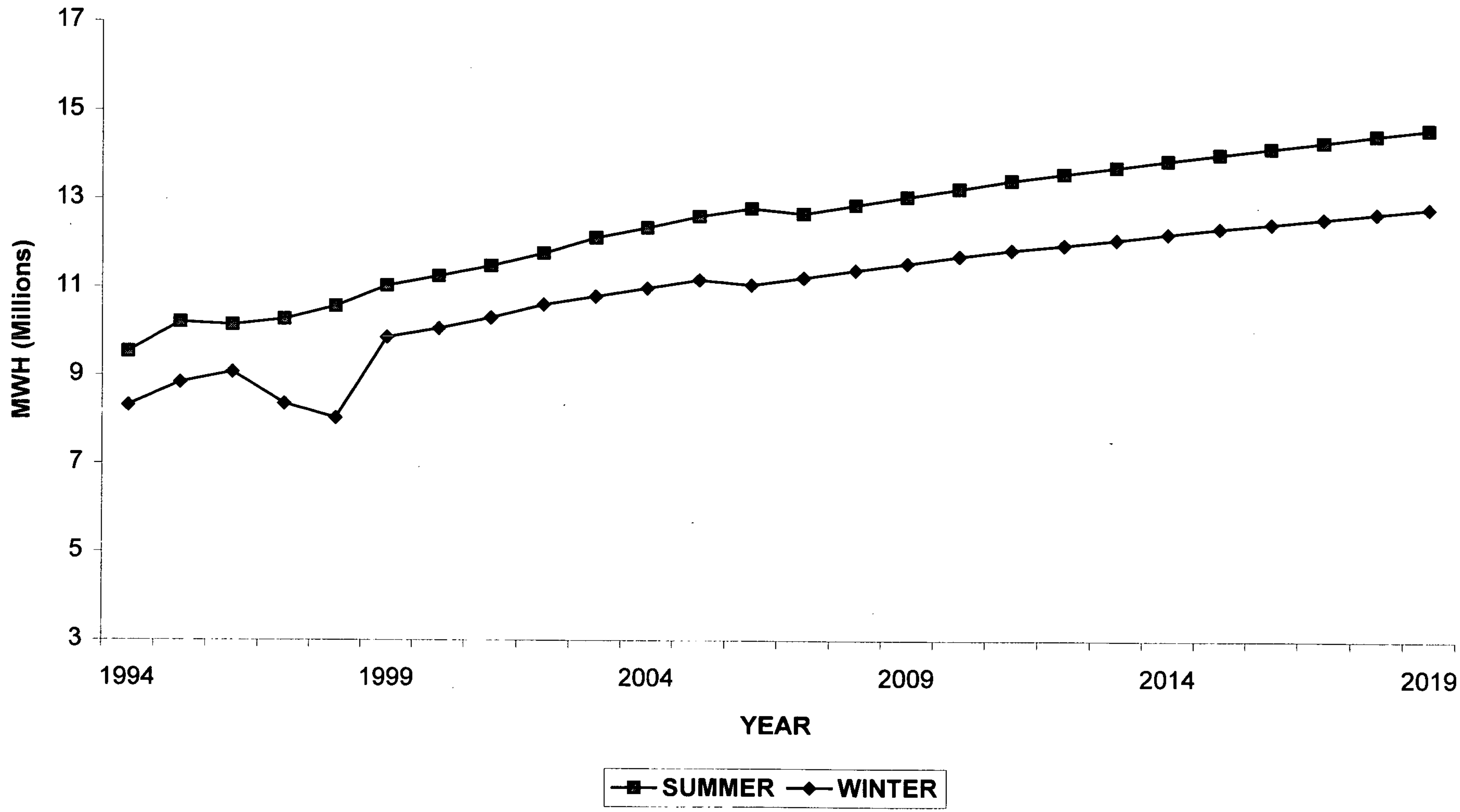

Figure 1-3

1999 CINERGY INTEGRATED RESOURCE PLAN

YEAR	NEW RESOURCE ADDITIONS
1999	DSM Bundle 763 MW Purchase
2000	1460 MW Purchase
2001	1740 MW Purchase
2002	2070 MW Purchase
2003	2200 MW Purchase 2-165 MW CTs
2004	11-214 MW CTs
2005	2-214 MW CTs
2006	1-214 MW CT
2007	
2008	
2009	8-25 MW Fuel Cells
2010	8-25 MW Fuel Cells
2011	1-378 MW CC
2012	
2013	8-25 MW Fuel Cells
2014	8-25 MW Fuel Cells
2015	1-214 MW CT
2016	1-214 MW CT
2017	1-214 MW CT
2018	1-214 MW CT
2019	

Figure 1-4

CINERGY
1999 INTEGRATED RESOURCE PLAN

CINERGY TOTAL

YEAR	INITIAL CAPACITY*	SHORT TERM PURCH.	INCR. CAPACITY ADDITIONS	INCR. CAPACITY RETIRE./ DERATES	PURCH. COGEN. CAPACITY	TOTAL CAPACITY	PEAK LOAD**	EXIST. DSM***	INCR. DSM	ENERGY OPTIONS	INDUSTRIAL AS AVAIL. LOAD	INDUSTRIAL INTER. LOAD	FIRM SALES	NET LOAD	RES. MAR. (%)
1999	11183	813	78	0	4	12078	11035	-2	-1	-103	-169	-165	70	10664	13.3
2000	11261	1460	5	0	4	12730	11252	-2	-2	-103	-170	-163	70	10881	17.0
2001	11266	1740	0	0	4	13010	11483	-2	-2	-103	-171	-158	70	11116	17.0
2002	11266	2070	0	0	4	13340	11772	-2	-2	-103	-171	-158	70	11405	17.0
2003	11266	2200	330	-44	4	13756	12124	-2	-2	-103	-172	-158	70	11756	17.0
2004	11552	0	2354	0	4	13910	12356	-2	-2	-103	-173	-158	70	11987	16.0
2005	13906	0	428	0	4	14338	12615	-2	-2	-103	-173	-158	70	12246	17.1
2006	14334	0	214	0	4	14552	12795	-2	-2	-103	-174	-158	70	12425	17.1
2007	14548	0	0	0	4	14552	12676	-2	-2	-103	-174	-158	70	12306	18.2
2008	14548	0	0	0	4	14552	12871	-2	-2	-103	-174	-158	70	12501	16.4
2009	14548	0	200	0	4	14752	13060	-2	0	-103	-174	-158	70	12692	16.2
2010	14748	0	200	0	4	14952	13246	-2	0	-103	-174	-158	70	12878	16.1
2011	14948	0	378	0	4	15330	13435	-2	0	-103	-174	-158	70	13067	17.3
2012	15326	0	0	0	4	15330	13586	-2	0	-103	-174	-158	70	13218	16.0
2013	15326	0	200	0	4	15530	13734	-1	0	-103	-174	-158	70	13367	16.2
2014	15526	0	200	0	4	15730	13884	0	0	-103	-174	-158	70	13518	16.4
2015	15726	0	214	0	4	15944	14035	0	0	-103	-174	-158	70	13669	16.6
2016	15940	0	214	0	4	16158	14176	0	0	-103	-174	-158	70	13810	17.0
2017	16154	0	214	0	4	16372	14314	0	0	-103	-174	-158	70	13948	17.4
2018	16368	0	214	0	4	16586	14467	0	0	-103	-174	-158	70	14101	17.6
2019	16582	0	0	0	4	16586	14599	0	0	-103	-174	-158	70	14233	16.5

* Including Gibson 5 capacity owned by IMPA and WVPA
Excluding EKPC Purchase and previous year's Short Term Purchases
15MW derate to serve steam to Inland Container has been deducted

** Including IMPA and WVPA peak load requirements corresponding to their Gibson 5 ownership
Excluding WVPA Supplemental Load beginning 1/1/98
Excluding IMPA Supplemental Load beginning 1/1/07
Excluding customer cogeneration

*** Not included in load forecast

Figure 1-4

CINERGY
1999 INTEGRATED RESOURCE PLAN

PSI SYSTEM

YEAR	INITIAL CAPACITY*	SHORT TERM PURCH.	INCR. CAPACITY ADDITIONS	INCR. CAPACITY RETIRE./ DERATES	PURCH. COGEN. CAPACITY	TOTAL CAPACITY	PEAK LOAD**	EXIST. DSM***	INCR. DSM	ENERGY OPTIONS	INDUSTRIAL AS AVAIL. LOAD	INDUSTRIAL INTER. LOAD	FIRM SALES	NET LOAD	RES. MAR. (%)
1999	6158	366	21	0	4	6549	6050	-2	-1	-44	-169	-132	70	5772	13.5
2000	6179	694	5	0	4	6882	6162	-2	-2	-44	-170	-132	70	5882	17.0
2001	6184	848	0	0	4	7036	6293	-2	-2	-44	-171	-132	70	6012	17.0
2002	6184	1055	0	0	4	7243	6473	-2	-2	-44	-171	-132	70	6192	17.0
2003	6184	1199	134	-25	4	7496	6688	-2	-2	-44	-172	-132	70	6406	17.0
2004	6293	0	1248	0	4	7545	6785	-2	-2	-44	-173	-132	70	6502	16.0
2005	7541	0	139	0	4	7684	6846	-2	-2	-44	-173	-132	70	6563	17.1
2006	7680	0	78	0	4	7762	6912	-2	-2	-44	-174	-132	70	6628	17.1
2007	7758	0	0	0	4	7762	6694	-2	-2	-44	-174	-132	70	6410	21.1
2008	7758	0	0	0	4	7762	6792	-2	-2	-44	-174	-132	70	6508	19.3
2009	7758	0	0	0	4	7762	6893	-2	0	-44	-174	-132	70	6611	17.4
2010	7758	0	37	0	4	7799	6999	-2	0	-44	-174	-132	70	6717	16.1
2011	7795	0	202	0	4	8001	7102	-2	0	-44	-174	-132	70	6820	17.3
2012	7997	0	0	0	4	8001	7189	-2	0	-44	-174	-132	70	6907	15.8
2013	7997	0	114	0	4	8115	7266	0	0	-44	-174	-132	70	6986	16.2
2014	8111	0	100	0	4	8215	7341	0	0	-44	-174	-132	70	7061	16.4
2015	8211	0	114	0	4	8329	7422	0	0	-44	-174	-132	70	7142	16.6
2016	8325	0	115	0	4	8444	7498	0	0	-44	-174	-132	70	7218	17.0
2017	8440	0	118	0	4	8562	7575	0	0	-44	-174	-132	70	7295	17.4
2018	8558	0	108	0	4	8670	7652	0	0	-44	-174	-132	70	7372	17.6
2019	8666	0	0	0	4	8670	7722	0	0	-44	-174	-132	70	7442	16.5

* Including Gibson 5 capacity owned by IMPA and WVPA
Excluding EKPC Purchase and previous year's Short Term Purchases
15MW derate to serve steam to Inland Container has been deducted

** Including IMPA and WVPA peak load requirements corresponding to their Gibson 5 ownership
Excluding WVPA Supplemental Load beginning 1/1/98
Excluding IMPA Supplemental Load beginning 1/1/07
Excluding customer cogeneration

*** Not included in load forecast

Figure 1-4

CINERGY
1999 INTEGRATED RESOURCE PLAN

CG&E SYSTEM

YEAR	INITIAL CAPACITY*	SHORT TERM PURCH.	INCR. CAPACITY ADDITIONS	INCR. CAPACITY RETIRE./ DERATES	PURCH. COGEN. CAPACITY	TOTAL CAPACITY	PEAK LOAD**	EXIST. DSM***	INCR. DSM	ENERGY OPTIONS	INDUSTRIAL AS AVAIL. LOAD	INDUSTRIAL INTER. LOAD	FIRM SALES	NET LOAD	RES. MAR. (%)
1999	5025	447	57	0	0	5530	4985	-1	0	-59	0	-33	0	4892	13.0
2000	5082	766	0	0	0	5848	5090	-1	0	-59	0	-31	0	4999	17.0
2001	5082	892	0	0	0	5974	5190	-1	0	-59	0	-26	0	5104	17.1
2002	5082	1015	0	0	0	6097	5299	-1	0	-59	0	-26	0	5213	17.0
2003	5082	1001	196	-20	0	6259	5436	-1	0	-59	0	-26	0	5350	17.0
2004	5258	0	1106	0	0	6364	5571	-1	0	-59	0	-26	0	5485	16.0
2005	6364	0	289	0	0	6653	5769	-1	0	-59	0	-26	0	5683	17.1
2006	6653	0	136	0	0	6789	5883	-1	0	-59	0	-26	0	5797	17.1
2007	6789	0	0	0	0	6789	5982	-1	0	-59	0	-26	0	5896	15.2
2008	6789	0	0	0	0	6789	6079	-1	0	-59	0	-26	0	5993	13.3
2009	6789	0	200	0	0	6989	6167	-1	0	-59	0	-26	0	6081	14.9
2010	6989	0	163	0	0	7152	6247	-1	0	-59	0	-26	0	6161	16.1
2011	7152	0	176	0	0	7328	6333	-1	0	-59	0	-26	0	6247	17.3
2012	7328	0	0	0	0	7328	6397	-1	0	-59	0	-26	0	6311	16.1
2013	7328	0	86	0	0	7414	6468	-1	0	-59	0	-26	0	6382	16.2
2014	7414	0	100	0	0	7514	6543	0	0	-59	0	-26	0	6458	16.4
2015	7514	0	100	0	0	7614	6613	0	0	-59	0	-26	0	6528	16.6
2016	7614	0	99	0	0	7713	6678	0	0	-59	0	-26	0	6593	17.0
2017	7713	0	96	0	0	7809	6739	0	0	-59	0	-26	0	6654	17.4
2018	7809	0	106	0	0	7915	6815	0	0	-59	0	-26	0	6730	17.6
2019	7915	0	0	0	0	7915	6877	0	0	-59	0	-26	0	6792	16.5

* Including Gibson 5 capacity owned by IMPA and WVPA
Excluding EKPC Purchase and previous year's Short Term Purchases
15MW derate to serve steam to Inland Container has been deducted

** Including IMPA and WVPA peak load requirements corresponding to their Gibson 5 ownership
Excluding WVPA Supplemental Load beginning 1/1/98
Excluding IMPA Supplemental Load beginning 1/1/07
Excluding customer cogeneration

*** Not included in load forecast

2. OBJECTIVES AND PROCESS

A. INTRODUCTION

The CG&E system consists of 36 generating units representing 5,082 MW of summer capability, and the PSI system consists of 41 generating units representing 6,194 MW of summer capacity (including the ownership interests of Indiana Municipal Power Agency (IMPA) and Wabash Valley Power Association, Inc. (WVPA) in Gibson 5).

In this Integrated Resource Plan (IRP) process, the modeling of CG&E includes the electric loads and supply resources associated with the CG&E franchised service territory and the franchised service territories of its subsidiaries, which include The Union Light, Heat and Power Company (ULH&P). The modeling of PSI includes the electric loads and supply resources associated with the PSI franchised service territory plus the WVPA and IMPA ownership shares in Gibson 5 and the corresponding load served by those shares since PSI provides back-up service for Gibson 5. In addition, the supplemental contract wholesale load of IMPA within the PSI control area is included in the modeling.

The supply resources referenced above are generally those owned by the Cinergy operating companies which are included in the franchised service territory rates. Exceptions whose capability and/or impacts are reflected in the modeling include: DSM resources, with costs deferred or otherwise not fully reflected in rates; Woodsdale CT Unit 1, which is not currently reflected in rates; and power purchases made specifically for franchised service territory load obligations.

Although the franchised service territories of CG&E and PSI were modeled as two areas of one company, a single-system planning approach was used, as specified in the Operating Agreement among CG&E, PSI, and Cinergy Services.

This chapter will explain the objectives of, and the process used to develop, the 1999 Cinergy Integrated Resource Plan, or strategy, for the combined franchised service territories as described above.

B. OBJECTIVES

An IRP process generally encompasses an assessment of a variety of supply-side, demand-side, and emission compliance alternatives leading to the formation of a diversified, long-term "least cost" portfolio of options intended to satisfy the electricity demands of customers located within a franchised service territory. The purpose of this IRP is to outline a strategy to furnish electric energy services in a reliable, efficient, and economic manner, while factoring in environmental considerations. Paramount to this strategy is flexibility that allows the utility to adapt to changing conditions. Another important aspect of the process is the preservation of options for the future, which also enhances flexibility.

Because of the uncertainties surrounding today's electric utility business environment, the information and data inputs to the planning process are changing more rapidly than in the past. Therefore, the planning process itself must be dynamic and continuously adapt to changing conditions. The resource plan, or strategy, presented herein represents merely one possible outcome based upon a snapshot in time along this dynamic continuum. Good business practice requires Cinergy to remain flexible, continue to study the options, and make adjustments as necessary and practical to reflect improved information and changing circumstances. Consequently, a good business planning process is truly an evolving analysis that can never be considered complete.

Cinergy's long-term planning objective is to develop a dynamic planning process and pursue a resource strategy that represents the greatest value for all stakeholders (customers, shareholders, employees, suppliers, and community). At times, this involves striking a balance between competing objectives. The major objectives of the plan presented in this filing are:

- Provide adequate, reliable, and economical service to customers while meeting all environmental requirements
- Maintain the flexibility and ability to alter the plan in the future as circumstances change
- Choose a near-term plan that is robust over a wide variety of possible futures
- Minimize risks

C. ASSUMPTIONS

The advancement of customer choice into the electric utility industry and the various proposed regulatory reforms have forced the electric utility business planning horizon to shrink. The analysis performed to prepare this IRP, or strategy, covered the period 1999-

2019. Most of the planning model runs and sensitivity analyses were performed over the first ten year period, 1999-2008 (modeling period), with the primary focus being on the first five years, 1999-2003 (focus period). This technique was used in order to focus on the near-term while recognizing the fact that course corrections may be made along the way.

At the time the analysis for this IRP was begun, restructuring legislation in Ohio had not been enacted into law. As a result, the load level in this IRP reflects Cinergy continuing to serve its existing franchised service territory load throughout the forecast period.

The major Business Case or Base Case environmental assumptions for the modeling period (1999-2008) were as follows:

- Cinergy will meet all current environmental requirements.
- Both the CG&E and the PSI Phase I compliance plans were implemented.
- Cinergy will be required to meet a 0.15 lb./MMBtu NO_x emission rate through a cap and trade program by May 1, 2003.

- No Global Climate Change legislation or regulation mandates will be implemented before the end of the modeling period.
- Cinergy's participation in the voluntary utility/DOE Global Climate Change Challenge will include those emission-reducing steps that have already been taken or approved by regulatory commissions.
- No lower emission limit or shorter averaging time SO_2 requirements will be imposed during the modeling period.
- No Hazardous Air Pollutant controls will be mandated and implemented during the modeling period.
- No Renewable Energy Portfolio Standard will be mandated and implemented during the modeling period.

Risks associated with potential changes to environmental regulations are discussed further later in this report (See Chapter 8, Section E). Risks associated with other changes to the Base Case assumptions are addressed through sensitivity analysis and qualitative reasoning later in this report (see Chapters 5, 6, and 8).

The main source of the construction cost and O&M escalation assumptions used was the *Standard & Poor's DRI Utility Cost and Price Review* for First Quarter, 1998.

The GDP Price Index from DRI's "The U.S. Economy- 25-Year Focus-Winter Issue 1999" was utilized to estimate general inflation. Cinergy's Financial Department provided the after-tax effective discount rate of 7.62% and the AFUDC rate of 9.25% to use for the development of the IRP. Levelized fixed charge rates corresponding to specific supply-side resources also were developed based on this information for use in the screening process.

The other, more detailed assumptions utilized in the development of the IRP can be found within the discussions of specific subject areas throughout this report.

D. RELIABILITY CRITERIA

The combination of the CG&E and PSI systems into a single Cinergy system, for operating and planning purposes, affects the level of reserves required to maintain adequate system reliability and security. From a technical standpoint, reserves should be adequate for the security of operation (which considers a combination of weather-induced load, probability of units on outage, and a spinning reserve), maintenance scheduling, and Cinergy's obligation as a member of the East Central Area Reliability Coordination Agreement (ECAR).

The reliability constraints utilized for this IRP are those currently approved by the Public Utilities Commission of Ohio (PUCO), Indiana Utility Regulatory Commission (IURC), and the Kentucky Public Service Commission (KyPSC), as listed below:

1. Minimum reserve margin of seventeen percent (17%);
2. Annual loss of load hours (LOLH) less than 175; and
3. Expected unserved energy (EUE) less than 0.18 percent.

As stated in previous filings since the merger was announced in December 1992, these criteria were based on a combination of the criteria used by CG&E and PSI on a stand-alone basis. CG&E had used a minimum reserve margin of 17%, an annual LOLH less than 175, and a seasonal EUE less than 0.25%. These criteria had been used in IRP filings with the PUCO and KyPSC. PSI had used a minimum reserve margin of 20% and an annual maximum EUE of 0.17-0.18%, which was based on a system reserve margin of 25%. The use of these criteria was approved by the IURC in PSI's last two Certificate of Public Convenience and Necessity (CPCN) proceedings prior to the merger.

Currently, the need for additional electricity resource options to satisfy service territory electricity demands is driven by the violation of any of the above reliability constraints. Violation of the above constraints can come about through either the loss of electric supply capability, by whatever means, or the increase in franchised service territory load obligations.

E. PLANNING PROCESS

The process utilized to develop the IRP consisted of two major components. One was organizational/structural, while the other was analytical. Both are discussed below.

1. Organizational Process

Development of an IRP requires that a high level of communication exist across key functional areas of Cinergy. In order to facilitate this process, an IRP Team was formed. Key functional areas represented included: electric load forecasting, resource (supply) planning, retail marketing (demand-side management program evaluation and development), emissions compliance planning, environmental, financial, power marketing & trading, fuel planning & procurement, engineering & construction, and transmission and distribution planning (to a limited extent due to the codes of conduct in FERC Order 889). It was the Team's responsibility to examine the IRP requirements contained within the Ohio, Kentucky, and Indiana rules and conduct the necessary analyses to comply with the filing requirements.

A key ingredient in the preparation of the IRP was the integration of the electric load forecast, generation options, emissions compliance options, and demand-side options. In addition, it was important to select the best way to conduct the integration while incorporating interrelationships with other planning areas, e.g., fuel planning & procurement, and, to the extent allowable considering the codes of conduct in FERC Order 889, transmission/distribution planning.

2. Analytical Process

The development of an IRP is a multi-step process involving the key functional planning areas mentioned above. The following is a discussion of the steps involved. To facilitate timely completion of this project, a number of these steps were performed in parallel.

1. Develop planning objectives and assumptions.

2. Prepare the franchised service territory electric load forecast(s).
   More details concerning this step of the process can be found in Chapter 3.

3. Identify and screen potential electric demand-side resource options.
   More details concerning this step of the process can be found in Chapter 4.

4. Identify, screen, and perform sensitivity analyses around the cost-effectiveness of potential electric supply-side resource options.
   More details concerning this step of the process can be found in Chapter 5.

5. Identify, screen, and perform sensitivity analyses around the cost-effectiveness of potential emission compliance options.

More details concerning this step of the process can be found in Chapter 6.

6. Integrate the demand-side, supply-side, and emission compliance options.
   More details concerning this step of the process can be found in Chapter 8.

7. Perform final sensitivity analyses on the integrated resource alternatives, and select the plan.
   More details concerning this step of the process can be found in Chapter 8.

8. Determine the best way to implement the chosen plan.
   More details concerning this step of the process can be found in Chapter 8.

Because of the rapid maturing of wholesale electricity markets, the screening and integration steps mentioned above involved comparisons to a projected market price for electricity. The analytical methodology also included the incorporation of sensitivity analysis within the screening stages of the overall analysis.

Incorporating sensitivity analysis in the early stages of the analysis provides insight into what conditions must be present to transform a potential resource into being an economic alternative or screening survivor. Generally, if resource parameters must be altered beyond what is judged to be within the realm of possibility, the resource is excluded from further analysis. If, however, only minor resource parameter changes from base conditions cause the potential resource to become an economic alternative, the resource is considered in future stages of the analysis.

Finally, Cinergy's planners attempt to keep abreast of new techniques, industry changes, and alternative models through attendance at various seminars, industry contacts, trade publications, and on-line via the Internet. This process may be modified in the future to incorporate any new approaches or changes that are appropriate.

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3. ELECTRIC LOAD FORECAST

A. GENERAL

Preparation of the Electric Load Forecast of the Cinergy operating companies franchised service territories (System) relies upon a bottom-up approach. The Cinergy System forecast is the sum of the individual forecasts for the franchised service territories of The Cincinnati Gas & Electric Company (CG&E) (including Union Light, Heat & Power Company or ULH&P) and PSI Energy, Inc. (PSI).

CG&E and PSI do not perform joint load forecasts with other companies. The forecasts are prepared independent of the forecasting efforts of other utilities.

B. FORECAST METHODOLOGY

Energy is a key commodity in the overall level of economic activity. As residential, commercial, and industrial economic activity increases or decreases, the use of energy, or more specifically electricity, should increase or decrease, respectively. It is this linkage to economic activity that is important to the development of long-range energy forecasts. For that reason, forecasts of the national and local economies must be key ingredients to energy forecasts.

The general framework of the Electric Energy and Peak Load Forecast of the Cinergy System - including CG&E and its subsidiaries and PSI - involves a national economic forecast, a service area economic forecast, and the electric load forecast.

The national economic forecast provides information about the prospective growth of the national economy. This involves projections of numerous national economic and demographic concepts such as population, employment, industrial production, inflation, wage rates, and income. The national economic forecast for both CG&E and PSI is obtained from Data Resources, Inc. (DRI), a national economic consulting firm.

The forecast of the national economy is employed in conjunction with local economic data and a service area economic model to develop a forecast of the service area economy. In turn, the service area economic forecast is used along with the energy and peak models to produce the electric load forecast.

1. **Service Area Economic Models**

CG&E and Subsidiaries

The forecast of the CG&E and subsidiaries (CG&E) service area economy is prepared using a series of econometric equations to project future levels of employment, income, industrial production, and wage rates. This set of equations plus an age-cohort model of population growth comprise the Service Area Economic Model (SAEM). The SAEM incorporates both national and local impacts into the local economic forecast. While local businesses are affected by national events, the impact at the local level is altered by the particular characteristics of the service area. These characteristics include growth and age structure of the population, industrial mix, and the cost of doing business locally versus nationally. The SAEM relies on national data, a national economic forecast, and historical local economic data.

There are four major sectors to the SAEM: employment, income, wages and prices, and population. Forecasts of employment are developed for Standard Industrial Classifications (SIC) and aggregated to major sectors such as commercial, industrial, and governmental. Total income for the local economy is forecasted by preparing projections of wages, rents, proprietors' income, personal contributions for social insurance, and transfer payments. The forecasts of these items are summed to produce the forecast of income less personal contributions for social insurance. The area wage rate is affected by the national wage rate as well as the relative change in manufacturing employment. Inflation, measured by changes in the Consumer Price Index (CPI), is projected by relying on the forecast of the national CPI.

Finally, population is projected by aggregating county level population forecasts produced using an age-cohort model. Changes in population affect the local demand for goods and services as well as the size of the available labor pool. Total population in the CG&E service area is projected as well as several age cohorts.

With the models from each of the four sectors of the SAEM, local forecasts are developed for income, industrial production by SIC, inflation, wage rate, population, and employment by SIC. This information serves as input into the energy and peak load forecast models.

Employment - Total service area employment for CG&E can be broken into two major categories: manufacturing and non-manufacturing. In general, different elements affect employment in these two categories. Thus, the breakdown into more common areas facilitates analysis of employment at the SIC level.

Manufacturing Employment - Employment in each industry is primarily related to national production within that sector. For example, if national steel production has increased, local steel production should be expected to increase. However, the increase may not be simultaneous with that of the nation nor of similar magnitude. Local steel production might experience a lagged response to changes at the national level depending, in part, upon the cost of doing business locally versus nationally. As industrial production increases, employment is expected to increase depending upon the length of that lagged response.

In addition to the impact of production, technological change measured by productivity (production per employee) also impacts employment. In the long-run, as technological development results in a more efficient use of labor, the level of employment is affected.

The impacts of industrial production, technological change, and the local versus national cost of business can be represented in a functional form as follows:

(1) Local Employment (i) =

f (National Industrial Production (i),
National Labor Productivity (i),
Local Electricity Cost/National Electricity Cost,
Local Gas Cost/National Gas Cost,
Local Real Wage Rate/National Real Wage Rate,
Real Minimum Wage,
Local Tax Rate/National Tax Rate),

where i represents each manufacturing SIC.

Energy costs, wage rates, and tax rates are primarily indicators of the relative cost of business locally versus nationally. As those relative costs increase, employment would be expected to decline.

Energy costs (electricity and natural gas) are measured by their average industrial price. Average gas and electricity prices are employed since they are most indicative of the level of energy costs and would affect service area economic decisions such as industrial location and expansion.

Non-manufacturing Employment - There are six major categories of non-manufacturing employment:

SIC 40	Transportation, communication, and public utilities
SIC 50	Trade: wholesale and retail
SIC 60	Finance, insurance, and real estate
SIC 70 to 89	Personal Services
SIC 90	Government
SIC 15	Construction

With the exception of Government, employment in each of these categories is affected by similar factors. The five non-government categories represent, in a broad sense, the "service" industries. The service industries primarily face a local market. Thus, growth in employment in the service industries in general tends to be constrained by local population growth. In addition to population, the ratio of the service industry employees to population at the national level is important in estimating employment levels.

The ratio of local to national real per capita income is another key ingredient since it accounts for the relative growth in the purchasing power of the service area.

The cost of labor also affects employment in service industries, in that as the cost increases, employment should fall. One measure of labor cost is examined: the local to national ratio of real average hourly earnings in the manufacturing sector.

The adjustment process of local service industry employment to changes at the national level is assumed to contain a lag structure. While the actual adjustment process may differ from that in the manufacturing industries, the structural form is similar (e.g., long-run versus short-run adjustments).

The impacts of national employment, relative income per capita, and the relative wage can be represented in a functional form for total commercial employment as follows:

(2) Local Employment (j) =

f (National Employment (j),

Local Real Income Per Capita/National

Real Income Per Capita,

Local Real Wage Rate/National Real Wage Rate,

Local Gas Price/National Gas Price.

For Construction employment (SIC 15), the level of employment is affected by the impacts of national employment, relative per capita income, relative change in commercial employment, and the real interest rate.

For the government sector, SIC 90, the principal factors found to impact local government employment are the national level of state and local governmental employment, the local to national ratio of income per capita, the minimum wage, and the local to national ratio of population.

Wages and Prices - In the long-run, the market for labor is assumed to be national in scope. As a result, the local real average hourly earnings should change in a similar pattern as the national real wage. Differential impacts of the business cycle are considered by including the local growth in manufacturing employment relative to national growth. Also, to account for the relative weight of higher wage industries, the relative percent of local employment in SICs 28, 33 and 37 must be included. The formulation of average hourly earnings in the service area is detailed as follows:

(3) Local Real Wage =

f (National real wage,

Local growth in manufacturing employment/National growth in manufacturing employment,

Relative percent of manufacturing employment in SICs 28, 33 and 37).

To complete the wage portion of this sector, a wage rate for the U.S. needs to be forecasted. Since average hourly earnings in manufacturing is the only concept available for the service area, a forecast of national average hourly earnings in manufacturing is also needed. The sector is completed by specifying national average hourly earnings in the manufacturing sector of the U.S. as a function of a non-farm employment cost index. The functional relationship is expressed as follows:

(4) National Wage =

f (Employment cost index for private wages and salaries).

The Consumer Price Index for the Cincinnati CMSA (Consolidated Metropolitan Statistical Area) is assumed to follow the prices of consumer goods at the national level. In other words, inflation in the Cincinnati CMSA will track inflation at the national level.

Income - The income sector affects most of the other sectors of the model. Income is broken into five components, the summation of which produces total nominal service area income. The five components are wage and salary disbursements, governmental transfer payments, property income, personal contributions for social insurance, and proprietors' income.

These can be summed to compute personal income as follows:

(5) Local Personal Income =

Local Wage and Salary Disbursements including other income +

Service Area Governmental Transfer Payments +

Local Property Income +

Local Proprietors' Income -

Local Personal Contributions for Social Insurance.

Each of the five components are related to key economic factors as follows:

(6) Service Area Governmental Transfer Payments Per Person =
f (National Governmental Transfer Payments Per Person)

(7) Local Wage and Salary Disbursements Per Employee =
f (National Wage and Salary Disbursements Per Employee)

(8) Local Real Proprietors' Income Per Person =
f (National Real Proprietors' Income Per Person)

(9) Local Real Property Income Per Person =
f (National Real Property Income Per Person) and

(10) Local Personal Contributions for Social Insurance Per Person (Age Group 20 to 64) =
f (National Personal Contributions for Social Insurance Per Person (Age Group 20 to 64)).

Population - Population projections for the CG&E service area are prepared for each five year age-cohort through the use of an age-cohort model. This methodology is similar to that which is used by the state agencies (Ohio, Kentucky and Indiana) to project population. (See the publication titled "POPULATION PROJECTIONS OHIO AND COUNTIES BY AGE AND SEX: 1990 to 2015 DETAILED METHODOLOGY", JULY, 1993). The 1990 census data has been incorporated into the model along with the current fertility and survival rates.

There are four major elements to the estimation of population. These are (1) the level of population in the previous period, (2) net migration, (3) fertility rates, and (4) survival rates. The four elements are available by sex, by five year age-cohort, and by county. There are eighteen five year age cohort groupings ranging from 0 to 4 years of age up to 85 and over. The thirteen counties in CG&E's franchised service area include BROWN, BUTLER, CLERMONT, HAMILTON, and WARREN in Ohio; BOONE, CAMPBELL, KENTON, GRANT, GALLATIN, and PENDLETON in Kentucky; DEARBORN and OHIO in Indiana.

Population is projected using the following formulas:

(11) Age 0 to 4

$$P = (B * S) + M$$

where:

P = population aged 0 to 4.

B = total five-year births.

S = survival rate for population aged 0 to 4.

M = net migration for population aged 0 to 4.

(12) Age 5 to 9 through 85 and over by five-year cohort

$$P = (p * s) + M$$

where:

P = population within each five-year cohort.

p = population within the immediate preceding five-year age cohort i.e., if P = age cohort 10 to 14 the p = age cohort 5 to 9.

s = survival rate for each five year age cohort.

M = net migration within each five-year age cohort.

Migration and its timing are extremely difficult to model as a result of the numerous causal factors which affect relocation. In this model, the net migration for most counties is assumed to decline gradually from the 1990 level towards zero by the year 2020. However, the rates for three counties (Butler, Clermont, Warren) that have demonstrated strong net in-migration historically, were assumed to continue showing net in-migration. Once the birth, death, and net migration variables are estimated, total population in the service area can be computed by summing across sex, age-cohort, and county. The county population projections are first aggregated to service area totals for each five year age-cohort, male and female. Secondly, these service area totals are aggregated by sex to five year age-cohort population totals. Finally, these five year age-cohort totals are aggregated to the following age distributions for use in the service area economic model:

(1) 5 to 19;

(2) 20 and over;

(3) 20 to 64;

(4) 0 to 19;

(5) 65 and over; and

(6) total population.

The methodology presented in the above four sections on employment, wages and prices, demographics, and income provides the basic structure to the CG&E SAEM. Using this model, a local economic forecast is prepared which is used to develop the electric energy and peak load forecasts for CG&E.

PSI Energy

PSI Energy (PSI) provides electric service to customers in portions of 69 counties in North Central, Central and Southern Indiana. The forecast of the economy for this service area is prepared by Cinergy. The structure of the service area economic model includes a set of econometric models used to forecast manufacturing employment by SIC, non-manufacturing employment, and total personal income. PSI's population forecast is derived from population projections produced by the Indiana Business Research Center (IBRC) which is a part of Indiana University.

As indicated above, PSI's franchised service area consists of portions of 69 counties. Currently, on a retail sales basis, PSI provides electric service to 5 percent or more of the population in 61 of these counties. This phenomenon occurs because PSI's service area is dotted with numerous municipal utilities and REMCs, many of which are sales for resale customers.

Employment - PSI begins the process of forecasting employment by collecting county-level employment data by industry. Each year PSI obtains monthly employment data by sector, for both manufacturing and non-manufacturing categories, for each of the 61 counties. This information is aggregated into a quarterly service territory total which is used to produce forecasts of manufacturing employment for ten 2-digit SIC codes as well as forecasts of two major non-manufacturing sectors.

Manufacturing Employment - Just as in the CG&E model, local manufacturing employment by SIC is closely related to national production for each SIC, as well as labor productivity. In general, employment in each industry is projected as a function of national output in that industry, and national output per employee in that industry. The impact of technological change and improved production methods, measured by national production per employee, is expected to impact local employment. On occasion, a qualitative variable is added to account for a discrete, non-recurring, historical event.

The relative impacts of industrial production, production per employee, and the impact of discrete qualitative variables is represented in a functional form as follows:

(13) Local Employment (i) =

f (National Industrial Production (i),
National Labor Productivity (i),
Local Electricity Cost/National Electricity Cost,
Local Gas Cost/National Gas Cost,
Local Real Wage Rate/National Real Wage Rate,
Real Minimum Wage,
Local Tax Rate/National Tax Rate),

where i represents each manufacturing SIC.

<u>**Non-Manufacturing**</u> - There are two major categories of non-manufacturing employment that are forecast for the PSI service territory. One major category is SIC 12, Mining. The other is total commercial employment which includes the following:

SIC 40	Transportation, communication and public utilities
SIC 50	Trade: wholesale and retail

SIC 60	Finance, insurance and real estate
SIC 70 to 89	Personal services, and
SIC 90	Government: Federal, state and local.

Local commercial employment is determined by local population and local real income per capita.

The functional form of the commercial employment model is as follows:

(14) Local Employment (j) =

f (National Employment (j),

Local Real Income Per Capita/National Real Income Per Capita,

Local Real Wage Rate/National Real Wage Rate,

Local Gas Price/National Gas Price.

Local mining employment is assumed to be affected by the same forces that affect local manufacturing employment. Local mining employment is closely related to national mining production. Additionally, the impact of technological change and improved production methods, measured by national mining production per employee, is also expected to impact local mining employment.

The relative impacts of industrial production, production per employee, and the impact of discrete qualitative variables is represented in a functional form as follows:

(15) Local Employment (Mining) =

f (National Industrial Production (Mining), National Labor Productivity (Mining), Relative Electric Price).

Income - Cinergy also produces a forecast of personal income in the PSI service area.

Historical income statistics for the 61 counties in which PSI serves five percent or more of the population is collected from the U.S. Bureau of Economic Analysis.

The income sector affects most of the other sectors of the model. Income is broken into five components, the summation of which produces total nominal service area income. The five components are wage and salary disbursements, governmental transfer payments, property income, personal contributions for social insurance, and proprietors' income.

These can be summed to compute personal income as follows:

(16) Local Personal Income =

Local Wage and Salary Disbursements including other income +

Service Area Governmental Transfer Payments +

Local Property Income +

Local Proprietors' Income -

Local Personal Contributions for Social Insurance.

Each of the five components are related to key economic factors as follows:

(17) Service Area Governmental Transfer Payments Per Person =

f (National Governmental Transfer Payments Per Person)

(18) Local Wage and Salary Disbursements Per Employee =

f (National Wage and Salary Disbursements Per Employee)

(19) Local Real Proprietors' Income Per Person =

f (National Real Proprietors' Income Per Person)

(20) Local Real Property Income Per Person =

f (National Real Property Income Per Person) and

(21) Local Personal Contributions for Social Insurance Per Person (Age Group 20 to 64) =

f (National Personal Contributions for Social Insurance Per Person (Age Group 20 to 64)).

Population - PSI's population forecast is derived from data provided by the Indiana Business Research Center. Population projections for the service area are prepared by first collecting county-level population forecasts developed by the University for the 61 counties in which PSI serves five percent or more of the population. These county-level projections were developed using an age-cohort model that has been approved for use by the U.S. Census Bureau.

The forecast of economic activity for the PSI service territory is used to develop the electric energy and peak load forecasts for PSI.

2. Electric Energy Forecast

The methodology follows economic theory in that the use of a commodity is dependent upon key economic factors such as income, production, energy prices, and the weather. As mentioned in a previous section, the forecast of energy usage depends upon a forecast of economic activity. The following sections provide the specifications of the econometric equations developed to forecast electricity sales for the CG&E (and subsidiaries) and PSI franchised service territories.

CG&E and Subsidiaries

Several sectors comprise the CG&E Electric Load Forecast Model. Forecasts are prepared for sales to the residential, commercial, industrial, government or other public authority (OPA), street lighting, and wholesale energy sectors. Forecasts are also prepared for three minor categories: interdepartmental use (Gas Department), Company (CG&E) use, and losses.

Residential Sector - There are two components to the residential sector energy forecast: the number of residential customers and kWh energy usage per customer. The forecast of total residential sales is developed by multiplying the forecasts of the two components. That is:

(22) Residential Sales =

Number of Residential Customers * Use per Residential Customer.

Econometric relationships were developed for each of the component pieces of total residential sales.

Customers - The number of electric residential customers (households) is affected by population in the household formation age groups and real per capita income. This is represented as follows:

(23) Residential Customers =

f (population Ages 20 and over, Real Per Capita Income)

where Real Per Capita Income = (Local Personal Income/Service Area Population/Local CPI).

While changes in population and per capita income are expected to alter the number of residential customers, the adjustment relating to real per capita income is not immediate. The number of customers will change gradually over time as a result of a change in real per capita income. This adjustment process is modeled using a lag structure.

Use Per Customer - The key ingredients that affect residential electricity usage are the stock of appliances, the efficiency of the appliance stock, weather, electricity price, and income. Energy use per customer tends to increase as the customer stock of energy-using appliances (especially those that are weather sensitive) grows. Energy use per customer tends to decrease as that stock becomes more efficient. However, as appliances become more efficient, there is also a potential for some rebound in energy usage because it is less costly to operate appliances. Nonetheless, the net effect of increased appliance efficiencies on energy use should decrease energy use. While the aggressiveness with which consumers choose to purchase and use more efficient appliances tends to be price-induced, projected increases in appliance efficiencies as a result of the standards established under the National Appliance Energy Conservation Act can be included in this model of energy usage.

The general formulation of the model which incorporates these factors is represented as follows:

(24) kWh usage per Customer =

f (Real Income Per Capita * Efficient Appliance Stock,

Real Marginal Electricity Price * Efficient Appliance Stock,

Saturation of Electric Resistance Heating Customers,

Saturation of Electric Heat Pump Customers,

Saturation of Customers with Central Air Conditioning,

Saturation of Window Air Conditioning Units,

Efficiency of Space Conditioning Appliances,

Billed Heating and Cooling Degree Days,

Gas Restrictions)

The derivation of the efficient appliance stock variable and the forecast of appliances are discussed in the data section.

Commercial Sector - Commercial electricity usage changes with variations in commercial economic activity and energy prices. The level of conservation/energy efficiency is driven by economics, hence prices.

The forecast for the commercial sector is prepared using a one equation model in which total commercial sales are dependent upon levels of commercial employment as a measure of economic activity, electric price, the price of natural gas, and the weather.

(25) Commercial Sales =

f (Commercial Employment,

Marginal Electric Price/Consumer Price Index,

Price of Natural Gas/Consumer Price Index,

Billed Heating and Cooling Degree Days)

Industrial Sector - Since electricity is primarily used for production processes in the industrial sector, it is expected that a close relationship should exist between electricity usage and industrial production.

In addition to production, energy prices certainly affect energy usage in the form of conservation/efficiency effects and substitution of energy sources.

The forecast for industrial electricity sales relies upon a system of equations which forecast industrial electricity sales by two-digit SIC. In the specification of the industrial energy equations, industrial electricity sales are dependent upon local industrial production indices, the real price of electricity, the price of electricity relative to the price of other energy sources (natural gas, coal, and oil), the wage rate, heating and cooling degree days, and selected qualitative variables for specific time periods to account for discrete, non-recurring historical events.

One issue that has required growing attention is the sensitivity of industrial usage to weather. With growth in air conditioning associated with computer controlled equipment and growth in weather sensitive processes, the data are showing that weather is becoming more important to industrial sales. This is evident from the fact that cooling degree days is included in six of the nine industrial equations. Heating degree days is just now emerging in importance with inclusion in six of the industrial equations.

The general form of the equation for kWh sales to industry is as follows:

(26) kWh Sales =

f (Local Industrial Production(i),

Marginal Electric Energy Price/Consumer Price Index,

Marginal Electric Energy Price/Price of Natural Gas,

Marginal Electric Energy Price/Price of Oil,

Marginal Electric Energy Price/Price of Coal,

Marginal Electric Energy Price/Average Hourly Earnings,

Marginal Electric Demand Price/Consumer Price Index,

Billing Heating and Cooling Degree Days,

Gas Restrictions)

where Local Industrial Production(i) =

(National Industrial

Production(i)/National Employment (i))

* Local Employment (i)

where i represents SIC.

Other Public Authority Sector - Two categories comprise the electricity sales in the Other Public Authority (OPA) sector: sales to OPA water pumping customers and sales to OPA non-water pumping customers.

In the case of OPA water pumping, electricity sales are related to the number of residential electricity customers, real price of electricity demand, precipitation levels, and heating and cooling degree days. That is:

(27) Water Pumping Sales =

f (Residential Electricity Customers,

Real Electricity Demand Price,

Precipitation,

Heating and Cooling Degree Days).

Electricity sales to the non-water pumping component of Other Public Authority is related to governmental employment, the real price of electricity, the real price of natural gas, and heating and cooling degree days. This relationship can be represented as follows:

(28) Non-Water Pumping Sales =

f (Governmental Employment,

Marginal Electric Energy Price/Consumer Price Index,

Marginal Electric Energy Price/Natural Gas Price,

Billed Heating Degree Days,

Billed Cooling Degree Days).

The total OPA electricity sales forecast is the sum of the individual forecasts of sales to water pumping and non-water pumping customers.

Street Lighting Sector - For the street lighting sector, electricity usage varies with the number of street lights and the efficiency of the lighting fixtures used. The number of street lights is associated with the number of residential customers. The efficiency of the street lights is related to the saturation of mercury and sodium vapor lights. That is:

(29) Street Lighting Sales =

f (Residential Customers,

Saturation of Mercury Vapor Lights,

Saturation of Sodium Vapor Lights).

In this sector, electric sales are seasonally adjusted before the model is developed.

Other Public Utility Sector - Six towns comprise the Other Public Utility (OPU) sector. Individual electric sales forecasts are prepared for each of the six towns using the relationship between a town's energy usage and electricity usage in the residential and/or commercial sectors for the total CG&E system. OPU sales are also related to weather conditions. It should be noted that the signs on weather variables or any other variable such as gas restrictions or marginal electric price could be positive or negative. These effects have already been captured to some extent in the consolidated residential/commercial electricity usage data.

Therefore, the variables adjust for the sensitivity of OPU sales relative to the sensitivity of CG&E residential/commercial sales. The general relationship is specified as follows:

(30) OPU Sales(i) =

f (Residential kWh sales for CG&E,
Commercial kWh sales for CG&E,
Gas Restrictions,
Billed Heating and Cooling Degree Days)

where i references each of the six towns which comprise the OPU sector.

The forecast for total OPU sales is prepared by summing the six individual forecasts.

Total Electricity Sales - Once these separate components have been projected - Residential sales, Commercial sales, Industrial sales, Other Public Authority sales, and Street Lighting sales - they can be summed along with Interdepartment sales to produce the projection of total electricity sales.

Total System Sendout - Upon completion of the total electric sales forecast, the forecast of total CG&E system sendout or net energy can be prepared. This requires that all the individual sector forecasts be combined along with forecasts of Other Public Utility sales, Company (CG&E) use, and system losses. After the system sendout forecast is completed, the peak load forecast can be prepared.

Peak Load - Forecasts of summer and winter peak demands for CG&E are developed using econometric models.

The peak forecasting model is designed to closely represent the relationship of weather to peak loads. Previous forecasting models, using monthly peak load data over several years, employed a constant relationship between loads and weather. Further research conducted by CG&E in this area indicates that the relationship between load and weather is not necessarily constant.

A preliminary analysis was conducted to identify the breakpoints where the relationship between load and temperature change. The process utilized splines to test the location of the breakpoints. It was determined from this preliminary analysis that only days when the temperature equaled or exceeded 90 degrees would be considered as candidates for inclusion in a summer peak model. For the winter, only those days with a temperature at or below 10 degrees would be considered for inclusion in the winter peak model.

Summer Peak - Summer peak loads are influenced by the current level of economic activity and a wide variety of weather conditions. The primary weather factors are temperature and humidity; however, there are several approaches for considering the temperature impact. Not only are the temperature and humidity at the time of the peak important, but also the morning low temperature, and high temperature from the day before. These other temperature variables are important due to the effect of thermal buildup.

The summer equation can be specified as follows:

(31) Peak =

f (Weather Normalized Sendout,
Weather Factors)

Winter Peak - Winter peak loads are also influenced by the current level of economic activity and a wide variety of weather conditions. The selection of winter weather factors depends upon whether the peak occurs in the morning or evening. For a morning peak, the primary weather factors are morning low temperatures, wind speed, and the prior evening's low temperature. For an evening peak, the primary weather factors are the evening low temperature, wind speed, and the morning low temperature.

The winter equation is specified in a similar fashion as the summer:

(32) Peak =

f (Weather Normalized Sendout,

Weather Factors).

The two peak equations are estimated separately for the respective seasonal periods. Peak load forecasts are produced under specific assumptions regarding the type of weather conditions typically expected to cause a peak.

Weather-Normalized Sendout - The level of peak demand is related to economic conditions such as income and prices. The best indicator of the combined influences of economic variables on peak demand is the level of base load demand exclusive of aberrations caused by non-normal weather. Thus, the first step in developing the above described peak equations is to weather normalize monthly sendout.

The procedure used to develop historical weather normalized sendout data involves two steps. First, instead of weather normalizing sendout in the aggregate, each component is weather normalized. In other words, residential, commercial, industrial, other public authority, and other public utility sales are individually adjusted for the difference between actual and normal weather. Street lighting sales are not weather normalized because they are not weather sensitive. Using the equations previously discussed, the adjustment process is performed as follows:

Let: $KWH(N) = f(W(N))g(E)$

$KWH(A) = f(W(A))g(E)$

Where: KWH(N) = electric sales - normalized

W(N) = weather variables - normal

E = economic variables

KWH(A) = electric sales - actual

W(A) = weather variables - actual

Then: $KWH(N) = KWH(A) * f(W(N))g(E)/f(W(A))g(E)$

$= KWH(A) * f(W(N))/f(W(A))$

With this process, weather normalized sales are computed by scaling actual sales for each class by a factor from the forecast equation that accounts for the impact of deviations from normal weather. Industrial sales are weather normalized using a factor from an aggregate equation developed for that purpose.

Second, weather normalized sendout is computed by summing the weather normalized sales with non-weather sensitive sector sales and other miscellaneous components. This weather adjusted sendout is then used as a variable in the summer and winter peak equations.

Forecast Procedure - The summer peak usually occurs in August in the afternoon and the winter peak occurs the following January in the morning. Since the energy model produces forecasts under the assumption of normal weather, the forecast of sendout is "weather normalized" by design. Thus, the forecast of sendout drives the forecast of the peaks. In the forecast, the weather variables are set to values determined to be normal peak-producing conditions. These values are derived using historical data on the worst weather conditions in each year (summer and winter) which are subsequently adjusted for the probability of occurrence on a weekday.

ULH&P

The ULH&P forecast is developed by allocating percentages of the total CG&E consolidated system forecast for each customer group. These percentages provide ULH&P forecasts for sales to the residential, commercial, industrial, government or other public authority (OPA), street lighting, and wholesale energy sectors. Forecasts are also prepared for three minor categories: interdepartmental use (Gas Department), Company (ULH&P) use, and losses. In a similar fashion, the ULH&P peak load forecast is developed by allocating a share from the CG&E total. Historical percentages and judgment are used to develop the allocations of sales and peak demands. However, the ULH&P peak is also adjusted for the growth in total energy use relative to the growth for the CG&E total.

PSI Energy

Several sectors comprise the PSI Electric Load Forecast Model. Forecasts are prepared for electricity sales to the residential, commercial, industrial, other sales, and wholesale energy sectors. Additionally, projections are made for summer and winter peak demands.

Residential Sector - Similar to CG&E, there are two components to PSI's residential sector energy forecast: the number of residential customers and kWh energy use per customer. The forecast of total residential sales is developed by multiplying the forecasts of these two components.

Customers - PSI provides service to 69 counties in North Central, Central and Southern Indiana. On a retail basis, PSI serves at least five percent of the population in 61 of these counties. These 61 counties were included in the analysis of residential customer growth.

The number of electric residential customers (households) is affected by population in the household formation age groups and real per capita income. This is represented as follows:

(33) Residential Customers =

f (population Ages 20 and over, Real Per Capita Income)

where Real Per Capita Income = (Local Personal Income/Service Area Population/Local CPI).

While changes in population and per capita income are expected to alter the number of residential customers, the adjustment relating to real per capita income is not immediate. The number of customers will change gradually over time as a result of a change in real per capita income. This adjustment process is modeled using a lag structure.

<u>Residential Use per Customer</u> - The key ingredients that impact energy use per customer are per capita income, real electricity prices and the combined impact of numerous other determinants such as: the saturation of air conditioners and their efficiency, the stock of other appliances and the efficiency of those appliances, the saturation of electric space heating, and weather.

(34) kWh usage per Customer =

f (Real Income per Capita * Efficient Appliance Stock,
Real Electricity Price * Efficient Appliance Stock,
Saturation of Customers with Central Air Conditioning,
Saturation of Window Air Conditioning Units,
Efficiency of Space Conditioning Appliances,
Saturation of Electric Heating Customers,

Billed Cooling and Heating Degree Days).

Commercial Sector - Commercial electricity usage changes with the changing level of local economic activity (as measured by local consumer spending on services), the ratio of real electricity prices to real gas prices, and the impact of weather. The forecast for the commercial sector is prepared using a one equation model dependent upon the level of commercial activity as measured by the above mentioned drivers. The model is formulated as follows:

(35) Commercial Sales =

f (Commercial Employment,

Marginal Electric Price/Consumer Price Index,

Price of Natural Gas/Consumer Price Index,

Billed Heating and Cooling Degree Days)

Industrial Sector - PSI produces two industrial sales forecasts. The first is for PSI's largest industrial customer. The second is for all other industrial sales. The sales forecast for the largest industrial customer is based upon their recent historical usage and a growth factor related to the industry (SIC) to which that customer belongs. Electricity use by all other industrial customers is primarily dependent upon the level of industrial production and the impacts of real electricity prices, real natural gas prices and weather. The general model of other industrial sales is formulated as follows:

(36) Industrial Sales =

f (Industrial Production,
Real Electricity Price,
Real Natural Gas Price,
Real Alternate Fuel Price,
Degree Days).

Other Sales - PSI provides electricity for municipal activities such as street and highway lighting and traffic signals. This "other" sales category is forecast using a historic time trend that captures not only the increasing number of these devices as the number of residential customers increase, but also their increasing efficiency over time.

Wholesale - PSI provides electricity on a contract basis to numerous wholesale customers. PSI's forecast of wholesale sales is developed in two parts: 1) sales to Rural Electric Membership Corporations (REMCs), and 2) sales to Other Electric Utilities.

REMCs - PSI provides electricity to several REMCs. The REMCs energy requirements were projected using historical trend analysis.

Other Electric Utilities - PSI also provides electricity to several municipalities and other wholesale customers. These other electric utilities were forecasted using historical trend analysis.

Total Electricity Sales - Once these separate components have been projected - Residential sales, Commercial sales, Industrial sales, and Other sales - they can be summed to produce the projection of total electricity sales.

Total System Sendout - Upon completion of the total electric sales forecast, the total PSI system sendout or net energy forecast can be prepared. This requires that all the individual sector forecasts be combined along with forecasts of Wholesale sales and system losses. After the system sendout forecast is completed, the peak load forecast can be prepared.

Peak Load - The forecast of peak demands is based on the historical relationship between energy sales and peak demands. Total system monthly load factors were developed from an analysis of twenty-five years of historical data. The system demand factors were used along with the monthly forecast of total energy kWh sales (including losses) to develop the forecast of peak demands.

C. ASSUMPTIONS

Due to the specific requirements of the respective state regulations, assumptions are reported separately for the CG&E consolidated system (including ULH&P) and the PSI system.

1. CG&E/ULH&P

a. General

1. A major risk to the national and regional economic forecast is the continued economic growth in the U.S. economy.

   Depending upon the international valuation of the dollar, the strength of the economy, and labor market pressures, the Federal Reserve could be forced to tighten growth in the money supply to curb inflation. The national economy has shown greater strength than expected as it enters the ninth year of positive growth. The ultimate outcome in the near term is dependent upon the success of the Federal Reserve to keep the economy from entering a recessionary period.

2. The forecast assumes there are no wars. Should a minor conflict occur, over the long-term horizon, it is expected that the path of the forecast would not be dramatically different.

3. Customers cannot completely alter energy consumption as a result of changes in price, income, or other economic forces in the immediate time frame. Only over time can customers fully adjust their stock of energy using appliances and their total energy usage. To incorporate this relationship into the electric energy demand equations, a distributed lag structure is employed to relate key economic concepts such as electricity price to energy usage.

b. Specific Information

(i) Current and Future Relative Prices and Availability of Commercial Fuels

At the time of the forecast, the equivalent energy prices ($/MMBtu) of natural gas and fuel oils (#2 and #6) are below the price of electricity. The price of natural gas is expected to increase at an annual rate of 3.4 percent and the price of oil is expected to rise at an annual rate of 4.6 percent. The price of electricity should increase at a 2.1 percent effective annual rate from 1999 to the year 2019.

For commercial and industrial customers, the equivalent ($/MMBtu) electricity price will remain above the prices of natural gas and fuel oils (#2 and #6). The major concern for commercial and industrial customers will be the relative prices of gas and oil. Natural gas prices are expected to increase somewhat over the forecast period while oil prices are projected to increase slightly throughout the report period.

Regarding availability of the conventional fuels, nothing on the horizon indicates any limitation in their supply. There are unknown potential impacts from future changes in legislation or a change in the pricing or supply policy of OPEC that might affect fuel supply. However, these cannot be quantified within the forecast. The only non-utility information sources relied upon are Data Resources, Inc. and the respective state agencies.

(ii) Current and Future Relative Prices and Availability of Alternative Energy Sources

The supply of energy from alternate energy sources and technologies currently is small and is expected to continue to remain a minor segment of total electricity supply in the forecast period. Therefore, alternate energy sources and technologies are not expected to significantly impact the forecast.

It is anticipated that no major changes in energy sales or peak demands in this region of the country will result from solar and wind power development. Although some specialized solar installations have been placed into service in the area, the economics of such units, due in part to the region's weather conditions, are expected to prohibit their widespread utility scale application. While there were three experimental wind generators planned for development in the CG&E service area, construction of one of the three was never completed. The wind speeds at the site of one generator are reported to average 5-6 MPH over the year. The conclusion drawn from the experiments has been that commercially available wind generator units are currently not economically feasible in the Southwestern Ohio region. Average wind speeds are not sufficient to produce substantial amounts of useful electric energy.

The use of wood for home heating has displaced the use of other fuels, including electricity, to some extent in the residential class. The 1997 CG&E appliance saturation survey indicated that a small percentage of electric customers in CG&E's service area use wood as a primary source for home heating. Some of those, of course, use gas rather than electric as a back-up heating system. No major change in energy sales or peak demands is expected from the use of wood for home heating.

(iii) Pricing Policy

(a) CG&E's electric tariffs for residential customers have a seasonal pattern. In addition, in Ohio, an optional time-of-day (TOD) rate is available for residential customers. Tariffs for commercial and industrial customers also have a seasonal rate characteristic and offer a Load Management Rider which includes an off-peak provision. In Kentucky, an inverted rate is now mandatory for residential customers and a time-of-day rate has been mandated for all large commercial and industrial customers.

(b) The purpose of the seasonal characteristics of the rate schedules is to promote conservation during summer months when demand upon CG&E's electric facilities is greatest.

The effect of the optional residential TOD rate in Ohio has been small due to the limited customer interest. Seventeen residential customers receive service under the TOD rate. The impact of the large customer TOD rate in Kentucky is not known. Previous analysis of the mandated TOD rate for commercial/industrial customers revealed little to no impact on energy or peak usage. Until further evidence can be obtained that more customers will request the TOD rate or that consumption patterns will be altered, little impact from those rates can be expected.

(c) Over the next five years, electricity prices adjusted for inflation are expected to decline at a -1.5% annual rate. Over the long-term, real electricity prices are expected to fall such that the long-term compound annual growth rate (1999 - 2019) in real electricity price is expected to be -1.3 percent.

(iv) Economic and Demographic Trends

Forecasts of local population, industrial production, and employment are key indicators of economic and demographic trends for the CG&E service area. Over the forecast period, growth of the Cincinnati economy, in terms of employment and industrial production, should generally keep pace with that of the nation. Growth in population depends greatly upon the availability of jobs as well as birth and death rates.

Historically, local population has not grown as fast as the nation and this trend is expected to continue throughout the forecast period with an annual local population growth of 0.5 percent per year versus a 0.8 percent expected growth rate for national population.

Employment projections for the service area are made for three major sectors: industrial, commercial, and government. Industrial employment is expected to remain relatively flat to declining throughout the forecast period. The growth that will come in employment will be in the commercial and government sectors. The rate of growth in local employment expected over the forecast will be close to the nation's: 0.9 percent locally versus 0.8 percent nationally.

Local industrial production is expected to grow at a rate below the national rate. For the forecast period, local industrial production is expected to increase at a 2.1 percent annual rate, while 3.2 percent is the expected growth rate for the nation.

(v) Assumed Inflation Rate

The annual inflation rate projected for the forecast period is 3.5 percent.

(vi) Anticipated Penetration of Cogeneration Technology

Cogeneration technology is viewed as most relevant to the industrial class of service. It is, however, not expected at this point in time to have a major effect on the energy sources of the area or on the energy requirements to be provided by CG&E during the range of the forecast. This is due to the thermal requirements that must exist to make cogeneration feasible. Some cogeneration exists now in the paper industry, but little additional is expected at this time. Some potential exists in the chemical industry, but would be limited since potential sites are at relatively small plants. Discussions have been held with a number of customers who have indicated some interest. CG&E has distributed information on cogeneration to anyone that has expressed interest. The development of cogeneration on CG&E's system and its effect on the forecast will be monitored closely in the future. The PUCO has approved a tariff applicable for cogeneration and small power production facilities with a capacity of 100 kW or less. This tariff has attracted little interest at potential qualifying facilities and to date no one uses this tariff. It should be pointed out that while the specific potential for cogeneration cannot be identified, the load forecast does reflect the impact of fuel switching and cogeneration which would occur due to the relative prices for alternative fuels such as oil, gas, and coal (See also Chapter 5, Section E).

(vii) **Year End Residential Customers**

In the following table, historical and projected total year-end residential customers disaggregated by electric heating and non-electric heating for the entire CG&E service area are provided.

NUMBER OF YEAR-END RESIDENTIAL CUSTOMERS

Year	Total Service Area
1990	604,819
1991	612,875
1992	621,685
1993	621,111
1994	631,059
1995	640,884
1996	649,668
1997	657,428
1998	665,798
1999	674,600
2000	683,326
2001	692,254
2002	701,325
2003	709,870
2004	718,379
2005	726,643
2006	733,667
2007	740,604
2008	747,780
2009	755,108
2010	762,454
2011	769,086
2012	775,605
2013	781,923
2014	788,176
2015	794,283
2016	799,248
2017	804,089
2018	808,954
2019	813,855

The sources and types of data used in the development of the population forecast are reviewed in the discussion on methodology and data base documentation above. As discussed in Section B, the population projections for the service area are prepared using an age-cohort model similar in methodology to that employed by the respective state agencies.

(viii) Municipal Customers and Sales

There are six wholesale customers. A list of the customers and their associated 1998 electricity consumption are provided below.

WHOLESALE CUSTOMER	**1998 MWH**
Bethel, Ohio	26,123
Blanchester, Ohio	46,457
Georgetown, Ohio	39,498
Hamersville, Ohio	4,670
Lebanon, Ohio	138,719
Ripley, Ohio	19,082

(ix) Impacts of Trends in Appliance Efficiencies

Trends in appliance efficiencies, saturations, and usage patterns have an impact on the projected use per residential customer. Overall, the forecast incorporates a projection of increasing saturation for many appliances including heat pumps, air conditioners, electric space heating equipment, electric water heaters, electric clothes dryers, dish washers, and freezers. In addition, the forecast embodies trends of increasing appliance efficiency consistent with standards established under the National Appliance Energy Conservation Act. While the trend of increasing appliance saturation tends to raise the projection of energy use per customer, increasing appliance efficiency reduces it.

The net impact of those two trends in conjunction with the changes in usage patterns brought on by changes in real energy prices and income per capita result in a forecast of use per customer that is relatively flat.

(x) Contracts For Firm Power Sales

CG&E has signed agreements with East Kentucky

Power Cooperative for seasonal capacity exchanges (diversity). These agreements are described in more detail in Section D of Chapter 5.

c. Special Information

Development and expansions in the Cincinnati economy required the addition of loads to the forecast. The sector involved is industrial (P&G, AK Steel Corp.).

2. PSI ENERGY

a. Macro Assumptions

It is generally assumed that the PSI service area economy will tend to react much like the national economy over the forecast period. PSI based its forecast on Data Resources Incorporated's (DRI) long-term forecast of the national economy.

No major wars or energy embargoes are assumed to occur during the forecast period. Even if minor conflicts and/or energy supply disruptions occurred during the forecast period, the path of the overall forecast would not be dramatically altered.

b. Local Assumptions

With regard to the local economy, the PSI service area has traditionally been strongly influenced by the level of manufacturing activity. While overall manufacturing employment shows little change over the forecast period, increasing manufacturing productivity helps keep both total manufacturing output and industrial kWh sales increasing. The majority of the employment growth over the forecast period occurs in the non-manufacturing sector. This reflects a continuation of the trend toward the service industries and the fundamental change that is occurring in manufacturing and other basic industries.

PSI is also affected by national population trends. The average age of the U.S. population is rising. The primary reasons for this phenomenon are stagnant birth rates and lengthening life expectancies. As a result, the portion of the population of the PSI service area that is "age 65 and older" increases over the forecast period. It is also assumed that PSI's relatively slow rate of population growth, compared to the U.S. as a whole, will continue in the future. During the period 1985 to 1995, PSI's population grew at an average annual rate of 0.2 percent. Annual average growth at the national level was 1.0 percent over the same time period. Over the period 1999 to 2019, PSI's population is expected to increase at an annual average rate of 0.3 percent. Nationally, population is expected to grow at an annual rate of 0.8 percent over the same period.

The relative mix of customers within the major sectors - residential, commercial and industrial - is expected to remain fairly constant within PSI's service area over the forecast period. The residential sector is the largest in terms of total existing customers and total new customers per year. Within the PSI service area, many commercial customers serve local markets. Therefore, there is a close relationship between the growth in local residential customers and the growth in commercial customers. The number of new industrial customers added per year is small.

c. **Customer Self-Generation**

Throughout the last 20 years many industrial customers, and some commercial customers, have inquired about cogeneration, the sequential production of electricity and process heat or steam. There have been few cases in which cogeneration has been installed. In almost every case analyzed, PSI's industrial rates were too low for the project to be economically justified. No additional cogeneration units that impact the load forecast are assumed to be built or operated within the PSI service area during the forecast period.

In the area of other self-generation, several units are in place within PSI's service territory to provide a source of emergency backup electricity. Since the primary purpose of these units is the provision of emergency power, they are not assumed to be operated during the forecast period.

D. DATA BASE DOCUMENTATION

In the following sections, information on data bases is provided for each jurisdiction in Cinergy.

1. CG&E/ULH&P

Data collection is one of the first steps in the forecasting process. The data base discussion for CG&E

is broken into three parts: Service Area Economic Model, Energy and Peak Models, and Forecast Data.

a. Service Area Economic Model (SAEM)

The major groups of data used in the process of developing the SAEM are employment, industrial production indices, population, income, prices, and wages. Historical values for these concepts are available from DRI. Local historical data is obtained from various state agencies or within CG&E. Some of the data collected is not in the appropriate form for analysis. In the following sections, descriptions are provided concerning any significant adjustments made on the data to develop the data series used in regression analyses.

Average Hourly Earnings-Manufacturing

Average hourly earnings for durable and nondurable manufacturing for the Cincinnati MSA are available on a monthly basis from DRI. Both series are converted to a quarterly basis by averaging their monthly values. Average hourly earnings for total manufacturing is computed as a weighted average of the durable and non-durable average hourly earnings series using service area durable and nondurable to total manufacturing employment ratios as weights.

Employment

Employment numbers are required on both a national and service area basis. Quarterly national employment series are obtained from DRI. Local data is obtained from the Ohio Bureau of Employment Services, Division of Research and Statistics. Employment series are collected for all SIC groups in the industrial and commercial sectors.

Data on the national level are essentially in the correct form except for one aggregation that is required. Total national commercial employment is derived from the sum of employment in SICs 40 through 89.

Service area employment data are available on a monthly basis for construction, industrial SICs 20, 23, 26, 27, 28, 30, 33, 34, 35, 36, 371, 372, all other industrials, durable goods (AOIDG), and all other industrials, non-durable goods (AOINDG), commercial SICs 40 through 89, and government SIC 90 for the Cincinnati PMSA, and Butler County. Once all of the monthly series are converted to quarterly series, total employments for each of the main SIC groups in the CG&E service area are produced by aggregating the data for the Cincinnati MSA and the two counties. An exception to this method is the employment data for SIC 33 which are broken into two parts: Butler County and total service area less Butler County.

Population

National values for total population and population by age cohort groups are obtained from DRI.

Population aged 20 and over is derived by subtracting population aged 16 to 19 from population aged 16 and over. Population aged 0 to 19 is derived by subtracting population aged 20 and over from total population. Population aged 6 to 19 is derived by subtracting population aged 5 and under from population aged 0 to 19. Population aged 20 to 64 is derived by subtracting population aged 65 and over from population aged 20 and over. Population series for the age-cohort 65 and over is available from DRI.

The source for local population by age-cohort groups is the U.S. Census Bureau. The data is aggregated over the cohort groups 0 to 4, 5 to 9, 10 to 14, and 15 to 19, both male and female, for each county to obtain service area population aged 0 to 19. An aggregation is performed over the cohort groups 20 to 24, 25 to 29, 30 to 34, 35 to 39, 40 to 44, 45 to 49, 50 to 54, 55 to 59, and 60 to 64, both male and female, for each county to obtain service area population aged 20 to 64. An aggregation is made over the cohort groups 65 to 69, 70 to 74, and 75 and older, both male and female, for each county to obtain service area population aged 65 and over.

Total population and the age-cohort series for the service area are required on a quarterly basis. To develop this data, each of these series is interpolated.

The forecast of population for the service area is produced by using an age-cohort model specific to the counties in the service area. The fertility and survival rates used in the model are obtained from the U.S. Department of Commerce, Bureau of the Census, and the appropriate state agencies.

Income

Updates of historical local income data series are obtained from the Bureau of Economic Analysis on a county level basis and summed to the service area level. This is performed for personal income; dividends, interest and rent; transfer payments; wage and salary disbursements plus other labor income; non-farm proprietors' income; and personal contributions for social insurance.

Seasonal Adjustments

For specific service area data, seasonal adjustments are performed for the quarterly series. Those series include average hourly earnings for manufacturing and employment series.

State Corporate Income Tax Rates

Ohio and Kentucky corporate income tax rates are obtained from state governments.

Electricity and Natural Gas Prices

The average price of electricity and natural gas is available from CG&E financial reports. These data are obtained annually and distributed to the respective quarters to remove any seasonality.

Industrial Production Indices for AOIDG & AOINDG

The National Industrial Production index for AOIDG and AOINDG is created from a value-added weighting of the individual SIC indices included in these sectors. The value added data are obtained from the Federal Reserve Board. The industrial production indices for SIC 21, 22, 23, 24, 25, 27, 29, 30, 31, 32, 34, 38, & 39 are obtained from DRI Inc.

b. **Energy and Peak Models**

The majority of the data required for developing the CG&E electric energy model is obtained from either the SAEM data or CG&E's financial reports. Also, data on additional national variables are generally obtained from DRI. As with the data collected for SAEM, some of the data collected for the energy model are not in the required form. The following are descriptions of the adjustments performed on various groups of data to develop the final data series actually used in regression analysis.

Kilowatthour Sales

Data on kilowatthour (kWh) energy usage are obtained monthly from CG&E financial reports for each customer class. Consolidated industrial sales by SIC group are computed for SICs 20, 26, 28, 33, 35, 36, 37, and 371 by adding sales for CG&E and ULH&P for each of these groups. Information on sales to AK Steel Corp. is obtained from CG&E records. AK Steel Corp. sales are subtracted from total sales for SIC 33 to obtain sales for SIC 33 less AK Steel Corp. CG&E sales for SIC 372 through 379 (372@9) are computed by subtracting CG&E sales for SIC 371 from CG&E sales for SIC 37. The same computation is performed for ULH&P. Consolidated 372 @ 9 sales are computed by adding those sales for CG&E and ULH&P previously computed. The last step is to derive sales for the all other industries (AOI) category for CG&E, ULH&P and Consolidated. This is accomplished by subtracting sales for SICs 20, 26, 28, 33, 35, 36, 371, and 372@9 from total industrial sales for both CG&E and ULH&P. Consolidated AOI sales is the sum of CG&E and ULH&P AOI sales and West Harrison Gas & Electric (WHG&E) total industrial sales.

The other public authorities (OPA) sales category is analyzed in two parts: water pumping and OPA less water-pumping sales. The data series for OPA less water-pumping sales for both CG&E and ULH&P are derived by subtracting the respective water-pumping series from the OPA series. Consolidated sales for water-pumping and OPA less water pumping are developed by adding those series for CG&E and ULH&P.

The total sales for the other public utilities (OPU) category for CG&E is computed by adding the sales for each of the six wholesale towns: Bethel, Blanchester, Georgetown, Hamersville, Lebanon, and Ripley in Ohio.

Residential Customers

The number of residential customers is obtained on a monthly basis from financial reports. Data on residential electric space heating customers are collected on a monthly basis for CG&E and ULH&P. The Consolidated CG&E series is converted to a quarterly and annual series by averaging.

Residential Use Per Customer

For the Consolidated CG&E System, residential kWh use per customer is computed on a monthly basis by dividing residential kWh sales by total residential customers.

Degree Days

Heating degree days and cooling degree days are collected on a monthly basis from the NOAA (National

Oceanic and Atmospheric Administration). The degree day series are required on a billing cycle as well as a difference from normal basis for use in regression analysis. Normal degree days are also obtained from the NOAA for use in the forecast.

Appliance Stock

To identify the impact of standards established under the National Appliance Energy Conservation Act, an appliance stock variable is created. This variable is composed of three parts: appliance efficiencies, appliance saturations, and fixed appliance energy consumption values. The fixed appliance energy consumption values are used as weights for the saturations and efficiencies to produce the estimate of the energy using stock of appliances or the connected load.

The appliance stock variable is calculated as follows:

(37) Appliance Stock (t)=SUM (K(i) * SAT(i,t) * EFF(i,t))

for all i

where t = time period

i = end-use appliance

$K(i)$ = fixed energy consumption value for appliance i,

$SAT(i,t)$ = saturation of appliance i in period t, and

$EFF(i,t)$ = efficiency of appliance i in period t.

The appliances included in the calculation of the Appliance Stock variable are: electric range, frost-free refrigerator, manual-defrost refrigerator, food freezer, dish washer, clothes washer, clothes dryer, water heater, microwave, color television, black and white television, room air conditioner, central air conditioner, electric resistance heat, and electric heat pump. Information on the fixed appliance energy consumption values for non-weather sensitive appliances and weather sensitive appliances are obtained from analysis of end-use surveys and CG&E load data.

<u>Appliance Saturation</u>

In general, information on historical appliance saturations for all appliances is obtained from CG&E's Appliance Saturation Surveys. For non-survey years, the data are obtained by interpolation. Historical appliance saturation data are built up from the survey data for each housing type (e.g. single family, apartment, condo, and mobile home) and the relative proportion of each housing type in the service area.

<u>**Space-Heating**</u>

The number of electric space-heating customers in the CG&E service area is available for the time period 1975, fourth quarter, through the present from CG&E company records. With the number of heating customers and total residential customers in the CG&E service area, the saturation of electric space heating customers can be computed.

<u>**Appliance Efficiency**</u>

Data on appliance efficiency are obtained from the Association of Home Appliance Manufacturers (AHAM), Air-Conditioning & Refrigeration Institute (ARI), and the Gas Appliance Manufacturers Association. Information on average appliance life is obtained from <u>Appliance Week</u>.

<u>**Seasonal Adjustments**</u>

Residential customers, street lighting sales, and electric sales for each SIC are seasonally adjusted using the technique discussed in Section F.

<u>**Peak Weather Data**</u>

The weather conditions associated with the monthly peak load are collected from the hourly and daily data recorded by the National Oceanic and Atmospheric Administration for the Cincinnati area. The weather variables which influence the summer peak are maximum temperature on the peak day and the day before, morning low temperature, and humidity on the peak day. The weather influence on the winter peak is measured by the low temperatures and the associated wind speed. The variables selected are dependent upon whether it is a morning or evening peak load.

An average of extreme weather conditions is used as the basis for the weather component in the preparation of the peak load forecast as previously discussed in Section B. Using historical data for the single worst summer weather occurrence and the single worst winter weather occurrence in each year, an average extreme weather condition can be computed. Since the peak load is not expected to occur on a weekend, these values are reduced to account for the probability of occurrence during the week.

Electricity Price

Data on electricity price (including fuel cost) is collected for each customer class. This information is obtained from CG&E and ULH&P rate schedules.

c. Forecast Data

Economy

The electric energy and peak load forecast is prepared using a forecast of the local economy which is developed with the Service Area Economic Model (SAEM). The local economic forecast from SAEM relies upon a national economic forecast prepared by DRI.

Appliance Saturations and Efficiencies.

The forecast of appliance saturations and efficiencies is obtained from an analysis conducted with EPRI's REEPS (Residential End-Use Energy Planning System) model. REEPS is a dynamic residential end-use forecasting model which incorporates engineering and economic relationships at the appliance level. It can model appliance purchase and efficiency decisions as well as usage. Using local data on historical appliance types, saturations by housing types, initial estimates of end-use appliance energy usages, target appliance efficiencies established by law, and forecasts of consumer income and energy prices, REEPS produces forecasts of appliance saturations and efficiencies. This information, in conjunction with the forecast of appliance saturation is employed to prepare the forecast of the appliance stock variable.

2. PSI ENERGY

As with CG&E, the first step in the forecasting process is the collection of relevant information and data. The data base discussion is broken into three parts: a) Economic Data, b) Energy and Peak Data, and c) Forecast Data.

a. Economic Data

The major groups of data that are used in developing the economic forecasts are employment, income, demographics, national production, and national employment.

Employment - Employment statistics, by industry, are collected on a county-wide basis. Data for both the manufacturing and non-manufacturing categories are then aggregated into a total of the 61 Indiana counties where PSI serves five percent or more of the total population. The source of this information is the U.S. Bureau of Labor Statistics.

Income - Updates of historical local income data series are obtained from the Bureau of Economic Analysis on a county level basis and summed to the service area level. This is performed for personal income; dividends, interest and rent; transfer payments; wage and salary disbursements plus other labor income; non-farm proprietors' income; and personal contributions for social insurance.

Population - Population statistics are also provided by the Indiana Business Research Center. This data is aggregated into a total of the 61 Indiana counties where PSI serves five percent or more of the total population. The IBRC receives this information directly from the U.S. Census Bureau.

National Production and Employment - National production and employment statistics are obtained from DRI. Production indices and employment statistics are obtained for each 2-digit SIC category. This information is utilized in the forecast of local employment.

Average Hourly Earnings - Average national hourly earnings data are also obtained from DRI.

b. Energy and Peak Data

The majority of data required to develop the electricity sales and peak forecasts is obtained from the PSI service area economic model, from PSI financial reports and research groups, and from national sources. With regard to the national sources of information, generally all national information is obtained from DRI. However, local weather data are obtained from the National Oceanic and Atmospheric Administration (NOAA).

The major groups of data that are used in developing the energy forecasts are: kilowatthour sales by customer class, number of customers, use per customer, electricity prices, natural gas prices, appliance saturations, local weather data, and seasonal demand factors.

Kilowatthour Sales and Revenue - PSI collects sales and revenue data monthly by rate class. For forecast purposes this information is aggregated into the following categories: residential, commercial, industrial and the other sales category. In the industrial sector, sales and revenue for each 2-digit manufacturing SIC are collected. Statistics regarding sales and revenue for each wholesale customer are also collected. From the sales and revenue information, average electricity prices by sector can be calculated.

Number of Customers - The number of customers by sector, on a monthly basis, is also obtained from PSI records. From the sales and customer data, average electricity use per customer can be calculated.

Natural Gas Prices - Natural gas prices are provided by DRI.

Saturation of Appliances - The saturation of appliances within the service area is provided via customer surveys conducted by the Company's Market Research group.

Local Weather Data - Local climatological data are provided by NOAA for the Indianapolis, Indiana reporting station.

Seasonal Demand Factors - Seasonal demand factors are computed using data from PSI records and the Company's Load Research group.

c. **Forecast Data**

Projections of exogenous variables in PSI's models are required in the following areas: national employment, industrial production, population, natural gas prices, and electricity prices.

National Employment -The forecast of national employment by industry is provided by DRI's Macro Forecasting service. These forecasts are 25 year simulations of the U.S. economy.

Industrial Production - The forecast of national industrial production is also provided by DRI's Macro Forecasting service.

Population - PSI's population forecast is derived from data provided by the Indiana Business

Research Center. Population projections for the service area are prepared by first collecting county-level population forecasts developed by the IBRC for the 61 counties in which the company serves five percent or more of the population. The PSI service territory population forecast can then be produced by calculating the total of the 61 county projections. These county-level projections were developed using an age-cohort model that has been approved for use by the U.S. Census Bureau.

Natural Gas Price - The forecast of natural gas prices is also provided by DRI's Macro Forecasting service.

Electricity Prices - The projected change in average electricity prices over the forecast interval, by rate class, is provided by the Company's Budgets and Forecasts department.

3. Load Research and Market Research Efforts

a. Load Research

Cinergy is committed to the continued development and maintenance of a substantive class load database of typical customer electricity consumption patterns. Complete load profile information, or 100% sample data, is maintained upon commercial and industrial customers whose average annual demand is greater than 500 kW. Additionally, both PSI and CG&E continue to collect whole premise or building level electricity consumption patterns on representative samples of the various customer classes and rate groups whose annual demands are less than 500 kW. SIC designations are available for each of the customers whose electrical consumption patterns are monitored.

Periodically, both PSI and CG&E also monitor selected end-uses or systems associated with energy efficiency evaluations performed in conjunction with demand-side management programs. These studies are performed as necessary and tend to be of a shorter duration.

b. **Market Research**

Primary research projects continue to be conducted at CG&E, ULH&P, and PSI as part of the on-going efforts to gain knowledge about Cinergy's customers. These projects include customer satisfaction studies, appliance saturation studies, end-use studies, studies to track competition (to monitor customer switching percentages in order to forecast future utility load), and related types of marketing research projects.

E. LOAD SHAPES

Graphical representations of the Cinergy summer peak day and winter peak day load curves are provided on Figures 3-1 and 3-2, respectively, for the years 1994 through 1998.

Graphical representation of the annual load duration curves are provided on Figures 3-3 through 3-7 for the years 1994 through 1998.

No significant trends or changes in load shape are expected over the forecast period. However, the ultimate load shape will depend, in part, on the impact of current and any planned DSM programs. To the extent that a general trend can be described, two factors are evident. First, implicit in the forecast of energy and peak demands is a forecast of the load factor which is projected to rise slightly over the forecast horizon. This will tend to slightly reduce the relative "peakedness" of the load duration curve. Second, the graphs of daily load curves and the annual load duration curves reflect actual experience. The historical load shapes would have been even more peaked if the existing DSM measures were not in place and if the interruptible loads on those days had not been interrupted. Even though the interruptible load does not satisfy the definition of interruptible loads contained in ECAR Document No. 2, it is likely that some form of interruption will occur. Therefore, the level of interruption should be above that represented in the historical load shapes. This will tend to also slightly reduce the "peakedness" of the daily load curves and the annual load duration curve.

F. MODELS

Specific analytical techniques for CG&E and PSI have been employed for development of the forecast models.

1. CG&E

a. Specific Analytical Techniques

Seasonal Adjustment

The time frequencies of the electric load forecasting models are quarterly and monthly. This includes service area economic and electric energy demand equations. To incorporate seasonal changes, the historical values of several economic concepts and energy consumption variables are seasonally adjusted before regression analysis is performed. The Census Bureau's X-11 procedure is employed to perform the seasonal adjustments.

Regression Analysis

Ordinary least squares is the principle regression technique employed to estimate economic/behavioral relationships among the relevant variables. However, quite often there is a lagged response between the change in one variable and a subsequent change in another variable. For example, if the real price of electricity changes, consumers usually do not fully adjust to the price change in the same time period. Rather, it takes several months or more for the consumer to alter the stock of energy using equipment in the home and to complete the adjustment process. To incorporate this concept of lagged response in the behavioral models, the service area economic and energy model equations employ a constrained distributed lag structure or a polynomial distributed lag structure. In some instances, the equation may use a standard multiple regression model without a lag structure.

Polynomial Distributed Lag Structure

One method of accounting for the lag between a change in one variable and its ultimate impact on another variable is through the use of polynomial distributed lags. This technique is also referred to as Almon lags. Polynomial Distributed Lag Structures derive their name from the fact that the lag weights follow a polynomial of specified degree. That is, the lag weights all lie on a line, parabola, or higher order polynomial as required.

This technique is employed in developing econometric models for most of the equations in SAEM and most of the energy equations.

Serial Correlation

It is often the case in forecasting an economic time series that residual errors in one period are related to those in a previous period (serial correlation). By correcting for the serial correlation of the estimated residuals, forecast error is reduced. The Gauss-Newton technique (similar to the Cochrane-Orcutt method) is employed to correct for the existence of autocorrelation. This correction technique was used in numerous instances in the development of the econometric equations (both service area economic and electric energy).

Qualitative Variables

In several equations, qualitative variables are employed. In estimating an econometric relationship using time series data, it is quite often the case that outliers will occur. The unusual deviations in the data can be the result of various data problems such as errors in the reporting of employment data by particular companies, labor-management disputes, or other such perturbations that do not repeat with predictability. Therefore, in order to identify the underlying economic relationship between the dependent and independent variables, qualitative variables are employed to remove the outliers.

b. Relationships Between The Specific Techniques

The manner in which specific methodologies for forecasting components of the total load are related is explained in the discussion of specific analytical techniques above.

c. Alternative Methodologies

A residential end-use conditional demand model has been estimated using a combined data base from the 1988, the 1991, and the 1994 Appliance Saturation Surveys. By combining the data bases, the model was able to incorporate the estimated impacts of price and income on the energy use of individual end-uses within the residential class. However, CG&E continues to use the current regression forecasting methods as they are considered to be accurate predictors of the future.

d. Changes In Methodology

There were no significant changes to the forecast methodology for CG&E.

e. Computer Software

Primarily two computer software packages are employed in the preparation of the forecast. One package, called EPS/PC, is developed by DRI. The other package, called EAL (Economic Analysis Language), is developed by Economic Analysis Associates, Inc. Both are licensed software products and are utilized on microcomputers.

2. PSI ENERGY

The basic analytical techniques used in the development of the PSI models used to produce the long-term forecast are very similar to those used by CG&E. Consequently, some of the following discussion repeats earlier discussions regarding analytical techniques.

a. <u>Specific Analytical Techniques</u>

<u>Regression Analysis</u>

Ordinary least-squares is the principal regression technique employed to estimate economic/behavioral relationships among the relevant variables. This econometric technique provides a method to perform quantitative analysis of economic behavior.

Ordinary least-squares techniques were used to model economic variables such as employment and income as well as kWh sales. Based upon their relationship with the dependent variable, several independent variables were tested in the regression models. The final models were chosen based upon their statistical strength and logical consistency.

<u>Logarithmic Transformations</u>

The projection of economic relationships over time requires the use of techniques that can account for non-linear relationships. By transforming the dependent variable, and socio-economic independent variables into their "natural logarithm", a non-linear relationship can be transformed into a linear relationship.

Serial Correlation

It is often the case in forecasting an economic time series that residual errors in one period are related to those in a previous period. This is known as serial correlation. By correcting for this serial correlation of the estimated residuals, forecast error is reduced and the estimated coefficients are more efficient. The Gauss-Newton technique is employed to correct for the existence of first-order autocorrelation.

Qualitative Variables

In several equations, qualitative variables are employed. In estimating an econometric relation using time series data, it is quite often the case that "outliers" are present in the historic data. These unusual deviations in the data can be the result of numerous problems such as errors in the reporting of data by particular companies and agencies, labor-management disputes, severe energy shortages or restrictions, and other perturbations that do not repeat with predictability. Therefore, in order to identify the true underlying economic relationship between the dependent variable and the other independent variables, qualitative variables are employed to account for the impact of the outliers.

b. **Changes in Methodology**

No significant changes in modeling techniques were made in the PSI long-term forecasting systems since the development of the last Integrated Resource Plan.

c. **End-Use Modeling**

PSI has not adopted end-use modeling for the development of the long-range forecasts used in this integrated resource plan. PSI considers the forecasting methods currently utilized to be accurate predictors of the future.

G. FORECASTED DEMAND AND ENERGY

The forecast of loads for Cinergy includes portions of Indiana, Kentucky and Ohio. On the following figures, the loads for the Cinergy System as well as a breakdown for the PSI, CG&E (Ohio only), and ULH&P (Kentucky) portions are provided. For each segment of the Cinergy System, forecast data is provided both before and after implementation of

DSM programs. To eliminate the creation of duplicative information in multiple formats, the format of the required Ohio forms has been chosen for presentation purposes because it provides the most detail.

1. Service Area Energy Forecasts

Cinergy's total service area includes areas in three states; thus, Cinergy is submitting on Figures 3-8 through 3-12 (Ohio FORMS FE1-1A, FE1-1B, and FE1-1D) forecasts which respectively indicate Cinergy's energy demand for its Ohio (CG&E), Indiana (PSI), and Kentucky (ULH&P) service areas as well as for the entire Cinergy service area.

Before implementation of any new DSM programs or incremental DSM impacts, Residential use for the twenty-year period of the forecast for the entire Cinergy service area is expected to increase an average of 1.2 percent per year; Commercial use, 1.0 percent per year; and Industrial use, 2.1 percent per year.

The summation of the forecast changes in each sector results in a growth rate forecast of 1.4 percent for Net Energy for Load. Plant Auxiliary Use is added to Net

Energy for Load for the Total Energy column on the forms.

After implementation of any planned new DSM programs and any incremental DSM impacts (Figures 3-13 through 3-16), Residential use is expected to increase an average of 1.2 percent per year; Commercial use, 1.0 percent per year; and Industrial use, 2.1 percent per year.

The figures in the Net Generation column plus any purchased power equals the Net Energy for Load column in conformance with the definition of generation output in FERC accounting and reporting requirements. The summation of the forecast changes in each sector results in a after DSM growth rate forecast of 1.4 percent for Net Energy for Load.

2. **Forecast of Energy Demand in Ohio (Only) by Industrial Sectors**

Figure 3-17 provides a table of historical and forecast power consumption inside Ohio by industrial sectors for each of the designated Standard Industrial Classification (SIC) codes.

3. System Seasonal Peak Load Forecast

Because Cinergy's total service area includes areas in three states, Cinergy is submitting a set of internal and native peak load forms (Figures 3-18 through 3-21). These figures contain forecasts of summer and winter peaks for the Ohio (CG&E), Indiana (PSI), and Kentucky (ULH&P) service areas as well as the total Cinergy system. There is no interruptible load that satisfies the definition in ECAR Document No. 2. However, the historical difference between native and internal load before DSM reflects the impact of the industrial interruptible rate tariff.

For Figures 3-18 through 3-21, those labeled "Internal Load" summarize historical and projected internal growth before implementation of DSM programs. The table shows the Summer and succeeding Winter Peaks, the Summer Peaks being the predominant ones historically. Projected growth in the summer peak demand for the Cinergy system is 1.4 percent. Projected growth in the winter peak demand is 1.3 percent.

Peak load forecasts after implementation of DSM programs (Figures 3-22 through 3-25) are shown for native and internal loads "after DSM". The projected growth in the summer peak is 1.4 percent. Projected growth in winter peak demand (after DSM) is 1.3 percent.

4. Controllable and Interruptible Loads

There are no controllable loads included in the before DSM forecast.

According to the definition of interruptible loads (ECAR Document No. 2), there are no interruptible loads on the system that satisfy the definition at this time. However, due to the nature of the operation of a few customers located in each state, it is possible that load may be curtailed. The amount of load curtailed depends upon the level of operation of the particular customers. For the before DSM forecast, approximately 37 MW exists for interruption in the Kentucky part of the service territory, approximately 49 MW in the Ohio portion of the service territory, and approximately 350 MW in the Indiana portion. The after DSM forecast reflects the 436 MW of interruptible load plus the impacts from DSM conservation programs. Some of the interruptible contracts expire over time. The difference between the internal and native peak loads consists of the impact from the interruptible loads.

5. Load Factor

The numbers below represent the annual percentage load factor for the Cinergy System before any new or incremental DSM. It shows the relationship between Net Energy for Load, FORM FE1-1B and the annual peak, FORM FE1-3B, before DSM.

YEAR	LOAD FACTOR
1994	59.45%
1995	57.42%
1996	59.73%
1997	60.57%
1998	61.58%
1999	60.75%
2000	61.18%
2001	61.65%
2002	62.03%
2003	62.34%
2004	59.97%
2005	59.97%
2006	60.08%
2007	59.85%
2008	59.89%
2009	59.94%
2010	59.98%
2011	60.01%
2012	60.05%
2013	60.05%
2014	60.07%
2015	60.10%
2016	60.12%
2017	60.13%
2018	60.12%
2019	60.16%

6. Range of Forecasts

Under the assumptions of normal weather, the most likely forecast of electrical energy demand and peak loads is generated using forecasts of numerous economic variables.

The source of the national economic forecast is Data Resources, Incorporated (DRI). DRI also prepares upper and lower forecasts for a range around the base economic or trend projection.

In general, the upper band reflects relatively optimistic assumptions about the future growth of industrial production, real per capita income, and employment. The lower band depicts the impact of a pessimistic scenario. The alternate national economic forecasts from DRI are run through the respective Service Area Economic Models. The resulting local economic forecasts are then used to drive the energy and peak forecasting models. The range of growth rates for key local economic concepts are as shown on the following GROWTH RATE table.

GROWTH RATES
ALTERNATE ECONOMIC SCENARIOS

	Pessimistic	Base	Optimistic
Local - CG&E			
Employment			
Manufacturing	-0.7%	-0.5%	-0.3%
Commercial	0.9%	1.3%	1.6%
Governmental	0.9%	1.0%	1.2%
Total	0.6%	0.9%	1.2%
Industrial Production	1.6%	2.1%	2.5%
Real Per Capita Income	0.5%	0.9%	1.3%
Consumer Price Index	5.5%	3.5%	2.0%
Local - PSI			
Employment			
Manufacturing	-0.1%	1.0%	1.2%
Commercial	-0.6%	0.8%	1.3%
Governmental	NA	NA	NA
Total	-0.4%	1.0%	1.2%
Industrial Production	2.5%	3.9%	4.1%
Real Per Capita Income	-0.5%	0.7%	1.1%
Consumer Price Index	5.5%	3.5%	2.0%

Figures 3-26 through 3-29 provide the high, low, and most likely before DSM forecasts of electric energy and peak demand for each portion of the service area as well as the entire Cinergy system. Figures 3-30 through 3-33 provide similar information after implementation of the DSM programs.

7. **Monthly Forecast**

Figures 3-34 and 3-37 contain the net monthly energy forecasts for each portion of the service area and the total system. Figures 3-35 and 3-38 present the net monthly interval peak load forecasts for each portion of the service area and the total system. Figures 3-36 and 3-39 provide the monthly forecasts of peak loads and resources.

The methodology used to prepare a monthly forecast of resources is to reduce the net dependable capability of each generating unit by an expected seasonal (ambient temperature) unit derate, if applicable. The resultant expected system capability can be seen on the seasonal capability line.

Figure

CINERGY SUMMER PEAK DAY 24-HOUR LOAD SHAPE

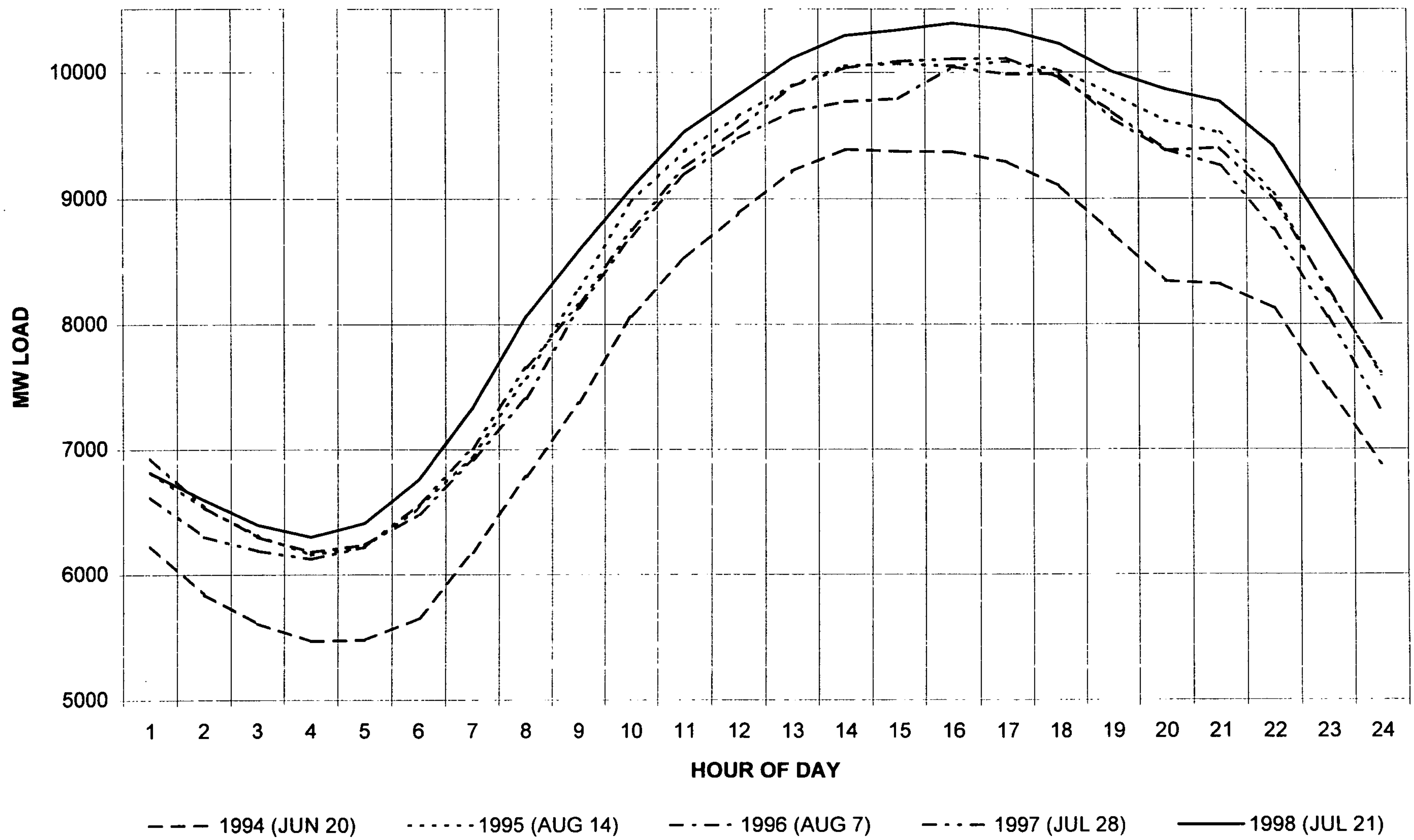


Figure 3-2

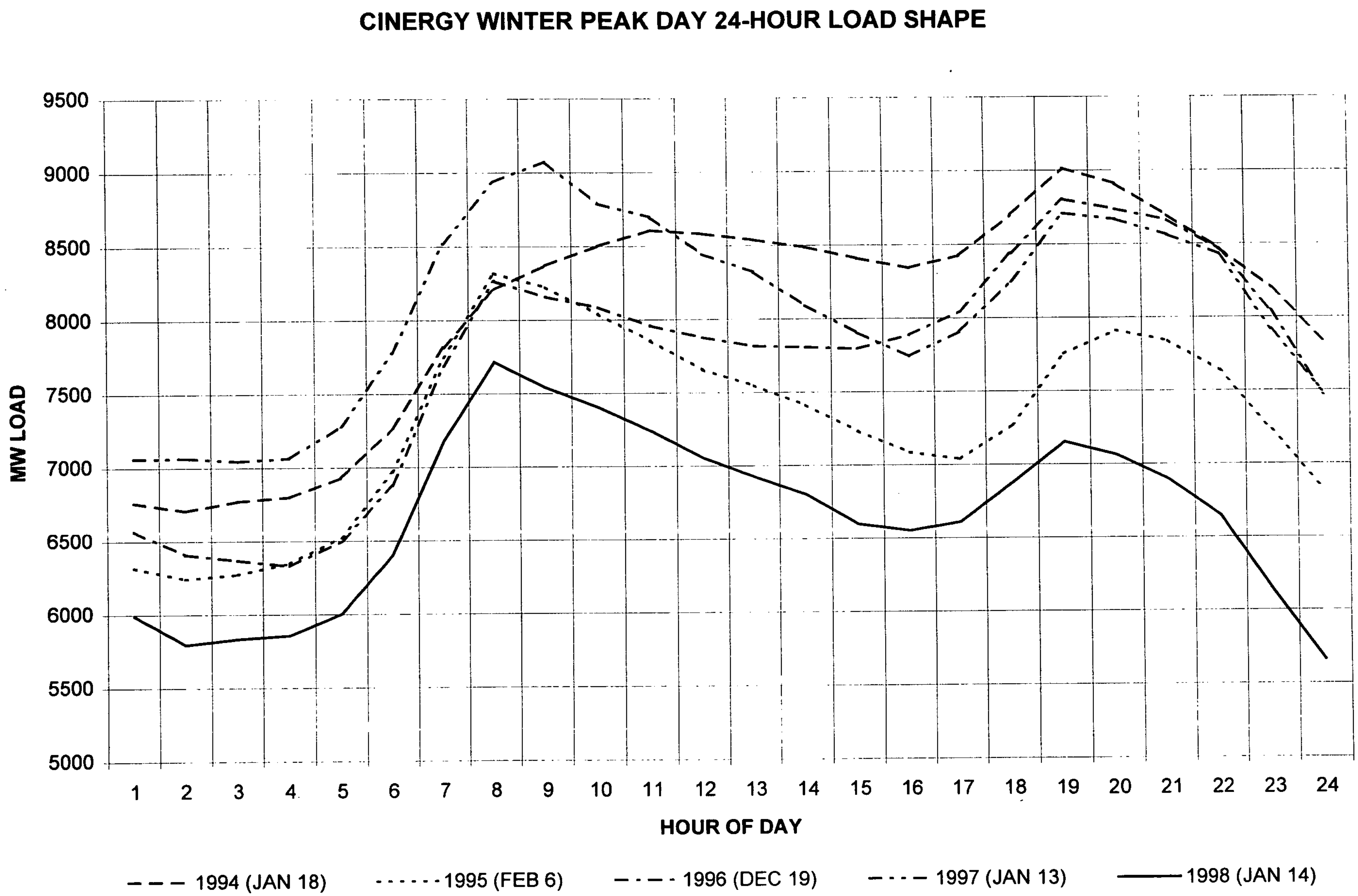

CINERGY WINTER PEAK DAY 24-HOUR LOAD SHAPE
9500
9000
8500
8000
7500
7000
6500
6000
5500
5000
MW LOAD
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOUR OF DAY
1994 (JAN 18)
1995 (FEB 6)
1996 (DEC 19)
1997 (JAN 13)
1998 (JAN 14)

Figure [illegible]-3

CINERGY 1994 LOAD DURATION CURVE

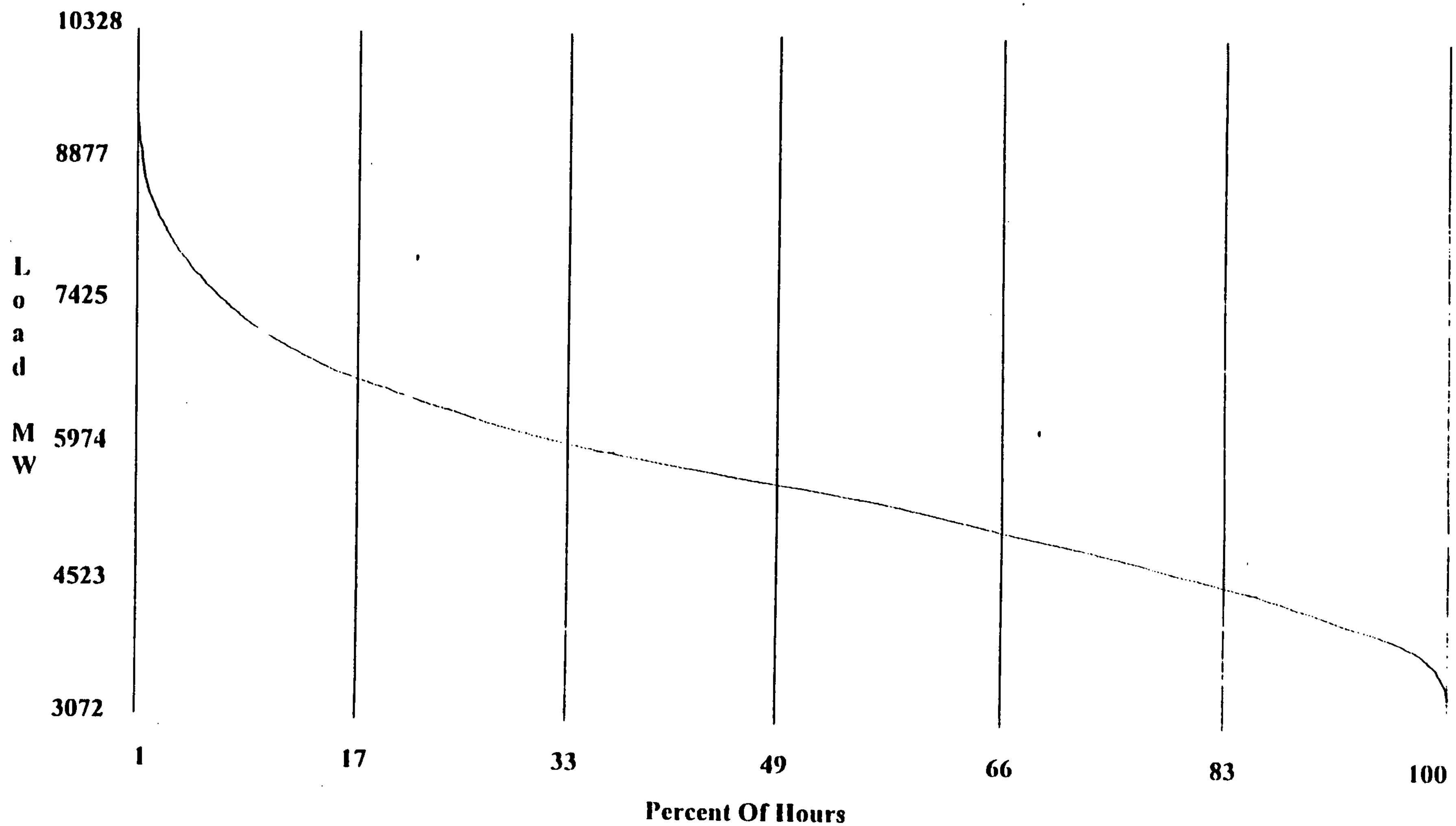
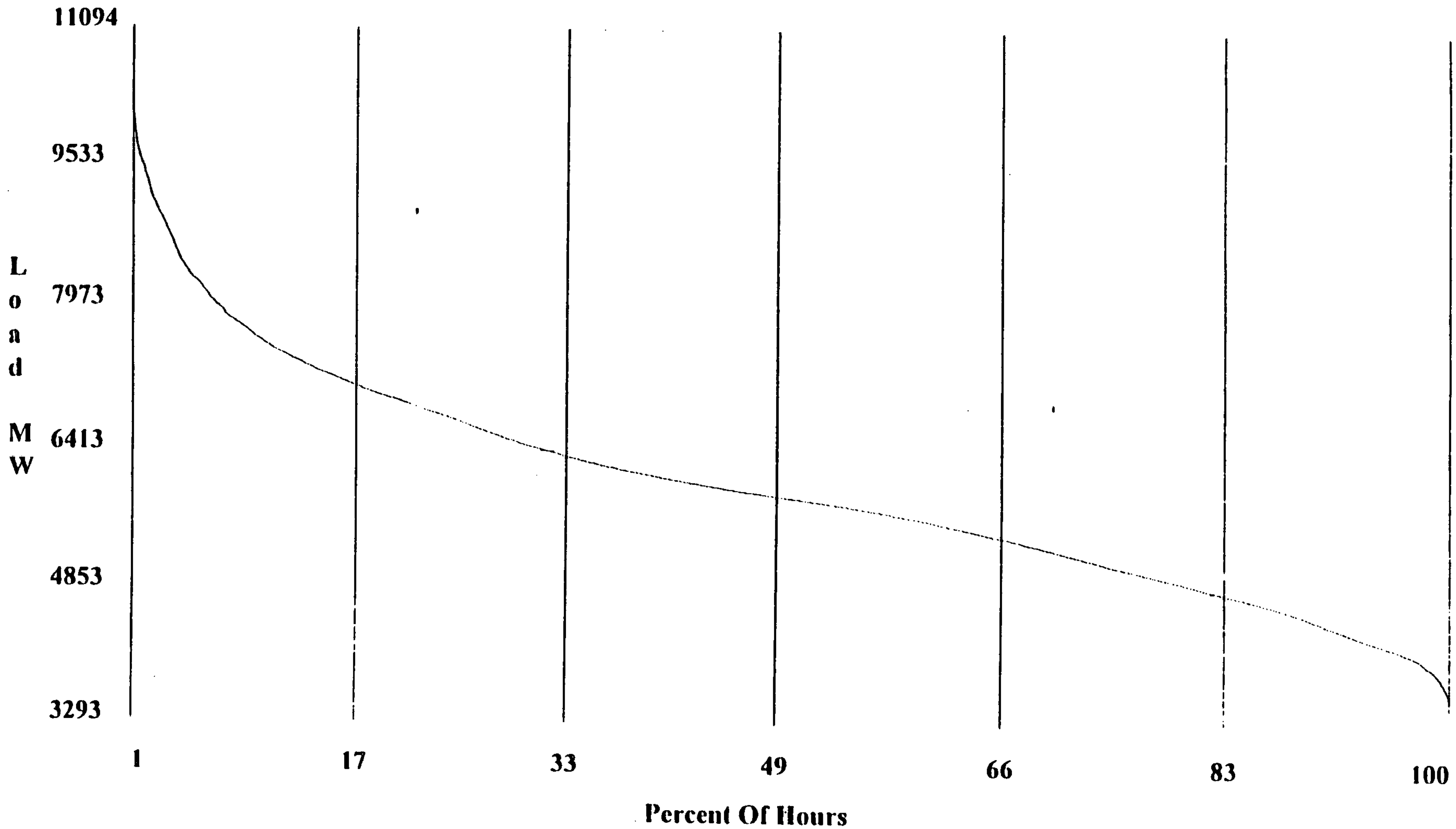


Figure 3-4

CINERGY 1995 LOAD DURATION CURVE



Figu -5

CINERGY 1996 LOAD DURATION CURVE

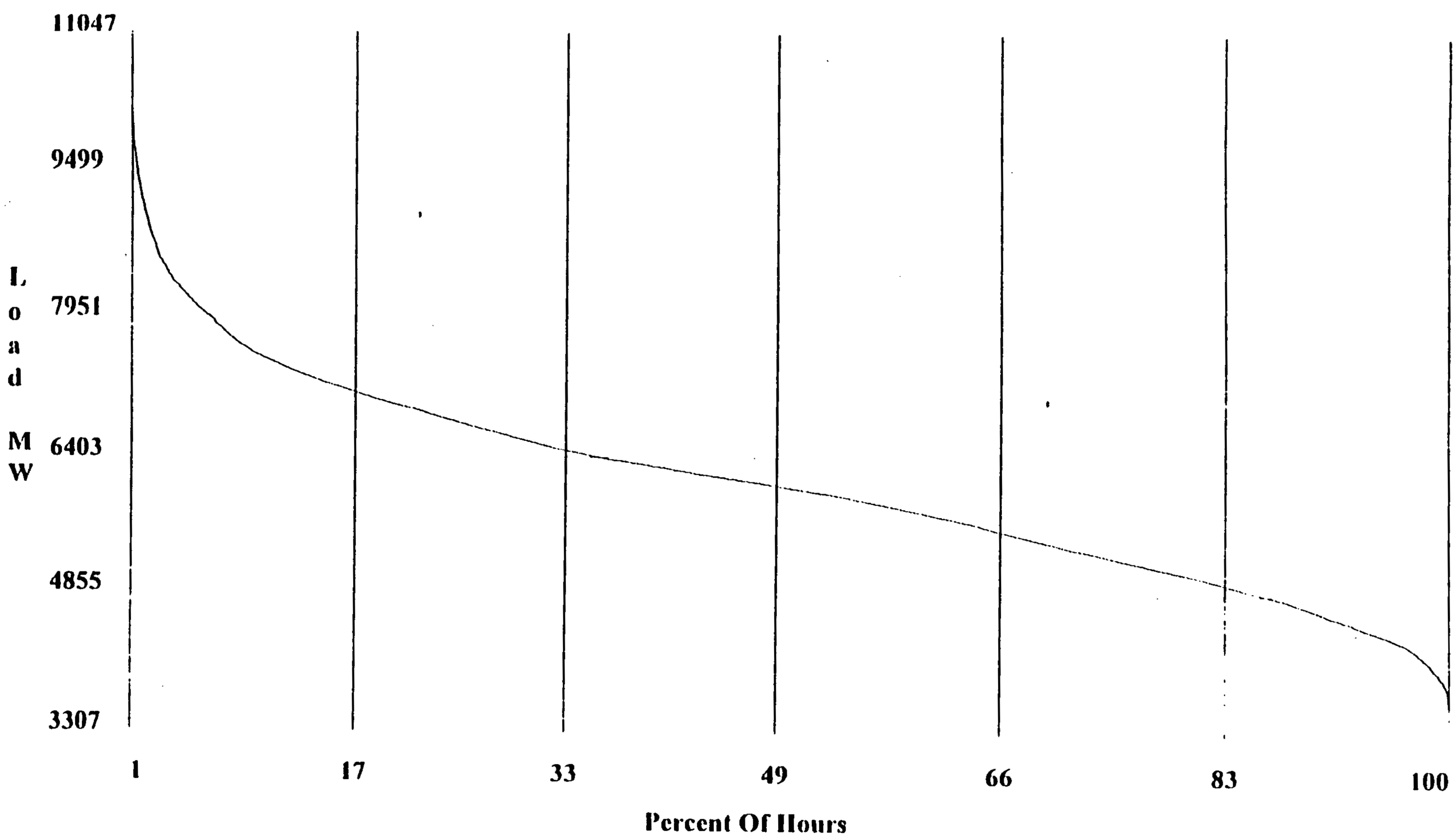
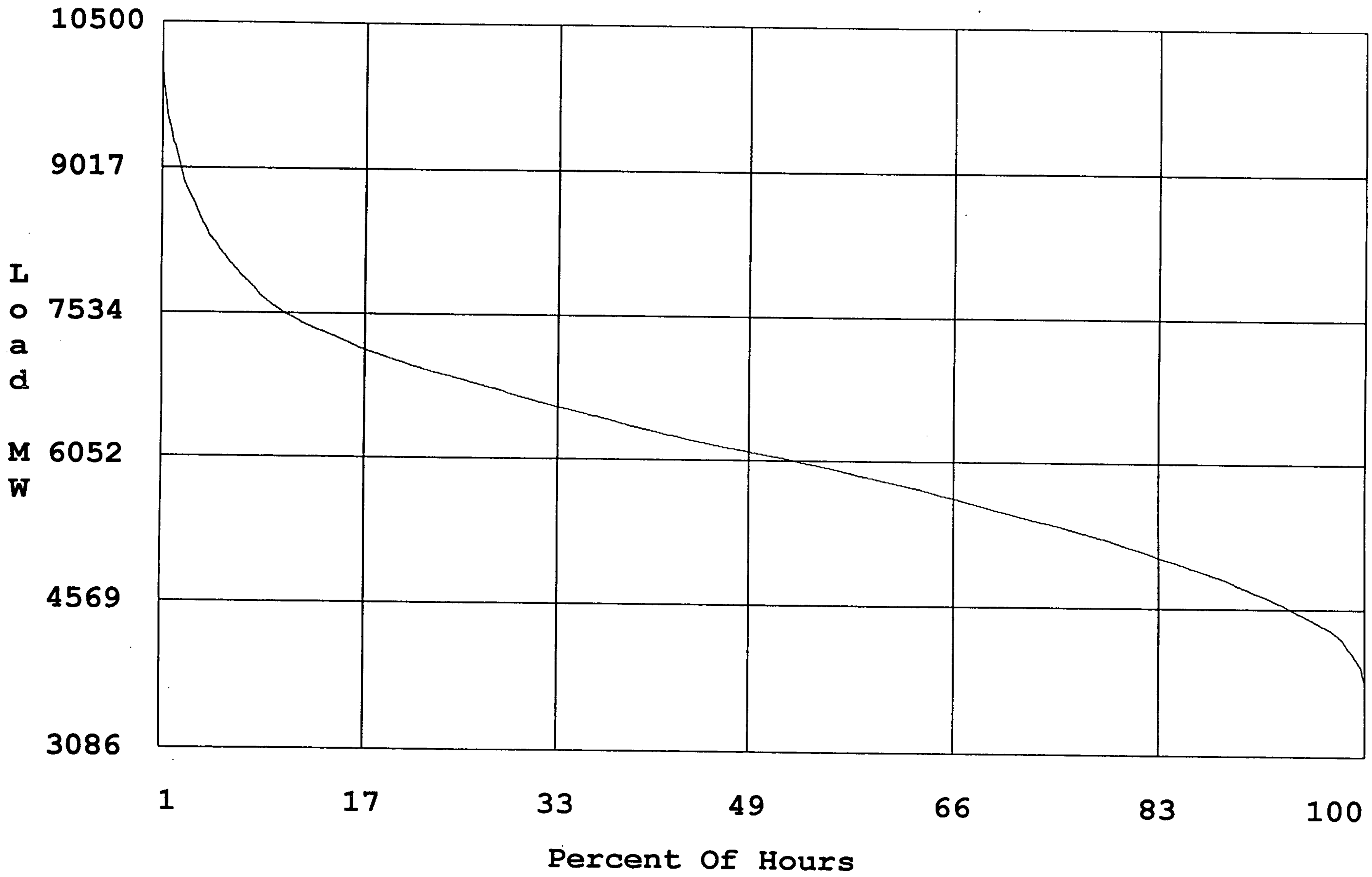


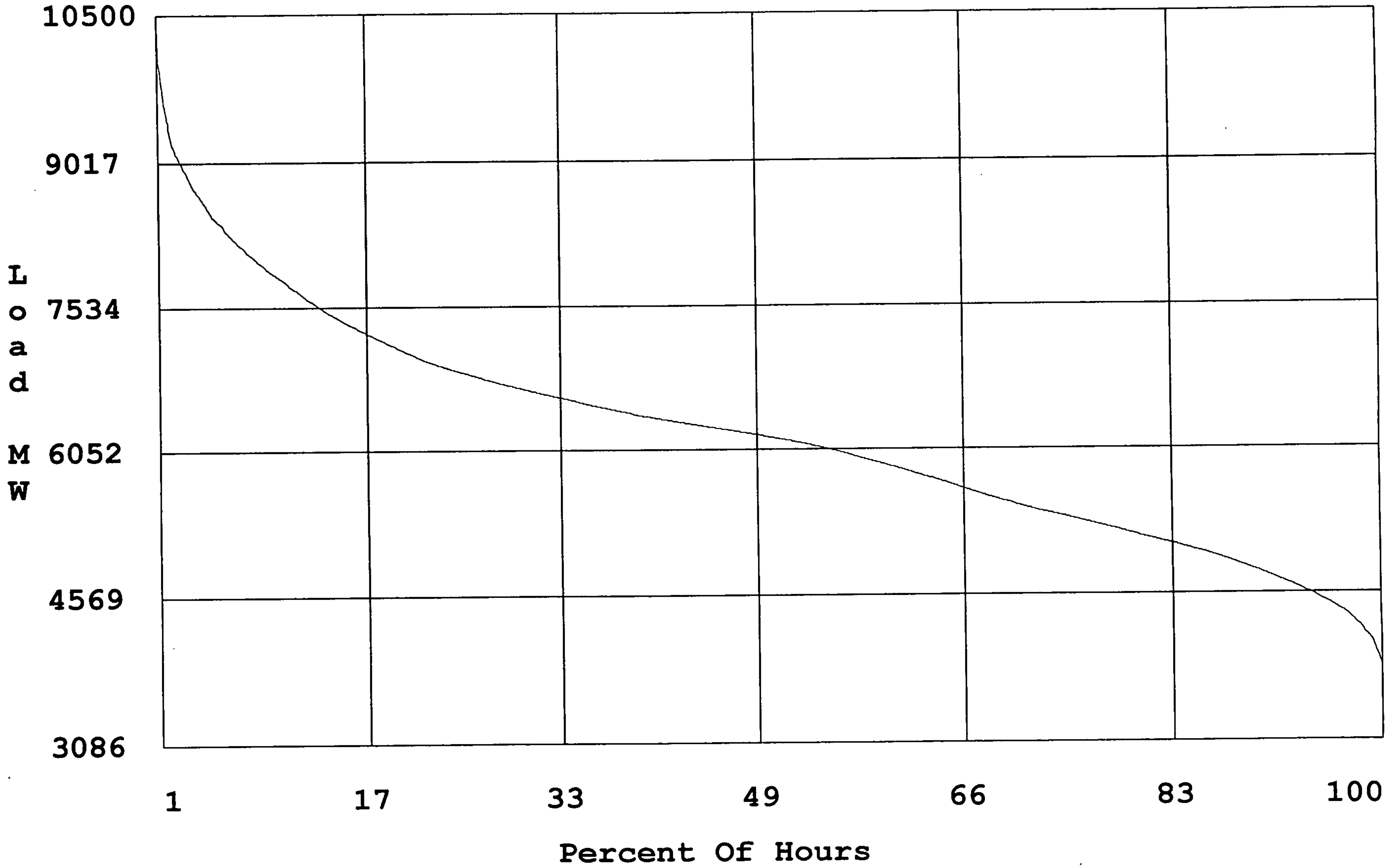
Figure 3-6

CINERGY 1997 LOAD DURATION CURVE



Fig[illegible] 3-7

CINERGY 1998 LOAD DURATION CURVE



Cinergy Corp.

4901 : 5 - 5 - 01
ODOE FE1-1A: SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)a,b
(OHIO PORTION ONLY)

PART 1

	YEAR	(1) RURAL AND RESIDENTIAL	(2) COMMERCIAL	(3) INDUSTRIAL	(4) STREET-HWY LIGHTING	(5) SALES FOR RESALE c	(6) OTHER
-5	1994	5,973,977	4,783,967	5,458,821	83,579	240,346	1,298,000
-4	1995	6,187,066	4,990,092	5,665,265	84,709	253,620	1,320,232
-3	1996	6,301,255	5,088,870	5,875,069	85,416	264,472	1,329,266
-2	1997	6,099,427	5,113,726	6,103,806	86,670	249,638	1,334,951
-1	1998	6,340,828	5,263,876	6,239,432	87,963	274,548	1,317,973
0	1999	6,509,153	5,352,059	6,731,300	86,433	286,870	1,345,216
1	2000	6,572,459	5,471,060	7,106,512	86,506	290,698	1,365,263
2	2001	6,674,571	5,601,708	7,456,018	86,582	295,008	1,403,413
3	2002	6,783,055	5,736,625	7,767,599	86,661	299,559	1,449,569
4	2003	6,911,131	5,891,856	8,144,525	86,838	304,970	1,492,037
5	2004	7,039,525	5,925,820	7,454,465	87,290	310,208	1,530,216
6	2005	7,178,326	6,154,467	7,812,638	87,751	317,676	1,599,053
7	2006	7,273,674	6,248,417	8,144,658	88,165	321,431	1,628,246
8	2007	7,370,598	6,322,825	8,391,033	88,551	324,713	1,648,733
9	2008	7,509,998	6,395,974	8,580,754	88,945	328,644	1,667,013
10	2009	7,606,279	6,472,591	8,773,462	89,357	331,945	1,684,271
11	2010	7,701,798	6,548,788	8,943,339	89,771	335,237	1,702,341
12	2011	7,813,614	6,624,061	9,107,032	90,157	338,754	1,719,775
13	2012	7,915,005	6,675,313	9,241,216	90,521	341,563	1,732,433
14	2013	7,997,160	6,729,975	9,372,690	90,878	344,124	1,744,170
15	2014	8,131,589	6,783,913	9,489,321	91,221	347,498	1,755,563
16	2015	8,247,355	6,834,716	9,624,391	91,568	350,500	1,767,321
17	2016	8,350,674	6,881,296	9,740,010	91,864	353,195	1,776,991
18	2017	8,407,360	6,934,174	9,879,854	92,129	355,298	1,785,450
19	2018	8,509,203	6,990,286	10,012,697	92,395	358,188	1,794,471
20	2019	8,601,979	7,044,923	10,138,497	92,660	360,901	1,803,854

(a) To be filled out by utilities operating across Ohio boundaries. The category breakdown should refer to the Ohio portion of the utility's service area. Utilities who do not serve customers in Ohio shall fill out only Net Generation on ODOE Form FE1-1A.

(b) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(c) Sales for resale to municipals.

Cinergy Corp.

4901 : 5 - 5 - 01
ODOE FORM FE1-1A: SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)c
(OHIO PORTION ONLY)

PART 2

	YEAR	(7) (1+2+3 +4+5+6) TOTAL CONSUMPTION	(8) LOSSES AND UNACCOUNTED FOR d	(9) (7+8) NET ENERGY FOR LOAD	(10) PLANT AUXILIARY USE	(11) (9+10) TOTAL ENERGY	(12) NET GENERATION e
-5	1994	17,838,690	1,175,263	19,013,953	1,338,546	20,352,499	19,855,217
-4	1995	18,500,985	1,208,079	19,709,064	1,340,004	21,049,068	21,029,445
-3	1996	18,944,348	1,177,357	20,121,705	1,558,835	21,680,540	23,121,582
-2	1997	18,988,218	1,112,639	20,100,857	1,516,165	21,617,022	23,475,360
-1	1998	19,524,620	1,256,538	20,781,158	1,654,843	22,436,001	23,475,360
0	1999	20,311,031	1,373,746	21,684,777	1,664,842	23,349,619	23,617,200
1	2000	20,892,498	1,413,913	22,306,411	1,439,963	23,746,374	20,427,100
2	2001	21,517,300	1,456,107	22,973,407	1,545,074	24,518,482	21,918,200
3	2002	22,123,068	1,498,884	23,621,952	1,608,997	25,230,949	22,825,000
4	2003	22,831,357	1,548,129	24,379,486	1,671,133	26,050,619	23,706,450
5	2004	22,347,524	1,515,714	23,863,238	1,849,787	25,713,024	26,240,800
6	2005	23,149,911	1,571,264	24,721,175	1,851,358	26,572,533	26,263,100
7	2006	23,704,591	1,606,924	25,311,515	1,862,253	27,173,769	26,417,650
8	2007	24,146,453	1,636,672	25,783,125	1,784,211	27,567,335	25,310,550
9	2008	24,571,328	1,665,326	26,236,654	1,826,866	28,063,520	25,915,650
10	2009	24,957,905	1,690,884	26,648,789	1,876,031	28,524,820	26,613,100
11	2010	25,321,274	1,715,714	27,036,988	1,879,341	28,916,329	26,660,050
12	2011	25,693,393	1,740,568	27,433,961	1,902,811	29,336,772	26,993,000
13	2012	25,996,051	1,760,387	27,756,438	1,951,846	29,708,284	27,688,600
14	2013	26,278,997	1,780,080	28,059,077	1,986,141	30,045,218	28,175,100
15	2014	26,599,105	1,801,702	28,400,807	1,992,513	30,393,320	28,265,500
16	2015	26,915,851	1,822,803	28,738,654	1,992,330	30,730,983	28,262,900
17	2016	27,194,030	1,841,183	29,035,213	2,035,436	31,070,649	28,874,400
18	2017	27,454,265	1,859,485	29,313,750	2,029,903	31,343,652	28,795,900
19	2018	27,757,240	1,880,216	29,637,456	2,041,809	31,679,264	28,964,800
20	2019	28,042,814	1,899,346	29,942,160	1,985,570	31,927,730	28,167,000

(c) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(d) Transmission, transformer and other losses and energy unaccounted for.

(e) The amount of net energy generated or estimated to be generated within Ohio by the reporting utility (do not include power purchased from other utilities). Energy from generating plants outside Ohio boundaries shall be shown on ODOE Form FE1-1B as part of Net Generation.

Cinergy Corp.

4901:5-5-01
ODOE FORM FE1-1A: SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)a,b
(INDIANA PORTION ONLY)

PART 3

		(1)	(2)	(3)	(4)	(5)	(6)
	YEAR	RURAL AND RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET-HWY LIGHTING	SALES FOR RESALE c	OTHER
-5	1994	6,657,729	5,708,667	9,291,967	61,212	4,327,305	248
-4	1995	6,950,085	5,894,713	9,697,861	63,038	4,465,067	425
-3	1996	7,204,063	5,933,850	10,016,412	64,057	4,262,421	690
-2	1997	7,067,126	5,955,217	10,241,682	64,279	4,759,537	578
-1	1998	7,293,805	6,288,686	10,790,132	64,837	4,982,402	637
0	1999	7,507,028	6,176,291	12,254,487	64,925	4,645,013	540
1	2000	7,657,002	6,251,836	12,726,473	65,250	4,739,250	540
2	2001	7,822,951	6,322,631	13,247,861	65,576	4,830,862	540
3	2002	7,995,073	6,468,840	13,894,814	65,904	4,926,341	540
4	2003	8,177,974	6,688,466	14,590,323	66,234	5,022,647	540
5	2004	8,204,568	6,664,430	13,742,253	66,565	5,194,750	540
6	2005	8,290,048	6,627,662	13,907,168	66,898	5,286,613	540
7	2006	8,335,845	6,558,858	14,166,817	67,232	5,376,876	540
8	2007	8,379,118	6,575,424	14,497,978	67,568	3,656,658	540
9	2008	8,447,135	6,621,430	14,854,387	67,906	3,674,734	540
10	2009	8,506,410	6,672,984	15,222,909	68,246	3,693,239	540
11	2010	8,571,659	6,734,076	15,603,829	68,587	3,712,171	540
12	2011	8,629,964	6,799,935	15,972,337	68,930	3,731,555	540
13	2012	8,671,778	6,842,930	16,298,392	69,275	3,751,392	540
14	2013	8,708,744	6,870,815	16,595,026	69,621	3,771,692	540
15	2014	8,743,416	6,896,609	16,885,007	69,969	3,792,471	540
16	2015	8,786,925	6,928,460	17,186,660	70,319	3,813,740	540
17	2016	8,835,873	6,957,610	17,465,743	70,671	3,835,508	540
18	2017	8,874,418	6,987,087	17,757,022	71,024	3,857,786	540
19	2018	8,906,141	7,019,438	18,049,662	71,379	3,880,590	540
20	2019	8,924,446	7,047,497	18,328,846	71,736	3,903,929	540

(a) To be filled out by utilities operating across Indiana boundaries. The category breakdown should refer to the Indiana portion of the utility's service area. Utilities who do not serve customers in Indiana shall fill out only Net Generation on ODOE Form FE1-1A.

(b) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(c) Sales for resale to municipals.

Cinergy Corp.

4901:5-5-01

ODOE FORM FE1-1A: SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)d
(INDIANA PORTION ONLY)

PART 4

	YEAR	(7) (1+2+3 +4+5+6) TOTAL CONSUMPTION	(8) LOSSES AND UNACCOUNTED FOR e	(9) (7+8) NET ENERGY FOR LOAD	(10) PLANT AUXILIARY USE	(11) (9+10) TOTAL ENERGY	(12) NET GENERATION f
-5	1994	26,047,128	1,617,567	27,664,695	1,999,054	29,663,749	29,762,208
-4	1995	27,071,189	1,673,775	28,744,964	2,012,731	30,757,695	30,509,912
-3	1996	27,481,493	2,269,134	29,750,627	2,172,436	31,923,063	28,824,973
-2	1997	28,088,419	1,890,497	29,978,916	2,352,717	32,331,633	31,998,755
-1	1998	29,420,499	2,208,569	31,629,068	2,465,029	34,094,097	33,139,788
0	1999	30,648,284	2,605,104	33,253,388	2,307,718	35,561,106	31,024,900
1	2000	31,440,351	2,672,430	34,112,781	2,451,552	36,564,333	32,958,600
2	2001	32,290,421	2,744,686	35,035,107	2,408,075	37,443,182	32,374,100
3	2002	33,351,512	2,834,879	36,186,391	2,452,809	38,639,199	32,975,500
4	2003	34,546,184	2,936,426	37,482,610	2,616,403	40,099,012	35,174,850
5	2004	33,873,106	2,879,214	36,752,320	2,869,977	39,622,297	38,583,900
6	2005	34,178,929	2,905,209	37,084,138	2,944,650	40,028,788	39,587,800
7	2006	34,506,168	2,933,024	37,439,192	2,996,796	40,435,988	40,288,850
8	2007	33,177,286	2,820,069	35,997,355	2,819,631	38,816,986	37,907,050
9	2008	33,666,132	2,861,621	36,527,753	2,938,539	39,466,293	39,505,650
10	2009	34,164,328	2,903,968	37,068,296	2,933,202	40,001,498	39,433,900
11	2010	34,690,862	2,948,723	37,639,585	2,956,190	40,595,776	39,742,950
12	2011	35,203,261	2,992,277	38,195,538	2,905,428	41,100,966	39,060,500
13	2012	35,634,307	3,028,916	38,663,223	2,919,851	41,583,074	39,254,400
14	2013	36,016,438	3,061,397	39,077,835	2,948,272	42,026,108	39,636,500
15	2014	36,388,012	3,092,981	39,480,993	2,975,407	42,456,400	40,001,300
16	2015	36,786,644	3,126,865	39,913,509	2,960,575	42,874,084	39,801,900
17	2016	37,165,945	3,159,105	40,325,050	2,896,911	43,221,961	38,946,000
18	2017	37,547,877	3,191,570	40,739,447	2,912,189	43,651,636	39,151,400
19	2018	37,927,750	3,223,859	41,151,609	2,970,803	44,122,412	39,939,400
20	2019	38,276,994	3,253,544	41,530,538	2,972,120	44,502,658	39,957,100

(d) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(e) Transmission, transformer and other losses and energy unaccounted for.

(f) The amount of net energy generated or estimated to be generated within Indiana by the reporting utility (do not include power purchased from other utilities). Energy from generating plants outside Indiana boundaries shall be shown on ODOE Form FE1-1B as part of Net Generation.

Cinergy Corp.

4901:5-5-01

ODOE FORM FE1-1A: SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)a,b
(KENTUCKY PORTION ONLY)

PART 5

	YEAR	(1) RURAL AND RESIDENTIAL	(2) COMMERCIAL	(3) INDUSTRIAL	(4) STREET-HWY LIGHTING	(5) SALES FOR RESALE c	(6) OTHER
-5	1994	1,094,862	818,526	860,298	14,578	47,464	299,955
-4	1995	1,151,799	862,235	902,983	15,018	50,845	337,474
-3	1996	1,185,677	899,658	951,636	15,144	53,362	346,190
-2	1997	1,158,180	921,281	975,729	15,725	29,130	344,507
-1	1998	1,217,326	978,973	1,048,860	15,713	0	348,392
0	1999	1,258,918	968,896	1,041,489	15,859	0	347,715
1	2000	1,289,935	996,473	1,080,674	15,998	0	352,980
2	2001	1,309,975	1,023,286	1,141,843	16,010	0	363,026
3	2002	1,331,265	1,045,358	1,225,564	16,023	0	375,186
4	2003	1,356,406	1,078,003	1,340,531	16,057	0	386,388
5	2004	1,381,603	1,087,817	1,245,444	16,139	0	396,441
6	2005	1,408,846	1,129,787	1,323,229	16,224	0	414,596
7	2006	1,427,559	1,147,033	1,401,664	16,300	0	422,292
8	2007	1,446,580	1,160,690	1,444,063	16,370	0	427,669
9	2008	1,473,942	1,174,117	1,477,916	16,446	0	432,464
10	2009	1,492,837	1,188,184	1,509,629	16,520	0	436,992
11	2010	1,511,586	1,202,170	1,535,148	16,598	0	441,748
12	2011	1,533,528	1,215,987	1,561,898	16,670	0	446,313
13	2012	1,553,430	1,225,396	1,584,192	16,737	0	449,626
14	2013	1,569,554	1,235,428	1,603,731	16,802	0	452,703
15	2014	1,595,938	1,245,330	1,624,234	16,869	0	455,678
16	2015	1,618,656	1,254,656	1,647,573	16,930	0	458,747
17	2016	1,638,935	1,263,207	1,669,140	16,985	0	461,266
18	2017	1,650,060	1,272,912	1,693,910	17,035	0	463,482
19	2018	1,670,048	1,283,212	1,717,786	17,083	0	465,824
20	2019	1,688,257	1,293,242	1,740,103	17,132	0	468,270

(a) To be filled out by utilities operating across Kentucky boundaries. The category breakdown should refer to the Kentucky portion of the utility's service area. Utilities who do not serve customers in Kentucky shall fill out only Net Generation on ODOE Form FE1-1A.

(b) Figures do not reflect the impact of the projected additional utility directed demand side programs

(c) Sales for resale to municipals.

Cinergy Corp.

4901:5-5-01

ODOE FORM FE1-1A: SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)d
(KENTUCKY PORTION ONLY)

PART 6

	YEAR	(7) (1+2+3 +4+5+6) TOTAL CONSUMPTION	(8) LOSSES AND UNACCOUNTE FOR e	(9) (7+8) NET ENERGY FOR LOAD	(10) PLANT AUXILIARY USE	(11) (9+10) TOTAL ENERGY	(12) NET GENERATION f
-5	1994	3,135,683	77,688	3,213,371	214,390	3,427,761	2,577,154
-4	1995	3,320,354	152,577	3,472,931	225,969	3,698,900	2,924,653
-3	1996	3,451,667	152,723	3,604,390	231,958	3,836,348	2,722,497
-2	1997	3,444,552	213,996	3,658,548	236,170	3,894,718	3,042,166
-1	1998	3,609,264	33,536	3,642,801	208,864	3,851,665	2,593,405
0	1999	3,632,877	170,191	3,803,068	273,720	4,076,787	3,398,700
1	2000	3,736,060	175,401	3,911,461	253,489	4,164,950	3,147,500
2	2001	3,854,140	180,964	4,035,104	232,912	4,268,015	2,892,000
3	2002	3,993,396	187,744	4,181,140	253,328	4,434,467	3,145,500
4	2003	4,177,385	196,460	4,373,845	275,250	4,649,095	3,417,700
5	2004	4,127,444	194,081	4,321,525	253,320	4,574,844	3,145,400
6	2005	4,292,682	202,132	4,494,814	275,250	4,770,064	3,417,700
7	2006	4,414,848	207,377	4,622,225	252,563	4,874,788	3,136,000
8	2007	4,495,372	210,981	4,706,353	275,250	4,981,603	3,417,700
9	2008	4,574,885	214,759	4,789,644	253,320	5,042,964	3,145,400
10	2009	4,644,162	217,861	4,862,023	275,250	5,137,273	3,417,700
11	2010	4,707,250	220,882	4,928,132	254,077	5,182,209	3,154,800
12	2011	4,774,396	223,985	4,998,381	275,250	5,273,631	3,417,700
13	2012	4,829,381	226,430	5,055,811	254,834	5,310,645	3,164,200
14	2013	4,878,218	228,827	5,107,045	275,250	5,382,295	3,417,700
15	2014	4,938,049	231,638	5,169,687	254,077	5,423,764	3,154,800
16	2015	4,996,562	234,317	5,230,879	275,250	5,506,128	3,417,700
17	2016	5,049,533	236,717	5,286,250	254,834	5,541,084	3,164,200
18	2017	5,097,399	239,072	5,336,471	275,250	5,611,721	3,417,700
19	2018	5,153,953	241,768	5,395,721	254,077	5,649,798	3,154,800
20	2019	5,207,004	244,204	5,451,208	275,250	5,726,458	3,417,700

(d) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(e) Transmission, transformer and other losses and energy unaccounted for.

(f) The amount of net energy generated or estimated to be generated within Kentucky by the reporting utility (do not include power purchased from other utilities). Energy from generating plants outside Kentucky boundaries shall be shown on ODOE Form FE1-1B as part of Net Generation.

Cinergy Corp.

4901:5-5-01

ODOE FORM FE1-1B: SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)a,b

PART 1

		(1)	(2)	(3)	(4)	(5)	(6)
	YEAR	RURAL AND RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET-HWY LIGHTING	SALES FOR RESALE c	OTHER
-5	1994	13,729,501	11,314,355	15,611,206	159,398	4,615,115	1,598,269
-4	1995	14,291,927	11,750,435	16,266,259	162,795	4,769,532	1,658,198
-3	1996	14,693,989	11,925,936	16,843,460	164,644	4,580,255	1,676,251
-2	1997	14,327,545	11,993,633	17,321,607	166,704	5,038,305	1,680,133
-1	1998	14,854,815	12,534,752	18,078,823	168,543	5,256,950	1,667,117
0	1999	15,278,129	12,500,980	20,027,632	167,247	4,931,883	1,693,571
1	2000	15,522,463	12,723,181	20,914,028	167,784	5,029,948	1,718,883
2	2001	15,810,612	12,951,517	21,846,100	168,198	5,125,870	1,767,083
3	2002	16,112,557	13,254,800	22,888,367	168,618	5,225,900	1,825,403
4	2003	16,448,737	13,662,403	24,075,784	169,159	5,327,617	1,879,076
5	2004	16,628,980	13,682,245	22,442,582	170,024	5,504,958	1,927,311
6	2005	16,880,571	13,916,254	23,043,474	170,903	5,604,289	2,014,308
7	2006	17,040,473	13,958,713	23,713,596	171,727	5,698,307	2,051,200
8	2007	17,199,737	14,063,396	24,333,544	172,519	3,981,371	2,077,065
9	2008	17,434,581	14,196,032	24,913,540	173,327	4,003,378	2,100,141
10	2009	17,609,077	14,338,323	25,506,498	174,153	4,025,184	2,121,928
11	2010	17,788,637	14,489,654	26,082,822	174,986	4,047,408	2,144,755
12	2011	17,980,752	14,644,654	26,641,779	175,787	4,070,309	2,166,756
13	2012	18,143,907	14,748,346	27,124,321	176,564	4,092,955	2,182,727
14	2013	18,279,191	14,840,966	27,571,972	177,332	4,115,816	2,197,541
15	2014	18,474,739	14,930,640	27,999,096	178,090	4,139,969	2,211,911
16	2015	18,656,785	15,022,655	28,459,162	178,848	4,164,240	2,226,738
17	2016	18,829,378	15,106,969	28,875,439	179,551	4,188,703	2,238,928
18	2017	18,935,762	15,199,065	29,331,340	180,219	4,213,084	2,249,605
19	2018	19,089,362	15,297,868	29,780,706	180,888	4,238,778	2,260,969
20	2019	19,218,697	15,390,634	30,208,017	181,559	4,264,830	2,272,799

(a) To be filled out by companies operating across Ohio boundaries. The category breakdowns should refer to the utility's total service area (both inside and outside of Ohio).

(b) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(c) Sales for resale to municipals and REMCs.

Cinergy Corp.

4901:5-5-01

ODOE FORM FE1-1B: SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR) d

PART 2

	YEAR	(7) (1+2+3 +4+5+6) TOTAL CONSUMPTION	(8) LOSSES AND UNACCOUNTED FOR e	(9) (7+8) NET ENERGY FOR LOAD	(10) PLANT AUXILIARY USE	(11) (9+10) TOTAL ENERGY	(12) NET GENERATION f
-5	1994	47,027,844	2,870,990	49,898,834	3,565,027	53,463,861	53,716,306
-4	1995	48,899,147	3,034,977	51,934,124	3,571,566	55,505,690	53,631,494
-3	1996	49,884,535	3,599,892	53,484,427	3,731,271	57,215,698	51,946,555
-2	1997	50,527,927	3,217,519	53,745,446	4,105,052	57,850,498	57,327,470
-1	1998	52,561,000	3,499,165	56,060,165	4,328,736	60,388,901	59,208,553
0	1999	54,599,442	4,149,629	58,749,071	4,239,137	62,988,208	58,040,800
1	2000	56,076,287	4,262,344	60,338,631	4,136,946	64,475,577	56,533,200
2	2001	57,669,380	4,382,366	62,051,746	4,181,805	66,233,551	57,184,300
3	2002	59,475,645	4,522,128	63,997,773	4,309,491	68,307,263	58,946,000
4	2003	61,562,776	4,681,652	66,244,428	4,555,561	70,799,989	62,299,000
5	2004	60,356,100	4,589,659	64,945,759	4,970,854	69,916,613	67,970,100
6	2005	61,629,799	4,679,277	66,309,076	5,066,588	71,375,664	69,268,600
7	2006	62,634,016	4,748,006	67,382,022	5,109,644	72,491,667	69,842,500
8	2007	61,827,632	4,668,410	66,496,042	4,873,470	71,369,512	66,635,300
9	2008	62,820,999	4,742,409	67,563,408	5,016,171	72,579,579	68,566,700
10	2009	63,775,163	4,813,424	68,588,587	5,080,163	73,668,750	69,464,700
11	2010	64,728,262	4,886,039	69,614,301	5,087,712	74,702,014	69,557,800
12	2011	65,680,037	4,957,557	70,637,594	5,079,548	75,717,143	69,471,200
13	2012	66,468,820	5,016,470	71,485,290	5,125,578	76,610,868	70,107,200
14	2013	67,182,818	5,071,047	72,253,865	5,206,903	77,460,769	71,229,300
15	2014	67,934,445	5,127,073	73,061,518	5,221,706	78,283,224	71,421,600
16	2015	68,708,428	5,184,742	73,893,170	5,225,483	79,118,653	71,482,500
17	2016	69,418,968	5,237,773	74,656,741	5,187,413	79,844,155	70,984,600
18	2017	70,109,075	5,290,899	75,399,974	5,215,203	80,615,176	71,365,000
19	2018	70,848,571	5,346,624	76,195,195	5,267,096	81,462,291	72,059,000
20	2019	71,536,536	5,397,884	76,934,420	5,230,171	82,164,592	71,541,800

(d) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(e) Transmission, transformer and other losses and energy unaccounted for.

(f) The amount of net energy generated or estimated to be generated within the total system. The difference between Column (12) Net Generation and Column (9) Net Energy for Load is the net energy purchased from and sold to other utilities by the reporting utility.

Cinergy Corp.

4901:5-5-01

ODOE FORM FE1-1D: SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR) a, b
(INDIANA AND KENTUCKY GENERATION)

	YEAR	PLANT AUXILIARY USE	NET GENERATION
-5	1994	2,226,481	33,861,089
-4	1995	2,231,562	32,602,049
-3	1996	2,172,436	28,824,973
-2	1997	2,588,887	33,852,110
-1	1998	2,673,893	35,733,193
0	1999	2,581,438	34,423,600
1	2000	2,705,041	36,106,100
2	2001	2,640,987	35,266,100
3	2002	2,706,137	36,121,000
4	2003	2,891,652	38,592,550
5	2004	3,123,297	41,729,300
6	2005	3,219,900	43,005,500
7	2006	3,249,359	43,424,850
8	2007	3,094,881	41,324,750
9	2008	3,191,859	42,651,050
10	2009	3,208,452	42,851,600
11	2010	3,210,267	42,897,750
12	2011	3,180,678	42,478,200
13	2012	3,174,685	42,418,600
14	2013	3,223,522	43,054,200
15	2014	3,229,484	43,156,100
16	2015	3,235,825	43,219,600
17	2016	3,151,745	42,110,200
18	2017	3,187,439	42,569,100
19	2018	3,224,880	43,094,200
20	2019	3,247,369	43,374,800

(a) To be filed by reporting utilities which do not operate across Ohio boundaries but which have generating facilities located outside Ohio.

(b) Figures do not reflect the impact of the projected additional utility directed demand side programs.

Cinergy Corp.

4901:5-5-01

ODOE FORM FE1-1A: SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEARS)a
(OHIO PORTION ONLY)

> AFTER DSM <

PART 1

		(1)	(2)	(3)	(4)	(5)	(6)
	YEAR	RURAL AND RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET-HWY LIGHTING	SALES FOR RESALE b	OTHER
-5	1994	5,973,977	4,783,967	5,458,821	83,579	240,346	1,298,000
-4	1995	6,184,632	4,909,947	5,636,493	84,709	253,620	1,320,232
-3	1996	6,300,502	5,025,150	5,848,788	85,416	264,472	1,329,266
-2	1997	6,099,427	5,100,004	6,095,142	86,670	249,638	1,334,951
-1	1998	6,340,828	5,263,876	6,239,432	87,963	274,548	1,317,973
0	1999	6,509,153	5,352,059	6,731,300	86,433	286,870	1,345,216
1	2000	6,572,459	5,471,060	7,106,512	86,506	290,698	1,365,263
2	2001	6,674,571	5,601,708	7,456,018	86,582	295,008	1,403,413
3	2002	6,783,055	5,736,625	7,767,599	86,661	299,559	1,449,569
4	2003	6,911,131	5,891,856	8,144,525	86,838	304,970	1,492,037
5	2004	7,039,525	5,925,820	7,454,465	87,290	310,208	1,530,216
6	2005	7,178,326	6,154,467	7,812,638	87,751	317,676	1,599,053
7	2006	7,273,674	6,248,417	8,144,658	88,165	321,431	1,628,246
8	2007	7,370,598	6,322,825	8,391,033	88,551	324,713	1,648,733
9	2008	7,509,998	6,395,974	8,580,754	88,945	328,644	1,667,013
10	2009	7,606,279	6,472,591	8,773,462	89,357	331,945	1,684,271
11	2010	7,701,798	6,548,788	8,943,339	89,771	335,237	1,702,341
12	2011	7,813,614	6,624,061	9,107,032	90,157	338,754	1,719,775
13	2012	7,915,005	6,675,313	9,241,216	90,521	341,563	1,732,433
14	2013	7,997,160	6,729,975	9,372,690	90,878	344,124	1,744,170
15	2014	8,131,589	6,783,913	9,489,321	91,221	347,498	1,755,563
16	2015	8,247,355	6,834,716	9,624,391	91,568	350,500	1,767,321
17	2016	8,350,674	6,881,296	9,740,010	91,864	353,195	1,776,991
18	2017	8,407,360	6,934,174	9,879,854	92,129	355,298	1,785,450
19	2018	8,509,203	6,990,286	10,012,697	92,395	358,188	1,794,471
20	2019	8,601,979	7,044,923	10,138,497	92,660	360,901	1,803,854

(a) To be filled out by utilities operating across Ohio boundaries. The category breakdown should refer to the Ohio portion of the utility's service area. Utilities who do not serve customers in Ohio shall fill out only Net Generation on ODOE Form FE1-1A.

(b) Sales for resale to municipals.

Cinergy Corp.

4901:5-5-03

ODOE FORM FE1-1A: SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)
(OHIO PORTION ONLY)

> AFTER DSM <

PART 2

	YEAR	(7) (1+2+3 +4+5+6) TOTAL CONSUMPTION	(8) LOSSES AND UNACCOUNTED FOR c	(9) (7+8) NET ENERGY FOR LOAD	(10) PLANT AUXILIARY USE	(11) (9+10) TOTAL ENERGY	(12) NET GENERATION d
-5	1994	17,838,690	1,175,263	19,013,953	1,338,546	20,352,499	19,855,217
-4	1995	18,389,634	1,208,079	19,597,713	1,340,004	20,937,717	21,029,445
-3	1996	18,853,594	1,177,357	20,030,951	1,558,835	21,589,786	23,121,582
-2	1997	18,965,832	1,112,639	20,078,470	1,516,165	21,594,635	23,475,360
-1	1998	19,524,620	1,256,538	20,781,158	1,654,843	22,436,001	23,475,360
0	1999	20,311,031	1,373,746	21,684,777	1,664,842	23,349,619	23,617,200
1	2000	20,892,498	1,413,913	22,306,411	1,439,963	23,746,374	20,427,100
2	2001	21,517,300	1,456,107	22,973,407	1,545,074	24,518,482	21,918,200
3	2002	22,123,068	1,498,884	23,621,952	1,608,997	25,230,949	22,825,000
4	2003	22,831,357	1,548,129	24,379,486	1,671,133	26,050,619	23,706,450
5	2004	22,347,524	1,515,714	23,863,238	1,849,787	25,713,024	26,240,800
6	2005	23,149,911	1,571,264	24,721,175	1,851,358	26,572,533	26,263,100
7	2006	23,704,591	1,606,924	25,311,515	1,862,253	27,173,769	26,417,650
8	2007	24,146,453	1,636,672	25,783,125	1,784,211	27,567,335	25,310,550
9	2008	24,571,328	1,665,326	26,236,654	1,826,866	28,063,520	25,915,650
10	2009	24,957,905	1,690,884	26,648,789	1,876,031	28,524,820	26,613,100
11	2010	25,321,274	1,715,714	27,036,988	1,879,341	28,916,329	26,660,050
12	2011	25,693,393	1,740,568	27,433,961	1,902,811	29,336,772	26,993,000
13	2012	25,996,051	1,760,387	27,756,438	1,951,846	29,708,284	27,688,600
14	2013	26,278,997	1,780,080	28,059,077	1,986,141	30,045,218	28,175,100
15	2014	26,599,105	1,801,702	28,400,807	1,992,513	30,393,320	28,265,500
16	2015	26,915,851	1,822,803	28,738,654	1,992,330	30,730,983	28,262,900
17	2016	27,194,030	1,841,183	29,035,213	2,035,436	31,070,649	28,874,400
18	2017	27,454,265	1,859,485	29,313,750	2,029,903	31,343,652	28,795,900
19	2018	27,757,240	1,880,216	29,637,456	2,041,809	31,679,264	28,964,800
20	2019	28,042,814	1,899,346	29,942,160	1,985,570	31,927,730	28,167,000

(c) Transmission, transformer and other losses and energy unaccounted for.

(d) The amount of net energy generated or estimated to be generated within Ohio by the reporting utility (do not include power purchased from other utilities). Energy from generating plants outside Ohio boundaries shall be shown on ODOE Form FE1-1B as part of Net Generation.

Cinergy Corp.

4901:5-5-03
ODOE FORM FE1-1A: SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)a
(INDIANA PORTION ONLY)

> AFTER DSM < PART 3

		(1)	(2)	(3)	(4)	(5)	(6)
	YEAR	RURAL AND RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET-HWY LIGHTING	SALES FOR RESALE b	OTHER
-5	1994	6,642,940	5,609,893	9,279,380	61,212	4,327,305	248
-4	1995	6,940,905	5,808,801	9,637,641	63,038	4,465,067	425
-3	1996	7,200,655	5,925,737	10,015,319	64,057	4,262,421	690
-2	1997	7,058,264	5,947,134	10,229,714	64,279	4,759,537	578
-1	1998	7,284,430	6,288,073	10,789,845	64,837	4,982,402	637
0	1999	7,489,623	6,173,169	12,254,199	64,925	4,645,013	540
1	2000	7,629,239	6,248,714	12,726,185	65,250	4,739,250	540
2	2001	7,795,188	6,319,509	13,247,573	65,576	4,830,862	540
3	2002	7,967,310	6,465,718	13,894,526	65,904	4,926,341	540
4	2003	8,150,211	6,685,344	14,590,035	66,234	5,022,647	540
5	2004	8,176,805	6,661,308	13,741,965	66,565	5,194,750	540
6	2005	8,262,285	6,624,540	13,906,880	66,898	5,286,613	540
7	2006	8,308,082	6,555,736	14,166,529	67,232	5,376,876	540
8	2007	8,351,355	6,572,302	14,497,690	67,568	3,656,658	540
9	2008	8,419,372	6,618,308	14,854,099	67,906	3,674,734	540
10	2009	8,497,035	6,672,371	15,222,621	68,246	3,693,239	540
11	2010	8,562,284	6,733,463	15,603,541	68,587	3,712,171	540
12	2011	8,620,589	6,799,322	15,972,049	68,930	3,731,555	540
13	2012	8,662,403	6,842,317	16,298,104	69,275	3,751,392	540
14	2013	8,708,744	6,870,202	16,594,738	69,621	3,771,692	540
15	2014	8,743,416	6,896,609	16,885,007	69,969	3,792,471	540
16	2015	8,786,925	6,928,460	17,186,660	70,319	3,813,740	540
17	2016	8,835,873	6,957,610	17,465,743	70,671	3,835,508	540
18	2017	8,874,418	6,987,087	17,757,022	71,024	3,857,786	540
19	2018	8,906,141	7,019,438	18,049,662	71,379	3,880,590	540
20	2019	8,924,446	7,047,497	18,328,846	71,736	3,903,929	540

(a) To be filled out by utilities operating across Indiana boundaries. The category breakdown should refer to the Indiana portion of the utility's service area. Utilities who do not serve customers in Indiana shall fill out only Net Generation on ODOE Form FE1-1A.

(b) Sales for resale to municipals.

Cinergy Corp.

4901:5-5-03

ODOE FORM FE1-1A: SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)
(INDIANA PORTION ONLY)

> AFTER DSM <

PART 4

	YEAR	(7) (1+2+3 +4+5+6) TOTAL CONSUMPTIO	(8) LOSSES AND UNACCOUNTED FOR c	(9) (7+8) NET ENERGY FOR LOAD	(10) PLANT AUXILIARY USE	(11) (9+10) TOTAL ENERGY	(12) NET GENERATION d
-5	1994	25,920,978	1,617,567	27,538,545	1,999,054	29,537,599	29,762,208
-4	1995	26,915,877	1,673,775	28,589,652	2,012,731	30,602,383	30,509,912
-3	1996	27,468,879	2,269,134	29,738,013	2,172,436	31,910,449	28,824,973
-2	1997	28,059,505	1,890,497	29,950,002	2,352,717	32,302,719	31,998,755
-1	1998	29,410,224	2,208,569	31,618,792	2,465,029	34,083,821	33,139,788
0	1999	30,627,470	2,605,104	33,232,574	2,307,718	35,540,292	31,024,900
1	2000	31,409,178	2,672,430	34,081,608	2,451,552	36,533,160	32,958,600
2	2001	32,259,248	2,744,686	35,003,934	2,408,075	37,412,009	32,374,100
3	2002	33,320,339	2,834,879	36,155,218	2,452,809	38,608,027	32,975,500
4	2003	34,515,011	2,936,426	37,451,437	2,616,403	40,067,840	35,174,850
5	2004	33,841,933	2,879,214	36,721,147	2,869,977	39,591,124	38,583,900
6	2005	34,147,756	2,905,209	37,052,965	2,944,650	39,997,615	39,587,800
7	2006	34,474,995	2,933,024	37,408,020	2,996,796	40,404,816	40,288,850
8	2007	33,146,113	2,820,069	35,966,183	2,819,631	38,785,814	37,907,050
9	2008	33,634,959	2,861,621	36,496,581	2,938,539	39,435,120	39,505,650
10	2009	34,154,052	2,903,968	37,058,020	2,933,202	39,991,223	39,433,900
11	2010	34,680,586	2,948,723	37,629,310	2,956,190	40,585,500	39,742,950
12	2011	35,192,985	2,992,277	38,185,262	2,905,428	41,090,690	39,060,500
13	2012	35,624,031	3,028,916	38,652,947	2,919,851	41,572,798	39,254,400
14	2013	36,015,537	3,061,397	39,076,934	2,948,272	42,025,207	39,636,500
15	2014	36,388,012	3,092,981	39,480,993	2,975,407	42,456,400	40,001,300
16	2015	36,786,644	3,126,865	39,913,509	2,960,575	42,874,084	39,801,900
17	2016	37,165,945	3,159,105	40,325,050	2,896,911	43,221,961	38,946,000
18	2017	37,547,877	3,191,570	40,739,447	2,912,189	43,651,636	39,151,400
19	2018	37,927,750	3,223,859	41,151,609	2,970,803	44,122,412	39,939,400
20	2019	38,276,994	3,253,544	41,530,538	2,972,120	44,502,658	39,957,100

(c) Transmission, transformer and other losses and energy unaccounted for.

(d) The amount of net energy generated or estimated to be generated within Indiana by the reporting utility (do not include power purchased from other utilities). Energy from generating plants outside Indiana boundaries shall be shown on ODOE Form FE1-1B as part of Net Generation.

Cinergy Corp.

4901:5-5-03

ODOE FORM FE1-1A: SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)a
(KENTUCKY PORTION ONLY)

> AFTER DSM <

PART 5

		(1)	(2)	(3)	(4)	(5)	(6)
	YEAR	RURAL AND RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET-HWY LIGHTING	SALES FOR RESALE b	OTHER
-5	1994	1,094,862	818,526	860,298	14,578	47,464	299,955
-4	1995	1,151,799	862,235	902,983	15,018	50,845	337,474
-3	1996	1,185,677	897,093	951,181	15,144	53,362	346,190
-2	1997	1,158,180	918,822	973,852	15,725	29,130	344,507
-1	1998	1,217,326	974,915	1,047,913	15,713	0	348,392
0	1999	1,258,918	964,839	1,040,542	15,859	0	347,715
1	2000	1,289,935	992,416	1,079,727	15,998	0	352,980
2	2001	1,309,975	1,019,229	1,140,896	16,010	0	363,026
3	2002	1,331,265	1,041,301	1,224,617	16,023	0	375,186
4	2003	1,356,406	1,073,946	1,339,584	16,057	0	386,388
5	2004	1,381,603	1,083,760	1,244,497	16,139	0	396,441
6	2005	1,408,846	1,125,730	1,322,282	16,224	0	414,596
7	2006	1,427,559	1,142,976	1,400,717	16,300	0	422,292
8	2007	1,446,580	1,156,633	1,443,116	16,370	0	427,669
9	2008	1,473,942	1,170,060	1,476,969	16,446	0	432,464
10	2009	1,492,837	1,184,127	1,508,682	16,520	0	436,992
11	2010	1,511,586	1,198,113	1,534,201	16,598	0	441,748
12	2011	1,533,528	1,211,930	1,560,951	16,670	0	446,313
13	2012	1,553,430	1,221,339	1,583,245	16,737	0	449,626
14	2013	1,569,554	1,231,371	1,602,784	16,802	0	452,703
15	2014	1,595,938	1,245,330	1,624,234	16,869	0	455,678
16	2015	1,618,656	1,254,656	1,647,573	16,930	0	458,747
17	2016	1,638,935	1,263,207	1,669,140	16,985	0	461,266
18	2017	1,650,060	1,272,912	1,693,910	17,035	0	463,482
19	2018	1,670,048	1,283,212	1,717,786	17,083	0	465,824
20	2019	1,688,257	1,293,242	1,740,103	17,132	0	468,270

(a) To be filled out by utilities operating across Kentucky boundaries. The category breakdown should refer to the Kentucky portion of the utility's service area. Utilities who do not serve customers in Kentucky shall fill out only Net Generation on ODOE Form FE1-1A.

(b) Sales for resale to municipals.

Cinergy Corp.

4901:5-5-03
ODOE FORM FE1-1A: SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)
(KENTUCKY PORTION ONLY)

> AFTER DSM <

PART 6

	YEAR	(7) (1+2+3 +4+5+6) TOTAL CONSUMPTION	(8) LOSSES AND UNACCOUNTED FOR c	(9) (7+8) NET ENERGY FOR LOAD	(10) PLANT AUXILIARY USE	(11) (9+10) TOTAL ENERGY	(12) NET GENERATION d
-5	1994	3,135,683	77,688	3,213,371	214,390	3,427,761	2,577,154
-4	1995	3,320,354	152,577	3,472,931	225,969	3,698,900	2,924,653
-3	1996	3,448,647	152,723	3,601,370	231,958	3,833,328	2,722,497
-2	1997	3,440,216	213,996	3,654,212	236,170	3,890,382	3,042,166
-1	1998	3,604,260	33,536	3,637,796	208,864	3,846,660	2,593,405
0	1999	3,627,873	170,191	3,798,063	273,720	4,071,783	3,398,700
1	2000	3,731,056	175,401	3,906,457	253,489	4,159,946	3,147,500
2	2001	3,849,136	180,964	4,030,099	232,912	4,263,011	2,892,000
3	2002	3,988,392	187,744	4,176,135	253,328	4,429,463	3,145,500
4	2003	4,172,381	196,460	4,368,841	275,250	4,644,091	3,417,700
5	2004	4,122,440	194,081	4,316,520	253,320	4,569,840	3,145,400
6	2005	4,287,678	202,132	4,489,810	275,250	4,765,060	3,417,700
7	2006	4,409,844	207,377	4,617,221	252,563	4,869,784	3,136,000
8	2007	4,490,368	210,981	4,701,349	275,250	4,976,599	3,417,700
9	2008	4,569,881	214,759	4,784,640	253,320	5,037,960	3,145,400
10	2009	4,639,158	217,861	4,857,019	275,250	5,132,269	3,417,700
11	2010	4,702,246	220,882	4,923,128	254,077	5,177,205	3,154,800
12	2011	4,769,392	223,985	4,993,377	275,250	5,268,627	3,417,700
13	2012	4,824,377	226,430	5,050,807	254,834	5,305,641	3,164,200
14	2013	4,873,214	228,827	5,102,041	275,250	5,377,291	3,417,700
15	2014	4,938,049	231,638	5,169,687	254,077	5,423,764	3,154,800
16	2015	4,996,562	234,317	5,230,879	275,250	5,506,128	3,417,700
17	2016	5,049,533	236,717	5,286,250	254,834	5,541,084	3,164,200
18	2017	5,097,399	239,072	5,336,471	275,250	5,611,721	3,417,700
19	2018	5,153,953	241,768	5,395,721	254,077	5,649,798	3,154,800
20	2019	5,207,004	244,204	5,451,208	275,250	5,726,458	3,417,700

(c) Transmission, transformer and other losses and energy unaccounted for.

(d) The amount of net energy generated or estimated to be generated within Kentucky by the reporting utility (do not include power purchased from other utilities). Energy from generating plants outside Kentucky boundaries shall be shown on ODOE Form FE1-1B as part of Net Generation.

Cinergy Corp.

4901:5-5-03

ODOE FORM FE1-1B: SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR) a

> AFTER DSM <

PART 1

		(1)	(2)	(3)	(4)	(5)	(6)
	YEAR	RURAL AND RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET-HWY LIGHTING	SALES FOR RESALE b	OTHER
-5	1994	13,714,712	11,215,581	15,598,619	159,398	4,615,115	1,598,269
-4	1995	14,280,313	11,584,378	16,177,267	162,795	4,769,532	1,658,198
-3	1996	14,689,828	11,851,538	16,815,631	164,644	4,580,255	1,676,251
-2	1997	14,318,682	11,969,368	17,299,097	166,704	5,038,305	1,680,133
-1	1998	14,845,440	12,530,081	18,077,588	168,543	5,256,950	1,667,117
0	1999	15,260,724	12,493,801	20,026,398	167,247	4,931,883	1,693,571
1	2000	15,494,700	12,716,002	20,912,794	167,784	5,029,948	1,718,883
2	2001	15,782,849	12,944,338	21,844,866	168,198	5,125,870	1,767,083
3	2002	16,084,794	13,247,621	22,887,133	168,618	5,225,900	1,825,403
4	2003	16,420,974	13,655,224	24,074,550	169,159	5,327,617	1,879,076
5	2004	16,601,217	13,675,066	22,441,348	170,024	5,504,958	1,927,311
6	2005	16,852,808	13,909,075	23,042,240	170,903	5,604,289	2,014,308
7	2006	17,012,710	13,951,534	23,712,362	171,727	5,698,307	2,051,200
8	2007	17,171,974	14,056,217	24,332,310	172,519	3,981,371	2,077,065
9	2008	17,406,818	14,188,853	24,912,306	173,327	4,003,378	2,100,141
10	2009	17,599,702	14,333,652	25,505,264	174,153	4,025,184	2,121,928
11	2010	17,779,262	14,484,983	26,081,588	174,986	4,047,408	2,144,755
12	2011	17,971,377	14,639,983	26,640,545	175,787	4,070,309	2,166,756
13	2012	18,134,532	14,743,675	27,123,087	176,564	4,092,955	2,182,727
14	2013	18,279,191	14,836,295	27,570,738	177,332	4,115,816	2,197,541
15	2014	18,474,739	14,930,640	27,999,096	178,090	4,139,969	2,211,911
16	2015	18,656,785	15,022,655	28,459,162	178,848	4,164,240	2,226,738
17	2016	18,829,378	15,106,969	28,875,439	179,551	4,188,703	2,238,928
18	2017	18,935,762	15,199,065	29,331,340	180,219	4,213,084	2,249,605
19	2018	19,089,362	15,297,868	29,780,706	180,888	4,238,778	2,260,969
20	2019	19,218,697	15,390,634	30,208,017	181,559	4,264,830	2,272,799

(a) To be filled out by companies operating across Ohio boundaries. The category breakdowns should refer to the utility's total service area (both inside and outside of Ohio).

(b) Sales for resale to municipals and REMCs.

Cinergy Corp.

4901:5-5-03

ODOE FORM FE1-1B: SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)

> AFTER DSM < PART 2

	YEAR	(7) (1+2+3 +4+5+6) **TOTAL CONSUMPTION**	(8) **LOSSES AND UNACCOUNTED FOR c**	(9) (7+8) **NET ENERGY FOR LOAD**	(10) **PLANT AUXILIARY USE**	(11) (9+10) **TOTAL ENERGY**	(12) **NET GENERATION d**
-5	1994	46,901,694	2,870,990	49,772,684	3,565,027	53,337,711	53,716,306
-4	1995	48,632,484	3,034,977	51,667,461	3,571,566	55,239,027	53,631,494
-3	1996	49,778,147	3,599,892	53,378,039	3,731,271	57,109,310	51,946,555
-2	1997	50,472,289	3,217,519	53,689,809	4,105,052	57,794,861	57,327,470
-1	1998	52,545,720	3,499,165	56,044,885	4,328,736	60,373,621	59,208,553
0	1999	54,573,624	4,149,629	58,723,253	4,239,137	62,962,390	58,040,800
1	2000	56,040,110	4,262,344	60,302,454	4,136,946	64,439,400	56,533,200
2	2001	57,633,203	4,382,366	62,015,569	4,181,805	66,197,374	57,184,300
3	2002	59,439,468	4,522,128	63,961,596	4,309,491	68,271,086	58,946,000
4	2003	61,526,599	4,681,652	66,208,251	4,555,561	70,763,812	62,299,000
5	2004	60,319,923	4,589,659	64,909,582	4,970,854	69,880,436	67,970,100
6	2005	61,593,622	4,679,277	66,272,899	5,066,588	71,339,488	69,268,600
7	2006	62,597,839	4,748,006	67,345,845	5,109,644	72,455,490	69,842,500
8	2007	61,791,455	4,668,410	66,459,865	4,873,470	71,333,335	66,635,300
9	2008	62,784,822	4,742,409	67,527,231	5,016,171	72,543,402	68,566,700
10	2009	63,759,883	4,813,424	68,573,307	5,080,163	73,653,470	69,464,700
11	2010	64,712,982	4,886,039	69,599,021	5,087,712	74,686,734	69,557,800
12	2011	65,664,757	4,957,557	70,622,314	5,079,548	75,701,863	69,471,200
13	2012	66,453,540	5,016,470	71,470,010	5,125,578	76,595,588	70,107,200
14	2013	67,176,913	5,071,047	72,247,960	5,206,903	77,454,864	71,229,300
15	2014	67,934,445	5,127,073	73,061,518	5,221,706	78,283,224	71,421,600
16	2015	68,708,428	5,184,742	73,893,170	5,225,483	79,118,653	71,482,500
17	2016	69,418,968	5,237,773	74,656,741	5,187,413	79,844,155	70,984,600
18	2017	70,109,075	5,290,899	75,399,974	5,215,203	80,615,176	71,365,000
19	2018	70,848,571	5,346,624	76,195,195	5,267,096	81,462,291	72,059,000
20	2019	71,536,536	5,397,884	76,934,420	5,230,171	82,164,592	71,541,800

(c) Transmission, transformer and other losses and energy unaccounted for.

(d) The amount of net energy generated or estimated to be generated within the total system. The difference between Column (12) Net Generation and Column (9) Net Energy for Load is the net energy purchased from and sold to other utilities by the reporting utility.

Cinergy Corp.

4901:5-5-01

ODOE FORM FE1-2: FORECAST OF ENERGY DEMAND BY INDUSTRIAL SECTORS (MEGAWATT HOURS/YEAR) a
(OHIO ONLY)

PART 1

		(1)	(2)	(3)	(4)	(5)	(6)
	SIC CODE	11-12	20	23	26	27	28
	YEAR	COAL MINING	FOOD AND KINDRED PRODUCTS	APPAREL AND PRODUCTS b	PAPER AND ALLIED PRODUCTS	PRINTING PUBLISHING b	CHEMICALS AND ALLIED PRODUCTS
-5	1994		299,434	10,327	463,686	168,881	1,104,508
-4	1995		309,216	8,802	468,049	137,690	1,171,516
-3	1996		292,040	9,354	451,362	143,367	1,177,856
-2	1997		299,175	0	444,120	0	1,199,593
-1	1998		306,977	0	454,829	0	1,217,303
0	1999		289,811	0	492,191	0	1,369,672
1	2000		287,450	0	510,527	0	1,402,656
2	2001		286,656	0	522,374	0	1,449,276
3	2002		287,503	0	531,633	0	1,509,340
4	2003		288,688	0	542,023	0	1,573,906
5	2004		290,622	0	551,112	0	1,643,621
6	2005		295,102	0	570,003	0	1,730,393
7	2006		299,151	0	576,872	0	1,816,813
8	2007		299,607	0	581,181	0	1,892,706
9	2008		299,182	0	585,677	0	1,949,096
10	2009		298,664	0	589,844	0	2,000,947
11	2010		298,228	0	593,417	0	2,052,119
12	2011		298,279	0	596,679	0	2,102,191
13	2012		298,727	0	600,964	0	2,157,144
14	2013		298,263	0	605,604	0	2,211,990
15	2014		298,214	0	609,111	0	2,266,394
16	2015		298,267	0	612,201	0	2,323,250
17	2016		298,525	0	615,050	0	2,381,164
18	2017		298,873	0	618,824	0	2,443,943
19	2018		299,061	0	622,446	0	2,507,926
20	2019		299,451	0	625,765	0	2,575,244

(a) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(b) SIC 23,27,30, and 34 are included in All Other Industrial.

Cinergy Corp.

4901:5-5-01

ODOE FORM FE1-2: FORECAST OF ENERGY DEMAND BY INDUSTRIAL SECTORS (MEGAWATT HOURS/YEAR) a
(OHIO ONLY)

PART 2

		(7)	(8)	(9)	(10)	(11)	(12)
	SIC CODE	29	30	32	33	34	35
	YEAR	PETROLEUM AND COAL PRODUCTS	RUBBER AND MISC PLASTICS b	STONE, CLAY AND GLASS PRODUCTS	PRIMARY METALS	FABRICATED METAL PRODUCTS b	INDUSTRIAL MACHINERY & EQUIPMENT
-5	1994		186,311		1,274,467	155,082	308,499
-4	1995		165,011		1,319,273	145,262	306,162
-3	1996		167,270		1,532,744	142,644	301,159
-2	1997		0		1,611,470	0	306,763
-1	1998		0		1,586,723	0	311,607
0	1999		0		1,606,190	0	330,951
1	2000		0		1,663,776	0	349,955
2	2001		0		1,707,339	0	366,878
3	2002		0		1,720,293	0	385,416
4	2003		0		1,807,222	0	403,684
5	2004		0		1,906,810	0	418,160
6	2005		0		2,020,400	0	432,914
7	2006		0		2,134,381	0	447,621
8	2007		0		2,210,420	0	460,168
9	2008		0		2,244,334	0	471,574
10	2009		0		2,300,724	0	483,508
11	2010		0		2,362,577	0	495,208
12	2011		0		2,419,800	0	506,138
13	2012		0		2,445,956	0	514,739
14	2013		0		2,474,529	0	522,901
15	2014		0		2,489,511	0	530,883
16	2015		0		2,516,352	0	539,346
17	2016		0		2,527,726	0	546,657
18	2017		0		2,547,984	0	554,119
19	2018		0		2,562,248	0	561,016
20	2019		0		2,568,305	0	566,978

(a) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(b) SIC 23,27,30, and 34 are included in All Other Industrial.

Cinergy Corp.

4901:5-5-01

ODOE FORM FE1-2: FORECAST OF ENERGY DEMAND BY INDUSTRIAL SECTOR (MEGAWATT HOURS/YEAR) a
(OHIO ONLY)

PART 3

		(13)	(14)	(15)	(16)
	SIC CODE	36	37		
	YEAR	**ELECTRONIC & OTHER ELEC EQUIPMENT**	**TRANS-PORTATION EQUIPMENT**	**ALL OTHER INDUSTRIALS**	**TOTAL INDUSTRIAL b**
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-5	1994	215,706	628,148	1,164,370	5,458,821
-4	1995	211,489	601,033	1,249,753	5,636,493
-3	1996	222,312	594,305	1,277,010	5,848,788
-2	1997	229,688	600,244	1,404,089	6,095,142
-1	1998	220,103	608,165	1,533,727	6,239,432
0	1999	243,790	648,991	1,394,740	6,731,300
1	2000	242,172	658,935	1,438,681	7,106,512
2	2001	251,689	671,341	1,481,043	7,456,018
3	2002	259,489	687,153	1,526,337	7,767,599
4	2003	267,406	708,942	1,579,271	8,144,525
5	2004	276,794	731,443	1,635,903	7,454,465
6	2005	290,273	764,148	1,709,405	7,812,638
7	2006	303,103	785,942	1,780,775	8,144,658
8	2007	311,598	804,812	1,830,541	8,391,033
9	2008	316,184	826,033	1,888,674	8,580,754
10	2009	320,588	837,476	1,941,711	8,773,462
11	2010	325,101	847,379	1,969,310	8,943,339
12	2011	329,771	856,696	1,997,478	9,107,032
13	2012	333,972	863,755	2,025,959	9,241,216
14	2013	337,126	871,093	2,051,184	9,372,690
15	2014	340,712	878,225	2,076,271	9,489,321
16	2015	344,061	887,565	2,103,349	9,624,391
17	2016	347,474	896,101	2,127,313	9,740,010
18	2017	350,381	904,423	2,161,307	9,879,854
19	2018	353,560	913,963	2,192,477	10,012,697
20	2019	356,587	922,253	2,223,914	10,138,497

(a) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(b) The Total Industrial column is equal to the sum of all previous items (1) through (15) . Total Industrial for a given year is also equal to column (3) Industrial on ODOE Form FE-1A.

Cinergy Corp.

4901:5-5-01

ODOE FORM FE1-3A: SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) a,b
(OHIO PORTION ONLY)

PART 1

NATIVE LOAD c

		SUMMER			WINTER f		
	YEAR	LOAD	CHANGE d	PERCENT CHANGE e	LOAD	CHANGE d	PERCENT CHANGE e
-5	1994	3,682			3,062		
-4	1995	3,838	156	4.2	3,302	240	7.8
-3	1996	3,746	-92	-2.4	3,379	77	2.3
-2	1997	3,907	161	4.3	2,998	-381	-11.3
-1	1998	3,981	74	1.9	3,348	350	11.7
0	1999	4,150	169	4.2	3,613	265	7.9
1	2000	4,234	84	2.0	3,687	74	2.0
2	2001	4,322	88	2.1	3,751	64	1.7
3	2002	4,410	88	2.0	3,837	86	2.3
4	2003	4,525	115	2.6	3,925	88	2.3
5	2004	4,638	113	2.5	4,032	107	2.7
6	2005	4,802	164	3.5	4,139	107	2.7
7	2006	4,895	93	1.9	4,203	64	1.5
8	2007	4,979	84	1.7	4,270	67	1.6
9	2008	5,060	81	1.6	4,334	64	1.5
10	2009	5,134	74	1.5	4,386	52	1.2
11	2010	5,202	68	1.3	4,445	59	1.3
12	2011	5,275	73	1.4	4,498	53	1.2
13	2012	5,329	54	1.0	4,535	37	0.8
14	2013	5,389	60	1.1	4,584	49	1.1
15	2014	5,452	63	1.2	4,638	54	1.2
16	2015	5,511	59	1.1	4,684	46	1.0
17	2016	5,565	54	1.0	4,718	34	0.7
18	2017	5,617	52	0.9	4,759	41	0.9
19	2018	5,681	64	1.1	4,805	46	1.0
20	2019	5,733	52	0.9	4,848	43	0.9

(a) To be filled out by utilities operating across Ohio boundaries. The category breakdowns should refer to the Ohio portion of the utility's service area. Utilities who do not serve customers in Ohio shall fill out FE1-3B and FE1-3C if applicable.

(b) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(c) Excludes interruptible load.

(d) Difference between reporting year and previous year.

(e) Difference expressed as a percent of previous year.

(f) Winter load reference is to peak loads which occur in the following winter.

Cinergy Corp.

4901:5-5-01

ODOE FORM FE1-3A: SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) a,b
(OHIO PORTION ONLY)

PART 2

INTERNAL LOAD c

		SUMMER			WINTER f		
	YEAR	LOAD	CHANGE d	PERCENT CHANGE e	LOAD	CHANGE d	PERCENT CHANGE e
-5	1994	3,729			3,062		
-4	1995	3,907	178	4.8	3,562	500	16.3
-3	1996	3,795	-112	-2.9	3,379	-183	-5.1
-2	1997	3,903	108	2.8	2,998	-381	-11.3
-1	1998	3,993	90	2.3	3,348	350	11.7
0	1999	4,205	212	5.3	3,644	296	8.8
1	2000	4,288	83	2.0	3,713	69	1.9
2	2001	4,370	82	1.9	3,777	64	1.7
3	2002	4,459	89	2.0	3,863	86	2.3
4	2003	4,573	114	2.6	3,951	88	2.3
5	2004	4,686	113	2.5	4,058	107	2.7
6	2005	4,850	164	3.5	4,166	108	2.7
7	2006	4,943	93	1.9	4,229	63	1.5
8	2007	5,027	84	1.7	4,296	67	1.6
9	2008	5,109	82	1.6	4,360	64	1.5
10	2009	5,183	74	1.4	4,412	52	1.2
11	2010	5,251	68	1.3	4,471	59	1.3
12	2011	5,323	72	1.4	4,524	53	1.2
13	2012	5,377	54	1.0	4,561	37	0.8
14	2013	5,438	61	1.1	4,611	50	1.1
15	2014	5,501	63	1.2	4,664	53	1.1
16	2015	5,559	58	1.1	4,711	47	1.0
17	2016	5,614	55	1.0	4,744	33	0.7
18	2017	5,666	52	0.9	4,785	41	0.9
19	2018	5,730	64	1.1	4,831	46	1.0
20	2019	5,781	51	0.9	4,874	43	0.9

(a) To be filled out by utilities operating across Ohio boundaries. The category breakdowns should refer to the Ohio portion of the utility's service area. Utilities who do not serve customers in Ohio shall fill out FE1-3B and FE1-3C if applicable.

(b) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(c) Includes interruptible load.

(d) Difference between reporting year and previous year.

(e) Difference expressed as a percent of previous year.

(f) Winter load reference is to peak loads which occur in the following winter.

Cinergy Corp.

4901:5-5-01

ODOE FORM FE1-3A: SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) a, b
(INDIANA PORTION ONLY)

PART 3

NATIVE LOAD c

		SUMMER			WINTER f		
	YEAR	LOAD	CHANGE d	PERCENT CHANGE e	LOAD	CHANGE d	PERCENT CHANGE e
-5	1994	5,205			4,674		
-4	1995	5,616	411	7.9	4,966	292	6.3
-3	1996	5,660	44	0.8	5,139	173	3.5
-2	1997	5,681	21	0.4	4,784	-355	-6.9
-1	1998	5,704	24	0.4	4,804	21	0.4
0	1999	5,705	1	0.0	5,235	431	9.0
1	2000	5,816	111	1.9	5,353	118	2.3
2	2001	5,946	130	2.2	5,514	161	3.0
3	2002	6,125	179	3.0	5,706	192	3.5
4	2003	6,340	215	3.5	5,793	87	1.5
5	2004	6,436	96	1.5	5,848	55	0.9
6	2005	6,496	60	0.9	5,907	59	1.0
7	2006	6,562	66	1.0	5,716	-191	-3.2
8	2007	6,344	-218	-3.3	5,805	89	1.6
9	2008	6,442	98	1.5	5,895	90	1.6
10	2009	6,543	101	1.6	5,991	96	1.6
11	2010	6,649	106	1.6	6,084	93	1.6
12	2011	6,752	103	1.5	6,162	78	1.3
13	2012	6,839	87	1.3	6,231	69	1.1
14	2013	6,916	77	1.1	6,299	68	1.1
15	2014	6,991	75	1.1	6,371	72	1.1
16	2015	7,072	81	1.2	6,440	69	1.1
17	2016	7,148	76	1.1	6,509	69	1.1
18	2017	7,225	77	1.1	6,578	69	1.1
19	2018	7,302	77	1.1	6,642	64	1.0
20	2019	7,372	70	1.0	6,699	57	0.9

(a) To be filled out by utilities operating across Indiana boundaries. The category breakdown should refer to the Indiana portion of the utility's service area.
Utilities who do not serve customers in Indiana shall fill out FE1-3B and FE1-3C if applicable.

(b) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(c) Excludes interruptible load.

(d) Difference between reporting year and previous year.

(e) Difference expressed as a percent of previous year.

(f) Winter load reference is to peak loads which occur in the following winter.

Cinergy Corp.

4901:5-5-01

ODOE FORM FE1-3A: SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) a, b
(INDIANA PORTION ONLY)

PART 4

INTERNAL LOAD c

		SUMMER			WINTER f		
	YEAR	LOAD	CHANGE d	PERCENT CHANGE e	LOAD	CHANGE d	PERCENT CHANGE e
-5	1994	5,205			4,674		
-4	1995	5,628	423	8.1	4,966	292	6.3
-3	1996	5,660	32	0.6	5,139	173	3.5
-2	1997	5,681	21	0.4	4,784	-355	-6.9
-1	1998	5,791	110	1.9	4,804	21	0.4
0	1999	6,050	259	4.5	5,537	733	15.3
1	2000	6,162	112	1.9	5,655	118	2.1
2	2001	6,293	131	2.1	5,818	163	2.9
3	2002	6,473	180	2.9	6,010	192	3.3
4	2003	6,688	215	3.3	6,097	87	1.4
5	2004	6,785	97	1.5	6,153	56	0.9
6	2005	6,846	61	0.9	6,212	59	1.0
7	2006	6,912	66	1.0	6,022	-190	-3.1
8	2007	6,694	-218	-3.2	6,110	88	1.5
9	2008	6,792	98	1.5	6,201	91	1.5
10	2009	6,893	101	1.5	6,296	95	1.5
11	2010	6,999	106	1.5	6,389	93	1.5
12	2011	7,102	103	1.5	6,468	79	1.2
13	2012	7,189	87	1.2	6,537	69	1.1
14	2013	7,266	77	1.1	6,604	67	1.0
15	2014	7,341	75	1.0	6,677	73	1.1
16	2015	7,422	81	1.1	6,746	69	1.0
17	2016	7,498	76	1.0	6,815	69	1.0
18	2017	7,575	77	1.0	6,884	69	1.0
19	2018	7,652	77	1.0	6,947	63	0.9
20	2019	7,722	70	0.9	7,005	58	0.8

(a) To be filled out by utilities operating across Indiana boundaries. The category breakdown should refer to the Indiana portion of the utility's service area.
Utilities who do not serve customers in Indiana shall fill out FE1-3B and FE1-3C if applicable.
(b) Figures do not reflect the impact of the projected additional utility directed demand side programs.
(c) Includes interruptible load.
(d) Difference between reporting year and previous year.
(e) Difference expressed as a percent of previous year.
(f) Winter load reference is to peak loads which occur in the following winter.

Cinergy Corp.

4901:5-5-01

ODOE FORM FE1-3A: SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) a, b
(KENTUCKY PORTION ONLY)

NATIVE LOAD c

PART 5

		SUMMER			WINTER f		
	YEAR	LOAD	CHANGE d	PERCENT CHANGE e	LOAD	CHANGE d	PERCENT CHANGE e
-5	1994	644			602		
-4	1995	710	66	10.2	611	9	1.5
-3	1996	721	11	1.5	645	34	5.6
-2	1997	737	16	2.2	588	-57	-8.9
-1	1998	704	-33	-4.4	585	-3	-0.5
0	1999	743	39	5.5	682	97	16.6
1	2000	765	22	3.0	698	16	2.3
2	2001	782	17	2.2	711	13	1.9
3	2002	803	21	2.7	730	19	2.7
4	2003	826	23	2.9	748	18	2.5
5	2004	848	22	2.7	769	21	2.8
6	2005	882	34	4.0	792	23	3.0
7	2006	903	21	2.4	807	15	1.9
8	2007	918	15	1.7	820	13	1.6
9	2008	934	16	1.7	832	12	1.5
10	2009	947	13	1.4	841	9	1.1
11	2010	959	12	1.3	852	11	1.3
12	2011	972	13	1.4	861	9	1.1
13	2012	982	10	1.0	868	7	0.8
14	2013	993	11	1.1	877	9	1.0
15	2014	1,005	12	1.2	887	10	1.1
16	2015	1,016	11	1.1	896	9	1.0
17	2016	1,027	11	1.1	902	6	0.7
18	2017	1,037	10	1.0	910	8	0.9
19	2018	1,049	12	1.2	919	9	1.0
20	2019	1,059	10	1.0	927	8	0.9

(a) To be filled out by utilities operating across Kentucky boundaries. The category breakdown should refer to the Kentucky portion of the utility's service area. Utilities who do not serve customers in Kentucky shall fill out FE1-3B and FE1-3C if applicable.

(b) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(c) Excludes interruptible load .

(d) Difference between reporting year and previous year.

(e) Difference expressed as a percent of previous year.

(f) Winter load reference is to peak loads which occur in the following winter.

Cinergy Corp.

4901:5-5-01

ODOE FORM FE1-3A: SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) a, b
(KENTUCKY PORTION ONLY)

INTERNAL LOAD c

PART 6

		SUMMER			WINTER f		
	YEAR	LOAD	CHANGE d	PERCENT CHANGE e	LOAD	CHANGE d	PERCENT CHANGE e
-5	1994	713			602		
-4	1995	747	34	4.8	611	9	1.5
-3	1996	763	16	2.1	645	34	5.6
-2	1997	741	-22	-2.9	588	-57	-8.9
-1	1998	744	3	0.4	585	-3	-0.5
0	1999	780	36	4.8	683	98	16.8
1	2000	802	22	2.8	698	15	2.2
2	2001	819	17	2.1	711	13	1.9
3	2002	840	21	2.6	730	19	2.7
4	2003	863	23	2.7	749	19	2.6
5	2004	885	22	2.6	770	21	2.8
6	2005	919	34	3.8	792	22	2.9
7	2006	940	21	2.3	807	15	1.9
8	2007	955	15	1.6	820	13	1.6
9	2008	971	16	1.7	832	12	1.5
10	2009	984	13	1.3	842	10	1.2
11	2010	996	12	1.2	852	10	1.2
12	2011	1,009	13	1.3	862	10	1.2
13	2012	1,019	10	1.0	868	6	0.7
14	2013	1,030	11	1.1	877	9	1.0
15	2014	1,042	12	1.2	887	10	1.1
16	2015	1,053	11	1.1	896	9	1.0
17	2016	1,064	11	1.0	903	7	0.8
18	2017	1,074	10	0.9	910	7	0.8
19	2018	1,086	12	1.1	919	9	1.0
20	2019	1,096	10	0.9	927	8	0.9

(a) To be filled out by utilities operating across Kentucky boundaries. The category breakdowns should refer to the Kentucky portion of the utility's service area. Utilities who do not serve customers in Kentucky shall fill out FE1-3B and FE1-3C if applicable.

(b) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(c) Includes interruptible load.

(d) Difference between reporting year and previous year.

(e) Difference expressed as a percent of previous year.

(f) Winter load reference is to peak loads which occur in the following winter.

Cinergy Corp.

4901:5-5-01

ODOE FORM FE1-3B: SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) a, b

PART 1

NATIVE LOAD c

		SUMMER			WINTER f		
	YEAR	LOAD	CHANGE d	PERCENT CHANGE e	LOAD g	CHANGE d	PERCENT CHANGE e
-5	1994	9,465			8,336		
-4	1995	10,153	688	7.3	8,822	486	5.8
-3	1996	10,095	-58	-0.6	9,125	303	3.4
-2	1997	10,119	24	0.2	8,369	-756	-8.3
-1	1998	10,389	270	2.7	8,737	368	4.4
0	1999	10,597	208	2.0	9,530	793	9.1
1	2000	10,815	218	2.1	9,737	207	2.2
2	2001	11,050	235	2.2	9,976	239	2.5
3	2002	11,338	288	2.6	10,273	297	3.0
4	2003	11,690	352	3.1	10,465	192	1.9
5	2004	11,921	231	2.0	10,649	184	1.8
6	2005	12,180	259	2.2	10,838	189	1.8
7	2006	12,360	180	1.5	10,726	-112	-1.0
8	2007	12,241	-119	-1.0	10,895	169	1.6
9	2008	12,436	195	1.6	11,061	166	1.5
10	2009	12,625	189	1.5	11,218	157	1.4
11	2010	12,810	185	1.5	11,381	163	1.5
12	2011	12,999	189	1.5	11,521	140	1.2
13	2012	13,150	151	1.2	11,634	113	1.0
14	2013	13,299	149	1.1	11,760	126	1.1
15	2014	13,448	149	1.1	11,896	136	1.2
16	2015	13,599	151	1.1	12,020	124	1.0
17	2016	13,740	141	1.0	12,129	109	0.9
18	2017	13,879	139	1.0	12,248	119	1.0
19	2018	14,032	153	1.1	12,366	118	1.0
20	2019	14,164	132	0.9	12,474	108	0.9

(a) To be filled out by companies operating across Ohio boundaries. The category breakdowns should refer to the utility's total service area (both inside and outside of Ohio).

(b) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(c) Excludes interruptible load.

(d) Difference between reporting year and previous year.

(e) Difference expressed as a percent of previous year.

(f) Winter load reference is to peak loads which occur in the following winter.

(g) 1998 winter company peak

Cinergy Corp.

4901:5-5-01

ODOE FORM FE1-3B: SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) a, b

PART 2

INTERNAL LOAD c

		SUMMER			WINTER f		
	YEAR	LOAD	CHANGE d	PERCENT CHANGE e	LOAD g	CHANGE d	PERCENT CHANGE e
-5	1994	9,581			8,336		
-4	1995	10,271	690	7.2	8,822	486	5.8
-3	1996	10,201	-70	-0.7	9,125	303	3.4
-2	1997	10,119	-82	-0.8	8,369	-756	-8.3
-1	1998	10,528	408	4.0	8,737	368	4.4
0	1999	11,035	507	4.8	9,864	1127	12.9
1	2000	11,252	217	2.0	10,066	202	2.0
2	2001	11,483	231	2.1	10,306	240	2.4
3	2002	11,772	289	2.5	10,604	298	2.9
4	2003	12,124	352	3.0	10,797	193	1.8
5	2004	12,356	232	1.9	10,981	184	1.7
6	2005	12,615	259	2.1	11,170	189	1.7
7	2006	12,795	180	1.4	11,058	-112	-1.0
8	2007	12,676	-119	-0.9	11,227	169	1.5
9	2008	12,871	195	1.5	11,393	166	1.5
10	2009	13,060	189	1.5	11,550	157	1.4
11	2010	13,246	186	1.4	11,713	163	1.4
12	2011	13,435	189	1.4	11,854	141	1.2
13	2012	13,586	151	1.1	11,966	112	0.9
14	2013	13,734	148	1.1	12,092	126	1.1
15	2014	13,884	150	1.1	12,228	136	1.1
16	2015	14,035	151	1.1	12,352	124	1.0
17	2016	14,176	141	1.0	12,461	109	0.9
18	2017	14,314	138	1.0	12,580	119	1.0
19	2018	14,467	153	1.1	12,698	118	0.9
20	2019	14,599	132	0.9	12,806	108	0.9

(a) To be filled out by companies operating across Ohio boundaries. The category breakdowns should refer to the utility's total service area (both inside and outside of Ohio).

(b) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(c) Includes interruptible load.

(d) Difference between reporting year and previous year.

(e) Difference expressed as a percent of previous year.

(f) Winter load reference is to peak loads which occur in the following winter.

(g) 1998 winter company peak

Cinergy Corp.

4901:5-5-03

ODOE FORM FE1-3A: SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) a
(OHIO PORTION ONLY)

> AFTER DSM < PART 1

		NATIVE LOAD b					
		SUMMER			WINTER e		
	YEAR	LOAD	CHANGE c	PERCENT CHANGE d	LOAD	CHANGE c	PERCENT CHANGE d
-5	1994	3,682			3,062		
-4	1995	3,799	117	3.2	3,292	230	7.5
-3	1996	3,731	-68	-1.8	3,364	72	2.2
-2	1997	3,902	171	4.6	2,994	-370	-11.0
-1	1998	3,981	79	2.0	3,348	354	11.8
0	1999	4,150	169	4.2	3,613	265	7.9
1	2000	4,234	84	2.0	3,687	74	2.0
2	2001	4,322	88	2.1	3,751	64	1.7
3	2002	4,410	88	2.0	3,837	86	2.3
4	2003	4,525	115	2.6	3,925	88	2.3
5	2004	4,638	113	2.5	4,032	107	2.7
6	2005	4,802	164	3.5	4,139	107	2.7
7	2006	4,895	93	1.9	4,203	64	1.5
8	2007	4,979	84	1.7	4,270	67	1.6
9	2008	5,060	81	1.6	4,334	64	1.5
10	2009	5,134	74	1.5	4,386	52	1.2
11	2010	5,202	68	1.3	4,445	59	1.3
12	2011	5,275	73	1.4	4,498	53	1.2
13	2012	5,329	54	1.0	4,535	37	0.8
14	2013	5,389	60	1.1	4,584	49	1.1
15	2014	5,452	63	1.2	4,638	54	1.2
16	2015	5,511	59	1.1	4,684	46	1.0
17	2016	5,565	54	1.0	4,718	34	0.7
18	2017	5,617	52	0.9	4,759	41	0.9
19	2018	5,681	64	1.1	4,805	46	1.0
20	2019	5,733	52	0.9	4,848	43	0.9

(a) To be filled out by utilities operating across Ohio boundaries. The category breakdowns should refer to the Ohio portion of the utility's service area. Utilities who do not serve customers in Ohio shall fill out FE1-3B and FE1-3C if applicable.

(b) Excludes interruptible load.

(c) Difference between reporting year and previous year.

(d) Difference expressed as a percent of previous year.

(e) Winter load reference is to peak loads which occur in the following winter.

Cinergy Corp.

4901:5-5-03

ODOE FORM FE1-3A: SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) a
(OHIO PORTION ONLY)

> AFTER DSM <

PART 2

		INTERNAL LOAD b					
		SUMMER			WINTER e		
	YEAR	LOAD	CHANGE c	PERCENT CHANGE d	LOAD	CHANGE c	PERCENT CHANGE d
-5	1994	3,729			3,062		
-4	1995	3,868	139	3.7	3,552	490	16.0
-3	1996	3,780	-88	-2.3	3,364	-188	-5.3
-2	1997	3,898	118	3.1	2,994	-370	-11.0
-1	1998	3,993	95	2.4	3,348	354	11.8
0	1999	4,205	212	5.3	3,644	296	8.8
1	2000	4,288	83	2.0	3,713	69	1.9
2	2001	4,370	82	1.9	3,777	64	1.7
3	2002	4,459	89	2.0	3,863	86	2.3
4	2003	4,573	114	2.6	3,951	88	2.3
5	2004	4,686	113	2.5	4,058	107	2.7
6	2005	4,850	164	3.5	4,166	108	2.7
7	2006	4,943	93	1.9	4,229	63	1.5
8	2007	5,027	84	1.7	4,296	67	1.6
9	2008	5,109	82	1.6	4,360	64	1.5
10	2009	5,183	74	1.4	4,412	52	1.2
11	2010	5,251	68	1.3	4,471	59	1.3
12	2011	5,323	72	1.4	4,524	53	1.2
13	2012	5,377	54	1.0	4,561	37	0.8
14	2013	5,438	61	1.1	4,611	50	1.1
15	2014	5,501	63	1.2	4,664	53	1.1
16	2015	5,559	58	1.1	4,711	47	1.0
17	2016	5,614	55	1.0	4,744	33	0.7
18	2017	5,666	52	0.9	4,785	41	0.9
19	2018	5,730	64	1.1	4,831	46	1.0
20	2019	5,781	51	0.9	4,874	43	0.9

(a) To be filled out by utilities operating across Ohio boundaries. The category breakdowns should refer to the Ohio portion of the utility's service area. Utilities who do not serve customers in Ohio shall fill out FE1-3B and FE1-3C if applicable.

(b) Includes interruptible load.

(c) Difference between reporting year and previous year.

(d) Difference expressed as a percent of previous year.

(e) Winter load reference is to peak loads which occur in the following winter.

Cinergy Corp.

4901:5-5-03

ODOE FORM FE1-3A: SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) a
(INDIANA PORTION ONLY)

> AFTER DSM < PART 3

NATIVE LOAD b

		SUMMER			WINTER e		
	YEAR	LOAD	CHANGE c	PERCENT CHANGE d	LOAD	CHANGE c	PERCENT CHANGE d
-5	1994	5,161			4,657		
-4	1995	5,581	420	8.1	4,949	292	6.3
-3	1996	5,623	42	0.8	5,102	153	3.1
-2	1997	5,676	53	0.9	4,778	-324	-6.4
-1	1998	5,703	27	0.5	4,803	25	0.5
0	1999	5,702	-1	0.0	5,230	427	8.9
1	2000	5,812	110	1.9	5,348	118	2.3
2	2001	5,943	131	2.3	5,510	162	3.0
3	2002	6,122	179	3.0	5,702	192	3.5
4	2003	6,336	214	3.5	5,788	86	1.5
5	2004	6,432	96	1.5	5,843	55	1.0
6	2005	6,493	61	0.9	5,902	59	1.0
7	2006	6,559	66	1.0	5,711	-191	-3.2
8	2007	6,341	-218	-3.3	5,800	89	1.6
9	2008	6,439	98	1.5	5,894	94	1.6
10	2009	6,542	103	1.6	5,990	96	1.6
11	2010	6,648	106	1.6	6,083	93	1.6
12	2011	6,751	103	1.5	6,161	78	1.3
13	2012	6,838	87	1.3	6,231	70	1.1
14	2013	6,916	78	1.1	6,299	68	1.1
15	2014	6,991	75	1.1	6,371	72	1.1
16	2015	7,072	81	1.2	6,440	69	1.1
17	2016	7,148	76	1.1	6,509	69	1.1
18	2017	7,225	77	1.1	6,578	69	1.1
19	2018	7,302	77	1.1	6,642	64	1.0
20	2019	7,372	70	1.0	6,699	57	0.9

(a) To be filled out by utilities operating across Indiana boundaries. The category breakdowns should refer to the Indiana portion of the utility's service area. Utilities who do not serve customer in Indiana shall fill out FE1-3B AND FE1-13C if applicable.

(b) Excludes interruptible load.

(c) Difference between reporting year and previous year.

(d) Difference expressed as a percent of previous year.

(e) Winter load reference is to peak loads which occur in the following winter.

Cinergy Corp.

4901:5-5-03

ODOE FORM FE1-3A: SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) a
(INDIANA PORTION ONLY)

> AFTER DSM < PART 4

INTERNAL LOAD b

		SUMMER			WINTER e		
	YEAR	LOAD	CHANGE c	PERCENT CHANGE d	LOAD	CHANGE c	PERCENT CHANGE d
-5	1994	5,161			4,657		
-4	1995	5,593	432	8.4	4,949	292	6.3
-3	1996	5,623	30	0.5	5,102	153	3.1
-2	1997	5,676	53	0.9	4,778	-324	-6.4
-1	1998	5,789	113	2.0	4,803	25	0.5
0	1999	6,047	258	4.5	5,532	729	15.2
1	2000	6,159	112	1.9	5,651	119	2.2
2	2001	6,290	131	2.1	5,813	162	2.9
3	2002	6,470	180	2.9	6,006	193	3.3
4	2003	6,685	215	3.3	6,093	87	1.4
5	2004	6,782	97	1.5	6,148	55	0.9
6	2005	6,843	61	0.9	6,208	60	1.0
7	2006	6,909	66	1.0	6,017	-191	-3.1
8	2007	6,691	-218	-3.2	6,106	89	1.5
9	2008	6,789	98	1.5	6,200	94	1.5
10	2009	6,892	103	1.5	6,295	95	1.5
11	2010	6,998	106	1.5	6,388	93	1.5
12	2011	7,101	103	1.5	6,466	78	1.2
13	2012	7,188	87	1.2	6,537	71	1.1
14	2013	7,266	78	1.1	6,604	67	1.0
15	2014	7,341	75	1.0	6,677	73	1.1
16	2015	7,422	81	1.1	6,746	69	1.0
17	2016	7,498	76	1.0	6,815	69	1.0
18	2017	7,575	77	1.0	6,884	69	1.0
19	2018	7,652	77	1.0	6,947	63	0.9
20	2019	7,722	70	0.9	7,005	58	0.8

(a) To be filled out by utilities operating across Indiana boundaries. The category breakdowns should refer to the Indiana portion of the utility's service area. Utilities who do not serve customers in Indiana shall fill out FE1-3B and FE1-3C if applicable.

(b) Includes interruptible load.

(c) Difference between reporting year and previous year.

(d) Difference expressed as a percent of previous year

(e) Winter load reference is to peak loads which occur in the following winter.

Cinergy Corp.

4901:5-5-03

ODOE FORM FE1-3A: SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) a
(KENTUCKY PORTION ONLY)

> AFTER DSM <

PART 5

NATIVE LOAD b

		SUMMER			WINTER e		
	YEAR	LOAD	CHANGE c	PERCENT CHANGE d	LOAD	CHANGE c	PERCENT CHANGE d
-5	1994	644			602		
-4	1995	710	66	10.2	611	9	1.5
-3	1996	721	11	1.5	645	34	5.6
-2	1997	736	15	2.1	587	-58	-9.0
-1	1998	703	-33	-4.5	584	-3	-0.5
0	1999	742	39	5.5	682	98	16.8
1	2000	764	22	3.0	697	15	2.2
2	2001	782	18	2.4	710	13	1.9
3	2002	802	20	2.6	729	19	2.7
4	2003	825	23	2.9	747	18	2.5
5	2004	847	22	2.7	769	22	2.9
6	2005	881	34	4.0	791	22	2.9
7	2006	902	21	2.4	806	15	1.9
8	2007	917	15	1.7	819	13	1.6
9	2008	933	16	1.7	831	12	1.5
10	2009	946	13	1.4	841	10	1.2
11	2010	958	12	1.3	851	10	1.2
12	2011	972	14	1.5	860	9	1.1
13	2012	982	10	1.0	867	7	0.8
14	2013	992	10	1.0	877	10	1.2
15	2014	1,005	13	1.3	887	10	1.1
16	2015	1,016	11	1.1	896	9	1.0
17	2016	1,027	11	1.1	902	6	0.7
18	2017	1,037	10	1.0	910	8	0.9
19	2018	1,049	12	1.2	919	9	1.0
20	2019	1,059	10	1.0	927	8	0.9

(a) To be filled out by utilities operating across Kentucky boundaries. The category breakdowns should refer to the Kentucky portion of the utility's service area. Utilities who do not serve customers in Kentucky shall fill out FE1-3B and FE1-3C if applicable.

(b) Excludes interruptible load.

(c) Difference between reporting year and previous year.

(d) Difference expressed as a percent of previous year.

(e) Winter load reference is to peak loads which occur in the following winter.

Cinergy Corp.

4901:5-5-03

ODOE FORM FE1-3A: SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) a
(KENTUCKY PORTION ONLY)

> AFTER DSM <

PART 6

INTERNAL LOAD b

		SUMMER			WINTER e		
	YEAR	LOAD	CHANGE c	PERCENT CHANGE d	LOAD	CHANGE c	PERCENT CHANGE d
-5	1994	713			602		
-4	1995	747	34	4.8	611	9	1.5
-3	1996	763	16	2.1	645	34	5.6
-2	1997	740	-23	-3.0	587	-58	-9.0
-1	1998	743	3	0.4	584	-3	-0.5
0	1999	779	36	4.8	682	98	16.8
1	2000	801	22	2.8	697	15	2.2
2	2001	818	17	2.1	710	13	1.9
3	2002	839	21	2.6	729	19	2.7
4	2003	862	23	2.7	748	19	2.6
5	2004	884	22	2.6	769	21	2.8
6	2005	918	34	3.8	791	22	2.9
7	2006	939	21	2.3	806	15	1.9
8	2007	954	15	1.6	819	13	1.6
9	2008	970	16	1.7	831	12	1.5
10	2009	983	13	1.3	841	10	1.2
11	2010	995	12	1.2	851	10	1.2
12	2011	1,008	13	1.3	861	10	1.2
13	2012	1,018	10	1.0	868	7	0.8
14	2013	1,029	11	1.1	877	9	1.0
15	2014	1,042	13	1.3	887	10	1.1
16	2015	1,053	11	1.1	896	9	1.0
17	2016	1,064	11	1.0	903	7	0.8
18	2017	1,074	10	0.9	910	7	0.8
19	2018	1,086	12	1.1	919	9	1.0
20	2019	1,096	10	0.9	927	8	0.9

(a) To be filled out by utilities operating across Kentucky boundaries. The category breakdowns should refer to the Kentucky portion of the utility's service area. Utilities who do not serve customers in Kentucky shall fill out FE1-3B and FE1-3C if applicable.

(b) Includes interruptible load.

(c) Difference between reporting year and previous year.

(d) Difference expressed as a percent of previous year.

(e) Winter load reference is to peak loads which occur in the following winter.

Cinergy Corp.

4901:5-5-03

ODOE FORM FE1-3B: SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) a

> AFTER DSM < PART 1

NATIVE LOAD b, f

		SUMMER			WINTER e		
	YEAR	LOAD	CHANGE c	PERCENT CHANGE d	LOAD g	CHANGE c	PERCENT CHANGE d
-5	1994	9,421			8,319		
-4	1995	10,079	658	7.0	8,795	476	5.7
-3	1996	10,043	-36	-0.4	9,073	278	3.2
-2	1997	10,109	66	0.7	8,359	-714	-7.9
-1	1998	10,387	278	2.8	8,735	376	4.5
0	1999	10,594	207	2.0	9,525	790	9.0
1	2000	10,811	217	2.0	9,731	206	2.2
2	2001	11,046	235	2.2	9,970	239	2.5
3	2002	11,334	288	2.6	10,267	297	3.0
4	2003	11,686	352	3.1	10,460	193	1.9
5	2004	11,917	231	2.0	10,643	183	1.7
6	2005	12,176	259	2.2	10,832	189	1.8
7	2006	12,355	179	1.5	10,720	-112	-1.0
8	2007	12,236	-119	-1.0	10,889	169	1.6
9	2008	12,432	196	1.6	11,059	170	1.6
10	2009	12,622	190	1.5	11,216	157	1.4
11	2010	12,808	186	1.5	11,379	163	1.5
12	2011	12,997	189	1.5	11,519	140	1.2
13	2012	13,148	151	1.2	11,633	114	1.0
14	2013	13,298	150	1.1	11,760	127	1.1
15	2014	13,448	150	1.1	11,896	136	1.2
16	2015	13,599	151	1.1	12,020	124	1.0
17	2016	13,740	141	1.0	12,129	109	0.9
18	2017	13,879	139	1.0	12,248	119	1.0
19	2018	14,032	153	1.1	12,366	118	1.0
20	2019	14,164	132	0.9	12,474	108	0.9

(a) To be filled out by companies operating across Ohio boundaries. The category breakdowns should refer to the utility's total service area (both inside and outside of Ohio).

(b) Excludes interruptible load.

(c) Difference between reporting year and previous year.

(d) Difference expressed as a percent of previous year.

(e) Winter load reference is to peak loads which occur in the following winter.

(f) Historical loads from 1991 to 1995 represent non-coincident peak loads.

(g) 1998 winter company peak

Cinergy Corp.

4901:5-5-03

ODOE FORM FE1-3B: SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) a

> AFTER DSM < PART 2

INTERNAL LOAD b, f

		SUMMER			WINTER e		
	YEAR	LOAD	CHANGE c	PERCENT CHANGE d	LOAD g	CHANGE c	PERCENT CHANGE d
-5	1994	9,537			8,319		
-4	1995	10,197	660	6.9	8,795	476	5.7
-3	1996	10,149	-48	-0.5	9,073	278	3.2
-2	1997	10,109	-40	-0.4	8,359	-714	-7.9
-1	1998	10,525	416	4.1	8,735	376	4.5
0	1999	11,031	506	4.8	9,858	1,123	12.9
1	2000	11,247	216	2.0	10,060	202	2.0
2	2001	11,478	231	2.1	10,300	240	2.4
3	2002	11,767	289	2.5	10,598	298	2.9
4	2003	12,120	353	3.0	10,791	193	1.8
5	2004	12,352	232	1.9	10,975	184	1.7
6	2005	12,611	259	2.1	11,165	190	1.7
7	2006	12,791	180	1.4	11,053	-112	-1.0
8	2007	12,672	-119	-0.9	11,221	168	1.5
9	2008	12,867	195	1.5	11,391	170	1.5
10	2009	13,058	191	1.5	11,548	157	1.4
11	2010	13,244	186	1.4	11,711	163	1.4
12	2011	13,432	188	1.4	11,851	140	1.2
13	2012	13,584	152	1.1	11,965	114	1.0
14	2013	13,733	149	1.1	12,092	127	1.1
15	2014	13,884	151	1.1	12,228	136	1.1
16	2015	14,035	151	1.1	12,352	124	1.0
17	2016	14,176	141	1.0	12,461	109	0.9
18	2017	14,314	138	1.0	12,580	119	1.0
19	2018	14,467	153	1.1	12,698	118	0.9
20	2019	14,599	132	0.9	12,806	108	0.9

(a) To be filled out by companies operating across Ohio boundaries. The category breakdowns should refer to the utility's total service area (both inside and outside of Ohio).

(b) Includes interruptible load.

(c) Difference between reporting year and previous year.

(d) Difference expressed as a percent of previous year.

(e) Winter load reference is to peak loads which occur in the following winter.

(f) Historical loads from 1991 to 1995 represent non-coincident peak loads.

(g) 1998 winter company peak

Cinergy

4901:5-5-01

ODOE FORM FE1-4A RANGE OF FORECASTS
a, b
ECONOMIC BANDS
(OHIO PORTION ONLY)

	ENERGY FORECAST (GWH/YR) (NET ENERGY FOR LOAD)			PEAK LOAD FORECAST (MW)		
YEAR	LOW	MOST LIKELY c	HIGH	LOW	MOST LIKELY d	HIGH
1999	21,454	21,685	22,056	4,152	4,205	4,266
2000	21,895	22,306	22,858	4,202	4,288	4,380
2001	22,380	22,973	23,696	4,252	4,370	4,493
2002	22,842	23,622	24,523	4,308	4,459	4,613
2003	23,406	24,379	25,474	4,387	4,573	4,762
2004	22,685	23,863	25,170	4,464	4,686	4,913
2005	23,321	24,721	26,310	4,589	4,850	5,129
2006	23,686	25,312	27,157	4,642	4,943	5,263
2007	23,922	25,783	27,856	4,684	5,027	5,387
2008	24,143	26,237	28,555	4,725	5,109	5,511
2009	24,322	26,649	29,215	4,758	5,183	5,628
2010	24,476	27,037	29,865	4,785	5,251	5,741
2011	24,633	27,434	30,534	4,815	5,323	5,860
2012	24,728	27,756	31,118	4,829	5,377	5,958
2013	24,800	28,059	31,688	4,849	5,438	6,065
2014	24,907	28,401	32,304	4,870	5,501	6,175
2015	25,007	28,739	32,932	4,887	5,559	6,283
2016	25,074	29,035	33,508	4,901	5,614	6,385
2017	25,115	29,314	34,083	4,911	5,666	6,488
2018	25,199	29,637	34,713	4,932	5,730	6,604
2019	25,268	29,942	35,320	4,943	5,781	6,707

(a) To be filled out by utilities operating across Ohio boundaries. The category breakdowns should refer to the Ohio portion of the utility's service area.

(b) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(c) Same as column 9 on Form FE1-1A, Part 2.

(d) Same as Highest of Summer or Winter of Internal Load on Form FE1-3A, Part 2.

Cinergy

4901:5-5-01

ODOE FORM FE1-4A RANGE OF FORECASTS
a, b
ECONOMIC BANDS
(INDIANA PORTION ONLY)

	ENERGY FORECAST (GWH/YR) (NET ENERGY FOR LOAD)			PEAK LOAD FORECAST (MW)		
		c			d	
YEAR	LOW	MOST LIKELY	HIGH	LOW	MOST LIKELY	HIGH
1999	33,037	33,253	33,588	5,999	6,050	6,102
2000	33,669	34,113	34,676	6,069	6,162	6,256
2001	34,342	35,035	35,759	6,154	6,293	6,417
2002	35,203	36,186	37,054	6,280	6,473	6,624
2003	36,163	37,483	38,487	6,432	6,688	6,864
2004	35,102	36,752	37,872	6,467	6,785	6,982
2005	35,119	37,084	38,325	6,470	6,846	7,066
2006	35,168	37,439	38,832	6,479	6,912	7,161
2007	33,495	35,997	37,401	6,228	6,694	6,955
2008	33,695	36,528	38,088	6,265	6,792	7,082
2009	33,893	37,068	38,779	6,302	6,893	7,211
2010	34,110	37,640	39,498	6,343	6,999	7,345
2011	34,300	38,196	40,198	6,378	7,102	7,475
2012	34,413	38,663	40,809	6,399	7,189	7,588
2013	34,485	39,078	41,366	6,412	7,266	7,692
2014	34,697	39,481	41,778	6,452	7,341	7,769
2015	34,790	39,914	42,347	6,469	7,422	7,874
2016	34,863	40,325	42,887	6,483	7,498	7,975
2017	34,933	40,739	43,421	6,496	7,575	8,074
2018	35,007	41,152	43,959	6,509	7,652	8,174
2019	35,062	41,531	44,464	6,520	7,722	8,268

(a) To be filled out by utilities operating across Indiana boundaries. The category breakdowns should refer to the Indiana portion of the utility's service area.

(b) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(c) Same as Column 9 on Form FE1-1A, Part 4.

(d) Same as Highest of Summer or Winter of Internal Load on Form FE1-3A, Part 4.

Figure 3-28

Cinergy

4901:5-5-01

ODOE FORM FE1-4A RANGE OF FORECASTS
a, b
ECONOMIC BANDS
(KENTUCKY PORTION ONLY)

	ENERGY FORECAST (GWH/YR) (NET ENERGY FOR LOAD)			PEAK LOAD FORECAST (MW)		
		c			d	
YEAR	LOW	MOST LIKELY	HIGH	LOW	MOST LIKELY	HIGH
1999	3,763	3,803	3,868	770	780	791
2000	3,839	3,911	4,008	786	802	819
2001	3,931	4,035	4,162	797	819	842
2002	4,043	4,181	4,341	811	840	869
2003	4,199	4,374	4,570	827	863	898
2004	4,108	4,322	4,558	843	885	927
2005	4,240	4,495	4,784	869	919	971
2006	4,325	4,622	4,959	882	940	1,001
2007	4,367	4,706	5,085	890	955	1,023
2008	4,407	4,790	5,213	898	971	1,047
2009	4,438	4,862	5,330	903	984	1,068
2010	4,461	4,928	5,444	908	996	1,089
2011	4,488	4,998	5,563	913	1,009	1,111
2012	4,504	5,056	5,668	915	1,019	1,130
2013	4,514	5,107	5,767	918	1,030	1,149
2014	4,534	5,170	5,880	923	1,042	1,170
2015	4,552	5,231	5,994	926	1,053	1,190
2016	4,565	5,286	6,100	929	1,064	1,210
2017	4,572	5,336	6,205	931	1,074	1,229
2018	4,588	5,396	6,320	935	1,086	1,252
2019	4,600	5,451	6,430	937	1,096	1,271

(a) To be filled out by utilities operating across Kentucky boundaries. The category breakdowns should refer to the Kentucky portion of the utility's service area.

(b) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(c) Same as Column 9 on Form FE1-1A, Part 6.

(d) Same as Highest of Summer or Winter of Internal Load on Form FE1-3A, Part 6.

Cinergy

4901:5-5-01

ODOE FORM FE1-4B RANGE OF FORECASTS
a, b
ECONOMIC BANDS

ENERGY FORECAST (GWH/YR)
(NET ENERGY FOR LOAD)

PEAK LOAD FORECAST (MW)

YEAR	LOW	MOST LIKELY c	HIGH	LOW	MOST LIKELY d	HIGH
1999	58,262	58,749	59,520	10,920	11,035	11,160
2000	59,411	60,339	61,550	11,058	11,252	11,455
2001	60,660	62,052	63,626	11,203	11,483	11,752
2002	62,096	63,998	65,926	11,399	11,772	12,106
2003	63,776	66,244	68,540	11,647	12,124	12,524
2004	61,903	64,946	67,609	11,773	12,356	12,822
2005	62,689	66,309	69,428	11,929	12,615	13,166
2006	63,187	67,382	70,958	12,003	12,795	13,425
2007	61,792	66,496	70,352	11,802	12,676	13,365
2008	62,253	67,563	71,865	11,887	12,871	13,640
2009	62,662	68,589	73,335	11,963	13,060	13,907
2010	63,056	69,614	74,817	12,035	13,246	14,175
2011	63,430	70,638	76,307	12,106	13,435	14,446
2012	63,654	71,485	77,606	12,144	13,586	14,676
2013	63,808	72,254	78,832	12,179	13,734	14,906
2014	64,147	73,062	79,974	12,245	13,884	15,114
2015	64,358	73,893	81,285	12,282	14,035	15,348
2016	64,511	74,657	82,506	12,313	14,176	15,570
2017	64,630	75,400	83,721	12,337	14,314	15,791
2018	64,802	76,195	85,004	12,376	14,467	16,029
2019	64,940	76,934	86,227	12,400	14,599	16,245

(a) To be filled out by utilities operating across Ohio boundaries. The category breakdowns should refer to the utility's total service area (both inside and outside Ohio).

(b) Figures do not reflect the impact of the projected additional utility directed demand side programs

(c) Same as Column 9 on Form FE1-1B, Part 2.

(d) Same as Highest of Summer or Winter of Internal Load on Form FE1-3B, Part 2.

Cinergy

4901:5-5-03

ODOE FORM FE1-4A RANGE OF FORECASTS
a
ECONOMIC BANDS
(OHIO PORTION ONLY)
> AFTER DSM <

	ENERGY FORECAST (GWH/YR) (NET ENERGY FOR LOAD)			PEAK LOAD FORECAST (MW)		
YEAR	LOW	MOST LIKELY b	HIGH	LOW	MOST LIKELY c	HIGH
1999	21,454	21,685	22,056	4,152	4,205	4,266
2000	21,895	22,306	22,858	4,202	4,288	4,380
2001	22,380	22,973	23,696	4,252	4,370	4,493
2002	22,842	23,622	24,523	4,308	4,459	4,613
2003	23,406	24,379	25,474	4,387	4,573	4,762
2004	22,685	23,863	25,170	4,464	4,686	4,913
2005	23,321	24,721	26,310	4,589	4,850	5,129
2006	23,686	25,312	27,157	4,642	4,943	5,263
2007	23,922	25,783	27,856	4,684	5,027	5,387
2008	24,143	26,237	28,555	4,725	5,109	5,511
2009	24,322	26,649	29,215	4,758	5,183	5,628
2010	24,476	27,037	29,865	4,785	5,251	5,741
2011	24,633	27,434	30,534	4,815	5,323	5,860
2012	24,728	27,756	31,118	4,829	5,377	5,958
2013	24,800	28,059	31,688	4,849	5,438	6,065
2014	24,907	28,401	32,304	4,870	5,501	6,175
2015	25,007	28,739	32,932	4,887	5,559	6,283
2016	25,074	29,035	33,508	4,901	5,614	6,385
2017	25,115	29,314	34,083	4,911	5,666	6,488
2018	25,199	29,637	34,713	4,932	5,730	6,604
2019	25,268	29,942	35,320	4,943	5,781	6,707

(a) To be filled out by utilities operating across Ohio boundaries. The category breakdowns should refer to the Ohio portion of the utility's service area.

(b) Same as Column 9 on Form FE1-1A, Part 2.

(c) Same as Highest of Summer or Winter of Internal Load on Form FE1-3A, Part 2.

Cinergy

4901:5-5-03

ODOE FORM FE1-4A RANGE OF FORECASTS
a
ECONOMIC BANDS
(INDIANA PORTION ONLY)
> AFTER DSM <

ENERGY FORECAST (GWH/YR)
(NET ENERGY FOR LOAD)

PEAK LOAD FORECAST (MW)

YEAR	LOW	MOST LIKELY b	HIGH	LOW	MOST LIKELY c	HIGH
1999	33,017	33,233	33,567	5,996	6,047	6,099
2000	33,638	34,082	34,645	6,066	6,159	6,253
2001	34,310	35,004	35,727	6,151	6,290	6,414
2002	35,172	36,155	37,023	6,277	6,470	6,621
2003	36,132	37,451	38,456	6,429	6,685	6,861
2004	35,070	36,721	37,840	6,464	6,782	6,979
2005	35,088	37,053	38,294	6,467	6,843	7,063
2006	35,137	37,408	38,800	6,476	6,909	7,158
2007	33,464	35,966	37,370	6,225	6,691	6,952
2008	33,663	36,497	38,056	6,262	6,789	7,079
2009	33,883	37,058	38,769	6,301	6,892	7,210
2010	34,100	37,629	39,488	6,342	6,998	7,344
2011	34,290	38,185	40,188	6,377	7,101	7,474
2012	34,402	38,653	40,799	6,398	7,188	7,587
2013	34,484	39,077	41,365	6,412	7,266	7,692
2014	34,697	39,481	41,778	6,452	7,341	7,769
2015	34,790	39,914	42,347	6,469	7,422	7,874
2016	34,863	40,325	42,887	6,483	7,498	7,975
2017	34,933	40,739	43,421	6,496	7,575	8,074
2018	35,007	41,152	43,959	6,509	7,652	8,174
2019	35,062	41,531	44,464	6,520	7,722	8,268

(a) To be filled out by utilities operating across Indiana boundaries. The category breakdowns should refer to the Indiana portion of the utility's service area.

(b) Same as Column 9 on Form FE1-1A, Part 4.

(c) Same as Highest of Summer or Winter of Internal Load on Form FE1-3A, Part 4.

Cinergy

4901:5-5-03

ODOE FORM FE1-4A RANGE OF FORECASTS
a
ECONOMIC BANDS
(KENTUCKY PORTION ONLY)
> AFTER DSM <

	ENERGY FORECAST (GWH/YR) (NET ENERGY FOR LOAD)			PEAK LOAD FORECAST (MW)		
YEAR	LOW	MOST LIKELY b	HIGH	LOW	MOST LIKELY c	HIGH
1999	3,758	3,798	3,863	769	779	790
2000	3,834	3,906	4,003	785	801	818
2001	3,926	4,030	4,157	796	818	841
2002	4,038	4,176	4,336	810	839	868
2003	4,194	4,369	4,565	827	862	897
2004	4,103	4,317	4,553	842	884	926
2005	4,235	4,490	4,779	868	918	971
2006	4,320	4,617	4,954	882	939	1,000
2007	4,362	4,701	5,080	889	954	1,022
2008	4,402	4,785	5,208	897	970	1,046
2009	4,433	4,857	5,325	902	983	1,067
2010	4,456	4,923	5,439	907	995	1,088
2011	4,483	4,993	5,558	912	1,008	1,110
2012	4,499	5,051	5,663	915	1,018	1,129
2013	4,509	5,102	5,762	918	1,029	1,148
2014	4,534	5,170	5,880	923	1,042	1,170
2015	4,552	5,231	5,994	926	1,053	1,190
2016	4,565	5,286	6,100	929	1,064	1,210
2017	4,572	5,336	6,205	931	1,074	1,229
2018	4,588	5,396	6,320	935	1,086	1,252
2019	4,600	5,451	6,430	937	1,096	1,271

(a) To be filled out by utilities operating across Ohio boundaries. The category breakdowns should refer to the Kentucky portion of the utility's service area.

(b) Same as Column 9 on Form FE1-1A, Part 6.

(c) Same as Highest of Summer or Winter of Internal Load on Form FE1-3A, Part 6.

Cinergy

4901:5-5-03

ODOE FORM FE1-4B RANGE OF FORECASTS
a
ECONOMIC BANDS

> AFTER DSM <

	ENERGY FORECAST (GWH/YR) (NET ENERGY FOR LOAD)			PEAK LOAD FORECAST (MW)		
YEAR	LOW	MOST LIKELY b	HIGH	LOW	MOST LIKELY c	HIGH
1999	58,236	58,723	59,494	10,917	11,031	11,156
2000	59,375	60,302	61,514	11,053	11,247	11,451
2001	60,624	62,016	63,589	11,199	11,478	11,748
2002	62,060	63,962	65,890	11,394	11,767	12,102
2003	63,740	66,208	68,504	11,642	12,120	12,520
2004	61,867	64,910	67,573	11,769	12,352	12,818
2005	62,653	66,273	69,392	11,924	12,611	13,162
2006	63,151	67,346	70,922	11,999	12,791	13,420
2007	61,756	66,460	70,316	11,798	12,672	13,360
2008	62,217	67,527	71,829	11,883	12,867	13,635
2009	62,647	68,573	73,320	11,961	13,058	13,905
2010	63,040	69,599	74,802	12,033	13,244	14,172
2011	63,415	70,622	76,292	12,104	13,432	14,444
2012	63,638	71,470	77,591	12,141	13,584	14,674
2013	63,802	72,248	78,826	12,178	13,733	14,905
2014	64,147	73,062	79,974	12,245	13,884	15,114
2015	64,358	73,893	81,285	12,282	14,035	15,348
2016	64,511	74,657	82,506	12,313	14,176	15,570
2017	64,630	75,400	83,721	12,337	14,314	15,791
2018	64,802	76,195	85,004	12,376	14,467	16,029
2019	64,940	76,934	86,227	12,400	14,599	16,245

(a) To be filled out by utilities operating across Ohio boundaries. The category breakdowns should refer to the utility's total service area (both inside and outside Ohio).

(b) Same as Column 9 on Form FE1-1B, Part 2.

(c) Same as Highest of Summer or Winter of Internal Load on Form FE1-3B, Part 2.

Cinergy

4901:5-5-01

ODOE FORM FE1-5 PART 2: NET MONTHLY INTERNAL LOAD FORECAST (MEGAWATTS) a

YEAR 0 1999	OHIO b	INDIANA b	KENTUCKY b	SYSTEM c	POOL d
January	3,599	5,437	669	9,704	9,704
February	3,346	5,372	633	9,351	9,351
March	2,965	4,819	562	8,346	8,346
April	2,861	4,413	497	7,771	7,771
May	3,073	4,809	531	8,412	8,412
June	3,620	5,715	630	9,966	9,966
July	3,994	6,036	683	10,713	10,713
August	4,205	6,050	780	11,035	11,035
September	4,124	5,416	710	10,250	10,250
October	2,894	4,477	503	7,874	7,874
November	3,037	4,889	538	8,464	8,464
December	3,638	5,281	605	9,525	9,525
YEAR 1 2000					
January	3,644	5,537	683	9,864	9,864
February	3,392	5,471	644	9,508	9,508
March	3,007	4,908	572	8,487	8,487
April	2,911	4,495	509	7,914	7,914
May	3,126	4,898	543	8,568	8,568
June	3,684	5,821	646	10,151	10,151
July	4,069	6,147	704	10,920	10,920
August	4,288	6,162	802	11,252	11,252
September	4,204	5,517	731	10,452	10,452
October	2,945	4,560	516	8,021	8,021
November	3,085	4,980	552	8,617	8,617
December	3,692	5,379	621	9,692	9,692

(a) Figures do not reflect the impact of the projected additional utility directed demand side programs.

(b) Utilities operating solely in Ohio, Indiana, and Kentucky shall provide data fore these columns only.

(c) Utilities operating across Ohio, Indiana, and Kentucky boundaries shall provide data for the System column.

(d) Members of a pool or holding company operated on a system basis spanning spanning state boundaries shall provide for the total pool in this column

Cinergy

4901:5-5-01

ODOE FORM FE1-5 PART 1: NET MONTHLY ENERGY FORECAST (MEGAWATT HOURS) a

YEAR 0 1999	OHIO b	INDIANA b	KENTUCKY b	SYSTEM c	POOL d
January	2,027,745	3,040,591	354,653	5,423,736	5,423,736
February	1,763,810	2,697,230	313,949	4,775,708	4,775,708
March	1,769,203	2,702,405	317,297	4,789,570	4,789,570
April	1,552,582	2,464,490	273,635	4,291,293	4,291,293
May	1,610,389	2,542,887	284,154	4,437,978	4,437,978
June	1,737,848	2,790,802	299,556	4,828,824	4,828,824
July	1,957,428	3,062,357	341,879	5,362,377	5,362,377
August	2,032,494	2,997,838	353,940	5,385,015	5,385,015
September	1,861,041	2,637,840	322,577	4,822,151	4,822,151
October	1,734,725	2,632,939	299,998	4,668,229	4,668,229
November	1,710,700	2,691,853	304,886	4,708,003	4,708,003
December	1,926,813	2,992,158	336,541	5,256,189	5,256,189
YEAR 1 2000					
January	2,076,676	3,115,990	362,326	5,555,752	5,555,752
February	1,805,668	2,766,874	320,495	4,893,765	4,893,765
March	1,813,740	2,771,418	323,757	4,909,590	4,909,590
April	1,597,747	2,530,161	281,105	4,409,610	4,409,610
May	1,660,325	2,609,792	292,122	4,562,797	4,562,797
June	1,791,277	2,863,039	308,208	4,963,153	4,963,153
July	2,018,847	3,139,017	353,417	5,512,009	5,512,009
August	2,095,187	3,074,221	365,929	5,536,094	5,536,094
September	1,921,199	2,708,474	333,752	4,964,132	4,964,132
October	1,786,831	2,702,845	309,406	4,799,660	4,799,660
November	1,760,434	2,762,918	314,451	4,838,377	4,838,377
December	1,978,481	3,068,032	346,491	5,393,692	5,393,692

(a) Figures do not reflect the impact of the projected additional utility dir programs.

(b) Utilities operating solely in Ohio, Indiana, and Kentucky shall provided columns only.

(c) Utilities operating across Ohio, Indiana, and Kentucky boundaries shall p for the System column.

(d) Members of a pool or holding company operated on a system basis spanning boundaries shall provide for the total pool in this column.

Cinergy

FORM FE1-5 PART 3: MONTHLY FORECAST OF PEAK LOAD AND RESOURCES [In MegaWatts]

> BEFORE DSM < Current Calendar Year [Year 1999]

MONTH >	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Net Demonstrated Capability	11533	11533	11533	11533	11533	11533	11533	11533	11533	11533	11533	11533
Net Seasonal Capability	11518	11518	11518	11364	11364	11261	11261	11261	11261	11364	11364	11365
Purchases	304	304	304	304	304	517	817	817	467	304	304	304
Sales	185	185	70	70	70	70	70	70	70	70	70	120
Available Capacity	11637	11637	11752	11598	11598	11708	12008	12008	11658	11598	11598	11549
Native Load	9417	9064	8089	7515	8156	9573	10320	10597	9812	7573	8162	9192
Available Reserve	2220	2573	3663	4084	3442	2135	1688	1411	1846	4026	3436	2357
Internal Load[1]	9704	9351	8346	7771	8412	9966	10713	11035	10250	7874	8464	9525
Reserve	1933	2286	3406	3827	3186	1742	1296	973	1409	3724	3135	2025

Next Calendar Year [Year 2000]

MONTH >	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Net Demonstrated Capability	11533	11533	11533	11533	11533	11538	11538	11538	11538	11538	11538	11538
Net Seasonal Capability	11365	11365	11365	11364	11364	11266	11266	11266	11266	11369	11369	11370
Purchases	4	4	4	4	4	1464	1464	1464	104	4	4	4
Sales	120	120	70	70	70	70	70	70	70	70	70	70
Available Capacity	11249	11249	11299	11298	11298	12660	12660	12660	11300	11303	11303	11304
Native Load	9531	9174	8185	7612	8265	9714	10483	10815	10015	7719	8315	9359
Available Reserve	1719	2075	3115	3687	3033	2946	2177	1846	1285	3585	2989	1946
Internal Load[1]	9864	9508	8487	7914	8568	10151	10920	11251	10452	8021	8617	9692
Reserve	1385	1742	2812	3384	2731	2510	1740	1409	849	3282	2686	1612

[1] INTERNAL LOAD EQUALS NATIVE LOAD PLUS INTERRUPTIBLE LOAD.

Cinergy

4901:5-5-01

ODOE FORM FE1-5 PART 1: NET MONTHLY ENERGY FORECAST (MEGAWATT HOURS) a

> AFTER DSM <

YEAR 0 1999	OHIO b	INDIANA b	KENTUCKY b	SYSTEM c	POOL d
January	2,027,745	3,037,605	354,236	5,420,333	5,420,333
February	1,763,810	2,694,382	313,532	4,772,443	4,772,443
March	1,769,203	2,699,489	316,880	4,786,237	4,786,237
April	1,552,582	2,462,966	273,218	4,289,352	4,289,352
May	1,610,389	2,541,375	283,737	4,436,049	4,436,049
June	1,737,848	2,790,086	299,139	4,827,691	4,827,691
July	1,957,428	3,061,603	341,462	5,361,206	5,361,206
August	2,032,494	2,997,108	353,523	5,383,867	5,383,867
September	1,861,041	2,637,154	322,160	4,821,048	4,821,048
October	1,734,725	2,631,429	299,581	4,666,302	4,666,302
November	1,710,700	2,690,345	304,469	4,706,078	4,706,078
December	1,926,813	2,989,032	336,124	5,252,646	5,252,646
YEAR 1 2000					
January	2,076,676	3,111,345	361,909	5,550,690	5,550,690
February	1,805,668	2,762,538	320,078	4,889,012	4,889,012
March	1,813,740	2,766,914	323,340	4,904,669	4,904,669
April	1,597,747	2,527,925	280,688	4,406,957	4,406,957
May	1,660,325	2,607,602	291,705	4,560,190	4,560,190
June	1,791,277	2,862,073	307,791	4,961,770	4,961,770
July	2,018,847	3,137,989	353,000	5,510,564	5,510,564
August	2,095,187	3,073,231	365,512	5,534,687	5,534,687
September	1,921,199	2,707,549	333,335	4,962,790	4,962,790
October	1,786,831	2,700,641	308,989	4,797,039	4,797,039
November	1,760,434	2,760,697	314,034	4,835,739	4,835,739
December	1,978,481	3,063,106	346,074	5,388,349	5,388,349

(a) Figures reflect the impact of the projected additional utility directed demand side programs.

(b) Utilities operating solely in Ohio, Indiana, and Kentucky shall provide data for these columns only.

(c) Utilities operating across Ohio, Indiana, and Kentucky boundaries shall provide data for the System column.

(d) Members of a pool or holding company operated on a system basis spanning state boundaries shall provide data for the total pool in this column.

Cinergy

4901:5-5-03

ODOE FORM FE1-5 PART 2: NET MONTHLY INTERNAL PEAK LOAD FORECAST (MEGAWATTS) a

> AFTER DSM <

YEAR 0 1999	OHIO b	INDIANA b	KENTUCKY b	SYSTEM c	POOL d
January	3,599	5,435	668	9,701	9,701
February	3,346	5,370	632	9,348	9,348
March	2,965	4,815	561	8,341	8,341
April	2,861	4,411	496	7,768	7,768
May	3,073	4,807	530	8,409	8,409
June	3,620	5,713	630	9,963	9,963
July	3,994	6,034	682	10,710	10,710
August	4,205	6,048	779	11,032	11,032
September	4,124	5,414	709	10,247	10,247
October	2,894	4,474	502	7,870	7,870
November	3,037	4,888	537	8,461	8,461
December	3,638	5,279	605	9,522	9,522
YEAR 1 2000					
January	3,644	5,533	682	9,858	9,858
February	3,392	5,467	643	9,502	9,502
March	3,007	4,899	571	8,478	8,478
April	2,911	4,492	508	7,910	7,910
May	3,126	4,895	542	8,564	8,564
June	3,684	5,818	645	10,147	10,147
July	4,069	6,144	703	10,916	10,916
August	4,288	6,159	801	11,248	11,248
September	4,204	5,514	730	10,448	10,448
October	2,945	4,555	515	8,015	8,015
November	3,085	4,978	551	8,614	8,614
December	3,692	5,374	620	9,687	9,687

(a) Figures reflect the impact of the projected additional utility directed demand side programs.

(b) Utilities operating solely in Ohio, Indiana, and Kentucky shall provide data for these columns only.

(c) Utilities operating across Ohio, Indiana, and Kentucky boundaries shall provide data for the system column.

(d) Members of a pool or holding company operated on a system basis spanning state boundaries shall provide data for the total pool in this column.

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FORM FE1-5 PART 3: MONTHLY FORECAST OF PEAK LOAD AND RESOURCES [In MegaWatts]

> AFTER DSM < Current Calendar Year [Year 1999]

MONTH >	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Net Demonstrated Capability	11533	11533	11533	11533	11533	11533	11533	11533	11533	11533	11533	11533
Net Seasonal Capability	11518	11518	11518	11364	11364	11261	11261	11261	11261	11364	11364	11365
Purchases	304	304	304	304	304	517	817	817	467	304	304	304
Sales	185	185	70	70	70	70	70	70	70	70	70	120
Available Capacity	11637	11637	11752	11598	11598	11708	12008	12008	11658	11598	11598	11549
Native Load	9414	9061	8085	7512	8153	9570	10317	10594	9809	7569	8160	9189
Available Reserve	2223	2576	3668	4087	3445	2138	1691	1414	1849	4030	3438	2360
Internal Load[1]	9701	9348	8341	7768	8409	9963	10710	11032	10247	7870	8461	9522
Reserve	1936	2289	3411	3830	3189	1746	1299	976	1412	3728	3137	2028

Next Calendar Year [Year 2000]

MONTH >	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Net Demonstrated Capability	11533	11533	11533	11533	11533	11538	11538	11538	11538	11538	11538	11538
Net Seasonal Capability	11365	11365	11365	11364	11364	11266	11266	11266	11266	11369	11369	11370
Purchases	4	4	4	4	4	1464	1464	1464	104	4	4	4
Sales	120	120	70	70	70	70	70	70	70	70	70	70
Available Capacity	11249	11249	11299	11298	11298	12660	12660	12660	11300	11303	11303	11304
Native Load	9525	9169	8175	7607	8261	9710	10479	10811	10011	7713	8312	9353
Available Reserve	1724	2081	3124	3691	3037	2950	2181	1849	1289	3591	2991	1951
Internal Load[1]	9858	9502	8478	7910	8564	10147	10916	11248	10448	8015	8614	9687
Reserve	1391	1747	2822	3388	2735	2513	1744	1413	852	3288	2689	1618

[1] INTERNAL LOAD EQUALS NATIVE LOAD PLUS INTERRUPTIBLE LOAD.

4. DEMAND-SIDE MANAGEMENT RESOURCES

A. Introduction

Cinergy, its customer representatives, and its regulators have begun taking steps to prepare for a competitive utility industry, not by abandoning energy efficiency, conservation, and demand reduction, but by shifting from ratepayer-subsidized Demand-Side Management (DSM) programs to market-based, customer-driven energy-efficiency related products and services. Since the 1996 IRP was filed in Ohio on October 1, 1996, several key developments have dramatically changed the DSM portfolios of both CG&E and PSI.

CG&E - OHIO

On December 19, 1996, the PUCO issued an order in the 1995 Electric Long-Term Forecast Report proceeding, Case No. 95-203-EL-FOR, et al. The primary issues in that proceeding dealt with the role of DSM in an increasingly competitive environment. In its Order in the Case, the PUCO recognized that the fundamental assumption that validates DSM, namely the inherent cost sharing linkage among all customers of a utility, is no longer valid in an open access, customer choice environment. This calls into question the sustainability of cost transfers between participants and non-participants as the industry moves toward customer choice at the retail level.

In an effort to "...balance the probable future of an open access environment and the inherent delinkage of DSM cost sharing discussed above, with the potential for future DSM initiatives to produce avoided cost savings..."[1] the following changes were made.

First, the Total Resource Cost (TRC) cost-effectiveness test for DSM programs was revised to include only:

- Avoided environmental costs based on the internal cost to the utility of same;
- Avoided capacity costs that will occur over the next five years; and
- Fuel costs, but only after a demonstration that fuel cost savings resulted in benefits to all customers or the particular customer class.[2]

Second, the PUCO expressed concerns about the potential for stranded investment resulting from utilities' investments in DSM, in general, and CG&E's deferral balance in particular, and concluded that steps should be taken immediately to minimize the risk.

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[1] **Order in Case No. 95-203-EL-FOR et al. at 19.**
[2] **Id. at 20.**

"Our primary concern with DSM investments in the transition to a deregulated industry is the level of deferred DSM program costs, lost revenues, and shared savings which captive ratepayers and/or company shareholders may have to absorb without corresponding benefits in capacity or energy cost savings."[3]

"Therefore, we believe it is in best interests of the company's shareholders and ratepayers alike to take immediate steps to minimize the risk of stranded investment in DSM deferrals where feasible."[4]

Finally, the PUCO reaffirmed its commitment to the Collaborative process in Ohio and ordered that up to one-half of the annual $4.8 million currently collected in rates should be allocated to community-beneficial energy conservation programs approved by the Collaborative and directed that the Collaborative should focus on programs which benefit difficult-to-reach segments of the residential market such as low-income customers. The PUCO's order also allows the costs associated with programs that do not pass cost-effectiveness tests to be

[3] **Id. at 21.**
[4] **Id. at 21.**

included in this amount as long as they are recommended by the Collaborative and approved by the PUCO. It further ordered that the balance of the $4.8 million be allocated to reduce deferrals attributable to CG&E's prior DSM programs.

In January 1997, the Cinergy Energy Collaborative was dissolved and reorganized as the Cinergy/Community Energy Partnership ("CCEP") with a charter reflecting the Commission's order re-emphasizing its focus on residential customers, particularly low-income and disadvantaged customers. Following its meeting with Chairman Glazer in February 1997, the CCEP began redefining and repositioning itself to implement the provisions of the Commission's Order.

The CCEP installed a new Board and developed the following new charter:

> *"The purpose of the Cinergy/Community Energy Partnership is to give Cinergy guidance and make recommendations on cost-effective programs that will benefit all residential customers, especially low income, and help the community become more energy efficient. The focus should be on the disadvantaged*

members of the community through weatherization assistance and help with PIPP [Percentage of Income Payment Plan]."

Consistent with its new charter, the CCEP discontinued funding for all programs that were not focused on the residential class. Since the CCEP Board did not recommend funding of the following programs through amounts already recovered in rates, and CG&E recognized the need to minimize the risks associated with its growing deferral balance, the following programs are no longer offered:

- Industrial Competitiveness Center
- Commercial/Industrial Energy Audit
- Commercial/Industrial Lighting Rebate
- Commercial/Industrial Lighting Technical Assistance
- Commercial/Industrial Adjustable Speed Drives
- Commercial/Industrial Premium Efficiency Motor
- Commercial/Industrial Customized Efficiency Audit
- Thermal Energy Storage

The following programs are currently offered:

- Electric Weatherization

- Energy Decisions Workshops
- Energy Efficient Refrigerator Replacement
- Energy-Recycle Education Awareness Program
- Energy Maintenance Services
- General Use Program
- Homebuyers' Workshop
- Home Energy House Call
- Internet Audit Tool
- Learn and Earn Program
- New Home Efficient Refrigerators
- New Home Owners' Training
- Non-Profit Energy Management Pilot Program (NEMP)
- Ohio Energy Project (formerly Ohio NEED)

The CCEP Board established a long term planning process that enables the CCEP Board to compare and develop programs that best serve the low income and community residents in the territory. The planning cycle:

- Allows the Board to coordinate the planning efforts.
- Allows the Board to make comparisons as to the value and merits of each program option.
- Provides clear expectations of task forces and existing program managers.

- Increases decision making time efficiency.
- Coincides with the annual budgets.

Union Light, Heat and Power (ULH&P) - KENTUCKY

As described in the April 1997 filing, the Kentucky Collaborative has continually considered the proper role of DSM as the industry moves toward retail competition. As a result, the Collaborative has focused on innovative low cost approaches for influencing the market, such as educational programs and collaborations with groups such as homebuilders' associations. It is continuing to work to leverage community and state funding sources to complement the ratepayer-provided program funds. As described in the previous IRP, the Commercial and Industrial (C&I) Work Team reviewed the C&I DSM program and decided not to request funding for their continuation beyond 1998. The primary reasons included: the lack of participation in the programs; the uncertainty that non-participants would realize projected benefits in a competitive environment; the belief that changes in the electric industry were driving the development of alternative approaches to conservation and/or load shape improvement that might be more sustainable than non-participant subsidized rebate programs. These include the development of innovative tariff options designed to influence the improvement of customers' load shapes and the growth of the competitive Energy Service Company (ESCo) market.

In October 1998, ULH&P, the Office of the Kentucky Attorney General (AG), and the Northern Kentucky Community Action Commission (CAC), with the consensus of the Kentucky Collaborative, filed a request with the Kentucky Public Service Commission (KyPSC) for the continued funding of the following programs in Case No. 95-312:

- Residential Conservation and Energy Education
- Residential Energy Conservation Rates
- Residential Home Energy House Call
- Residential Comprehensive Energy Education Program
- Residential New Construction/Renovation Program, known as the Savings and Value through Energy Efficiency (SAVEE)

On November 23, 1998, the KyPSC approved the proposed DSM Riders, which were implemented in the first billing cycle of January 1999. The agreement and subsequent Commission order that established cost recovery methods granting ULH&P contemporaneous recovery of the revenue requirements associated with DSM programs expires at the end of 1999. The Collaborative is currently developing its joint application for approval of a two-year plan. The program details will be provided in that filing, which will be submitted to the Kentucky Public Service Commission in October for review and action.

Cinergy does not rely on these programs as resources in developing its integrated resource plan.

Since DSM costs are recovered contemporaneously in Kentucky, there are no issues related to outstanding deferral balances.

PSI Energy- INDIANA

In mid-1996, PSI began working with representatives from the Office of Utility Consumer Counselor (OUCC), the Citizen's Action Coalition of Indiana, Inc. (CAC), and the PSI-Industrial Group (PSI-IG) to develop a settlement agreement (Settlement Agreement or Agreement) that would: 1) Begin to move from traditional, ratepayer-subsidized DSM to market-based, customer-driven energy efficiency products and services; and 2) provide for recovery of PSI's DSM-related deferral balance.

The Indiana Utility Regulatory Commission (IURC) approved a Settlement Agreement on December 18, 1996 (Cause No. 40229). The Agreement provided ratepayer-subsidized incentives only for those market segments that the parties believed would not be priority targets for the "non-regulated" energy services companies, specifically residential and small to medium-sized commercial and industrial customers. In keeping with the terms of the Agreement, PSI discontinued all but the Low Income and Smart $aver® programs. The Smart $aver® program was changed in that its participant eligibility requirements were modified to include only the new construction residential market. While the Low Income and the Smart $aver® programs continue to be delivered by PSI, the four prescriptive incentive programs listed below were developed and implemented during the first quarter of 1997. The last three on the list were available only to commercial and industrial customers with peak electric demand below 500 kW.

- Residential Audit
- Residential Low-Income Program
- Lighting Incentive Plan
- Energy Efficient Cooling Systems

- Energy Efficient Motors

This is truly a transition strategy, wherein the traditional providers and energy service companies are primarily responsible for promotion and delivery of the programs to the market, and PSI is primarily responsible for administration of the program and processing of incentives.

The DSM Settlement Agreement is currently being renegotiated for the post-1999 period. The programs and impacts represented in this filing reflect Cinergy/PSI's best estimate regarding the outcome of those negotiations. Some of the changes represented in this filing are reductions in the budget.

B. EXISTING PROGRAMS, HISTORICAL PERFORMANCE

CG&E System

As discussed earlier in the chapter, there are currently no DSM resource programs being offered by CG&E to its customers in Ohio or Kentucky.

PSI System

The following table presents the historical impacts of

Cinergy/PSI's DSM programs since 1995. These impacts include demand reductions resulting from interruptible contracts.

Year	Demand (MW)	Energy (GWh)
1995	291	686
1996	335	815
1997	315	877
1998	419	894

C. ASSUMPTIONS, DATA SOURCES

Cinergy System

Since the CCEP Board did not recommend funding for non-residential programs through amounts already recovered in rates and because CG&E recognizes the need to minimize its growing deferral balance, no DSM programs for CG&E's Ohio commercial and industrial customers were considered for inclusion in the 1997 IRP. Furthermore, the residential programs approved by the CCEP for continuation and those currently being reviewed are not considered resource programs, and therefore require no screening. Similarly, the Kentucky Collaborative has not recommended any resource programs for ULH&P, and none were screened for cost-effectiveness.

The following section briefly describes the assumptions used in screening PSI's DSM programs.

Since the PSI DSM programs are only expected to be approved for one year, no escalators were applied. The discount rate of 7.62% used in all tests represents an estimate of Cinergy's after-tax discount rate (weighted average cost of capital). Initial screenings were based on the forecasted load for Cinergy's franchised service territory and market-based marginal energy costs. Annual distribution and transmission loss estimates by sector were determined using historical data. The marginal energy values, due to their voluminous nature, are not included. Documents providing the expected cost and performance data for each demand-side option are voluminous and will be provided upon request.

The programs modeled for PSI in this IRP were developed by the parties to the Settlement Agreement described in Section A of this chapter. The program descriptions and estimated impacts and costs may be found in the Short-Term Implementation Plan.

D. DESCRIPTION OF MODELS

Cinergy System

DSManager is a proprietary software package used for screening demand-side management programs. The model was developed by Electric Power Research Institute (EPRI) and is supported through EPRI by Electric Power Software (EPS).

DSManager is a software model that takes the net present values of streams of financial costs associated with DSM and balances these costs against the net present values of annual static "avoided cost" electric system benefits (calculated from changes in the end-use load shapes for the demand-side program technology). The resultant benefit/cost ratios, or tests, provide a summary of the program impacts.

DSManager uses a static marginal analysis approach that is based on the current load forecast, capacity over time, available fuel costs, and other currently available utility specific information that are input into the model. The model then uses this information to calculate the projected benefits and costs of a particular demand-side program.

E. SCREENING PROCESS DESCRIPTION, SUCCESS CRITERIA

Cinergy System

Process Description

The DSManager model described in Section D was used to screen DSM options being considered for inclusion in the IRP. Resource options that passed this screening then became candidates for selection as future cost-effective resource options in the PROVIEW™ integration process (described in Chapter 8).

Success Criteria

The primary criteria used for screening DSM programs for PSI was the Utility Cost (UC). The programs considered for inclusion in the IRP had utility cost test ratios above one.

DSM Cost Recovery Issues

CG&E - Ohio

The PUCO's December 19, 1996, order provides for $2.4 million, one-half of the $4.8 million currently collected in rates for DSM, to be used to reduce CG&E's deferral balance. It should be noted that the deferral balance will still grow since the annual deferrals associated with lost revenues caused by CG&E's historical DSM programs and carrying costs on the deferral amount are greater than $2.4 million.

ULH&P - Kentucky

On December 1, 1995, the KyPSC approved a Joint Application by ULH&P and representatives of its major customer groups, which granted concurrent cost recovery of Cinergy's program related costs, lost revenues, and shared savings incentives in Kentucky.

PSI - Indiana

The Settlement Agreement approved by the IURC on December 18, 1996, provides for concurrent recovery of the costs of Cinergy's on-going DSM activities in Indiana. The Agreement also provides for recovery (over the period 1997-2000) of the outstanding deferral amounts resulting from PSI's past DSM activities. This agreement will terminate at the end of 1999, and a new agreement for the year 2000 is currently being negotiated.

F. RESULTS OF DSM PROGRAM SCREENING

CG&E - Ohio

As previously discussed, no new resource programs were considered for inclusion in this IRP for CG&E's Ohio service territory. However, the CCEP Board has approved the continuation of several non-resource, education programs.

ULH&P - Kentucky

As previously discussed, no new resource programs were considered for inclusion in this IRP for ULH&P's service territory. However, the Kentucky Collaborative has approved the continuation of several non-resource, education programs. The agreement that approved cost recovery for DSM programs expires at the end of 1999. Continuation of the programs is currently under consideration by the Collaborative. A stipulated agreement will be filed with the KyPSC in October 1999.

PSI - Indiana

The results of the screening and the assumptions underlying the screening are voluminous and will be made available for viewing at Cinergy offices and at other locations during normal business hours. Please contact Van Needham at (513) 287-2609 for more information.

G. BUNDLING OF PROGRAMS INTO IRP OPTIONS

PSI

Final selection of the PSI DSM programs followed an iterative approach that was designed to closely approximate a dynamic solution to resource selection. The large number of potential resource options (i.e., DSM programs, supply-side options, and compliance options) produce more possible solution combinations than can be reasonably solved by the computer systems available to Cinergy. Therefore, the DSM programs were condensed into a "bundle" to allow the PROVIEW™ optimization model to function. The program bundle submitted for optimization was selected for inclusion in the final plan.

5. SUPPLY-SIDE RESOURCES

A. INTRODUCTION

The phrase "supply-side resources" encompasses a wide variety of options. These can include existing generating units on a utility's system, repowering or refurbishing options for these units, existing or potential purchases from other utilities, IPPs and cogenerators, and new utility-built generating units (conventional, advanced technologies, and renewables). The evaluation of these options considers technical feasibility, fuel availability and price, length of the contract or life of the resource, construction or implementation lead time, capital cost, O&M cost, reliability, and environmental effects. This chapter will discuss in detail the specific options considered, the screening processes utilized, and the results of the screening processes.

B. EXISTING UNITS

1. Description

Figure 5-1 contains information concerning Cinergy's existing generating units. This Figure shows the station name and location, system (CG&E or PSI), unit number, type of unit, installation date, tentative retirement year, net dependable summer and winter capability (Cinergy share), and current environmental protection measures. For those units which are jointly owned with other utilities, Figure 5-2 shows the total capability of the unit and the share owned by each company. Actual capability changes during the past five years (1994-1998) are shown in Figure 5-3. Figure 5-4 gives a summary of actual loads and required generating capability for 1994-1998. The approximate fuel storage capacity at each generating station is shown in Figure 5-5.

PSI has a total installed net summer generation capability of 5,882 Megawatts (MW) (excluding the ownership interests of Indiana Municipal Power Agency (IMPA)(156 MW) and Wabash Valley Power Association, Inc. (WVPA)(156 MW) in Gibson Generating Station Unit No. 5). This capacity consists of 5,535 MW of coal-fired, synthetic gas-fired (syngas-fired), or oil-fired steam capacity, 45 MW of hydroelectric capacity and 302 MW of peaking capacity. The steam capacity is comprised of twenty coal-fired units, one syngas-fired combined cycle unit, and one oil-fired unit located at six stations. The hydroelectric generation is a run-of-river facility comprised of three units. The peaking capacity consists of seven oil-fired diesels located at two stations, eight oil-fired Combustion Turbine (CT) units located at two stations, and one natural gas-fired CT with oil back-up.

CG&E has a total installed net summer generation capability of 5,082 MW, which includes 4,184 MW of coal-fired steam capacity and 898 MW of Combustion Turbine (CT) peaking capacity. The coal-fired capacity is comprised of eighteen units located at seven stations. Eight of the CTs are oil-fired and ten are natural gas-fired. This includes the six newest, located at the Woodsdale Generating Station, which are natural gas-fired with propane as a back-up fuel. Seven of the coal-fired steam units supplying capacity and energy to CG&E are jointly owned with Columbus Southern Power Company (CSP) and The Dayton Power and Light Company (DP&L). Four of the coal-fired steam units supplying capacity and energy to CG&E are jointly owned with DP&L.

The largest units on the Cinergy system are the five Gibson units at about 620-630 MW each, Zimmer Unit 1 at about 605 MW (Cinergy share), and the two Cayuga units at about 500 MW each. The smallest coal-fired units on the system are 45 MW units at Edwardsport and Noblesville. The large range in sizes of the coal-fired units on Cinergy's system is mainly due to the vintage of the units.

The peaking units on the Cinergy system range in size from 2-3 MW oil-fired internal combustion units at Wabash River and Cayuga to the 106 MW Cayuga Unit 4 CT. The newest peaking units on the system are the Woodsdale 1-6 gas-fired CTs (83 MW each) and the gas-fired Cayuga 4 CT.

In preparation for Summer 1999, Cinergy added inlet cooling to Cayuga 4 CT, Woodsdale 1-6 CTs, Beckjord 1-4 CTs, and Wabash River Repowering CT. Since combustion turbines inherently lose power as ambient air temperatures increase, cooling the inlet air to the turbine helps to recover that power. The inlet cooling fog project accomplishes cooler inlet air by injecting a water fog, or small water droplets, into the inlet air duct. When these small water droplets enter the duct they evaporate and thus reduce the inlet air temperature. Dictated by both ambient temperature and humidity, cooling is best during hot dry days. If operated below a certain ambient temperature, the small water droplets can become ice which can damage the unit's compressor; therefore, this cooling technique is only used in the summer.

In Fall 1998, Cinergy reached an agreement to purchase the remainder of its 25-year contract with Dynegy Inc. for coal gasification services at the Wabash River Coal Gasification Repowering Project (WRCGRP). Pending regulatory approval, Cinergy plans to install flexible burner technology on this unit, which will enable the company to accept either synthetic gas or natural gas so that the plant could continue to operate as a syngas facility if economically feasible. The conversion to natural gas capability, which is expected to be completed prior to Summer 2000, is estimated to reduce the summer derate of the unit by 5 MW due to the installation of an evaporative boiler.

2. Availability

The unplanned outage rates of the units used for planning purposes were derived from the historical Generating Availability Data System (GADS) data on these units. Planned outages were based on maintenance requirement projections as discussed below. The data for the jointly-owned units operated by DP&L and CSP were provided by those companies. This IRP assumes that Cinergy's generating units generally will continue to operate at their present availability and efficiency (heat rate) levels.

3. **Maintenance Requirements**

A comprehensive maintenance program is important in providing reliable low cost service. The following tabulation outlines the general guidelines governing the preparation of a maintenance schedule for existing units operated by Cinergy (both fully and jointly owned). It is anticipated that future units will be governed by similar guidelines.

Scheduling Guidelines for Units Operated by Cinergy

1. Major maintenance on baseload units 400 MW and larger is to be performed at about six to ten year intervals (Beckjord 6, Cayuga 1-2, East Bend 2, Gibson 1-5, Miami Fort 7-8, and Zimmer 1).
2. Major maintenance on intermediate-duty units between 140-400 MW is to be performed at about six to ten year intervals (Beckjord 4-5,

Gallagher 1-4, Wabash River 1 and 6, and Miami Fort 6).

3. Due to the more limited run-time of steam peaking units, judgment and predictive maintenance will be used to determine the need for major maintenance (Beckjord 1-3, Edwardsport 6-8, Miami Fort 5, Noblesville 1-2, and Wabash River 2-5).

4. Major maintenance on CT peaking units is to be performed in accordance with manufacturers' recommendations, generally not to exceed 25,000 equivalent operation hours (Cayuga 4, Connersville 1-2, Dicks Creek 1 and 3-5, Miami Fort 3-6, Miami-Wabash 1-6, Beckjord 1-4, and Woodsdale 1-6).

The general maintenance requirements for all of the existing generating units were entered into the PROSCREEN II® model (described in Chapter 8) which was used to develop the IRP.

4. Fuel Supply

Coal

Electricity generated from burning or gasifying coal accounts for over 90% of Cinergy's total electric generation. The cost of coal is the most significant element in Cinergy's cost of electric production. The goal of Cinergy's Fuels Department is to provide a reliable supply of fuel in quantities sufficient to meet generating requirements, of the quality required to meet environmental regulations, at the lowest reasonable cost. The "cost" of the coal is the evaluated cost which includes the purchase price of the coal FOB the shipping point, transportation to the stations, sulfur content, and the effects of the coal quality on boiler operation and station operation.

Cinergy has set broad fuel procurement policies such as: contract/spot ratios, inventory levels, and aid in contract negotiations. Cinergy generally will seek the expertise of an independent consultant to review such policies. The policies are then combined with economic and market forecasts and probabilistic dispatch models to provide a five year strategy for fuel purchasing. The strategy provides a guide to meet the goal of having a reliable supply of low cost fuel.

To provide fuel supply reliability, Cinergy purchases coal from a widely dispersed supply area, uses a mix of term contract and spot market purchases, and purchases from a variety of proven suppliers. Cinergy also maintains stockpiles of coal at each Station to guard against short-term supply disruptions.

Coal supplied to Cinergy currently comes primarily from the states of Ohio, Indiana, Kentucky, Pennsylvania, West Virginia and Illinois. These states are rich in coal reserves with decades of remaining economically recoverable reserves. In addition, limited testing of coal from the Powder River Basin (PRB) has been conducted on Gibson Unit 3 and operational problems appear to be manageable if PRB is proven to be economically feasible.

Approximately 80% of the coal supplied to Cinergy is under term contracts. Contract commitments offer Cinergy greater reliability than spot market purchases. The financial stability, managerial integrity, and overall reliability of the suppliers is evaluated prior to entering into a contractual commitment. Dedicated, proven reserves assure coal of the specified quantity and quality. Specified pricing, delivery schedules, and length of contract provide suppliers with the financial stability for capital investment and labor requirements and guard Cinergy against primarily upward price fluctuations in the market while allowing Cinergy to take advantage of price reductions in the market. This is accomplished using a combination of low fixed escalation, buyers sole option market re-openers, and contract extension options.

PSI has five large long-term coal supply agreements. Currently, all of PSI's coal-fired generating stations, except Noblesville and Edwardsport, receive coal under long-term coal supply agreements. Individual coal supply agreements may provide for delivery of coal to several PSI generating stations. Because the Noblesville and Edwardsport Generating Stations are older stations used essentially for peaking purposes, coal is not customarily delivered under long-term coal supply agreements. The coal requirements for Noblesville and Edwardsport Generating Stations are supplied by diverting contract tonnages from other stations or from short-term purchases. Wabash River and Cayuga Generating

Stations customarily receive approximately 60% and 85%, respectively, of their annual coal requirements under long-term coal supply agreements. Gibson Generating Station customarily receives approximately 80% of its annual coal supply requirements under long-term agreements. Gallagher Generating Station customarily receives approximately 50% of its annual coal supply requirement under flexible long-term coal supply agreements diverted from other Cinergy generating stations.

All of CG&E's coal-fired power plants receive contract coal. CG&E has roughly two-thirds of its burn requirement under contract. The Public Utilities Commission of Ohio (PUCO), which annually requires both a financial audit and a management performance audit of CG&E's fuel procurement policies and practices, has approved the contract-to-spot guidelines currently employed by CG&E.

Cinergy fills out the remainder of its fuel needs with spot coal purchases. Spot coal purchases are used to 1) take advantage of low priced incremental tonnage, 2) test new coal supplies, and 3) supplement coal during peak periods or during contract delivery disruptions.

Cinergy also maintains coal stockpiles at the Stations in order to assure fuel supply reliability. In general, disruptions that could affect the coal supply are evaluated along with their potential duration, and the probability that they will occur. Sufficient coal is then kept on hand to meet those potential supply disruptions.

Natural Gas

Cinergy's use of natural gas for electric generating purposes is limited to peaking applications. This natural gas is currently purchased on the spot market and is transported (delivered) using interruptible transportation tariffs. The high hourly demand combined with the low capacity factor associated with this type of application make contracting for firm gas and transportation prohibitively expensive. This being the case, backup fuels are utilized at the newer gas-fired peaking facilities. At Woodsdale, propane is the back-up fuel and at Cayuga Unit 4, oil is the back-up fuel.

The availability of natural gas for peaking and emergency service is not expected to be a problem in the long-term. However, the transportation, or deliverability, of the gas from the producer areas, in the South and Southwest, to the Midwest and Northeast markets may become more problematic as the capacities of the transmission pipelines are reached, either during winter peak demand, or summer maintenance and storage recharge periods. Short-term availability and/or transportation problems during the periods described above are also expected to be encountered from time to time.

Propane

The long-term availability of propane is very favorable. The phase-out of lead in gasoline along with the sustained demand for gasoline will mean that refinery output of propane will continue to grow. Currently, Cinergy's use of propane for electric generation is limited to use as a back-up and emergency start-up fuel for one of Cinergy's natural gas-fired peaking plants (Woodsdale).

Oil

Cinergy uses fuel oil for starting coal-fired boilers and for flame stabilization during low load periods. Some Combustion Turbine peaking facilities are also oil-fired or use oil as a back-up fuel. In addition, one steam unit is oil-fired. Oil supplies are expected to be sufficient to meet needs for the foreseeable future.

Synthetic/Alternate Fuels

Cinergy will continue to explore fuels that can compete with coal for the lowest cost production of electricity. Technologies being considered are Refuse Derived Fuel (RDF), tire chips, and advanced coal slurry. Historically, both CG&E and PSI have supported EPRI and various other research organizations in developing new economically competitive, environmentally conscious sources of energy.

Cinergy's Fuels Department monitors potential changes in the fuel industry including mining methodologies, and the availability of different fuels. To the extent that any of these potential changes has an influence on the IRP, they have been incorporated.

The focus of Cinergy's fuel-related R&D efforts is to develop leading-edge technologies and provide information, assessments, and decision-making tools to support fossil power plants in reducing their costs for coal utilization and managing environmental risk.

5. Fuel Prices

The coal and oil prices for both existing and new units utilized in this IRP were developed using a combination of consultants and in-house expertise and judgment. Cinergy personnel who are knowledgeable in the gas trading business forecast the gas prices. Cinergy's projected fuel prices are considered by Cinergy to be trade secrets and proprietary competitive information.

6. Condition Assessment

In the past, both PSI and CG&E have had engineering condition assessment programs. Cinergy continues these types of programs, and with them intends to maintain its generating units, where economically feasible, at their current level of efficiency and reliability. In fact, many of the steps necessary to preserve the existing performance have been taken already.

The retirement of generating units depends on a number of factors including environmental regulations, unit operating performance, and the economics of continued operation. The Wabash River Coal Gasification Repowering Project represents an extension in the previous tentative retirement date (2007) of the Wabash River Unit 1 steam turbine. Other units could be candidates for future repowering projects.

7. Efficiency

Cinergy evaluates individual potential repairs or replacement of components on the existing generating units for their cost-effectiveness. If the potential changes prove to be cost-justified, they are budgeted and generally undertaken during a future scheduled unit maintenance outage. However, due to modeling limitations, the large number and wide ranging impacts of these individual options made it impossible to include these numerous smaller-scale options within the context of the IRP integration process. The routine economic evaluation of these smaller-scale options generally is consistent with that utilized in the overall IRP process. As a result, the outcome and validity of this plan have not been affected by this approach.

Also, Cinergy generally pursues opportunistic power sales which enhance the efficient utilization of the generating facilities.

8. **Environmental Regulations**

The technology available to meet environmental regulations has added constraints to the power plant fuel cycle and also expends energy to operate. The net result is a reduction in the "energy and capacity for load" capability and a lower overall efficiency. The loss in capability must be replaced by newly acquired resources, by off-system purchased power, or by the increased operation of less efficient units. On either a system or regional basis, lost capacity ultimately translates into a cost (to replace the reduction in capacity) for new resource acquisitions.

Likewise, one potential effect of meeting environmental regulations can be to degrade the reliability (i.e., the "availability") of each generating unit by increasing the complexity of the overall system. This could translate into a "cost to replace the unavailable capacity" in terms of new resource acquisitions.

The technology to meet environmental regulations for fossil-fueled generation generally includes flue gas scrubbers, flue gas conditioning, precipitators for particulate removal, selective noncatalytic reduction (SNCR) technology, selective catalytic reduction (SCR) technology, and low NO_x burners for NO_x control, and cooling towers.

East Bend Unit 2, Gibson Unit 5 and Zimmer Unit 1 were constructed originally incorporating flue gas scrubbing systems. East Bend Unit 2 has been in commercial operation since early 1981. Gibson Unit 5 has been in commercial operation since late 1982. The W.H. Zimmer Station Unit 1 has been in commercial operation since early 1991. Gibson Unit 4, which originally entered commercial service in 1979, was retrofitted with a flue gas scrubbing system during 1994.

The above mentioned flue gas scrubbers reduce the net output capacity. At East Bend and Gibson the reduction in output is about 1.0-1.5% and at Zimmer the reduction is about 2%.

The environmental standards limiting the stack discharge of particulates have necessitated retrofitting precipitators on several existing generating units. The upgraded precipitators require more "energy to function" amounting to about 0.75% to 1.00% of generating unit output. Data on the effect of these precipitators on the efficiency of the fuel cycle is not available.

In the future, new sources may have to meet more stringent standards for the reduction of particulates, which might require an alternate technology (e.g., baghouse filters) that could result in higher investment and operating costs for particulate removal.

The first six Woodsdale Combustion Turbine units and the Cayuga 4 Combustion Turbine required water injection to control NO_x emissions. Additional capital expenditures were required for water treatment, injection systems, and controls. The addition of these systems will also reduce unit efficiency and reliability. The specific magnitude of these reductions is currently not known; only future operating experience can provide accurate data. Any future combustion turbine units planned at Cayuga, Woodsdale, or other sites will require similar water injection systems or special low NO_x combustors or selective catalytic reduction technology. Changes to Cinergy's existing coal-fired units as a result of new NO_x regulations are discussed in Chapter 6.

Cinergy has either natural draft or forced draft cooling towers installed for condenser waste heat rejection on eleven generating units in which it has ownership interests. The Gibson station has a large dedicated cooling lake.

The capital cost required for the construction of thermal pollution control equipment in modern steam-cycle power plants has increased over the conventional methods for generating plants sited on major inland waterways (e.g., once-through cooling). The cooling systems cause an overall reduction in the efficiency of the energy cycle of about 2% in the summer season and 1% in the winter season. For a system which has its greatest generation capacity requirement in the summer, the 2% reduction in available output at peak load must be replaced by additional capacity, and the efficiency reduction must be replaced by the purchase and burning of additional fuel.

Compliance with the Clean Air Act Amendments of 1990 (described in more detail in Chapter 6) has increased, and will continue to increase, the cost of producing electricity. The various options available to achieve compliance along with the specific assumptions utilized (including SO_2 Emission Allowance prices) are also discussed in Chapter 6.

Cinergy supports R&D efforts concerning products that cover air toxics measurement and control, NO_x, SO_2 and particulate control, heat rate improvement analysis, waste and effluent management, pollutant prevention, and by-product use.

C. EXISTING NON-UTILITY GENERATION

At the time that the analysis for this IRP was performed, there were two contracts with small, alternative fueled, non-utility generators within the PSI service territory. Currently, only about 4 MW of this capacity is operational.

Some of PSI's and CG&E's customers have electric production facilities for self-generation, peak shaving, or emergency back-up. Non-emergency self-generation facilities are normally of the baseload type and are generally sized for reasons other than electric demand (e.g., steam or other thermal demands of industrial processes or heating). Peak shaving equipment is typically oil- or gas-fired and is generally used only to reduce the customer's peak billing demand. Depending on whether it is operated at peak, this capacity can reduce the load otherwise required to be served by Cinergy which, like DSM programs, also reduces the need for new capacity. The relationship of these facilities to the load forecast was discussed in Chapter 3. In compliance with the codes of conduct in FERC Order 889, any effects of these facilities on transmission and distribution planning are discussed in the Transmission Volume of this report, which was prepared independently.

D. EXISTING POOLING AND BULK POWER AGREEMENTS

At present, Cinergy does not participate in any formal type of power pooling other than the common economic dispatch of the CG&E and PSI generating units. CG&E has participated with The Dayton Power and Light Company (DP&L) and Columbus Southern Power Company (CSP) in the joint construction and ownership of eleven generating units located at seven stations during the past 31 years. PSI co-owns Gibson Unit 5 with Wabash Valley Power Association, Inc. (WVPA) and Indiana Municipal Power Agency (IMPA), and provides Reserve Capacity and Back-up Energy for this unit.

Cinergy is interconnected directly with East Kentucky Power Cooperative, Inc., Louisville Gas & Electric Company, Indiana Michigan Power Company, Ohio Power Company, The Dayton Power and Light Company, Columbus Southern Power Company, Ohio Valley Electric Corporation, Central Illinois Public Service, Hoosier Energy, Indianapolis Power and Light, Kentucky Utilities, Northern Indiana Public Service, and Southern Indiana Gas and Electric, and indirectly with the Tennessee Valley Authority.

As a matter of routine operation, Cinergy contacts neighboring utilities, utilities beyond them, power marketers, and power brokers on a daily basis in the interest of promoting opportunistic purchases and sales. Cinergy also routinely meets with utilities in the region generally to discuss the daily interconnection operations, opportunities for short-term energy transactions which may be beneficial to both parties, and the long term purchase/sale of capacity as an alternative to the construction/operation of additional generation facilities.

CG&E signed an agreement with East Kentucky Power Cooperative (EKPC), a winter peaking utility, for 150 MW of seasonal capacity exchange, also referred to as diversity power, in May 1987. Under the terms of the eight (8) year agreement which began April 1, 1988, and ended March 31, 1996, CG&E supplied EKPC with 150 MW of power in the months of December, January, and February and EKPC supplied CG&E with 150 MW of power in the months of June, July, and August. This agreement worked well for both parties and was extended for one year to March 31, 1997. Subsequently, a separate three year agreement for 50 MW of diversity power covering April 1, 1997, through March 31, 2000, was signed. Finally, in March

1997, a separate two year diversity power agreement covering April 1, 1997, through March 31, 1999, was signed. This most recent diversity power agreement covers the same summer and winter periods as the original agreements. These EKPC agreements are modeled at their contractual amounts.

PSI had a contract with WVPA to provide firm partial requirements service until January 1, 1998. As part of the Marble Hill settlement between WVPA and PSI, PSI has a contract to provide 70 MW of firm capacity and energy to WVPA for their use outside of the PSI control area for up to 35 years. PSI has a contract with IMPA to provide firm partial requirements service for the IMPA load in the PSI control area above IMPA's ownership in Gibson Unit 5 and their member-owned generation in the PSI control area through January 1, 2007. The IMPA contract will continue thereafter unless five years written notice by either party has been given. These obligations have been modeled as firm load in the IRP through the initial contract termination dates.

Cinergy Power Marketing & Trading has numerous single and multi-year contracts to buy and sell power. However, since these power transactions do not contractually obligate Cinergy to either build generation to serve them, or to be forced to take the power to supply jurisdictional customers, the capacity associated with these contracts has not been included in the expansion plan modeling. Further information on power contracts not associated with franchised service territory jurisdictional loads is considered to be trade secrets and proprietary competitive information.

Additional information, if any, concerning power purchase and sale contracts associated with jurisdictional franchised service territory customers may be found in Section G below, and/or in the Short-Term Implementation Plan contained in the back section of this Volume.

E. NON-UTILITY GENERATION AS FUTURE RESOURCE OPTIONS

It is Cinergy's practice to cooperate with potential cogenerators and independent power producers. A major concern, however, exists in situations where either customers would be subsidizing generation projects through higher than avoided cost buyback rates, or the safety or reliability of the electric system would be jeopardized. Both PSI and CG&E typically receive several requests a year for independent/small power production and cogeneration buyback rates. Currently, on the CG&E

system, prospective cogenerators proposing the sale of 100 kW or less are sent both a copy of the filed tariff for small power producers of 100 kW and under, and a copy of the standard interconnection agreement. The larger prospective cogenerators are provided with an explanation of the CG&E methodology for determining avoided cost which is market-based and, if requested, interconnection requirements. The CG&E avoided costs are determined on a case-by-case basis depending on MW size, contract length, and the projected reliability of the cogeneration unit. Currently, on the PSI system, prospective cogenerators are given the interconnection requirements and the current rates under Standard Contract Rider No. 50 - Parallel Operation for Qualifying Facility.

A customer's decision to self-generate or cogenerate is, of course, based on economics. Customers know their costs, profit goals, and competitive positions. The cost of electricity is just one of the many costs associated with the successful operation of their business. If customers believe they can lower their overall costs by self-generating, they will investigate this possibility on their own. There is no way that a utility can know all of the projected costs and/or savings associated with a customer's self-generation. However, during a customer's investigation into self-generation, the customer usually will contact the utility for an estimate of electricity buyback rates. With Cinergy's comparatively low electricity rates and avoided cost buyback rates, cogeneration and small power production are generally uneconomical for most customers.

For these reasons, neither PSI nor CG&E attempts to forecast specific megawatt levels of this activity in their service areas. However, as contracts are signed, the resulting energy and capacity supply will be reflected in future plans. The electric load forecasts discussed in Chapter 3 do consider the impacts on electricity consumption caused by the relative price differences between alternate fuels (such as oil and natural gas) and electricity. As the relative price gap favors alternate fuels, electricity is displaced lowering the forecasted use of electricity and increasing the use of the alternate fuels. Some of the decrease in forecasted electricity consumption may be due to self-generation/cogeneration projects, but the exact composition cannot be determined.

Cinergy has direct involvement in the cogeneration area. In December 1996, Cinergy and Trigen Energy Corporation formed a joint venture, Trigen-Cinergy Solutions, LLC. The joint venture company will build, own, and operate cogeneration and trigeneration facilities for industrial plants, office buildings, shopping centers, hospitals, universities, and other major energy users that can benefit from combined heating/cooling and power production economies.

Other supply-side options such as simple-cycle Combustion Turbines, Combined Cycle units, Fuel Cells, coal-fired units, and/or renewables (all discussed later in this chapter) could represent potential non-utility generating units, power purchases, or utility-constructed units. At the time that Cinergy initiates the acquisition of new capacity, a decision will be made as to the best source.

F. SUPPLY-SIDE RESOURCE SCREENING

A list of over one hundred supply-side resources was developed as potential alternatives for the IRP process. Due to the size and run time limitations of the PROVIEW™ integration model (described in detail in Chapter 8), it was necessary to determine, through a screening process, which of these resources were the most viable and cost-effective.

1. **Process Description**

<u>**Information Sources**</u>

Most of the specific technology parameters used in the screening process were based on information taken from The Technical Assessment Guide Supply-Side Technologies (TAG-Supply™), Version 3.08, dated August 1998, produced by the Electric Power Research Institute (EPRI) of Palo Alto, California. TAG-Supply™ is proprietary software that provides up-to-date information for use in the preliminary stages of supply-side planning analyses and studies. It contains conventional and advanced power generation technologies, including their current status and trends for future development, estimated cost and power performance data, economic factors, and environmental emissions data. In addition to the EPRI information, Sargent & Lundy supplied data on specific repowering options as part of the SO_2 compliance screening work undertaken in 1994 (see Cinergy 1995 IRP, Chapters 5 and 6). Due to the increase in demand for Combustion Turbines and Combined Cycle Units following the Summer of 1998, price estimates from vendors were also used to supplement the EPRI data.

Technical Screening

The first step in the screening process was a technical screening of the technologies to eliminate those that are not feasible in the service territories served by the Cinergy operating companies. The two general categories of resources that were eliminated were Geothermal, because there are no suitable geothermal sources in this area, and Nuclear, because of current regulatory/political/ environmental concerns. Further technical screening involved determining which technologies to consider within each of the two time periods: 1999-2008 (modeling period) and 2009-2019 period. Because TAG-Supply™ contains emerging technologies that are not yet commercially viable, only technologies whose Technical Development Rating was either Mature or Commercial were considered available to go in service between 1999 and 2008. All technologies (Mature, Commercial, Demonstration, or Pilot) were considered to be available beginning in 2009. The costs contained in TAG-Supply™ are intended to represent mature plant costs, so the estimated costs for Demonstration or Pilot technologies may differ substantially from those achieved at the time the technology is commercially available.

Economic Screening

The next step in the screening process was to economically screen the specific technologies within each general technology class against each other to determine the "Best in Class." Additional screening of these survivors across classes would occur later in the analysis. The ten general technology classes were:

- Pulverized Coal
- Fluidized Bed
- Integrated Coal Gasification Combined Cycle
- Combined Cycle
- Simple Cycle Combustion Turbines
- Fuel Cells
- Wind
- Solar
- Other Renewables
- Storage

The specific technologies within each class were adjusted using TAG-Supply™ to reflect representative capital, labor, and fuel costs for Cinergy's service territory. These adjusted technologies were then screened using relative dollar per kilowatt-year versus capacity factor screening curves. The initial screening within each general class used the TAG-Supply™ software to reduce the number of technologies to a manageable number. The final screening of specific survivors within a class, and across the general classes, used a spreadsheet-based screening curve model developed by Cinergy that is more thorough in its treatment of SO_2 allowance costs and can compare more technologies on the same graph.

Both screening curve analysis models calculate the fixed costs associated with owning and maintaining a technology type over its lifetime and compute a levelized fixed $/kW-year value. This value represents the cost of operating the technology at a zero capacity factor or not at all, i.e., the Y-intercept on the graph (see the General Appendix for individual graphs). Then the variable costs, such as fuel, variable O&M, and emission costs associated with operating the technology at 100% capacity factor, or at full load, over its lifetime are calculated and the present worth is computed back to the start year. This levelized operating $/kW-year is added to the levelized fixed $/kW-year value to arrive at a total owning and operating value at 100% utilization in $/kW-year. Then a straight line is drawn connecting the two points. This line represents the technology's "screening curve". This process is repeated for each supply technology to be screened resulting in a family of lines (curves). The lower envelope along the curves represents the least costly supply options for various capacity factors or unit utilizations.

Lines that never become part of the lower envelope, or those that become part of the lower envelope only at very high capacity factors (95%+), probably will not be part of the least cost solution, and therefore can be eliminated from further analysis.

2. Screening Results

Figures 5-6 through 5-16 show the technologies screened within each of the ten classes using TAG-Supply™ and identify which candidates within each class were the least cost, "Best in Class." As mentioned earlier, these survivors were passed to the next screening step involving across-class screening. The results of the screening within each class are discussed in more detail below.

Pulverized Coal

The pulverized coal units were divided into high sulfur and low sulfur coal groups. Figures GA-5-1 through GA-5-4 in the General Appendix show the resulting screening curves from TAG-Supply™. The least cost high sulfur and low sulfur units were then screened against each other using the Cinergy model as shown in Figures GA-5-5 and GA-5-6. The 500 MW high sulfur coal unit was the "Best in Class" for both modeling periods in the relevant capacity factor range.

Fluidized Bed

The fluidized bed units also were divided into high sulfur and low sulfur coal groups. Figures GA-5-7 through GA-5-8 show the resulting screening curves from TAG-Supply™ for the period 1999-2008, and Figures GA-5-9 through GA-5-13 show the results for the period after 2008. The Cinergy model was used to screen the least cost high sulfur and low sulfur units against each other for the two time frames as shown in Figures GA-5-14 and GA-5-15. The 200 MW PRB (low sulfur) unit was the "Best in Class" in the first ten years and the 688 MW Advanced Subcritical unit using high sulfur coal was the "Best in Class" for installation after 2008.

Integrated Coal Gasification Combined Cycle

There were no Mature or Commercial technologies in the 1999-2008 time period. Figure GA-5-16 shows the screening curve from TAG-Supply™ for the time period after 2008. The "Best in Class" technology was a 460 MW Advanced GCC unit.

Simple Cycle Combustion Turbines

The price spikes that occurred during Summer 1998 have caused increased demand for new Combustion Turbine units. As a result, CT manufacturers have increased their prices. At the time the screening was performed, the prices for CTs and Combined Cycle units in TAG-Supply™ had not been updated yet to reflect the price increases. In order to use more realistic prices for the first few years during which the higher prices are expected to persist, Cinergy surveyed a number of manufacturers concerning current prices. For the years 1999-2003, the assumption was made that a conventional 171.7 MW (ISO rating, 164.8 MW summer rating with inlet cooling) Frame 7F CT would be used at current prices. After that, the

TAG-Supply™ technologies and their prices were used under the assumption that prices would return to normal levels by about 2004. For the period 2004-2019, the CTs, which all had a Mature Technology Development Rating, were first screened in TAG-Supply™ within the classifications of Heavy Duty, Aeroderivative, and Steam Injected as shown in Figures GA-5-17 through GA-5-19. The best units from these classifications were then screened against each other as shown in Figure GA-5-20. The resulting "Best in Class" CT was a 230 MW (ISO rating, 214.2 MW summer rating with inlet cooling) Heavy Duty CT.

Combined Cycle

As with the Simple Cycle CTs, for the years 1999-2003, the assumption was made that a conventional 262.6 MW (ISO rating, 256 MW summer rating with inlet cooling) CC unit using a Frame 7F CT would be used at current prices. After that, the TAG-Supply™ technologies and their prices were used under the assumption that prices would return to normal levels by about 2004. For the period 2004-2019, the conventionally fueled Combined Cycle units, which all had a Mature Technology Development Rating, were first screened in TAG-Supply™ against each other and then the best unit was screened against the Cascaded Humidified Advanced Turbine as shown in Figures GA-5-21 and GA-5-22. The resulting "Best in Class" Combined Cycle unit was a 400 MW (ISO rating, 378.3 MW summer rating with inlet cooling) unit.

Fuel Cells

The 2 MW Phosphoric Acid Ambient Pressure Fuel Cell was the only viable alternative for the 1999-2008 time frame. For the period after 2008, the Phosphoric Acid and Molten Carbonate Fuel Cells were screened against each other (after adjusting their capital costs to be more representative of commercial status) and the Solid Oxide Fuel Cells were screened against each other in TAG-Supply™ as shown in Figures GA-5-23 and GA-5-24. The best of these classes were then screened against each other as shown in Figure GA-5-25. The resulting "Best in Class" unit was a 25 MW Pressurized Solid Oxide Pressurized Fuel Cell.

Alternative Technologies - Overview

The information obtained from a continuing review of available alternative energy technologies was considered in the preparation of the 1999 IRP. There is a very limited opportunity to apply renewable resource technologies in Central Indiana, Southwestern Ohio, and Northern Kentucky. With wind speeds averaging 5-6 MPH and relatively low solar power density, generation of significant amounts of electricity using wind or solar energy is not cost-effective relative to more conventional technologies. This is not to say that these technologies may not be feasible in supplying limited amounts of power in very remote locations or in other special applications. However, their use on a large utility scale is not practical in this region and no major breakthroughs on a utility scale are anticipated in the near future. Consequently, under current environmental assumptions, they continue to be not as cost competitive or as reliable in the Midwest as the more conventional power supply technologies.

Biogas, or landfill gas, generally has both high levels of contaminants and a low-heat content resulting in an overall quality far below that required for pipeline quality natural gas. It is possible to process the gas to pipeline quality standards but doing so increases the cost. This low grade gas may be collected, transported short distances and used in various manufacturing processes, but this activity is generally best suited to private enterprise ventures, not utility-scale projects. To Cinergy's knowledge, a few private companies currently collect landfill gas at three or four different landfills within Cinergy's franchised service territory.

At the present time, the use of tire-derived fuel is not a significant utility-scale energy source. Over time, as operational and environmental issues are resolved, tires or tire residue may become a competitive, but limited, fuel source.

Municipal solid waste (MSW) burning to produce energy is rarely economical from the energy production standpoint. The technology to burn this waste cleanly and reliably is very expensive. Generally, when communities resort to MSW burning it is to dispose of the waste more economically than alternative methods, not to generate low-cost energy. In most instances, the energy sales help to offset some of the costs associated with burning the waste. Siting a MSW burning facility is also a challenge. Concerns abound about truck traffic, odors, vectors, and air toxins. The Public Utility Regulatory

Policies Act of 1978 (PURPA) obligates Cinergy to purchase power and energy from a MSW facility within its franchised service territories. However, Cinergy will defend electric customers against subsidizing the disposal costs of municipal solid wastes.

Biomass energy production facilities are generally limited by the availability of fuel within about a 50-mile radius. This is a result of the bulk material handling problems due to the low heat content of current biomass fuels. This limitation negatively impacts both the size and economics of biomass energy facilities. Development of specialized energy crops and further technology developments will be necessary to permit expansion of biomass-generated energy.

Storage technologies such as Pumped Hydro and Compressed Air Energy Storage (CAES) generally have limited application due to the need for suitable geologic formations. Other storage technologies such as Batteries and Superconducting Magnetic Energy Storage (SMES) are applicable to more areas, but the storage time (one to five hours) is a limiting factor. Presently, batteries perform best in systems that require relatively short bursts of energy on an infrequent basis. Demonstration plants such as the 10 MW CHINO Battery Plant at Southern California Edison have been difficult to maintain and have proven to be more suitable for power delivery system stabilization than as a capacity resource. Other demonstration projects, such as EPRI's Transportable Battery System, should further quantify the benefits and appropriate applications of battery storage systems. However, at this point in time, large utility scale battery storage systems are not commercially viable.

The focus of Cinergy's R&D efforts with regard to Alternative Technologies is to provide planning and evaluation methods to assure a strategic advantage in the deployment of emerging technologies and the use of storage to manage energy supply. Despite the fact that Alternative Technologies are generally not economic in comparison to more traditional technologies, they were included nevertheless as part of the screening process to allow an economic comparison between the different technologies and to allow sensitivity analysis around base assumptions to be performed. The specific Alternative Technologies included in the supply-side screening were:

Wind

There were no Mature or Commercial wind technologies in TAG-Supply™ available during the 1999-2008 time period. A 350 kW (0.35 MW) Wind Turbine located in the Midwest was selected for final screening for the 2009-2019 time frame.

Solar

The 80 MW and 200 MW Solar Thermal units were the only technologies that were either Mature or Commercial during the 1999-2008 modeling period. Figure GA-5-26 shows the results of the TAG-Supply™ screening, with the 200 MW unit being the "Best in Class." During the 2009-2019 period, the solar units were divided into the two groupings of Flat Plat, and High Concentration and Solar Thermal. The TAG-Supply™ screening curves are shown in Figures GA-5-27 through GA-5-29. The "Best in Class" technology was the 200 MW Solar Thermal unit.

Other Renewable Resources

For both time periods, the technologies were divided into the groupings of Municipal Solid Waste and Biomass-Fueled units. The TAG-Supply™ screening curves for 1999-2008 are shown in Figures GA-5-30 through GA-5-32. The 50 MW Wood-fired Stoker was the "Best in Class." The TAG-Supply™ screening curves for 2009-2019 are shown in Figures GA-5-33 through GA-5-35. The 100 MW Whole Tree Burner was the "Best in Class" during this time frame.

Storage

The categories of Batteries, Pumped Hydro, Compressed Air, and Superconducting Magnetic Storage were used. The TAG-Supply™ screening results for Batteries for 1999-2008 are shown in Figure GA-5-36. The 20 MW Light Duty Lead Battery and the 350 MW Pumped Hydro unit were the most economical. The TAG-Supply™ screening curves for 2009-2019 are shown in Figures GA-5-37 through GA-5-39. The 20 MW Light Duty Lead Battery, 350 MW Pumped Hydro unit, the 350 MW Compressed Air Storage unit with Humid Air Turbine using Porous media, and the 500 MW SMES unit were the most economical. Cinergy's screening model screened these technologies against each other for each time period as shown in Figures GA-5-40 and GA-5-41. The 20 MW Battery for both 1999-2008 and 2009-2019 and the 350 MW Compressed Air technologies for 2009-2019 were the "Best in Class" over their respective capacity factor ranges.

3. Other Technologies Considered

Other Hydro Resources

Hydro resources tend to be site-specific; therefore, Cinergy normally evaluates both pumped storage capacity and run-of-river energy resources on a project-specific basis (see Chapter 5 Section G for more information).

Repowering Resources

Cinergy's 1995 IRP filing contained an extensive screening of repowering options at Cinergy's generating stations (see Cinergy 1995 IRP, Chapters 5 and 6). The Engineering and Construction Department reviewed the previous costs and determined that they were still representative; therefore, no new screening was performed. In addition, since the cost estimates for Combined Cycle repowering at Edwardsport and Noblesville were similar to the costs of new Combined Cycle plants, the characteristics of the new plants acted as proxies for repowering in the planning analysis. If this technology is consistently selected as an economic alternative in the final integration process, repowering existing sites will be thoroughly investigated prior to initiating construction at a new site.

4. Final Supply-Side Alternatives

The "Best in Class" technologies that survived the above screening process within each of the previous technological categories are listed in Figure 5-17. These technologies were then screened against each other, or across all classes, using Cinergy's model to develop the final supply-side alternatives to be carried into the integration model.

The resultant final screening curve for 1999-2008, Figure GA-5-42, shows that the two sets of Combustion Turbines and Combined Cycle units make up the lower envelope of the final curve. The curve for the 2009-2019 period, Figure GA-5-43, shows that the Combustion Turbine, the Combined Cycle, and Solid

Oxide Fuel Cell units make up the lower envelope of the final curve over their respective capacity factor ranges.

As a result of the screening process, the following supply technologies were selected to be utilized as candidate supply-side resources in the PROVIEW™ dynamic integration computer runs: 1) 171.7 MW Frame 7F CT units with inlet cooling for the 1999-2003 time period, 2) 230 MW generic new site CT units with inlet cooling for the 2004-2019 time period, 3) 262.6 MW Frame 7F Combined Cycle units with inlet cooling for the 1999-2003 time period, 4) 400 MW generic Combined Cycle units with inlet cooling for the 2004-2019 time period, and 5) 25 MW Fuel Cells for the 2009-2019 period. The summer ratings for these units are 164.8 MW, 214.2 MW, 256 MW, 378.3 MW, and 25 MW, respectively. More detailed information on the final supply side technologies screened can be found in Figures GA-5-44 and GA-5-45. Since the SO_2 emissions of each of these potential resources will be modeled in the integration process, their effects on compliance with the Clean Air Act Amendments of 1990 were factored into the analysis.

5. Screening Sensitivities

The screening model also can provide useful information concerning how much certain input parameters would need to change to make a technology that is not in the lower envelope under base assumptions become economical. Sensitivities were performed on each "Best in Class" final technology type in the 1999-2008 modeling period to determine what data input and/or assumption changes would be necessary to move it into the lower envelope (i.e., become an economic choice) within the relevant capacity factor range. Sensitivities were not performed for the 2009-2019 time frame because little additional information relevant to Cinergy's immediate resource decisions would be gained.

This methodology using the screening model (rather than performing all sensitivities at the end of the analysis) is more efficient and gives Cinergy a better understanding of the magnitude of changes in fuel prices, Emission Allowance prices, capital costs, etc., that will affect its resource decisions. In addition, it allows the most economical technologies from each individual class to be included in the sensitivity analysis.

Pulverized Coal

The parameters that should have the greatest impact on coal unit economics are relative fuel prices (coal prices versus gas prices), capital cost, and emission allowance prices. A sensitivity study showed either a reduction in coal prices to $0/MMBtu or an increase of 60% in gas prices is necessary before the coal unit would become competitive at about a 65%-75% capacity factor (see Figures GA-5-46 and GA-5-47). Figure GA-5-48 shows that the estimated capital cost of the coal unit would have to decrease by 50% to make the unit economical. The unit is insensitive to emission allowance price changes in that it did not become economical even when reducing allowance prices to $0/ton (see Figure GA-5-49).

Fluidized Bed

The same parameters that affect pulverized coal units should also affect fluidized bed units. However, even at coal prices of $0/MMBtu, the fluidized bed unit is not competitive (see Figure GA-5-46). Higher gas prices do not affect it either, because the pulverized coal unit is always comparatively less expensive in this sensitivity (see Figure GA-5-50). Figure GA-5-51 shows that the estimated capital cost of the fluidized bed unit would have to decrease by 70% to make it economical. As with the pulverized coal unit, the fluidized bed unit is insensitive to changes in allowance prices (see Figure GA-5-49).

Fuel Cell

The parameters that should have the greatest impact on Fuel Cell economics are relative fuel prices (coal prices versus gas prices), and capital cost. The Fuel Cell was insensitive to changes in gas prices because the CT and Combined Cycle units, which also use gas, were already more economical and continued to dominate it. Lowering the estimated capital cost alone is not sufficient to make the Fuel Cell economical because the Combined Cycle unit has a much better heat rate. The capital cost must be reduced by 90% and the heat rate must be reduced by 35% for the Fuel Cell to compete with the Combined Cycle unit (see Figure GA-5-52). These are precisely the types of improvements anticipated by TAG-Supply™ for Fuel Cells ten years in the future, which is why the Fuel Cell became economical in the 2009-2019 period.

Solar

For solar to be economical in a relevant capacity factor range, the estimated capital cost must be reduced by 95% to compete with Combined Cycle units, and, even then, the insolation is limited in the Midwest as discussed earlier (see Figure GA-5-53). Because of the high capital cost of solar units, gas and coal prices would have to be 20 times higher before the technology would be competitive (see Figure GA-5-54).

Wood-Fired Stoker

For the Wood-fired Stoker to become competitive with a Combined Cycle unit, a 78% decrease in the estimated capital cost, an 81% decrease in Fixed O&M, and a 53% decrease in heat rate would all be necessary at the same time (see Figure GA-5-55). Alternatively, a 60% decrease in the estimated capital cost, an 81% decrease in Fixed O&M, a 25% decrease in heat rate, and a doubling of gas prices would be necessary at the same time for the Wood-fired Stoker to be competitive (see Figure GA-5-56).

Battery

A 20% decrease in the estimated capital cost is necessary for the battery to be competitive with the CT (see Figure GA-5-57). However, the battery has other shortcomings such as being much more limited in its flexibility due to its one hour storage time in comparison with the allowable runtime of the CT. Reducing the cost of charging energy to $0 is not sufficient to make the battery competitive with the CT at extremely low capacity factors (see Figure GA-5-58).

6. Environmental Sensitivities

The "Best in Class" Technologies were screened also using more stringent environmental regulation assumptions to determine the resulting changes in their relative economics. To perform this analysis, the Cinergy screening curve model was modified to incorporate NO_x and CO_2 emissions from each unit as well as estimated emission allowance prices for these emissions. The costs of the emissions were then added to the other unit costs to develop the screening curves.

NO_x

An article in the May 18, 1999, issue of AirDaily contained an estimate of the OTC NOx allowance prices for the years 1999-2002. The allowance price assumed for the NO_x sensitivity was the 1999 price of

$5450/ton. Figure GA-5-59 shows the results of the screening for 1999-2008. As expected, renewable technologies became relatively more economical, especially in comparison to coal-burning technologies, but CTs and CCs remained the most economical overall. Figure GA-5-60 shows the results of the screening for 2009-2019, which utilized an allowance price of $7324/ton in 2009 dollars ($5450/ton escalated at 3% per year). Again, renewable technologies became more economical in comparison to coal-burning technologies, but CTs, CCs, and Fuel Cells remained the most economical choices. Wind was economical only at capacity factors exceeding its relevant capacity factor range.

<u>CO_2</u>

The allowance price assumed for the CO_2 sensitivity was $21/ton in 1999 dollars, which was derived from the U.S. Energy Information Administration (EIA) study "What Does the Kyoto Protocol Mean to U.S. Energy Markets and the U.S. Economy?". This is equivalent to $77.33/metric ton of carbon. Figure GA-5-61 shows the results of the screening for 1999-2008. As expected, renewable technologies became relatively more economical, especially in comparison to coal-burning technologies, but CTs and CCs continued to be the most economical overall. Figure GA-5-62 shows the results of the screening for 2009-2019, which utilized an allowance price of $28/ton in 2009 dollars ($21/ton escalated at 3% per year). Again, renewable technologies became more economical in comparison to coal-burning technologies, but CTs, CCs, and Fuel Cells were the most economical choices. Wind became economical only at capacity factors exceeding its relevant capacity factor range.

Combination NO_x and CO_2

Figure GA-5-63 shows the results of the screening for 1999-2008 for a combination of NO_x and CO_2 emissions. The allowance prices used were those described above. CTs and CCs still remained the most economical for this time period. Figure GA-5-64 shows the results of the screening for 2009-2019. As with the CO_2 only sensitivity, CTs, CCs and Fuel Cells were the most economical. Wind became economical only at capacity factors exceeding its relevant capacity factor range.

Summary of Screening Sensitivities

Since the most economical technologies did not change for the 1999-2008 period, no additional technologies were passed to the Integration stage of the IRP process. However, Cinergy will continue to monitor the renewable and storage technologies that looked more promising under the more stringent environmental assumptions for possible inclusion in future planning scenarios.

7. Unit Size

As described previously, various unit sizes were screened for the Combustion Turbine, the Combined Cycle plant, and the Fuel Cell. The unit sizes selected for planning purposes are the largest technologies available today and the largest listed in TAG-Supply™ because they generally offer lower $/kW installed capital costs.

8. Cost, Availability, and Performance Uncertainty

Supply-side alternative costs used for planning purposes for conventional technology types such as Simple Cycle Combustion Turbine units and Combined Cycle units are relatively well known and are estimated in the TAG-Supply™ and can be obtained from vendors. Cinergy's experience also confirms their reasonability. The TAG-Supply™ costs include step-up transformers and a simplified substation to connect with the transmission system. Since any additional transmission costs would be site-specific and since specific sites requiring additional transmission are unknown at this time, the screening process did not include other transmission costs. A listing of the projected generating facility costs from the screening curves can be found in Figures GA-5-44 and GA-5-45. The availability and performance of conventional supply-side options is also relatively well known and the EPRI TAG-Supply™ software contains estimates of these parameters.

9. Lead Time for Construction

The estimated construction lead time and the lead time used for modeling purposes for the proposed Simple Cycle Combustion Turbine units is about two years. For the Combined Cycle units, the estimated lead time is about three years. However, the time required to obtain regulatory approvals and environmental permits adds uncertainty to the process, so judgment is used also.

10. RD&D Efforts and Technology Advances

New energy and technology alternatives are needed to ensure a long-term sustainable electric future. Cinergy's research, development, and delivery (RD&D) activities enable Cinergy to track new options including modular and potentially dispersed generation systems, Combustion Turbines, and advanced fossil technologies as well as enhancements to existing fossil power facilities. Emphasis is placed on providing information, assessment tools, validated technology, demonstration/deployment support, and RD&D investment opportunities for planning and implementing projects utilizing new fossil power generation technology to assure a strategic advantage in electricity supply and delivery. Cinergy is also a member of EPRI.

Within the 20-year horizon of this forecast, it is expected that significant advances will continue to be made in Combustion Turbine technology. Advances in stationary industrial Combustion Turbine technology should result from ongoing research and development efforts to improve both commercial and military aircraft engine efficiency and power density.

Cinergy's RD&D activities also involve Fuel Cell technology. For example, by joining forces with the U.S. Government and Ballard Generation Systems, Cinergy is installing one of the world's first 250 kW class, natural gas-powered Fuel Cells. This unit is scheduled to be installed in 1999 at the Naval Surface Warfare Center located in Crane, Indiana. Cinergy is also licensing a 3 kW hydrogen Fuel Cell from Ballard to help develop military and civilian applications. In addition, Cinergy participates in the IEEE Fuel Cell Standards Committee to establish national standards for stationary deployment.

G. CINERGY 1999 RESOURCE BIDDING PROGRAM

1. Overview

On January 12, 1999, Cinergy issued a Request for Proposals (RFP) as part of its strategy for meeting future capacity and energy needs. The company sought proposals for firm summer peaking capacity and associated energy for all or any portion of a five-year period from 1999 to 2003. Proposals covering capacity and energy offered in other seasons or beyond the year 2003 would be considered also.

The RFP was open to all parties, including, but not limited to: independent power producers, exempt wholesale generators, qualifying facilities (under PURPA), power marketers, utilities, and utility holding companies and their subsidiaries. Offers could be based on new facilities, existing facilities, and utility system capacity , as well as demand side or renewable options.

Proposals were due by February 12, 1999. On March 19, 1999, the bidders were notified whether their proposals were to be considered for further negotiation (placed on the short list).

2. **Results**

Fifteen bidders submitted thirty-four proposals. Many of the proposals represented alternative pricing strategies for the same power, so they were mutually exclusive. Eleven of the bids were Summer 5X16 proposals, eight of the bids were Summer daily call/unit power proposals, six were calendar daily call/unit power proposals, eight were renewable proposals, and 1 was an interruptible DSM proposal. The amount of summer capacity offered ranged from 2750 MW to 3440 MW over the five-year period.

The bids were evaluated to determine their cost-effectiveness or value. Using New Energy Associates' PROSCREEN II® model, eight Bidders were chosen for the short-list. Of the eight chosen, three were Summer 5X16 proposals, two were Summer daily call/unit power proposals, two were renewable proposals, and one was an interruptible DSM proposal.

Because the proposals were submitted on February 12, most needed to be adjusted to match current market conditions by the time the short list was finished. In particular, the market price for Summer 5X16 futures had decreased dramatically since the proposals were received. Therefore, each of the bidders was given the opportunity to lower their pricing. This step resulted in substantial downward movement of the Summer 5X16 prices and very little change in the pricing of the other remaining proposals.

Of the eight short-listed proposals, only the Summer 5X16 alternatives were capable of delivering the necessary capacity by Summer 1999. However, at the time Cinergy purchased several hundred Megawatts of 5X16 July/August capacity, the price on the open market was lower than the prices of the updated 5X16 bids received. As a result, Cinergy did not contract with any of the RFP bidders for Summer 1999 and instead made purchases from other suppliers. A decision was made to not purchase any 5X16s beyond Summer 1999 due to the high price volatility associated with this product.

Once Cinergy's immediate needs (Summer 1999) were satisfied, attention was focused on signing contracts with the five remaining bidders. Unfortunately, once negotiations began with the two bidders proposing Summer daily call/unit power proposals, each of them requested substantial price increases. These price increases were large enough to make both proposals uneconomic. In addition, the downward price movement of the market made one of the renewable options un-economic.

At this point in time, Cinergy is still in contract negotiations with one of the renewable energy bidders to purchase approximately 100 MW of run-of-river hydro capacity under a long term contract. The interruptible DSM proposal is still undergoing evaluation.

The details of the bids, agreements and/or contracts are considered to be trade secrets and proprietary and confidential information by both Cinergy and the individual suppliers/bidders.

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FORM FE2-1: SUMMARY OF EXISTING ELECTRIC GENERATING FACILITIES

STATION NAME & LOCATION	SYSTEM*	FOOT NOTES	UNIT	TYPE OF UNIT*	INSTALLATION DATE MONTH & YEAR	TENTATIVE RETIREMENT YEAR	MAXIMUM GENERATING CAPABILITY (net kW) SUMMER	WINTER	ENVIRONMENTAL PROTECTION MEASURES*
W.C.Beckjord	CG&E		1	CF-S	6-1952	Unknown	94,000	94,000	EP & FGC
New Richmond,			2	CF-S	10-1953	Unknown	94,000	94,000	EP & FGC
Ohio			3	CF-S	11-1954	Unknown	128,000	128,000	EP & FGC
			4	CF-S	7-1958	Unknown	150,000	150,000	EP & FGC
			5	CF-S	12-1962	Unknown	238,000	238,000	EP & LNB/OFA
		A	6	CF-S	7-1969	Unknown	155,250	157,500	EP & LNB/OFA
			1-GT	OF-GT	4-1972	Unknown	51,225	61,200	None
			2-GT	OF-GT	4-1972	Unknown	51,225	61,200	None
			3-GT	OF-GT	6-1972	Unknown	51,225	61,200	None
			4-GT	OF-GT	6-1972	Unknown	51,225	61,200	None
						Station Total:	1,064,150	1,106,300	
Cayuga	PSI		1	CF-S	10-1970	Unknown	500,000	505,000	EP, LNB/OFA, FGC & CT
Cayuga, Indiana			2	CF-S	6-1972	Unknown	495,000	500,000	EP, LNB/OFA, FGC & CT
			3 A	OF-IC	6-1972	Unknown	3,000	3,000	None
			3 B	OF-IC	6-1972	Unknown	3,000	3,000	None
			3 C	OF-IC	6-1972	Unknown	2,000	3,000	None
			3 D	OF-IC	6-1972	Unknown	2,000	2,000	None
			4	GF/OF-GT	6-1993	Unknown	105,800	120,000	WI
						Station Total:	1,110,800	1,136,000	
Conesville Conesville, OH	CG&E	B	4	CF-S	6-1973	Unknown	312,000	312,000	EP & CT
Connersville	PSI		1	OF-GT	5-1972	Unknown	42,000	49,000	None
Connersville, Indiana			2	OF-GT	5-1972	Unknown	43,000	49,000	None
						Station Total:	85,000	98,000	
Dicks Creek	CG&E		1	GF/OF-GT	9-1965	Unknown	92,000	110,000	SC
Middletown,			3	GF/OF-GT	6-1969	Unknown	14,200	19,500	SC
Ohio			4	GF/OF-G	10-1969	Unknown	15,000	21,400	None
			5	GF/OF-G	10-1969	Unknown	15,000	21,400	None
						Station Total:	136,200	172,300	
East Bend Boone County Kentucky	CG&E	C	2	CF-S	3-1981	Unknown	414,000	414,000	EP, LNB, CT & SO2 Scrubber
Edwardsport	PSI	D	6	OF-S	7-1944	Unknown	40,000	40,000	EP
Edwardsport,		D	7	CF-S	1-1949	Unknown	45,000	45,000	EP
Indiana		D	8	CF-S	12-1951	Unknown	75,000	75,000	EP
		D				Station Total:	160,000	160,000	
Gallagher	PSI		1	CF-S	6-1959	Unknown	140,000	140,000	EP & LNB/OFA
New Albany, Indiana			2	CF-S	12-1958	Unknown	140,000	140,000	EP & LNB/OFA
			3	CF-S	4-1960	Unknown	140,000	140,000	EP & LNB/OFA
			4	CF-S	3-1961	Unknown	140,000	140,000	EP & LNB/OFA
						Station Total:	560,000	560,000	
Gibson	PSI		1	CF-S	5-1976	Unknown	630,000	635,000	EP, LNB/OFA & CL
Owensville, Indiana			2	CF-S	4-1975	Unknown	630,000	635,000	EP, LNB/OFA & CL
			3	CF-S	3-1978	Unknown	630,000	635,000	EP, LNB/OFA, FGC & CL
			4	CF-S	3-1979	Unknown	622,000	627,000	EP, LNB/OFA, FGC, CL & SO2 Scrubber
		E	5	CF-S	10-1982	Unknown	307,813	312,813	EP, LNB/OFA, CL & SO2 Scrubber
						Station Total:	2,819,813	2,844,813	
Killen	CG&E	F	2	CF-S	6-1982	Unknown	198,000	198,000	EP & CT

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FORM FE2-1: SUMMARY OF EXISTING ELECTRIC GENERATING FACILITIES

STATION NAME & LOCATION	SYSTEM*	FOOT NOTES	UNIT	TYPE OF UNIT*	INSTALLATION DATE MONTH & YEAR	TENTATIVE RETIREMENT YEAR	MAXIMUM GENERATING CAPABILITY (net kW) SUMMER	WINTER	ENVIRONMENTAL PROTECTION MEASURES*
Wrightsville, OH									
Markland	PSI		1	HY	4-1967	Unknown	15,000	15,000	None
Florence, Indiana			2	HY	1-1967	Unknown	15,000	15,000	None
			3	HY	2-1967	Unknown	15,000	15,000	None
						Station Total:	45,000	45,000	
Miami Fort	CG&E		5	CF-S	12-1949	Unknown	80,000	80,000	EP
North Bend,			6	CF-S	11-1960	Unknown	163,000	163,000	EP & SNCR
Ohio			3-GT	OF-GT	7-1971	Unknown	14,200	19,500	None
			4-GT	OF-GT	8-1971	Unknown	14,200	19,500	None
			5-GT	OF-GT	9-1971	Unknown	14,200	19,500	None
			6-GT	OF-GT	10-1971	Unknown	14,200	19,500	None
		G	7	CF-S	5-1975	Unknown	320,000	320,000	EP, LNB, FGC & CT
		G	8	CF-S	2-1978	Unknown	320,000	320,000	EP, LNB & CT
						Station Total:	939,800	961,000	
Miami-Wabash	PSI		1	OF-GT	6-1968	Unknown	16,000	17,000	None
Wabash, Indiana			2	OF-GT	6-1968	Unknown	16,000	17,000	None
			3	OF-GT	6-1968	Unknown	15,000	17,000	None
			4	OF-GT	6-1968	Unknown	15,000	17,000	None
			5	OF-GT	8-1969	Unknown	15,000	18,000	None
			6	OF-GT	7-1969	Unknown	16,000	18,000	None
						Station Total:	93,000	104,000	
Noblesville	PSI		1	CF-S	12-1950	Unknown	45,000	45,000	EP & CT
Noblesville, Indiana			2	CF-S	9-1950	Unknown	45,000	45,000	EP & CT
						Station Total:	90,000	90,000	
J.M.Stuart	CG&E	H	1	CF-S	5-1971	Unknown	228,150	228,150	EP & FGC
Aberdeen,		H	2	CF-S	10-1970	Unknown	228,150	228,150	EP & FGC
Ohio		H	3	CF-S	5-1972	Unknown	228,150	228,150	EP & FGC
		H	4	CF-S	6-1974	Unknown	228,150	228,150	EP, FGC & CT
						Station Total:	912,600	912,600	
Wabash River	PSI		1	SF/OF-CC	11-1995	Unknown	242,300	262,000	SI
West Terre Haute,			2	CF-S	8-1953	Unknown	85,000	85,000	EP & LNB/OFA
Indiana			3	CF-S	9-1954	Unknown	85,000	85,000	EP & LNB/OFA
			4	CF-S	1-1955	Unknown	85,000	85,000	EP & LNB/OFA
			5	CF-S	5-1956	Unknown	95,000	95,000	EP & LNB/OFA
			6	CF-S	8-1968	Unknown	318,000	318,000	EP & LNB/OFA
			7A	OF-IC	5-1967	Unknown	3,000	3,000	None
			7B	OF-IC	5-1967	Unknown	3,000	3,000	None
			7C	OF-IC	5-1967	Unknown	2,000	2,000	None
						Station Total:	918,300	938,000	
Woodsdale	CG&E	I	1	GF/PF-GT	5-1993	Unknown	83,433	94,000	WI
Trenton,			2	GF/PF-GT	7-1992	Unknown	83,433	94,000	WI
Ohio			3	GF/PF-GT	5-1992	Unknown	83,433	94,000	WI
			4	GF/PF-GT	7-1992	Unknown	83,433	94,000	WI
			5	GF/PF-GT	5-1992	Unknown	83,433	94,000	WI
			6	GF/PF-GT	5-1992	Unknown	83,433	94,000	WI
						Station Total:	500,598	564,000	

Figure 5-1

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FORM FE2-1: SUMMARY OF EXISTING ELECTRIC GENERATING FACILITIES

STATION NAME & LOCATION	SYSTEM*	FOOT NOTES	UNIT	TYPE OF UNIT*	INSTALLATION DATE MONTH & YEAR	TENTATIVE RETIREMENT YEAR	MAXIMUM GENERATING CAPABILITY (net kW) SUMMER	WINTER	ENVIRONMENTAL PROTECTION MEASURES*
W.H.Zimmer Moscow, OH	CG&E	J	1	CF-S	3-1991	Unknown	604,500	604,500	EP, LNB, CT & SO2 Scrubber
					SYSTEM TOTAL:		10,963,761	11,220,513	

*LEGEND:

CF = Coal Fired
OF = Oil Fired
GF = Natural Gas Fired
PF = Propane Fired
SF = Syngas Fired

S = Steam
CC = Combined-Cycle Combustion Turbine
GT = Simple-Cycle Combustion Turbine
HY = Hydro
IC = Internal Combustion

EP = Electrostatic Precipitator
SC = Smokeless Combustor
CT = Cooling Tower(s)
CL = Cooling Lake
WI = Water Injection, NOx
SI = Steam Injection, NOx
LNB = Low Nox Burners
OFA = Overfire Air
SNCR = Selective Non-Catalytic Reduction
FGC = Flue Gas Conditioning

CG&E = The Cincinnati Gas & Electric Company   PSI = PSI Energy

FOOT NOTES:

(A) Unit 6 is commonly owned by The Cincinnati Gas & Electric Company (37.5% - Operator); The Dayton Power and Light Company (50%) and Columbus Southern Power Company (12.5%).
(B) Unit 4 is commonly owned by The Cincinnati Gas & Electric Company (40%); The Dayton Power and Light Company (16.5%) and Columbus Southern Power Company (43.5% - Operator).
(C) Unit 2 is commonly owned by The Cincinnati Gas & Electric Company (69% - Operator) and The Dayton Power and Light Company (31%). Earlier vintage LNB installed.
(D) Total Plant is limited to 160,000kW due to boiler capability. Unit 6 rating is reduced by 5MW to reflect this station steam supply limitation.
(E) Unit 5 is commonly owned by PSI Energy (50.05% - Operator); Wabash Valley Power Association (25%) and Indiana Municipal Power Agency (24.95%).
(F) Unit 2 is commonly owned by The Cincinnati Gas & Electric Company (33%) and The Dayton Power and Light Company (67% - Operator).
(G) Units 7 and 8 are commonly owned by The Cincinnati Gas & Electric Company (64% - Operator) and by The Dayton Power and Light Company (36%). Unit 8 has earlier vintage LNB installed.
(H) This station is commonly owned by The Cincinnati Gas & Electric Company (39%); The Dayton Power and Light Company (35% - Operator) and Columbus Southern Power Company (26%).
(I) In November 1996, CG&E entered into a sale-leaseback agreement associated with Woodsdale Unit 1.
(J) Unit 1 is commonly owned by The Cincinnati Gas & Electric Company (46.5% - Operator); The Dayton Power and Light Company (28.1%) and Columbus Southern Power Company (25.4%). Earlier vintage LNB installed.

Figure 5-2

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SUPPLEMENT TO FORM FE2-1

MAXIMUM NET DEMONSTRATED CAPABILITY OF JOINTLY OWNED GENERATING UNITS

Station Name and Location	Unit Number	Installation Date	Total MW Summer	Total MW Winter	CG&E Share Summer	CG&E Share Winter	CSP Share Summer	CSP Share Winter	DP&L Share Summer	DP&L Share Winter	PSI Share Summer	PSI Share Winter	WVPA Share Summer	WVPA Share Winter	IMPA Share Summer	IMPA Share Winter
Walter C. Beckjord New Richmond, OH	6	7-1969	414	420	155	158	52	52	207	210	-	-	-	-	-	-
Conesville Conesville, OH	4	6-1973	780	780	312	312	339	339	129	129	-	-	-	-	-	-
East Bend Boone County, KY	2	3-1981	600	600	414	414	-	-	186	186	-	-	-	-	-	-
Gibson Owensville, IN	5	10-1982	620	625	-	-	-	-	-	-	308	313	156	156	156	156
Killen Wrightsville, OH	2	6-1982	600	600	198	198	-	-	402	402	-	-	-	-	-	-
Miami Fort North Bend, OH	7	5-1975	500	500	320	320	-	-	180	180	-	-	-	-	-	-
	8	2-1978	500	500	320	320	-	-	180	180	-	-	-	-	-	-
J. M. Stuart Aberdeen, OH	1	5-1971	585	585	228	228	152	152	205	205	-	-	-	-	-	-
	2	10-1970	585	585	228	228	152	152	205	205	-	-	-	-	-	-
	3	5-1972	585	585	228	228	152	152	205	205	-	-	-	-	-	-
	4	6-1974	585	585	228	228	152	152	205	205	-	-	-	-	-	-
W. H. Zimmer Moscow, OH	1	3-1991	1300	1300	605	605	330	330	365	365	-	-	-	-	-	-

NOTE: Totals may not add due to rounding to whole numbers.

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FORM FE2-2 PART 3: ACTUAL GENERATING CAPABILITY CHANGES [In MegaWatts]

				CAPABILITY CHANGES		SEASONAL TOTAL	
YEAR	UNIT DESIGNATION	NOTES	COMMENT	SUMMER	WINTER	SUMMER	WINTER
1994	Gibson - Unit 4	[1]	(derate)		-8.0		
						0.0	-8.0
1995	Gibson - Unit 4	[1]	(derate)	-8.0			
	Wabash River - Unit 1	[2]	(repower)	143.0	177.0		
						135.0	177.0
1996	Miami Fort GT - Unit 1	[3]	(retire)		-64.5		
	Miami Fort GT - Unit 2	[4]	(retire)		-64.5		
						0.0	-129.0
1997	Miami Fort GT - Unit 1	[3]	(retire)	-48.0			
	Miami Fort GT - Unit 2	[4]	(retire)	-48.0			
						-96.0	0.0
1998							
						0.0	0.0

[1] The Gibson Unit 4 derate was the result of a scrubber addition.

[2] Wabash River Unit 1 was repowered as an integrated coal gasification combined-cycle generating facility in a joint venture between PSI Energy and Destec. The values reported here are incremental to the Unit 1 existing capability.

[3] Miami Fort GT Unit 1 retired on December 20, 1996.

[4] Miami Fort GT Unit 2 retired on October 14, 1996.

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FORM FE2-2 PART 1: SUMMARY OF ACTUAL LOADS AND REQUIRED GENERATING CAPABILITY [In MegaWatts] [1]

Calendar Year>	1994		1995		1996		1997		1998	
Forecast Year>	Year -5		Year -4		Year -3		Year -2		Year -1	
	summer	winter	summer	winter	summer	winter	summer	winter	summer	winter
1. TOTAL ELECTRIC POWER PEAK GENERATING CAPABILITY REQUIRED										
(a) Net Utility Service Area Peak Load [2]	9421	8319	10079	8795	10043	9073	10109	8359	10387	8735
(b) Purchased Power Used to Meet Peak Load [Firm]	150	3	153	4	210	96	504	4	554	4
(c) Power Sales Coincident with Service Peak Load	70	220	70	220	70	220	70	180	70	185
(d) Power Pooling (Net Power Available from Pool(-) or Committed to Pool(+))	0	0	0	0	0	0	0	0	0	0
NET CAPABILITY REQUIRED (a)-(b)+(c)+(d) [3] [Not including Reserve Requirements]	9341	8536	9996	9011	9903	9197	9675	8535	9903	8916
2. REPORTING UTILITY'S ACTUAL HISTORIC GENERATING CAPABILITY [4]										
(a) Previous Year Capability [5]	11493	11493	11493	11485	11662	11662	11662	11533	11533	11533
(b) Retirements and other Decreases in capacity	0	8	8	0	0	129	96	0	0	0
(c) Uprating and Increases in Capability	0	0	143	177	0	0	0	0	0	0
(d) Seasonal Deratings	349	15	383	15	383	15	350	15	350	15
NET CAPABILITY [3] [4]	11144	11470	11279	11647	11279	11518	11183	11518	11183	11518
3. DIFFERENTIAL BETWEEN EXISTING AND REQUIRED CAPABILITY FOR EACH YEAR (2-1) [3][4]	1803	2934	1283	2636	1376	2321	1508	2983	1280	2602

[1] WINTER designated Year -5 is that WINTER SEASON which followed the SUMMER of Year -5, etc.

[2] Historical native peak load served, after DSM and/or interruptible load reductions.

[3] Totals may not be exact due to rounding to whole numbers.

[4] Assuming increases and decreases in Capability, including all appropriate unit derates, for Equipment in-service at the time of the seasonal peak.

[5] "Previous Year Capability" (Year -5) equals "Net Capability" from Year -6 plus "Seasonal Deratings" from Year -6, etc.

Figure 5-5

APPROXIMATE FUEL STORAGE CAPACITY

Generating Station	Coal Capacity (Tons)	Oil Capacity (Gallons)	Propane Capacity (Gallons)
W.C. Beckjord	550,000	2,100,000	--
Cayuga	900,000	290,000 #2 High Sulfur +336,000 #2 Low Sulfur	--
Conesville	750,000	420,000	--
Connersville	--	500,000	--
Dicks Creek	--	500,000	--
East Bend	300,000	540,000	--
Edwardsport	75,000-80,000	250,000	--
Gallagher	750,000	130,000	--
Gibson	2,800,000-3,000,000 w/three piles	500,000	--
Killen	190,000	2,650,000	--
Miami Fort	700,000	4,000,000	--
Miami-Wabash	--	750,000	--
Noblesville	70,000-75,000	45,000	--
J.M. Stuart	900,000	50,000	--
Wabash River	500,000 +90,000 for WRCGRP	140,000 +198,000 for WRCGRP	--
Woodsdale	--	--	450,000
W.H. Zimmer	1,000,000	3,000,000	--

Figure 5-6

TAG-SUPPLY™ SCREENING: PULVERIZED COAL TECHNOLOGIES

1999-2008 and 2009-2019

<u>High Sulfur</u>
Subcritical:
1.1A Limestone Forced Ox. Sub. 300MW
1.1B Limestone Forced Ox. Sub. 500MW
1.1C Limestone Forced Ox. Sub. 400MW
1.1D Limestone Forced Ox. Sub. 300MW
1.1E Limestone Forced Ox. Sub. 300MW
1.1G Limestone Forced Ox. Sub.200MW
1.1H Limestone Forced Ox. Sub. 2X300MW
1.4A Wallboard Gypsum Sub. 300MW

→ 1.1B Limestone Forced Ox. Sub. 500MW

Supercritical:
1.5A Limestone Forced Ox. Supercr. 300MW
1.5C Adv. LS Forced Ox. Supercr. 400MW

→ 1.5C Adv. LS Forced Ox. Supercr. 400MW

→ 1.1B Limestone Forced Ox. Sub. 500MW

<u>Low Sulfur</u>
1.1F Limestone Forced Ox. Sub. 500MW
1.1I Limestone Forced Ox. Sub. 200MW
1.1J Limestone Forced Ox. Sub. 2 X 275MW
1.2A Lime Spray Dryer Sub. 300MW
1.2C Lime Spray Dryer Sub. 200MW
1.2F Lime Spray Dryer Sub. 300MW
1.5B Lime Spray Dryer Supercr. 300MW

→ 1.1F Limestone Forced Ox. Sub. 500MW

TAG-SUPPLY™ SCREENING: FLUIDIZED BED TECHNOLOGIES

1999-2008

High Sulfur
Atmospheric Fl.-Bed Combustion (AFBC):
5.2A Circulating AFBC 200MW
5.3A Circulating AFBC 200MW
5.4A Circulating AFBC 200MW

→ 5.2A Circulating AFBC 200MW

Low Sulfur
Atmospheric Fl.-Bed Combustion (AFBC):
5.5A Circulating AFBC 200MW
5.7A Circulating AFBC 200MW

→ 5.5A Circulating AFBC 200MW

Figure 5-8

TAG-SUPPLY™ SCREENING: FLUIDIZED BED TECHNOLOGIES (Cont.)

2009-2019

High Sulfur
Atmospheric Fl.-Bed Combustion (AFBC):
5.2A Circulating AFBC 200MW
5.3A Circulating AFBC 200MW
5.4A Circulating AFBC 200MW
→ 5.2A Circulating AFBC 200MW

Bubbling Pressurized Fl.-Bed Comb. (PFBC):
6.1 Subcr. Reheat 80MW
6.2 Subcr. Non-reheat 2 X 80MW
6.3 Subcr. 350MW
6.7 Subcr. 350MW
6.8 Supercr. 350MW
6.9 Supercr. 350MW
→ 6.9 Supercr. 350MW

Circulating Pressurized Fl.-Bed Comb. (PFBC):
7.1 Subcr. Reheat 80MW
7.2 Subcr. Non-reheat 1 X 160MW
7.3 Subcr. Non-reheat 1 X 350MW
7.7 Subcr. Reheat 350MW
7.8 Supercr. Non-reheat 350MW
7.9 Supercr. 350MW
8.0 Subcr. 1 X 350MW
8.1 Adv Subcr. 688MW
→ 8.1 Adv Subcr. 688MW

(High Sulfur overall) → 8.1 Adv Subcr. 688MW

Low Sulfur
5.5A Circulating AFBC 200MW
5.7A Circulating AFBC 200MW
6.5 Bubbling PFBC Subcr. 350MW
6.6 Subcr. 350MW
7.5 Circulating PFBC Subcr. 350MW
7.6 Subcr. Reheat 350MW
→ 7.6 Subcr. Reheat 350MW

Figure 5-9

TAG-SUPPLY™ SCREENING: INTEGRATED COAL GASIFICATION COMBINED CYCLE

1999-2008

No Mature or Commercial Technologies

2009-2019

10.1A Shell Ent. Flow Med. Int.568MW
10.2A Texaco HR Ent. Flow Med. Int. 610MW
10.3A Texaco Quench Ent. Flow Med. Int. 508MW
10.4A Destec Ent. Flow Med. Int. 593MW
10.5A IGCHAT 600MW
10.5B IGCASH 410MW
10.5C IGMCFC 400MW
10.6 Advanced GCC 460MW

→ 10.6 Advanced GCC 460MW

Figure 5-10

TAG-SUPPLY™ SCREENING: SIMPLE CYCLE COMBUSTION TURBINES

1999-2003

Combustion Turbine:
Conventional Frame 7F 171.7MW

2004-2019

Heavy Duty:
15.0 50MW
15.1 80MW
15.2 110MW
15.3 160MW
15.4 230MW

→ 15.4 230MW

Aeroderivative:
15.5 25MW
15.6 35MW
15.7 45MW

→ 15.7 45MW

Steam Injected:
17.0 1 X 30MW
17.1 1 X 50MW

→ 17.1 1 X 50MW

→ 15.4 230MW

Fi e 5-11

TAG-SUPPLY™ SCREENING: COMBINED CYCLE

1999-2003

Combined Cycle:
Conventional Frame 7F 262.6MW

2004-2019

Combined Cycle:
16.0 75MW
16.1 120MW
16.2 165MW
16.3 235MW
16.4 345MW
16.5 400MW

Cascaded Humidified Adv. Turbine (CHAT):
17.2 300MW

16.5 400MW

17.2 300MW

16.5 400MW

Figure 5-12

TAG-SUPPLY™ SCREENING: FUEL CELLS

1999-2008

Phosphoric Acid:
20.1D PA Ambient Pressure 2MW

2009-2019

Phosphoric Acid and Molten Carbonate:
20.1A PA Pressurized 10MW
20.1D PA Ambient Pressure 2MW
20.1E PA Ambient Pressure 2.5MW
20.2 MC Ambient Pressure 2MW
20.2A MC Pressurized 10MW

→ 20.2A MC Pressurized 10MW

Solid Oxide:
20.3A SO Ambient Pressure 0.5MW
20.3B SO Ambient Pressure 2MW
20.3C SO Pressurized 10MW
20.3D SO Pressurized 25MW

→ 20.3D SO Pressurized 25MW

→ 20.3D SO Pressurized 25MW

Figure 5-13

TAG-SUPPLY™ SCREENING: WIND

1999-2008

No Mature or Commercial Technologies

2009-2019

24.2 Wind Turbine .35MW each

Figure 5-14

TAG-SUPPLY™ SCREENING: SOLAR

1999-2008

Solar Thermal:
23.1 Solar Thermal 80MW
23.2 Solar Thermal 200MW

→ 23.2 Solar Thermal 200MW

2009-2019

Flat Plate:
22.2A PV Flat 1MW
22.2B PV Flat 5MW
22.2C PV Flat 10 X 5MW
22.2D PV Tracking 1MW
22.2E PV Tracking 5MW
22.2F PV Tracking 10 X 5MW

→ 22.2C PV Flat 10 X 5MW

High Conc and Solar Thermal:
22.3A PV High Conc 1MW
22.3B PV High Conc 5MW
22.3C PV High Conc 10 X 5MW
23.1 Solar Thermal 80MW
23.2 Solar Thermal 200MW

→ 23.2 Solar Thermal 200MW

→ 23.2 Solar Thermal 200MW

Figure 5-15

TAG-SUPPLY™ SCREENING: OTHER RENEWABLES

1999-2008

Municipal Solid Waste:
25.1 MSW Mass Burn 40MW
25.2 MSW Refuse Derived 40MW
25.3 Scrap Tire Mass Burn 40MW

→ 25.3 Scrap Tire Mass Burn 40MW

Biomass-Fueled:
26.1 Wood-fired Stoker 50MW
26.2 Wood-fired Circ. FBC 50MW

→ 26.1 Wood-fired Stoker 50MW

→ 26.1 Wood-fired Stoker 50MW

2009-2019

Municipal Solid Waste:
25.1 MSW Mass Burn 40MW
25.2 MSW Refuse Derived 40MW
25.3 Scrap Tire Mass Burn 40MW

→ 25.3 Scrap Tire Mass Burn 40MW

Biomass-Fueled:
26.1 Wood-fired Stoker 50MW
26.2 Wood-fired Circ. FBC 50MW
26.3 Whole Tree 100MW
26.4A Wood-fired Gas./CC- Conv. 100MW
26.4B Wood-fired Gas./CC- Adv. 100MW

→ 26.3 Whole Tree 100MW

→ 26.3 Whole Tree 100MW

Figure 5-16

TAG-SUPPLY™ SCREENING: STORAGE

1999-2008

Batteries:	
30.1 Lead Battery-LD 20MW	→ 30.1 Lead Battery-LD 20MW
30.2 Lead Battery-HD 20MW	
Hydro:	
32.1 Pumped Hydro 350MW	→ 32.1 Pumped Hydro 350MW

2009-2019

Batteries:	
30.1 Lead Battery-LD 20MW	→ 30.1 Lead Battery-LD 20MW
30.2 Lead Battery-HD 20MW	
31.1 AdvBat3 20MW	
31.2 AdvBat5 20MW	
Hydro:	
32.1 Pumped Hydro 350MW	→ 32.1 Pumped Hydro 350MW
32.2 Underground Pumped 2000MW	
Compressed Air:	
33.1A CAES R350MW	→ 33.2C CASH P350MW
33.1C CAES P350MW	
33.2A CASH R350MW	
33.2C CASH P350MW	
Super Conducting Magnetic:	
34.1 SMES 500MW	→ 34.1 SMES 500MW

Figure 5-17

Supply-Side Screening "Best in Class" Technologies

Category	1999-2008	2009-2019
Pulverized Coal	500 MW Coal- High SO_2	500 MW Coal- High SO_2
Fluidized Bed	200 MW AFBC- PRB	688 MW CPFBC- High SO_2
IGCC	---	460 MW Adv. GCC
Simple Cycle CT	171.7 MW CT 1999-2003 230 MW CT 2004-2008	230 MW CT
Combined Cycle	262.6 MW CC 1999-2003 400 MW CC 2004-2008	400 MW CC
Fuel Cell	2 MW Phosphoric Acid	25 MW Solid Oxide
Wind	---	.35 MW Wind
Solar	200 MW Solar Thermal	200 MW Solar Thermal
Other Renewables	50 MW Wood-Fired Stoker	100 MW Whole Tree
Storage	20 MW Battery	20 MW Battery 350 MW CASH

Note: See text for explanation of individual technology types

6. CLEAN AIR COMPLIANCE

A. INTRODUCTION

The Clean Air Act of 1970, together with the subsequent Clean Air Act Amendments of 1977, set forth a structure of air pollution control known as "command and control." With this control method, ambient standards are set, allowable emission levels are calculated for each plant, and limits are incorporated on a plant-by-plant or stack-by-stack basis.

Title IV (i.e., the acid rain provisions) of the Clean Air Act Amendments of 1990 (CAAA) left the existing mechanism in place, strengthened it, and added another layer of provisions in order to achieve even greater sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emission reductions. The ultimate goal of the CAAA is to reduce annual SO_2 emissions from U.S. utilities by 10 million tons from 1980 levels by 2000. Additionally, NO_x emissions will be reduced by 2 million tons annually compared to the levels from 1980. The CAAA call for the reductions to occur in two phases. Phase I began January 1, 1995, and continues through December 31, 1999. Phase II will begin January 1, 2000, and continues indefinitely.

1. **SO_2 Requirements**

During Phase I, the CAAA target existing generating units that are 100 megawatts (MW) or greater, and had an SO_2 emission rate of 2.5 lbs. of SO_2/MMBtu (i.e., emitted 2.5 lbs. of SO_2 per million Btu of fuel consumed) or greater during 1985. These units are commonly referred to as "Phase I affected units." Any source that includes one or more affected units is referred to as an "affected source." The CAAA define Phase II affected units as all existing units (prior to the CAAA of 1990) that are not Phase I affected units, except for existing simple cycle Combustion Turbines or units 25 MW or less. A utility may voluntarily opt a Phase II affected unit into Phase I, whereby the opt-in unit would become a Phase I affected unit and receive allowances based upon the lower of 2.5 lbs. of SO_2/MMBtu or the unit's actual 1985 emission rate.

A unique feature of the CAAA is that it employs a market-based "allowance" system rather than requiring a "command-and-control" method of SO_2 emission reduction. During Phase I the U.S. Environmental Protection Agency (USEPA or EPA) allocated allowances to affected units based upon their average annual

MMBtu fuel consumption during the 1985-1987 baseline period, using a 2.5 lbs. of SO_2/MMBtu emission rate. In Phase II, the USEPA will allocate allowances to affected units in the same manner as Phase I, except that the emission rate will be lowered to 1.2 lbs. of SO_2/MMBtu. An affected unit must hold one allowance for each ton of SO_2 emitted by that unit in a given year. Some of the ways this can be achieved are by: 1) reducing the SO_2 emissions of the unit to equal the number of allowances allocated by the USEPA; 2) transferring allowances from early-, or over-complying units; or 3) purchasing allowances. This ability to purchase allowances from, or sell allowances to, other sources has created a market for SO_2 allowances.

For the most part, the USEPA will not allocate Phase II allowances to any units constructed after 1987. Instead, these units must obtain allowances from the market, from other pre-1987 units, or from the EPA auctions and/or direct sales.

Another important aspect of the allowance system is the ability to save, or "bank," allowances for future use. Allowances allocated to an affected unit may be used in the year in which they are allocated, or later. For example, a vintage 1995 allowance may be used in any year 1995 or later. Thus, a utility could over-comply on its Phase I affected units or purchase allowances in order to build up a "bank" of allowances. This "bank" could then be used to delay necessary SO_2 reductions on a unit (or group of units) at a later date by transferring the banked allowances to that unit.

Title IV contains provisions to discourage the reduction of SO_2 emissions on Phase I affected units simply by shifting generation away from these units onto Phase II units during the Phase I period. In each year of Phase I, the total heat input (fuel consumed) to Phase I units (in Btus) must be greater than or equal to the average heat input to the Phase I units during the baseline period 1985-1987. If this standard is not met, then underutilization, or reduced utilization, occurs and allowances must be surrendered back to the USEPA under provisions within Title IV.

Although Congress defined the number of Phase I allowances originally allotted to each affected unit

(CAAA Section 404 Table A), the USEPA was given the authority to make adjustments to this allotment by allocating alternate or additional allowances. These allowances may be allocated during Phase I to most affected utility sources in Illinois, Indiana, and Ohio on a pro-rata share of 200,000 additional allowances each year. This allocation was created since it was anticipated that these three states would be the states most economically affected by the CAAA. During Phase II, there are utilities in ten states, including Indiana, Ohio, and Kentucky, which will receive these additional allowances. In addition, allowances are available from four (4) USEPA additional reserves, as follows: 1) by installing qualifying Phase I technology or by reassigning their reduction requirements among other units employing such technology (i.e., Phase I Extension Reserve); 2) as incentives for units achieving SO_2 emissions reductions through customer-oriented conservation measures or renewable energy generation (Conservation and Renewable Energy Reserve); 3) as set aside for auctions and direct sales which are sponsored yearly by EPA (Special Allowance Reserve); and 4) as incentives for utilities that replace boilers with new, cleaner, and more efficient technologies, or install qualifying Clean Coal Technology re-powered units (Repowered Sources). Allowances from these reserves are available to affected units in all states.

Figure 6-1 shows the number of allowances allotted by the USEPA for affected units on the Cinergy system.

The purpose of the compliance planning process is to develop an integrated resource/compliance plan, or strategy, that meets the future resource needs of Cinergy while at the same time meeting the requirements of the CAAA in a reliable and economic manner.

2. **NO_x Requirements**

The Acid Rain Program is using a two-phase program to reduce NO_x emissions from coal-fired electric utility plants. Phase I took effect on January 1, 1996 and limited emissions from two boiler types, known as Group I. Phase II, starting January 1, 2000, will effect Group II utility units.

The NO_x emission reduction goal under the program is to cut NO_x emissions by 2 million tons below 1980 levels. Utilities may choose the method of compliance that is most cost effective.

- An operator may choose to meet a standard annual emission limitation assigned by USEPA per boiler type.
- A utility may choose to average the emissions from two or more boilers and meet the combined emission rate for the units. This will allow more cost-effective reductions to be made on some units that can reduce emissions well below the USEPA standard and avoid more costly reductions on others.
- A utility may also apply for an alternative emission limit, if it can demonstrate that it cannot meet the standard emission limit.

Cinergy filed its averaging plan for Phase II NO_x emissions on December 19, 1997. Zimmer Station was filed as an early election unit during Phase I and must continue to meet its standard emission rate through 2007. Gibson Station Units 1 & 2 had applied for alternative emission limits, but will no longer pursue those; instead they will be incorporated into the system averaging plan.

B. PHASE I SO_2 & NO_x COMPLIANCE PLANS

CG&E filed a petition with the Public Utilities Commission of Ohio (PUCO) on June 30, 1992, (Case No. 92-1172-EL-ECP), seeking approval of its Phase I Environmental Compliance Plan (ECP). On September 3, 1992, the ECP case was consolidated with the 1991 and 1992 Electric Long-Term Forecast Report proceedings. Intervenor status was granted to the following parties in the case: the Office of Consumers' Counsel (OCC), Industrial Energy Consumers (IEC), the Sierra Club (Sierra Club) and three individual members, the City of Cincinnati (the City), Armco Steel Company and Air Products and Chemicals (Armco/Air Products), the Citywide Coalition for Utility Reform (CCUR), and the United Mine Workers of America (UMWA). All parties in the ECP case except the City and CCUR were signatories to a stipulation. The PUCO approved the stipulation and found the CG&E ECP reasonable in an Opinion and Order dated February 24, 1994.

On November 15, 1995, CG&E filed the two-year review of its ECP pursuant to Section 4913.05 of the Ohio Revised Code. This filing (Case No. 95-747-EL-ECP) provided the PUCO with information to commence a review on the continued appropriateness of the approved ECP. The PUCO found that CG&E's ECP, as modified, was adequately documented and complied with the requirements of Section 4913.04(A), Ohio Revised Code, and constituted an appropriate strategy for compliance with Phase I of the Clean Air Act Amendment requirements. The PUCO approved the modified ECP in an Opinion and Order dated December 19, 1996.

The CG&E Phase I ECP, as modified, includes the following compliance measures:

1. Modify W. C. Beckjord unit 5 and Miami Fort units 6&7 to allow the burning of lower sulfur coals in the range of 1.2 to 2.0 lbs. of SO_2/MMBtu;
2. Designate East Bend unit 2 as a substitute ("opt-in") unit, and increase its scrubber SO_2 removal rate;
3. Build up an Operating Reserve of SO_2 allowances of approximately 13 percent of the Phase I annual allotment;
4. Use allowance purchases and sales to optimize CG&E's electric production operations with respect to compliance with the requirements in Phase I;
5. Use emissions affected economic dispatch of its generating units to minimize costs in a manner consistent with underutilization regulations;

6. Designate W. H. Zimmer unit 1 as a compensating unit if reduced utilization becomes a concern;
7. Implement DSM programs consistent with cost-effectiveness criteria established by the PUCO, and study additional DSM programs for possible implementation to create bonus allowances, reduce unit emissions, and offset possible unit underutilization;
8. Install, operate and maintain low NO_x burners at W. C. Beckjord unit 5 and other units as necessary to comply with the NO_x requirements of the CAAA; and
9. Install, operate and maintain continuous emission monitoring systems (CEMS) at all Phase I and Phase II units.

CG&E was also required to follow the development of the SO_2 allowance market and develop in-house allowance market expertise.

Similarly, in accordance with the Indiana Environmental Compliance Plan Pre-Approval Act, PSI filed a petition with the Indiana Utility Regulatory Commission (IURC) on January 2, 1992, (Cause No. 39346) requesting approval of its Phase I Environmental Compliance Plan, including its estimated cost and schedule. Public hearings were conducted in this cause during August 1992, and November through December 1992. The IURC issued an order on October 27, 1993, approving PSI's Environmental Compliance Plan.

The approved PSI Phase I ECP includes the following compliance measures:

1. The use of environmentally affected economic dispatch (sometimes referred to as "emissions affected dispatch") in the dispatch of its generating units;
2. A continued commitment to DSM/conservation programs;
3. Tailored coal switching at most of its generating units; this includes the blending/switching of lower-sulfur coals, and tailoring the sulfur content to the operating parameters and the economics of each individual unit. This includes:
   a) the addition of flue gas conditioning equipment on Gibson unit 3, Gallagher units 1-4, Cayuga units 1&2, and the burning of lower sulfur coals at these units, and the inclusion of the already installed flue gas conditioning equipment on Wabash River unit 3;

b) the addition of new precipitators on Gibson units 1&2 and Wabash River unit 6, combined with the burning of lower sulfur coals at these units, and the upgrade of the precipitators on Gallagher units 1-4 and Wabash River units 2-5;

4. Installation of the Gibson unit 4 flue gas desulfurization system (scrubber). This scrubber is needed for economic compliance with the State Implementation Plan (SIP) of Gibson County as well as for CAAA compliance reasons;
5. Installation of continuous emission rate monitors on all of its Phase I and Phase II affected units;
6. Installation of low NO_x burners and over-fire air capability on all applicable Phase I affected units;
7. Build up an operating reserve of 30,000 SO_2 emission allowances;
8. The use of an SO_2 emission allowance banking strategy as part of an overall economic strategy to delay the installation of higher cost options in Phase II.

PSI is complying with Phase I requirements using its IURC pre-approved Phase I plan, with a few minor changes. Subsequent to the approval of the Phase I plan, it was determined that certain projects could be delayed or eliminated while still meeting Phase I requirements (for example, flue gas conditioning at Gallagher units 1-4).

Prior to the merger of PSI and CG&E, each company had studied the issue of how best to manage the SO_2 emission allowances, and each had assigned the responsibility to a single department (the Fuels Department at CG&E and the Financial Department at PSI), with representatives of other departments becoming involved as needed. Both companies participated in the USEPA allowance auctions in 1993 and 1994, and have analyzed other potential offers from brokers wishing to purchase or sell allowances. Since the formation of Cinergy, an interdepartmental working group has been created to perform these functions.

The SO_2 emission allowance market impacts the Phase I and Phase II strategies in two ways. First, the projected allowance market price is the basis against which the costs of compliance options are compared to determine whether the options are economic (i.e., a "market-based" compliance planning process). Second, Cinergy plans to use an emission allowance banking strategy to delay implementation of higher cost options in Phase II. The economics of this banking strategy, or strategic bank, are dependent upon the market price of allowances.

C. PHASE II SO_2 COMPLIANCE PLANNING PROCESS

1. Process Description

The Phase II compliance planning process involved three phases: 1) an initial technical feasibility screening of possible compliance options; 2) an economic screening of the feasible options that survived the technical feasibility screening; and 3) integration of the most economic options from the economic screening into the optimization process along with the supply- and demand-side resource options to develop an integrated resource/CAAA compliance plan, or strategy. The reason for the analysis being performed in three steps is that it would be virtually impossible to evaluate all possible technologies and/or options in one step. This section of the report describes the first two phases of the process. Chapter 8 contains a description of the third phase.

2. Technical Feasibility Screening

In general, the purpose of a technical feasibility screening is to prepare a list of available technologies, or options, analyze each from a technical perspective, and screen out those technologies that are not feasible for use at a particular unit or station. To the extent possible, work previously performed for the Phase I planning process was used in the technical feasibility screening.

During Phase I planning, CG&E performed a technical screening of technologies for its units using a Kepner-Tregoe® decision analysis. Technologies included in this analysis included coal switching/blending options, natural gas firing/co-firing, switching to low sulfur oil, and post-combustion processes such as wet FGD, sorbent injection, and dry spray FGD.

It should be noted that, for the CG&E units that are jointly owned by Columbus Southern Power and Dayton Power & Light, the impacts on the co-owners must be considered and a decision made jointly as to how to meet CAAA compliance requirements. The results of this study reflect only the preliminary economic analysis performed by Cinergy, from a Cinergy perspective.

Sargent & Lundy Engineers performed a similar analysis for the units on the PSI system. This analysis involved the following steps: 1) create a list of candidate control technologies or options; 2) develop a technical profile of each technology; and 3) perform a technology screening. The list of candidate technologies was developed from Sargent & Lundy's data base, a review of relevant literature, and input from PSI engineering staff.

Figure 6-2 shows the technologies chosen for further analysis on the Cinergy system.

3. Economic Screening

a. Methodology and Data Assumptions

The second phase of the CAAA compliance planning process was a detailed economic screening of technologies or options to determine which ones to evaluate along with the supply- and demand-side options later in the integration phase.

Cinergy uses models developed by The NorthBridge Group (NorthBridge), an economic and strategic consulting group, to assist in the CAAA compliance option economic screening process. NorthBridge worked closely with PSI in its Phase I compliance planning process, and developed compliance planning models for the PSI system. These models were developed in Lotus® 1-2-3, and contain cost and performance characteristics for each compliance option to be considered, for each unit or group of units. The models have been brought in-house, and will continue to be developed and utilized for future studies.

Cinergy worked with NorthBridge to update these models to incorporate the CG&E system and update other data from the original PSI Phase I planning study. Although Phase II does not begin until the year 2000, to ensure consideration of possible economic options, the analysis encompassed the years 1999 through 2009.

For those options being analyzed in the economic screening, Sargent & Lundy prepared capital cost estimates, operation and maintenance cost estimates, and operational impact assessments (heat rate, capacity, availability, etc.) for the PSI units. Similar data were reviewed and updated for the CG&E units from the study performed for CG&E's Phase I compliance plan.

The economic screening uses a marginal cost methodology to eliminate options dominated by others, and ranks the remaining options into "supply curves" based on the cost per incremental ton of SO_2 removed. The procedure captures the key interactions and tradeoffs inherent in compliance decisions:

- Compliance options were ranked not for individual units but for entire stations in order to reflect station-wide facilities and constraints. This was accomplished by comparing the costs and tons of SO_2 removed for the feasible combinations of unit-specific options at each station.
- Plans were developed by examining a series of annual supply curves reflecting annual tons removed and annualized costs (including a levelized carrying charge for capital), rather than through use of a single lifecycle supply curve. This allowed planners to take into

account changes in the relative economics of various compliance options over time.

- Impact of compliance options on performance variables such as heat rate, capacity rating and availability were explicitly valued to make the screening assessments as complete as possible. Where an option could be implemented in more than one way (for example, either replace a pulverizer or accept a performance penalty), both approaches were considered.

Much of the analysis was carried out with the assistance of the two NorthBridge specialized computer models: the first model computes the tons removed and costs for each compliance option at individual units, and the second model determines feasible station-wide combinations and develops the rankings. These models do not directly value the effects of changes in dispatch. Instead, a preliminary compliance option ranking is developed using an initial set of generating unit capacity factors from a dispatch model (see Chapter 8 for a more detailed description of the PROMOD IV® production cost and reliability evaluation program used for the dispatch modeling). Sensitivity analyses are then performed on the generating unit capacity factors to evaluate the impact of changes to the compliance options due to changes in capacity factors. These sensitivities are described later in this chapter.

After the marginal cost supply curve was created, the marginal cost of each on-system compliance option was compared to the projected market price of SO_2 emission allowances. Ignoring other possible factors, options with a marginal cost less than the market price of allowances are deemed economic. The General Appendix contains the marginal cost supply curve data for the years 2000, 2005, and 2009. Cinergy considers the data to be trade secrets and proprietary information.

An important aspect of this market-based compliance planning process is the projected price of SO_2 emission allowances. Cinergy uses an emission allowance price forecast prepared by Energy Ventures Analysis, Inc. (EVA) in its planning. This IRP analysis incorporated the 1999 edition of the forecast. The projected allowance prices are trade secrets and proprietary to EVA.

For the base scenario, the major assumptions (such as load forecast and fuel forecast) were coordinated with those used in the supply- and demand-side resource option screening.

b. **Sensitivity Analyses**

Sensitivity analysis was also an important part of the overall process. Scenarios reflecting alternative assumptions for major variables were tested to assess how robust the base scenario supply curves really were, which assumptions were most critical, and which compliance options were sufficiently promising in scenarios other than the base case to merit further examination. For the Cinergy sensitivity analyses, changes in generating unit capacity factors, relative fuel prices, coal contract constraints, equipment modification costs, replacement power costs, market SO_2 allowance prices, and ash credits for PRB coal were considered.

In the capacity factor sensitivity, the capacity factors were adjusted by 10% above and below those used in the base. In the fuel price sensitivity, the fuel prices were adjusted 10% above and below those used in the base. The coal contract constraint sensitivity assumed no existing long-term coal contracts. High and low capital cost estimates were prepared for retrofits and other options requiring capital.

The following sensitivity analyses were performed for the years 2000, 2005, and 2009.

Capacity Factor Sensitivity

The high capacity factor sensitivity results in no change from the base case. In the low capacity factor sensitivity, one unit would switch to a lower percentage blend of a low Sulfur coal in 2000 only. A station would switch to higher sulfur coal in 2009. Economic options at other units would be unchanged from the base scenario.

Relative Fuel Price Sensitivity

Fuel price sensitivities were also performed for a price adjustment of +10% and -10% for each fuel, while holding the price of all other fuels constant. This, of course, eliminates the correlation in price movements that may occur among fuels. Therefore, the results of these sensitivities are for general indications and are not to be taken as conclusive.

Unless a change because of the relative fuel price sensitivity analysis is stated below, the economic options at other units would remain as in the base scenario.

Potential opportunities for economically reducing SO_2 emissions on the Cinergy system between 1999 and 2009 include the switching to Powder River Basin (PRB) coal in Phase II. PRB coal is a very low sulfur coal (typically 0.8 lbs. of SO_2/MMBtu or less) that is abundant in the Powder River Basin of Wyoming and Montana. Due to other characteristics of the coal (e.g., low heat content, unique ash qualities, and dusting characteristics), a significant amount of testing is necessary to determine how successfully units designed to burn higher sulfur, higher heat content Midwestern coals can burn the PRB coal. Raising the delivered price of PRB coal by 10% relative to other coals would cause one station to delay switching to PRB coal until 2009. Another station would continue to burn the planned low sulfur coal instead of switching to 100% PRB in 2009. Lowering the price of PRB coal by 10% would bring PRB coal to several units in 2000. Other units would continue to burn the base coal in 2000.

Lowering the coal price forecast 10% for 1.0 lb. Colorado Basin Low Sulfur coal results in two stations using that coal beginning in 2009. A high price sensitivity for 1.0 lb. Colorado Basin Low Sulfur coal was not necessary because there were no fuel switches to that coal in the base case.

Lowering the price of 1.2 lb. Central Appalachian Low Sulfur coal by 10% would cause several units to adopt the coal in 2000. Other units would also switch to the 1.2 lb. coal in 2000 but switch back to their base coals in 2005 and then switch back to the 1.2 lb. coal in 2009. One other unit would switch to the 1.2 lb. coal in 2009. Raising the price of 1.2 lb. Central Appalachian Low Sulfur coal by 10% would cause one station to continue to burn the base coal in 2000.

Lowering the coal price forecast 10% for 1.2 lb. Illinois Basin Low Sulfur coal results in no change from the base case. Raising the price of 1.2 lb. Illinois Basin Low Sulfur coal by 10% would cause several units to continue to burn the base coal. One unit would switch to lower sulfur coal in 2000 and then switch back to base coal in 2009.

Raising the coal price forecast 10% for 1.6 lb. Central Appalachian Low/Medium Sulfur coal results in a lower sulfur coal becoming the economic option at one station beginning in 2000. Lowering the coal price forecast 10% for 1.6 lb. coal results in several units using that coal beginning in 2000. One unit would switch to the 1.6 lb. coal in 2005. Another unit would continue to use the 1.6 lb. coal in 2009.

Raising the coal price forecast 10% for 2.1 lb. Northern Appalachian Medium Sulfur coal results in one station switching to higher sulfur coal in 2005. One unit would switch to a lower sulfur coal in 2009. In addition, a lower sulfur coal becomes the economic option at several units in 2000 and 2009 but not in 2005. Lowering the coal price forecast 10% for 2.1 lb. Northern Appalachian Medium Sulfur coal results in one station switching to that coal in 2000.

Raising the coal price forecast 10% for 2.3 lb. Illinois Basin Medium Sulfur coal results in one station switching to a lower sulfur coal in 2000. One unit would switch to a lower sulfur coal in 2009. Lowering the coal price forecast 10% for 2.3 lb.

Illinois Basin Medium Sulfur coal results in one station switching to that coal beginning in 2005.

Raising the coal price forecast 10% for 3.3 lb. Northern Appalachian Medium/High Sulfur coal was not necessary because there were no fuel switches to that coal in the base case. Lowering the coal price forecast 10% for 3.3 lb. Northern Appalachian Medium/High Sulfur coal results in one station switching to that coal beginning in 2000.

Raising the coal price forecast 10% for 3.5 lb. Illinois Basin Medium/High Sulfur coal was not necessary because there were no fuel switches to that coal in the base case. Lowering the coal price forecast 10% for 3.5 lb. Illinois Basin Medium/High Sulfur coal results in no change from the base case.

Raising the coal price forecast 10% for 6.6 lb. Northern Appalachian High Sulfur coal results in a lower sulfur coal becoming the economic option at one unit in 2000 only. Lowering the coal price forecast 10% for 6.6 lb. Northern Appalachian High Sulfur coal was not necessary because there were no fuel switches to that coal in the base case.

Raising the natural gas price forecast was not necessary because there were no fuel switches to natural gas in the base case. Lowering the natural gas price forecast 10% results in no change from the base case.

Ash Credit Sensitivity

Sensitivity analyses were performed with different ash credit prices for those units with 100% PRB coal as a compliance option. The ash produced from burning 100% PRB coal is a commercially viable product that can be sold, thereby reducing the effective cost of burning 100% PRB coal. In the base case, the ash credit was $25 per ton of ash. Sensitivities were performed for the ash credit at $0, $20 and $30 per ton of ash.

The ash credit at $30 per ton resulted in no change from the base case. At $20 per ton, the ash credit resulted in one station switching to a higher sulfur coal in 2009. At $0 per ton, the ash credit resulted in one station switching to a higher sulfur coal in 2009. Another station would switch to a higher sulfur coal in 2005 only.

Coal Contract Constraint Sensitivity

Sensitivity analysis of base case coal contract constraint assumptions was performed by assuming that the contracts were eliminated in 1999. There was no analysis performed to determine any costs associated with eliminating these contracts, nor was there any detailed discussion as to the feasibility of eliminating the contracts. Rather, this sensitivity analysis was performed merely to determine if the contracts were a binding constraint on the selection of economic options.

The contracts did constrain the economic alternatives at two stations. It was economical to switch to a lower sulfur coal at one unit beginning in 2005 and several units in 2009. One station switched to a lower sulfur coal in 2000 only.

Capital Cost Modification Sensitivity

Since some options are more capital cost intensive (e.g., PRB fuel switching, natural gas conversion, and scrubber installation), this sensitivity has a greater effect on these options compared to others. In the low capital sensitivity, a lower sulfur coal becomes economic at one unit in 2000 and 2005.

Several units would switch to a lower sulfur coal in 2000. In the high capital case, a higher sulfur coal becomes economic at one station in 2005 and another station in 2009.

Replacement Power Cost Sensitivity

Since some options cause a derate to the unit (e.g., PRB fuel switching and scrubber installation), this sensitivity has a greater affect on these options compared to others. The sensitivity analysis used an electricity market approach, which incorporated a forecasted range of projected electricity market prices. Both the upper 90% case and lower 10% case from Cinergy's energy market forecast for spot electricity prices were used for the high and low replacement energy cost sensitivities, respectively.

In the high replacement power cost sensitivities, one station would switch to a higher sulfur coal in 2005 and another station 2009. In the low replacement power cost sensitivity, one station would switch to a lower sulfur coal beginning in 2000.

SO_2 Emission Allowance Market Price Sensitivity

Cinergy used the high (90^{th} percentile) and low (10^{th}

percentile) SO_2 emission allowance price projections from the 1999 ICF Resources emission allowance price forecast for the high and low price sensitivities. The projected allowance prices are trade secrets and proprietary to ICF Resources. The high emission allowance price forecast was driven by the National Ambient Air Quality Standards (NAAQS) for fine particulate matter which lowers the SO_2 emission allowances allocated by the EPA. The low emission allowance price forecast was driven by the CO_2 Kyoto Protocol in 2008.

In the low allowance price sensitivity, one station would switch to a higher sulfur coal in 2000. Two stations would continue to burn the base coal and consume allowances.

There were many additions in 2000 for the high SO_2 allowance price sensitivity scenario. By 2000 it would be economical to switch several units to a lower sulfur coal. Wet scrubbers would be economically justified in 2005 at several units under the high SO_2 allowance price sensitivity. In 2009, several units would switch to a lower sulfur coal. It would also be economical to install a wet scrubber on several other units.

c. Conclusions

The compliance screening curve data and final CAAA compliance option results for the 1999 IRP are shown in Figure GA-6-3 in the General Appendix. Cinergy considers these results to be a trade secret and confidential, competitive information. The redacted information will be made available to the appropriate parties upon execution of an appropriate confidentiality agreement or protective order.

D. USEPA NO_x SIP CALL COMPLIANCE PLANNING

On September 24, 1998, USEPA Administrator, Carol Browner, signed the "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for purposes of Reducing Regional Transport of Ozone" or State Implementation Plan (SIP) call for revision under Section 110 of the Clean Air Act. The final rule was published in the Federal Register on October 27, 1998. States are directed to respond to the call by submitting revised SIPs by September 24, 1999, and source reductions to meet the NO_x emission budget per state are to be met by May 1, 2003.

The NO_x SIP Call establishes NO_x budgets for each of the 23 effected jurisdictions that will apply during the summer ozone season (May 1 through September 30) beginning in 2003. States are directed to revise their SIPs by reducing NO_x emissions from a number of sources including electric utilities. The electric utility NO_x emission rate is based upon 0.15 lb./MMBtu, but would be administered by USEPA through a regional cap and trade program similar to the Acid Rain Program for SO_2.

The United States Court of Appeals has recently (May 25, 1999) stayed indefinitely the implementation of USEPA's NO_x SIP Call pending the Court's resolution of the various other NO_x emission and ozone related regulatory and litigation activities. See Chapter 8 for more explanation of those activities.

Even though the stay of the SIP Call has been granted, Cinergy continues to study the compliance options available to comply with future NO_x emission reductions. The level of reductions and timing for compliance are unknown and likely to remain uncertain until next spring.

However, given that USEPA's previous compliance date would have been extremely difficult to meet and still retain Cinergy's system reliability, it is still prudent to be prepared to cost effectively meet USEPA's emission reduction goals.

For this IRP, the NO_x compliance level required was assumed to be 0.15 lb./MMBtu by 2003 because the stay of the SIP call had not yet been granted at the time that a decision had to be made for modeling purposes.

1. **Allowance Allocations**

EPA's NO_x SIP Call is based upon a cap of utility NO_x emissions equivalent to 0.15 lb./MMBtu of heat input. This cap was determined using a baseline of heat input in the years 1995 and 1996. EPA then used the ICF Resources, Inc. Integrated Planning Model (IPM) to inflate this heat input to projected 2007 levels. EPA then calculated a tonnage cap based using the 0.15 lb. NO_x/MMBtu emissions rate. This cap was then allocated to the individual states. In their individual SIP Plans, the states must determine how their individual budgets are to be allocated.

Cinergy has projected its potential allocations from the three states in which it operates for each of its generating units. This projection is a total of 23,429 tons. There is an expectation that the states could hold back as much as 5% of the allotments. This hold back would be kept in reserve for allocations to new generation and for other purposes. This hold back would reduce Cinergy's allowance to 22,258 tons. In addition, a 5% compliance margin was built into Cinergy's compliance plan to allow for many of the variables that can affect operations. As a result, Cinergy estimates that its target emissions during the ozone season beginning in 2003 will be approximately 21,145 tons.

2. Determination of Baseline Emissions

The projected baseline emissions from Cinergy units were needed for future years to determine the total tons of reduction needed. Actual 1997 emissions data was used to characterize NO_x emissions from each unit as a function of load. Future projected operating hours provided from the Energy Market Forecast Model (see Chapter 8) were used to develop future load profiles. Since most of the Cinergy generating units have higher NO_x emission rates at higher loads, the load distribution profiles were used to calculate the projected emissions. The emission rates and projected unit operations were used to calculate total baseline emissions.

3. Evaluation of Potential Reduction Projects

A large number of potential NO_x reduction projects were considered. They include Combustion Controls, such as Low NO_x burners and combustion tuning, and post Combustion NO_x Controls, such as Selective Non-catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). For modeling purposes, SCRs were assumed to be 85% efficient based on available industry experience. SNCRs were also assumed to be limited to units smaller than 330 MW. Sensitivity analyses were performed to evaluate a number of emerging technologies.

4. Compliance Plan

Cinergy used an Excel-based spreadsheet model called the Engineering and Construction Model (E&C) to determine what combination of controls would be required to meet various compliance scenarios including the 0.15 lb. NO_x/MMBtu recommended by USEPA. It was developed externally by NorthBridge and then brought in house. It is a marginal cost based model that ranks each potential NO_x reduction project using the potential NO_x tons removed, the capital cost, and the O&M costs (both fixed and variable). After ranking the projects from lowest to highest marginal cost per ton of NO_x reduced, the model continues to select projects until enough tons have been removed so that estimated emissions are less than the expected allocation. It will run in a state by state mode, a PSI/CGE mode, using an emissions rate or tons of emissions.

The model contained average cost and effectiveness data for the available technologies, current emissions data for all of the Cinergy units, and projected unit capacity factors for future years. To verify and refine the model data and prepare a more refined compliance plan, Sargent & Lundy Engineers and Stone & Webster were retained to conduct two independent compliance studies. Each consultant conducted site visits to gather actual unit data and to develop conceptual designs for the projects. Multiple model runs evaluated different sensitivities that could affect the final compliance requirements and project needs. Data from both reports were incorporated into the model, which was used to prepare the compliance plan shown in Figure GA-6-4 in the General Appendix.

5. Trading

The compliance plan assumes that trading will be permitted across the entire Cinergy system. This decision ultimately rests with the individual States when they develop their State Implementation Plans (SIP). Both the USEPA and the individual states have shown the desire to implement a system of interstate trading of NO_x allowances. This would permit sources accumulating surplus allowances through over compliance to trade with other sources. It is assumed that because of the stringency of EPA's NO_x SIP Call and the lack of a fluid market, that trading will comprise a relatively small amount of overall compliance. The Cinergy compliance plan therefore assumes that compliance will be accomplished on system. However the plan is structured to utilize trading should allowance prices fall below the highest marginal cost reduction projects.

6. Co-Ownership Issues

The compliance plan includes only Cinergy operated units. However Cinergy co-owns several units with American Electric Power (AEP) and Dayton Power and Light (DP&L). As a sensitivity case, the plan also evaluates the system on an ownership basis as well as an operated basis.

7. Non-Attainment Issues

Several of Cinergy's generating units are located close to areas in non-attainment with the current one-hour ozone standard. These areas include Cincinnati and Louisville. In addition, USEPA is implementing a new, more restrictive 8-hour ozone standard. This new standard is expected to create many additional non-attainment areas. In preparation of the SIPs, states have the ability to target specific areas for reductions. As a result, Cinergy could be required to make specific reductions in these areas. These reductions may not result in the lowest cost plan based on marginal cost per ton removed.

Figure 6-1

SO2 ALLOWANCES ALLOCATED TO CINERGY UNITS

Operating Company	Plant Name	Unit/ Boiler No.	Percent Ownership	ALLOWANCES ALLOCATED 1999	2000-2009	2010 & after
CG & E	Conesville	4	40.00	21,342	8,393	8,410
CG & E	Miami Fort	5-1	100.00	417	144	143
CG & E	Miami Fort	5-2	100.00	417	144	143
CG & E	Miami Fort	6	100.00	12,475	4,906	4,917
CG & E	Miami Fort	7	64.00	27,048	10,637	10,658
CG & E	Miami Fort	8	64.00	0	11,623	11,647
CG & E	W. C. Beckjord	1	100.00	0	1,834	472
CG & E	W. C. Beckjord	2	100.00	0	1,859	711
CG & E	W. C. Beckjord	3	100.00	0	2,530	1,077
CG & E	W. C. Beckjord	4	100.00	0	3,261	2,141
CG & E	W. C. Beckjord	5	100.00	9,811	3,857	3,864
CG & E	W. C. Beckjord	6	37.50	9,236	3,631	3,639
CG & E	W. H. Zimmer	1	46.50	0	7,509	7,524
CG & E	East Bend	2	69.00	12,277	12,888	12,916
CG & E	Woodsdale	1	100.00	0	294	295
CG & E	Woodsdale	2	100.00	0	294	295
CG & E	Woodsdale	3	100.00	0	294	295
CG & E	Woodsdale	4	100.00	0	294	295
CG & E	Woodsdale	5	100.00	0	294	295
CG & E	Woodsdale	6	100.00	0	294	295
CG & E	Killen	2	33.00	0	4,796	4,806
CG & E	Stuart	1	39.00	16,474	7,850	7,866
CG & E	Stuart	2	39.00	15,622	7,445	7,460
CG & E	Stuart	3	39.00	15,220	7,253	7,268
CG & E	Stuart	4	39.00	16,619	7,918	7,934
Total - CG & E owned units				156,958	110,242	105,366

Note: Number of allowances shown are Cinergy's portion for jointly owned units.

Figure 6-1 (Cont'd)

SO_2 ALLOWANCES ALLOCATED TO CINERGY UNITS

Operating Company	Plant Name	Unit/ Boiler No.	Percent Ownership	1999	2000-2009	2010 & after
PSI Energy	Cayuga	1	100.00	36,581	14,386	14,415
PSI Energy	Cayuga	2	100.00	37,415	14,710	14,740
PSI Energy	Cayuga	4	100.00	0	0	0
PSI Energy	Gibson	1	100.00	44,288	17,415	17,449
PSI Energy	Gibson	2	100.00	44,956	17,678	17,713
PSI Energy	Gibson	3	100.00	45,033	17,709	17,743
PSI Energy	Gibson	4	100.00	57,289	17,384	17,419
PSI Energy	Gibson	5	50.05	0	9,099	9,118
PSI Energy	R. Gallagher	1	100.00	7,115	2,908	2,914
PSI Energy	R. Gallagher	2	100.00	7,980	3,137	3,144
PSI Energy	R. Gallagher	3	100.00	7,159	2,814	2,821
PSI Energy	R. Gallagher	4	100.00	8,386	2,932	2,938
PSI Energy	Wabash River	1	100.00	5,217	1,722	1,726
PSI Energy	Wabash River	2	100.00	3,135	1,392	1,394
PSI Energy	Wabash River	3	100.00	4,111	1,616	1,619
PSI Energy	Wabash River	4	100.00	0	1,532	1,534
PSI Energy	Wabash River	5	100.00	4,023	1,582	1,584
PSI Energy	Wabash River	6	100.00	13,462	5,293	5,304
PSI Energy	Noblesville	1	100.00	0	66	66
PSI Energy	Noblesville	2	100.00	0	54	54
PSI Energy	Noblesville	3	100.00	0	40	40
PSI Energy	Edwardsport	6-1	100.00	0	0	0
PSI Energy	Edwardsport	7-1	100.00	0	347	348
PSI Energy	Edwardsport	7-2	100.00	0	354	355
PSI Energy	Edwardsport	8-1	100.00	0	375	375
Total PSI owned units				326,150	134,545	134,813

Note: Number of allowances shown are Cinergy's portion for jointly owned units.

Figure 6-2

COMPLIANCE OPTIONS CONSIDERED FOR CINERGY UNITS IN DETAILED PHASE II ANALYSIS

	BeckJ 1-4	BeckJ 5	BeckJ 6	M Fort 5	M Fort 6&7	M Fort 8	Cones 4	Stuart 1-4	Kil 2	Cay 1&2	Gal 1-4	Gib 1-3	Wab 2-5	Wab 6
PRB Coal (.8 lb SO_2/MMBtu)	X	X	X		X	X				X	X	X	X	X
Colorado Basin Coal (1.0)										X	X	X	X	X
Compliance Coal (≤1.2)	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Low/Med. Sulfur Coal (>1.2-2.5)	X	X	X	X	X	(2)		X	(2)	X	X	X	X	X
Med./High Sulf. Coal (>2.5)	(2)	X	X	X	X	(2)	X	(2)	(2)		X	(2)		
Nat Gas Firing	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Nat Gas Co-Firing	X	X	X	X	X	X				X	X	X	X	X
Wet FGD	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Sorbent Injection	X	X	(1)	X	X (unit 6 only)	(1)	(1)	(1)	(1)					
Dry FGD	X	X	X	X	X	X								

(1) Not considered on units greater than 300 MW

(2) Cannot burn coals that exceed the SO_2 lb/MMBtu SIP limit

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7. ELECTRIC TRANSMISSION FORECAST

In compliance with the codes of conduct in FERC Order 889, the relevant transmission information is located in the Transmission Volume of this report, which was prepared independently.

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8. SELECTION AND IMPLEMENTATION OF THE PLAN

A. INTRODUCTION

Once the individual screening processes for demand-side, supply-side, and emission compliance options reduced the universe of options to a manageable number, the next step was to integrate the options. This chapter will describe the integration process, the sensitivity analyses, the selection of a 1999 IRP, and its general implementation.

B. RESOURCE INTEGRATION PROCESS

The goal of the integration process was to take all of the pre-screened demand-side and supply-side options, along with the SO_2 and NO_x compliance plans, and develop an integrated resource plan, or strategy, using a consistent method of evaluation. The tool used to perform this final integration was PROSCREEN II®. In addition, PROMOD IV® was used to calculate generating unit capacity factors used in the preliminary screening of the SO_2 compliance options and in the development of the NO_x compliance plan (see Chapter 6).

1. Model Descriptions

PROSCREEN II® is a state-of-the-art computer model developed by New Energy Associates, LLC of Atlanta, Georgia. PROSCREEN II® is commercially licensed to many utilities and has been used by both PSI and CG&E for several years. As configured at Cinergy, the model consists of three modules: (1) Load Forecast Adjustment (LFA), (2) Generation and Fuels (GAF), and (3) PROVIEW™.

The LFA module is a tool for storing and processing load forecasts and incorporating the impacts of demand-side management programs. These load forecasts, in conjunction with existing unit data (i.e., availability, heat rate, fuel prices, and emission rates) are then used by the GAF module to simulate electric production system operation. The GAF provides production costs and generation reliability indicators that are essential to the automatic expansion planning module, PROVIEW™.

The PROVIEW™ module uses a dynamic programming optimization procedure coupled with end effects analysis to select expansion plans, or strategies, based on Present Value Total Cost (PVTC). The module calculates the cost and reliability effects of modifying the load with demand-side management programs or adding supply-side resources to the system. In addition, the modeling of emission-related constraints enables the user to integrate environmental compliance strategies with the supply-side and demand-side resource options. Units with high SO_2 or NO_x emission rates incur larger dispatch penalty cost adders than units with low or no SO_2 or NO_x emission rates. The dispatch adders are calculated by the model using the projected prices of emission allowances and the emission rates of the generating unit. In addition, PROVIEW™ keeps track of total company emissions and buys or sells SO_2 and NO_x allowances as needed so that every plan is in compliance with the Clean Air Act Amendments of 1990 (CAAA) and the proposed new NO_x regulations. The costs of purchasing additional SO_2 and NO_x allowances and the revenues from selling surplus SO_2 and NO_x allowances are included in the final cost accounting of each plan.

In each year, combinations of alternatives which meet pre-defined reliability and expansion criteria are evaluated and saved as states containing potential alternatives for that year. As previously outlined in Chapter 2, Cinergy uses the following criteria for resource planning: (1) minimum reserve margin of

17%, (2) maximum loss of load hours (LOLH) of 175, and (3) maximum expected unserved energy (EUE) of 0.18%. As the years in the planning horizon progress and larger amounts of new resources are needed, the number of possible combinations of options and feasible states increase nearly exponentially with the number of alternatives considered. By comparing the PVTC of the various plans generated by the model, Cinergy was able to evaluate the relative economics of different resource combinations.

PROMOD IV®, like PROSCREEN II®, has been used by both PSI and CG&E for several years and is widely accepted throughout the industry. It is a commercially licensed product also developed by New Energy Associates, LLC of Atlanta, Georgia. However, unlike PROSCREEN II®, PROMOD IV® is not a generation expansion model. It is principally a very detailed production costing model used to simulate the operation of the electric production facilities of an electric utility. Cinergy uses PROMOD IV® to develop fuel budgets, evaluate energy sales and purchases, project marginal and avoided energy costs, and gauge system reliability.

PROMOD IV® uses a probabilistic modeling technique to account for random unit forced outages and derates. It also contains algorithms that are capable of simulating unit commitment and dispatch, modeling fixed-energy transactions, estimating interruptible load curtailments, calculating emission rates, computing inter-company/region energy exchange, and modeling multiple unit-specific fuel limits. The system has inputs that fall into five general categories: (1) generating unit data, (2) fuel data, (3) load data, (4) transaction data, and (5) utility specific system operating data. These inputs, along with the complex algorithms discussed above, make PROMOD IV® a powerful tool for projecting utility electric production facility operating costs.

The energy market forecasting (EMF) model is a proprietary, trade secret model developed for Cinergy whose primary purpose is to forecast regional electric energy prices in a liquid, efficient electricity market. The EMF model is a probabilistic, scenario-based model, i.e., the model forecasts future electricity market prices based on projected price scenarios for each of the major market drivers and the probability of each scenario occurring. Presently, the EMF model includes the utilities located in the East Central Area Reliability Coordination Agreement (ECAR), and the Mid-America Interconnected Network (MAIN) North American Electric Reliability Council (NERC) regions of the country. Together, ECAR and MAIN make up a region which contains most of the Midwestern United States. The model projects prices on a monthly basis.

2. **Process**

The first step in the integration process was to develop a new PROSCREEN II® GAF module database from the most up-to-date PROMOD IV® database. Once this was completed, output reports were compared with PROMOD IV® to determine the reasonableness of such things as: unit capacity factors, fuel blends, and emission rates. Because PROMOD IV® output is used regularly for budgeting and regulatory support, the results are scrutinized carefully to ensure close simulation of reality. Throughout the IRP process the modeling was reviewed for accuracy. Also, system load reports were reviewed to make sure forecasted peak and energy values, as well as DSM impacts, were modeled correctly. The projected market prices for electricity from the October 1998 EMF were included in the PROMOD IV® and PROSCREEN II® databases to better simulate the interactions between Cinergy's system and the ECAR/MAIN market.

Once the supply-side, demand-side, and compliance screening processes were completed, the options shown below were modeled in PROVIEW™. The year(s) in parentheses denote which year(s) the alternatives were candidates available for incorporation into resource plans:

Demand-side	Supply-side
DSM Bundle (1999)	100 MW 1996 RFP Option Purchase (2000-2002)
25 MW Interruptible DSM June-September 2000-2003 (2000)	300 MW Market-Based June-August 5X16 Purchase (2000-2001)
	300 MW Unit Power Purchase June-September 2000-2003 (2000)
	56 MW 30-Year Hydro Purchase (2001)
	46 MW 30-Year Hydro Purchase (2001)
	300 MW Market-Based June-September 5X16 Purchase (2002-2003)
	165 MW New CT (2002-2003)
	214 MW New CC (2002-2003)
	256 MW New TAG CT (2004-2019)
	378 MW New TAG CC (2004-2019)
	25 MW New Fuel Cell in blocks of 200 MW (2009-2019)

Notes: 1) RFP = Request for Proposals

2) CT = Combustion Turbine

3) CC = Combined Cycle

4) 5X16 = 5 days/week, 16 hours/day

Despite the fact that the 300 MW Unit Power proposals from the 1999 RFP process were priced above market at the time of this analysis (see Chapter 5), one proposal was modeled in PROVIEW™ to further examine the economic trade-off between a four-year purchase and a series of one-year purchases. To limit the time needed to run the integration, the supply-side options were constrained somewhat with regard to the size of the alternatives available to the model. For example, the Summer Market 5X16 Purchases were made available in blocks of 300 MW, even though purchases from the market generally are available in smaller increments. In addition, the Fuel Cells were made available in blocks of 200 MW, even though the Fuel Cells are actually 25 MW in size. Furthermore, the CTs were made available in blocks of two units. Making the block sizes of alternatives larger decreases the number of states generated by PROVIEW™ and, thus, reduces run time. In the implementation of a resource plan, or strategy, the size of the resources acquired can be scaled to match the need. For ease of modeling, the 25 MW Interruptible DSM alternative was modeled as a 29 MW (25MW + Reserve Margin) dispatchable unit.

Although market purchases were not available after 2003 in PROVIEW™, the CTs and CCs selected by the model can be viewed as "placeholders" for further "peaking" and "intermediate" duty market purchases. In addition, the CCs can be viewed as "placeholders" for repowering existing units, as discussed in Chapter 5.

The integration analysis was performed over the ten year modeling period (1999-2008) with infinite end-effects. This enabled the immediate focus to be placed on the first five years, while assuring that longer-term economics were considered also. After the plan was selected, the first ten years were fixed and PROVIEW™ was re-run for the 2009-2019 period. Use of this methodology would neither change any short-term activities nor preclude any options that could be viable. Although the minimum Reserve Margin criterion was 17%, PROVIEW™ was allowed to consider plans with a minimum of 16.0% Reserve Margin in order to prevent large overshoots of the Reserve Margin criterion. This reflects the reality that installation of a unit whose size is 200-300 MW might not be financially prudent if the Company was only about 100 MW short of the criterion.

C. IDENTIFICATION OF SIGNIFICANTLY DIFFERENT PLANS

As discussed in Chapter 2, the analysis performed to develop the plan contained in this filing generally focused in more detail on the first five years, 1999-2003. This is the most important period, during which some near-term decisions will have to be made. Therefore, five years was chosen as the cut-off for determining which of the numerous plans produced by PROVIEW™ were significantly different.

The main differences during the first five years concerned the selection of different types of purchases, DSM, CTs, and CCs. Figure 8-1 shows the four plans of interest, which were: the Least Cost Plan, the 2002 CT Plan, the No DSM Plan, and the 1st CC Plan.

The Least Cost Plan was the plan with the lowest Present Value Total Cost (PVTC). It contains the DSM bundle, and supply-side resources consisting of the 5X16 summer purchases for 2000-2003, and a number of Combustion

Turbines in 2003-2005. No new resources were required for 2006-2009.

The 2002 CT Plan is identical to the Least Cost Plan through 2001, and it contains the DSM bundle. In 2002, two CTs are added, which reduces the size of the purchase required in 2002. From 2004 through 2008, the plan is identical to the Least Cost Plan.

The first plan without DSM was identical to the Least Cost Plan because the amount of DSM is relatively small.

The 1st CC Plan is identical to the Least Cost Plan through 2001, and it contains the DSM bundle. In 2002, one Combined Cycle unit is added and in 2003, two Combined Cycle units are added, which reduce the size of the purchases required in 2002 and 2003. In 2004, ten CTs are added, and in 2005, two CTs are added.

In all of these plans, the dominant reliability constraint was the minimum reserve margin. In other words, the supply-side and DSM additions contained in the plans were necessitated by the reserve margin dropping below the minimum rather than by the annual loss of load hours (LOLH) exceeding 175 or the expected unserved energy (EUE) exceeding 0.18%. The actual combination of options contained in these plans was then a result of an optimization based on the lowest PVTC.

The values obtained from the PROVIEW™ model for relative Present Value Total Cost for the four plans are as follows:

	1998 Present Value Total Cost ($1000)*	% Change from Least Cost Plan
Least Cost Plan	$24,307,116	0.00%
2002 CT Plan	$24,308,622	+0.01%
No DSM Plan	$24,316,464	+0.04%
1st CC Plan	$24,358,836	+0.21%

* Based on Market Purchases in increments of 300 MW

The effective after-tax discount rate used was 7.62%. It should be noted that these values should NOT be viewed as absolute values. They should be used only for the relative comparison of the four plans.

D. SENSITIVITY ANALYSES

The IRP Team identified a number of possible business threats during the focus period that could have large impacts on stakeholders over the modeling period. They were (in no particular order):

- Changes in technology

- Changes in relative fuel prices (coal vs. natural gas and oil and/or high sulfur coal vs. low sulfur coal)
- Increased environmental regulation or rules
- Lower level of service area load (through milder weather, lower level of economic growth, customer choice laws, regulations, rules, or pilots)

As discussed earlier, the methodology regarding the sensitivity analysis in this IRP performs more analysis at the front-end, or screening stage and less analysis at the back-end, or final integration stage. The first two threats were addressed during the screening and the results can be found in Chapters 5 and 6. Changes in environmental regulations will be discussed below in Section E. The lower level of service area load was addressed as a sensitivity at the integration stage.

For the lower load sensitivity, the plans were re-optimized from 1999 to 2008, with infinite end-effects. This allowed Cinergy to gain more insights into how its actions in the first five years would change under different assumptions. The four significantly different types of plans identified in the Base Case analysis were chosen to perform comparisons. It should be noted that the results of the sensitivity and scenario analysis is to be used for comparison of the plans to each other on a relative basis. The results of this sensitivity are discussed in more detail below.

Lower Load Sensitivity

The recent passage of customer choice legislation in Ohio and the prospect of customer choice legislation in Indiana cause uncertainty with regard to the service territory load level that must be served by the Cinergy energy production facilities. Given a constant reserve margin criterion, franchised service territory load level is the prime determinant of when and in what quantity new resources are required. Therefore, a sensitivity with a lower load level was chosen. However, the forecast does not incorporate explicit assumptions regarding the level of customer switching that could be expected because, as stated in Chapter 1, restructuring legislation in Ohio had not been enacted into law at the time the analysis for this IRP was begun. Instead, the load forecast used in this sensitivity incorporated both pessimistic economic assumptions and a lower level of weather-induced load. By the year 2008, the peak demand in this forecast is 7.9% lower while the energy requirement is 8.0% lower than in the Base Case.

Figure 8-2 shows the resulting plans under this lower load sensitivity. The Least Cost Plan contains the DSM bundle, as did the Base Case Least Cost Plan. The supply-side resources again consist of purchases for 1998-2001. One difference is that the first year that CTs are built is 2002, instead of 2003 in the Base Least Cost Plan. There are additional purchases in 2002 and 2003, and additional CTs are built in 2003 and 2004, but no new resources are required from 2005-2008. As expected, the main difference is that the level of purchases and the number of CTs required are lower.

The 2003 CT Plan is identical to the Least Cost Plan through 2001. It contains the DSM bundle. In 2002, 1300 MW is purchased while in 2003, six CTs are added, along with a 900 MW purchase. In 2004, the number of new CTs is identical to the Least Cost Plan, but there are also 2 CTs built in 2005 in this plan.

The No DSM Plan was identical to the Least Cost Plan. Again, the main difference between this sensitivity and the Base Case was the level of supply-side resources required.

The 1st CC Plan, on the surface, looks like it contains a higher level of purchase requirements in 2000 and a lower level in 2001 than the Least Cost Plan. However, this is a function of the size of the blocks of purchases required. If adjustments are made to the purchases to match the load level, the purchase amounts would be identical. In 2002, one Combined Cycle unit is added along with 1029 MW of purchases. In 2003, four CTs are added, along with 929 MW of purchases, and, in 2004, six CTs are added.

The values obtained from the PROVIEW™ model for relative Present Value Total Cost for the four plans are as follows:

	1998 Present Value Total Cost ($1000)*	% Change from Least Cost Plan
Least Cost Plan	$21,225,756	0.00%
2003 CT Plan	$21,249,860	+0.11%
No DSM Plan	$21,234,800	+0.04%
1st CC Plan	$21,234,528	+0.04%

* Based on Market Purchases in increments of 300 MW

Again, the figures above should be used only for the relative comparison of the four plans.

E. ENVIRONMENTAL RISK/REGULATORY IMPACTS

There are a number of environmental risks/regulatory changes that can affect Cinergy in the future. As a result, the Environmental Services department closely monitors these changes and participates with other departments in developing Cinergy's response to the changes. The most significant risks are discussed in more detail below.

NO_x and Ozone

A number of existing Cinergy generating facilities are located in moderate ozone non-attainment areas in both the greater Cincinnati and the greater Louisville areas. Current air quality modeling in the Cincinnati and Louisville areas has shown that additional NO_x reductions may be counterproductive in reducing ground level ozone concentrations. However, regulatory approval of these 182(f) exemptions has not been finalized. In the Louisville area, Cinergy's Gallagher generating station is currently meeting the State of Indiana's NO_x Reasonably Available Control Technology (RACT) standard. In Cincinnati, the United States Environmental

Protection (USEPA or EPA) has proposed revocation of the 1-hour ozone standard based upon the determination that the monitoring data shows the area has attained the standard. The proposal was published in the June 9, 1999 Federal Register.

Cinergy's facilities could be required to make additional NO_x reductions to contribute to achieving attainment of the ozone health standards outside of the areas in which they are located. This potential is the result of several ongoing activities.

The first is the assumption that some of the PSI generating facilities contribute to the severe non-attainment area of the greater Chicago region. This non-attainment area includes counties located in extreme Northwest Indiana. The Indiana Department of Environmental Management has given notice to Indiana utility plants that they (through participation in the Lake Michigan Air Directors Consortium (LADCO) and Ozone Transport Assessment Group (OTAG)) recommend that NO_x reductions from "upwind sources" in Indiana and other surrounding states are needed to reduce background levels of ozone in the greater Chicago area.

On July 19, 1997, EPA announced a new and tighter ozone standard to protect human health. The standard would establish new limits for the permissible levels of ground level ozone in the atmosphere. Compliance with the new standard will require significant reductions in volatile organic compounds (VOC) and nitrogen oxide emissions from utility, automotive and industrial sources including Cinergy facilities. Applicable nitrogen oxide emission reductions would likely be coordinated with other existing emission reduction requirements. EPA has suggested that controls may be mandated sometime between 2008 and 2012.

On September 24, 1998, Carol Browner signed the "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone" or State Implementation Plan (SIP) call for revision. The final rule was published in the Federal Register on October 27, 1998. With this action, EPA also released two proposed rules in support of the SIP call, "Federal Implementation Plans to Reduce the Regional Transport of Ozone" or FIP and "Findings of Significant Contribution and Rulemaking on Section 126 Petitions for Purposes of Reducing Interstate Ozone Transport" or 126 Petitions.

States were directed to respond to the call by submitting revised SIPs by September 24, 1999, and, if the submittal is substantially identical to the "model" provided by EPA, it will be approved quickly, although EPA has up to a year to complete its review. In other words, the exact requirements and administrative details for affected sources in the SIP Call will not be known with certainty until sometime in 2000.

The SIP call is based upon the premise that NO_x emissions are transported into states with ozone attainment problems and therefore EPA has set a limit or budget for NO_x emissions on each identified state. Mobile, area, industrial, and utility sources are targeted by the SIP, with utilities being called to reduce the most. As proposed, EPA has based the budgets on a 0.15 lb./MMBtu NO_x emission rate limit for utilities with a compliance date of May 1, 2003. Trading and early reduction credit after the year 2000 are also included in the "model" SIP. The following 22 jurisdictions are affected:

> Alabama, Connecticut, District of Columbia, Delaware, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, Missouri, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island,

South Carolina, Tennessee, Virginia, Wisconsin, and West Virginia.

On May 14, 1999, the Court of Appeals for the District of Columbia remanded the new National Ambient Air Quality Standards ("NAAQS") for ozone established by EPA in 1997. Since the new 8-hour ozone standard serves as the basis for a number of EPA's initiatives aimed at reducing emissions from coal-fired power plants, the decision is of high importance to Cinergy.

On May 25, 1999, the United States Court of Appeals for the District of Columbia Circuit stayed implementation of EPA's NO_x SIP Call pending the Court's resolution of the various challenges to EPA's action. The challenges are scheduled for hearing this fall with a decision expected no earlier than the end of the year.

Also on May 25, 1999, EPA published its final determination granting the 126 petitions, only to request a partial stay and begin a new rulemaking reconsidering the 126 petitions on June 11, 1999. EPA is planning to further propose another rulemaking that would include specific NO_x emission reduction requirements and specific details for a NO_x emission trading program by July 15, 1999 (EPA has missed this deadline). The new rulemakings are to be completed by November 30, 1999.

Numerous uncertainties remain concerning the technical and legal implementation of any new NO_x emission controls. However, Cinergy is investigating potential compliance approaches.

New Particulate Standard (PM 2.5)

EPA announced on July 19, 1997, new particulate standards intended to protect human health. The standards would establish limits for very small particulate, those considered respirable, less than 2.5 microns in diameter. The control of these very small particles, considered aerosols, could require significant reductions in gaseous sulfur and nitrogen emissions as well as reductions in solid particulate emissions. In any case, the particulate and aerosol controls required would result in new costs in addition to costs associated with options for the CAAA Phase II compliance. EPA has suggested that no controls would be mandated until at least 2008.

On May 14, 1999, the Court of Appeals for the District of Columbia remanded the new National Ambient Air Quality Standards ("NAAQS") for fine particulate established by EPA in 1997. Therefore it is premature to estimate compliance costs at this time. However, Cinergy is investigating potential compliance alternatives.

Regional Haze

On July 1, 1999, the EPA issued final regional haze rules under authority of Section 169A and 169B of the CAAA. These rules established planning and emission reduction timelines for states to use to improve visibility in national parks throughout the United States. The ultimate effect of the new regional haze rules is to eliminate man-made "regional haze" in the next 60 years. The rules would require states to submit visibility SIPs by 2008 which include emission reduction requirements for subsequent years. These new emission reduction rules could require newer and cleaner generation technologies and additional controls on utility sources of SO_2 and NO_x. In August 1999, numerous state, industry, and environmental groups filed legal challenges to the regional haze rule. Cinergy will continue to monitor these developments and their impact on the company.

<u>Hazardous Air Pollutants from Utility Power Plants</u>

The Clean Air Act Amendments of 1990 required the EPA to conduct a study of the impact on human health of power plant emissions of a list of 189 Hazardous Air Pollutants (HAPs), and, if warranted by that study, to develop regulations to control those emissions. The HAP study was due to Congress November 15, 1993. The EPA determined that the best data to be used for this study was field data being collected by the Electric Power Research Institute (EPRI), a research arm of the electric utility industry, and the Department of Energy (DOE). Because this data was not yet available, EPA informed Congress that it would delay its report. EPA released an interim draft report in mid-October of 1996. The final HAP report was submitted to Congress in February 1998.

EPA has identified mercury as a potential human health concern and has proposed that mercury emissions from power plants be further researched and monitored. Recent health studies based on mercury levels in exposed humans, even in sustenance fishermen, show no link of mercury exposure to health risks. Despite these facts, enough political interest and pressure exist that mercury controls could be regulated by the EPA or legislated by Congress.

The Executive Committee of the Science Advisory Board (SAB), created by Congress in 1978, approved a draft mercury report from the SAB Subcommittee on Mercury in July 1997. The report was forwarded to EPA for consideration and action. EPA issued the final Mercury Report to Congress in December 1997.

In 1999, USEPA has implemented an information collection request that includes fuel sampling and stack testing within the utility industry. The massive data collection effort will be completed in 2000. The data is being collected to supplement USEPA's Report to Congress and will support any decision on the regulation of mercury emissions from utility sources. Specifically, the information collection request will provide more certainty on the quantity and speciation of mercury emitted and the removal efficiency of existing emission control equipment.

Cinergy will continue to monitor the development of this issue.

Global Climate Change

Since 1994 Cinergy Corp. has been actively involved in climate change issues. In addition, Cinergy has been studying its activities that emit greenhouse gases (GHG) and evaluating strategies to reduce or offset those emissions. With the signing of a U.S. Department of Energy (DOE) Climate Challenge Participation Accord (Climate Challenge or Participation Accord) in February 1995, Cinergy's management endorsed the goal of trying to return Cinergy's GHG emissions to 1990 levels by 2000 in a cost effective manner.

In keeping with its Climate Challenge commitment, Cinergy chose to participate in the U.S. Initiative on Joint Implementation (USIJI) approved Belize Rio Bravo forest preservation and sustainable management project with three other investor owned utilities, The Nature Conservancy, The Programme for Belize (a non-profit environmental organization), and UtiliTree Carbon Company (a utility industry initiative through the Edison Electric Institute). The project includes two components: Component A, forest preservation; and Component B, sustainable forestry practices.

Component A of the project involved the purchase of a 15,000-acre parcel of endangered forest land that links two protected properties with the Rio Bravo Conservation Area. Imminent conversion to agricultural use threatened this property. Winrock International, an independent consultant, measured the greenhouse gas benefit of this purchase and estimated it at more than 800,000 tons of carbon dioxide. This figure is higher than what was originally estimated.

Component B of the project will implement a sustainable forest management program on the Rio Bravo Conservation and Management Area. The program is designed to increase the total pool of sequestered carbon in a 60,000-acre area of the 125,000-acre Rio Bravo Conservation Area, including the area of Component A. It will then seek to extend the sustainable forestry model into adjacent properties. This component also includes plans to develop and implement a marketing strategy for sustainable timber extraction.

Cinergy has committed to invest in the project over a ten-year period. However, Cinergy will receive carbon offsets for a forty-year period. After the first ten years, the Programme for Belize will be self-sufficient based on revenues generated by the sustainable forestry program, forest products program, and environmental tourism. Cinergy estimates that the cost of carbon offsets from the Belize project will be about $0.64 per ton of CO_2.

In accordance with its DOE Participation Accord, Cinergy submits an annual Section 1605(b) report concerning Cinergy's GHG emission reduction and offsetting activities. Cinergy's first report in 1995 identified activities implemented between 1991 and 1994 that reduced or offset Cinergy's GHG emissions. This first report listed activities that reduced or offset Cinergy's GHG emissions by an estimated 1.3 million tons of CO_2 equivalents (CO_2 equivalents include actual CO_2 emissions as well as methane and CFCs converted to CO_2 equivalents by using the Intergovernmental Panel on Climate Change (IPCC) factors for these other GHGs). Cinergy's 1998 report listed activities that reduced or offset Cinergy's GHG emissions by an estimated 3.7 million tons of CO_2 equivalents.

Activities implemented or supported by Cinergy that have reduced or offset its GHG emissions include:

- Electric generation from recovered landfill (methane) gas;
- Demand-side management programs;
- Landfill gas recovery for use as a natural gas supply;
- Rio Bravo carbon sequestration project;
- Trees planted at Cinergy facilities;
- Forestry projects with the Ohio and Indiana Chapters of The Nature Conservancy, Ducks Unlimited, and the National Wild Turkey Federation;
- Edison Electric Institute UtiliTree Carbon Co.;
- Beneficial reuse of coal ash;
- Efficiencies created through merged dispatching;
- Power plant efficiency programs;
- Paper and aluminum recycling.

Cinergy's Climate Challenge program efforts have resulted in a cumulative total of nearly 12.5 million tons of CO_2 equivalent reductions and offsets since 1991.

In 1999, Cinergy agreed with USEPA to voluntarily join the SF_6 Emissions Reduction Partnership for Electric

Power Systems. The purpose of the agreement is to achieve environmental and economic benefits by reducing emissions of sulfur hexafluoride (SF_6) during operation and maintenance of equipment used in transmission and distribution of electricity.

Cinergy, through its non-regulated subsidiary companies, Cinergy Global Power and Trigen-Cinergy solutions, is developing and implementing a number of renewable energy and higher energy efficiency projects (e.g. cogeneration, district heating and cooling, etc.). These projects are being developed in the United States, including Ohio, and in other countries around the world.

Alternative property and right-of-way management practices are being investigated to reduce annual property management costs. One of the more promising practices appears to be the planting of warm season prairie grasses. Benefits of planting the prairie grasses include less mowing, wildlife habitat, and sequestration of carbon. Cinergy is identifying potential properties and transmission rights-of-way on which to implement the alternative management practices. Part of the program will be to engage the services of a state university to assist Cinergy in developing a protocol for measuring the amount of carbon sequestered by the warm season grasses.

New technologies are the only long-term solution that would make the large reductions in carbon dioxide (CO_2) emissions necessary to have any real effect on atmospheric carbon concentrations. Research and development will be very important to any effort to reduce CO_2 emissions by the electric industry.

Even without short-term changes in the carbon-based fossil fuels used to generate electricity, electricity can be part of the solution to reducing GHG emissions. Through the promotion of electrotechnologies to replace less efficient use of fossil fuels, GHG emissions can be reduced. The more wide spread use of electrotechnologies will increase CO_2 emissions from the electric sector, but will be more than offset by the overall reduced CO_2 emissions from the fossil fuels that they replace.

The Electric Power Research Institute (EPRI) has completed several GHG research projects that demonstrate that there is sufficient time to deal with climate change, assuming that science eventually demonstrates that there are real climate change dangers associated with human activity and the associated emissions. Currently, there are many uncertainties concerning the science of the Earth's climate systems and whether or not a change in the Earth's climate is actually occurring, and if so, whether a change will be harmful to Earth's human, animal, and plant populations.

The most notable research conducted by EPRI to date are two economic research projects; one by Manne and Richels (1996) which dealt with the timing and cost of GHG emission reductions, and the other by Wigley, Richels, and Edmonds (1996) which dealt with stabilization of atmospheric CO_2.

The research conducted by Wigley, Richels, and Edmonds demonstrated that there are a number of scenarios that could be used to reach the same level of atmospheric carbon concentrations. They demonstrated that the most cost-effective approach to achieve stabilization of atmospheric CO_2 would be to establish a carbon budget for an extended period of time, which would allow existing capital stock to turn over naturally. The scenario developed by the authors allows for "business as usual" over the next 30 to 50 years with the replacement of existing capital stock at the end of its useful life with carbon-less energy technologies. The IPCC's Second Science Assessment Report published in December 1996 included the research work conducted by these authors and sponsored by EPRI.

The concept developed by Manne and Richels demonstrated that allowing spatial (where CO_2 reductions are implemented) and intertemporal (when CO_2 reductions are implemented) efficiency rather than year to year constraints on atmospheric carbon concentrations could reduce the cost of GHG mitigation by more than 80%. Joint Implementation, for the trading of carbon credits throughout the world, is an integral component of the Manne and Richels concept.

F. PLAN SELECTION

1. Description

Based upon both the quantitative and qualitative results of the screening analyses, sensitivity analyses, and environmental considerations outlined above, the Least Cost Plan under Base Case conditions was selected to be the 1999 IRP. In both the Base Case and the sensitivity, a plan showing purchases through 2001 had the lowest Present Value Total Cost.

Under Base Case conditions, the plan with purchases in 2002 and CTs in 2003 was slightly less costly than the plan with CTs in 2002, while in the Lower Load Sensitivity, the plan with CTs in 2002 was slightly less costly than the plan with CTs in 2003. Based on these results, Cinergy will continue to investigate the economics of purchases versus CTs as updated information is available with regard to purchase prices and CT prices.

The impacts of the risks of future environmental regulations do not play a significant role in the selection of the plan in this IRP due to the nature of the Significantly Different Plans. Only market purchases and gas-fired Combustion Turbines or Combined Cycle units were selected in any of the plans. The environmental risks discussed above in Section E have a much greater impact on the existing generating units (which were common to all of the plans). In addition, selection of the Least Cost Plan does not foreclose any options for dealing with these environmental risks as they mature.

The final step in the process involved longer-term analysis of the last eleven years. The first ten years of the Least Cost Plan were fixed and PROVIEW™ was run for the period 2009-2019. A plan covering the entire 1999-2019 period is shown in Figure 8-3. Judgement was exercised to develop the plan shown in that the purchases were sized to meet the 17% reserve margin criteria and one CT was delayed from 2004 to 2006 to better match resources with the load to be served.

This plan contains the DSM bundle (described in Chapter 4). The supply-side resources consist of purchases for 2000-2002, a combination of purchases and CTs in 2003, and a number of Combustion Turbines in 2004-2006. From 2009 to 2014, the plan contains 800 MW of Fuel Cell capacity. In 2011, 378 MW of CC capacity is added, and, from 2015 to 2018, one CT each year is added.

The purchases shown in the plan can represent summer 5X16 purchases, options, multi-year unit power purchases from or of new capacity scheduled to be built in the region, or a combination of the above. The decision as to the actual types of purchases that Cinergy will make depends on the relative prices of the alternatives available at that time.

The final plan again contains Fuel Cells, as it did in the 1997 and 1998 IRPs. As discussed in Chapter 5, Fuel Cells were the preferred technology for baseload operation. Of course, whether or not they are the technology of choice in 2009 is highly dependent on whether EPRI's projections of Fuel Cell capital cost and heat rate can become a reality. Nonetheless, the selection of Fuel Cells in the final plan indicates a need for low cost, clean, and efficient baseload capacity during the last ten years, for which Fuel Cells currently act as a "placeholder."

The year-by-year Projected Generating Capability Changes to the Cinergy system (including existing unit changes) are shown in Figure GA-8-4, found in the General Appendix. The capacity changes as a result of the NO_x compliance plan have been redacted because Cinergy considers this to be Proprietary and Confidential information.

The allocations of the supply-side resources to CG&E and PSI, based on the allocation methodology outlined in The Operating Agreement among CG&E, PSI, and Cinergy Services, are shown in Figure 8-5. However, the actual allocations will depend on the relative needs of the two operating companies at the time the decision is made to acquire new resources. The Operating Agreement states,

> "The new Generating Resources shall be assigned (in megawatts (MW)) to each Operating Company so that, to the extent practicable, the Forecasted Reserve Margins of each Operating Company are equalized consistent with the Cinergy IRP upon which the decision to acquire is predicated."

This rule also applies to purchases made to fulfill capacity requirements rather than for operating reasons.

The details of the 1999 IRP including yearly capacity, purchases, capacity additions, retirements/derates, cogeneration, load, DSM, interruptible load, firm sales and reserve margins for Cinergy, PSI and CG&E are shown in Figure 8-6. In December 1998, the Operating Committee approved the purchase of about 700 MW of power to maintain no less than a 12% Operating Reserve Margin for the 1999 summer. This purchase was in addition to an assumed

90 MW purchase from OVEC which would be allocated 100% to CG&E. Any additional capacity needs required for the period would be purchased on the spot market. At the time the Operating Committee met, the proper allocation of the 700 MW of purchases to equalize the reserve margins was 48% to CG&E and 52% to PSI. However, the 1999 IRP reflects more up-to-date information concerning capacity (including the fact that the actual OVEC purchase was 63 MW instead of 90 MW), load, and DSM impacts, which is why the 1999 reserve margins of the individual Operating Companies shown in Figure 8-6 are not exactly equal.

The IRP includes the projected SO_2 and NO_x compliance options described earlier in Chapter 6.
Any shortfalls between the yearly allowance allocation from the EPA and the actual SO_2 or NO_x emitted will be supplied by Cinergy's allowance banks or by allowance purchases from the market.

The relative value for the 1998 Present Value Total Cost obtained from the PROVIEW™ output for the 1999 IRP is $29,869,692,000. The effective after-tax discount rate used was 7.62%.

With the inclusion of estimates of both spot market purchases from, and sales to, the ECAR/MAIN regional electricity market within the PROVIEW™ modeling, Present Value Average Rate figures would not accurately reflect projected customer rates, so they have been omitted.

Figure 8-7 summarizes the annual forecasted loads and required generating capability for the planning period (1999-2019) for both summer and winter seasons. Figures 8-8 and 8-9 show the actual and forecasted peak load and resources for 1994-2019 for the summer season and the winter season, respectively. Figures 8-10 through 8-13 give some of the estimated specifications and characteristics of the planned generating facilities contained in the IRP: 165 MW New CTs (CT), 214 MW New CTs (NCT), 378 MW CCs (NCC), and New Fuel Cell Units (NFC).

2. Projected Reliability

Since the plan selected, as well as the other significantly different plans, shows additional DSM in 1999, along with purchases and new supply-side resources throughout the plan, it is obvious that the existing system does not meet the system reliability standard, either in the short-term or the long-term. This assessment, of course, is highly dependent on the actual load levels realized compared to those forecasted.

The 1999 IRP satisfies the reliability criteria described in Chapter 2 throughout the planning period. However, this is dependent on the demand-side resources performing as expected, the continued levels of reliability of existing resources, and the load level experienced.

3. Environmental Effects

As mentioned previously, the plan contains electricity purchases from the market from 1999 through 2003, along with gas-fired CTs, a Combined Cycle unit, and Fuel Cells starting in 2003. The emissions of the market purchases are unknown at this time because the exact source(s) of the power are unknown. However, since peaking capacity is preferred, the power may well be generated from gas or oil. The CTs, CC, and Fuel Cells are relatively clean technologies. Therefore, the majority of air emissions in the plan will be produced by the existing coal-fired units on Cinergy's system.

Hazardous Air Pollutants or Air Toxics were previously discussed in Section E of this chapter.

The only solid waste streams of significance in this study are the coal combustion by-products. These include the fly ash, bottom ash, and the fixated sludge from the scrubbers. Historically, Cinergy has disposed of the fly and bottom ash in mono-purpose facilities. Scrubber sludge is also landfilled in a mono-purpose facility. These materials are non-hazardous and can be safely disposed of in this manner. Of importance is Cinergy's continued commitment to pollution prevention. This effort will lead to a continued search for alternative reuses of these materials. Both Operating Companies have some experience with selling fly ash as a component of building materials. Cinergy is also investing capital dollars at Zimmer Station to make high quality synthetic gypsum that will be sold to a new wallboard manufacturing plant (see the Short-Term Implementation Plan, STATUS Report, and Ohio Appendix for more details). Cinergy expects to create a significant environmental benefit by converting the by-product from the unit's sulfur dioxide scrubber into synthetic gypsum, rather than landfilling it. The amount of material placed in the station's landfill can be reduced by as much as 77 percent.

An additional issue is the discharge of waste heat used to cool generating plants. Any new steam units will be required to provide for waste heat control by utilizing a closed cycle cooling system.

The Wabash River Unit 1 Coal Gasification Repowering Project, when operating on syngas, produces two salable by-products: elemental sulfur, and a glass-like inert slag that also has use in the construction industry.

Cinergy currently complies with existing environmental requirements and is committed to continue to do so. In fact, Cinergy's Board of Directors approved a Cinergy Environmental Leadership Pledge, which states:

> "Cinergy and its subsidiaries will be industry leaders in protecting our environment. We will meet or exceed all applicable regulatory requirements and seek ways to enhance our natural surroundings while providing our customers with low cost,

reliable and efficient energy services. Each employee of Cinergy will work with respect for the environment and in accordance with this environmental pledge."

The cost of environmental controls is included in the cost estimates for any new resources (both supply-side and compliance). The costs at existing generating units have been accounted for in their O&M cost estimates.

G. UNCERTAINTIES AFFECTING PLAN IMPLEMENTATION

In making decisions concerning what steps to take to begin the implementation of an IRP, careful consideration must be given to the current business environment in which utilities operate. The industry stands on the threshold of a new century, and at this point, the only thing that is certain is that the future of the entire industry is more uncertain now than it has ever been. Since three of the IRP Objectives discussed in Chapter 2 were to maintain flexibility, provide economical service, and minimize risk, it is imperative that the uncertainties facing Cinergy be factored into the decisions concerning the implementation of the 1999 IRP.

1. Regulatory Climate

Investor-owned public utilities are among the most regulated and scrutinized of our nation's industries. In addition to federal regulation, Ohio, Indiana and Kentucky have steadily increased the number of regulations that affect Cinergy.

A chart on Federal Energy and Environmental Legislation impacting investor-owned public utilities, promulgated since 1899, would show that well over 80% have gone into effect since 1970. More than 50% of all legislation of this kind has been developed since 1976. On the environmental side alone, over 33% of the federal laws, amendments, and reauthorizations were enacted during the 1980s.

The regulatory climate is becoming more onerous and burdensome for the public utility industry. USEPA finalized new NAAQS for ozone, fine particulate matter, and regional haze in July 1997, and, in September 1998, finalized the ozone transport SIP Call requiring NO_x emission reductions. However, implementation of all three regulations have been delayed by the courts and future requirements for emission reductions and deadlines are uncertain.

The potential exists for additional regulation to be imposed on utilities in the form of CO_2 legislation, carbon taxes and energy taxes, regional haze, air-toxics measures, and additional new facility siting requirements. The outlook, from the regulated utility's perspective, contains a great deal of uncertainty with respect to the regulatory climate.

2. **Customer Choice/Competition**

The electric utility industry has already experienced substantial competition in the wholesale power market. The effect of the Energy Policy Act of 1992 (Energy Act), the most comprehensive energy legislation enacted since the late 1970s, is to provide essentially open competition, at the wholesale level, for new generation resources. The Energy Act increases the level of competition by creating a new class of wholesale power providers that is not subject to the restrictive requirements of the Public Utility Holding Company Act of 1935 (PUHCA) nor the ownership restrictions of the Public Utility Regulatory Policies Act of 1978 (PURPA). This, combined with the provision of the Energy Act granting the Federal Energy Regulatory Commission (FERC) the authority to order wholesale transmission access, makes competition a current reality in the wholesale power market.

Utilities also currently experience competition, in a more limited sense, in the retail energy markets. There is competition between electricity, natural gas, propane and oil for certain end-uses. In addition, there is competition for the attraction of new customers and facilities, the expansion of existing customers and facilities, the relocation of existing customers and facilities from other areas, and the retention of existing economically distressed customer loads. Customer self-generation and cogeneration are also sources of competition.

Recently, the increasing competitive pressures in the retail power market have been magnified, driven primarily by the need for low cost power by U.S. industries in order to remain competitive in the global marketplace. Many state commissions and legislatures (including Ohio & Indiana) either have been investigating restructuring the utility industry to allow direct access or retail wheeling or have already enacted such changes (see Amended Substitute Senate Bill Number 3 as passed by the 123rd General

Assembly of Ohio, and signed by the Governor of Ohio on July 6, 1999). Federal legislation also has been introduced which could mandate retail competition. Deregulation will weaken or totally de-couple the traditional one-to-one correspondence present in the industry between generating capability and franchised geographical service territory load obligations, which heightens the uncertainty surrounding the load level that should be included in a utility's plan.

3. **Wholesale Customer Uncertainties**

About 10-15 years ago, Wholesale customers (REMCs, municipals, etc.) began to band together to form Power Associations/Agencies to collectively purchase power, and, in some instances, build or buy generation and transmission. Now, with wholesale transmission access to multiple suppliers a reality, these wholesale customers are not renewing full or partial requirement contracts with their traditional suppliers or are trying to renegotiate or cancel their existing contracts. This trend in the wholesale power market leads to uncertainty in planning for wholesale customers' loads.

4. **Supply-Side Uncertainty**

Not only is there uncertainty surrounding the level of load to be served in the future, but the potential still exists under PURPA for Cinergy to be forced to purchase power from cogenerators, whether the power is actually required or not. Under this Federal law, utilities are mandated to purchase power at "avoided cost" from Qualifying Facilities (QFs). It is Cinergy's practice to negotiate with these QFs in good faith.

5. **Technological and Market Advances**

It is always possible that a future technological breakthrough could result in newer and better options being made available to serve resource needs. Technological advances could even include a paradigm shift in the fundamental method of producing and delivering power to customers from a mainly centralized approach to a totally dispersed approach.

With the current level of competition in the wholesale market and the increasing level of competition in the retail market, it is conceivable that electricity could become a commodity on the market very similar to oil, corn, or wheat.

Electricity options and futures trading are current realities in the Cinergy area as well as in other parts of the country. The heightened level of awareness of and sophistication to the electricity market will undoubtedly cause the industry to re-evaluate the way resource procurement is undertaken in the future.

H. PLAN IMPLEMENTATION

All of the uncertainties outlined above underscore the need to remain flexible in the implementation of the plan. Future investments must be approached cautiously to maintain or enhance the opportunity to anticipate, react, respond, and adjust to change as it occurs, while still preserving as many options as reasonably possible.

1. Supply-Side Resources

Cinergy has not yet contracted for the purchases shown in the plan for the summers of 2000-2003. Decisions concerning whether to exercise the 100 MW call option purchased in the 1996 RFP will be made prior to the Option Exercise Date each Spring based on the economics at the time. The purchases will be comprised of a combination of forward or option or unit power contracts secured prior to the time required and spot purchases from the market on either a weekly or daily basis. As stated earlier, the decision as to the actual types of purchases that Cinergy will make depends on the relative prices of the alternatives available at that time. In addition, the uncertainties enumerated above suggest that smaller purchases than what is shown in the plan may be required. As a result, the Operations and Power Marketing and Trading departments, which are constantly monitoring both the Cinergy system and the regional marketplace, in consultation with Resource Planning and the Operating Committee, will use their judgment to make decisions concerning the proper timing, type, and quantity of purchases required based on the need projections and applicable conditions at the time.

The magnitude of the purchases shown in the plan raises the question of whether the quantity of power required can be imported physically into the Cinergy system. Cinergy's Bulk Transmission Planning department will be evaluating whether upgrades to existing transmission or construction of new transmission capacity is required to accommodate the purchase requirements. The cost of any changes necessary to the transmission system will then be added to the costs to purchase power and compared to the cost of constructing new generating capacity to determine the most economical way to meet Cinergy's needs.

The CTs shown in the plan beginning in 2003 will continue to be studied to determine whether the need is of the magnitude indicated (see discussion of uncertainties above) and to determine the most economical ways of serving whatever need exists. Cinergy will continue to investigate the economics of purchases versus CTs as updated information is available with regard to purchase prices and CT prices. As stated previously, the purchases, CTs, CC, and Fuel Cells in the plan represent "placeholders" for capacity and energy needs on the system. These needs can be fulfilled by purchases from the market, cogeneration, repowering, or other capacity that may be economical at the time decisions to acquire new capacity are required. Decisions concerning coordinating the construction and operation of new units with other utilities or entities can also be made at the proper time. Until then, coordination will be achieved through purchases and sales in the bulk power market.

2. Compliance Resources

To comply with Phase II sulfur dioxide emission requirements, Cinergy's current strategy, as described in detail in Chapter 6, includes a combination of switching to lower-sulfur coals and using an emission allowance banking strategy. This cost-effective strategy will allow Cinergy to meet Phase II sulfur dioxide reduction requirements while maintaining optimal flexibility. Cinergy intends to use an emission allowance banking strategy to the extent a viable emission allowance market exists. However, the availability and economic value of emission allowances over the long term is still uncertain. In the event the market price for emission allowances or lower-sulfur coal increases substantially from the current forecast, Cinergy could be forced to implement high capital cost compliance options. Fuel switches generally can be implemented in two years or less. Therefore, the implementation of a number of these fuel switches has not been finalized at this time.

The NO_x compliance strategy was also detailed in Chapter 6. Even though the stay of the SIP Call has been granted, Cinergy continues to study the compliance options available to comply with future NO_x emission reductions. The level of reductions and timing for compliance are unknown and likely to remain uncertain until next spring. However, given that USEPA's previous compliance date would have been extremely difficult to meet and still retain Cinergy's system reliability, it is still prudent to be prepared to cost effectively meet USEPA's emission reduction goals. Whenever possible, Cinergy plans to implement the NO_x compliance controls during regularly scheduled unit outages.

It should be noted that, for the CG&E units that are jointly owned by Columbus Southern Power and Dayton Power & Light, the impacts on the co-owners must be considered and a decision made jointly as to how to meet environmental requirements. The results of this IRP reflect only the preliminary economic analysis performed by Cinergy, from a Cinergy perspective.

Cinergy will be closely monitoring the SO_2 and NO_x emission allowance markets to determine whether the

SO_2 and NO_x compliance plans continue to be economic. These compliance strategies will be adjusted as needed to ensure that the most economical plans are implemented.

3. Demand-Side Resources

The only difference between the programs modeled for PSI and CG&E in the IRP and those currently planned for implementation by each operating company is that only the programs that Cinergy considers resource programs are modeled in the IRP. Omission of the estimated impacts of the non-resource programs does not constitute a material difference in the results of the planning process.

4. Consistency with Planning Objectives and Goals

The 1999 IRP, with its proposed implementation, is consistent with the overall planning objectives and goals discussed in Chapter 2. The plan, or strategy, that was chosen was the least cost (PVTC), minimizes new generating facility investments in the near-term, and allows Cinergy flexibility to respond to changes. Purchases from the market permit Cinergy to delay decisions involving the long-term commitment of capital. In addition, fuel test burns and monitoring of the SO_2 and NO_x emission allowance markets provide flexibility to Cinergy's compliance strategy. The level of flexibility in the implementation of the IRP also reduces risk.

5. Financial Impact

Cinergy estimates that a combination of internal and external funds will be used to meet its capital needs. External funds will be used for refinancing of maturing debt and preferred stock, and the early refunding of existing high-cost debt and preferred stock, in addition to financing other capital needs. The impact of the 1999 IRP on the financial status of Cinergy is dependent on the actual amount of new resources required, legislative and regulatory actions, and on the frequency and timing of future rate relief.

Figure 8-1

Significantly Different Plans- Base Case

	Least Cost Plan	2002 CT Plan	No DSM Plan	1st CC Plan
1999	763MW Purch. DSM Bundle	763MW Purch. DSM Bundle	763MW Purch.	763MW Purch. DSM Bundle
2000	1600MW Purch.	1600MW Purch.	1600MW Purch.	1600MW Purch.
2001	1900MW Purch.	1900MW Purch.	1900MW Purch.	1900MW Purch.
2002	2200MW Purch.	2-165MW CTs 1900MW Purch.	2200MW Purch.	1-256MW CC 1300MW Purch.
2003	2-165MW CTs 2100MW Purch.	2100MW Purch.	2-165MW CTs 2100MW Purch.	2-256MW CCs 1800MW Purch.
2004	12-214MW CTs	12-214MW CTs	12-214MW CTs	10-214MW CTs
2005	2-214MW CTs	2-214MW CTs	2-214MW CTs	2-214MW CTs
2006				
2007				
2008				

Figure 8-2

Significantly Different Plans- Lower Load Sensitivity

	Least Cost Plan	2003 CT Plan	No DSM Plan	1st CC Plan
1999	763MW Purch. DSM Bundle	763MW Purch. DSM Bundle	763MW Purch.	763MW Purch. DSM Bundle
2000	1000MW Purch.	1000MW Purch.	1000MW Purch.	1029MW Purch.
2001	1300MW Purch.	1300MW Purch.	1300MW Purch.	1029MW Purch.
2002	2-165MW CTs 1000MW Purch.	1300MW Purch.	2-165MW CTs 1000MW Purch.	1-256MW CC 1029MW Purch.
2003	6-165MW CTs 600MW Purch.	6-165MW CTs 900MW Purch.	6-165MW CTs 600MW Purch.	4-165MW CTs 929MW Purch.
2004	4-214MW CTs	4-214MW CTs	4-214MW CTs	6-214MW CTs
2005		2-214MW CTs		
2006				
2007				
2008				

Figure 8-3

1999 CINERGY INTEGRATED RESOURCE PLAN

YEAR	NEW RESOURCE ADDITIONS
1999	DSM Bundle 763 MW Purchase
2000	1460 MW Purchase
2001	1740 MW Purchase
2002	2070 MW Purchase
2003	2200 MW Purchase 2-165 MW CTs
2004	11-214 MW CTs
2005	2-214 MW CTs
2006	1-214 MW CT
2007	
2008	
2009	8-25 MW Fuel Cells
2010	8-25 MW Fuel Cells
2011	1-378 MW CC
2012	
2013	8-25 MW Fuel Cells
2014	8-25 MW Fuel Cells
2015	1-214 MW CT
2016	1-214 MW CT
2017	1-214 MW CT
2018	1-214 MW CT
2019	

Figure 8-5

CURRENT ESTIMATE OF SUPPLY-SIDE RESOURCE ALLOCATIONS

Year	Supply-Side Resource Added	CG&E % Allocation	PSI % Allocation
1999*	763 MW Purchase	52.0	48.0
2000	1460 MW Purchase	52.5	47.5
2001	1740 MW Purchase	51.2	48.8
2002	2070 MW Purchase	49.1	50.9
2003	2200 MW Purchase	45.5	54.5
	2-165 MW CTs	59.5	40.5
2004	11-214 MW CTs	47.0	53.0
2005	2-214 MW CTs	67.5	32.5
2006	1-214 MW CT	63.3	36.7
2007			
2008			
2009	8-25 MW Fuel Cells	100.0	0.0
2010	8-25 MW Fuel Cells	81.7	18.3
2011	1-378 MW CC	46.5	53.5
2012			
2013	8-25 MW Fuel Cells	42.9	57.1
2014	8-25 MW Fuel Cells	50.0	50.0
2015	1-214 MW CT	46.6	53.4
2016	1-214 MW CT	46.5	53.5
2017	1-214 MW CT	45.1	54.9
2018	1-214 MW CT	49.4	50.6
2019			

* 1999 Actual

Figure 8-6

CINERGY
1999 INTEGRATED RESOURCE PLAN

CINERGY TOTAL

YEAR	INITIAL CAPACITY*	SHORT TERM PURCH.	INCR. CAPACITY ADDITIONS	INCR. CAPACITY RETIRE./ DERATES	PURCH. COGEN. CAPACITY	TOTAL CAPACITY	PEAK LOAD**	EXIST. DSM***	INCR. DSM	ENERGY OPTIONS	INDUSTRIAL AS AVAIL. LOAD	INDUSTRIAL INTER. LOAD	FIRM SALES	NET LOAD	RES. MAR. (%)
1999	11183	813	78	0	4	12078	11035	-2	-1	-103	-169	-165	70	10664	13.3
2000	11261	1460	5	0	4	12730	11252	-2	-2	-103	-170	-163	70	10881	17.0
2001	11266	1740	0	0	4	13010	11483	-2	-2	-103	-171	-158	70	11116	17.0
2002	11266	2070	0	0	4	13340	11772	-2	-2	-103	-171	-158	70	11405	17.0
2003	11266	2200	330	-44	4	13756	12124	-2	-2	-103	-172	-158	70	11756	17.0
2004	11552	0	2354	0	4	13910	12356	-2	-2	-103	-173	-158	70	11987	16.0
2005	13906	0	428	0	4	14338	12615	-2	-2	-103	-173	-158	70	12246	17.1
2006	14334	0	214	0	4	14552	12795	-2	-2	-103	-174	-158	70	12425	17.1
2007	14548	0	0	0	4	14552	12676	-2	-2	-103	-174	-158	70	12306	18.2
2008	14548	0	0	0	4	14552	12871	-2	-2	-103	-174	-158	70	12501	16.4
2009	14548	0	200	0	4	14752	13060	-2	0	-103	-174	-158	70	12692	16.2
2010	14748	0	200	0	4	14952	13246	-2	0	-103	-174	-158	70	12878	16.1
2011	14948	0	378	0	4	15330	13435	-2	0	-103	-174	-158	70	13067	17.3
2012	15326	0	0	0	4	15330	13586	-2	0	-103	-174	-158	70	13218	16.0
2013	15326	0	200	0	4	15530	13734	-1	0	-103	-174	-158	70	13367	16.2
2014	15526	0	200	0	4	15730	13884	0	0	-103	-174	-158	70	13518	16.4
2015	15726	0	214	0	4	15944	14035	0	0	-103	-174	-158	70	13669	16.6
2016	15940	0	214	0	4	16158	14176	0	0	-103	-174	-158	70	13810	17.0
2017	16154	0	214	0	4	16372	14314	0	0	-103	-174	-158	70	13948	17.4
2018	16368	0	214	0	4	16586	14467	0	0	-103	-174	-158	70	14101	17.6
2019	16582	0	0	0	4	16586	14599	0	0	-103	-174	-158	70	14233	16.5

* Including Gibson 5 capacity owned by IMPA and WVPA
Excluding EKPC Purchase and previous year's Short Term Purchases
15MW derate to serve steam to Inland Container has been deducted

** Including IMPA and WVPA peak load requirements corresponding to their Gibson 5 ownership
Excluding WVPA Supplemental Load beginning 1/1/98
Excluding IMPA Supplemental Load beginning 1/1/07
Excluding customer cogeneration

*** Not included in load forecast

Figure 8-6

CINERGY
1999 INTEGRATED RESOURCE PLAN

PSI SYSTEM

YEAR	INITIAL CAPACITY*	SHORT TERM PURCH.	INCR. CAPACITY ADDITIONS	INCR. CAPACITY RETIRE./ DERATES	PURCH. COGEN. CAPACITY	TOTAL CAPACITY	PEAK LOAD**	EXIST. DSM***	INCR. DSM	ENERGY OPTIONS	INDUSTRIAL AS AVAIL. LOAD	INDUSTRIAL INTER. LOAD	FIRM SALES	NET LOAD	RES. MAR. (%)
1999	6158	366	21	0	4	6549	6050	-2	-1	-44	-169	-132	70	5772	13.5
2000	6179	694	5	0	4	6882	6162	-2	-2	-44	-170	-132	70	5882	17.0
2001	6184	848	0	0	4	7036	6293	-2	-2	-44	-171	-132	70	6012	17.0
2002	6184	1055	0	0	4	7243	6473	-2	-2	-44	-171	-132	70	6192	17.0
2003	6184	1199	134	-25	4	7496	6688	-2	-2	-44	-172	-132	70	6406	17.0
2004	6293	0	1248	0	4	7545	6785	-2	-2	-44	-173	-132	70	6502	16.0
2005	7541	0	139	0	4	7684	6846	-2	-2	-44	-173	-132	70	6563	17.1
2006	7680	0	78	0	4	7762	6912	-2	-2	-44	-174	-132	70	6628	17.1
2007	7758	0	0	0	4	7762	6694	-2	-2	-44	-174	-132	70	6410	21.1
2008	7758	0	0	0	4	7762	6792	-2	-2	-44	-174	-132	70	6508	19.3
2009	7758	0	0	0	4	7762	6893	-2	0	-44	-174	-132	70	6611	17.4
2010	7758	0	37	0	4	7799	6999	-2	0	-44	-174	-132	70	6717	16.1
2011	7795	0	202	0	4	8001	7102	-2	0	-44	-174	-132	70	6820	17.3
2012	7997	0	0	0	4	8001	7189	-2	0	-44	-174	-132	70	6907	15.8
2013	7997	0	114	0	4	8115	7266	0	0	-44	-174	-132	70	6986	16.2
2014	8111	0	100	0	4	8215	7341	0	0	-44	-174	-132	70	7061	16.4
2015	8211	0	114	0	4	8329	7422	0	0	-44	-174	-132	70	7142	16.6
2016	8325	0	115	0	4	8444	7498	0	0	-44	-174	-132	70	7218	17.0
2017	8440	0	118	0	4	8562	7575	0	0	-44	-174	-132	70	7295	17.4
2018	8558	0	108	0	4	8670	7652	0	0	-44	-174	-132	70	7372	17.6
2019	8666	0	0	0	4	8670	7722	0	0	-44	-174	-132	70	7442	16.5

* Including Gibson 5 capacity owned by IMPA and WVPA
Excluding EKPC Purchase and previous year's Short Term Purchases
15MW derate to serve steam to Inland Container has been deducted

** Including IMPA and WVPA peak load requirements corresponding to their Gibson 5 ownership
Excluding WVPA Supplemental Load beginning 1/1/98
Excluding IMPA Supplemental Load beginning 1/1/07
Excluding customer cogeneration

*** Not included in load forecast

Figure 8-6

CINERGY
1999 INTEGRATED RESOURCE PLAN

CG&E SYSTEM

YEAR	INITIAL CAPACITY*	SHORT TERM PURCH.	INCR. CAPACITY ADDITIONS	INCR. CAPACITY RETIRE./ DERATES	PURCH. COGEN. CAPACITY	TOTAL CAPACITY	PEAK LOAD**	EXIST. DSM***	INCR. DSM	ENERGY OPTIONS	INDUSTRIAL AS AVAIL. LOAD	INDUSTRIAL INTER. LOAD	FIRM SALES	NET LOAD	RES. MAR. (%)
1999	5025	447	57	0	0	5530	4985	-1	0	-59	0	-33	0	4892	13.0
2000	5082	766	0	0	0	5848	5090	-1	0	-59	0	-31	0	4999	17.0
2001	5082	892	0	0	0	5974	5190	-1	0	-59	0	-26	0	5104	17.1
2002	5082	1015	0	0	0	6097	5299	-1	0	-59	0	-26	0	5213	17.0
2003	5082	1001	196	-20	0	6259	5436	-1	0	-59	0	-26	0	5350	17.0
2004	5258	0	1106	0	0	6364	5571	-1	0	-59	0	-26	0	5485	16.0
2005	6364	0	289	0	0	6653	5769	-1	0	-59	0	-26	0	5683	17.1
2006	6653	0	136	0	0	6789	5883	-1	0	-59	0	-26	0	5797	17.1
2007	6789	0	0	0	0	6789	5982	-1	0	-59	0	-26	0	5896	15.2
2008	6789	0	0	0	0	6789	6079	-1	0	-59	0	-26	0	5993	13.3
2009	6789	0	200	0	0	6989	6167	-1	0	-59	0	-26	0	6081	14.9
2010	6989	0	163	0	0	7152	6247	-1	0	-59	0	-26	0	6161	16.1
2011	7152	0	176	0	0	7328	6333	-1	0	-59	0	-26	0	6247	17.3
2012	7328	0	0	0	0	7328	6397	-1	0	-59	0	-26	0	6311	16.1
2013	7328	0	86	0	0	7414	6468	-1	0	-59	0	-26	0	6382	16.2
2014	7414	0	100	0	0	7514	6543	0	0	-59	0	-26	0	6458	16.4
2015	7514	0	100	0	0	7614	6613	0	0	-59	0	-26	0	6528	16.6
2016	7614	0	99	0	0	7713	6678	0	0	-59	0	-26	0	6593	17.0
2017	7713	0	96	0	0	7809	6739	0	0	-59	0	-26	0	6654	17.4
2018	7809	0	106	0	0	7915	6815	0	0	-59	0	-26	0	6730	17.6
2019	7915	0	0	0	0	7915	6877	0	0	-59	0	-26	0	6792	16.5

* Including Gibson 5 capacity owned by IMPA and WVPA
Excluding EKPC Purchase and previous year's Short Term Purchases
15MW derate to serve steam to Inland Container has been deducted

** Including IMPA and WVPA peak load requirements corresponding to their Gibson 5 ownership
Excluding WVPA Supplemental Load beginning 1/1/98
Excluding IMPA Supplemental Load beginning 1/1/07
Excluding customer cogeneration

*** Not included in load forecast

Figure 8-7

Cinergy

FORM FE2-2 PART 2: SUMMARY OF FORECAST LOADS AND REQUIRED GENERATING CAPABILITY [In Mega Watts][1]

Calendar Year>	1999		2000		2001		2002	
Forecast Year>	Year 0		Year 1		Year 2		Year 3	
	summer	winter	summer	winter	summer	winter	summer	winter
1. TOTAL ELECTRIC POWER PEAK GENERATING CAPABILITY REQUIRED IN EACH FORECAST YEAR								
(a) Forecasted Net Utility Service Area Peak Load [8]	10594	9525	10811	9731	11046	9970	11334	10267
(b) Purchased Power Available to Meet Peak Load [6]	817	304	1464	4	1744	4	2074	4
(c) Power Committed to Sale Coincident with Service Area Peak Load	70	120	70	70	70	70	70	70
(d) Power Pooling (Net Power Available from Pool(-) or Committed to Pool(+))	0	0	0	0	0	0	0	0
NET CAPABILITY REQUIRED (a)-(b)+(c)+(d)[7] (Not including reserve requirements)	9846	9340	9416	9797	9372	10036	9330	10333
2. REPORTING UTILITY'S FORECAST GENERATION CAPABILITY								
(a) Previous Year Capability [3]	11533	11533	11533	11533	11538	11538	11538	11538
(b) Retirements and Other Minor Decreases in Capability [4]	0	153	0	0	0	0	0	0
(c) Uprating and Minor Increases in Capability [4]	78	0	5	5	0	0	0	0
(d) Seasonal Deratings	272	168	272	168	272	168	272	168
NET CAPABILITY [2] [7]	11261	11365	11266	11370	11266	11370	11266	11370
3. DIFFERENTIAL BETWEEN NET CAPABILITY REQUIRED AND NET CAPABILITY FOR EACH YEAR OF FORECAST (2-1) [7]	1414	2024	1850	1573	1894	1334	1936	1037
4. PLANNED CAPABILITY OF NEW FACILITIES								
(a) Previous Additions [5]	0	0	0	0	0	0	0	0
(b) Planned Generating Capability of New Facilities	0	0	0	0	0	0	0	0
Total Planned Additional Capability (a)+(b)	0	0	0	0	0	0	0	0
5. TOTAL PROJECTED CAPABILITY (2+4) [7]	11261	11365	11266	11370	11266	11370	11266	11370
6. PROJECTED RESERVES (5-1) [7]	1414	2024	1850	1573	1894	1334	1936	1037

[ ] See the last page of FORM FE2-2 PART 2 for notes.

Figure 8-7

Cinergy

FORM FE2-2 PART 2: SUMMARY OF FORECAST LOADS AND REQUIRED GENERATING CAPABILITY [In Mega Watts][1]

Calendar Year>	2003		2004		2005		2006	
Forecast Year>	Year 4		Year 5		Year 6		Year 7	
	summer	winter	summer	winter	summer	winter	summer	winter
1. TOTAL ELECTRIC POWER PEAK GENERATING CAPABILITY REQUIRED IN EACH FORECAST YEAR								
(a) Forecasted Net Utility Service Area Peak Load [8]	11686	10459	11917	10643	12175	10832	12355	10720
(b) Purchased Power Available to Meet Peak Load [6]	2204	4	4	4	4	4	4	4
(c) Power Committed to Sale Coincident with Service Area Peak Load	70	70	70	70	70	70	70	70
(d) Power Pooling (Net Power Available from Pool(-) or Committed to Pool(+))	0	0	0	0	0	0	0	0
NET CAPABILITY REQUIRED (a)-(b)+(c)+(d)[7] (Not including reserve requirements)	9551	10525	11983	10709	12241	10898	12421	10786
2. REPORTING UTILITY'S FORECAST GENERATION CAPABILITY								
(a) Previous Year Capability [3]	11538	11538	11538	11538	11538	11538	11538	11538
(b) Retirements and Other Minor Decreases in Capability [4]	44	0	0	0	0	0	0	0
(c) Uprating and Minor Increases in Capability [4]	0	0	0	0	0	0	0	0
(d) Seasonal Deratings	316	168	316	168	316	168	316	168
NET CAPABILITY [2] [7]	11222	11370	11222	11370	11222	11370	11222	11370
3. DIFFERENTIAL BETWEEN NET CAPABILITY REQUIRED AND NET CAPABILITY FOR EACH YEAR OF FORECAST (2-1) [7]	1670	845	-761	661	-1019	472	-1199	584
4. PLANNED CAPABILITY OF NEW FACILITIES								
(a) Previous Additions [5]	0	0	330	368	2684	2997	3112	3475
(b) Planned Generating Capability of New Facilities	330	368	2354	2629	428	478	214	239
Total Planned Additional Capability (a)+(b)	330	368	2684	2997	3112	3475	3326	3714
5. TOTAL PROJECTED CAPABILITY (2+4) [7]	11552	11738	13906	14367	14334	14845	14548	15084
6. PROJECTED RESERVES (5-1) [7]	2000	1213	1923	3658	2093	3947	2127	4298

[ ] See the last page of FORM FE2-2 PART 2 for notes.

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FORM FE2-2 PART 2: SUMMARY OF FORECAST LOADS AND REQUIRED GENERATING CAPABILITY [In Mega Watts][1]

Calendar Year>	2007		2008		2009		2010	
Forecast Year>	Year 8		Year 9		Year 10		Year 11	
	summer	winter	summer	winter	summer	winter	summer	winter
1. TOTAL ELECTRIC POWER PEAK GENERATING CAPABILITY REQUIRED IN EACH FORECAST YEAR								
(a) Forecasted Net Utility Service Area Peak Load [8]	12236	10890	12431	11058	12622	11216	12808	11379
(b) Purchased Power Available to Meet Peak Load [6]	4	4	4	4	4	4	4	4
(c) Power Committed to Sale Coincident with Service Area Peak Load	70	70	70	70	70	70	70	70
(d) Power Pooling (Net Power Available from Pool(-) or Committed to Pool(+))	0	0	0	0	0	0	0	0
NET CAPABILITY REQUIRED (a)-(b)+(c)+(d)[7] (Not including reserve requirements)	12302	10955	12497	11124	12688	11282	12874	11445
2. REPORTING UTILITY'S FORECAST GENERATION CAPABILITY								
(a) Previous Year Capability [3]	11538	11538	11538	11538	11538	11538	11538	11538
(b) Retirements and Other Minor Decreases in Capability [4]	0	0	0	0	0	0	0	0
(c) Uprating and Minor Increases in Capability [4]	0	0	0	0	0	0	0	0
(d) Seasonal Deratings	316	168	316	168	316	168	316	168
NET CAPABILITY [2] [7]	11222	11370	11222	11370	11222	11370	11222	11370
3. DIFFERENTIAL BETWEEN NET CAPABILITY REQUIRED AND NET CAPABILITY FOR EACH YEAR OF FORECAST (2-1) [7]	-1080	415	-1275	246	-1466	88	-1652	-75
4. PLANNED CAPABILITY OF NEW FACILITIES								
(a) Previous Additions [5]	3326	3714	3326	3714	3326	3714	3526	3914
(b) Planned Generating Capability of New Facilities	0	0	0	0	200	200	200	200
Total Planned Additional Capability (a)+(b)	3326	3714	3326	3714	3526	3914	3726	4114
5. TOTAL PROJECTED CAPABILITY (2+4) [7]	14548	15084	14548	15084	14748	15284	14948	15484
6. PROJECTED RESERVES (5-1) [7]	2246	4129	2051	3960	2060	4002	2074	4039

[ ] See the last page of FORM FE2-2 PART 2 for notes.

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FORM FE2-2 PART 2: SUMMARY OF FORECAST LOADS AND REQUIRED GENERATING CAPABILITY [In Mega Watts][1]

Calendar Year>	2011		2012		2013		2014	
Forecast Year>	Year 12		Year 13		Year 14		Year 15	
	summer	winter	summer	winter	summer	winter	summer	winter
1. TOTAL ELECTRIC POWER PEAK GENERATING CAPABILITY REQUIRED IN EACH FORECAST YEAR								
(a) Forecasted Net Utility Service Area Peak Load [8]	12997	11519	13148	11633	13297	11760	13449	11896
(b) Purchased Power Available to Meet Peak Load [6]	4	4	4	4	4	4	4	4
(c) Power Committed to Sale Coincident with Service Area Peak Load	70	70	70	70	70	70	70	70
(d) Power Pooling (Net Power Available from Pool(-) or Committed to Pool(+))	0	0	0	0	0	0	0	0
NET CAPABILITY REQUIRED (a)-(b)+(c)+(d)[7] (Not including reserve requirements)	13063	11585	13214	11698	13363	11826	13514	11961
2. REPORTING UTILITY'S FORECAST GENERATION CAPABILITY								
(a) Previous Year Capability [3]	11538	11538	11538	11538	11538	11538	11538	11538
(b) Retirements and Other Minor Decreases in Capability [4]	0	0	0	0	0	0	0	0
(c) Uprating and Minor Increases in Capability [4]	0	0	0	0	0	0	0	0
(d) Seasonal Deratings	316	168	316	168	316	168	316	168
NET CAPABILITY [2] [7]	11222	11370	11222	11370	11222	11370	11222	11370
3. DIFFERENTIAL BETWEEN NET CAPABILITY REQUIRED AND NET CAPABILITY FOR EACH YEAR OF FORECAST (2-1) [7]	-1841	-215	-1992	-328	-2141	-456	-2293	-591
4. PLANNED CAPABILITY OF NEW FACILITIES								
(a) Previous Additions [5]	3726	4114	4104	4529	4104	4529	4304	4729
(b) Planned Generating Capability of New Facilities	378	415	0	0	200	200	200	200
Total Planned Additional Capability (a)+(b)	4104	4529	4104	4529	4304	4729	4504	4929
5. TOTAL PROJECTED CAPABILITY (2+4) [7]	15326	15899	15326	15899	15526	16099	15726	16299
6. PROJECTED RESERVES (5-1) [7]	2263	4314	2112	4201	2163	4273	2211	4338

[ ] See the last page of FORM FE2-2 PART 2 for notes.

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FORM FE2-2 PART 2: SUMMARY OF FORECAST LOADS AND REQUIRED GENERATING CAPABILITY [In Mega Watts][1]

Calendar Year>	2015		2016		2017		2018	
Forecast Year>	Year 16		Year 17		Year 18		Year 19	
	summer	winter	summer	winter	summer	winter	summer	winter
1. TOTAL ELECTRIC POWER PEAK GENERATING CAPABILITY REQUIRED IN EACH FORECAST YEAR								
(a) Forecasted Net Utility Service Area Peak Load [8]	13600	12020	13741	12129	13879	12248	14032	12365
(b) Purchased Power Available to Meet Peak Load [6]	4	4	4	4	4	4	4	4
(c) Power Committed to Sale Coincident with Service Area Peak Load	70	70	70	70	70	70	70	70
(d) Power Pooling (Net Power Available from Pool(-) or Committed to Pool(+))	0	0	0	0	0	0	0	0
NET CAPABILITY REQUIRED (a)-(b)+(c)+(d)[7] (Not including reserve requirements)	13665	12086	13806	12194	13944	12313	14097	12431
2. REPORTING UTILITY'S FORECAST GENERATION CAPABILITY								
(a) Previous Year Capability [3]	11538	11538	11538	11538	11538	11538	11538	11538
(b) Retirements and Other Minor Decreases in Capability [4]	0	0	0	0	0	0	0	0
(c) Uprating and Minor Increases in Capability [4]	0	0	0	0	0	0	0	0
(d) Seasonal Deratings	316	168	316	168	316	168	316	168
NET CAPABILITY [2] [7]	11222	11370	11222	11370	11222	11370	11222	11370
3. DIFFERENTIAL BETWEEN NET CAPABILITY REQUIRED AND NET CAPABILITY FOR EACH YEAR OF FORECAST (2-1) [7]	-2444	-716	-2585	-824	-2723	-943	-2876	-1061
4. PLANNED CAPABILITY OF NEW FACILITIES								
(a) Previous Additions [5]	4504	4929	4718	5168	4932	5407	5146	5646
(b) Planned Generating Capability of New Facilities	214	239	214	239	214	239	214	239
Total Planned Additional Capability (a)+(b)	4718	5168	4932	5407	5146	5646	5360	5885
5. TOTAL PROJECTED CAPABILITY (2+4) [7]	15940	16538	16154	16777	16368	17016	16582	17255
6. PROJECTED RESERVES (5-1) [7]	2274	4452	2347	4583	2423	4703	2484	4824

[ ] See the last page of FORM FE2-2 PART 2 for notes.

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FORM FE2-2 PART 2: SUMMARY OF FORECAST LOADS AND REQUIRED GENERATING CAPABILITY [In Mega Watts][1]

	Calendar Year>	2019	
	Forecast Year>	Year 20	
		summer	winter
1. TOTAL ELECTRIC POWER PEAK GENERATING CAPABILITY REQUIRED IN EACH FORECAST YEAR			
(a) Forecasted Net Utility Service Area Peak Load [8]		14164	12474
(b) Purchased Power Available to Meet Peak Load [6]		4	4
(c) Power Committed to Sale Coincident with Service Area Peak Load		70	70
(d) Power Pooling (Net Power Available from Pool(-) or Committed to Pool(+))		0	0
NET CAPABILITY REQUIRED (a)-(b)+(c)+(d)[7] (Not including reserve requirements)		14229	12540
2. REPORTING UTILITY'S FORECAST GENERATION CAPABILITY			
(a) Previous Year Capability [3]		11538	11538
(b) Retirements and Other Minor Decreases in Capability [4]		0	0
(c) Uprating and Minor Increases in Capability [4]		0	0
(d) Seasonal Deratings		316	168
NET CAPABILITY [2] [7]		11222	11370
3. DIFFERENTIAL BETWEEN NET CAPABILITY REQUIRED AND NET CAPABILITY FOR EACH YEAR OF FORECAST (2-1) [7]		-3008	-1170
4. PLANNED CAPABILITY OF NEW FACILITIES			
(a) Previous Additions [5]		5360	5885
(b) Planned Generating Capability of New Facilities		0	0
Total Planned Additional Capability (a)+(b)		5360	5885
5. TOTAL PROJECTED CAPABILITY (2+4) [7]		16582	17255
6. PROJECTED RESERVES (5-1) [7]		2352	4715

NOTES

[1] The Winter Designated Year 0 is the WINTER SEASON following the summer of Year 0, etc.

[2] Assuming NO ADDITIONS to Generation but that Retirements take place as scheduled and including all appropriate unit derates.

[3] The PREVIOUS YEAR CAPABILITY of Year 1 is the NET CAPABILITY plus the Seasonal Deratings at the end of the corresponding season of Year 0, etc. New facility additions are NOT included here.

[4] These are Increases and Decreases which are not associated with "coming on line" of new generating units.

[5] In Year 0, Item 4(a) is zero by definition, and is year-by-year cumulative throughout the term of the Forecast.

[6] Portions of the Purchased Power shown in this tabulation may not be finalized regarding amount, type, timing or source.

[7] Totals may not be exact due to rounding to whole numbers.

[8] After DSM and/or Interruptible load reductions.

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FORM FE2-3 PART1: ACTUAL AND FORECAST PEAK LOAD AND RESOURCES [In MegaWatts]

SUMMER SEASON

Calendar Year >	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Forecast Year >	-5	-4	-3	-2	-1	0	1	2	3	4	5	6	7
Net Demonstrated Capability [1]	11493	11662	11662	11533	11533	11533	11538	11538	11538	11906	14535	15013	15252
Net Seasonal Capability	11144	11279	11279	11183	11183	11261	11266	11266	11266	11552	13906	14334	14548
Purchases	150	153	210	504	554	817	1464	1744	2074	2204	4	4	4
Sales	70	70	70	70	70	70	70	70	70	70	70	70	70
Available Capacity	11224	11362	11419	11617	11667	12008	12660	12940	13270	13686	13840	14268	14482
Native Load [2]	9421	10079	10043	.10109	10387	10594	10811	11046	11334	11686	11917	12175	12355
Available Reserve	1803	1283	1376	1508	1280	1414	1850	1894	1936	2000	1923	2093	2127
Internal Load [3]	9537	10197	10149	10109	10525	11031	11248	11479	11768	12120	12352	12611	12791
Reserve	1687	1165	1270	1508	1142	977	1413	1462	1503	1566	1488	1657	1691

SUMMER SEASON

Calendar Year >	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Forecast Year >	8	9	10	11	12	13	14	15	16	17	18	19	20
Net Demonstrated Capability [1]	15252	15252	15452	15652	16067	16067	16267	16467	16706	16945	17184	17423	17423
Net Seasonal Capability	14548	14548	14748	14948	15326	15326	15526	15726	15940	16154	16368	16582	16582
Purchases	4	4	4	4	4	4	4	4	4	4	4	4	4
Sales	70	70	70	70	70	70	70	70	70	70	70	70	70
Available Capacity	14482	14482	14682	14882	15260	15260	15460	15660	15874	16088	16302	16516	16516
Native Load [2]	12236	12431	12622	12808	12997	13148	13297	13449	13600	13741	13879	14032	14164
Available Reserve	2246	2051	2060	2074	2263	2112	2163	2211	2274	2347	2423	2484	2352
Internal Load [3]	12672	12867	13058	13244	13433	13584	13733	13884	14035	14176	14314	14467	14599
Reserve	1810	1615	1624	1638	1827	1676	1727	1776	1839	1912	1988	2049	1917

[1] Includes 15MW for Cayuga steam supply contract.
[2] Historical and projected loads are after DSM and/or interruptible load reductions.
[3] Internal Load equals Native Load plus interruptible load.

Figure 8-9

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FORM FE2-3 PART2: ACTUAL AND FORECAST PEAK LOAD AND RESOURCES [In MegaWatts]

WINTER SEASON

Calendar Year >	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Forecast Year >	-5	-4	-3	-2	-1	0	1	2	3	4	5	6	7
Net Demonstrated Capability [1]	11485	11662	11533	11533	11533	11533	11538	11538	11538	11906	14535	15013	15252
Net Seasonal Capability	11470	11647	11518	11518	11518	11365	11370	11370	11370	11738	14367	14845	15084
Purchases	3	4	96	4	4	304	4	4	4	4	4	4	4
Sales	220	220	220	180	185	120	70	70	70	70	70	70	70
Available Capacity	11253	11431	11394	11342	11337	11549	11304	11304	11304	11672	14301	14779	15018
Native Load [2]	8319	8795	9073	8359	8735	9525	9731	9970	10267	10459	10643	10832	10720
Available Reserve	2934	2636	2321	2983	2602	2024	1573	1334	1037	1213	3658	3947	4298
Internal Load [3]	8319	8795	9073	8359	8735	9858	10061	10300	10598	10791	10975	11165	11052
Reserve	2934	2636	2321	2983	2602	1691	1244	1004	707	881	3326	3615	3966

WINTER SEASON

Calendar Year >	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Forecast Year >	8	9	10	11	12	13	14	15	16	17	18	19	20
Net Demonstrated Capability [1]	15252	15252	15452	15652	16067	16067	16267	16467	16706	16945	17184	17423	17423
Net Seasonal Capability	15084	15084	15284	15484	15899	15899	16099	16299	16538	16777	17016	17255	17255
Purchases	4	4	4	4	4	4	4	4	4	4	4	4	4
Sales	70	70	70	70	70	70	70	70	70	70	70	70	70
Available Capacity	15018	15018	15218	15418	15833	15833	16033	16233	16472	16711	16950	17189	17189
Native Load [2]	10890	11058	11216	11379	11519	11633	11760	11896	12020	12129	12248	12365	12474
Available Reserve	4129	3960	4002	4039	4314	4201	4273	4338	4452	4583	4703	4824	4715
Internal Load [3]	11222	11391	11548	11711	11851	11965	12092	12228	12353	12461	12580	12697	12807
Reserve	3797	3628	3670	3707	3982	3868	3941	4006	4120	4250	4370	4492	4383

[1] Includes 15MW for Cayuga steam supply contract.
[2] Historical and projected loads are after DSM and/or interruptible load reductions.
[3] Internal Load equals Native Load plus interruptible load.

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FORM FE2-4

SPECIFICATIONS OF PLANNED ELECTRIC GENERATING FACILITIES:

1.	FACILITY NAME	New Combustion Turbine (CT)
2.	FACILITY LOCATION	Specific location(s) not yet determined.
3.	FACILITY TYPE	Gas (Combustion) Turbine, Simple-Cycle. Multiple Units.
4.	ANTICIPATED CAPABILITY	Approximately 165 MW Summer and 184 MW Winter each unit. Exact capability depends on vendor(s), site(s) and other parameters.
5.	ANTICIPATED CAPITAL INVESTMENT	Final estimate unavailable.
6.	APPLICATION TIMING	Ohio PSB and/or IURC CPCN application timing are both unknown at this time.
7.	CONSTRUCTION TIMING	Unknown at this time.
8.	PLANNING POLLUTION CONTROL MEASURES	Unknown at this time.
9.	FUEL	Natural Gas and an undetermined secondary fuel. With the capability to be converted to coal derived gasses or liquids.
10.	MISCELLANEOUS	Area Served: South, Central and North Central Indiana, Southwestern Ohio and Northern Kentucky.

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FORM FE2-4

SPECIFICATIONS OF PLANNED ELECTRIC GENERATING FACILITIES:

1.	FACILITY NAME	New Combustion Turbine (NCT)
2.	FACILITY LOCATION	Specific location(s) not yet determined.
3.	FACILITY TYPE	Gas (Combustion) Turbine, Simple-Cycle. Multiple Units.
4.	ANTICIPATED CAPABILITY	Approximately 214 MW Summer and 239 MW Winter each unit. Exact capability depends on vendor(s), site(s) and other parameters.
5.	ANTICIPATED CAPITAL INVESTMENT	Final estimate unavailable.
6.	APPLICATION TIMING	Ohio PSB and/or IURC CPCN application timing are both unknown at this time.
7.	CONSTRUCTION TIMING	Unknown at this time.
8.	PLANNING POLLUTION CONTROL MEASURES	Unknown at this time.
9.	FUEL	Natural Gas and an undetermined secondary fuel. With the capability to be converted to coal derived gasses or liquids.
10.	MISCELLANEOUS	Area Served: South, Central and North Central Indiana, Southwestern Ohio and Northern Kentucky.

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FORM FE2-4

SPECIFICATIONS OF PLANNED ELECTRIC GENERATING FACILITIES:

1.	FACILITY NAME	New Combined-Cycle (NCC)
2.	FACILITY LOCATION	Specific location(s) not yet determined.
3.	FACILITY TYPE	Gas (Combustion) Turbine, Combined-Cycle.
4.	ANTICIPATED CAPABILITY	Approximately 378 MW Summer and 415 MW Winter each unit. Exact capability depends on vendor(s), site(s) and other parameters.
5.	ANTICIPATED CAPITAL INVESTMENT	Final estimate unavailable.
6.	APPLICATION TIMING	Ohio PSB and/or IURC CPCN application timing are both unknown at this time.
7.	CONSTRUCTION TIMING	Unknown at this time.
8.	PLANNING POLLUTION CONTROL MEASURES	Unknown at this time.
9.	FUEL	Natural Gas and an undetermined secondary fuel. With the capability to be converted to coal derived gasses or liquids.
10.	MISCELLANEOUS	Area Served: South, Central and North Central Indiana, Southwestern Ohio and Northern Kentucky.

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FORM FE2-4

SPECIFICATIONS OF PLANNED ELECTRIC GENERATING FACILITIES:

1.	FACILITY NAME	New Fuel Cell (NFC)
2.	FACILITY LOCATION	Specific location(s) not yet determined.
3.	FACILITY TYPE	Solid Oxide Pressurized Fuel Cell. Multiple Units (depends on technology available).
4.	ANTICIPATED CAPABILITY	Approximately 25 MW Summer and 25 MW Winter each unit. Exact capability depends on vendor(s), site(s) and other parameters.
5.	ANTICIPATED CAPITAL INVESTMENT	Final estimate unavailable.
6.	APPLICATION TIMING	Ohio PSB and/or IURC CPCN application timing are both unknown at this time.
7.	CONSTRUCTION TIMING	Unknown at this time.
8.	PLANNING POLLUTION CONTROL MEASURES	Unknown at this time.
9.	FUEL	Natural Gas.
10.	MISCELLANEOUS	Area Served: South, Central and North Central Indiana, Southwestern Ohio and Northern Kentucky.

CINERGY®

PSI Energy, Inc.
The Cincinnati Gas & Electric Company
The Union Light, Heat & Power Company

1999

INTEGRATED RESOURCE PLAN

VOLUME I

SHORT-TERM IMPLEMENTATION PLAN

November 1, 1999

By: Cinergy Services
Douglas F. Esamann, Vice President
139 East Fourth Street
P.O. Box 960
Cincinnati, Ohio 45201-0960

TABLE OF CONTENTS

PREFACE

This section, entitled Cinergy 1999 Integrated Resource Plan Short-Term Implementation Plan, contains Cinergy's plan for implementing supply-side resources and demand-side management program resources over the next several years. The supply-side resources are generally forecast for the period 2000 through 2002. As explained herein, the demand-side resources to be implemented by PSI and CG&E are forecast for a one-year period and the ULH&P resources are projected for a two-year period. The names of some of the demand-side programs may differ slightly from those contained in previous filings as programs are continually reviewed.

EXECUTIVE SUMMARY

Planned Improvements in Operations of Existing Generation, Transmission, and Distribution

Over the next five years, Cinergy has planned changes to some of its existing generating units as part of its compliance strategy for the Clean Air Act Amendments (CAAA), NO_x SIP Call, and state and local requirements. Also, routine maintenance will continue to occur throughout the period. Compliance changes to existing units may require approximately $721 million over the next five years.

Cinergy has added Inlet Cooling to some of the Combustion Turbine units to improve performance during the summer months (see Figure GA-8-4 found in the General Appendix for the units affected).

Cinergy plans to install flexible burner technology at its Wabash River Coal Gasification Repowering Project (WRCGRP) which will enable the unit to utilize either synthetic gas or natural gas. Other equipment includes an auxiliary evaporator boiler with stack, a CT bypass stack, stack monitors (CEMS), and a gas pipeline.

In compliance with the codes of conduct in FERC Order 889, the relevant transmission information is located in the Transmission Volume of this report, which was prepared independently.

Planned Conservation, Load Modification, or Other Demand-Side Management Programs

The forecasts provided in this STIP are based upon the best information available. However, the reader should be aware that there is considerable uncertainty with respect to the disposition of DSM/energy efficiency programs in all three states. The Ohio legislature recently passed electric restructuring legislation. But, Cinergy/CG&E has yet to file its transition plan. The details of that plan and the outcome of subsequent deliberation and action by the PUCO are unknown, but could significantly affect the plans reflected herein. Due to this uncertainty and the fact the (Cinergy/Community Energy Partnership - the present-day incarnation of the CG&E DSM Collaborative group) (CCEP) has the prerogative to review and redirect funding, projections are only presented for 2000. In Indiana, the Parties to the DSM Settlement Agreement (IURC Cause No. 40229) are negotiating a renewal of that agreement, which expires at the end of 1999. The term of the Agreement is to be one year, so the STIP reflects only the projections for 2000.

Finally, a stipulated settlement, which established cost recovery methods granting ULH&P contemporaneous recovery of the revenue requirement associated with DSM programs expires at the end of 1999. The Collaborative is currently developing its filing, which will be submitted to the Kentucky Public Service Commission in October for review and action. The signatory parties and the Collaborative have established a two-year term for its joint application.

CG&E currently plans to offer at least the following programs in Ohio through the end of 2000:

- Electric Weatherization
- Energy Decisions Workshops
- Energy Efficient Refrigerator Replacement
- Energy-Recycle Education Awareness Program
- Energy Maintenance Services
- General Use Program
- Homebuyers' Workshop
- Home Energy House Call
- Internet Audit Tool
- Learn and Earn Program
- New Home Efficient Refrigerators
- New Home Owners' Training
- Non-Profit Energy Management Pilot Program (NEMP)

- Ohio Energy Project (formerly Ohio NEED)

The CCEP is currently considering continuation of existing energy efficiency programs, additional programs and/or redirection of funds consistent with its charter:

> "*The purpose of the Cinergy/Community Energy Partnership is to give Cinergy guidance and make recommendations on cost-effective programs that will benefit all residential customers, especially low income, and help the community become more energy efficient. The focus should be on the disadvantaged members of the community through weatherization assistance and help with PIPP* [Percentage of Income Payment Plan]."

More detail about the CCEP's activities is provided in Section B.

ULH&P plans to offer the following programs in Kentucky through 2001:

- Residential Conservation and Energy Education
- Residential Energy Conservation Rates
- Residential Home Energy House Call
- Residential Comprehensive Energy Education Program
- Savings and Value through Energy Efficiency

PSI currently plans to offer the following programs through 2000 in Indiana:

- Residential Audit
- Smart $aver®and Summer $aver™
- Low Income Energy Efficiency
- Commercial/Industrial Lighting Incentive Plan
- Commercial/Industrial Energy Efficient Cooling Systems
- Commercial/Industrial Energy Efficient Motors

Planned New Generation and Transmission Facilities

No new generation is being planned at this time for the 2000-2002 time period. Cinergy plans to meet current and future demand with the existing generating facilities and power purchases.

In compliance with the codes of conduct in FERC Order 889, the relevant transmission information is located in the Transmission Volume of this report, which was prepared independently.

Securities Projected to be Issued

Cinergy estimates that a combination of internal and external funds will be used to meet its capital needs. External funds will be used for refinancing of maturing debt and preferred stock, and the early refunding of existing high-cost debt and preferred stock, in addition to financing other capital needs.

CHANGES IN THE STIP SINCE THE 1997 STIP

Planned Improvements in Operations of Existing Generation, Transmission, and Distribution

The significant changes in this STIP since the 1997 STIP include the development of a NO_x compliance plan to address the requirements of the NO_x SIP call, the addition of inlet cooling on a number of Cinergy's combustion turbine units, the installation of flexible burner technology at the Wabash River Repowering Project to enable it to burn natural gas as well as syngas, and the Zimmer synthetic gypsum project. The details of these changes appear in Section A of this report.

Planned Conservation, Load Modification, or Other Demand-Side Management Programs

The only significant change in the Ohio programs since the 1997 STIP is that five new programs have been developed and implemented by the CCEP in Ohio. At the time of the 1997 STIP, five programs had been approved by the CCEP for continuation (identified in the list below by an *) and several new programs were under consideration. In 2000, the CCEP expects to offer the following fourteen programs.

- Electric Weatherization
- Energy Decisions Workshops*
- Energy Efficient Refrigerator Replacement
- Energy-Recycle Education Awareness Program
- Energy Maintenance Services
- General Use Program*
- Homebuyers' Workshop*
- Home Energy House Call*
- Internet Audit Tool
- Learn and Earn Program
- New Home Efficient Refrigerators
- New Home Owners' Training
- Non-Profit Energy Management Pilot Program (NEMP)
- Ohio Energy Project (formerly Ohio NEED)*

The only significant change reflected in this STIP for programs to be offered by PSI in Indiana is the revival of the Summer $aver™ component of the Smart $aver® program and anticipated budget reductions Cinergy believes will result from on-going discussions with the Parties to the PSI DSM Settlement Agreement.

Planned New Generation and Transmission Facilities

The only major change in this STIP is that current plans do not include installing Woodsdale Unit 7 in the near future, as was discussed in the 1997 STIP.

Securities Projected to be Issued

The only change since the 1997 STIP is that a combination of internal and external funds will be used to meet Cinergy's capital needs.

IMPLEMENTATION PLAN

A. Planned Improvements In Operations of Existing Generation, Transmission, and Distribution

NO_x Compliance

Project Description

Cinergy plans to add NO_x control technologies to some of its existing generating units as part of its compliance strategy for the Federal Clean Air Act Amendments (CAAA), NO_x SIP Call, and state and local requirements.

Goal of Project

The goal of the project is to comply with applicable Federal and State environmental requirements.

Criteria and Objective for Monitoring Success

The success of the projects is determined based upon performance to budget and schedule.

Anticipated Time Frame and Estimated Costs

These changes may require approximately $721 million over the next five years distributed as indicated below. Where projects involve jointly owned units, only the capital budgeted to be spent by the Cinergy Operating Company is shown in the figures below.

Estimated Costs (Millions of Dollars)

	PSI Energy	**CG&E**	**Cinergy**
1999	$ 1	$ 4	$ 5
2000	$ 35	$ 59	$ 94
2001	$185	$102	$287
2002	$168	$104	$272
2003	$ 51	$ 12	$ 63

Inlet Cooling

Project Description

Since combustion turbines inherently lose power as ambient air temperatures increase, cooling the inlet air to the turbine helps to recover that power. The inlet cooling fog project accomplishes cooler inlet air by injecting a water fog, or small water droplets, into the inlet air duct. When these small water droplets enter the duct they evaporate and thus reduce the inlet air temperature. Dictated by both ambient temperature and humidity, cooling is best during hot dry days. If operated below a certain ambient temperature, the small water droplets can become ice which can damage the unit's compressor; therefore, this cooling technique is only used in the summer.

Goal of Project

The goal is to improve performance during summer months.

Criteria and Objectives for Monitoring Success

The success of the project is determined based upon performance to budget and schedule.

Anticipated Time Frame and Estimated Costs

Inlet Cooling changes were added to some Cinergy Combustion Turbines (see Figure GA-8-4 found in the General Appendix for the units affected) in 1999. The total capital expenditures for this project were approximately $4.36 million with the 1999 expenditures as shown below:

Costs (Millions of Dollars)

	PSI Energy	CG&E	Cinergy
1999	$ 0.82	$ 3.45	$ 4.27

Wabash River Repowering Project

Project Description

Cinergy plans to install flexible burner technology at its Wabash River Coal Gasification Repowering Project (WRCGRP) which will enable the company to accept either synthetic gas or natural gas. Other pieces of equipment include an auxiliary evaporator boiler with stack, a CT bypass stack, stack monitors (CEMS), and a gas pipeline.

Goal of Project

The goal is to allow the unit to burn either synthetic gas or natural gas.

Criteria and Objectives for Monitoring Success

The success of the project is determined based upon performance to budget and schedule.

Anticipated Time Frame and Estimated Costs

These changes may require approximately $13.33 million over the next two years distributed as indicated below.

Estimated Costs (Millions of Dollars)

	PSI Energy	CG&E	Cinergy
1999	$ 1.33	$ 0	$ 1.33
2000	$12.00	$ 0	$12.00

Zimmer Synthetic Gypsum Project

Project Description

Cinergy is investing capital dollars at Zimmer Station to make high quality synthetic gypsum that will be sold to a new wallboard manufacturing plant. Cinergy expects to create a significant environmental benefit by converting the by-product from the unit's sulfur dioxide scrubber into synthetic gypsum, rather than landfilling it. The amount of material placed in the station's landfill can be reduced by as much as 77 percent.

Goal of Project

The goal is to make high quality synthetic gypsum from the by-product that is produced from Zimmer's sulfur dioxide scrubber.

Criteria and Objectives for Monitoring Success

The success of the project is determined based upon performance to budget and schedule.

Anticipated Time Frame and Estimated Costs

These changes may require approximately $9.86 million over the next two years distributed as indicated below.

Estimated Costs (Millions of Dollars)

	PSI Energy	CG&E	Cinergy
1999	$ 0	$ 3.67	$ 3.67
2000	$ 0	$ 6.19	$ 6.19

In compliance with the codes of conduct in FERC Order 889, the relevant transmission information is located in the Transmission Volume of this report, which was prepared independently.

B. Planned Conservation, Load Modification, or Other Demand Side Management Programs

As planned, CG&E, ULH&P and PSI estimate that collectively they will spend more than seven million dollars annually on Demand-Side Management (DSM) programs. An estimate of the expenditures for the resource programs is provided in a table located at the end of this STIP.

CG&E Planned DSM Programs

There are a number of factors that could cause the implementation of CG&E's energy efficiency programs to differ from the plan described below. The CCEP is currently developing its plans for the year 2000 and has not made final decisions regarding the programs to be offered. Furthermore, the Ohio legislature recently passed electric restructuring legislation and the details of Cinergy's transition plan and the results of subsequent action by the PUCO are unknown at this time. Therefore, this STIP reflects the assumption that the 1999 programs will continue to be offered in 2000. The CCEP's decisions and/or the PUCO's actions following review of Cinergy's transition plan may result in significant changes. As of August 1999, the CCEP expects the following programs to continue through the end of 2000:

- Electric Weatherization
- Energy Decisions Workshops
- Energy Efficient Refrigerator Replacement
- Energy-Recycle Education Awareness Program
- Energy Maintenance Services
- General Use Program
- Homebuyers' Workshop
- Home Energy House Call
- Internet Audit Tool
- Learn and Earn Program
- New Home Efficient Refrigerators
- New Home Owners' Training
- Non-Profit Energy Management Pilot Program (NEMP)

- Ohio Energy Project (formerly Ohio NEED)

The CCEP Board continues to employ the long term planning process described below to develop programs for 2000. This planning cycle enables the CCEP Board to compare and develop programs that best serve the low income and community residents in the territory. The planning cycle:

- Allows the Board to coordinate the planning efforts.
- Allows the Board to make comparisons as to the value and merits of each program option.
- Provides clear expectations of task forces and existing program managers.
- Increases decision making time efficiency.
- Coincides with the annual budgets.

CCEP Planning Criteria

Program proposals are evaluated based on the following information:

- Target customer segments
- Customer need addressed
- Number of people impacted
- Individual savings potential and bill impact for the customer

- Leverage or spin-off with other customer activities/programs
- Delivery structure - if the program delivery is new or based on existing activities
- Local contractors providing service
- Barriers or risks - Has it been done elsewhere or tested
- Research support
- Cost effectiveness and impacts of program
- Cost and budget over the life of the program including shut down costs
- Community impacts
- Impacts on low income community if not target group
- Evaluation and tracking capability

CCEP Planning Cycle Schedule

MONTH	ACTIVITY
January	Implementation issues based on PUCO approvals.
February	Initial idea generation meeting for potential funding in following year.
March/April	Staff research, data gathering and idea review. Task Force work as needed.
April/May	Preliminary concept development phase by Staff. Task Force work as needed.
June	Preliminary Review of Concepts. Board review and guidance on concepts that need to go to design phase.
July - September	Program design by Staff.
October	Board review and approvals. Staff prepares submittal to PUCO.
November-December	PUCO approvals. Initial implementation planning by Staff.
January	Implementation plans and execution.

2000 CCEP Planning Efforts to Date

- The CCEP Board is in the middle of its planning process for 2000 at the time of this writing. Programs are in various stages of planning and review.

Once decisions are made regarding implementation or new programs and continuation of current programs, the selected programs will be submitted to the PUCO for approval as described in the "Entry On Rehearing" to Case No. 95-203-EL-FOR.

Electric Weatherization

Program Description

The Electric Weatherization Program provides energy education and direct installation of energy saving measures in the homes of CG&E's electrically heated residential customers with income levels up to 200% of the poverty level. The program consists of the direct installation of specific DSM measures and energy education on the energy savings features of the measures. This program results in a reduction in the energy consumption of electric appliances and provides energy education for participants so that they can learn how to save energy and lower their electric bills. The measures available for installation under this program are:

- weatherization measures
- insulation
- compact fluorescent lamps
- low flow showerheads
- faucet aerators
- pipe wrap
- water heater wraps

* small repairs to help energy integrity

Implementation Strategy

This program is marketed through direct mail, bill inserts, and referrals. People Working Cooperatively (PWC), a non-profit service agency, provides the weatherization services for CG&E's electric and gas weatherization programs. Working In Neighborhoods (WIN), a non-profit service agency, performs the post installation inspections and provides energy education to participants.

Program Update

Projected participation has been revised to reflect refined estimate of market potential.

Energy Decisions Workshop

Program Description

Energy Decisions is a teacher training program designed to improve the quantity and quality of instruction about energy production, consumption, and public policy decision making. The workshops consist of presentations, activities, evaluation of resources, and discussions that help classroom teachers develop better ways to help their students understand energy use issues and make important energy use decisions.

Implementation Strategy

The program is delivered by The Greater Cincinnati Center for Economic Education/University of Cincinnati.

Program Update

No significant changes are anticipated. Energy Decisions has been selected to receive the Ohio Governor's Award of Excellence for Energy Efficiency.

Energy Efficient Refrigerator Replacement

Program Description

Refrigerators are a major energy waster in low-income homes. Many refrigerators are old, second-owner units with poor performance. A way to remedy this problem is to replace poor performing units when the home is weatherized. This program provides additional funds to add refrigerator replacements to the existing gas and electric weatherization programs.

Before recommending this program, the CCEP Board investigated two similar high-efficiency refrigerator replacement programs. The first is a national purchase program for refrigerators in public housing. It has been operating since 1997. This program is expanding the units available to include 18 ft^3 sizes for homes in addition to the current 15 ft^3 for apartments. This new size will be available in 1999 and can be used for low-income programs like CCEP. Once the contract for the new units is final, CG&E has the option to join the buying group to order for its program.

The second program CCEP investigated was Toledo Edison's low-income customer program, which is also associated with the three-year old weatherization program. In this program, the weatherization agency monitors the customer's refrigerator when they are in the home. If the old refrigerator uses more than 5 kWh per day the weatherization agency replaces the unit with a unit sold to Toledo Edison at a wholesale rate. The agency removes the old unit, Sears installs the new unit and the city picks up the old units. The agency also provides the education about the unit and efficiency. Approximately 20-30% of the weatherization customers have refrigerators replaced under their program.

Implementation Strategy

High efficiency (Energy Star) units are being installed in homes that are being weatherized by CG&E's weatherization contractor PWC. The old refrigerator is monitored for two hours to measure its efficiency. If the unit is inefficient it is replaced. A replacement rate of 25-30% is expected. Since this program is new to CG&E territory, the program is being implemented in two phases. The first is a fifty unit trial period. During this time CG&E will review the experience, problems and costs, and adjust the program. The second phase will be the continuation of the program after adjustments. Any cost adjustments will be taken from the contingency funds. This will allow CCEP to get realistic experience with installations and costs.

Program Update

This is the first STIP report for this program.

Energy-Recycle Education Awareness Program (E-REAP)

Program Description

E-REAP consists of various complementary activities, designed to increase community awareness about and use of energy conservation methods and recycling and waste reduction activities. The program will include:

- Regularly scheduled, energy conservation and recycling education meetings
- Door-to-door energy conservation and recycling education
- Presentations to community organizing towards greater understanding and activity on energy conservation and recycling awareness
- Greater cooperation and networking between various community organizations and agencies in the neighborhood
- Advocacy for increased energy conservation and recycling

Implementation Strategy

The program provider, Working in Neighborhoods (WIN), will work with a variety of neighborhood groups, including the community council, area churches, senior citizen groups, block clubs, etc. WIN will develop a core group of volunteers to work with staff to deliver the programs.

Staff will knock on doors of 1,000 households and deliver information on Cinergy Energy Wise Programs, the "Neighborhood Recycler" published by WIN, recycling and trash reduction tips, a green recycle bin (if needed) and an information sheet containing Energy Saving Tips. Of the 1000 households, two hundred will be selected to receive retrofit and/or re-lamping services. Based upon interest, further energy education will be scheduled. The services and information provided will include:

- Installation of an average of three fluorescent light bulbs. An assessment will be made to see if the bulbs are needed. Information about energy saving features of lamps will be provided.
- An average of four furnace filters will be provided. An average of two filters will be changed and an average of two will be left with customers. The educator will show the customer how to install the filter.
- Hot water conservation measures will be installed in the homes of customers with electric water heat. These will include water heater wraps, sink aerators, and pipe insulation.
- Education, including reading utility bills and Energy Saving Tips will also be reviewed and left with the selected customers.

Program Update

This is the first STIP report for this program.

Energy Maintenance Services

Program Description

The Maintenance Service Program is designed to reduce energy consumption for participants through performance of routine maintenance. The services provided through this program include routine cleaning and maintenance of water heaters, air conditioners, furnaces, refrigerators and freezers, as well as installing up to three compact fluorescent light bulbs. In some cases a second home-visit is conducted by an HVAC contractor to perform a tune-up and safety check of the furnace and water heater.

This program is directed primarily at elderly and disabled customers who are income qualified at or below 150% of the poverty level and who own their dwelling are the primary program participants.

Implementation Strategy

Customers are enrolled in the program directly through the implementing agencies of People Working Cooperatively (PWC), Clermont County Community Services, Inc. (CCCSI), and Adams Brown Counties Economic Opportunities (ABC). The program was typically delivered through a single home-visit providing for the direct installation of up to 24 energy efficiency and safety measures.

Program Update

During the first half of 1999, the pilot was reviewed by the CCEP and was approved for full-scale implementation.

General Use Program

Program Description

The General Use (Piggyback) Program provides direct installation of energy saving measures in the homes of CG&E's electrically heated residential customers with income levels up to 200% of the poverty level. The program is delivered in conjunction with the State Weatherization Program through Community Action Agencies (CAA's) as a piggyback effort to their existing services. The program consists of the direct installation of specific DSM measures and energy education on the energy savings features of the measures. This program results in a reduction in the energy consumption of electric appliances and provides energy education for participants so that they can learn how to save energy and lower their electric bills. The measures available for installation under this program are:

- compact fluorescent lamps
- low flow showerheads
- faucet aerators
- pipe wrap
- water heater wraps
- waterbed covers

Compact fluorescent lamps are the most frequently installed measures.

Implementation Strategy

The CAA's solicit participation in this program. This program is only available to customers whose homes are being weatherized as part of the State Weatherization program. This "piggyback" approach enhances efficient delivery. The project manager ensures that periodic site visits and customer contacts are conducted to ensure contract compliance, customer satisfaction, and quality. The percentage reviewed may be revised as performance indicates.

Program Update

No significant changes are planned.

Homebuyers' Workshop

Program Description

The Homebuyer Energy Education program provides first time homebuyers in low/moderate income communities with training and education in three areas: (1) how to shop for an energy efficient home; (2) energy efficient lighting and a compact fluorescent bulb to install in the home; (3) how to save once consumers are in their new home. Additionally, the program provider, Communities United for Action (CUFA) provides energy education for homeowners after the purchase by providing a "walk-through" audit to point out energy savings opportunities and potential energy concerns with the new home.

Implementation Strategy

This program was submitted to the CCEP Board by CUFA and is being delivered by CUFA in 1999 with active involvement by the program manager including direct monitoring of workshops and audits.

Program Update

There are no significant changes in the program.

Home Energy House Call

Program Description

The Home Energy House Call consists of three major components:

- Home Energy Survey
- Comprehensive Energy Audit & Review
- Measures Installation Opportunity

When a Home Energy House Call is requested by a customer, a qualified home energy specialist visits the site to gather information about the home. A questionnaire about the energy usage is also completed. The energy specialist gives the customer a detailed report that explains how their home uses energy each month. The specialist also checks the home for air leaks, inspects the furnace filter, and looks at the insulation levels in different areas. The specialist describes and recommends cost saving actions to make the home more energy efficient. Specific energy conservation measures are described and limited low cost conservation items are made available to participants for purchase and installation at the time of the audit.

In addition to helping the customer with energy efficiency, the Home Energy House Call assists the customer with "Earth Perks." This part of the program looks at the natural resources and pollution prevention needs of the customer's home and community and offers a list of action items. This list of action items is prioritized using the home's environmental profile.

Implementation Strategy

The program is promoted primarily through direct mail. Other channels are also used, including bill inserts and cross-promotion by Cinergy's Call Center and other DSM programs. For example, customers complaining of high bills are referred to the program as are customers connecting to Cinergy for the first time.

The contract for program delivery was awarded following a competitive bid process. The program manager and the implementation contractor work as partners to continually ensure efficient, effective achievement of the established targets. The program manager and the contractor review contractor performance on a regular basis. The results of the process and impact evaluations will continue to be used to refine the program delivery and improve adoption of audit recommendations.

The project manager conducts periodic site visits and customer contacts (approximately five percent of the audits) to ensure contract compliance, customer satisfaction, and quality. This may be revised as performance indicates.

Program Update

An evaluation of the program completed in 1999 revealed high participant satisfaction and a significant adoption rate for recommended measures.

Internet Audit Tool

Program Description

Many residential customers are looking for a way to analyze the efficiency of their home but cannot take advantage of the other CG&E energy programs. The Internet Audit Tool, available at www.cinergy.com, allows customers to analyze the energy use in their home using their CG&E billing history. This audit tool provides a dissagregation of their energy use by end use and provides recommendations on ways to save energy. There are also extensive energy library and frequently asked questions sections.

Implementation Strategy

This service is offered at no charge to CG&E customers and is promoted through CG&E programs and general promotion of the Internet site.

Program Update

This is the first STIP report for this program.

Learn and Earn Program

Program Description

The Learn and Earn Program provides a series of individual training and counseling sessions to participants on energy usage and conservation, as well as budget management. This program is open to any Percentage of Income Payment Plan (PIPP) customer as of January 1, 1998. The education sessions, which include a home energy audit, in-home basics education program, and follow-up counseling sessions for participants, are provided by social service/weatherization agencies now serving the PIPP customers. As an incentive for Program participation and energy consumption changes, CG&E, through the Providers, offers customers a two-part incentive award: the first incentive is for Program Participation and the second incentive is for lowering monthly energy consumption from a pre-determined baseline amount of energy consumption.

Implementation Strategy

The program is promoted to Cinergy's PIPP customers directly by the social service / weatherization agency. The contact may be made by targeted direct mail or by telephone. Cinergy provides a listing of PIPP customers that have been weatherized either by the local agency or through the state.

Program Update

This is the first STIP report for this program.

New Home Efficient Refrigerators

Program Description

Habitat for Humanity and other subsidized home construction programs do not have in their budgets the opportunity to upgrade to high-efficiency appliances. The CCEP believes that it is beneficial to get high-efficiency refrigerators installed in these homes of income disadvantaged residents. To qualify, an organization will need to be building and selling the homes with major price subsidies. It is estimated that approximately 30 homes per year are built in the territory that would qualify.

Implementation Strategy

This program is operated as a companion program with the refrigerator replacement program addition to weatherization. This allows CG&E to order additional refrigerators from the bulk refrigerator purchases for weatherization. CG&E is offering the units to the primary subsidized home building agencies in its franchised service territory.

Program Update

This is the first STIP report for this program.

New Home Owners' Training

Program Description

The New Home Owners' Training program focuses on helping new homeowners understand how energy impacts their new home investment and finances. This information is incorporated into an existing "Life As a Homeowner Class" offered by the Better Housing League which is a one-night/morning 3-hour class offered monthly. Participants are educated about energy efficient upgrades and how they can make their home less expensive to maintain. They are also provided a compact fluorescent bulb. The program is designed to educate customers on energy consumption within their home, so they can modify their energy use behavior and reduce their energy consumption. Basic budgeting and money management skills are also included in the program.

Implementation Strategy

The Better Housing League incorporates energy education in the context of existing classes offered monthly by the Better Housing League.

Program Update

No significant changes are planned.

Non-Profit Energy Management Program

Program Description

The Not-for-Profit Energy Management Program (NEMP) is an energy audit and financial assistance service offered to small non-profit, social service agencies in the CG&E service area. The audit is provided at no cost to the customer and the program funds 50% percent of the cost of energy efficiency improvements implemented by participants with a 5-year or less simple payback up to $3,000. Workshops are also periodically offered to representatives of the targeted market segment to encourage participation in the program and to provide energy education. The program is designed to help non-profit social-service organizations reduce their own overhead costs through sound energy management practices. In theory, reducing these costs frees-up money to be applied to the provision of agency services.

Implementation Strategy

The program is primarily promoted by the service provider through targeted direct mail and telephone. A listing of potential customers by SIC code will be provided to the selected contractor.

Program Update

The program was reviewed in 1999 and was recently approved for a one-year period.

Ohio Energy Project

Program Description

The goals of this statewide program are to assist in the development of ongoing, comprehensive energy education programs in all schools, for all students, at all grade levels; and to develop a grassroots energy education network, coordinated by students, educators, businesses, and government representatives.

This program was identified in the Ohio Energy Strategy Report, under Strategy I: Educational Needs and Benefits, as an implementation strategy. The strategy recommends expansion of the Ohio Energy Project. As a response to the Strategy Report, CG&E funded the first state regional office in July 1994. Cinergy was presented the Regional Award at the 1995 Ohio Energy Project Youth Awards Banquet on May 17, 1995. This program was presented the 1995 Ohio BEST (Building Excellent Schools Today) Practices Award and was recognized by the Ohio Business Roundtable (a business and education partnership) as a successful program.

Implementation Strategy

The program trains teachers and students through workshops to train other teachers and students, compounding the dissemination of education throughout the school systems. Program runs concurrently with the school season, beginning in late summer and ending in the spring.

Program Update

No significant changes are planned.

PSI Planned DSM Programs

PSI's DSM program portfolio reflects the expected provisions of the Settlement Agreement being negotiated by the parties to Cause No. 40229. There are several significant changes reflected in this STIP for programs to be offered by PSI in Indiana. These include the revival of the Summer $aver™ component of the Smart $aver® program and anticipated budget reductions Cinergy believes will result from on-going discussions with the Parties to the PSI DSM Settlement Agreement.

Smart $aver®/Summer $aver™

Program Description

The Smart $aver® component of this program promotes the installation of high-efficiency air conditioning and heat pumps (including geothermal) in new construction single-family homes, while also promoting selected energy efficiency construction practices that exceed state building codes. Requirements for Smart $aver® include minimum Seasonal Energy Efficiency Rating ("SEER") levels for HVAC equipment, minimum insulation levels for building shell and ductwork outside conditioned airspace, and minimum individual airflow requirements. Incentives (in the form of traditional incentives or an interest-rate buydown) are available to encourage higher than minimum SEER levels.

The Summer $aver™ component of this program promotes the installation of high-efficiency air conditioning in single-family homes, while also promoting selected energy efficiency construction practices that exceed state building codes. Requirements for Summer $aver™ include minimum Seasonal Energy Efficiency Rating ("SEER") levels for HVAC equipment, minimum insulation levels for building shell and ductwork outside conditioned airspace, and minimum individual airflow requirements. Incentives (in the form of traditional incentives or an interest-rate buydown) are available to encourage higher than minimum SEER levels.

Implementation Strategy

This program will continue to be implemented by PSI Retail Sales while the parties to the Settlement Agreement discuss other options for program delivery.

The budget estimate is provided in the table attached to this STIP.

Program Update

This program has been slightly modified to include the Summer Saver (air conditioning) component.

Residential Low-Income Efficiency (R-9) Program

Program Description

This program provides the installation of energy saving devices to PSI residential customers who qualify for weatherization or heating bill assistance as part of state or federal programs.

This program provides incentives for faucet aerators, energy-efficient shower heads, water heater jackets, pipe insulation, and compact fluorescent light bulbs. Customers with electric space heating also receive caulking, outlet gaskets, weather-stripping, door sweeps, foam seal, and duct mastic to reduce infiltration in the home. PSI will continue to work with the Indiana Community Action Agencies to identify opportunities to increase participation prior to December 1999. Program modifications may include enhanced program offerings, adjustments for cost escalation, revised eligibility criteria, and/or support for infrastructure investments. There is no charge to the customer for this program.

Implementation Strategy

PSI contracts with the Indiana Community Action Program Director's Association (ICDA) to provide the energy efficiency measures. ICDA subcontracts with the local Community Action Program (CAP) agencies within PSI's service area. The CAP agencies determine the eligibility of participants and coordinate the installation of the measures. Most customers receive these measures as part of weatherization services administered by the State of Indiana and provided by the CAPs and their local weatherization departments. In some areas, CAPs subcontract to local businesses to perform the weatherization services and installation of the PSI-sponsored measures. Some of the CAPs also provide measures to customers qualifying for assistance on their heating bills. This effort has created new jobs for those agencies.

The budget estimate is provided in the table attached to this STIP.

Program Update

The modifications discussed above are currently being investigated as are options to leverage state funds.

Residential Audit Program

Program Description

PSI ratepayers will subsidize an audit program, which will be available to all Cinergy/PSI residential customers with electric heat and/or electric water heat. The offering will consist of a walk through energy audit, including an inspection of mechanical systems and the home's thermal envelope, development and delivery of a computer-generated audit report, and detailed review of the report and recommendations. Under either of two delivery approaches being considered, energy-efficiency measures associated with electric heat and/or electric hot water heaters will be available for installation at the time of the audit (either direct install or purchase). Some of these will include faucet aerators, energy-efficient shower heads, water heater jackets, compact fluorescent light bulbs, pipe wrapping, foam seal, caulking, outlet gaskets, weather stripping, door sweeps and ductwork sealant (when ductwork is accessible). The education component of the program will address all recommended measures, not only those available on-site at the time of the audit.

Implementation Strategy

One of the following delivery approaches will be employed: 1) co-payment from the customer and direct installation of recommended measures at no cost; or 2) no charge for the audit and purchase (at participant expense) of recommended weatherization and water heat conservation measures.

The budget estimate is provided in the table attached to this STIP.

Program Update

This program is currently being redesigned.

Lighting Incentive Plan

Program Description

This program targets commercial and industrial customers with annual peak electric demand of 500 kW or less. The program provides incentives to encourage the installation of high-efficiency lighting measures.

Implementation Strategy

As provided for in the Settlement Agreement, this program is promoted and delivered by the traditional providers and ESCos. PSI's program manager provides interested callers with a list of providers that are participating in the programs and the programs have also been promoted through direct mail to eligible customers.

The budget estimate is provided in the table attached to this STIP.

Program Update

Cinergy has taken a limited but more active role in promoting the program among the provider community. Additional options to increase participation are under consideration.

Energy Efficient Cooling Systems

Program Description

This program targets commercial and industrial customers with annual peak electric demand of 500 kW or less. The program provides incentives to encourage the installation of energy-efficient HVAC systems.

Implementation Strategy

As provided for in the Settlement Agreement, this program is promoted and delivered by the traditional providers and ESCos. PSI's Call Center provides interested callers with a list of providers that are participating in the programs and the programs have also been promoted through direct mail to eligible customers.

The budget estimate is provided in the table attached to this STIP.

Program Update

Cinergy has taken a limited but more active role in promoting the program among the provider community. Additional options to increase participation are under consideration.

Energy Efficient Motors

Program Description

This program targets commercial and industrial customers with annual peak electric demand of 500 kW or less. The program provides incentives to encourage the installation of energy-efficient motors.

Implementation Strategy

As provided for in the Settlement Agreement, this program is promoted and delivered by the traditional providers and ESCos. PSI's program manager provides interested callers with a list of providers that are participating in the programs and the programs have also been promoted through direct mail to eligible customers.

The budget estimate is provided in the table attached to this STIP.

Program Update

Cinergy has taken a limited but more active role in promoting the program among the provider community. Additional options to increase participation are under consideration.

C. Planned New Generation and Transmission Facilities

Generation Facilities

No new generation facilities are planned at this time for the 2000-2002 time period.

Transmission Facilities

In compliance with the codes of conduct in FERC Order 889, the relevant transmission information is located in the Transmission Volume of this report, which was prepared independently.

D. Planned Sales and Purchases of Power with Other Utilities and Non-Utility Generators

The following tables detail committed purchases and sales associated with the jurisdictional franchised service territories within the U.S. served by the Cinergy operating companies and their affiliates.

COMMITTED PURCHASES
1999 - 2002

YEAR	COMPANY	PURCHASE TYPE	MW(1)	OPER. COMPANY
1999	EKPC	Diversity	Contractual	CG&E
	OVEC	Firm	63	CG&E
	Purch. A (2)	Firm	100	CG&E/PSI(3)
	Purch. B (4)	Firm	300	CG&E/PSI(3)
	Purch. C (5)	Firm	300	CG&E/PSI(3)
	Alternative Fuels	PURPA-QF	1(6)	PSI
	Bio-Energy	PURPA-QF	3	PSI
2000	Alternative Fuels	PURPA-QF	1(6)	PSI
	Bio-Energy	PURPA-QF	3	PSI
2001	Alternative Fuels	PURPA-QF	1(6)	PSI
	Bio-Energy	PURPA-QF	3	PSI
2002	Alternative Fuels	PURPA-QF	1(6)	PSI
	Bio-Energy	PURPA-QF	3	PSI

NOTES: (1) Rounded to the nearest full MW.

(2) Purchase made through or associated with the 1996 request for proposals process. The specific vendor is confidential.
(3) Split between operating companies, see Chapter 8.
(4) Calendar Strip 5X16 purchases from a number of vendors.
(5) July/August 5X16 purchases from a number of vendors.
(6) Expected capacity.

The resource plan outlined in this 1999 filing identified the need for additional power purchases in 2000, 2001, and 2002 beyond what has been identified in the above table. Specific arrangements for these purchases either have not been made, or finalized at this time.

COMMITTED SALES
1999 - 2002

YEAR	COMPANY	SALE TYPE (1)	MW (2)	OPER. COMPANY
1999	WVPA (3)	Partial Req.	156	PSI
	WVPA	Firm	70	PSI
	IMPA (3)	Partial Req.	502	PSI
	Logansport	Partial Req.	47	PSI
	Jackson REMC	Full Req.	76	PSI
	Bethel	Full Req.	6	CG&E
	Blanchester	Full Req.	11	CG&E
	Georgetown	Full Req.	9	CG&E
	Hamersville	Full Req.	1	CG&E
	Lebanon	Full Req.	27	CG&E
	Ripley	Full Req.	4	CG&E
	Williamstown	Full Req.	10	CG&E-ULH&P
	Other Municipalities (4)	Full Req.	48	PSI
	EKPC	Diversity	Contractual	CG&E
2000	WVPA (3)	Partial Req.	156	PSI
	WVPA	Firm	70	PSI
	IMPA (3)	Partial Req.	516	PSI
	Logansport	Partial Req.	47	PSI
	Jackson REMC	Full Req.	78	PSI
	Bethel	Full Req.	6	CG&E
	Blanchester	Full Req.	11	CG&E
	Georgetown	Full Req.	9	CG&E
	Hamersville	Full Req.	1	CG&E
	Lebanon	Full Req.	27	CG&E
	Ripley	Full Req.	4	CG&E
	Williamstown	Full Req.	10	CG&E-ULH&P
	Other Municipalities (4)	Full Req.	49	PSI
	EKPC	Diversity	Contractual	CG&E
2001	WVPA (3)	Partial Req.	156	PSI
	WVPA	Firm	70	PSI
	IMPA (3)	Partial Req.	531	PSI
	Logansport	Partial Req.	47	PSI
	Jackson REMC	Full Req.	80	PSI
	Bethel	Full Req.	6	CG&E
	Blanchester	Full Req.	11	CG&E
	Georgetown	Full Req.	9	CG&E
	Hamersville	Full Req.	1	CG&E
	Lebanon	Full Req.	28	CG&E
	Ripley	Full Req.	4	CG&E
	Williamstown	Full Req.	10	CG&E-ULH&P
	Other Municipalities (4)	Full Req.	51	PSI

COMMITTED SALES (Continued)
1999 - 2002

2002	WVPA(3)	Partial Req.	156	PSI
	WVPA	Firm	70	PSI
	IMPA(3)	Partial Req.	531	PSI
	Logansport	Partial Req.	47	PSI
	Jackson REMC	Full Req.	80	PSI
	Bethel	Full Req.	6	CG&E
	Blanchester	Full Req.	11	CG&E
	Georgetown	Full Req.	9	CG&E
	Hamersville	Full Req.	1	CG&E
	Lebanon	Full Req.	28	CG&E
	Ripley	Full Req.	4	CG&E
	Williamstown	Full Req.	10	CG&E-ULH&P
	Other Municipalities(4)	Full Req.	51	PSI

NOTES:
(1) Req. is Requirements.
(2) Rounded to the nearest full MW. Partial and Full Requirements are forecast based on historical load levels.
(3) These WVPA and IMPA sales include their ownership shares of Gibson 5.
(4) Other municipalities include: Lewisville, Straughn, Brooklyn, Coatesville, Dublin, Dunreith, Hagerstown, Knightstown, Montezuma, New Ross, Pittsboro, Pittsboro East, Rockville, South Whitley, Spiceland, Thorntown, Veedersburg, Veedersburg East, and Williamsport.

E. Criteria and Objectives Used to Evaluate the Progress of Implementation of Programs

Criteria and objectives used to evaluate the progress and success of implementation of each program and project are contained above in the description of each program and project.

F. **Estimates of Expenditures Necessary to Implement Cinergy's Integrated Resource Plan**

Forecast expenditures for CG&E DSM programs, which are not included as resources in Cinergy's IRP, will be provided in a separate filing by the CCEP. Estimates for PSI's DSM programs are provided in the table attached to the STIP. Estimates for generation projects were provided with the project descriptions.

G. **Estimates of the Securities Projected to be Issued for Implementation of Cinergy's Integrated Resource Plan**

Cinergy estimates that a combination of internal and external funds will be used to meet its capital needs. External funds will be used for refinancing of maturing debt and preferred stock, and the early refunding of existing high-cost debt and preferred stock, in addition to financing other capital needs.

H. **Project Timelines or Critical Paths Indicating Major Planning, Program, Permitting or Construction Milestones**

Project timelines or critical paths indicating major milestones for the CG&E DSM programs will be provided in a separate filing by the CCEP. Those for the PSI DSM programs and for generation projects are discussed with the program and project descriptions.

I. Changes in the Short-Term Implementation Plan From the Previously Filed Plan

There have been significant changes since the last filing. These are explained in Section B of this STIP.

J. Other Appropriate Matters

This section is not applicable at this time.

K. Amended STIP Associated With Amended Integrated Resource Plan

This section is not applicable at this time.

Table STIP-1

PSI ENERGY - PRELIMINARY
DSM PROGRAMS REFLECTED IN DSM SETTLEMENT AGREEMENT
PROGRAM COSTS ($000)

Program	2000
Residential Programs	
Home Energy Audit/Residential Measures	$400,000
Smart $aver®/Summer $aver™ ($700,000 for Smart $aver®; $400,000 for Summer $aver™)	$1,100,000
Low Income	$400,000
Small C&I Programs	
Motors, lighting, HVAC	$500,000
Total On-Going DSM	$2,400,000

CINERGY®

PSI Energy, Inc.
The Cincinnati Gas & Electric Company
The Union Light, Heat & Power Company

1999

INTEGRATED RESOURCE PLAN

VOLUME I

GENERAL APPENDIX

November 1, 1999

By: Cinergy Services
Douglas F. Esamann, Vice President
139 E. Fourth St.
P.O. Box 960
Cincinnati, Ohio 45201-0960

<u>GENERAL APPENDIX</u>
<u>Table of Contents</u>

IN COMPLIANCE WITH THE CODES OF CONDUCT IN FERC ORDER 889, ALL OF THE FOLLOWING SECTIONS ARE CONTAINED IN THE TRANSMISSION VOLUME OF THIS REPORT, WHICH WAS PREPARED INDEPENDENTLY

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1998 Hourly Load Data

The 1998 hourly load data for Cinergy, the CG&E system, and the PSI system is voluminous in nature. This data will be made available to appropriate parties for viewing at Cinergy offices and at other locations during normal business hours. Please contact Jim Riddle at (513) 287-3858 for more information.

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Cinergy Long-Term Electric and Gas Forecasts

The following Cinergy Long-Term Electric and Gas Forecasts report pertains to customer demand for electric and/or gas energy within the franchised electric and/or gas service territories of The Cincinnati Gas & Electric Company and subsidiaries (CG&E) and PSI Energy, Inc. (PSI). Differences between the figures shown in this document and those contained in Volume I are due to the treatment of DSM.

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Cinergy

The Cincinnati Gas and Electric Company and Subsidiaries
PSI Energy

Long Term
Electric and Gas Forecasts

Market Analysis
December 1998

CINERGY - LONG-TERM ELECTRIC AND GAS FORECASTS

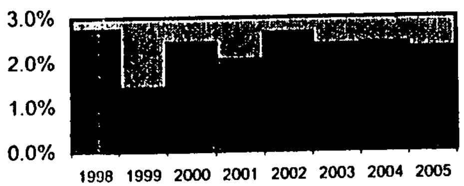
CONTENTS

NATION

ECONOMY

The national economy is entering the eighth year of the economic expansion and is expected to grow in the 2% to 3% range over the next several years. The economy grew 3.8% in 1997 as measured by Gross Domestic Product or GDP. This is up from the rate of 2.8% reported for 1996. Recent projections have the economy finishing 1998 at 3.7% followed by a slight slowdown in 1999 to 2.1%. The Fed has lowered interest rates in the third quarter of 1998 and the stock market has rebounded from its low point in August to a new record high in late November.

NATIONAL GDP
(1998 - 2005 Forecast)



Over the next five years total employment for the nation is expected to increase at an annual growth rate of 1.2%, industrial production at 3.3% and population at 0.8%.

Both the CG&E and PSI service territories have benefited from growth in the national economy. Local economic numbers, as well as growth in gas and electric sales, give evidence of the favorable conditions.

CG&E

The following summary provides a brief overview of the economic and energy climate for the CG&E service area.

ECONOMY

The Greater Cincinnati economy remains in a position of strength. Total employment continued to rise in 1997, especially in the commercial sector. Federal and local government employment decreased slightly in 1997. In the industrial sector, total employment dropped ½ of 1% in 1997.

In 1998, through October, year-to-date industrial electric sales increased 3.7% over the 1997 level for the same time period. Commercial sales through October, 1998 are 4.7% above 1997, however, governmental sales are down 1.5%. Through October, residential customers increased by 1.3% when compared to the same ten months in 1997.

Over the next five years total employment is expected to increase at an annual growth rate of 1.5%, industrial production at 2.8% and population is projected to grow 0.7% per year.

ELECTRIC

Overall, 1999 is expected to show positive growth, approximately 2.1% over 1998. The fastest growing sector is expected to

CG&E (cont.)

be the industrial sector with an annual growth rate of 2.4% forecasted for the next five years.

Residential sales are expected to grow annually at a rate of 1.9% over the next five years, commercial at 2.0%, and total sendout is expected to grow 2.1% per year.

NATURAL GAS

Interruptible deliveries of natural gas continue to increase in volume and percentage of total deliveries. For 1999, the forecast projects 0.8% growth in firm deliveries including firm transportation, 4.1% growth in interruptible deliveries exclusive of AK Steel, and 1.5% growth in total sendout which includes all transportation gas. As with electric sales, the largest sector in gas deliveries is industrial. Over the next five years industrial deliveries are forecasted to grow annually at the rate of 4.1%.

Residential gas deliveries are projected to grow at an annual rate of 1.2% over the next five years, commercial at a 0.5% rate of growth, and expect total sendout to grow 1.8% per year over the next five.

This report contains information reflecting the loss of gas deliveries to AK Steel, CG&E's largest customer in terms of volume, starting in the year 1999.

PSI

The following summary provides a brief overview of the economic and energy climate in the PSI service area.

ECONOMY

The Indiana economy in general and the PSI service area economy in particular have continued to outpace the national economy during the 90's.

For the PSI service area economy, 1997 total employment numbers indicate growth of 0.3% above the 1996 level. Total personal income grew 6.7% in 1997.

Year-to-date through October, 1998 industrial electric sales are running 6.6% above the same 1997 time period and commercial sales are up 6.3%. Residential customers (on an average basis) increased by 2.1% over 1997.

The local economic outlook over the next five years is as follows. Total employment will grow at 1.9% per year, industrial production is expected to increase 4.4% annually and population is projected to grow 0.9% per year during the next five years.

PSI (cont.)

ELECTRIC

In 1999 total electric sendout is expected to show positive growth, approximately 3.4% over 1998. The fastest growing sector will be the industrial sector with an annual growth rate of 3.6% forecast for the next five years. This includes additional loads for the new Qualitech plant and expansions at AE Staley, INTAT, and Ford.

Residential sales are expected to grow at the annual rate of 2.1% over the next five years and commercial sales are projected to grow at 1.6%. Total electric sendout is expected to increase 2.6% per year over the next five years.

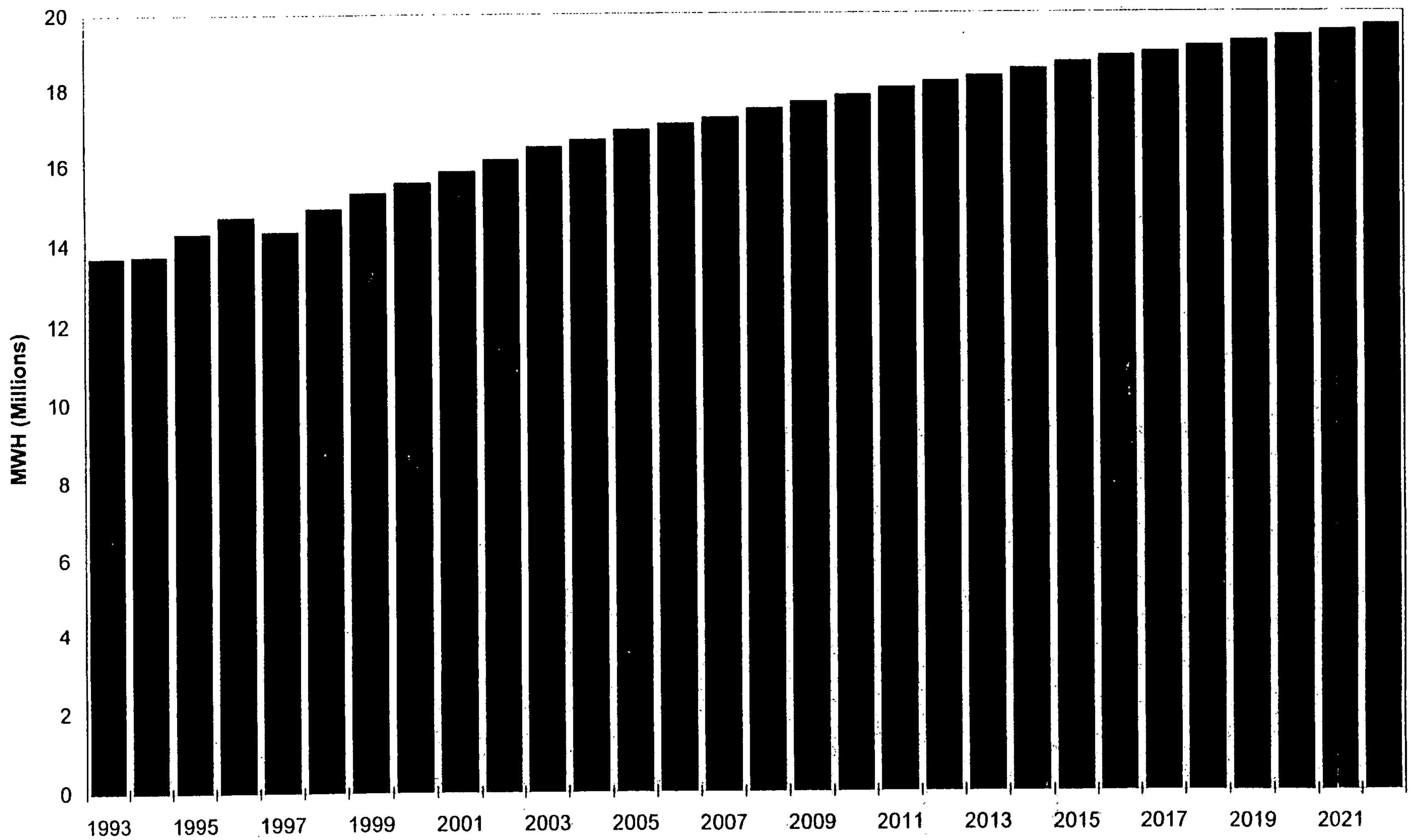
Residential customer growth is expected to be remain strong this year and next growing 2.0% in 1999 and 2.0% in 2000. For the next five years, customers are forecasted to grow at the annual rate of 1.7%.

PSI (cont.)

Counties surrounding Indianapolis and those adjacent to Louisville continue to show strong growth in residential and commercial sales. Following close behind in terms of growth are those counties with a large university (Purdue and Indiana University) influence. These counties are expected to continue growing at a rate above the state of Indiana as a whole.

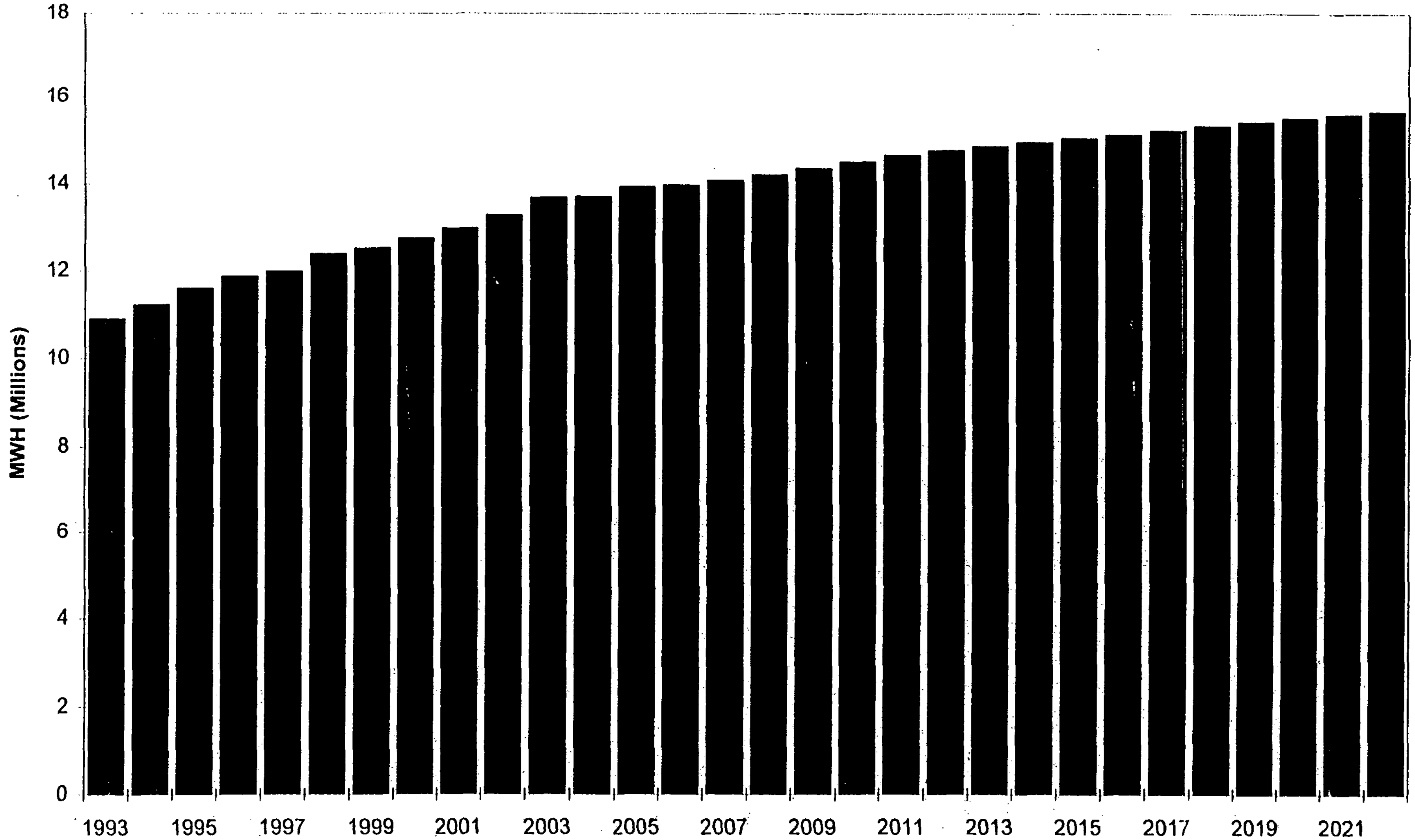
This forecast reflects a dramatic change in sales to the Wholesale sector which reflects the termination of the contract with Indiana Municipal Power Agency (IMPA), a major wholesale customer, beginning in the year 2007.

CINERGY
Total Residential Electric Sales



(DRI Forecast February 1998)

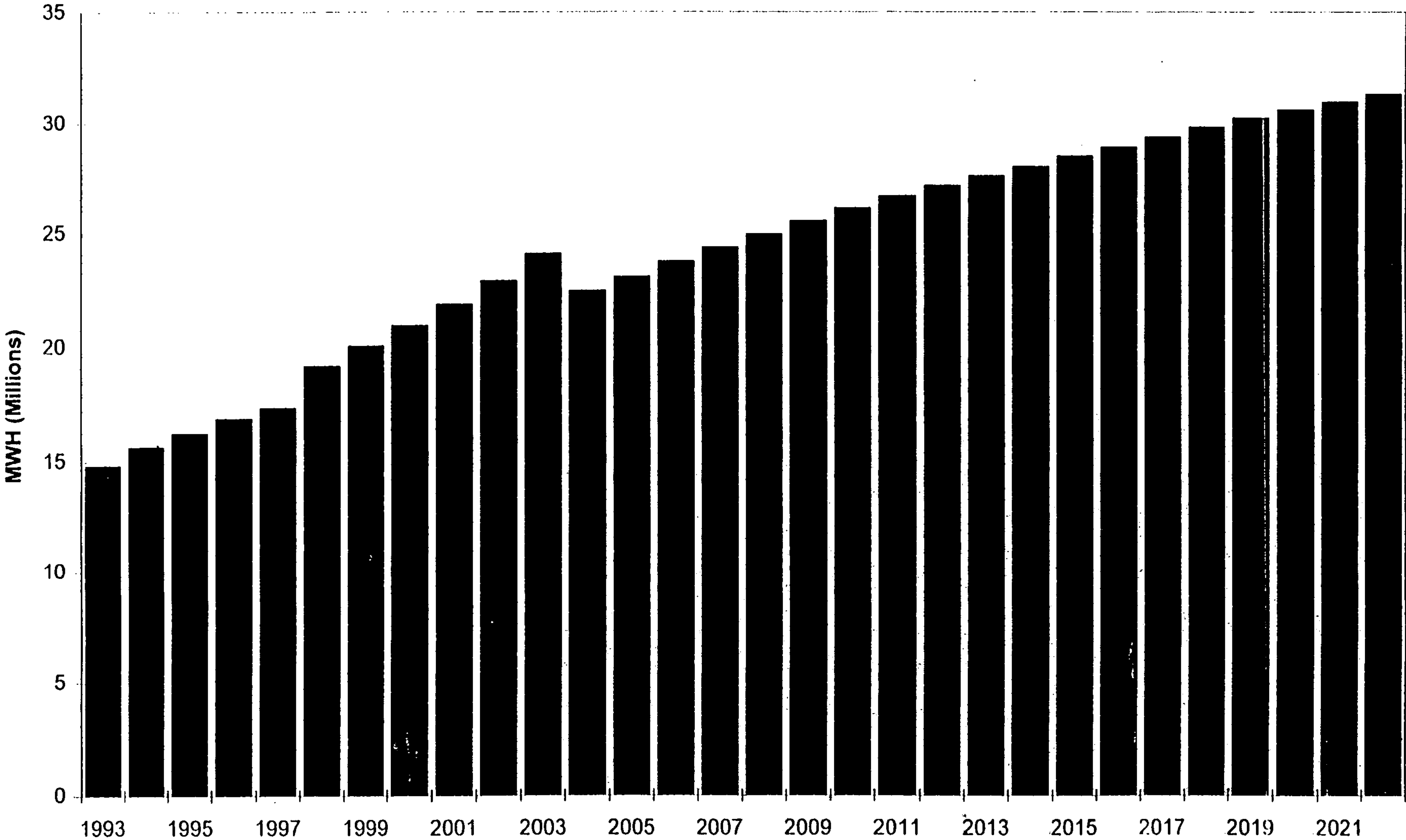
CINERGY
Total Commercial Electric Sales



(DRI Forecast February 1998)

CINERGY

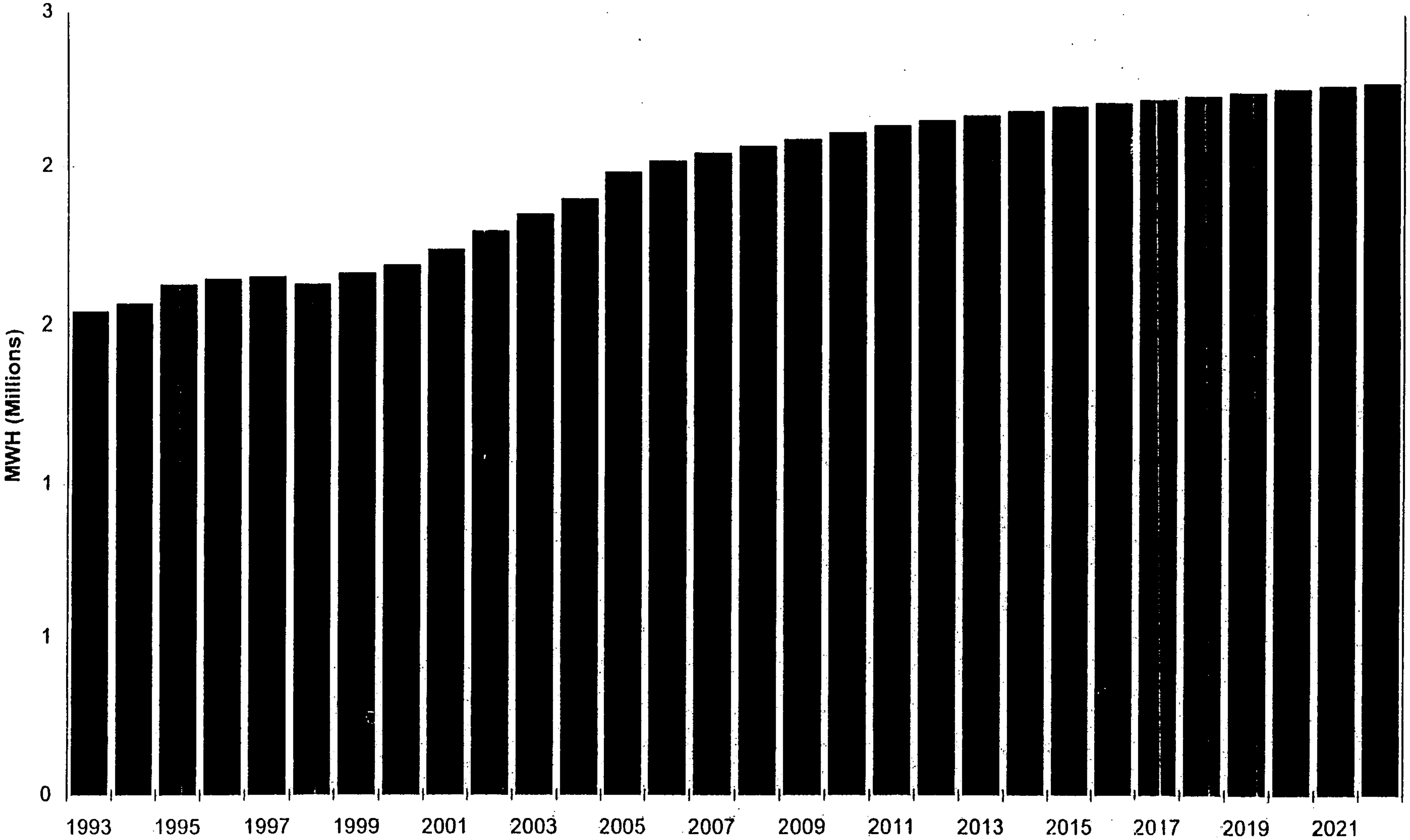
Total Industrial Electric Sales



(DRI Forecast February 1998)

CINERGY

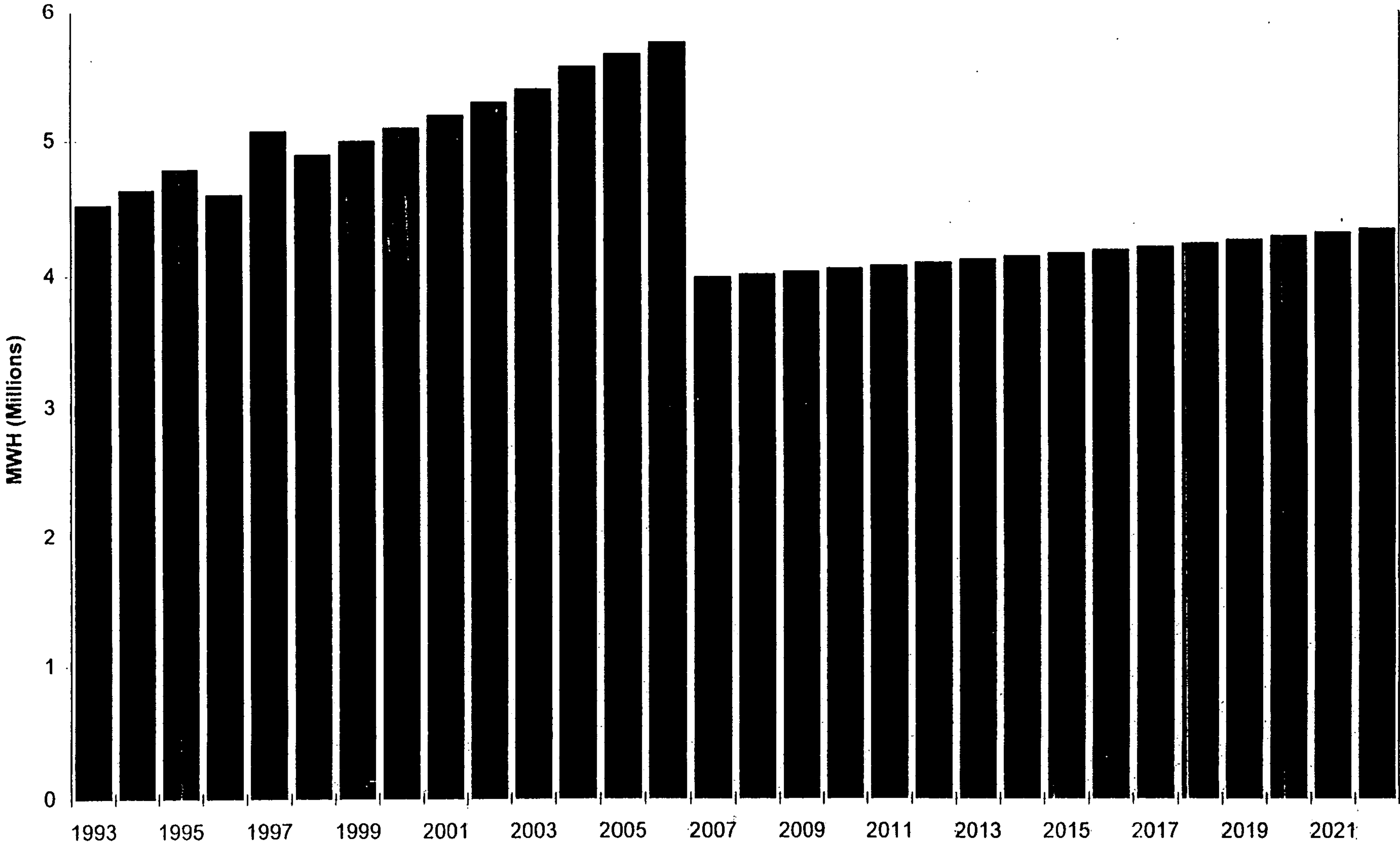
Total Other Public Authorities Electric Sales



(DRI Forecast February 1

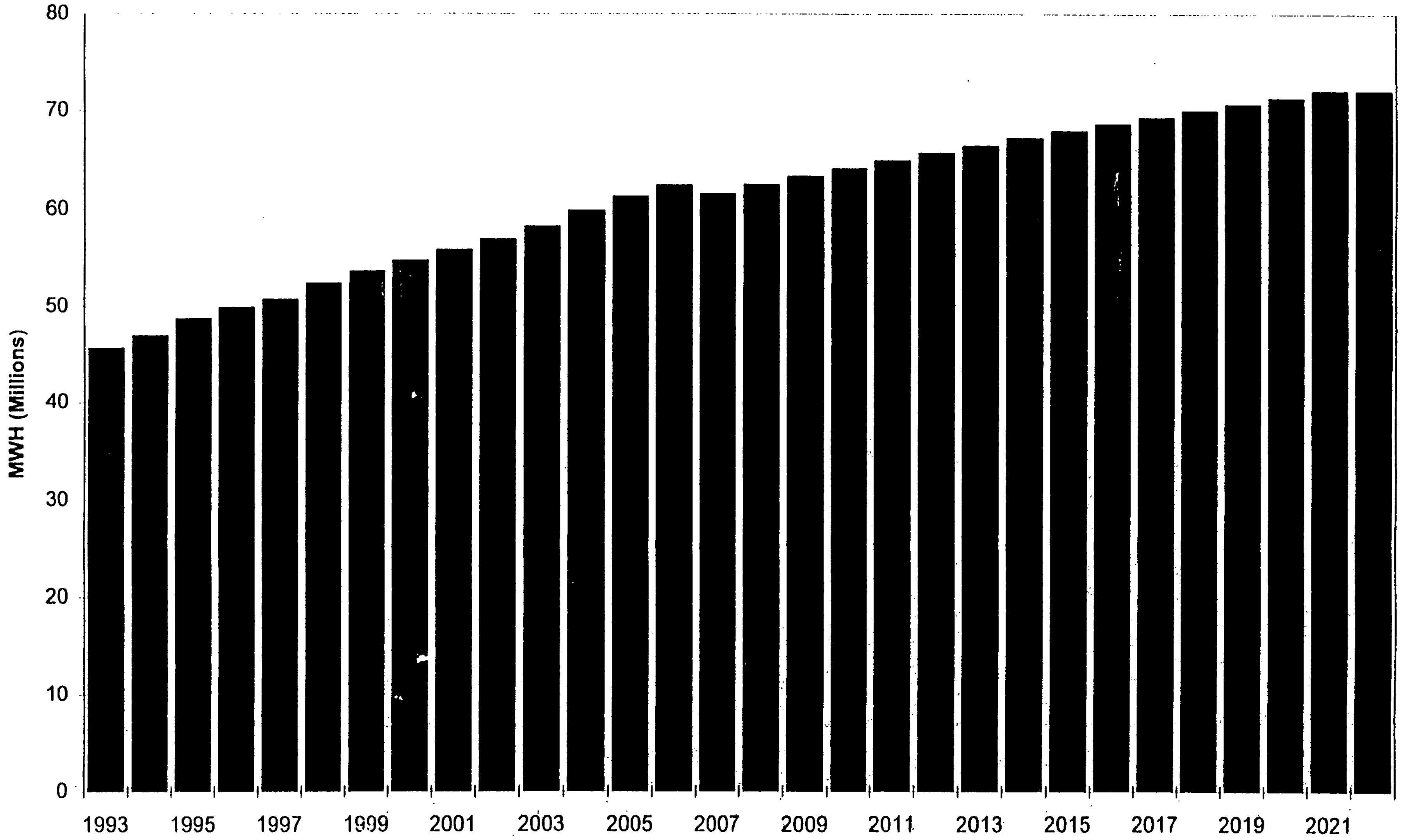
CINERGY

Total Wholesale Electric Sales



(DRI Forecast February 1998)

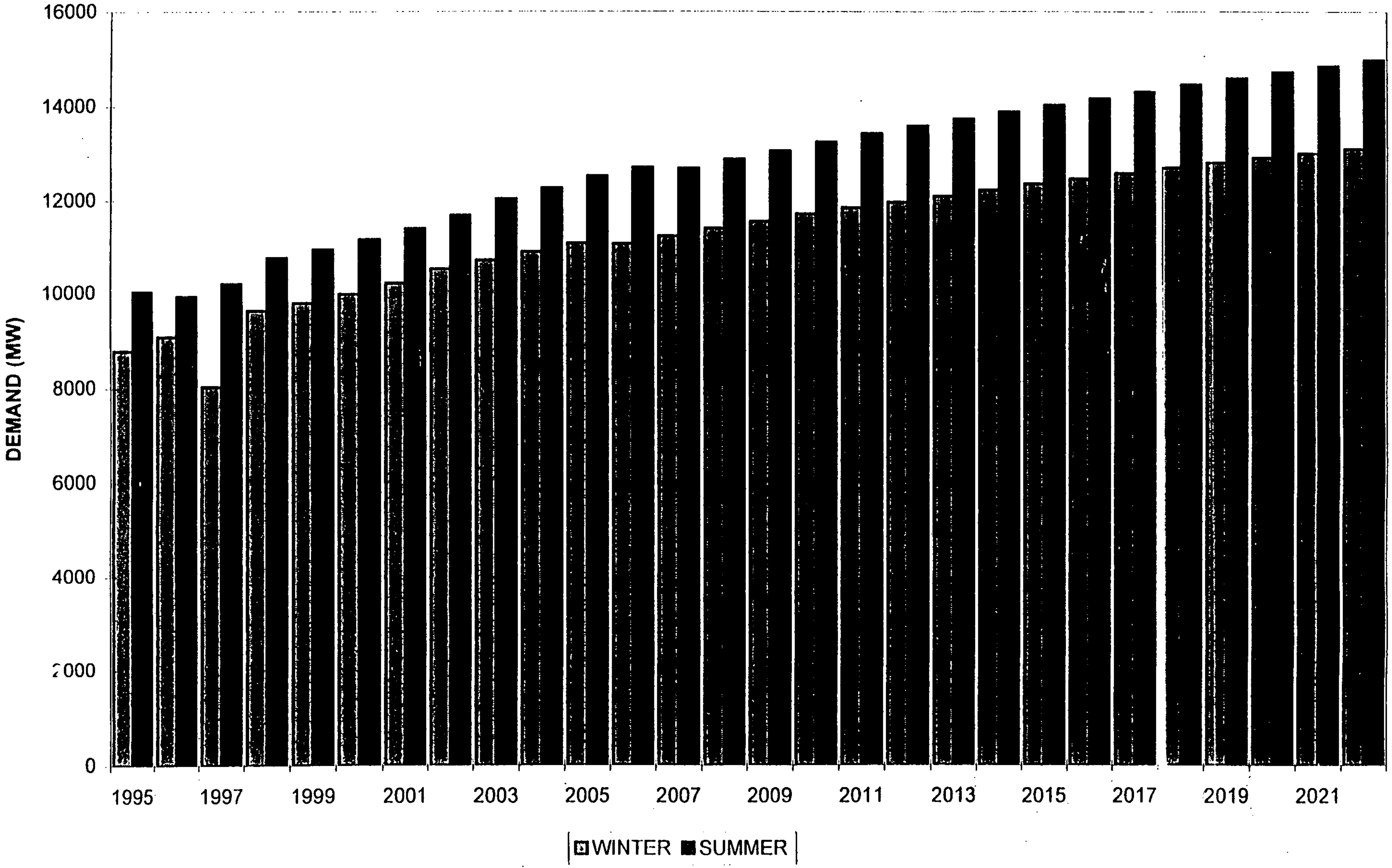
CINERGY
Total Electric Sendout



(DRI Forecast February 3)

CINERGY

Electric Peak Demand (ESAL)



(DR Forecast February 1998)

CINERGY
FORECAST OF ELECTRIC SALES
MWH - BILLING

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL EXC. STEEL *	STEEL *	TOTAL INDUSTRIAL	STREET LIGHTING	OPA	INTER-DEPT	TOTAL RETAIL
1993	13,675,561	10,890,465	12,991,180	1,791,273	14,782,453	156,725	1,539,097	10,369	41,054,670
1994	13,714,712	11,215,581	13,603,623	1,994,995	15,598,619	159,398	1,562,454	10,810	42,261,574
1995	14,280,313	11,584,378	14,005,758	2,171,509	16,177,267	162,795	1,621,019	10,281	43,836,054
1996	14,689,828	11,851,538	14,319,692	2,495,939	16,815,631	164,644	1,638,710	10,054	45,170,404
1997	14,318,683	11,969,367	14,674,740	2,624,358	17,299,098	166,704	1,645,999	9,757	45,409,608
1998	14,896,499	12,373,693	16,439,696	2,719,966	19,159,662	166,936	1,622,942	9,996	48,229,728
1999	15,278,129	12,500,980	17,368,813	2,658,819	20,027,632	167,247	1,657,823	9,996	49,641,807
2000	15,522,463	12,723,181	18,165,931	2,748,097	20,914,028	167,784	1,683,003	9,996	51,020,455
2001	15,810,612	12,951,517	19,040,498	2,805,602	21,846,100	168,198	1,731,071	9,996	52,517,494
2002	16,112,557	13,254,800	20,030,147	2,858,220	22,888,367	168,618	1,789,259	9,996	54,223,597
2003	16,448,737	13,662,403	21,106,761	2,969,023	24,075,784	169,159	1,842,800	9,996	56,208,879
2004	16,628,980	13,682,245	19,365,033	3,077,549	22,442,582	170,024	1,890,903	9,996	54,824,730
2005	16,880,571	13,916,254	19,857,327	3,186,147	23,043,474	170,903	1,977,768	9,996	55,998,966
2006	17,040,473	13,958,713	20,415,761	3,297,835	23,713,596	171,727	2,014,528	9,996	56,909,033
2007	17,199,737	14,063,396	20,945,586	3,387,958	24,333,544	172,519	2,040,261	9,996	57,819,453
2008	17,434,581	14,196,032	21,467,454	3,446,086	24,913,540	173,327	2,063,205	9,996	58,790,681
2009	17,609,077	14,338,323	21,978,328	3,528,170	25,506,498	174,153	2,084,860	9,996	59,722,907
2010	17,788,637	14,489,654	22,468,890	3,613,932	26,082,822	174,986	2,107,555	9,996	60,653,650
2011	17,980,752	14,644,654	22,950,840	3,690,939	26,641,779	175,787	2,129,412	9,996	61,582,380
2012	18,143,907	14,748,346	23,389,108	3,735,213	27,124,321	176,564	2,145,251	9,996	62,348,385
2013	18,279,191	14,840,966	23,790,352	3,781,620	27,571,972	177,332	2,159,921	9,996	63,039,378
2014	18,474,739	14,930,640	24,201,683	3,797,413	27,999,096	178,090	2,174,159	9,996	63,766,720
2015	18,656,785	15,022,655	24,641,101	3,818,061	28,459,162	178,848	2,188,842	9,996	64,516,288
2016	18,829,378	15,106,969	25,051,874	3,823,565	28,875,439	179,551	2,200,900	9,996	65,202,233
2017	18,935,762	15,199,065	25,493,470	3,837,870	29,331,340	180,219	2,211,433	9,996	65,867,815
2018	19,089,362	15,297,868	25,934,441	3,846,265	29,780,706	180,888	2,222,653	9,996	66,581,473
2019	19,218,697	15,390,634	26,360,824	3,847,193	30,208,017	181,559	2,234,351	9,996	67,243,254
2020	19,354,003	15,474,406	26,747,128	3,838,310	30,585,438	182,234	2,246,407	9,996	67,852,484
2021	19,485,309	15,550,131	27,121,089	3,827,793	30,948,882	182,860	2,257,338	9,996	68,434,516
2022	19,619,984	15,622,539	27,481,716	3,822,383	31,304,099	183,465	2,267,310	9,996	69,007,393
GROWTH RATE									
1998-2003	2.0%	2.0%	5.1%	1.8%	4.7%	0.3%	2.6%	0.0%	3.1%
1998-2008	1.6%	1.4%	2.7%	2.4%	2.7%	0.4%	2.4%	0.0%	2.0%
1998-2022	1.2%	1.0%	2.2%	1.4%	2.1%	0.4%	1.4%	0.0%	1.5%

* A K Steel and Nucor

** NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February)

CINERGY

FORECAST OF ELECTRIC SENDOUT AND PEAK DEMAND

	MWH - BILLING						ESAL * PEAK DEMAND - MW	
	TOTAL RETAIL	WHOLESALE	COMPANY USE	TOTAL DELIVERIES	LOSSES	TOTAL SENDOUT	WINTER	SUMMER
1993	41,054,670	4,508,639	25,998	45,589,307	2,806,886	48,396,193	NA	NA
1994	42,261,574	4,615,115	25,006	46,901,694	2,870,990	49,772,684	NA	NA
1995	43,836,054	4,769,532	26,898	48,632,484	3,034,977	51,667,461	8,765	10,025
1996	45,170,404	4,580,255	27,488	49,778,147	3,599,892	53,378,039	9,057	9,921
1997	45,409,608	5,060,014	24,377	50,493,999	3,195,810	53,689,809	8,035	10,196
1998	48,229,728	4,881,447	25,632	53,136,807	4,049,325	57,186,132	9,609	10,757
1999	49,641,807	4,984,443	25,752	54,652,002	4,154,097	58,806,099	9,769	10,940
2000	51,020,455	5,082,508	25,884	56,128,847	4,266,811	60,395,658	9,971	11,156
2001	52,517,494	5,178,430	26,016	57,721,940	4,386,833	62,108,773	10,211	11,388
2002	54,223,597	5,278,460	26,148	59,528,205	4,526,595	64,054,800	10,509	11,677
2003	56,208,879	5,380,177	26,280	61,615,336	4,686,119	66,301,455	10,702	12,028
2004	54,824,730	5,557,518	26,412	60,408,660	4,594,127	65,002,787	10,886	12,261
2005	55,998,966	5,656,849	26,544	61,682,359	4,683,745	66,366,104	11,075	12,520
2006	56,909,033	5,750,867	26,676	62,686,576	4,752,474	67,439,050	11,058	12,700
2007	57,819,453	3,981,371	26,808	61,827,632	4,668,410	66,496,042	11,227	12,676
2008	58,790,681	4,003,378	26,940	62,820,999	4,742,409	67,563,408	11,393	12,872
2009	59,722,907	4,025,184	27,072	63,775,163	4,813,424	68,588,587	11,550	13,060
2010	60,653,650	4,047,408	27,204	64,728,262	4,886,039	69,614,301	11,713	13,246
2011	61,582,380	4,070,309	27,348	65,680,037	4,957,557	70,637,594	11,854	13,435
2012	62,348,385	4,092,955	27,480	66,468,820	5,016,470	71,485,290	11,966	13,586
2013	63,039,378	4,115,816	27,624	67,182,818	5,071,047	72,253,865	12,092	13,734
2014	63,766,720	4,139,969	27,756	67,934,445	5,127,073	73,061,518	12,228	13,884
2015	64,516,288	4,164,240	27,900	68,708,428	5,184,742	73,893,170	12,352	14,034
2016	65,202,233	4,188,703	28,032	69,418,968	5,237,773	74,656,741	12,461	14,176
2017	65,867,815	4,213,084	28,176	70,109,075	5,290,899	75,399,974	12,580	14,315
2018	66,581,473	4,238,778	28,320	70,848,571	5,346,624	76,195,195	12,698	14,467
2019	67,243,254	4,264,830	28,452	71,536,536	5,397,884	76,934,420	12,806	14,599
2020	67,852,484	4,291,475	28,596	72,172,555	5,445,029	77,617,584	12,907	14,724
2021	68,434,516	4,318,657	28,740	72,781,913	5,490,474	78,272,387	13,002	14,849
2022	69,007,393	4,346,362	28,884	73,382,639	5,535,220	78,917,859	13,099	14,976
GROWTH RATE								
1998-2003	3.1%	2.0%	0.5%	3.0%	3.0%	3.0%	2.2%	2.3%
1998-2008	2.0%	-2.0%	0.5%	1.7%	1.6%	1.7%	1.7%	1.8%
1998-2022	1.5%	-0.5%	0.5%	1.4%	1.3%	1.4%	1.3%	1.4%

* ESAL peaks are unavailable for PSI prior to 1995.

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February 1998)

CINERGY
ELECTRIC CUSTOMERS BY MAJOR CLASSIFICATIONS
ANNUAL AVERAGES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	OPA	WHOLE-SALE	TOTAL CUSTOMERS	ANNUAL INCREASE	ELECTRIC - KWH RESIDENTIAL USE PER CUSTOMER
1993	1,160,513	142,767	6,263	1,808	3,869	39	1,315,259		11,784
1994	1,174,705	144,766	6,345	1,818	3,914	41	1,331,589	16,331	11,675
1995	1,195,323	147,888	6,424	1,927	4,029	45	1,355,638	24,048	11,947
1996	1,216,005	149,050	6,471	2,053	4,115	63	1,377,756	22,119	12,080
1997	1,236,974	151,094	6,472	2,139	4,141	75	1,400,894	23,560	11,576
1998	1,256,579	154,545	6,531	2,179	4,271	75	1,424,179	23,285	11,855
1999	669,131	74,360	3,102	778	4,361	8	751,740	(672,439)	22,833
2000	1,285,875	158,950	6,645	2,225	4,446	75	1,458,216	706,476	12,072
2001	1,306,277	161,946	6,721	2,249	4,529	75	1,481,797	23,582	12,104
2002	1,325,406	164,767	6,793	2,275	4,616	75	1,503,931	22,134	12,157
2003	1,343,812	167,486	6,862	2,303	4,703	75	1,525,241	21,310	12,240
2004	1,361,790	170,134	6,929	2,331	4,790	75	1,546,049	20,808	12,211
2005	721,346	82,711	3,233	934	4,879	8	813,111	(732,938)	23,402
2006	1,386,853	173,935	7,008	2,388	4,960	75	1,575,219	762,109	12,287
2007	1,401,663	176,155	7,068	2,414	5,025	75	1,592,400	17,181	12,271
2008	1,414,654	178,072	7,129	2,440	5,089	75	1,607,459	15,059	12,324
2009	1,426,737	179,890	7,188	2,467	5,153	75	1,621,510	14,051	12,342
2010	1,439,251	181,773	7,247	2,495	5,217	75	1,636,059	14,548	12,360
2011	764,205	89,601	3,290	1,099	5,267	8	863,470	(772,589)	23,529
2012	1,457,867	184,655	7,305	2,552	5,292	75	1,657,746	794,276	12,446
2013	1,469,311	186,381	7,359	2,578	5,314	75	1,671,019	13,273	12,441
2014	1,480,124	188,020	7,412	2,605	5,335	75	1,683,571	12,552	12,482
2015	1,489,979	189,530	7,464	2,632	5,356	75	1,695,036	11,465	12,522
2016	1,498,384	190,837	7,512	2,659	5,363	75	1,704,831	9,795	12,566
2017	799,740	95,394	3,297	1,257	5,342	8	905,038	(799,793)	23,677
2018	1,511,310	192,867	7,556	2,704	5,318	75	1,719,830	814,793	12,631
2019	1,519,722	194,152	7,602	2,726	5,294	75	1,729,571	9,740	12,646
2020	1,527,984	195,419	7,649	2,749	5,270	75	1,739,146	9,575	12,666
2021	1,535,087	196,519	7,692	2,770	5,235	75	1,747,378	8,232	12,693
2022	1,541,180	197,461	7,734	2,790	5,179	75	1,754,419	7,041	12,730
GROWTH RATE									
1998-2003	1.4%	1.6%	1.0%	1.1%	1.9%	0.0%	1.4%		0.6%
1998-2008	1.2%	1.4%	0.9%	1.1%	1.8%	0.0%	1.2%		0.4%
1998-2022	0.9%	1.0%	0.7%	1.0%	0.8%	0.0%	0.9%		0.3%

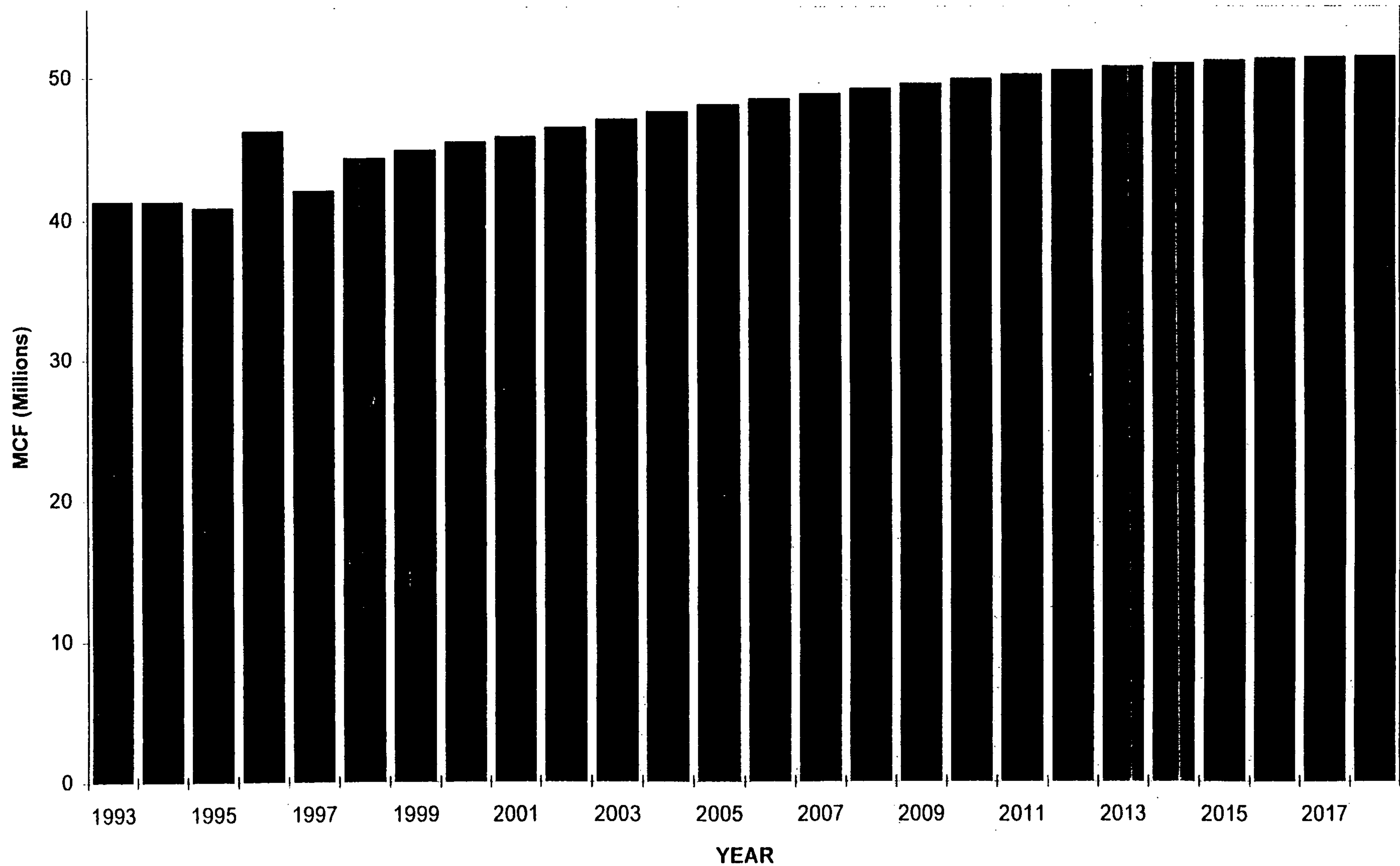
NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

GA-18

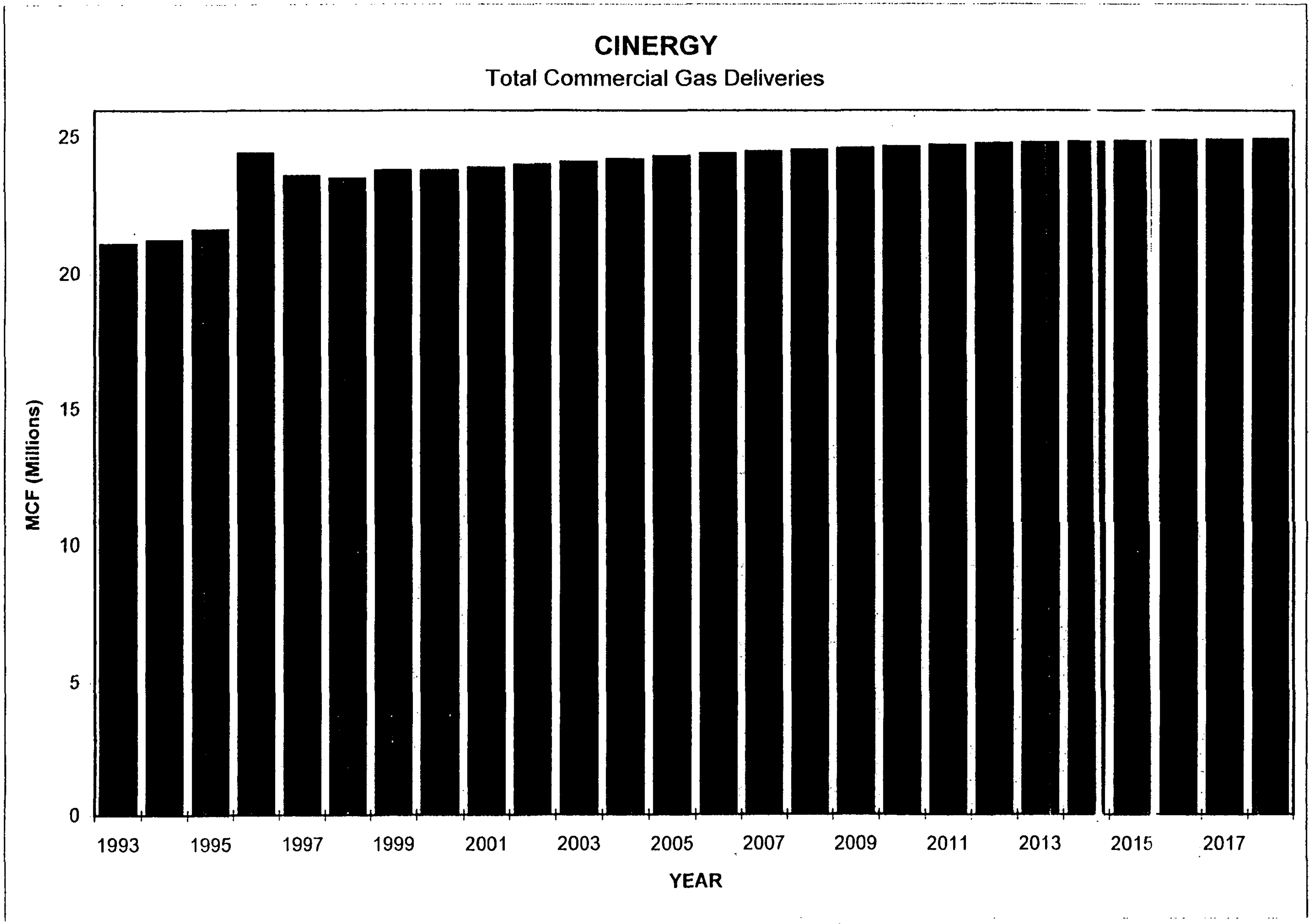
(DRI Forecast February)

CINERGY

Total Residential Gas Deliveries



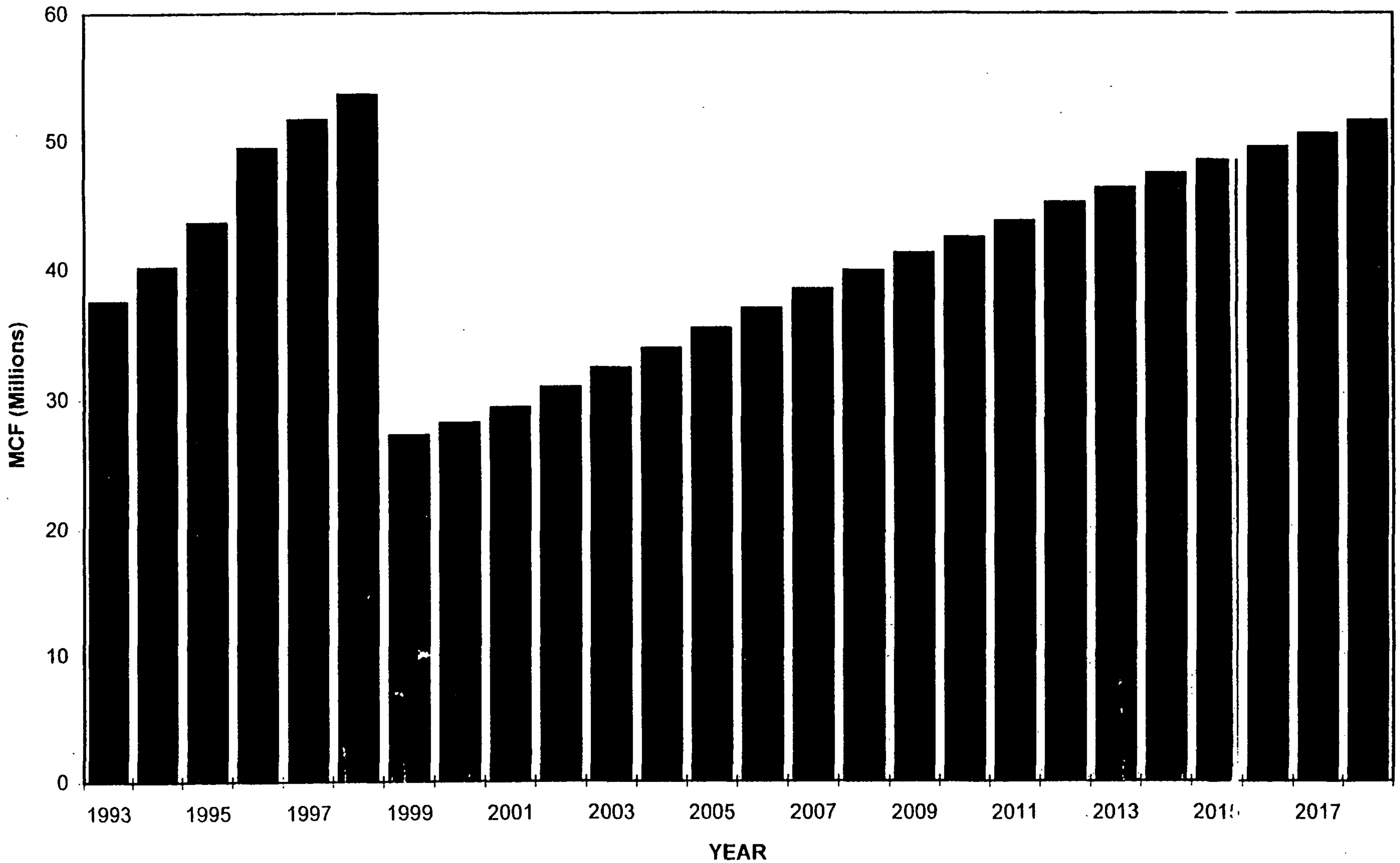
(DRI Forecast February 1998)



(DRI Forecast February 1998)

CINERGY

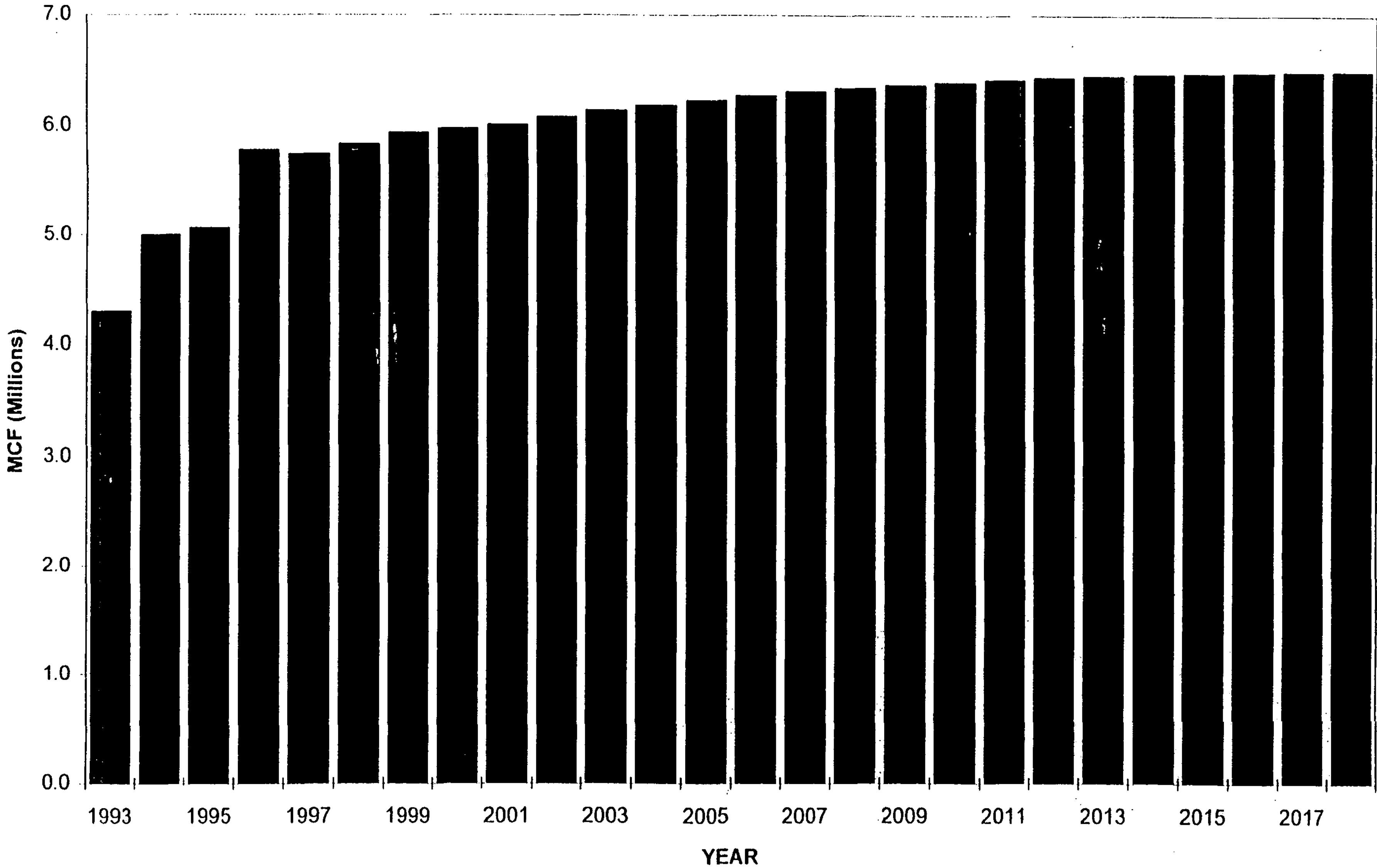
Total Industrial Gas Deliveries



(DRI Forecast February 1998)

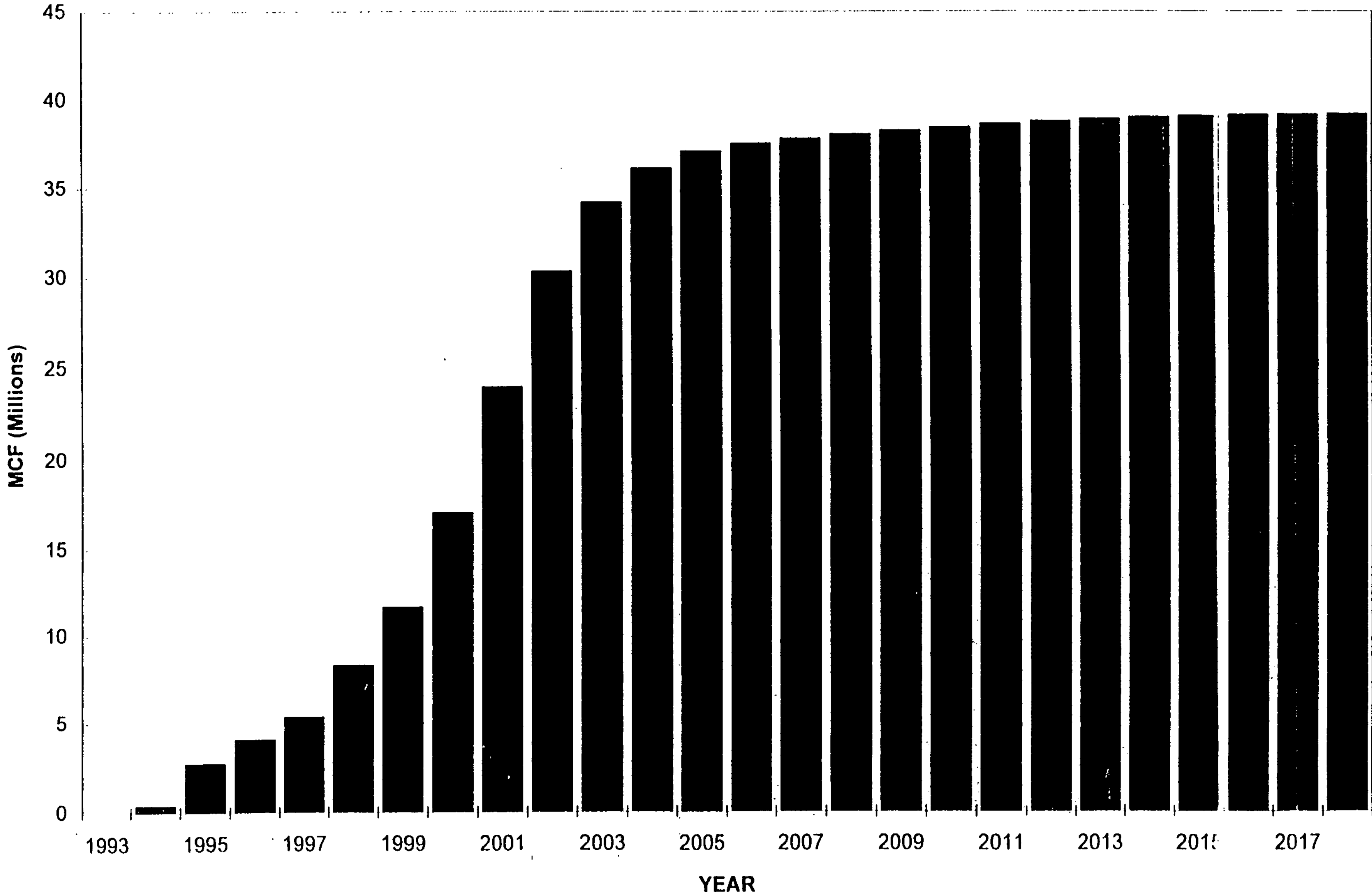
CINERGY

Total Other Public Authorities Gas Deliveries



(DRI Forecast February 1[illegible]8)

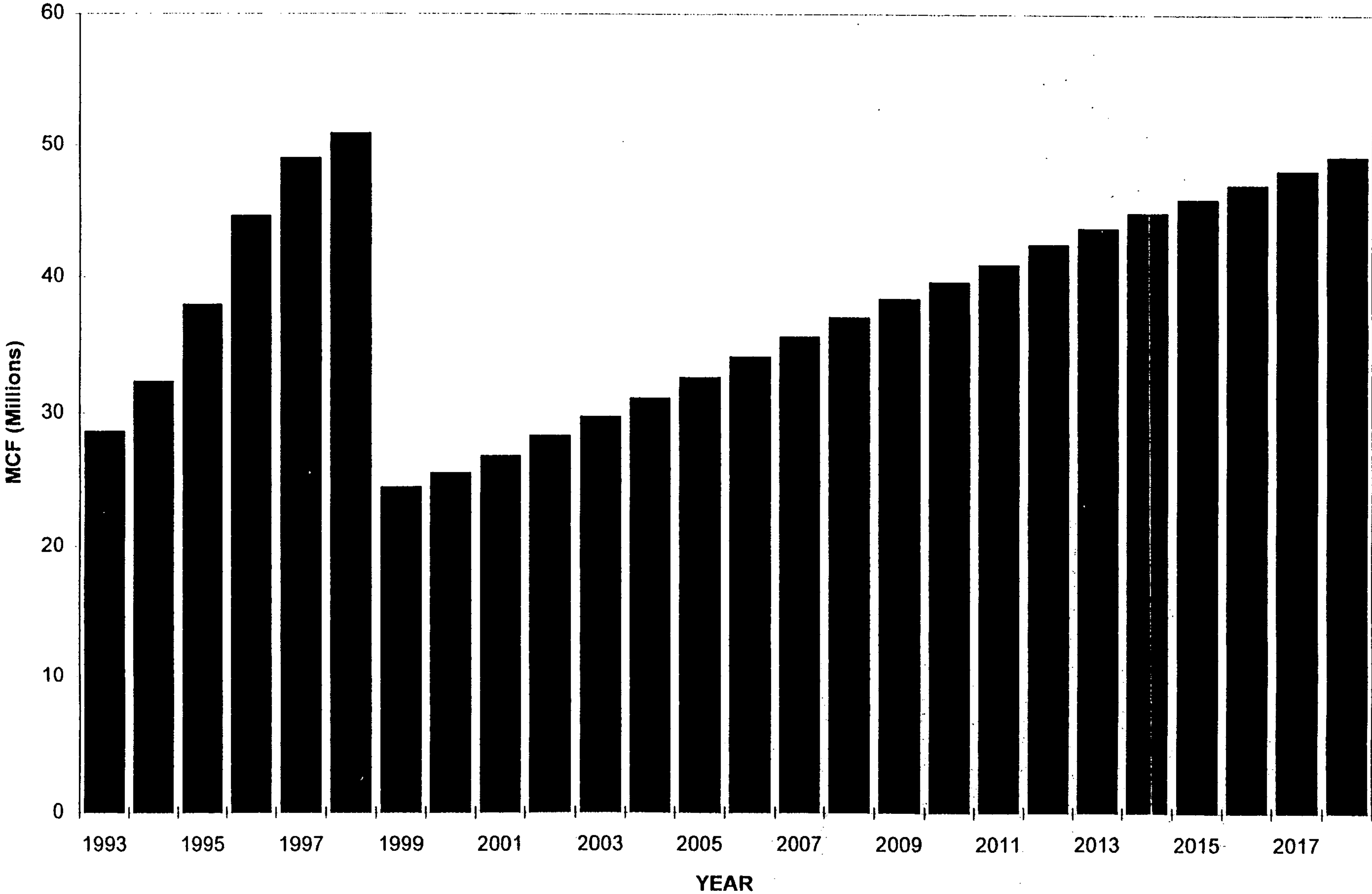
CINERGY
Total Firm Transportation Gas Deliveries



(DRI Forecast February 1998)

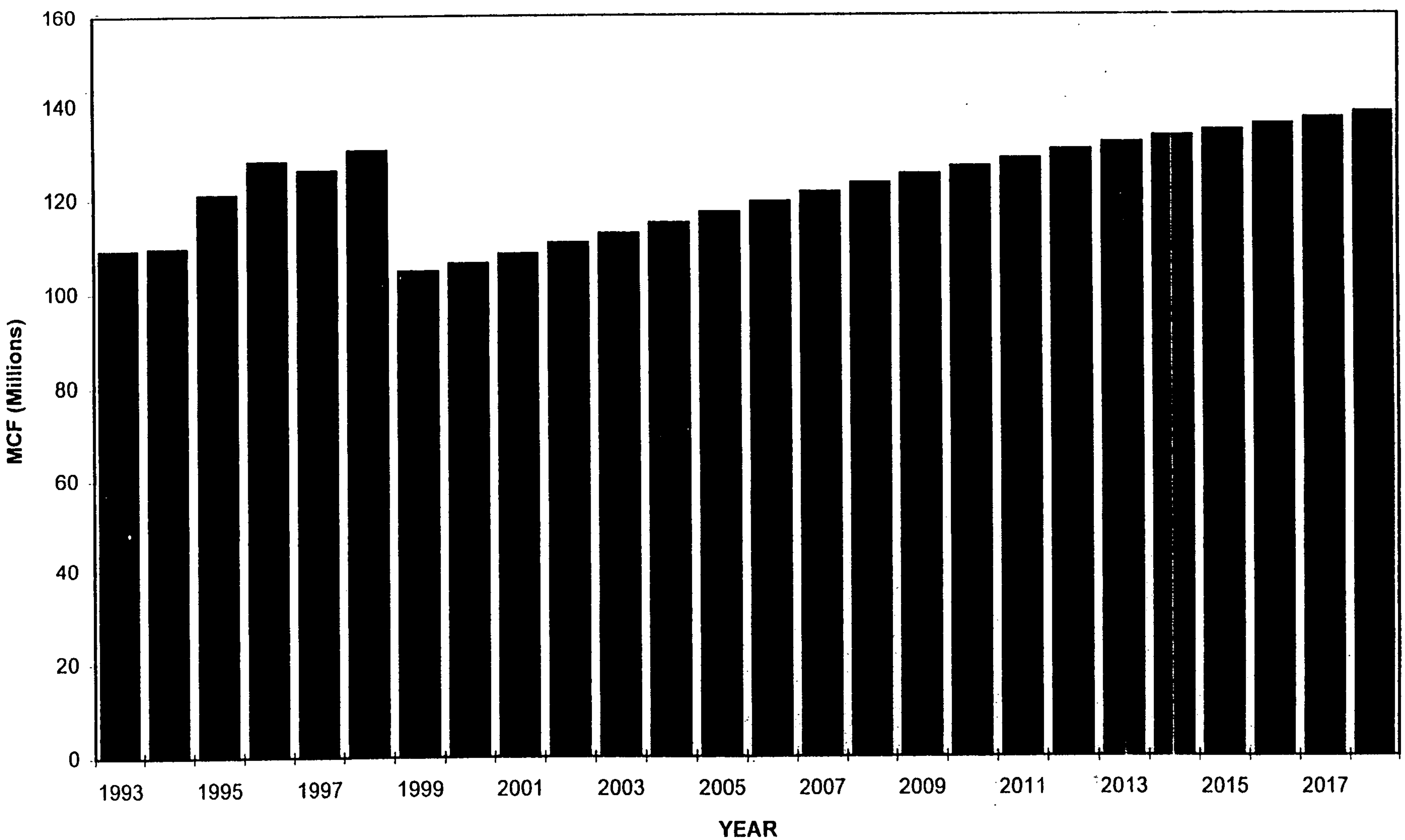
CINERGY

Total Interruptible Transportation Gas Deliveries



(DRI Forecast February 8)

CINERGY
Total Gas Sendout



(DRI Forecast February 1998)

CINERGY
FORECAST OF FIRM GAS SALES AND TRANSPORTATION
MCF - BILLING

	FIRM SALES								FIRM TRANSPORTATION				
	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	O.P.A.	WHOLE-SALE	INTER-DEPT.	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	O.P.A.	TOTAL
1993	41,245,097	19,824,738	6,637,149	39,927	3,077,125	306,947	83,531	71,214,514	0	0	0	0	0
1994	41,215,827	19,813,301	6,293,039	40,892	3,171,763	296,395	76,220	70,907,437	0	118,869	208,989	3,817	331,675
1995	40,786,826	18,867,539	4,851,309	40,892	2,993,963	279,204	84,237	67,903,970	0	1,155,685	1,338,274	163,701	2,657,660
1996	46,170,385	21,157,313	5,112,469	41,583	2,927,289	352,245	96,028	75,857,312	0	1,612,063	1,763,139	631,353	4,006,554
1997	41,992,397	19,199,952	4,718,931	41,273	2,610,307	349,321	124,248	69,036,429	565	2,366,725	2,130,923	807,296	5,305[illegible]
1998	43,680,254	17,608,716	4,353,767	41,350	2,436,969	354,504	125,300	68,600,860	566,842	3,945,769	2,562,690	1,225,397	8,300,698
1999	42,593,218	16,696,343	4,198,166	41,350	2,243,335	353,379	125,300	66,251,091	2,225,524	5,053,612	2,805,954	1,486,429	11,571,519
2000	39,763,425	15,092,533	3,905,685	41,350	2,071,481	353,205	125,300	61,352,979	5,600,903	6,638,287	3,019,888	1,685,176	16,944,254
2001	35,255,184	13,413,397	3,598,527	41,350	1,971,105	355,031	125,300	54,759,894	10,480,736	8,401,154	3,251,807	1,804,261	23,937,958
2002	31,354,849	12,097,361	3,365,555	41,350	1,941,311	357,173	125,300	49,282,899	15,027,632	9,804,846	3,527,724	1,879,994	30,240,196
2003	29,199,858	11,336,720	3,187,421	41,350	1,936,156	359,250	125,300	46,186,055	17,744,827	10,655,976	3,791,163	1,921,432	34,113,398
2004	28,446,856	10,985,101	3,056,348	41,350	1,939,850	361,498	125,300	44,956,303	19,010,487	11,092,740	4,015,466	1,944,741	36,063,434
2005	28,348,142	10,875,377	2,982,331	41,350	1,950,044	363,907	125,300	44,686,451	19,602,750	11,299,547	4,189,301	1,962,628	37,054,226
2006	28,452,054	10,903,234	2,989,450	41,350	1,963,617	366,139	125,300	44,841,144	19,915,502	11,362,404	4,255,129	1,977,370	37,510,405
2007	28,607,827	10,937,743	3,012,473	41,350	1,975,855	368,202	125,300	45,068,750	20,119,227	11,387,166	4,294,459	1,989,697	37,790,549
2008	28,786,955	10,968,338	3,034,212	41,350	1,985,800	370,315	125,300	45,312,270	20,290,920	11,409,371	4,328,018	1,999,716	38,028,025
2009	28,979,323	10,996,456	3,051,371	41,350	1,993,972	372,570	125,300	45,560,342	20,454,460	11,429,775	4,352,278	2,007,946	38,244,459
2010	29,166,954	11,022,798	3,055,485	41,350	2,001,320	374,964	125,300	45,788,171	20,608,546	11,449,372	4,356,968	2,015,341	38,430,227
2011	29,331,176	11,050,665	3,059,141	41,350	2,008,625	377,322	125,300	45,993,579	20,746,252	11,469,540	4,360,927	2,022,692	38,599,411
2012	29,484,588	11,079,117	3,053,888	41,350	2,016,054	379,791	125,300	46,180,088	20,875,859	11,490,401	4,352,456	2,030,183	38,748[illegible]
2013	29,632,261	11,096,553	3,039,017	41,350	2,020,817	382,113	125,300	46,337,411	21,000,151	11,503,173	4,330,536	2,034,972	38,868[illegible]
2014	29,756,575	11,114,122	3,018,860	41,350	2,024,552	384,538	125,300	46,465,297	21,107,890	11,516,074	4,300,612	2,038,732	38,963,308
2015	29,867,736	11,126,424	2,998,493	41,350	2,027,442	386,900	125,300	46,573,645	21,206,302	11,526,061	4,270,537	2,041,650	39,044,550
2016	29,936,107	11,142,283	2,975,082	41,350	2,030,029	389,166	125,300	46,639,317	21,274,540	11,537,572	4,235,930	2,044,257	39,092,299
2017	29,979,921	11,153,576	2,955,049	41,350	2,031,746	391,235	125,300	46,678,177	21,324,161	11,546,239	4,206,286	2,045,979	39,122,665
2018	30,013,544	11,169,519	2,934,997	41,350	2,033,278	393,435	125,300	46,711,423	21,366,633	11,557,922	4,176,397	2,047,522	39,148,474
GROWTH RATES													
1998-2003	-7.7%	-8.4%	-6.0%	0.0%	-4.5%	0.3%	0.0%	-7.6%	99.1%	22.0%	8.1%	9.4%	32.7%
1998-2008	-4.1%	-4.6%	-3.5%	0.0%	-2.0%	0.4%	0.0%	-4.1%	43.0%	11.2%	5.4%	5.0%	16.4%
1998-2018	-1.6%	-1.9%	-1.6%	0.0%	-0.8%	0.4%	0.0%	-1 6%	16.3%	4.6%	2.1%	2.2%	6.7%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DI I Forecast February 1998)

CINERGY

FORECAST OF FIRM GAS DELIVERIES
MCF - BILLING

FIRM DELIVERIES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER *	O.P.A.	TOTAL RETAIL	WHOLE-SALE	COMPANY USE	FIRM LOSSES	TOTAL DELIVERIES
1993	41,245,097	19,824,738	6,637,149	123,458	3,077,125	70,907,567	306,947	81,135	NA	71,295,649
1994	41,215,827	19,932,170	6,502,028	117,112	3,175,580	70,942,717	296,395	79,697	NA	71,318,809
1995	40,786,826	20,023,224	6,189,583	125,129	3,157,664	70,282,426	279,204	80,614	NA	70,642,244
1996	46,170,385	22,769,376	6,875,608	137,611	3,558,641	79,511,621	352,245	93,348	NA	79,957,214
1997	41,992,962	21,566,677	6,849,854	165,521	3,417,603	73,992,617	349,321	99,876	NA	74,441,814
1998	44,247,096	21,554,485	6,916,457	166,650	3,662,366	76,547,054	354,504	98,700	1,795,198	78,795,456
1999	44,818,742	21,749,955	7,004,120	166,650	3,729,764	77,469,231	353,379	98,700	1,465,299	79,386,609
2000	45,364,328	21,730,820	6,925,573	166,650	3,756,657	77,944,028	353,205	98,700	1,420,059	79,815,992
2001	45,735,920	21,814,551	6,850,334	166,650	3,775,366	78,342,821	355,031	98,700	1,469,815	80,266,367
2002	46,382,481	21,902,207	6,893,279	166,650	3,821,305	79,165,922	357,173	98,700	1,483,480	81,105,275
2003	46,944,685	21,992,696	6,978,584	166,650	3,857,588	79,940,203	359,250	98,700	1,491,651	81,889,804
2004	47,457,343	22,077,841	7,071,814	166,650	3,884,591	80,658,239	361,498	98,700	1,499,356	82,617,793
2005	47,950,892	22,174,924	7,171,632	166,650	3,912,672	81,376,770	363,907	98,700	1,510,312	83,349,689
2006	48,367,556	22,265,638	7,244,579	166,650	3,940,987	81,985,410	366,139	98,700	1,515,249	83,965,498
2007	48,727,054	22,324,909	7,306,932	166,650	3,965,552	82,491,097	368,202	98,700	1,520,108	84,478,107
2008	49,077,875	22,377,709	7,362,230	166,650	3,985,516	82,969,980	370,315	98,700	1,523,995	84,962,990
2009	49,433,783	22,426,231	7,403,649	166,650	4,001,918	83,432,231	372,570	98,700	1,529,953	85,433,454
2010	49,775,500	22,472,170	7,412,453	166,650	4,016,661	83,843,434	374,964	98,700	1,534,300	85,851,398
2011	50,077,428	22,520,205	7,420,068	166,650	4,031,317	84,215,668	377,322	98,700	1,538,276	86,229,966
2012	50,360,447	22,569,518	7,406,344	166,650	4,046,237	84,549,196	379,791	98,700	1,541,798	86,569,485
2013	50,632,412	22,599,726	7,369,553	166,650	4,055,789	84,824,130	382,113	98,700	1,542,308	86,847,251
2014	50,864,465	22,630,196	7,319,472	166,650	4,063,284	85,044,067	384,538	98,700	1,543,519	87,070,824
2015	51,074,038	22,652,485	7,269,030	166,650	4,069,092	85,231,295	386,900	98,700	1,544,703	87,261,598
2016	51,210,647	22,679,855	7,211,012	166,650	4,074,286	85,342,450	389,166	98,700	1,543,849	87,374,165
2017	51,304,082	22,699,815	7,161,335	166,650	4,077,725	85,409,607	391,235	98,700	1,540,795	87,440,337
2018	51,380,177	22,727,441	7,111,394	166,650	4,080,800	85,466,462	393,435	98,700	1,539,451	87,498,048
GROWTH RATES										
1998-2003	1.2%	0.4%	0.2%	0.0%	1.0%	0.9%	0.3%	0.0%	-3.6%	0.8%
1998-2008	1.0%	0.4%	0.6%	0.0%	0.8%	0.8%	0.4%	0.0%	-1.6%	0.8%
1998-2018	0.6%	0.2%	0.1%	0.0%	0.5%	0.5%	0.4%	0.0%	-0.6%	0.4%

* The other category includes street lighting and inter-departmental sales

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

GA-27

(DRI Forecast February 1998)

CINERGY
FORECAST OF INTERRUPTIBLE GAS DELIVERIES
MCF - BILLING

INTERRUPTIBLE DELIVERIES

	COMMERCIAL	INDUSTRIAL EXCL. AK STEEL	AK STEEL	TOTAL INDUSTRIAL	O.P.A.	TOTAL RETAIL	ELECTRIC GENERATION	INTERRUPTIBLE LOSSES	TOTAL DELIVERIES
1993	1,279,781	14,874,817	15,896,637	30,771,454	1,209,926	33,261,161	46,835	NA	33,307,996
1994	1,307,177	15,804,266	17,822,530	33,626,796	1,817,573	36,751,546	166,337	NA	36,917,883
1995	1,599,646	16,444,768	20,997,686	37,442,454	1,899,198	40,941,298	178,867	NA	41,120,165
1996	1,632,528	17,839,206	24,677,856	42,517,062	2,214,990	46,364,580	16,477	NA	46,381,057
1997	1,999,733	18,714,140	26,087,642	44,801,782	2,320,789	49,122,304	40,851	NA	49,163,155
1998	1,910,981	19,527,915	27,210,097	46,738,012	2,165,680	50,814,673	134,788	636,757	51,586,218
1999	2,022,323	20,178,806	0	20,178,806	2,202,735	24,403,864	169,603	807,541	25,381,008
2000	2,035,945	21,217,169	0	21,217,169	2,212,599	25,465,713	343,049	825,119	26,633,881
2001	2,059,908	22,479,931	0	22,479,931	2,228,492	26,768,331	508,184	884,393	28,160,908
2002	2,078,218	23,957,913	0	23,957,913	2,254,888	28,291,019	376,496	918,967	29,586,482
2003	2,095,941	25,313,495	0	25,313,495	2,274,907	29,684,343	82,730	947,289	30,714,362
2004	2,111,886	26,672,720	0	26,672,720	2,290,560	31,075,166	81,745	987,908	32,144,819
2005	2,132,721	28,123,812	0	28,123,812	2,307,149	32,563,682	71,055	1,025,986	33,660,723
2006	2,148,285	29,610,007	0	29,610,007	2,323,435	34,081,727	69,619	1,063,520	35,214,866
2007	2,160,453	31,054,197	0	31,054,197	2,337,511	35,552,161	49,779	1,099,652	36,701,592
2008	2,170,392	32,446,050	0	32,446,050	2,348,795	36,965,237	70,492	1,135,528	38,171,257
2009	2,179,341	33,807,135	0	33,807,135	2,358,226	38,344,702	72,920	1,166,068	39,583,690
2010	2,187,087	35,027,577	0	35,027,577	2,366,718	39,581,382	69,353	1,196,630	40,847,365
2011	2,196,482	36,303,042	0	36,303,042	2,375,463	40,874,987	74,301	1,230,231	42,179,519
2012	2,207,024	37,776,158	0	37,776,158	2,384,064	42,367,246	69,429	1,267,938	43,704,613
2013	2,212,019	38,962,615	0	38,962,615	2,389,208	43,563,842	72,533	1,291,857	44,928,232
2014	2,217,207	40,112,902	0	40,112,902	2,393,610	44,723,719	75,235	1,322,151	46,121,105
2015	2,219,105	41,146,221	0	41,146,221	2,396,770	45,762,096	70,500	1,343,259	47,175,855
2016	2,224,075	42,242,015	0	42,242,015	2,400,058	46,866,148	63,091	1,374,555	48,303,794
2017	2,226,084	43,345,293	0	43,345,293	2,401,688	47,973,065	125,699	1,401,780	49,500,544
2018	2,230,720	44,456,207	0	44,456,207	2,403,777	49,090,704	128,214	1,430,840	50,649,758
GROWTH RATES									
1998-2003	1.9%	5.3%	-100.0%	-11.5%	1.0%	-10.2%	-9.3%	8.3%	-9.9%
1998-2008	1.3%	5.2%	-100.0%	-3.6%	0.8%	-3.1%	-6.3%	6.0%	-3.0%
1998-2018	0.8%	4.2%	-99.9%	-0.2%	0.5%	-0.2%	-0.2%	4.1%	-0.1%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February 3)

CINERGY

FORECAST OF GAS SENDOUT AND PEAK DEMAND

MCF - BILLING

TOTAL DELIVERIES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER *	O.P.A.	TOTAL RETAIL	WHOLE-SALE	COMPANY USE	ELECTRIC GENERATION	TOTAL LOSSES	SENDOUT	SEASONAL PEAK
1993	41,245,097	21,104,519	37,408,603	123,458	4,287,051	104,168,728	306,947	81,135	46,835	4,677,903	109,281,548	955,102
1994	41,215,827	21,239,347	40,128,824	117,112	4,993,153	107,694,263	296,395	79,697	166,337	1,405,717	109,642,409	812,515
1995	40,786,826	21,622,870	43,632,037	125,129	5,056,862	111,223,724	279,204	80,614	178,867	9,073,866	120,836,275	860[illegible]
1996	46,170,385	24,401,904	49,392,670	137,611	5,773,631	125,876,201	352,245	93,348	16,477	1,563,053	127,901,324	869,[illegible]
1997	41,992,962	23,566,409	51,651,636	165,521	5,738,392	123,114,921	349,321	99,876	40,851	2,362,162	125,967,131	931,831
1998	44,247,096	23,465,466	53,654,469	166,650	5,828,046	127,361,727	354,504	98,700	134,788	2,431,955	130,381,674	838,663
1999	44,818,742	23,772,278	27,182,926	166,650	5,932,499	101,873,095	353,379	98,700	169,603	2,272,840	104,767,617	828,121
2000	45,364,328	23,766,765	28,142,742	166,650	5,969,256	103,409,741	353,205	98,700	343,049	2,245,178	106,449,873	829,743
2001	45,735,920	23,874,459	29,330,265	166,650	6,003,858	105,111,152	355,031	98,700	508,184	2,354,208	108,427,275	832,637
2002	46,382,481	23,980,425	30,851,192	166,650	6,076,193	107,456,941	357,173	98,700	376,496	2,402,447	110,691,757	835,412
2003	46,944,685	24,088,637	32,292,079	166,650	6,132,495	109,624,546	359,250	98,700	82,730	2,438,940	112,604,166	837,843
2004	47,457,343	24,189,727	33,744,534	166,650	6,175,151	111,733,405	361,498	98,700	81,745	2,487,264	114,762,612	840,329
2005	47,950,892	24,307,645	35,295,444	166,650	6,219,821	113,940,452	363,907	98,700	71,055	2,536,298	117,010,412	842,626
2006	48,367,556	24,413,923	36,854,586	166,650	6,264,422	116,067,137	366,139	98,700	69,619	2,578,769	119,180,364	844,709
2007	48,727,054	24,485,362	38,361,129	166,650	6,303,063	118,043,258	368,202	98,700	49,779	2,619,760	121,179,699	846,681
2008	49,077,875	24,548,101	39,808,280	166,650	6,334,311	119,935,217	370,315	98,700	70,492	2,659,523	123,134,247	848,597
2009	49,433,783	24,605,572	41,210,784	166,650	6,360,144	121,776,933	372,570	98,700	72,920	2,696,021	125,017,144	850,303
2010	49,775,500	24,659,257	42,440,030	166,650	6,383,379	123,424,816	374,964	98,700	69,353	2,730,930	126,698,763	851,868
2011	50,077,428	24,716,687	43,723,110	166,650	6,406,780	125,090,655	377,322	98,700	74,301	2,768,507	128,409,485	853[illegible]
2012	50,360,447	24,776,542	45,182,502	166,650	6,430,301	126,916,442	379,791	98,700	69,429	2,809,736	130,274,098	855,[illegible]
2013	50,632,412	24,811,745	46,332,168	166,650	6,444,997	128,387,972	382,113	98,700	72,533	2,834,165	131,775,483	856,205
2014	50,864,465	24,847,403	47,432,374	166,650	6,456,894	129,767,786	384,538	98,700	75,235	2,865,670	133,191,929	857,380
2015	51,074,038	24,871,590	48,415,251	166,650	6,465,862	130,993,391	386,900	98,700	70,500	2,887,962	134,437,453	858,283
2016	51,210,647	24,903,930	49,453,027	166,650	6,474,344	132,208,598	389,166	98,700	63,091	2,918,404	135,677,959	859,272
2017	51,304,082	24,925,899	50,506,628	166,650	6,479,413	133,382,672	391,235	98,700	125,699	2,942,575	136,940,881	860,063
2018	51,380,177	24,958,161	51,567,601	166,650	6,484,577	134,557,166	393,435	98,700	128,214	2,970,291	138,147,806	860,957
GROWTH RATES												
1998-2003	1.2%	0.5%	-9.7%	0.0%	1.0%	-3.0%	0.3%	0.0%	-9.3%	0.1%	-2.9%	0.0%
1998-2008	1.0%	0.5%	-2.9%	0.0%	0.8%	-0.6%	0.4%	0.0%	-6.3%	0.9%	-0.6%	0.1%
1998-2018	0.6%	0.3%	-0.2%	0.0%	0.4%	0.2%	0.4%	0.0%	-0.2%	0.8%	0.2%	0.1%

* The other category includes street lighting and inter-departmental sales

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

GA-29

(DRI Forecast February 1998)

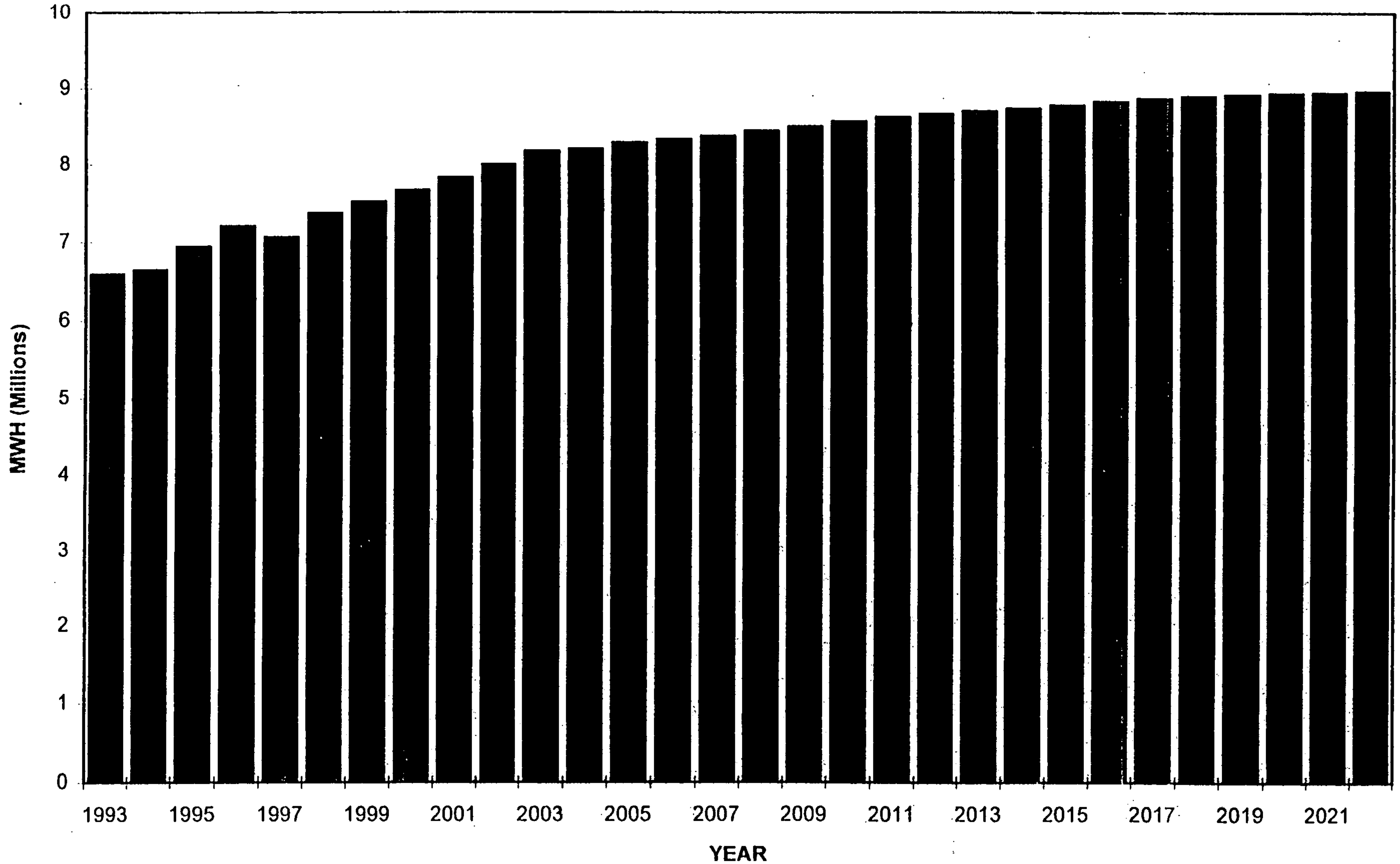
CINERGY
GAS CUSTOMERS BY MAJOR CLASSIFICATIONS
ANNUAL AVERAGES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	O.P.A.	WHOLE-SALE	TOTAL CUSTOMERS	ANNUAL INCREASE	GAS - MCF RESIDENTIAL USE PER CUSTOMER
1993	373,494	40,347	2,176	6	1,466	1	417,490	5,861	110
1994	379,953	40,573	2,177	6	1,513	1	424,223	6,733	108
1995	389,165	41,335	2,095	6	1,579	1	434,180	9,957	105
1996	397,672	42,065	2,115	10	1,638	1	443,501	9,321	116
1997	407,097	42,563	1,970	10	1,655	1	453,295	9,794	103
1998	415,231	42,712	2,187	10	1,682	1	461,823	8,528	107
1999	423,416	43,808	2,261	10	1,737	1	471,233	9,410	106
2000	431,791	44,552	2,317	10	1,798	1	480,469	9,236	105
2001	440,081	45,119	2,380	10	1,848	1	489,439	8,970	104
2002	448,539	45,734	2,445	10	1,896	1	498,625	9,186	103
2003	456,575	46,301	2,506	10	1,946	1	507,339	8,714	103
2004	464,363	46,830	2,567	10	1,995	1	515,766	8,427	102
2005	472,094	47,349	2,629	10	2,042	1	524,125	8,359	102
2006	479,156	47,811	2,679	10	2,081	1	531,738	7,613	101
2007	485,730	48,244	2,725	10	2,116	1	538,826	7,088	100
2008	492,402	48,679	2,770	10	2,152	1	546,014	7,188	100
2009	499,309	49,113	2,815	10	2,187	1	553,435	7,421	99
2010	506,255	49,544	2,857	10	2,221	1	560,888	7,453	98
2011	512,910	49,943	2,878	10	2,239	1	567,981	7,093	98
2012	519,288	50,338	2,895	10	2,250	1	574,782	6,801	97
2013	525,604	50,731	2,909	10	2,262	1	581,517	6,735	96
2014	531,859	51,095	2,924	10	2,274	1	588,163	6,646	96
2015	538,033	51,447	2,934	10	2,284	1	594,709	6,546	95
2016	543,591	51,745	2,923	10	2,275	1	600,545	5,836	94
2017	548,718	52,018	2,903	10	2,262	1	605,912	5,367	93
2018	553,879	52,283	2,885	10	2,247	1	611,305	5,393	93
GROWTH RATE									
1998-2003	1.9%	1.6%	2.8%	0.0%	3.0%	0.0%	1.9%		-0.7%
1997-2007	1.7%	1.3%	2.4%	0.0%	2.5%	0.0%	1.7%		-0.7%
1997-2017	1.5%	1.0%	1.4%	0.0%	1.5%	0.0%	1.4%		-0.7%

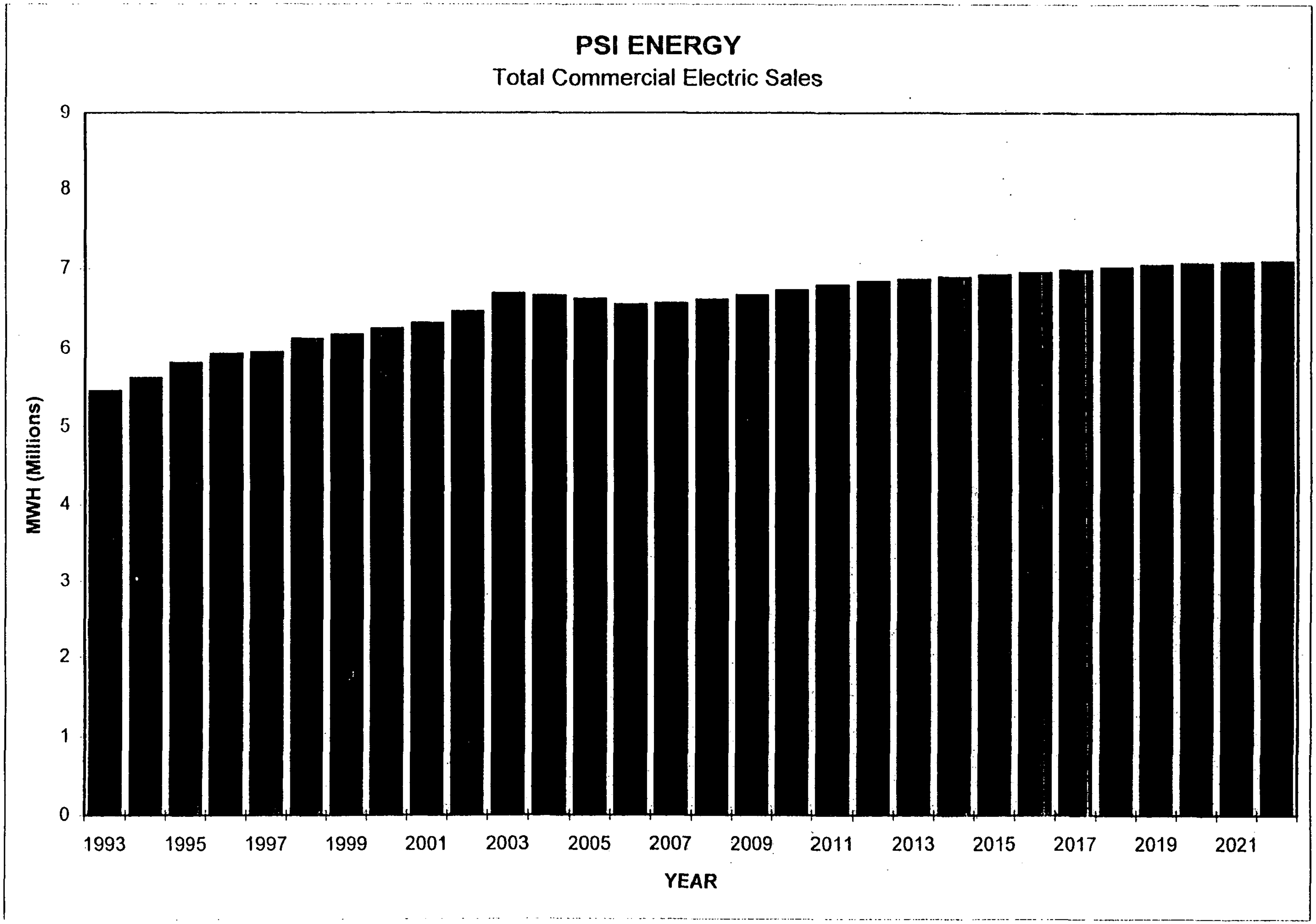
NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February 1998)

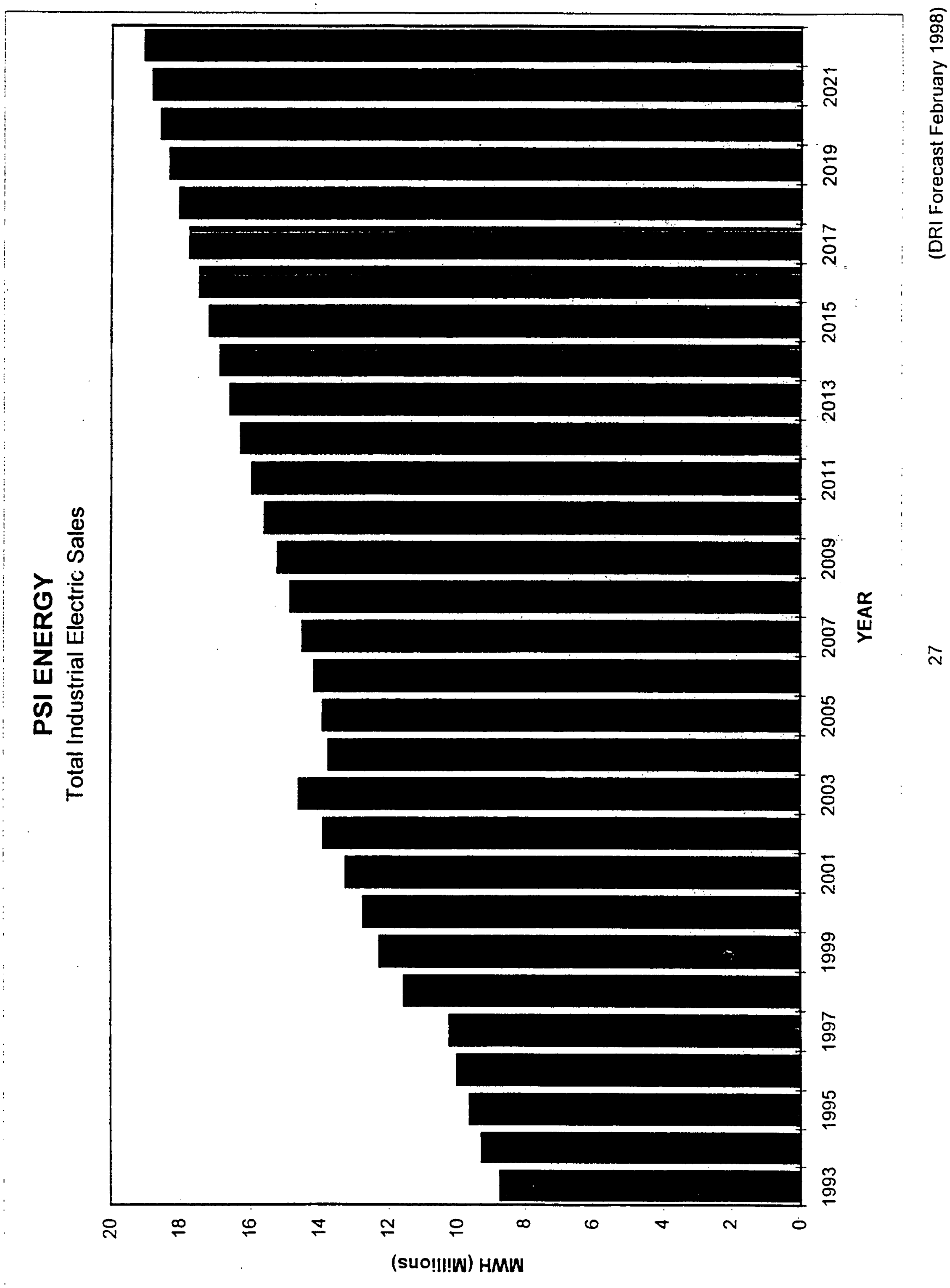
PSI ENERGY
Total Residential Electric Sales



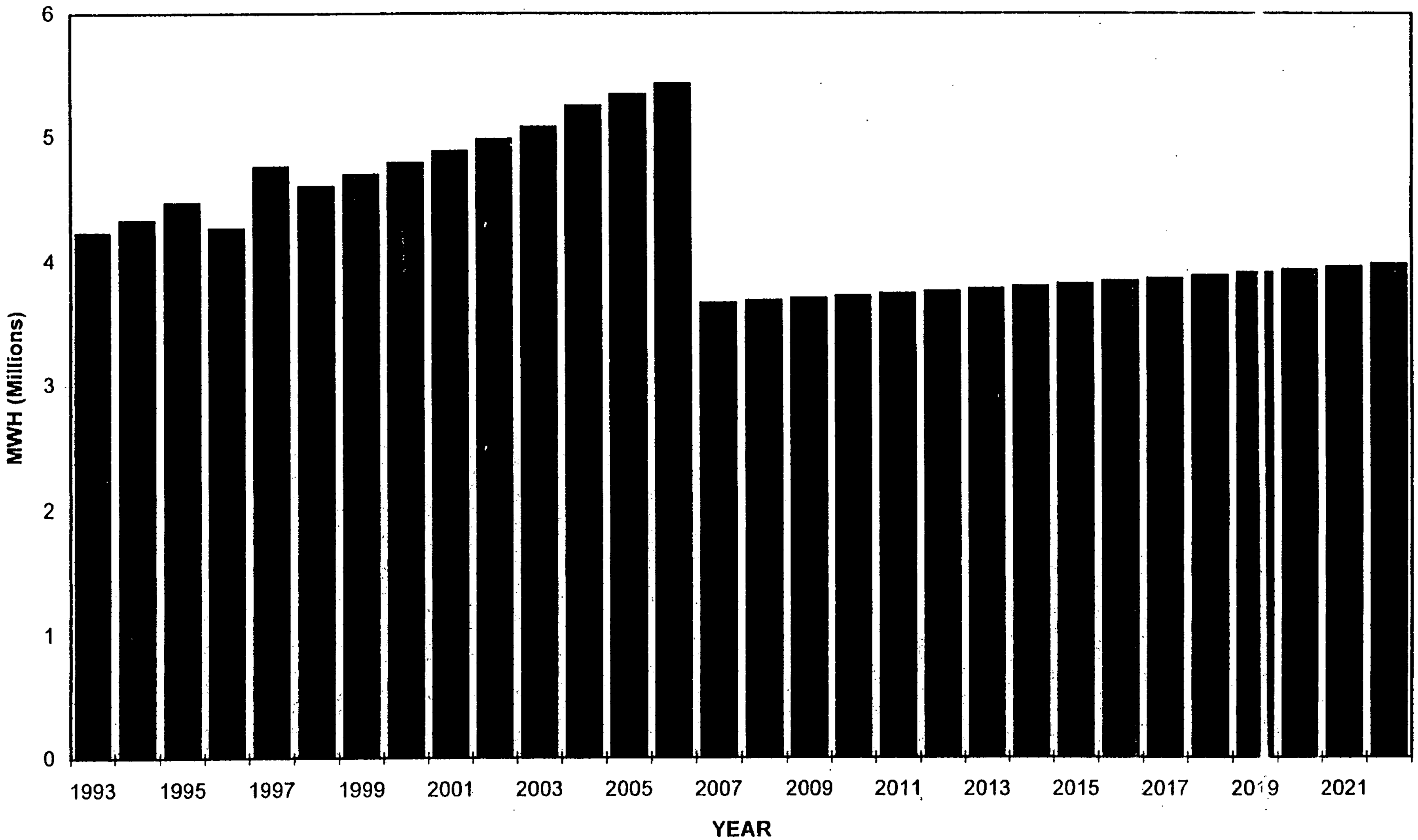
(DRI Forecast February 1998)



(DRI Forecast February 8)

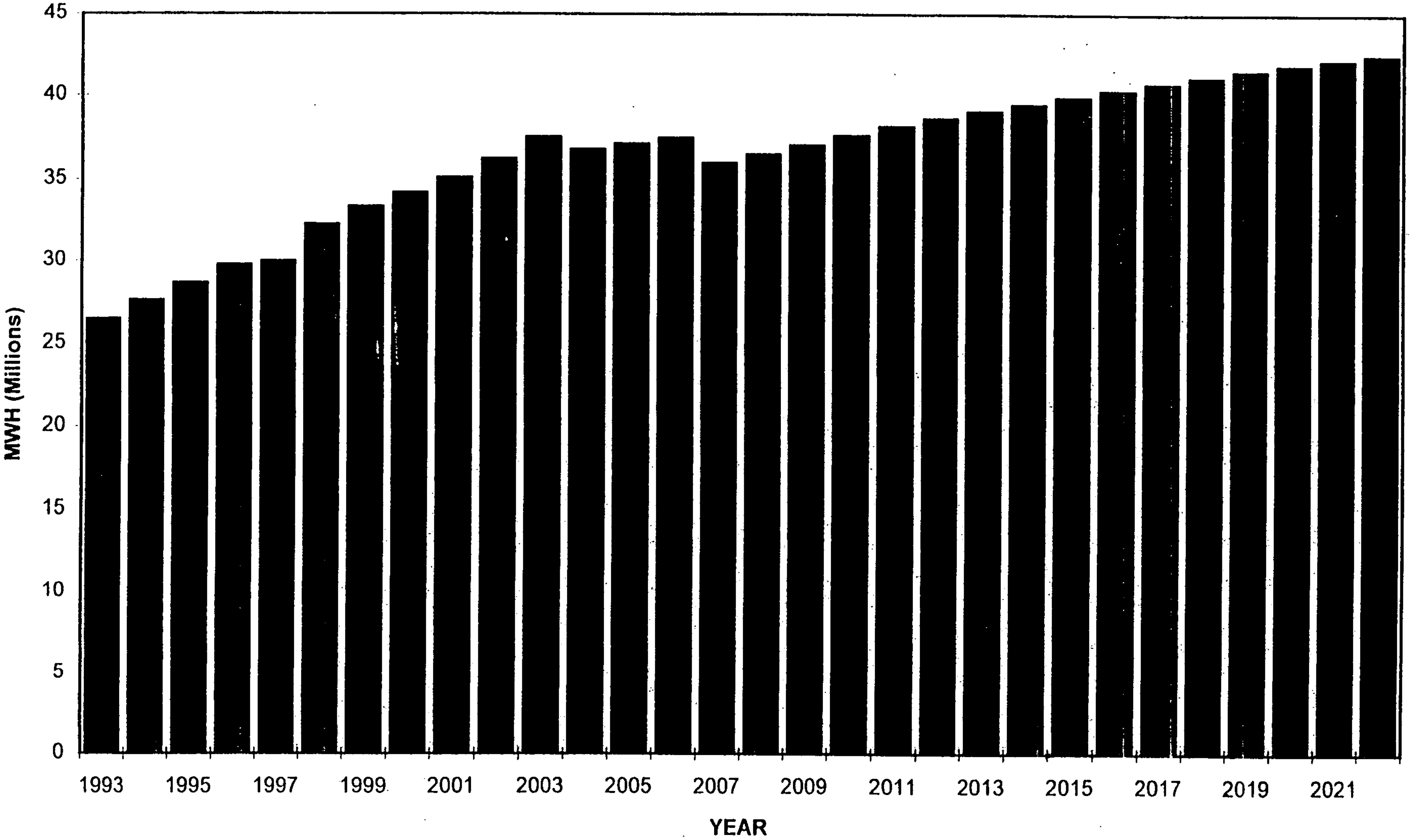

PSI ENERGY
Total Industrial Electric Sales
MWH (Millions)
0
2
4
6
8
10
12
14
16
18
20
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
YEAR
(DRI Forecast February 1998)
27

PSI ENERGY
Total Wholesale Electric Sales

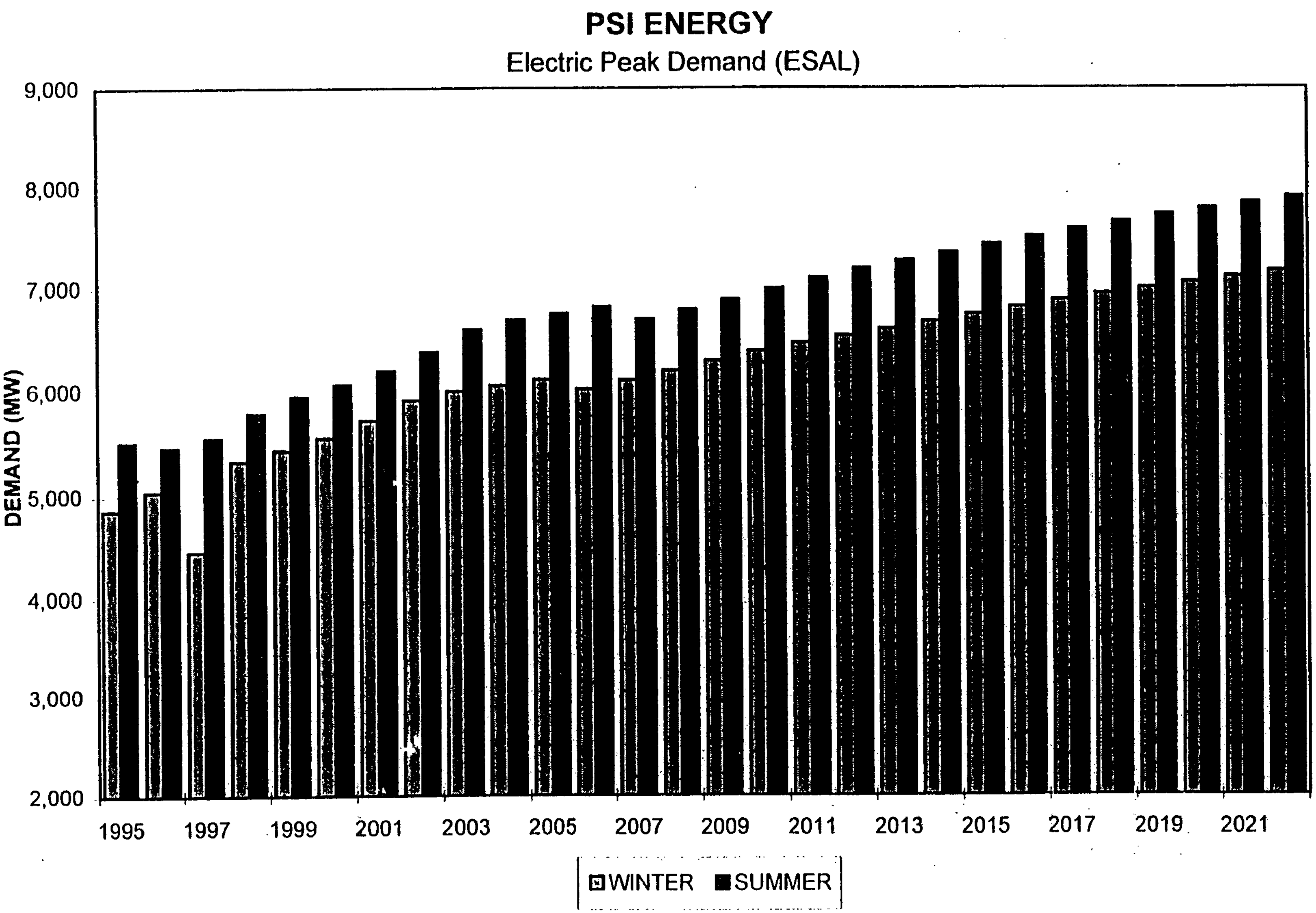


(DRI Forecast February [illegible]3)

PSI ENERGY
Total Electric Sendout



(DRI Forecast February 1998)



(DRI Forecast February 1998)

PSI ENERGY
FORECAST OF ELECTRIC SALES
MWH - BILLING

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL EXCL. NUCOR	NUCOR	TOTAL INDUSTRIAL	STREET LIGHTING & OPA	TOTAL RETAIL
1993	6,589,828	5,445,120	7,932,357	796,068	8,728,425	60,213	20,823,586
1994	6,642,940	5,609,893	8,385,054	894,326	9,279,380	61,460	21,593,673
1995	6,940,905	5,808,801	8,608,877	1,028,764	9,637,641	63,463	22,450,810
1996	7,200,655	5,925,737	8,873,298	1,142,021	10,015,319	64,747	23,206,458
1997	7,058,264	5,947,133	9,043,741	1,185,973	10,229,714	64,857	23,299,968
1998	7,362,290	6,119,982	10,300,595	1,250,841	11,551,436	65,142	25,098,850
1999	7,507,028	6,176,291	11,002,879	1,251,608	12,254,487	65,465	26,003,271
2000	7,657,002	6,251,836	11,441,261	1,285,212	12,726,473	65,790	26,701,101
2001	7,822,951	6,322,631	11,938,050	1,309,811	13,247,861	66,116	27,459,559
2002	7,995,073	6,468,840	12,531,545	1,363,269	13,894,814	66,444	28,425,171
2003	8,177,974	6,688,466	13,187,342	1,402,981	14,590,323	66,774	29,523,537
2004	8,204,568	6,664,430	12,314,130	1,428,123	13,742,253	67,105	28,678,356
2005	8,290,048	6,627,662	12,459,608	1,447,560	13,907,168	67,438	28,892,316
2006	8,335,845	6,558,858	12,695,640	1,471,177	14,166,817	67,772	29,129,292
2007	8,379,118	6,575,424	13,001,104	1,496,874	14,497,978	68,108	29,520,628
2008	8,447,135	6,621,430	13,327,059	1,527,328	14,854,387	68,446	29,991,398
2009	8,506,410	6,672,984	13,663,488	1,559,421	15,222,909	68,786	30,471,089
2010	8,571,659	6,734,076	14,013,452	1,590,377	15,603,829	69,127	30,978,691
2011	8,629,964	6,799,935	14,354,514	1,617,823	15,972,337	69,470	31,471,706
2012	8,671,778	6,842,930	14,656,946	1,641,446	16,298,392	69,815	31,882,915
2013	8,708,744	6,870,815	14,931,040	1,663,986	16,595,026	70,161	32,244,746
2014	8,743,416	6,896,609	15,215,007	1,670,000	16,885,007	70,509	32,595,541
2015	8,786,925	6,928,460	15,516,660	1,670,000	17,186,660	70,859	32,972,904
2016	8,835,873	6,957,610	15,795,743	1,670,000	17,465,743	71,211	33,330,437
2017	8,874,418	6,987,087	16,087,022	1,670,000	17,757,022	71,564	33,690,091
2018	8,906,141	7,019,438	16,379,662	1,670,000	18,049,662	71,919	34,047,160
2019	8,924,446	7,047,497	16,658,846	1,670,000	18,328,846	72,276	34,373,065
2020	8,940,082	7,069,949	16,912,254	1,670,000	18,582,254	72,635	34,664,920
2021	8,950,365	7,086,166	17,151,845	1,670,000	18,821,845	72,995	34,931,371
2022	8,969,759	7,097,701	17,383,063	1,670,000	19,053,063	73,357	35,193,880
GROWTH RATE							
1998-2003	2.1%	1.8%	5.1%	2.3%	4.78%	0.5%	3.3%
1998-2008	1.4%	0.8%	2.6%	2.0%	2.55%	0.5%	1.8%
1998-2022	0.8%	0.6%	2.2%	1.2%	2.11%	0.5%	1.4%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February 1998)

PSI ENERGY

FORECAST OF ELECTRIC SENDOUT AND PEAK DEMAND

	MWH - BILLING					ESAL * PEAK DEMAND - MW	
	TOTAL RETAIL	WHOLESALE	TOTAL DELIVERIES	LOSSES	TOTAL SENDOUT	WINTER	SUMMER
1993	20,823,586	4,226,635	25,050,221	1,375,692	26,425,913	NA	NA
1994	21,593,673	4,327,305	25,920,978	1,617,567	27,538,545	NA	NA
1995	22,450,810	4,465,067	26,915,877	1,673,775	28,589,652	4,862	5,516
1996	23,206,458	4,262,421	27,468,879	2,269,134	29,738,013	5,048	5,469
1997	23,299,968	4,759,537	28,059,505	1,890,497	29,950,002	4,454	5,558
1998	25,098,850	4,600,906	29,699,756	2,524,479	32,224,235	5,342	5,791
1999	26,003,271	4,697,573	30,700,844	2,609,572	33,310,416	5,442	5,955
2000	26,701,101	4,791,810	31,492,911	2,676,897	34,169,808	5,560	6,067
2001	27,459,559	4,883,422	32,342,981	2,749,153	35,092,134	5,723	6,198
2002	28,425,171	4,978,901	33,404,072	2,839,346	36,243,418	5,915	6,378
2003	29,523,537	5,075,207	34,598,744	2,940,893	37,539,637	6,002	6,593
2004	28,678,356	5,247,310	33,925,666	2,883,682	36,809,348	6,058	6,690
2005	28,892,316	5,339,173	34,231,489	2,909,677	37,141,166	6,117	6,751
2006	29,129,292	5,429,436	34,558,728	2,937,492	37,496,220	6,022	6,817
2007	29,520,628	3,656,658	33,177,286	2,820,069	35,997,355	6,110	6,694
2008	29,991,398	3,674,734	33,666,132	2,861,621	36,527,753	6,201	6,792
2009	30,471,089	3,693,239	34,164,328	2,903,968	37,068,296	6,296	6,893
2010	30,978,691	3,712,171	34,690,862	2,948,723	37,639,585	6,389	6,999
2011	31,471,706	3,731,555	35,203,261	2,992,277	38,195,538	6,468	7,102
2012	31,882,915	3,751,392	35,634,307	3,028,916	38,663,223	6,537	7,189
2013	32,244,746	3,771,692	36,016,438	3,061,397	39,077,835	6,604	7,266
2014	32,595,541	3,792,471	36,388,012	3,092,981	39,480,993	6,677	7,341
2015	32,972,904	3,813,740	36,786,644	3,126,865	39,913,509	6,746	7,422
2016	33,330,437	3,835,508	37,165,945	3,159,105	40,325,050	6,815	7,498
2017	33,690,091	3,857,786	37,547,877	3,191,570	40,739,447	6,884	7,575
2018	34,047,160	3,880,590	37,927,750	3,223,859	41,151,609	6,947	7,652
2019	34,373,065	3,903,929	38,276,994	3,253,544	41,530,538	7,005	7,722
2020	34,664,920	3,927,818	38,592,738	3,280,383	41,873,121	7,057	7,786
2021	34,931,371	3,952,271	38,883,642	3,305,110	42,188,752	7,110	7,845
2022	35,193,880	3,977,294	39,171,174	3,329,550	42,500,724	7,163	7,903
GROWTH RATE							
1998-2003	3.3%	2.0%	3.1%	3.1%	3.1%	2.4%	2.6%
1998-2008	1.8%	-2.2%	1.3%	1.3%	1.3%	1.5%	1.6%
1998-2022	1.4%	-0.6%	1.2%	1.2%	1.2%	1.2%	1.3%

* ESAL peaks are unavailable for PSI prior to 1995

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February 1998)

PSI ENERGY

POTENTIAL REDUCTIONS DUE TO NUCOR CONTRACT
ELECTRIC SENDOUT AND PEAK DEMAND

This data is for informational purposes only

		PEAK DEMAND -MW	
	ELECTRIC - MWH	WINTER	SUMMER
1998	27,800	132	132
1999	29,800	132	132
2000	31,100	132	132
2001	31,700	132	132
2002	32,400	132	132
2003	33,000	132	132
2004	33,800	132	132
2005	34,300	132	132
2006	34,500	132	132
2007	34,500	132	132
2008	34,500	132	132
2009	34,500	132	132
2010	34,500	132	132
2011	34,500	132	132
2012	34,500	132	132
2013	34,500	132	132
2014	34,500	132	132
2015	34,500	132	132
2016	34,500	132	132
2017	34,500	132	132
2018	34,500	132	132
2019	34,500	132	132
2020	34,500	132	132
2021	34,500	132	132
2022	34,500	132	132

(DRI Forecast February 1998)

PSI ENERGY
ELECTRIC CUSTOMERS BY MAJOR CLASSIFICATIONS
ANNUAL AVERAGES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	WHOLE-SALE	TOTAL CUSTOMERS	ANNUAL INCREASE	ELECTRIC - KWH RESIDENTIAL USE PER CUSTOMER
1993	539,955	73,810	3,122	1,276	31	618,194	10,691	12,204
1994	549,502	75,545	3,244	1,250	33	629,574	11,380	12,089
1995	560,215	77,780	3,326	1,319	37	642,677	13,103	12,390
1996	573,119	77,731	3,389	1,387	55	655,681	13,004	12,564
1997	584,487	79,003	3,412	1,425	67	668,394	12,713	12,076
1998	595,941	81,525	3,462	1,425	67	682,419	14,025	12,354
1999	607,955	83,168	3,512	1,425	67	696,127	13,708	12,348
2000	619,592	84,760	3,562	1,425	67	709,406	13,279	12,358
2001	629,690	86,142	3,612	1,425	67	720,936	11,530	12,423
2002	639,371	87,466	3,662	1,425	67	731,991	11,055	12,505
2003	648,869	88,765	3,712	1,425	67	742,838	10,847	12,603
2004	658,069	90,024	3,762	1,425	67	753,346	10,508	12,468
2005	666,013	91,111	3,812	1,425	67	762,428	9,081	12,447
2006	671,933	91,920	3,862	1,425	67	769,207	6,780	12,406
2007	676,768	92,582	3,912	1,425	67	774,754	5,546	12,381
2008	681,917	93,286	3,962	1,425	67	780,658	5,904	12,387
2009	687,140	94,001	4,012	1,425	67	786,645	5,988	12,379
2010	692,203	94,693	4,062	1,425	67	792,450	5,805	12,383
2011	696,774	95,319	4,112	1,425	67	797,697	5,247	12,386
2012	700,433	95,819	4,162	1,425	67	801,907	4,210	12,381
2013	703,469	96,234	4,212	1,425	67	805,407	3,500	12,380
2014	706,728	96,680	4,262	1,425	67	809,163	3,756	12,372
2015	710,268	97,165	4,312	1,425	67	813,237	4,074	12,371
2016	713,692	97,633	4,362	1,425	67	817,179	3,942	12,381
2017	716,653	98,038	4,412	1,425	67	820,595	3,415	12,383
2018	718,989	98,358	4,462	1,425	67	823,300	2,706	12,387
2019	720,681	98,589	4,512	1,425	67	825,274	1,974	12,383
2020	721,939	98,761	4,562	1,425	67	826,755	1,480	12,383
2021	722,990	98,905	4,612	1,425	67	827,999	1,245	12,380
2022	723,827	99,020	4,662	1,425	67	829,001	1,002	12,392
GROWTH RATE								
1998-2003	1.7%	1.7%	1.4%	0.0%	0.0%	1.7%		0.4%
1998-2008	1.4%	1.4%	1.4%	0.0%	0.0%	1.4%		0.0%
1998-2022	0.8%	0.8%	1.2%	0.0%	0.0%	0.8%		0.0%

NOTE: 1998 FIGURE REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February [illegible])

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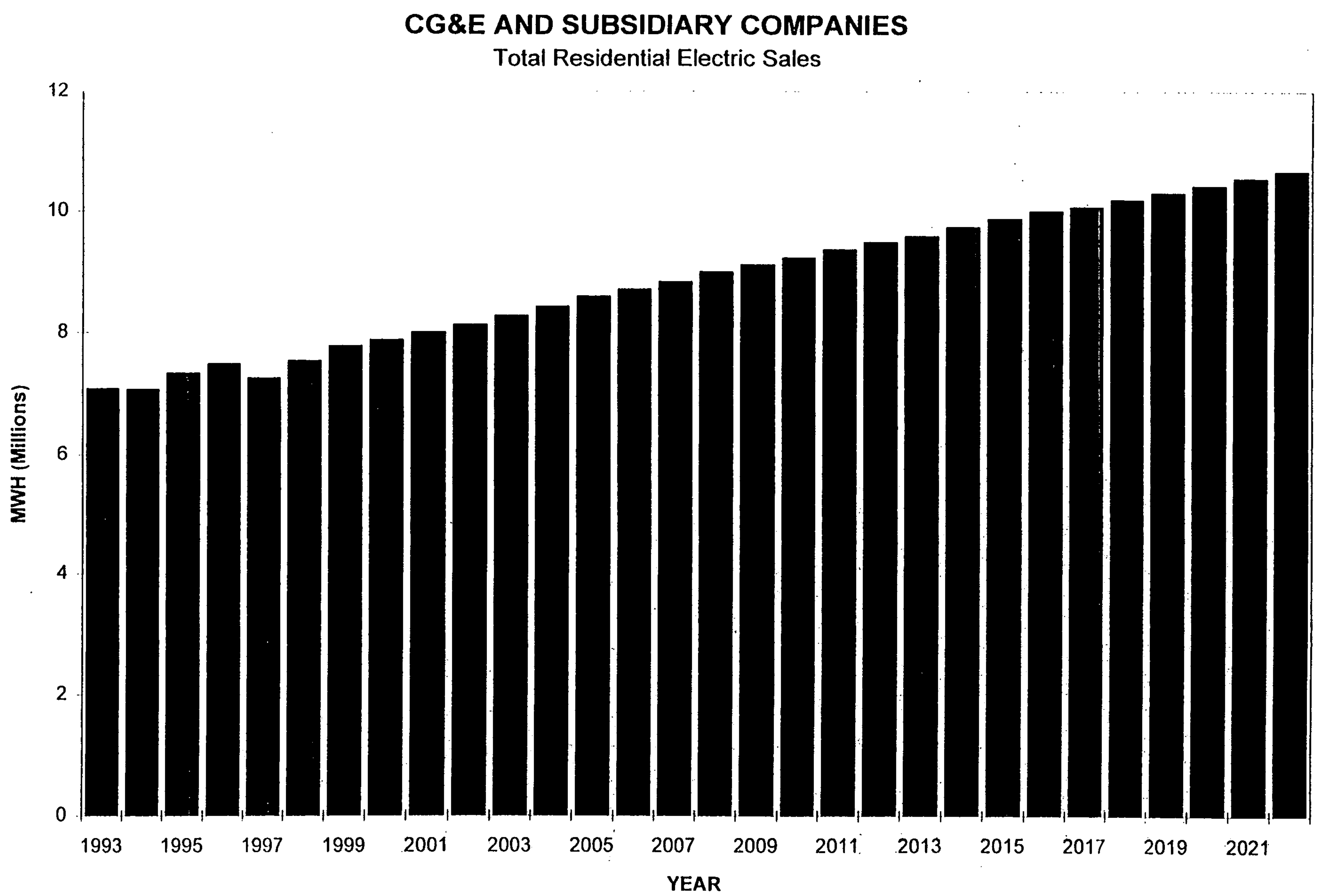
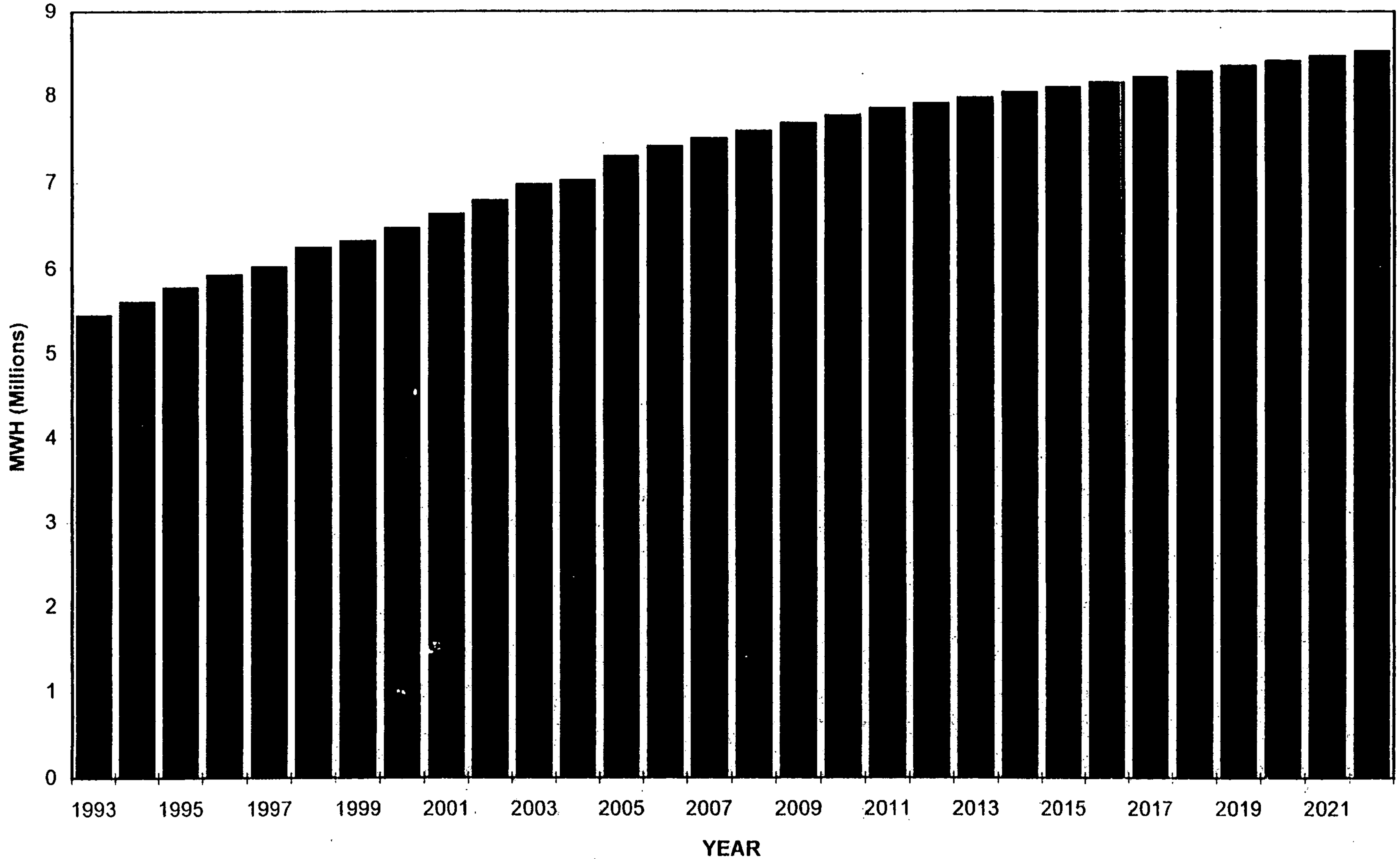


(DRI Forecast February 1998)

CG&E AND SUBSIDIARY COMPANIES

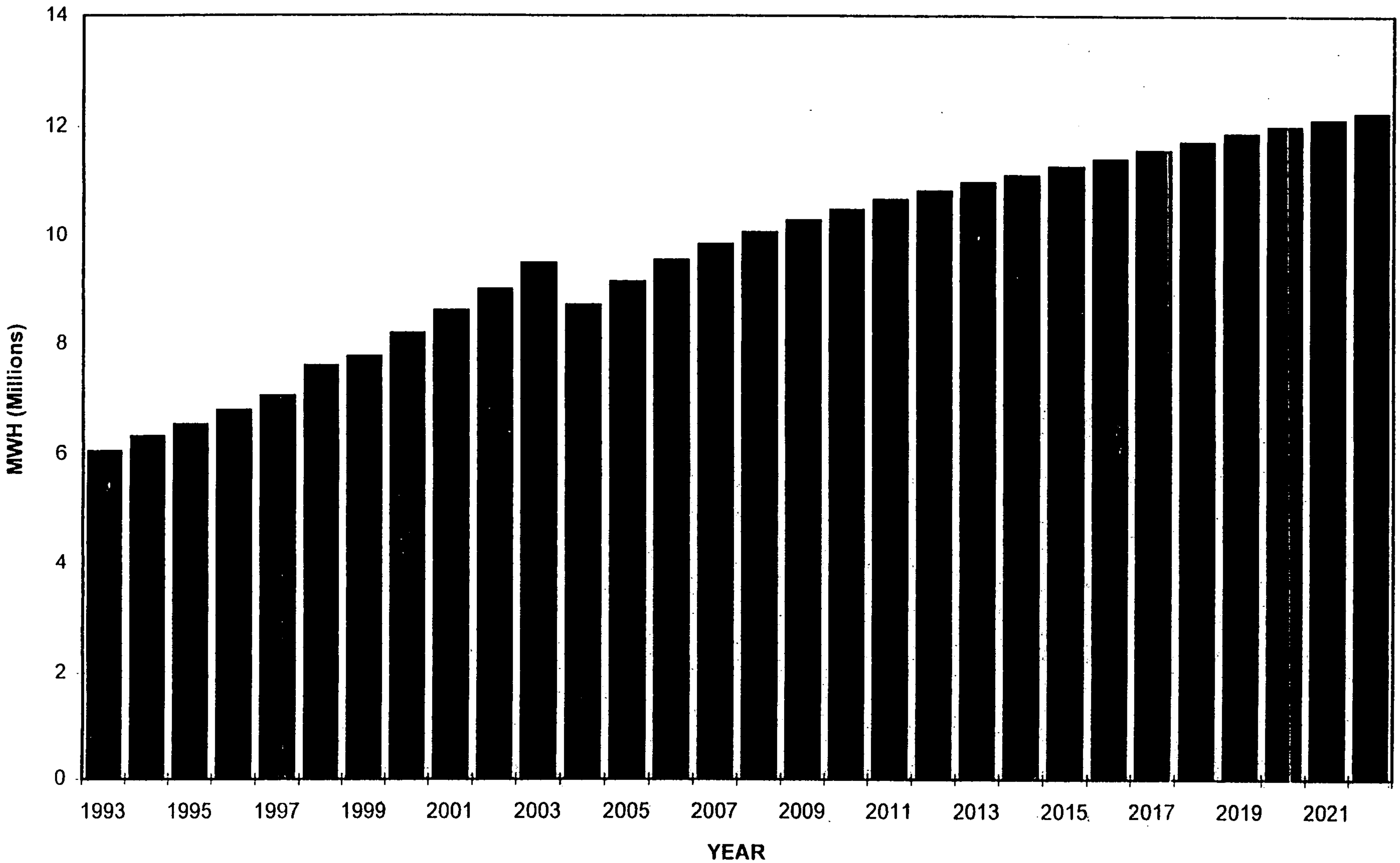
Total Commercial Electric Sales



(DRI Forecast February)

CG&E AND SUBSIDIARY COMPANIES

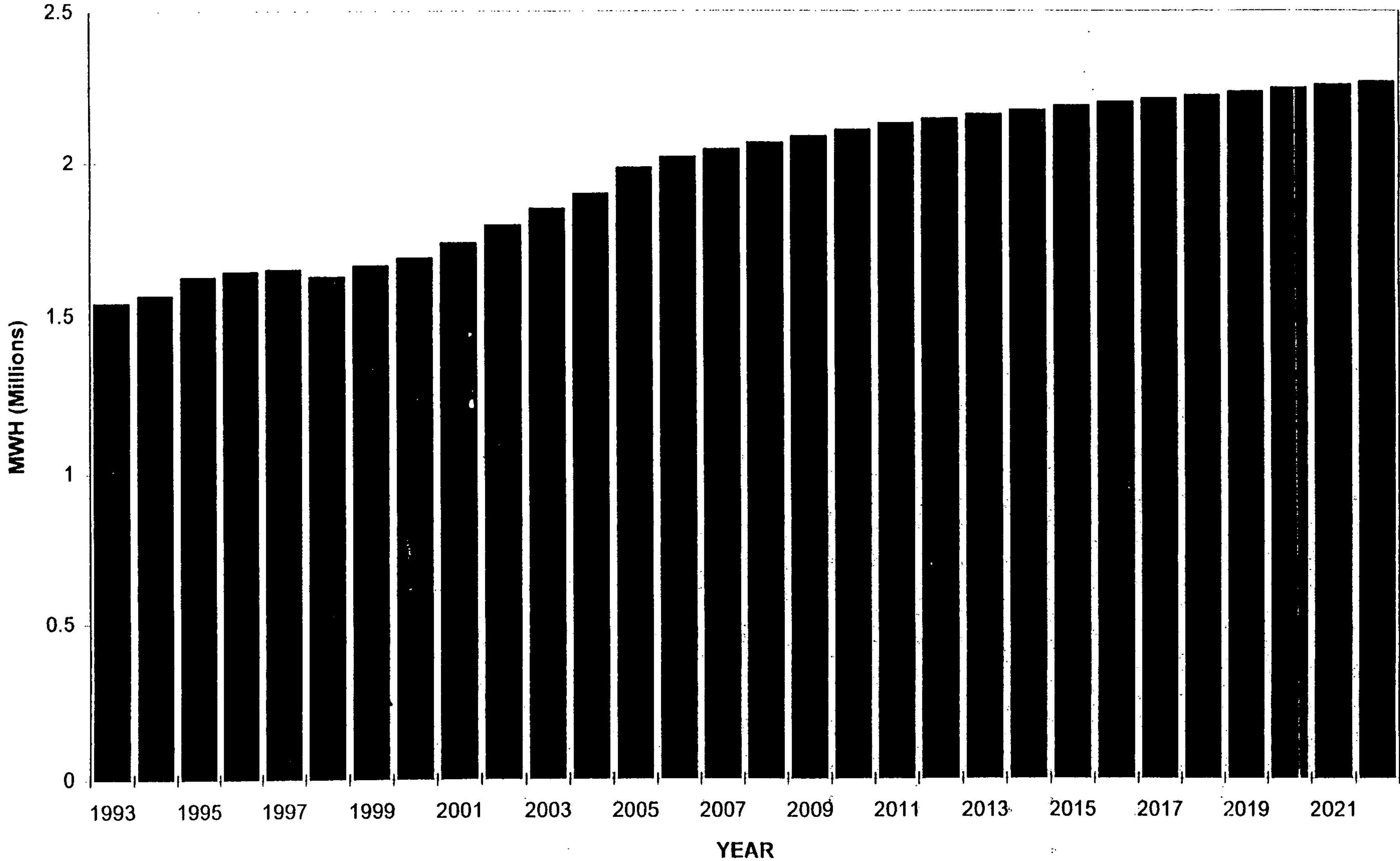
Total Industrial Electric Sales



(DRI Forecast February 1998)

CG&E AND SUBSIDIARY COMPANIES

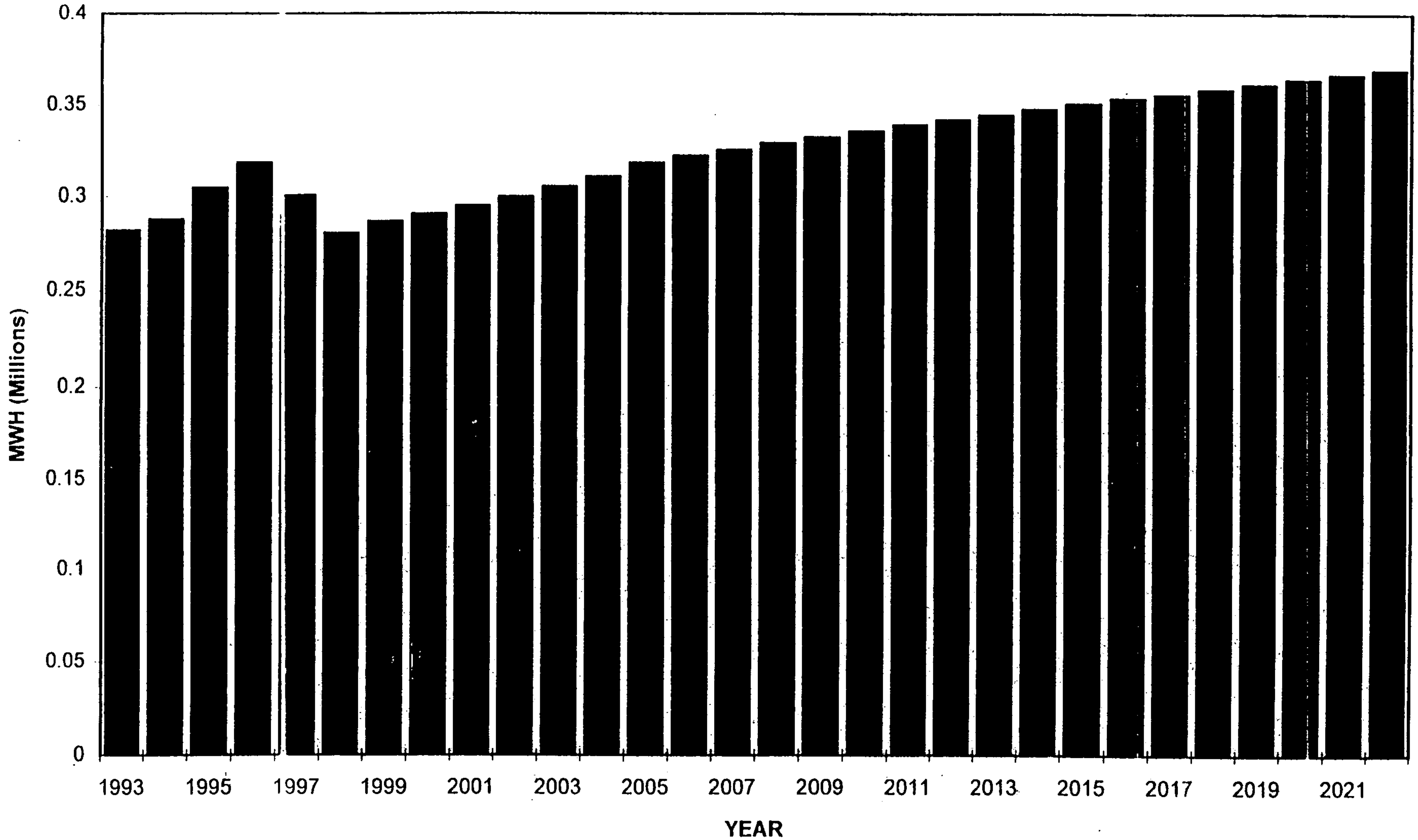
Total Other Public Authorities Electric Sales



(DRI Forecast February)

CG&E AND SUBSIDIARY COMPANIES

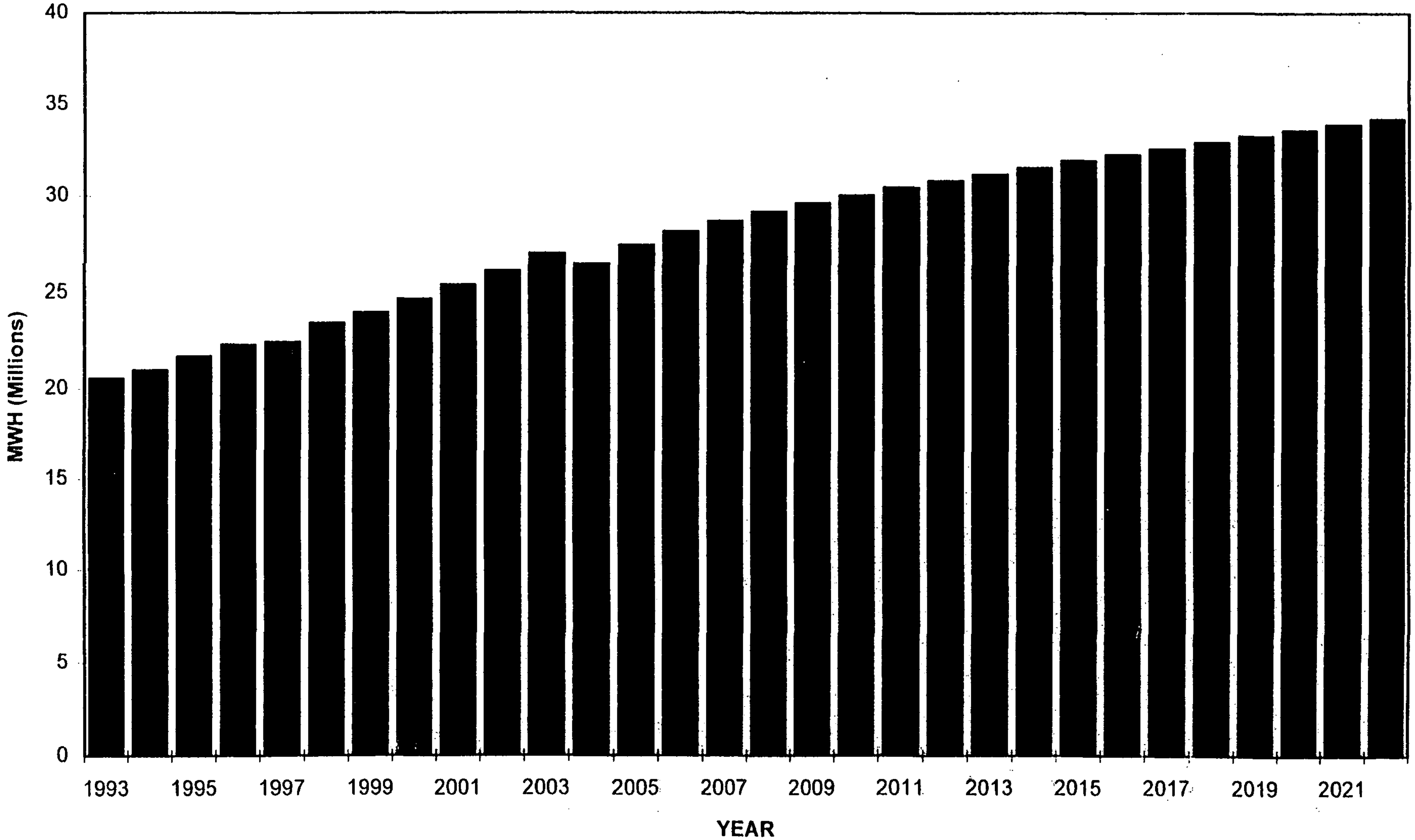
Total Wholesale Electric Sales



(DRI Forecast February 1998)

CG&E AND SUBSIDIARY COMPANIES

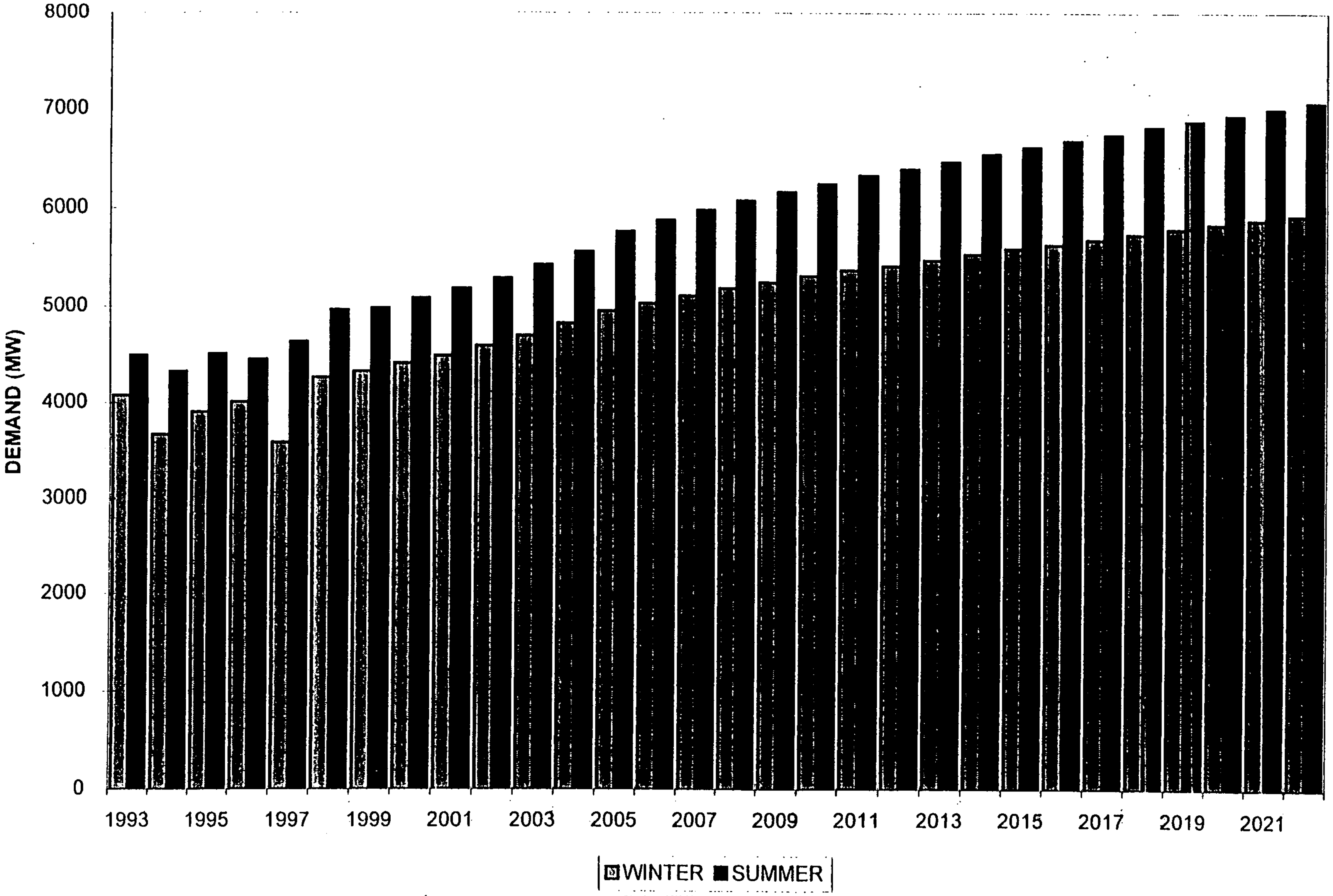
Total Electric Sendout



(DRI Forecast February)

CG&E AND SUBSIDIARY COMPANIES

Electric Peak Demand (ESAL)



(DRI Forecast February 1998)

CINCINNATI GAS & ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

FORECAST OF ELECTRIC SALES

MWH - BILLING

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL EXCL. AK STEEL	AK STEEL	TOTAL INDUSTRIAL	STREET LIGHTING	O.P.A.	INTER-DEPARTMENT	TOTAL RETAIL
1993	7,085,733	5,445,345	5,058,823	995,205	6,054,028	96,937	1,538,672	10,369	20,231,084
1994	7,071,772	5,605,688	5,218,569	1,100,669	6,319,239	98,186	1,562,206	10,810	20,667,901
1995	7,339,408	5,775,577	5,396,881	1,142,745	6,539,626	99,757	1,620,594	10,281	21,385,244
1996	7,489,173	5,925,801	5,446,394	1,353,918	6,800,312	100,587	1,638,020	10,054	21,963,946
1997	7,260,419	6,022,234	5,630,999	1,438,385	7,069,384	102,425	1,645,421	9,757	22,109,640
1998	7,534,209	6,253,711	6,139,101	1,469,125	7,608,226	102,334	1,622,402	9,996	23,130,878
1999	7,771,101	6,324,689	6,365,934	1,407,211	7,773,145	102,322	1,657,283	9,996	23,638,536
2000	7,865,461	6,471,345	6,724,670	1,462,885	8,187,555	102,534	1,682,463	9,996	24,319,354
2001	7,987,661	6,628,886	7,102,448	1,495,791	8,598,239	102,622	1,730,531	9,996	25,057,935
2002	8,117,484	6,785,960	7,498,602	1,494,951	8,993,553	102,714	1,788,719	9,996	25,798,426
2003	8,270,763	6,973,937	7,919,419	1,566,042	9,485,461	102,925	1,842,260	9,996	26,685,342
2004	8,424,412	7,017,815	7,050,903	1,649,426	8,700,329	103,459	1,890,363	9,996	26,146,374
2005	8,590,523	7,288,592	7,397,719	1,738,587	9,136,306	104,005	1,977,228	9,996	27,106,650
2006	8,704,628	7,399,855	7,720,121	1,826,658	9,546,779	104,495	2,013,988	9,996	27,779,741
2007	8,820,619	7,487,972	7,944,482	1,891,084	9,835,566	104,951	2,039,721	9,996	28,298,825
2008	8,987,446	7,574,602	8,140,395	1,918,758	10,059,153	105,421	2,062,665	9,996	28,799,283
2009	9,102,667	7,665,339	8,314,840	1,968,749	10,283,589	105,907	2,084,320	9,996	29,251,818
2010	9,216,978	7,755,578	8,455,438	2,023,555	10,478,993	106,399	2,107,015	9,996	29,674,959
2011	9,350,788	7,844,719	8,596,326	2,073,116	10,669,442	106,857	2,128,872	9,996	30,110,674
2012	9,472,129	7,905,416	8,732,162	2,093,767	10,825,929	107,289	2,144,711	9,996	30,465,470
2013	9,570,447	7,970,151	8,859,312	2,117,634	10,976,946	107,711	2,159,381	9,996	30,794,632
2014	9,731,323	8,034,031	8,986,676	2,127,413	11,114,089	108,121	2,173,619	9,996	31,171,179
2015	9,869,860	8,094,195	9,124,441	2,148,061	11,272,502	108,529	2,188,302	9,996	31,543,384
2016	9,993,505	8,149,359	9,256,131	2,153,565	11,409,696	108,880	2,200,360	9,996	31,871,796
2017	10,061,344	8,211,978	9,406,448	2,167,870	11,574,318	109,195	2,210,893	9,996	32,177,724
2018	10,183,221	8,278,430	9,554,779	2,176,265	11,731,044	109,509	2,222,113	9,996	32,534,313
2019	10,294,251	8,343,137	9,701,978	2,177,193	11,879,171	109,823	2,233,811	9,996	32,870,189
2020	10,413,921	8,404,457	9,834,874	2,168,310	12,003,184	110,139	2,245,867	9,996	33,187,564
2021	10,534,944	8,463,965	9,969,244	2,157,793	12,127,037	110,405	2,256,798	9,996	33,503,145
2022	10,650,225	8,524,838	10,098,653	2,152,383	12,251,036	110,648	2,266,770	9,996	33,813,513
GROWTH RATE									
1998-2003	1.9%	2.20%	5.2%	1.3%	4.5%	0.1%	2.6%	0.00%	2.9%
1998-2008	2.0%	2.20%	2.9%	2.7%	2.8%	0.3%	2.4%	0.00%	2.2%
1998-2022	1.6%	1.43%	2.1%	1.6%	2.0%	0.3%	1.4%	0.00%	1.6%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February)

CINCINNATI GAS & ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

FORECAST OF ELECTRIC SENDOUT AND PEAK DEMAND

	MWH - BILLING						ESAL PE K DEMAND - MW	
	TOTAL RETAIL	WHOLESALE	COMPANY USE	TOTAL DELIVERIES	LOSSES	TOTAL SENDOUT	WIN ER	SUMMER
1993	20,231,084	282,004	25,998	20,539,086	1,431,194	21,970,280	,077	4,493
1994	20,667,901	287,810	25,006	20,980,716	1,253,423	22,234,139	,664	4,326
1995	21,385,244	304,465	26,898	21,716,607	1,361,202	23,077,809	,903	4,509
1996	21,963,946	317,834	27,488	22,309,268	1,330,758	23,640,026	,009	4,452
1997	22,109,640	300,477	24,377	22,434,494	1,305,313	23,739,807	,581	4,638
1998	23,130,878	280,541	25,632	23,437,051	1,524,846	24,961,897	,267	4,966
1999	23,638,536	286,870	25,752	23,951,158	1,544,525	25,495,683	,327	4,985
2000	24,319,354	290,698	25,884	24,635,936	1,589,914	26,225,850	,411	5,090
2001	25,057,935	295,008	26,016	25,378,959	1,637,680	27,016,639	,488	5,190
2002	25,798,426	299,559	26,148	26,124,133	1,687,249	27,811,382	,593	5,299
2003	26,685,342	304,970	26,280	27,016,592	1,745,226	28,761,818	,699	5,436
2004	26,146,374	310,208	26,412	26,482,994	1,710,445	28,193,439	,828	5,571
2005	27,106,650	317,676	26,544	27,450,870	1,774,068	29,224,938	,958	5,769
2006	27,779,741	321,431	26,676	28,127,848	1,814,982	29,942,830	,036	5,883
2007	28,298,825	324,713	26,808	28,650,346	1,848,341	30,498,687	,117	5,982
2008	28,799,283	328,644	26,940	29,154,867	1,880,788	31,035,655	,192	6,079
2009	29,251,818	331,945	27,072	29,610,835	1,909,456	31,520,291	,254	6,167
2010	29,674,959	335,237	27,204	30,037,400	1,937,316	31,974,716	,324	6,247
2011	30,110,674	338,754	27,348	30,476,776	1,965,280	32,442,056	,386	6,333
2012	30,465,470	341,563	27,480	30,834,513	1,987,554	32,822,067	,429	6,397
2013	30,794,632	344,124	27,624	31,166,380	2,009,650	33,176,030	,488	6,468
2014	31,171,179	347,498	27,756	31,546,433	2,034,092	33,580,525	,551	6,543
2015	31,543,384	350,500	27,900	31,921,784	2,057,877	33,979,661	,607	6,613
2016	31,871,796	353,195	28,032	32,253,023	2,078,668	34,331,691	,646	6,678
2017	32,177,724	355,298	28,176	32,561,198	2,099,329	34,660,527	,696	6,739
2018	32,534,313	358,188	28,320	32,920,821	2,122,765	35,043,586	,750	6,815
2019	32,870,189	360,901	28,452	33,259,542	2,144,340	35,403,882	802	6,877
2020	33,187,564	363,657	28,596	33,579,817	2,164,646	35,744,463	849	6,938
2021	33,503,145	366,386	28,740	33,898,271	2,185,364	36,083,635	893	7,004
2022	33,813,513	369,068	28,884	34,211,465	2,205,670	36,417,135	936	7,073
GROWTH RATE								
1998-2003	2.9%	1.7%	0.5%	2.9%	2.7%	2.9%	.9%	1.8%
1998-2008	2.2%	1.6%	0.5%	2.2%	2.1%	2.2%	.0%	2.0%
1998-2022	1.6%	1.1%	0.5%	1.6%	1.5%	1.6%	.4%	1.5%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

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(DRI Forecast February 1998)

CINCINNATI GAS & ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
ELECTRIC CUSTOMERS BY MAJOR CLASSIFICATIONS
ANNUAL AVERAGES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	O.P.A.	WHOLE-SALE	TOTAL CUSTOMERS	ANNUAL INCREASE	ELECTRIC - KWH RESIDENTIAL USE PER CUSTOMER
1993	620,558	68,957	3,141	532	3,869	8	697,065	3,879	11,418
1994	625,203	69,221	3,101	568	3,914	8	702,016	4,951	11,311
1995	635,108	70,108	3,098	608	4,029	8	712,960	10,944	11,556
1996	642,886	71,319	3,082	666	4,115	8	722,076	9,116	11,649
1997	652,487	72,091	3,060	714	4,141	8	732,501	10,424	11,127
1998	660,638	73,020	3,069	754	4,271	7	741,759	9,258	11,404
1999	669,131	74,360	3,102	778	4,361	7	751,739	9,980	11,614
2000	677,920	75,782	3,133	800	4,446	7	762,088	10,349	11,602
2001	686,686	77,186	3,159	824	4,529	7	772,391	10,303	11,632
2002	695,716	78,625	3,181	850	4,616	7	782,995	10,604	11,668
2003	704,441	80,020	3,200	878	4,703	7	793,249	10,255	11,741
2004	712,921	81,369	3,217	906	4,790	7	803,210	9,961	11,817
2005	721,346	82,711	3,233	934	4,879	7	813,110	9,900	11,909
2006	728,785	83,911	3,246	963	4,960	7	821,872	8,762	11,944
2007	735,650	85,044	3,256	989	5,025	7	829,971	8,100	11,990
2008	742,721	86,152	3,267	1,015	5,089	7	838,251	8,279	12,101
2009	749,970	87,308	3,276	1,042	5,153	7	846,756	8,505	12,137
2010	757,334	88,487	3,285	1,070	5,217	7	855,400	8,645	12,170
2011	764,205	89,601	3,290	1,099	5,267	7	863,469	8,069	12,236
2012	770,727	90,654	3,293	1,127	5,292	7	871,100	7,631	12,290
2013	777,108	91,688	3,297	1,153	5,314	7	878,567	7,467	12,315
2014	783,350	92,701	3,300	1,180	5,335	7	885,873	7,306	12,423
2015	789,546	93,711	3,302	1,207	5,356	7	893,129	7,256	12,501
2016	794,916	94,603	3,300	1,234	5,363	7	899,423	6,294	12,572
2017	799,740	95,394	3,297	1,257	5,342	7	905,037	5,614	12,581
2018	804,582	96,187	3,294	1,279	5,318	7	910,667	5,630	12,657
2019	809,454	96,987	3,290	1,301	5,294	7	916,333	5,667	12,718
2020	814,292	97,786	3,287	1,324	5,270	7	921,966	5,633	12,789
2021	818,434	98,481	3,280	1,345	5,235	7	926,782	4,817	12,872
2022	822,191	99,103	3,272	1,365	5,179	7	931,117	4,335	12,953
GROWTH RATE									
1998-2003	1.3%	1.8%	0.8%	3.1%	1.9%	0.0%	1.4%		0.6%
1998-2008	1.2%	1.7%	0.6%	3.0%	1.8%	0.0%	1.2%		0.6%
1998-2022	0.9%	1.3%	0.3%	2.5%	0.8%	0.0%	1.0%		0.5%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February 1998)

CINCINNATI GAS & ELECTRIC COMPANY
FORECAST OF ELECTRIC SALES
MWH - BILLING

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL EXCL. AK STEEL	AK STEEL	TOTAL INDUSTRIAL	STREET LIGHTING	O.P.A.	INTER-DEPARTMENT	TOTAL RETAIL
1993	5,995,003	4,672,433	4,258,261	995,205	5,253,466	82,719	1,255,113	9,223	17,267,956
1994	5,973,977	4,783,967	4,358,152	1,100,669	5,458,821	83,579	1,264,102	9,560	17,574,006
1995	6,184,632	4,909,947	4,493,748	1,142,745	5,636,493	84,709	1,285,009	9,290	18,110,080
1996	6,300,502	5,025,150	4,494,870	1,353,918	5,848,788	85,416	1,293,211	9,320	18,562,386
1997	6,099,427	5,100,004	4,656,757	1,438,385	6,095,142	86,670	1,302,034	9,133	18,692,409
1998	6,325,798	5,298,233	5,086,206	1,469,125	6,555,331	86,544	1,283,221	9,300	19,558,427
1999	6,509,153	5,352,059	5,324,089	1,407,211	6,731,300	86,433	1,310,812	9,300	19,999,057
2000	6,572,459	5,471,060	5,643,627	1,462,885	7,106,512	86,506	1,330,727	9,300	20,576,564
2001	6,674,571	5,601,708	5,960,227	1,495,791	7,456,018	86,582	1,368,745	9,300	21,196,924
2002	6,783,055	5,736,625	6,272,648	1,494,951	7,767,599	86,661	1,414,769	9,300	21,798,009
2003	6,911,131	5,891,856	6,578,483	1,566,042	8,144,525	86,838	1,457,117	9,300	22,500,767
2004	7,039,525	5,925,820	5,805,039	1,649,426	7,454,465	87,290	1,495,164	9,300	22,011,564
2005	7,178,326	6,154,467	6,074,051	1,738,587	7,812,638	87,751	1,563,869	9,300	22,806,351
2006	7,273,674	6,248,417	6,318,000	1,826,658	8,144,658	88,165	1,592,942	9,300	23,357,156
2007	7,370,598	6,322,825	6,499,949	1,891,084	8,391,033	88,551	1,613,297	9,300	23,795,604
2008	7,509,998	6,395,974	6,661,996	1,918,758	8,580,754	88,945	1,631,445	9,300	24,216,416
2009	7,606,279	6,472,591	6,804,713	1,968,749	8,773,462	89,357	1,648,571	9,300	24,599,560
2010	7,701,798	6,548,788	6,919,784	2,023,555	8,943,339	89,771	1,666,521	9,300	24,959,517
2011	7,813,614	6,624,061	7,033,916	2,073,116	9,107,032	90,157	1,683,811	9,300	25,327,975
2012	7,915,005	6,675,313	7,147,449	2,093,767	9,241,216	90,521	1,696,337	9,300	25,627,692
2013	7,997,160	6,729,975	7,255,056	2,117,634	9,372,690	90,878	1,707,942	9,300	25,907,945
2014	8,131,589	6,783,913	7,361,908	2,127,413	9,489,321	91,221	1,719,203	9,300	26,224,547
2015	8,247,355	6,834,716	7,476,330	2,148,061	9,624,391	91,568	1,730,817	9,300	26,538,147
2016	8,350,674	6,881,296	7,586,445	2,153,565	9,740,010	91,864	1,740,355	9,300	26,813,499
2017	8,407,360	6,934,174	7,711,984	2,167,870	9,879,854	92,129	1,748,682	9,300	27,071,499
2018	8,509,203	6,990,286	7,836,432	2,176,265	10,012,697	92,395	1,757,559	9,300	27,371,440
2019	8,601,979	7,044,923	7,961,304	2,177,193	10,138,497	92,660	1,766,810	9,300	27,654,169
2020	8,701,976	7,096,706	8,077,469	2,168,310	10,245,779	92,928	1,776,344	9,300	27,923,033
2021	8,803,104	7,146,951	8,195,973	2,157,793	10,353,766	93,150	1,784,990	9,300	28,191,261
2022	8,899,434	7,198,354	8,312,004	2,152,383	10,464,387	93,356	1,792,880	9,300	28,457,711
GROWTH RATE									
1998-2003	1.8%	2.1%	5.3%	1.3%	4.4%	0.1%	2.6%	0.0%	2.8%
1998-2008	1.7%	1.9%	2.7%	2.7%	2.7%	0.3%	2.4%	0.0%	2.2%
1998-2022	1.4%	1.3%	2.1%	1.6%	2.0%	0.3%	1.4%	0.0%	1.6%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February 1998)

GA-51

CINCINNATI GAS & ELECTRIC COMPANY

FORECAST OF ELECTRIC SENDOUT AND PEAK DEMAND

GA-52

	MWH - BILLING						ESAL PEAK DE~~MAND~~ - MW	
	TOTAL RETAIL	WHOLESALE	COMPANY USE	TOTAL DELIVERIES	LOSSES	TOTAL SENDOUT	WINTER	SUMMER
1993	17,267,956	236,984	24,991	17,529,931	1,312,403	18,842,334	3,448	3,830
1994	17,574,006	240,346	24,338	17,838,690	1,175,263	19,013,953	3,062	3,682
1995	18,110,080	253,620	25,934	18,389,634	1,208,079	19,597,713	3,292	3,799
1996	18,562,386	264,472	26,736	18,853,594	1,177,357	20,030,951	3,401	3,736
1997	18,692,409	249,638	23,784	18,965,832	1,112,639	20,078,470	2,940	3,902
1998	19,558,427	280,541	24,996	19,863,964	1,354,891	21,218,855	3,599	4,188
1999	19,999,057	286,870	25,104	20,311,031	1,373,746	21,684,777	3,644	4,205
2000	20,576,564	290,698	25,236	20,892,498	1,413,913	22,306,411	3,713	4,288
2001	21,196,924	295,008	25,368	21,517,300	1,456,107	22,973,407	3,777	4,370
2002	21,798,009	299,559	25,500	22,123,068	1,498,884	23,621,952	3,863	4,459
2003	22,500,767	304,970	25,620	22,831,357	1,548,129	24,379,486	3,951	4,573
2004	22,011,564	310,208	25,752	22,347,524	1,515,714	23,863,238	4,058	4,686
2005	22,806,351	317,676	25,884	23,149,911	1,571,264	24,721,175	4,166	4,850
2006	23,357,156	321,431	26,004	23,704,591	1,606,924	25,311,515	4,229	4,943
2007	23,795,604	324,713	26,136	24,146,453	1,636,672	25,783,125	4,296	5,027
2008	24,216,416	328,644	26,268	24,571,328	1,665,326	26,236,654	4,360	5,109
2009	24,599,560	331,945	26,400	24,957,905	1,690,884	26,648,789	4,412	5,183
2010	24,959,517	335,237	26,520	25,321,274	1,715,714	27,036,988	4,471	5,251
2011	25,327,975	338,754	26,664	25,693,393	1,740,568	27,433,961	4,524	5,323
2012	25,627,692	341,563	26,796	25,996,051	1,760,387	27,756,438	4,561	5,377
2013	25,907,945	344,124	26,928	26,278,997	1,780,080	28,059,077	4,611	5,438
2014	26,224,547	347,498	27,060	26,599,105	1,801,702	28,400,807	4,664	5,501
2015	26,538,147	350,500	27,204	26,915,851	1,822,803	28,738,654	4,711	5,559
2016	26,813,499	353,195	27,336	27,194,030	1,841,183	29,035,213	4,744	5,614
2017	27,071,499	355,298	27,468	27,454,265	1,859,485	29,313,750	4,785	5,666
2018	27,371,440	358,188	27,612	27,757,240	1,880,216	29,637,456	4,831	5,730
2019	27,654,169	360,901	27,744	28,042,814	1,899,346	29,942,160	4,874	5,781
2020	27,923,033	363,657	27,876	28,314,566	1,917,440	30,232,006	4,915	5,833
2021	28,191,261	366,386	28,020	28,585,667	1,935,918	30,521,585	4,951	5,889
2022	28,457,711	369,068	28,164	28,854,943	1,954,210	30,809,153	4,988	5,950
GROWTH RATE								
1998-2003	2.2%	1.7%	0.5%	2.8%	2.7%	2.8%	1.9%	1.8%
1998-2008	1.6%	1.6%	0.5%	2.1%	2.1%	2.1%	1.9%	2.0%
1998-2022	0.0%	1.1%	0.5%	1.6%	1.5%	1.6%	1.4%	1.5%

NOTE: [illegible]8 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February [illegible]8)

CINCINNATI GAS & ELECTRIC COMPANY
ELECTRIC CUSTOMERS BY MAJOR CLASSIFICATIONS
ANNUAL AVERAGES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	O.P.A.	WHOLE-SALE	TOTAL CUSTOMERS	ANNUAL INCREASE	ELECTRIC - KWH RESIDENTIAL USE PER CUSTOMER
1993	522,592	58,675	2,733	424	3,055	7	587,484	2,787	11,472
1994	526,163	58,801	2,699	453	3,074	7	591,196	3,712	11,354
1995	534,000	59,540	2,697	494	3,177	7	599,915	8,719	11,582
1996	540,189	60,491	2,679	552	3,231	7	607,149	7,234	11,664
1997	547,681	61,070	2,659	595	3,249	7	615,262	8,113	11,137
1998	553,997	61,826	2,668	628	3,363	7	622,489	7,227	11,418
1999	560,451	62,886	2,697	648	3,433	7	630,122	7,633	11,614
2000	567,134	64,014	2,724	666	3,500	7	638,045	7,923	11,589
2001	574,468	65,199	2,746	686	3,566	7	646,672	8,627	11,619
2002	582,022	66,415	2,765	708	3,635	7	655,552	8,880	11,654
2003	589,321	67,593	2,782	731	3,703	7	664,137	8,586	11,727
2004	596,416	68,732	2,797	754	3,771	7	672,477	8,340	11,803
2005	603,464	69,866	2,811	778	3,842	7	680,768	8,291	11,895
2006	609,687	70,880	2,822	802	3,905	7	688,103	7,335	11,930
2007	615,430	71,836	2,831	824	3,957	7	694,885	6,783	11,976
2008	621,345	72,773	2,840	845	4,007	7	701,817	6,931	12,087
2009	627,410	73,750	2,848	868	4,058	7	708,941	7,124	12,123
2010	633,571	74,745	2,856	891	4,108	7	716,178	7,238	12,156
2011	639,319	75,686	2,860	916	4,147	7	722,935	6,757	12,222
2012	644,774	76,575	2,863	939	4,167	7	729,325	6,390	12,276
2013	650,113	77,449	2,866	961	4,185	7	735,581	6,256	12,301
2014	655,335	78,304	2,869	983	4,201	7	741,699	6,118	12,408
2015	660,518	79,157	2,871	1,006	4,218	7	747,777	6,078	12,486
2016	665,011	79,911	2,869	1,028	4,223	7	753,049	5,272	12,557
2017	669,046	80,579	2,866	1,048	4,206	7	757,752	4,703	12,566
2018	673,097	81,249	2,864	1,066	4,187	7	762,470	4,718	12,642
2019	677,173	81,925	2,860	1,084	4,169	7	767,218	4,749	12,703
2020	681,220	82,600	2,858	1,103	4,150	7	771,938	4,720	12,774
2021	684,685	83,187	2,852	1,121	4,122	7	775,974	4,037	12,857
2022	687,829	83,712	2,845	1,138	4,078	7	779,609	3,635	12,938
GROWTH RATE									
1998-2003	1.2%	1.8%	0.8%	3.1%	1.9%	0.0%	1.3%		0.5%
1998-2008	1.2%	1.6%	0.6%	3.0%	1.8%	0.0%	1.2%		0.6%
1998-2022	0.9%	1.3%	0.3%	2.5%	0.8%	0.0%	0.9%		0.5%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February 1998)

UNION LIGHT, HEAT AND POWER COMPANY
FORECAST OF ELECTRIC SALES
MWH - BILLING

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	O.P.A.	INTER-DEPARTMENT	TOTAL RETAIL
1993	1,087,831	770,012	800,406	14,190	298,474	1,147	2,972,059
1994	1,094,862	818,526	860,298	14,578	298,037	1,250	3,087,551
1995	1,151,799	862,235	902,983	15,018	335,518	991	3,268,544
1996	1,185,677	897,093	951,181	15,144	344,704	734	3,394,533
1997	1,158,180	918,822	973,852	15,725	343,290	625	3,410,493
1998	1,205,473	951,781	1,052,532	15,760	339,083	696	3,565,325
1999	1,258,918	968,896	1,041,489	15,859	346,371	696	3,632,229
2000	1,289,935	996,473	1,080,674	15,998	351,636	696	3,735,412
2001	1,309,975	1,023,286	1,141,843	16,010	361,682	696	3,853,492
2002	1,331,265	1,045,358	1,225,564	16,023	373,842	696	3,992,748
2003	1,356,406	1,078,003	1,340,531	16,057	385,032	696	4,176,725
2004	1,381,603	1,087,817	1,245,444	16,139	395,085	696	4,126,784
2005	1,408,846	1,129,787	1,323,229	16,224	413,240	696	4,292,022
2006	1,427,559	1,147,033	1,401,664	16,300	420,924	696	4,414,176
2007	1,446,580	1,160,690	1,444,063	16,370	426,301	696	4,494,700
2008	1,473,942	1,174,117	1,477,916	16,446	431,096	696	4,574,213
2009	1,492,837	1,188,184	1,509,629	16,520	435,624	696	4,643,490
2010	1,511,586	1,202,170	1,535,148	16,598	440,368	696	4,706,566
2011	1,533,528	1,215,987	1,561,898	16,670	444,933	696	4,773,712
2012	1,553,430	1,225,396	1,584,192	16,737	448,246	696	4,828,697
2013	1,569,554	1,235,428	1,603,731	16,802	451,311	696	4,877,522
2014	1,595,938	1,245,330	1,624,234	16,869	454,286	696	4,937,353
2015	1,618,656	1,254,656	1,647,573	16,930	457,355	696	4,995,866
2016	1,638,935	1,263,207	1,669,140	16,985	459,874	696	5,048,837
2017	1,650,060	1,272,912	1,693,910	17,035	462,078	696	5,096,691
2018	1,670,048	1,283,212	1,717,786	17,083	464,420	696	5,153,245
2019	1,688,257	1,293,242	1,740,103	17,132	466,866	696	5,206,296
2020	1,707,885	1,302,744	1,756,829	17,180	469,387	696	5,254,721
2021	1,727,730	1,311,970	1,772,687	17,224	471,672	696	5,301,979
2022	1,746,636	1,321,404	1,786,060	17,261	473,753	696	5,345,810
GROWTH RATE							
1998-200	2.4%	2.5%	5.0%	0.4%	2.6%	0.0%	3.2%
1998-200	2.0%	2.1%	3.5%	0.4%	2.4%	0.0%	2.5%
1998-202	1.6%	1.4%	2.2%	0.4%	1.4%	0.0%	1.7%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February [illegible])

UNION LIGHT, HEAT AND POWER COMPANY
FORECAST OF ELECTRIC PURCHASES (SENDOUT) AND PEAK DEMAND

	MWH - BILLING						PEAK DEMAND - MW	
	TOTAL RETAIL	WHOLESALE *	COMPANY USE	TOTAL DELIVERIES	LOSSES	TOTAL PURCHASES	WINTER	SUMMER
1993	2,972,059	45,021	1,007	3,018,087	103,296	3,121,383	629	663
1994	3,087,551	47,464	668	3,135,683	77,688	3,213,371	602	644
1995	3,268,544	50,845	965	3,320,354	152,577	3,472,931	611	710
1996	3,394,533	53,362	752	3,448,647	152,723	3,601,370	608	716
1997	3,410,493	50,839	593	3,461,925	192,287	3,654,212	641	736
1998	3,565,325	0	636	3,565,961	169,376	3,735,337	669	778
1999	3,632,229	0	648	3,632,877	170,191	3,803,068	683	780
2000	3,735,412	0	648	3,736,060	175,401	3,911,461	698	802
2001	3,853,492	0	648	3,854,140	180,964	4,035,104	711	819
2002	3,992,748	0	648	3,993,396	187,744	4,181,140	730	840
2003	4,176,725	0	660	4,177,385	196,460	4,373,845	749	863
2004	4,126,784	0	660	4,127,444	194,081	4,321,525	770	885
2005	4,292,022	0	660	4,292,682	202,132	4,494,814	792	919
2006	4,414,176	0	672	4,414,848	207,377	4,622,225	807	940
2007	4,494,700	0	672	4,495,372	210,981	4,706,353	820	955
2008	4,574,213	0	672	4,574,885	214,759	4,789,644	832	971
2009	4,643,490	0	672	4,644,162	217,861	4,862,023	842	984
2010	4,706,566	0	684	4,707,250	220,882	4,928,132	852	996
2011	4,773,712	0	684	4,774,396	223,985	4,998,381	862	1,009
2012	4,828,697	0	684	4,829,381	226,430	5,055,811	868	1,019
2013	4,877,522	0	696	4,878,218	228,827	5,107,045	877	1,030
2014	4,937,353	0	696	4,938,049	231,638	5,169,687	887	1,042
2015	4,995,866	0	696	4,996,562	234,317	5,230,879	896	1,053
2016	5,048,837	0	696	5,049,533	236,717	5,286,250	903	1,064
2017	5,096,691	0	708	5,097,399	239,072	5,336,471	910	1,074
2018	5,153,245	0	708	5,153,953	241,768	5,395,721	919	1,086
2019	5,206,296	0	708	5,207,004	244,204	5,451,208	927	1,096
2020	5,254,721	0	720	5,255,441	246,411	5,501,852	935	1,105
2021	5,301,979	0	720	5,302,699	248,645	5,551,344	941	1,115
2022	5,345,810	0	720	5,346,530	250,648	5,597,178	949	1,124
GROWTH RATE								
1998-2003	3.2%	0	0.7%	3.2%	3.0%	3.2%	2.3%	2.1%
1998-2008	2.5%	0	0.6%	2.5%	2.4%	2.5%	2.2%	2.2%
1998-2022	1.7%	0	0.5%	1.7%	1.6%	1.7%	1.5%	1.5%

* Wholesale reflects the loss of Williamstown in 1998.
NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February 1998)

UNION LIGHT, HEAT AND POWER COMPANY
ELECTRIC CUSTOMERS BY MAJOR CLASSIFICATIONS
ANNUAL AVERAGES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	O.P.A.	WHOLE-SALE	TOTAL CUSTOMERS	ANNUAL INCREASE	ELECTRIC - KWH RESIDENTIAL USE PER CUSTOMER
1993	97,686	10,201	406	107	811	1	109,212	1,084	11,136
1994	98,765	10,334	401	112	837	1	110,451	1,239	11,086
1995	100,830	10,477	400	113	849	1	112,670	2,219	11,423
1996	102,419	10,734	401	113	881	1	114,548	1,879	11,577
1997	104,529	10,926	399	117	889	1	116,861	2,313	11,080
1998	106,363	11,099	399	124	905	0	118,890	2,029	11,334
1999	108,399	11,377	403	128	925	0	121,232	2,342	11,614
2000	110,501	11,670	407	132	943	0	123,653	2,421	11,674
2001	111,930	11,887	411	136	960	0	125,324	1,671	11,704
2002	113,402	12,108	414	140	978	0	127,042	1,718	11,739
2003	114,824	12,323	416	145	997	0	128,705	1,663	11,813
2004	116,206	12,531	418	150	1,016	0	130,321	1,616	11,889
2005	117,579	12,738	420	154	1,034	0	131,925	1,604	11,982
2006	118,792	12,922	422	159	1,052	0	133,347	1,422	12,017
2007	119,911	13,097	423	163	1,065	0	134,659	1,312	12,064
2008	121,064	13,267	425	168	1,079	0	136,003	1,344	12,175
2009	122,245	13,445	426	172	1,092	0	137,380	1,377	12,212
2010	123,445	13,627	427	177	1,106	0	138,782	1,402	12,245
2011	124,565	13,799	428	181	1,117	0	140,090	1,308	12,311
2012	125,629	13,961	428	186	1,122	0	141,326	1,236	12,365
2013	126,669	14,120	429	190	1,126	0	142,534	1,208	12,391
2014	127,686	14,276	429	195	1,131	0	143,717	1,183	12,499
2015	128,696	14,432	429	199	1,135	0	144,891	1,174	12,577
2016	129,571	14,569	429	204	1,137	0	145,910	1,019	12,649
2017	130,358	14,691	429	207	1,133	0	146,818	908	12,658
2018	131,147	14,813	428	211	1,128	0	147,727	909	12,734
2019	131,941	14,936	428	215	1,122	0	148,642	915	12,796
2020	132,730	15,059	427	219	1,117	0	149,552	910	12,867
2021	133,405	15,166	426	222	1,110	0	150,329	777	12,951
2022	134,017	15,262	425	225	1,098	0	151,027	698	13,033
GROWTH RATE									
1998-2003	1.5%	2.1%	0.8%	3.2%	2.0%	N/A	1.6%		0.8%
1998-2008	1.3%	1.8%	0.6%	3.1%	1.8%	N/A	1.4%		0.7%
1998-2022	1.0%	1.3%	0.3%	2.5%	0.8%	N/A	1.0%		0.6%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February 1998)

GA-56

WEST HARRISON GAS & ELECTRIC COMPANY
FORECAST OF ELECTRIC SALES AND PURCHASES (SENDOUT)
MWH - BILLING

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	O.P.A.	TOTAL RETAIL	LOSSES	TOTAL PURCHASES
1993	2,899	2,900	156	28	85	6,069	527	6,596
1994	2,933	3,194	120	29	67	6,343	472	6,815
1995	2,977	3,395	151	29	67	6,619	547	7,165
1996	2,995	3,558	343	26	105	7,027	678	7,705
1997	2,812	3,409	390	30	97	6,737	387	7,125
1998	2,938	3,697	363	30	98	7,126	579	7,705
1999	3,030	3,734	356	30	100	7,250	587	7,837
2000	3,067	3,812	369	30	100	7,378	600	7,978
2001	3,115	3,892	378	30	104	7,519	610	8,129
2002	3,164	3,977	390	30	108	7,669	621	8,290
2003	3,226	4,078	405	30	111	7,850	636	8,486
2004	3,284	4,178	420	30	114	8,026	651	8,677
2005	3,351	4,338	439	30	119	8,277	671	8,948
2006	3,395	4,405	457	30	122	8,409	681	9,090
2007	3,441	4,457	470	30	123	8,521	690	9,211
2008	3,506	4,511	483	30	124	8,654	702	9,356
2009	3,551	4,564	498	30	125	8,768	710	9,478
2010	3,594	4,620	506	30	126	8,876	719	9,595
2011	3,646	4,671	512	30	128	8,987	727	9,714
2012	3,694	4,707	521	31	128	9,081	735	9,816
2013	3,733	4,748	525	31	128	9,165	743	9,908
2014	3,796	4,788	534	31	130	9,279	752	10,031
2015	3,849	4,823	538	31	130	9,371	758	10,129
2016	3,896	4,856	546	31	131	9,460	767	10,227
2017	3,924	4,892	554	31	133	9,534	770	10,304
2018	3,970	4,932	561	31	134	9,628	780	10,408
2019	4,015	4,972	571	31	135	9,724	789	10,513
2020	4,060	5,007	576	31	136	9,810	795	10,605
2021	4,110	5,044	584	31	136	9,905	802	10,707
2022	4,155	5,080	589	31	137	9,992	811	10,803
GROWTH RATE								
1998-2003	1.9%	2.0%	2.2%	0.0%	2.5%	2.0%	1.9%	1.9%
1998-2008	1.8%	2.0%	2.9%	0.0%	2.4%	2.0%	1.9%	2.0%
1998-2022	1.5%	1.3%	2.0%	0.1%	1.4%	1.4%	1.4%	1.4%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February 1998)

WEST HARRISON GAS & ELECTRIC COMPANY
ELECTRIC CUSTOMERS BY MAJOR CLASSIFICATIONS
ANNUAL AVERAGES

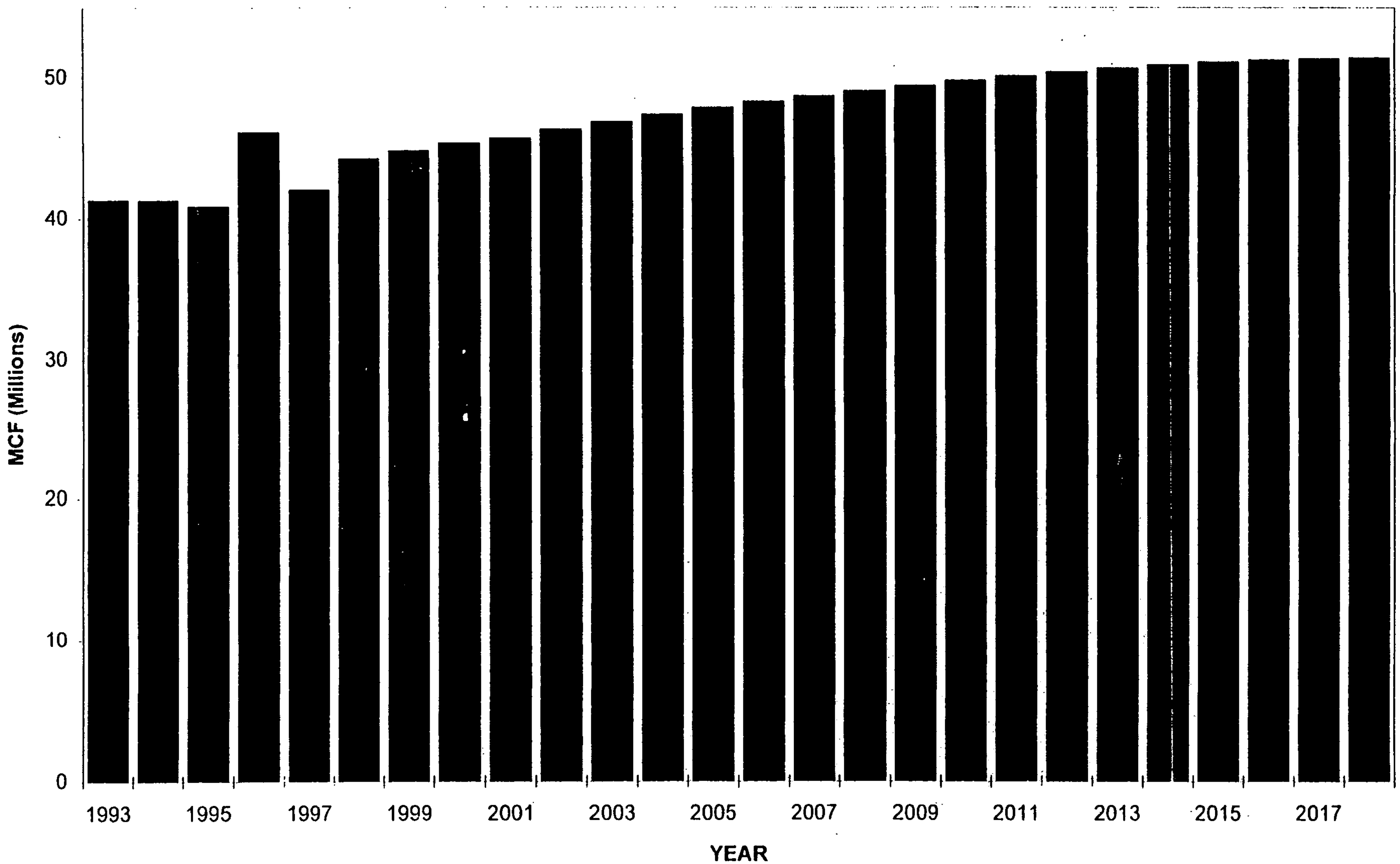
	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	O.P.A.	TOTAL CUSTOMERS	ANNUAL INCREASE	ELECTRIC - KWH RESIDENTIAL USE PER CUSTOMER
1993	280	81	2	2	3	368		10,353
1994	276	86	1	2	3	368	(0)	10,633
1995	278	91	2	2	3	376	7	10,705
1996	278	94	2	2	3	378	2	10,778
1997	277	94	2	2	3	378	(0)	10,165
1998	278	95	2	2	3	380	2	10,568
1999	281	97	2	2	3	385	5	10,783
2000	285	98	2	2	3	390	5	10,761
2001	288	100	2	2	3	395	5	10,816
2002	292	102	2	2	3	401	6	10,836
2003	296	104	2	2	3	407	6	10,899
2004	299	106	2	2	3	412	5	10,983
2005	303	107	2	2	3	417	5	11,059
2006	306	109	2	2	3	422	5	11,095
2007	309	111	2	2	3	427	5	11,136
2008	312	112	2	2	3	431	4	11,237
2009	315	113	2	2	3	435	4	11,273
2010	318	115	2	2	3	440	5	11,302
2011	321	116	2	2	3	444	4	11,358
2012	324	118	2	2	3	449	5	11,401
2013	326	119	2	2	3	452	3	11,451
2014	329	121	2	2	3	457	5	11,538
2015	332	122	2	2	3	461	4	11,593
2016	334	123	2	2	3	464	3	11,665
2017	336	124	2	2	3	467	3	11,679
2018	338	125	2	2	3	470	3	11,746
2019	340	126	2	2	3	473	3	11,809
2020	342	127	2	2	3	476	3	11,871
2021	344	128	2	2	3	479	3	11,948
2022	345	129	2	2	3	481	2	12,043
GROWTH RATE								
1998-2003	1.3%	1.8%	0.0%	0.0%	0.0%	1.4%		0.6%
1998-2008	1.2%	1.7%	0.0%	0.0%	0.0%	1.3%		0.6%
1998-2022	0.9%	1.3%	0.0%	0.0%	0.0%	1.0%		0.5%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

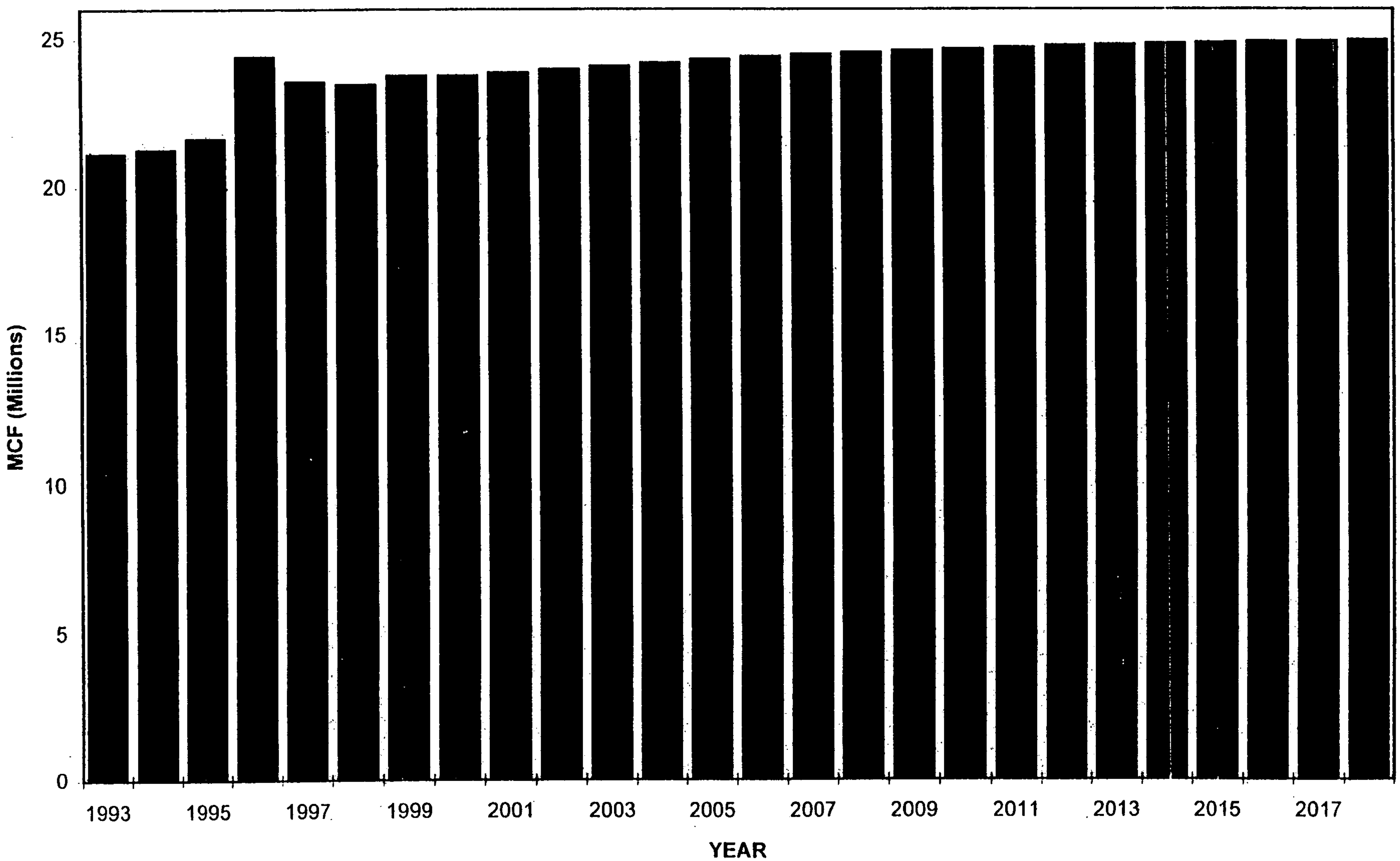
(DRI Forecast February [illegible]7)

CG&E AND SUBSIDIARY COMPANIES

Total Residential Gas Deliveries



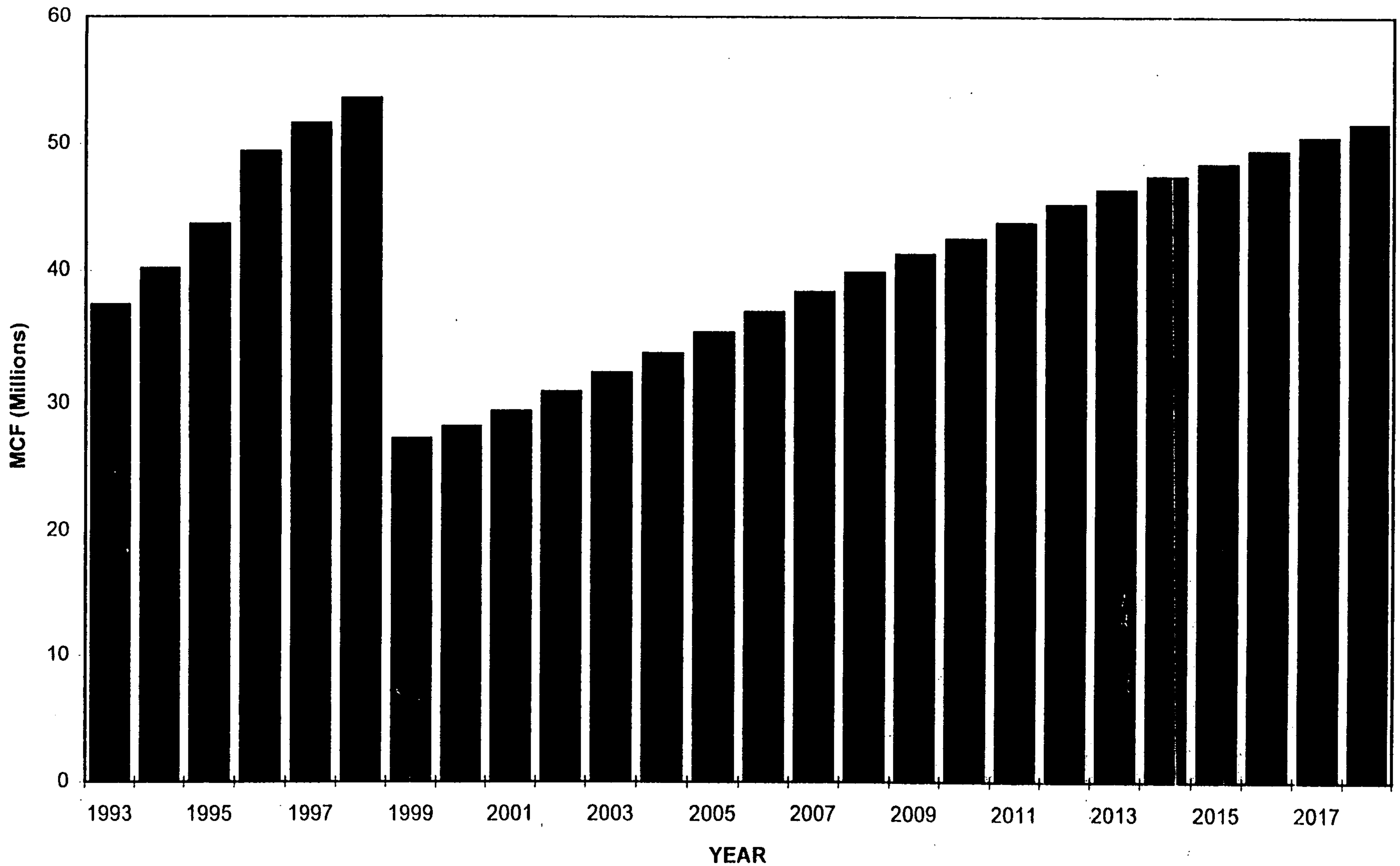
(DRI Forecast February 1998)



(DRI Forecast February 8)

CG&E AND SUBSIDIARY COMPANIES

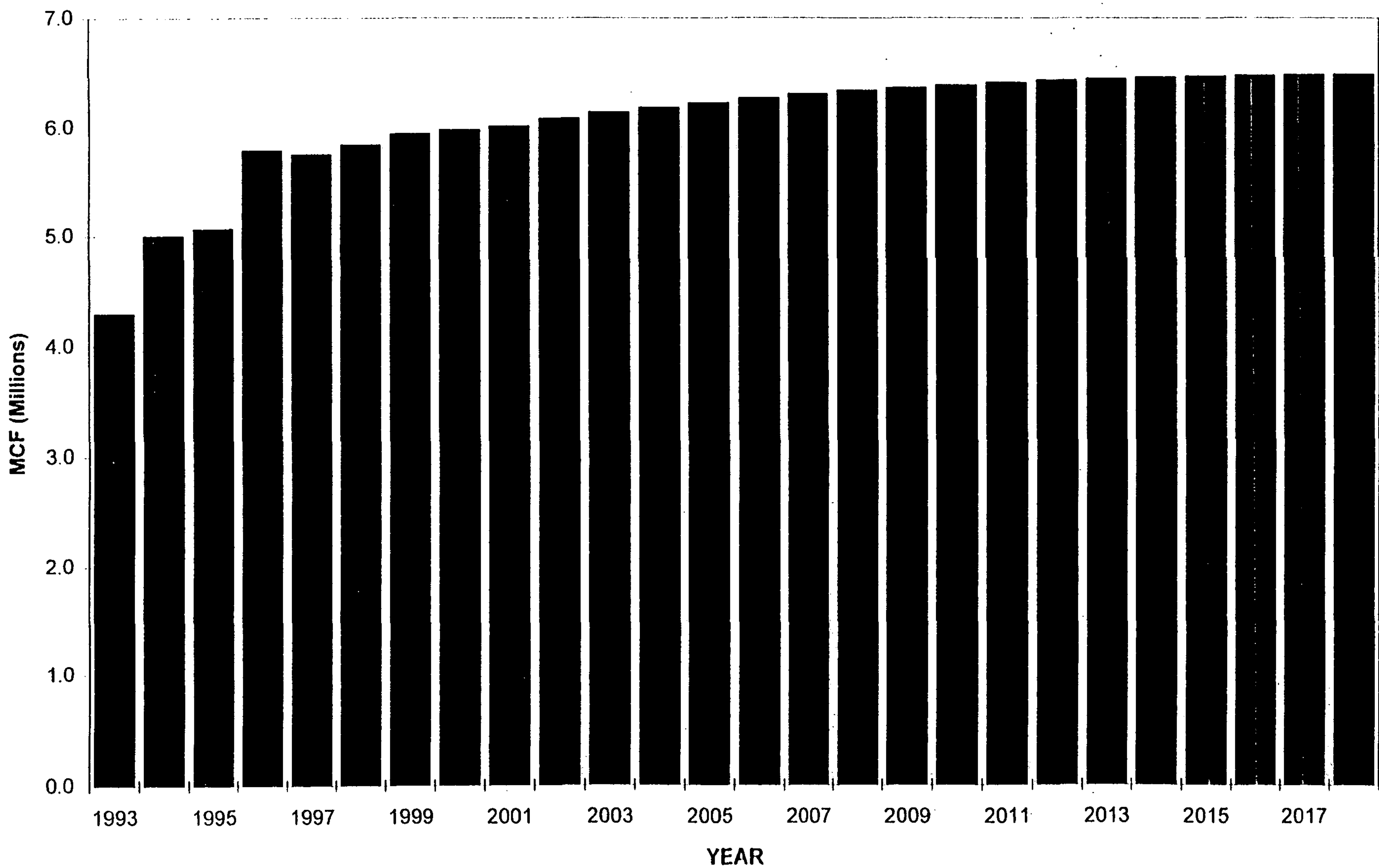
Total Industrial Gas Deliveries



(DRI Forecast February 1998)

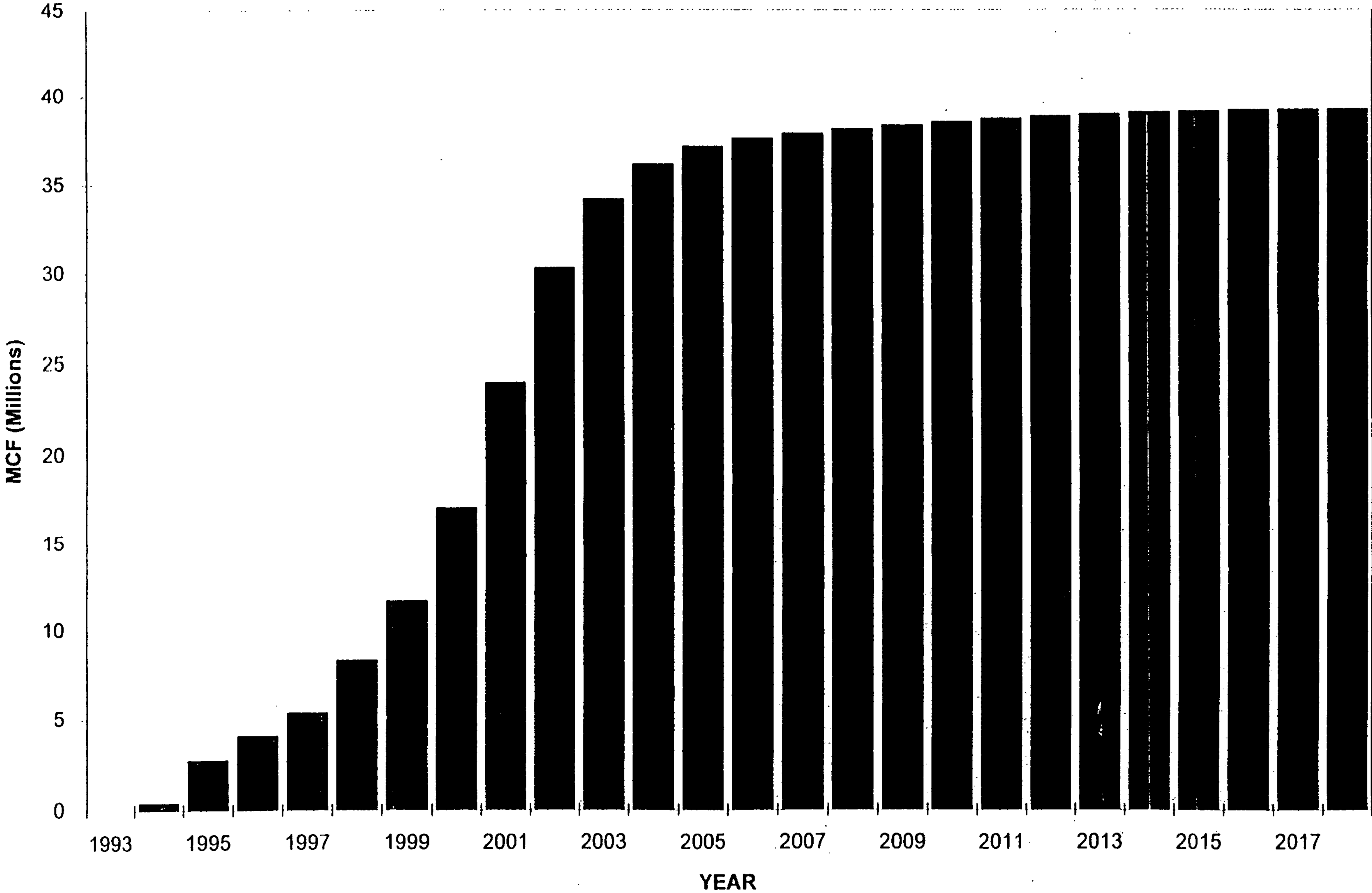
CG&E AND SUBSIDIARY COMPANIES

Total Other Public Authorities Gas Deliveries

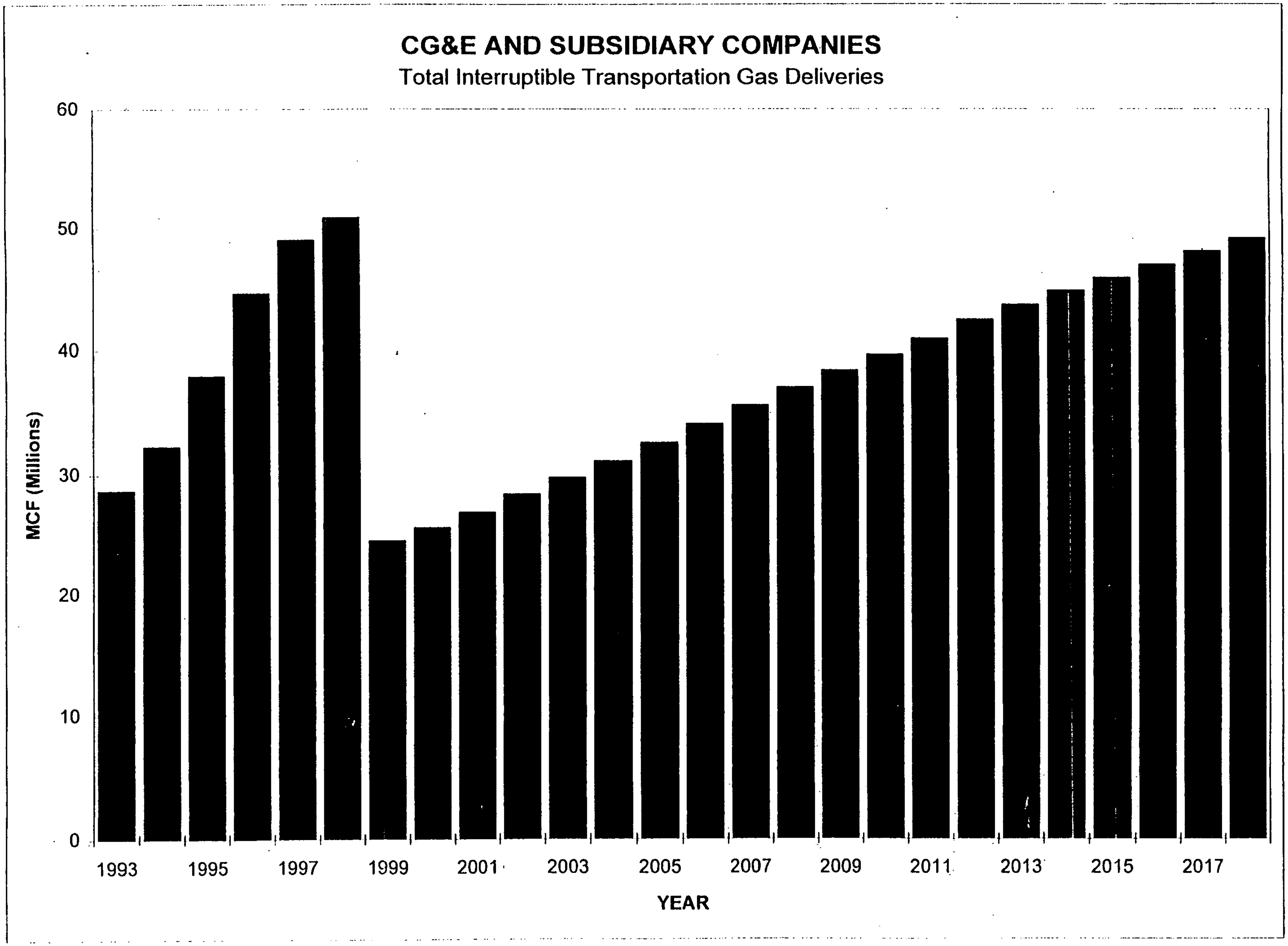


(DRI Forecast February)

CG&E AND SUBSIDIARY COMPANIES
Total Firm Transportation Gas Deliveries



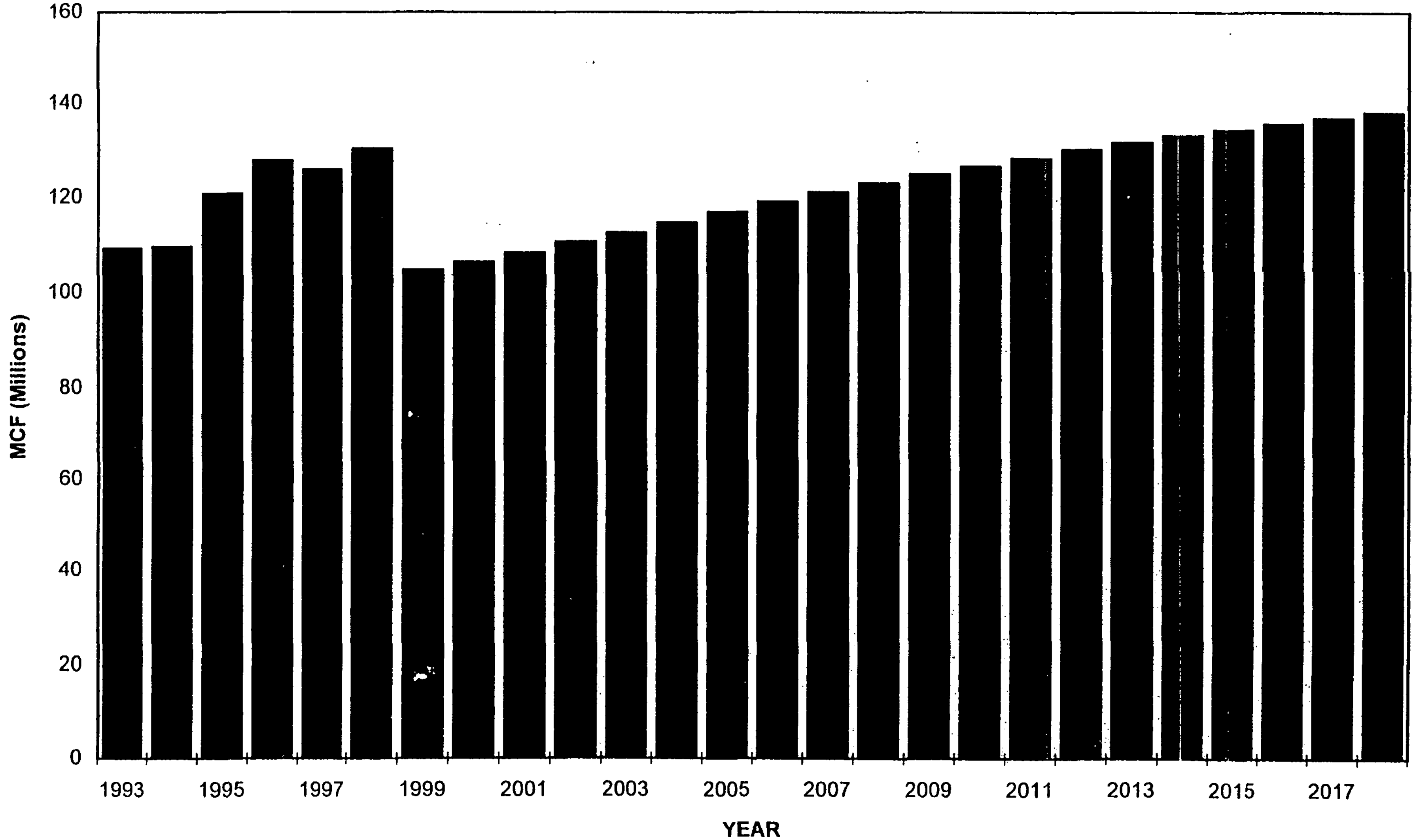
(DRI Forecast February 1998)



(DRI Forecast February 1998)

CG&E AND SUBSIDIARY COMPANIES

Total Gas Sendout



(DRI Forecast February 1998)

THE CINCINNATI GAS & ELECTRIC COMPANY AND SUBSIDIARIES

FORECAST OF FIRM GAS SALES AND TRANSPORTATION

MCF - BILLING

	FIRM SALES								FIRM TRANSPORTATION				
	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	O.P.A.	WHOLE-SALE	INTER-DEPT.	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	O.P.A.	TOTAL
1993	41,245,097	19,824,738	6,637,149	39,927	3,077,125	306,947	83,531	71,214,514	0	0	0	0	0
1994	41,215,827	19,813,301	6,293,039	40,892	3,171,763	296,395	76,220	70,907,437	0	118,869	20[illegible],989	3,817	331,675
1995	40,786,826	18,867,539	4,851,309	40,892	2,993,963	279,204	84,237	67,903,970	0	1,155,685	1,33[illegible],274	163,701	2,657,660
1996	46,170,385	21,157,313	5,112,469	41,583	2,927,289	352,245	96,028	75,857,312	0	1,612,063	1,76[illegible],139	631,353	4,006,554
1997	41,992,397	19,199,952	4,718,931	41,273	2,610,307	349,321	124,248	69,036,429	565	2,366,725	2,13[illegible],923	807,296	5,305,[illegible]
1998	43,680,254	17,608,716	4,353,767	41,350	2,436,969	354,504	125,300	68,600,860	566,842	3,945,769	2,56[illegible],690	1,225,397	8,300,698
1999	42,593,218	16,696,343	4,198,166	41,350	2,243,335	353,379	125,300	66,251,091	2,225,524	5,053,612	2,80[illegible],954	1,486,429	11,571,519
2000	39,763,425	15,092,533	3,905,685	41,350	2,071,481	353,205	125,300	61,352,979	5,600,903	6,638,287	3,01[illegible],888	1,685,176	16,944,254
2001	35,255,184	13,413,397	3,598,527	41,350	1,971,105	355,031	125,300	54,759,894	10,480,736	8,401,154	3,251,807	1,804,261	23,937,958
2002	31,354,849	12,097,361	3,365,555	41,350	1,941,311	357,173	125,300	49,282,899	15,027,632	9,804,846	3,52[illegible],724	1,879,994	30,240,196
2003	29,199,858	11,336,720	3,187,421	41,350	1,936,156	359,250	125,300	46,186,055	17,744,827	10,655,976	3,791,163	1,921,432	34,113,398
2004	28,446,856	10,985,101	3,056,348	41,350	1,939,850	361,498	125,300	44,956,303	19,010,487	11,092,740	4,01[illegible],466	1,944,741	36,063,434
2005	28,348,142	10,875,377	2,982,331	41,350	1,950,044	363,907	125,300	44,686,451	19,602,750	11,299,547	4,18[illegible],301	1,962,628	37,054,226
2006	28,452,054	10,903,234	2,989,450	41,350	1,963,617	366,139	125,300	44,841,144	19,915,502	11,362,404	4,25[illegible],129	1,977,370	37,510,405
2007	28,607,827	10,937,743	3,012,473	41,350	1,975,855	368,202	125,300	45,068,750	20,119,227	11,387,166	4,294,459	1,989,697	37,790,549
2008	28,786,955	10,968,338	3,034,212	41,350	1,985,800	370,315	125,300	45,312,270	20,290,920	11,409,371	4,32[illegible],018	1,999,716	38,028,025
2009	28,979,323	10,996,456	3,051,371	41,350	1,993,972	372,570	125,300	45,560,342	20,454,460	11,429,775	4,352,278	2,007,946	38,244,459
2010	29,166,954	11,022,798	3,055,485	41,350	2,001,320	374,964	125,300	45,788,171	20,608,546	11,449,372	4,356,968	2,015,341	38,430,227
2011	29,331,176	11,050,665	3,059,141	41,350	2,008,625	377,322	125,300	45,993,579	20,746,252	11,469,540	4,360,927	2,022,692	38,599,411
2012	29,484,588	11,079,117	3,053,888	41,350	2,016,054	379,791	125,300	46,180,088	20,875,859	11,490,401	4,352,456	2,030,183	38,748,[illegible]
2013	29,632,261	11,096,553	3,039,017	41,350	2,020,817	382,113	125,300	46,337,411	21,000,151	11,503,173	4,330,536	2,034,972	38,868,[illegible]
2014	29,756,575	11,114,122	3,018,860	41,350	2,024,552	384,538	125,300	46,465,297	21,107,890	11,516,074	4,300,612	2,038,732	38,963,308
2015	29,867,736	11,126,424	2,998,493	41,350	2,027,442	386,900	125,300	46,573,645	21,206,302	11,526,061	4,270,537	2,041,650	39,044,550
2016	29,936,107	11,142,283	2,975,082	41,350	2,030,029	389,166	125,300	46,639,317	21,274,540	11,537,572	4,235,930	2,044,257	39,092,299
2017	29,979,921	11,153,576	2,955,049	41,350	2,031,746	391,235	125,300	46,678,177	21,324,161	11,546,239	4,206,286	2,045,979	39,122,665
2018	30,013,544	11,169,519	2,934,997	41,350	2,033,278	393,435	125,300	46,711,423	21,366,633	11,557,922	4,176,397	2,047,522	39,148,474
GROWTH RATES													
1998-2003	-7.7%	-8.4%	-6.0%	0.0%	-4.5%	0.3%	0.0%	-7.6%	99.1%	22.0%	[illegible].1%	9.4%	32.7%
1998-2008	-4.1%	-4.6%	-3.5%	0.0%	-2.0%	0.4%	0.0%	-4.1%	43.0%	11.2%	[illegible].4%	5.0%	16.4%
1998-2018	-1.6%	-1.9%	-1.6%	0.0%	-0.8%	0.4%	0.0%	-1.6%	16.3%	4.6%	[illegible].1%	2.2%	6.7%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February 1998)

CINCINNATI GAS & ELECTRIC COMPANY AND SUBSIDIARIES

FORECAST OF FIRM GAS DELIVERIES
MCF - BILLING

FIRM DELIVERIES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER *	O.P.A.	TOTAL RETAIL	WHOLE-SALE	COMPANY USE	FIRM LOSSES	TOTAL DELIVERIES
1993	41,245,097	19,824,738	6,637,149	123,458	3,077,125	70,907,567	306,947	81,135	NA	71,295,649
1994	41,215,827	19,932,170	6,502,028	117,112	3,175,580	70,942,717	296,395	79,697	NA	71,318,809
1995	40,786,826	20,023,224	6,189,583	125,129	3,157,664	70,282,426	279,204	80,614	NA	70,642,244
1996	46,170,385	22,769,376	6,875,608	137,611	3,558,641	79,511,621	352,245	93,348	NA	79,957,214
1997	41,992,962	21,566,677	6,849,854	165,521	3,417,603	73,992,617	349,321	99,876	NA	74,441,814
1998	44,247,096	21,554,485	6,916,457	166,650	3,662,366	76,547,054	354,504	98,700	1,795,198	78,795,456
1999	44,818,742	21,749,955	7,004,120	166,650	3,729,764	77,469,231	353,379	98,700	1,465,299	79,386,609
2000	45,364,328	21,730,820	6,925,573	166,650	3,756,657	77,944,028	353,205	98,700	1,420,059	79,815,992
2001	45,735,920	21,814,551	6,850,334	166,650	3,775,366	78,342,821	355,031	98,700	1,469,815	80,266,367
2002	46,382,481	21,902,207	6,893,279	166,650	3,821,305	79,165,922	357,173	98,700	1,483,480	81,105,275
2003	46,944,685	21,992,696	6,978,584	166,650	3,857,588	79,940,203	359,250	98,700	1,491,651	81,889,804
2004	47,457,343	22,077,841	7,071,814	166,650	3,884,591	80,658,239	361,498	98,700	1,499,356	82,617,793
2005	47,950,892	22,174,924	7,171,632	166,650	3,912,672	81,376,770	363,907	98,700	1,510,312	83,349,689
2006	48,367,556	22,265,638	7,244,579	166,650	3,940,987	81,985,410	366,139	98,700	1,515,249	83,965,498
2007	48,727,054	22,324,909	7,306,932	166,650	3,965,552	82,491,097	368,202	98,700	1,520,108	84,478,107
2008	49,077,875	22,377,709	7,362,230	166,650	3,985,516	82,969,980	370,315	98,700	1,523,995	84,962,990
2009	49,433,783	22,426,231	7,403,649	166,650	4,001,918	83,432,231	372,570	98,700	1,529,953	85,433,454
2010	49,775,500	22,472,170	7,412,453	166,650	4,016,661	83,843,434	374,964	98,700	1,534,300	85,851,398
2011	50,077,428	22,520,205	7,420,068	166,650	4,031,317	84,215,668	377,322	98,700	1,538,276	86,229,966
2012	50,360,447	22,569,518	7,406,344	166,650	4,046,237	84,549,196	379,791	98,700	1,541,798	86,569,485
2013	50,632,412	22,599,726	7,369,553	166,650	4,055,789	84,824,130	382,113	98,700	1,542,308	86,847,251
2014	50,864,465	22,630,196	7,319,472	166,650	4,063,284	85,044,067	384,538	98,700	1,543,519	87,070,824
2015	51,074,038	22,652,485	7,269,030	166,650	4,069,092	85,231,295	386,900	98,700	1,544,703	87,261,598
2016	51,210,647	22,679,855	7,211,012	166,650	4,074,286	85,342,450	389,166	98,700	1,543,849	87,374,165
2017	51,304,082	22,699,815	7,161,335	166,650	4,077,725	85,409,607	391,235	98,700	1,540,795	87,440,337
2018	51,380,177	22,727,441	7,111,394	166,650	4,080,800	85,466,462	393,435	98,700	1,539,451	87,498,048
GROWTH RATES										
1998-2003	1.2%	0.4%	0.2%	0.0%	1.0%	0.9%	0.3%	0.0%	-3.6%	0.8%
1998-2008	1.0%	0.4%	0.6%	0.0%	0.8%	0.8%	0.4%	0.0%	-1.6%	0.8%
1998-2018	0.6%	0.2%	0.1%	0.0%	0.5%	0.5%	0.4%	0.0%	-0.6%	0.4%

* The other category includes street lighting and inter-departmental sales

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

GA-67

CINCINNATI GAS & ELECTRIC COMPANY AND SUBSIDIARIES
FORECAST OF INTERRUPTIBLE GAS DELIVERIES
MCF - BILLING

INTERRUPTIBLE DELIVERIES

	COMMERCIAL	INDUSTRIAL EXCL. AK STEEL	AK STEEL	TOTAL INDUSTRIAL	O.P.A.	TOTAL RETAIL	ELECTRIC GENERATION	INTERRUPTIBLE LOSSES	TOTAL DELIVERIES
1993	1,279,781	14,874,817	15,896,637	30,771,454	1,209,926	33,261,161	46,835	NA	33,307,996
1994	1,307,177	15,804,266	17,822,530	33,626,796	1,817,573	36,751,546	166,337	NA	36,917,883
1995	1,599,646	16,444,768	20,997,686	37,442,454	1,899,198	40,941,298	178,867	NA	41,120,165
1996	1,632,528	17,839,206	24,677,856	42,517,062	2,214,990	46,364,580	16,477	NA	46,381,057
1997	1,999,733	18,714,140	26,087,642	44,801,782	2,320,789	49,122,304	40,851	NA	49,163,155
1998	1,910,981	19,527,915	27,210,097	46,738,012	2,165,680	50,814,673	134,788	636,757	51,586,218
1999	2,022,323	20,178,806	0	20,178,806	2,202,735	24,403,864	169,603	807,541	25,381,008
2000	2,035,945	21,217,169	0	21,217,169	2,212,599	25,465,713	343,049	825,119	26,633,881
2001	2,059,908	22,479,931	0	22,479,931	2,228,492	26,768,331	508,184	884,393	28,160,908
2002	2,078,218	23,957,913	0	23,957,913	2,254,888	28,291,019	376,496	918,967	29,586,482
2003	2,095,941	25,313,495	0	25,313,495	2,274,907	29,684,343	82,730	947,289	30,714,362
2004	2,111,886	26,672,720	0	26,672,720	2,290,560	31,075,166	81,745	987,908	32,144,819
2005	2,132,721	28,123,812	0	28,123,812	2,307,149	32,563,682	71,055	1,025,986	33,660,723
2006	2,148,285	29,610,007	0	29,610,007	2,323,435	34,081,727	69,619	1,063,520	35,214,866
2007	2,160,453	31,054,197	0	31,054,197	2,337,511	35,552,161	49,779	1,099,652	36,701,592
2008	2,170,392	32,446,050	0	32,446,050	2,348,795	36,965,237	70,492	1,135,528	38,171,257
2009	2,179,341	33,807,135	0	33,807,135	2,358,226	38,344,702	72,920	1,166,068	39,583,690
2010	2,187,087	35,027,577	0	35,027,577	2,366,718	39,581,382	69,353	1,196,630	40,847,365
2011	2,196,482	36,303,042	0	36,303,042	2,375,463	40,874,987	74,301	1,230,231	42,179,519
2012	2,207,024	37,776,158	0	37,776,158	2,384,064	42,367,246	69,429	1,267,938	43,704,613
2013	2,212,019	38,962,615	0	38,962,615	2,389,208	43,563,842	72,533	1,291,857	44,928,232
2014	2,217,207	40,112,902	0	40,112,902	2,393,610	44,723,719	75,235	1,322,151	46,121,105
2015	2,219,105	41,146,221	0	41,146,221	2,396,770	45,762,096	70,500	1,343,259	47,175,855
2016	2,224,075	42,242,015	0	42,242,015	2,400,058	46,866,148	63,091	1,374,555	48,303,794
2017	2,226,084	43,345,293	0	43,345,293	2,401,688	47,973,065	125,699	1,401,780	49,500,544
2018	2,230,720	44,456,207	0	44,456,207	2,403,777	49,090,704	128,214	1,430,840	50,649,758
GROWTH RATES									
1998-2003	1.9%	5.3%	-100.0%	-11.5%	1.0%	-10.2%	-9.3%	8.3%	-9.9%
1998-2008	1.3%	5.2%	-100.0%	-3.6%	0.8%	-3.1%	-6.3%	6.0%	-3.0%
1998-2018	0.8%	4.2%	-99.9%	-0.2%	0.5%	-0.2%	-0.2%	4.1%	-0.1%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February 1998)

THE CINCINNATI GAS & ELECTRIC COMPANY AND SUBSIDIARIES

FORECAST OF GAS SENDOUT AND PEAK DEMAND

MCF - BILLING

TOTAL DELIVERIES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER *	O.P.A.	TOTAL RETAIL	WHOLE-SALE	COMPANY USE	ELECTRIC GENERATION	TOTAL LOSSES	SENDOUT	SEASONAL PEAK
1993	41,245,097	21,104,519	37,408,603	123,458	4,287,051	104,168,728	306,947	81,135	46,835	4,677,903	109,281,548	955,102
1994	41,215,827	21,239,347	40,128,824	117,112	4,993,153	107,694,263	296,395	79,697	166,337	1,405,717	109,642,409	812,545
1995	40,786,826	21,622,870	43,632,037	125,129	5,056,862	111,223,724	279,204	80,614	178,867	9,073,866	120,836,275	860,930
1996	46,170,385	24,401,904	49,392,670	137,611	5,773,631	125,876,201	352,245	93,348	16,477	1,563,053	127,901,324	869,[illegible]
1997	41,992,962	23,566,409	51,651,636	165,521	5,738,392	123,114,921	349,321	99,876	40,851	2,362,162	125,967,131	931,8[illegible]
1998	44,247,096	23,465,466	53,654,469	166,650	5,828,046	127,361,727	354,504	98,700	134,788	2,431,955	130,381,674	838,663
1999	44,818,742	23,772,278	27,182,926	166,650	5,932,499	101,873,095	353,379	98,700	169,603	2,272,840	104,767,617	828,121
2000	45,364,328	23,766,765	28,142,742	166,650	5,969,256	103,409,741	353,205	98,700	343,049	2,245,178	106,449,873	829,743
2001	45,735,920	23,874,459	29,330,265	166,650	6,003,858	105,111,152	355,031	98,700	508,184	2,354,208	108,427,275	832,637
2002	46,382,481	23,980,425	30,851,192	166,650	6,076,193	107,456,941	357,173	98,700	376,496	2,402,447	110,691,757	835,412
2003	46,944,685	24,088,637	32,292,079	166,650	6,132,495	109,624,546	359,250	98,700	82,730	2,438,940	112,604,166	837,843
2004	47,457,343	24,189,727	33,744,534	166,650	6,175,151	111,733,405	361,498	98,700	81,745	2,487,264	114,762,612	840,329
2005	47,950,892	24,307,645	35,295,444	166,650	6,219,821	113,940,452	363,907	98,700	71,055	2,536,298	117,010,412	842,626
2006	48,367,556	24,413,923	36,854,586	166,650	6,264,422	116,067,137	366,139	98,700	69,619	2,578,769	119,180,364	844,709
2007	48,727,054	24,485,362	38,361,129	166,650	6,303,063	118,043,258	368,202	98,700	49,779	2,619,760	121,179,699	846,681
2008	49,077,875	24,548,101	39,808,280	166,650	6,334,311	119,935,217	370,315	98,700	70,492	2,659,523	123,134,247	848,597
2009	49,433,783	24,605,572	41,210,784	166,650	6,360,144	121,776,933	372,570	98,700	72,920	2,696,021	125,017,144	850,303
2010	49,775,500	24,659,257	42,440,030	166,650	6,383,379	123,424,816	374,964	98,700	69,353	2,730,930	126,698,763	851,888
2011	50,077,428	24,716,687	43,723,110	166,650	6,406,780	125,090,655	377,322	98,700	74,301	2,768,507	128,409,485	853,46[illegible]
2012	50,360,447	24,776,542	45,182,502	166,650	6,430,301	126,916,442	379,791	98,700	69,429	2,809,736	130,274,098	855,0[illegible]
2013	50,632,412	24,811,745	46,332,168	166,650	6,444,997	128,387,972	382,113	98,700	72,533	2,834,165	131,775,483	856,20[illegible]
2014	50,864,465	24,847,403	47,432,374	166,650	6,456,894	129,767,786	384,538	98,700	75,235	2,865,670	133,191,929	857,380
2015	51,074,038	24,871,590	48,415,251	166,650	6,465,862	130,993,391	386,900	98,700	70,500	2,887,962	134,437,453	858,283
2016	51,210,647	24,903,930	49,453,027	166,650	6,474,344	132,208,598	389,166	98,700	63,091	2,918,404	135,677,959	859,222
2017	51,304,082	24,925,899	50,506,628	166,650	6,479,413	133,382,672	391,235	98,700	125,699	2,942,575	136,940,881	860,063
2018	51,380,177	24,958,161	51,567,601	166,650	6,484,577	134,557,166	393,435	98,700	128,214	2,970,291	138,147,806	860,957
GROWTH RATES												
1998-2003	1.2%	0.5%	-9.7%	0.0%	1.0%	-3.0%	0.3%	0.0%	-9.3%	0.1%	-2.9%	0.0%
1998-2008	1.0%	0.5%	-2.9%	0.0%	0.8%	-0.6%	0.4%	0.0%	-6.3%	0.9%	-0.6%	0.1%
1998-2018	0.6%	0.3%	-0.2%	0.0%	0.4%	0.2%	0.4%	0.0%	-0.2%	0.8%	0.2%	0.1%

* The other category includes street lighting and inter-departmental sales
NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

GA-69

(DRI Forecast February 1998)

CINCINNATI GAS & ELECTRIC COMPANY AND SUBSIDIARIES
GAS CUSTOMERS BY MAJOR CLASSIFICATIONS
ANNUAL AVERAGES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	O.P.A.	WHOLE-SALE	TOTAL CUSTOMERS	ANNUAL INCREASE	GAS - MCF RESIDENTIAL USE PER CUSTOMER
1993	373,494	40,347	2,176	6	1,466	1	417,490	5,861	110
1994	379,953	40,573	2,177	6	1,513	1	424,223	6,733	108
1995	389,165	41,335	2,095	6	1,579	1	434,180	9,957	105
1996	397,672	42,065	2,115	10	1,638	1	443,501	9,321	116
1997	407,097	42,563	1,970	10	1,655	1	453,295	9,794	103
1998	415,231	42,712	2,187	10	1,682	1	461,823	8,528	107
1999	423,416	43,808	2,261	10	1,737	1	471,233	9,410	106
2000	431,791	44,552	2,317	10	1,798	1	480,469	9,236	105
2001	440,081	45,119	2,380	10	1,848	1	489,439	8,970	104
2002	448,539	45,734	2,445	10	1,896	1	498,625	9,186	103
2003	456,575	46,301	2,506	10	1,946	1	507,339	8,714	103
2004	464,363	46,830	2,567	10	1,995	1	515,766	8,427	102
2005	472,094	47,349	2,629	10	2,042	1	524,125	8,359	102
2006	479,156	47,811	2,679	10	2,081	1	531,738	7,613	101
2007	485,730	48,244	2,725	10	2,116	1	538,826	7,088	100
2008	492,402	48,679	2,770	10	2,152	1	546,014	7,188	100
2009	499,309	49,113	2,815	10	2,187	1	553,435	7,421	99
2010	506,255	49,544	2,857	10	2,221	1	560,888	7,453	98
2011	512,910	49,943	2,878	10	2,239	1	567,981	7,093	98
2012	519,288	50,338	2,895	10	2,250	1	574,782	6,801	97
2013	525,604	50,731	2,909	10	2,262	1	581,517	6,735	96
2014	531,859	51,095	2,924	10	2,274	1	588,163	6,646	96
2015	538,033	51,447	2,934	10	2,284	1	594,709	6,546	95
2016	543,591	51,745	2,923	10	2,275	1	600,545	5,836	94
2017	548,718	52,018	2,903	10	2,262	1	605,912	5,367	93
2018	553,879	52,283	2,885	10	2,247	1	611,305	5,393	93
GROWTH RATE									
1998-2003	1.9%	1.6%	2.8%	0.0%	3.0%	0.0%	1.9%		-0.7%
1997-2007	1.7%	1.3%	2.4%	0.0%	2.5%	0.0%	1.7%		-0.7%
1997-2017	1.5%	1.0%	1.4%	0.0%	1.5%	0.0%	1.4%		-0.7%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast Febr 1998)

THE CINCINNATI GAS & ELECTRIC COMPANY
FORECAST OF FIRM GAS SALES AND TRANSPORTATION
MCF - BILLING

	FIRM SALES							FIRM TRANSPORTATION				
	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	O.P.A.	INTER-DEPT.	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	O.P.A.	TOTAL
1993	33,895,793	17,174,475	5,618,597	39,927	2,562,373	77,723	59,368,888	0	0	0	0	0
1994	33,880,429	17,007,105	5,295,979	40,892	2,646,523	70,126	58,941,054	0	118,869	208,989	3,817	331,675
1995	33,543,200	15,981,310	3,820,689	40,892	2,486,817	80,031	55,952,939	0	1,150,013	1,315,059	163,701	2,628,773
1996	37,941,258	17,856,976	4,052,859	41,583	2,353,599	93,687	62,339,961	0	1,519,693	1,620,974	626,365	3,767,032
1997	34,515,195	16,161,866	3,738,821	41,273	2,066,624	121,048	56,644,827	565	2,171,942	1,776,569	796,555	4,745,631
1998	35,743,138	14,401,106	3,510,788	41,350	1,834,317	121,000	55,651,699	566,842	3,851,552	2,209,870	1,221,030	7,849,2[illegible]
1999	34,581,309	13,449,747	3,392,330	41,350	1,629,592	121,000	53,215,328	2,225,524	4,958,232	2,417,644	1,481,982	11,083,382
2000	31,692,308	11,864,568	3,140,543	41,350	1,453,313	121,000	48,313,082	5,600,903	6,543,447	2,573,218	1,680,697	16,398,265
2001	27,160,797	10,157,019	2,882,929	41,350	1,349,861	121,000	41,712,956	10,480,736	8,305,453	2,732,949	1,799,758	23,318,896
2002	23,180,884	8,813,017	2,689,113	41,350	1,312,506	121,000	36,157,870	15,027,632	9,708,309	2,934,172	1,875,436	29,545,549
2003	20,955,211	8,023,535	2,534,262	41,350	1,301,377	121,000	32,976,735	17,744,827	10,558,575	3,136,754	1,916,833	33,356,989
2004	20,140,291	7,646,294	2,411,017	41,350	1,300,629	121,000	31,660,581	19,010,487	10,994,568	3,316,666	1,940,110	35,261,831
2005	19,982,947	7,504,448	2,331,879	41,350	1,306,201	121,000	31,287,825	19,602,750	11,200,406	3,455,236	1,957,963	36,216,355
2006	20,041,210	7,508,367	2,328,776	41,350	1,315,116	121,000	31,355,819	19,915,502	11,262,547	3,493,164	1,972,672	36,643,885
2007	20,160,481	7,524,502	2,338,692	41,350	1,323,312	121,000	31,509,337	20,119,227	11,286,757	3,508,036	1,984,970	36,898,990
2008	20,304,384	7,538,982	2,345,884	41,350	1,329,973	121,000	31,681,573	20,290,920	11,308,477	3,518,829	1,994,963	37,113,189
2009	20,460,941	7,552,290	2,347,492	41,350	1,335,447	121,000	31,858,520	20,454,460	11,328,432	3,521,239	2,003,173	37,307,304
2010	20,615,075	7,565,081	2,338,843	41,350	1,340,368	121,000	32,021,717	20,608,546	11,347,623	3,508,264	2,010,550	37,474,983
2011	20,752,822	7,578,232	2,329,651	41,350	1,345,255	121,000	32,168,310	20,746,252	11,367,347	3,494,472	2,017,886	37,625,957
2012	20,882,478	7,591,841	2,311,350	41,350	1,350,235	121,000	32,298,254	20,875,859	11,387,763	3,467,029	2,025,357	37,756,008
2013	21,006,809	7,600,171	2,285,828	41,350	1,353,425	121,000	32,408,583	21,000,151	11,400,260	3,428,742	2,030,136	37,859,289
2014	21,114,580	7,608,588	2,255,913	41,350	1,355,927	121,000	32,497,358	21,107,890	11,412,884	3,383,867	2,033,887	37,938,528
2015	21,213,025	7,615,131	2,226,416	41,350	1,357,864	121,000	32,574,786	21,206,302	11,422,696	3,339,623	2,036,797	38,005,4[illegible]
2016	21,281,280	7,622,637	2,194,490	41,350	1,359,598	121,000	32,620,355	21,274,540	11,433,953	3,291,736	2,039,397	38,039,6[illegible]
2017	21,330,918	7,628,298	2,164,702	41,350	1,360,744	121,000	32,647,012	21,324,161	11,442,449	3,247,051	2,041,117	38,054,778
2018	21,373,403	7,635,916	2,135,130	41,350	1,361,770	121,000	32,668,569	21,366,633	11,453,879	3,202,694	2,042,657	38,065,863
GROWTH RATES												
1998-2003	-10.1%	-11.0%	-6.3%	0.0%	-6.6%	0.0%	-9.9%	99.1%	22.3%	7.3%	9.4%	33.6%
1998-2008	-5.5%	-6.3%	-4.0%	0.0%	-3.2%	0.0%	-5.5%	43.0%	11.4%	4.8%	5.0%	16.8%
1998-2018	-2.5%	-3.1%	-2.5%	0.0%	-1.5%	0.0%	-2.6%	19.9%	5.6%	1.9%	2.6%	8.2%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

GA-71

(DRI Forecast February 1998)

THE CINCINNATI GAS & ELECTRIC COMPANY
FORECAST OF FIRM GAS DELIVERIES
MCF - BILLING

FIRM DELIVERIES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER *	O.P.A.	TOTAL RETAIL	COMPANY USE	FIRM LOSSES	TOTAL
1993	33,895,793	17,174,475	5,618,597	117,650	2,562,373	59,368,888	69,994	NA	59,438,882
1994	33,880,429	17,125,974	5,504,968	111,018	2,650,340	59,272,729	67,848	NA	59,340,577
1995	33,543,200	17,131,523	5,135,748	120,923	2,650,518	58,581,712	72,969	NA	58,654,681
1996	37,941,258	19,376,669	5,673,833	135,270	2,979,964	66,106,993	83,821	NA	66,190,814
1997	34,515,760	18,333,808	5,515,390	162,321	2,863,179	61,390,458	86,195	NA	61,476,653
1998	36,309,980	18,252,658	5,720,658	162,350	3,055,347	63,500,993	85,000	1,527,714	65,113,707
1999	36,806,833	18,407,979	5,809,974	162,350	3,111,574	64,298,710	85,000	1,109,676	65,493,386
2000	37,293,211	18,408,015	5,713,761	162,350	3,134,010	64,711,347	85,000	1,073,049	65,869,396
2001	37,641,533	18,462,472	5,615,878	162,350	3,149,619	65,031,852	85,000	1,111,909	66,228,761
2002	38,208,516	18,521,326	5,623,285	162,350	3,187,942	65,703,419	85,000	1,121,269	66,909,688
2003	38,700,038	18,582,110	5,671,016	162,350	3,218,210	66,333,724	85,000	1,125,862	67,544,586
2004	39,150,778	18,640,862	5,727,683	162,350	3,240,739	66,922,412	85,000	1,130,067	68,137,479
2005	39,585,697	18,704,854	5,787,115	162,350	3,264,164	67,504,180	85,000	1,136,947	68,726,127
2006	39,956,712	18,770,914	5,821,940	162,350	3,287,788	67,999,704	85,000	1,139,521	69,224,225
2007	40,279,708	18,811,259	5,846,728	162,350	3,308,282	68,408,327	85,000	1,141,724	69,635,051
2008	40,595,304	18,847,459	5,864,713	162,350	3,324,936	68,794,762	85,000	1,144,001	70,023,763
2009	40,915,401	18,880,722	5,868,731	162,350	3,338,620	69,165,824	85,000	1,146,998	70,397,822
2010	41,223,621	18,912,704	5,847,107	162,350	3,350,918	69,496,700	85,000	1,149,362	70,731,062
2011	41,499,074	18,945,579	5,824,123	162,350	3,363,141	69,794,267	85,000	1,151,093	71,030,360
2012	41,758,337	18,979,604	5,778,379	162,350	3,375,592	70,054,262	85,000	1,152,068	71,291,330
2013	42,006,960	19,000,431	5,714,570	162,350	3,383,561	70,267,872	85,000	1,151,651	71,504,523
2014	42,222,470	19,021,472	5,639,780	162,350	3,389,814	70,435,886	85,000	1,151,294	71,672,180
2015	42,419,327	19,037,827	5,566,039	162,350	3,394,661	70,580,204	85,000	1,151,627	71,816,831
2016	42,555,820	19,056,590	5,486,226	162,350	3,398,995	70,659,981	85,000	1,149,459	71,894,440
2017	42,655,079	19,070,747	5,411,753	162,350	3,401,861	70,701,790	85,000	1,146,155	71,932,945
2018	42,740,036	19,089,795	5,337,824	162,350	3,404,427	70,734,432	85,000	1,144,006	71,963,438
GROWTH RATES									
1998-2003	1.3%	0.4%	-0.2%	0.0%	1.0%	0.9%	0.0%	-5.9%	0.7%
1998-2008	1.1%	0.3%	0.2%	0.0%	0.8%	0.8%	0.0%	-2.9%	0.7%
1998-2018	0.8%	0.2%	-0.3%	0.0%	0.5%	0.5%	0.0%	-1.4%	0.5%

* The other category includes street lighting and inter-departmental sales
NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

THE CINCINNATI GAS & ELECTRIC COMPANY
FORECAST OF INTERRUPTIBLE GAS DELIVERIES
MCF - BILLING

INTERRUPTIBLE DELIVERIES

	COMMERCIAL	INDUSTRIAL EXCL. AK STEEL	AK STEEL	TOTAL INDUSTRIAL	O.P.A.	TOTAL RETAIL	ELECTRIC GENERATION	INTERRUPTIBLE LOSSES	TOTAL
1993	1,014,752	12,042,711	15,896,637	27,939,348	1,181,801	30,135,901	46,835	NA	30,182,736
1994	1,026,682	12,877,653	17,822,530	30,700,183	1,749,914	33,476,779	166,337	NA	33,643,116
1995	1,370,019	13,140,642	20,997,686	34,138,328	1,789,007	37,297,354	178,867	NA	37,476,221
1996	1,368,282	14,392,921	24,677,856	39,070,777	2,111,110	42,550,170	16,477	NA	42,566,647
1997	1,705,544	14,925,162	26,087,642	41,012,804	2,219,919	44,938,267	40,851	NA	44,979,118
1998	1,604,040	15,847,296	27,210,097	43,057,393	2,074,643	46,736,076	134,788	497,723	47,368,587
1999	1,686,383	16,521,978	0	16,521,978	2,110,142	20,318,503	169,603	658,532	21,146,638
2000	1,690,220	17,451,131	0	17,451,131	2,119,592	21,260,943	343,049	672,753	22,276,745
2001	1,697,460	18,542,085	0	18,542,085	2,134,812	22,374,357	508,184	723,437	23,605,978
2002	1,701,260	19,829,976	0	19,829,976	2,160,103	23,691,339	376,496	750,095	24,817,930
2003	1,703,916	21,015,712	0	21,015,712	2,179,279	24,898,907	82,730	774,278	25,755,915
2004	1,706,166	22,206,100	0	22,206,100	2,194,274	26,106,540	81,745	808,135	26,996,420
2005	1,708,831	23,477,752	0	23,477,752	2,210,165	27,396,748	71,055	840,601	28,308,404
2006	1,711,380	24,778,833	0	24,778,833	2,225,766	28,715,979	69,619	872,318	29,657,916
2007	1,713,146	26,043,469	0	26,043,469	2,239,256	29,995,871	49,779	902,957	30,948,607
2008	1,714,018	27,265,710	0	27,265,710	2,250,061	31,229,789	70,492	932,639	32,232,920
2009	1,714,433	28,460,740	0	28,460,740	2,259,094	32,434,267	72,920	959,235	33,466,422
2010	1,714,461	29,556,261	0	29,556,261	2,267,229	33,537,951	69,353	985,791	34,593,095
2011	1,715,238	30,693,464	0	30,693,464	2,275,608	34,684,310	74,301	1,014,840	35,773,451
2012	1,717,262	31,990,653	0	31,990,653	2,283,846	35,991,761	69,429	1,046,931	37,108,121
2013	1,716,953	33,063,849	0	33,063,849	2,288,776	37,069,578	72,533	1,068,036	38,210,147
2014	1,716,914	34,108,087	0	34,108,087	2,292,991	38,117,992	75,235	1,095,094	39,288,321
2015	1,715,727	35,070,786	0	35,070,786	2,296,020	39,082,533	70,500	1,114,595	40,267,628
2016	1,716,044	36,074,154	0	36,074,154	2,299,171	40,089,369	63,091	1,142,430	41,294,890
2017	1,714,819	37,097,974	0	37,097,974	2,300,732	41,113,525	125,699	1,167,081	42,406,305
2018	1,714,621	38,120,930	0	38,120,930	2,302,732	42,138,283	128,214	1,193,290	43,459,787
GROWTH RATES									
1998-2003	1.2%	5.8%	-100.0%	-13.4%	1.0%	-11.8%	-9.3%	9.2%	-11.5%
1998-2008	0.7%	5.6%	-100.0%	-4.5%	0.8%	-4.0%	-6.3%	6.5%	-3.8%
1998-2018	0.3%	4.5%	-99.9%	-0.6%	0.5%	-0.5%	-0.2%	4.5%	-0.4%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February 1998)

THE CINCINNATI GAS & ELECTRIC COMPANY
FORECAST OF GAS SENDOUT AND PEAK DEMAND
MCF - BILLING

TOTAL DELIVERIES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER *	O.P.A.	TOTAL RETAIL	COMPANY USE	ELECTRIC GENERATION	TOTAL LOSSES	SENDOUT	SEASONAL PEAK
1993	33,895,793	18,189,227	33,557,945	117,650	3,744,174	89,504,789	69,994	46,835	3,949,034	93,570,652	801,483
1994	33,880,429	8,152,656	36,205,151	111,018	4,400,254	92,749,508	67,848	166,337	1,280,650	94,264,343	684,162
1995	33,543,200	8,501,342	39,274,076	120,923	4,439,525	95,879,066	72,969	178,867	8,040,994	104,171,896	717,652
1996	37,941,258	20,744,951	44,744,610	135,270	5,091,074	108,657,163	83,821	16,477	1,291,709	110,049,170	743,997
1997	34,515,760	20,039,351	46,528,194	162,321	5,083,098	106,328,724	86,195	40,851	2,159,133	108,614,903	789,132
1998	36,309,980	9,856,698	48,778,051	162,350	5,129,990	110,237,069	85,000	134,788	2,025,437	112,482,294	700,308
1999	36,806,833	20,094,362	22,331,952	162,350	5,221,716	84,617,213	85,000	169,603	1,768,208	86,640,024	689,549
2000	37,293,211	20,098,235	23,164,892	162,350	5,253,602	85,972,290	85,000	343,049	1,745,802	88,146,141	690,846
2001	37,641,533	20,159,932	24,157,963	162,350	5,284,431	87,406,209	85,000	508,184	1,835,346	89,834,739	693,284
2002	38,208,516	20,222,586	25,453,261	162,350	5,348,045	89,394,758	85,000	376,496	1,871,364	91,727,618	695,598
2003	38,700,038	20,286,026	26,686,728	162,350	5,397,489	91,232,631	85,000	82,730	1,900,140	93,300,501	697,635
2004	39,150,778	20,347,028	27,933,783	162,350	5,435,013	93,028,952	85,000	81,745	1,938,202	95,133,899	699,696
2005	39,585,697	20,413,685	29,264,867	162,350	5,474,329	94,900,928	85,000	71,055	1,977,548	97,034,531	701,610
2006	39,956,712	20,482,294	30,600,773	162,350	5,513,554	96,715,683	85,000	69,619	2,011,839	98,882,141	703,343
2007	40,279,708	20,524,405	31,890,197	162,350	5,547,538	98,404,198	85,000	49,779	2,044,681	100,583,658	704,990
2008	40,595,304	20,561,477	33,130,423	162,350	5,574,997	100,024,551	85,000	70,492	2,076,640	102,256,683	706,561
2009	40,915,401	20,595,155	34,329,471	162,350	5,597,714	101,600,091	85,000	72,920	2,106,233	103,864,244	707,996
2010	41,223,621	20,627,165	35,403,368	162,350	5,618,147	103,034,651	85,000	69,353	2,135,153	105,324,157	709,326
2011	41,499,074	20,660,817	36,517,587	162,350	5,638,749	104,478,577	85,000	74,301	2,165,933	106,803,811	710,627
2012	41,758,337	20,696,866	37,769,032	162,350	5,659,438	106,046,023	85,000	69,429	2,198,999	108,399,451	711,926
2013	42,006,960	20,717,384	38,778,419	162,350	5,672,337	107,337,450	85,000	72,533	2,219,687	109,714,670	712,938
2014	42,222,470	20,738,386	39,747,867	162,350	5,682,805	108,553,878	85,000	75,235	2,246,388	110,960,501	713,948
2015	42,419,327	20,753,554	40,636,825	162,350	5,690,681	109,662,737	85,000	70,500	2,266,222	112,084,459	714,712
2016	42,555,820	20,772,634	41,560,380	162,350	5,698,166	110,749,350	85,000	63,091	2,291,889	113,189,330	715,527
2017	42,655,079	20,785,566	42,509,727	162,350	5,702,593	111,815,315	85,000	125,699	2,313,236	114,339,250	716,235
2018	42,740,036	20,804,416	43,458,754	162,350	5,707,159	112,872,715	85,000	128,214	2,337,296	115,423,225	716,997
GROWTH RATES											
1998-2003	1.3%	0.4%	-11.4%	0.0%	1.0%	-3.7%	0.0%	-9.3%	-1.3%	-3.7%	-0.1%
1998-2008	1.1%	0.3%	-3.8%	0.0%	0.8%	-1.0%	0.0%	-6.3%	0.2%	-0.9%	0.1%
1998-2018	0.8%	0.2%	-0.6%	0.0%	0.5%	0.1%	0.0%	-0.2%	0.7%	0.1%	0.1%

* The other category includes stree lighting and inter-departmental sales

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST MCF GAS

(DRI Forecast Febru 1998)

CINCINNATI GAS & ELECTRIC COMPANY
GAS CUSTOMERS BY MAJOR CLASSIFICATIONS
ANNUAL AVERAGES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	O.P.A.	TOTAL CUSTOMERS	ANNUAL INCREASE	;AS - MCF RESIDENTIAL ;ISE PER CUSTOMER
1993	306,036	34,236	1,868	6	1,125	343,271	4,528	111
1994	311,132	34,332	1,882	6	1,160	348,512	5,241	109
1995	318,355	34,944	1,795	6	1,211	356,310	7,798	105
1996	324,870	35,536	1,807	10	1,250	363,473	7,163	117
1997	331,979	35,888	1,664	10	1,266	370,806	7,333	104
1998	338,018	36,160	1,869	10	1,282	377,339	6,533	107
1999	344,697	37,088	1,933	10	1,324	385,052	7,713	107
2000	351,530	37,718	1,981	10	1,370	392,609	7,557	106
2001	358,295	38,197	2,035	10	1,408	399,945	7,336	105
2002	365,197	38,718	2,090	10	1,445	407,460	7,515	105
2003	371,754	39,198	2,142	10	1,483	414,587	7,127	104
2004	378,110	39,646	2,195	10	1,520	421,481	6,894	104
2005	384,418	40,085	2,248	10	1,556	428,317	6,836	103
2006	390,180	40,476	2,290	10	1,585	434,541	6,224	102
2007	395,545	40,843	2,330	10	1,612	440,340	5,799	102
2008	400,989	41,212	2,368	10	1,640	446,219	5,879	101
2009	406,625	41,579	2,406	10	1,667	452,287	6,068	101
2010	412,294	41,944	2,443	10	1,692	458,383	6,096	100
2011	417,724	42,282	2,461	10	1,706	464,183	5,800	99
2012	422,928	42,616	2,475	10	1,714	469,743	5,560	99
2013	428,082	42,949	2,487	10	1,724	475,252	5,509	98
2014	433,187	43,257	2,500	10	1,733	480,687	5,435	97
2015	438,225	43,555	2,509	10	1,740	486,039	5,352	97
2016	442,760	43,808	2,499	10	1,734	490,811	4,772	96
2017	446,943	44,039	2,482	10	1,723	495,197	4,386	95
2018	451,154	44,262	2,466	10	1,712	499,604	4,407	95
GROWTH RATE								
1998-2003	1.9%	1.6%	2.8%	0.0%	3.0%	1.9%		-0.6%
1998-2008	1.7%	1.3%	2.4%	0.0%	2.5%	1.7%		-0.6%
1998-2018	2.9%	2.0%	2.8%	0.0%	2.9%	2.8%		-1.2%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

DRI Forecast February 1998)

THE UNION LIGHT, HEAT AND POWER COMPANY
FORECAST OF FIRM GAS SALES AND TRANSPORTATION
MCF - BILLING

	FIRM SALES						FIRM TRANSPORTATION			
	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	O.P.A.	INTER-DEPT.	TOTAL	COMMERCIAL	INDUSTRIAL	O.P.A.	TOTAL
1993	6,889,043	2,499,742	864,566	463,537	5,808	10,722,696	0	0	0	0
1994	6,874,190	2,638,590	876,930	474,771	6,094	10,870,575	0	0	0	0
1995	6,780,659	2,718,144	905,625	458,938	4,206	10,867,572	5,672	23,215	0	28,887
1996	7,712,122	3,123,319	922,872	508,070	2,341	12,268,724	92,370	142,164	4,988	239,522
1997	6,999,278	2,845,632	847,826	479,930	3,200	11,175,866	194,783	354,354	10,741	559,878
1998	7,440,956	3,046,353	734,619	541,503	4,300	11,767,731	94,217	352,820	4,367	451,404
1999	7,513,324	3,083,950	704,091	551,469	4,300	11,857,134	95,380	388,310	4,447	488,137
2000	7,571,797	3,066,481	666,151	555,445	4,300	11,864,174	94,840	446,670	4,479	545,989
2001	7,590,758	3,094,306	618,903	558,209	4,300	11,866,476	95,701	518,858	4,503	619,062
2002	7,665,504	3,121,332	580,102	565,002	4,300	11,936,240	96,537	593,552	4,558	694,647
2003	7,731,492	3,149,331	555,916	570,368	4,300	12,011,407	97,401	654,409	4,599	756,409
2004	7,788,299	3,174,236	546,902	574,362	4,300	12,088,099	98,172	698,800	4,631	801,603
2005	7,841,544	3,205,503	550,735	578,514	4,300	12,180,596	99,141	734,065	4,665	837,871
2006	7,882,138	3,228,728	560,153	582,700	4,300	12,258,019	99,857	761,965	4,698	866,520
2007	7,913,902	3,246,560	572,697	586,333	4,300	12,323,792	100,409	786,423	4,727	891,559
2008	7,944,221	3,262,235	586,734	589,282	4,300	12,386,772	100,894	809,189	4,753	914,836
2009	7,974,780	3,276,678	601,785	591,706	4,300	12,449,249	101,343	831,039	4,773	937,155
2010	8,002,684	3,289,916	614,578	593,887	4,300	12,505,365	101,749	848,704	4,791	955,244
2011	8,023,677	3,304,271	627,431	596,058	4,300	12,555,737	102,193	866,455	4,806	973,454
2012	8,041,753	3,318,657	641,169	598,261	4,300	12,604,140	102,638	885,427	4,826	992,891
2013	8,059,642	3,327,521	653,020	599,675	4,300	12,644,158	102,913	901,794	4,836	1,009,543
2014	8,070,497	3,336,473	663,851	600,781	4,300	12,675,902	103,190	916,745	4,845	1,024,780
2015	8,077,597	3,342,152	674,112	601,639	4,300	12,699,800	103,365	930,914	4,853	1,039,132
2016	8,072,396	3,350,321	683,728	602,406	4,300	12,713,151	103,619	944,194	4,860	1,052,673
2017	8,061,678	3,355,875	694,618	602,917	4,300	12,719,388	103,790	959,235	4,862	1,067,887
2018	8,047,646	3,364,045	705,095	603,373	4,300	12,724,459	104,043	973,703	4,865	1,082,611
GROWTH RATES										
1998-2003	0.8%	0.7%	-5.4%	1.0%	0.0%	0.4%	0.7%	13.2%	1.0%	10.9%
1998-2008	0.7%	0.7%	-2.2%	0.8%	0.0%	0.5%	0.7%	8.7%	0.9%	7.3%
1998-2018	0.8%	1.0%	-0.4%	1.1%	0.0%	0.8%	1.0%	10.7%	1.1%	9.1%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February 1998)

THE UNION LIGHT, HEAT AND POWER COMPANY
FORECAST OF FIRM GAS DELIVERIES
MCF - BILLING

FIRM DELIVERIES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	INTER-DEPT.	O.P.A.	TOTAL RETAIL	COMPANY USE	FIRM LOSSES	TOTAL
1993	6,889,043	2,499,742	864,566	5,808	463,537	10,722,696	9,812	NA	10,732,508
1994	6,874,190	2,638,590	876,930	6,094	474,771	10,870,575	9,821	NA	10,880,396
1995	6,780,659	2,723,816	928,840	4,206	458,938	10,896,459	7,126	NA	10,903,585
1996	7,712,122	3,215,689	1,065,037	2,341	513,058	12,508,246	8,577	NA	12,516,823
1997	6,999,278	3,040,415	1,202,180	3,200	490,671	11,735,744	12,479	NA	11,748,223
1998	7,440,956	3,140,570	1,087,439	4,300	545,870	12,219,135	12,500	234,106	12,465,741
1999	7,513,324	3,179,330	1,092,401	4,300	555,916	12,345,271	12,500	314,883	12,672,654
2000	7,571,797	3,161,321	1,112,821	4,300	559,924	12,410,163	12,500	306,902	12,729,565
2001	7,590,758	3,190,007	1,137,761	4,300	562,712	12,485,538	12,500	316,999	12,815,037
2002	7,665,504	3,217,869	1,173,654	4,300	569,560	12,630,887	12,500	321,067	12,964,454
2003	7,731,492	3,246,732	1,210,325	4,300	574,967	12,767,816	12,500	324,361	13,104,677
2004	7,788,299	3,272,408	1,245,702	4,300	578,993	12,889,702	12,500	327,538	13,229,740
2005	7,841,544	3,304,644	1,284,800	4,300	583,179	13,018,467	12,500	331,210	13,362,177
2006	7,882,138	3,328,585	1,322,118	4,300	587,398	13,124,539	12,500	333,285	13,470,324
2007	7,913,902	3,346,969	1,359,120	4,300	591,060	13,215,351	12,500	335,669	13,563,520
2008	7,944,221	3,363,129	1,395,923	4,300	594,035	13,301,608	12,500	337,068	13,651,176
2009	7,974,780	3,378,021	1,432,824	4,300	596,479	13,386,404	12,500	339,660	13,738,564
2010	8,002,684	3,391,665	1,463,282	4,300	598,678	13,460,609	12,500	341,327	13,814,436
2011	8,023,677	3,406,464	1,493,886	4,300	600,864	13,529,191	12,500	343,281	13,884,972
2012	8,041,753	3,421,295	1,526,596	4,300	603,087	13,597,031	12,500	345,507	13,955,038
2013	8,059,642	3,430,434	1,554,814	4,300	604,511	13,653,701	12,500	346,198	14,012,399
2014	8,070,497	3,439,663	1,580,596	4,300	605,626	13,700,682	12,500	347,482	14,060,664
2015	8,077,597	3,445,517	1,605,026	4,300	606,492	13,738,932	12,500	348,082	14,099,514
2016	8,072,396	3,453,940	1,627,922	4,300	607,266	13,765,824	12,500	349,120	14,127,444
2017	8,061,678	3,459,665	1,653,853	4,300	607,779	13,787,275	12,500	349,185	14,148,960
2018	8,047,646	3,468,088	1,678,798	4,300	608,238	13,807,070	12,500	349,714	14,169,284
GROWTH RATES									
1998-2003	0.8%	0.7%	2.2%	0.0%	1.0%	0.9%	0.0%	6.7%	1.0%
1998-2008	0.7%	0.7%	2.5%	0.0%	0.8%	0.9%	0.0%	3.7%	0.9%
1998-2018	0.8%	1.0%	4.4%	0.0%	1.1%	1.2%	0.0%	4.1%	1.3%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February 1998)

THE UNION LIGHT, HEAT AND POWER COMPANY
FORECAST OF INTERRUPTIBLE GAS DELIVERIES
MCF - BILLING

	INTERRUPTIBLE DELIVERIES					
	COMMERCIAL	INDUSTRIAL	O.P.A.	TOTAL RETAIL	INTERRUPTIBLE LOSSES	TOTAL
1993	265,029	2,167,859	0	2,432,888	NA	2,432,888
1994	280,495	2,219,108	40,994	2,540,597	NA	2,540,597
1995	229,627	2,505,463	86,734	2,821,824	NA	2,821,824
1996	264,246	2,647,458	82,073	2,993,777	NA	2,993,777
1997	294,189	3,090,766	79,634	3,464,589	NA	3,464,589
1998	306,941	2,860,330	50,385	3,217,656	109,170	3,326,826
1999	335,940	2,847,800	51,245	3,234,985	116,000	3,350,985
2000	345,725	2,945,283	51,475	3,342,483	119,099	3,461,582
2001	362,448	3,092,348	51,848	3,506,644	126,464	3,633,108
2002	376,958	3,261,310	52,460	3,690,728	133,481	3,824,209
2003	392,025	3,414,291	52,926	3,859,242	136,991	3,996,233
2004	405,720	3,566,489	53,290	4,025,499	143,029	4,168,528
2005	423,890	3,727,757	53,676	4,205,323	147,961	4,353,284
2006	436,905	3,895,369	54,055	4,386,329	153,094	4,539,423
2007	447,307	4,058,146	54,379	4,559,832	157,933	4,717,765
2008	456,374	4,211,660	54,645	4,722,679	163,428	4,886,107
2009	464,908	4,362,469	54,866	4,882,243	166,896	5,049,139
2010	472,626	4,480,813	55,062	5,008,501	170,632	5,179,133
2011	481,244	4,610,363	55,265	5,146,872	174,842	5,321,714
2012	489,762	4,772,185	55,465	5,317,412	179,935	5,497,347
2013	495,066	4,881,378	55,585	5,432,029	182,598	5,614,627
2014	500,293	4,984,149	55,688	5,540,130	185,693	5,725,823
2015	503,378	5,054,713	55,761	5,613,852	187,299	5,801,151
2016	508,031	5,143,853	55,837	5,707,721	190,631	5,898,352
2017	511,265	5,222,048	55,874	5,789,187	193,122	5,982,309
2018	516,099	5,306,788	55,923	5,878,810	195,867	6,074,677
GROWTH RATES						
1998-2003	5.0%	3.6%	1.0%	3.7%	4.6%	3.7%
1998-2008	4.0%	3.9%	0.8%	3.9%	4.1%	3.9%
1998-2018	5.3%	6.4%	1.0%	6.2%	6.0%	6.2%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

THE UNION LIGHT, HEAT AND POWER COMPANY
FORECAST OF GAS SENDOUT AND PEAK DEMAND
MCF - BILLING

TOTAL DELIVERIES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	INTER-DEPT.	O.P.A.	TOTAL RETAIL	COMPANY USE	TOTAL LOSSES	SENDOUT	SEASONAL PEAK
1993	6,889,043	2,764,771	3,032,425	5,808	463,537	13,155,584	9,812	681,844	1[illegible],847,24[illegible]	139,784
1994	6,874,190	2,919,085	3,096,038	6,094	515,765	13,411,172	9,821	79,429	1[illegible],500,42[illegible]	118,954
1995	6,780,659	2,953,443	3,434,303	4,206	545,672	13,718,283	7,126	917,613	1[illegible],643,02[illegible]	132,035
1996	7,712,122	3,479,935	3,712,495	2,341	595,131	15,502,024	8,577	243,133	1[illegible],753,73[illegible]	129,491
1997	6,999,278	3,334,604	4,292,945	3,200	570,305	15,200,332	12,479	164,754	1[illegible],377,56[illegible]	111,129
1998	7,440,956	3,447,511	3,947,769	4,300	596,255	15,436,791	12,500	343,276	1[illegible],792,56[illegible]	124,790
1999	7,513,324	3,515,270	3,940,201	4,300	607,161	15,580,256	12,500	430,883	1[illegible],023,63[illegible]	124,972
2000	7,571,797	3,507,046	4,058,104	4,300	611,399	15,752,646	12,500	426,001	1[illegible],191,14[illegible]	125,123
2001	7,590,758	3,552,455	4,230,109	4,300	614,560	15,992,182	12,500	443,463	1[illegible],448,14[illegible]	125,375
2002	7,665,504	3,594,827	4,434,964	4,300	622,020	16,321,615	12,500	454,548	1[illegible],788,66[illegible]	125,635
2003	7,731,492	3,638,757	4,624,616	4,300	627,893	16,627,058	12,500	461,352	1[illegible],100,91[illegible]	125,849
2004	7,788,299	3,678,128	4,812,191	4,300	632,283	16,915,201	12,500	470,567	17,398,26[illegible]	126,076
2005	7,841,544	3,728,534	5,012,557	4,300	636,855	17,223,790	12,500	479,171	17,715,46[illegible]	126,277
2006	7,882,138	3,765,490	5,217,487	4,300	641,453	17,510,868	12,500	486,379	18,009,74[illegible]	126,454
2007	7,913,902	3,794,276	5,417,266	4,300	645,439	17,775,183	12,500	493,602	18,281,28[illegible]	126,616
2008	7,944,221	3,819,503	5,607,583	4,300	648,680	18,024,287	12,500	500,496	18,537,28[illegible]	126,782
2009	7,974,780	3,842,929	5,795,293	4,300	651,345	18,268,647	12,500	506,556	18,787,70[illegible]	126,918
2010	8,002,684	3,864,291	5,944,095	4,300	653,740	18,469,110	12,500	511,959	18,993,56[illegible]	127,044
2011	8,023,677	3,887,708	6,104,249	4,300	656,129	18,676,063	12,500	518,123	19,206,68[illegible]	127,173
2012	8,041,753	3,911,057	6,298,781	4,300	658,552	18,914,443	12,500	525,442	19,452,38[illegible]	127,290
2013	8,059,642	3,925,500	6,436,192	4,300	660,096	19,085,730	12,500	528,796	19,627,02[illegible]	127,380
2014	8,070,497	3,939,956	6,564,745	4,300	661,314	19,240,812	12,500	533,175	19,786,48[illegible]	127,455
2015	8,077,597	3,948,895	6,659,739	4,300	662,253	19,352,784	12,500	535,381	19,900,66[illegible]	127,510
2016	8,072,396	3,961,971	6,771,775	4,300	663,103	19,473,545	12,500	539,751	20,025,79[illegible]	127,560
2017	8,061,678	3,970,930	6,875,901	4,300	663,653	19,576,462	12,500	542,307	20,131,26[illegible]	127,608
2018	8,047,646	3,984,187	6,985,586	4,300	664,161	19,685,880	12,500	545,581	20,243,96[illegible]	127,656
GROWTH RATES										
1998-2003	0.8%	1.1%	3.2%	0.0%	1.0%	1.5%	0.0%	6.1%	1.6%	0.2%
1998-2008	0.7%	1.0%	3.6%	0.0%	0.8%	1.6%	0.0%	3.8%	1.6%	0.2%
1998-2018	0.8%	1.5%	5.9%	0.0%	1.1%	2.5%	0.0%	4.7%	2.5%	0.2%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

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(DRI Forecast February 1998)

UNION LIGHT, HEAT AND POWER COMPANY
GAS CUSTOMERS BY MAJOR CLASSIFICATIONS
ANNUAL AVERAGES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	O.P.A.	TOTAL CUSTOMERS	ANNUAL INCREASE	GAS - MCF RESIDENTIAL USE PER CUSTOMER
1993	62,997	5,583	279	295	69,154	1,171	109
1994	64,202	5,696	269	303	70,470	1,316	107
1995	66,058	5,832	274	313	72,477	2,007	103
1996	67,893	5,960	280	328	74,461	1,984	114
1997	70,081	6,086	279	326	76,772	2,311	100
1998	72,034	5,980	289	343	78,646	1,874	103
1999	73,442	6,133	299	354	80,228	1,582	102
2000	74,883	6,237	306	367	81,793	1,565	101
2001	76,309	6,317	314	377	83,317	1,524	99
2002	77,763	6,403	323	387	84,876	1,559	99
2003	79,146	6,482	331	397	86,356	1,480	98
2004	80,485	6,556	339	407	87,787	1,431	97
2005	81,815	6,629	347	417	89,208	1,421	96
2006	83,030	6,694	354	425	90,503	1,295	95
2007	84,160	6,754	360	432	91,706	1,203	94
2008	85,308	6,815	366	439	92,928	1,222	93
2009	86,496	6,876	372	446	94,190	1,262	92
2010	87,690	6,936	377	453	95,456	1,266	91
2011	88,835	6,992	380	457	96,664	1,208	90
2012	89,932	7,047	382	459	97,820	1,156	89
2013	91,019	7,102	384	461	98,966	1,146	89
2014	92,094	7,153	386	464	100,097	1,131	88
2015	93,156	7,203	387	466	101,212	1,115	87
2016	94,112	7,244	386	464	102,206	994	86
2017	94,994	7,282	383	462	103,121	915	85
2018	95,882	7,320	381	459	104,042	921	84
GROWTH RATE							
1998-2003	1.9%	1.6%	2.8%	3.0%	1.9%		-.1%
1998-2008	1.7%	1.3%	2.4%	2.5%	1.7%		-.0%
1998-2018	2.9%	2.0%	2.8%	3.0%	2.8%		-.1%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February 1998)

LAWRENCEBURG GAS COMPANY
FORECAST OF FIRM GAS SALES
MCF - BILLING

FIRM SALES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	O.P.A.	WHOLE-SALE	TOTAL
1993	460,261	150,521	153,986	51,215	306,947	1,122,930
1994	461,208	167,606	120,130	50,469	296,395	1,095,808
1995	462,967	168,085	124,995	48,208	279,204	1,083,459
1996	517,005	177,018	136,738	65,620	352,245	1,248,626
1997	477,924	192,454	132,285	63,753	349,321	1,215,737
1998	496,160	161,257	108,360	61,149	354,504	1,181,430
1999	498,585	162,646	101,745	62,274	353,379	1,178,629
2000	499,320	161,484	98,991	62,723	353,205	1,175,723
2001	503,629	162,072	96,695	63,035	355,031	1,180,462
2002	508,461	163,012	96,340	63,803	357,173	1,188,789
2003	513,155	163,854	97,243	64,411	359,250	1,197,913
2004	518,266	164,571	98,429	64,859	361,498	1,207,623
2005	523,651	165,426	99,717	65,329	363,907	1,218,030
2006	528,706	166,139	100,521	65,801	366,139	1,227,306
2007	533,444	166,681	101,084	66,210	368,202	1,235,621
2008	538,350	167,121	101,594	66,545	370,315	1,243,925
2009	543,602	167,488	102,094	66,819	372,570	1,252,573
2010	549,195	167,801	102,064	67,065	374,964	1,261,089
2011	554,677	168,162	102,059	67,312	377,322	1,269,532
2012	560,357	168,619	101,369	67,558	379,791	1,277,694
2013	565,810	168,861	100,169	67,717	382,113	1,284,670
2014	571,498	169,061	99,096	67,844	384,538	1,292,037
2015	577,114	169,141	97,965	67,939	386,900	1,299,059
2016	582,431	169,325	96,864	68,025	389,166	1,305,811
2017	587,325	169,403	95,729	68,085	391,235	1,311,777
2018	592,495	169,558	94,772	68,135	393,435	1,318,395
GROWTH RATES						
1998-2003	0.7%	0.3%	-2.1%	1.0%	0.3%	0.3%
1998-2008	0.8%	0.4%	-0.6%	0.8%	0.4%	0.5%
1998-2018	1.8%	0.5%	-1.3%	1.1%	1.0%	1.1%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February 1998)

LAWRENCEBURG GAS COMPANY
FORECAST OF FIRM GAS DELIVERIES
MCF - BILLING

FIRM DELIVERIES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	O.P.A.	TOTAL RETAIL	WHOLE-SALE	COMPANY USE	FIRM LOSSES	TOTAL
1993	460,261	150,521	153,986	51,215	815,983	306,947	1,329	NA	1,124,259
1994	461,208	167,606	120,130	50,469	799,413	296,395	2,028	NA	1,097,836
1995	462,967	168,085	124,995	48,208	804,255	279,204	519	NA	1,083,978
1996	517,005	177,018	136,738	65,620	896,381	352,245	950	NA	1,249,576
1997	477,924	192,454	132,285	63,753	866,416	349,321	1,202	NA	1,216,939
1998	496,160	161,257	108,360	61,149	826,926	354,504	1,200	33,378	1,216,008
1999	498,585	162,646	101,745	62,274	825,250	353,379	1,200	40,740	1,220,569
2000	499,320	161,484	98,991	62,723	822,518	353,205	1,200	40,108	1,217,031
2001	503,629	162,072	96,695	63,035	825,431	355,031	1,200	40,907	1,222,569
2002	508,461	163,012	96,340	63,803	831,616	357,173	1,200	41,144	1,231,133
2003	513,155	163,854	97,243	64,411	838,663	359,250	1,200	41,428	1,240,541
2004	518,266	164,571	98,429	64,859	846,125	361,498	1,200	41,751	1,250,574
2005	523,651	165,426	99,717	65,329	854,123	363,907	1,200	42,155	1,261,385
2006	528,706	166,139	100,521	65,801	861,167	366,139	1,200	42,443	1,270,949
2007	533,444	166,681	101,084	66,210	867,419	368,202	1,200	42,715	1,279,536
2008	538,350	167,121	101,594	66,545	873,610	370,315	1,200	42,926	1,288,051
2009	543,602	167,488	102,094	66,819	880,003	372,570	1,200	43,295	1,297,068
2010	549,195	167,801	102,064	67,065	886,125	374,964	1,200	43,611	1,305,900
2011	554,677	168,162	102,059	67,312	892,210	377,322	1,200	43,902	1,314,634
2012	560,357	168,619	101,369	67,558	897,903	379,791	1,200	44,223	1,323,117
2013	565,810	168,861	100,169	67,717	902,557	382,113	1,200	44,459	1,330,329
2014	571,498	169,061	99,096	67,844	907,499	384,538	1,200	44,743	1,337,980
2015	577,114	169,141	97,965	67,939	912,159	386,900	1,200	44,994	1,345,253
2016	582,431	169,325	96,864	68,025	916,645	389,166	1,200	45,270	1,352,281
2017	587,325	169,403	95,729	68,085	920,542	391,235	1,200	45,455	1,358,432
2018	592,495	169,558	94,772	68,135	924,960	393,435	1,200	45,731	1,365,326
GROWTH RATES									
1998-2003	0.7%	0.3%	-2.1%	1.0%	0.3%	0.3%	0.0%	4.4%	0.4%
1998-2008	0.8%	0.4%	-0.6%	0.8%	0.6%	0.4%	0.0%	2.5%	0.6%
1998-2018	1.8%	0.5%	-1.3%	1.1%	1.1%	1.0%	0.0%	3.2%	1.2%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

GA-82

(DRI Forecast February 1998)

LAWRENCEBURG GAS COMPANY
FORECAST OF INTERRUPTIBLE GAS DELIVERIES
MCF - BILLING

	INTERRUPTIBLE DELIVERIES				
	INDUSTRIAL	O.P.A.	TOTAL RETAIL	INTERRUPTIBLE LOSSES	TOTAL
1993	664,247	28,125	692,372	NA	692,372
1994	707,505	26,665	734,170	NA	734,170
1995	798,663	23,457	822,120	NA	822,120
1996	798,827	21,806	820,633	NA	820,633
1997	698,212	21,236	719,448	NA	719,448
1998	820,289	40,652	860,941	29,864	890,805
1999	809,028	41,348	850,376	33,009	883,385
2000	820,755	41,532	862,287	33,267	895,554
2001	845,498	41,832	887,330	34,492	921,822
2002	866,627	42,325	908,952	35,391	944,343
2003	883,492	42,702	926,194	36,020	962,214
2004	900,131	42,996	943,127	36,744	979,871
2005	918,303	43,308	961,611	37,424	999,035
2006	935,805	43,614	979,419	38,108	1,017,527
2007	952,582	43,876	996,458	38,762	1,035,220
2008	968,680	44,089	1,012,769	39,461	1,052,230
2009	983,926	44,266	1,028,192	39,937	1,068,129
2010	990,503	44,427	1,034,930	40,207	1,075,137
2011	999,215	44,590	1,043,805	40,549	1,084,354
2012	1,013,320	44,753	1,058,073	41,072	1,099,145
2013	1,017,388	44,847	1,062,235	41,223	1,103,458
2014	1,020,666	44,931	1,065,597	41,364	1,106,961
2015	1,020,722	44,989	1,065,711	41,365	1,107,076
2016	1,024,008	45,050	1,069,058	41,494	1,110,552
2017	1,025,271	45,082	1,070,353	41,577	1,111,930
2018	1,028,489	45,122	1,073,611	41,683	1,115,294
GROWTH RATES					
1998-2003	1.5%	1.0%	1.5%	3.8%	1.6%
1998-2008	1.7%	0.8%	1.6%	2.8%	1.7%
1998-2018	2.3%	1.0%	2.2%	3.4%	2.3%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

(DRI Forecast February 1998)

LAWRENCEBURG GAS COMPANY
FORECAST OF GAS SENDOUT AND PEAK DEMAND
MCF - BILLING

TOTAL DELIVERIES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	O.P.A.	TOTAL RETAIL	WHOLE-SALE	COMPANY USE	TOTAL LOSSES	SENDOUT	SEASONAL PEAK
1993	460,261	150,521	818,233	79,340	1,508,355	306,947	1,329	47,025	1,863,656	13,835
1994	461,208	167,606	827,635	77,134	1,533,583	296,395	2,028	45,638	1,877,644	13,074
1995	462,967	168,085	923,658	71,665	1,626,375	279,204	519	115,259	2,021,357	13,376
1996	517,005	177,018	935,565	87,426	1,717,014	352,245	950	28,211	2,098,420	15,046
1997	477,924	192,454	830,497	84,989	1,585,864	349,321	1,202	38,276	1,974,663	12,100
1998	496,160	161,257	928,649	101,801	1,687,867	354,504	1,200	63,242	2,106,813	13,565
1999	498,585	162,646	910,773	103,622	1,675,626	353,379	1,200	73,749	2,103,954	13,600
2000	499,320	161,484	919,746	104,255	1,684,805	353,205	1,200	73,375	2,112,585	13,774
2001	503,629	162,072	942,193	104,867	1,712,761	355,031	1,200	75,399	2,144,391	13,979
2002	508,461	163,012	962,967	106,128	1,740,568	357,173	1,200	76,535	2,175,476	14,179
2003	513,155	163,854	980,735	107,113	1,764,857	359,250	1,200	77,448	2,202,755	14,359
2004	518,266	164,571	998,560	107,855	1,789,252	361,498	1,200	78,495	2,230,445	14,557
2005	523,651	165,426	1,018,020	108,637	1,815,734	363,907	1,200	79,579	2,260,420	14,739
2006	528,706	166,139	1,036,326	109,415	1,840,586	366,139	1,200	80,551	2,288,476	14,912
2007	533,444	166,681	1,053,666	110,086	1,863,877	368,202	1,200	81,477	2,314,756	15,075
2008	538,350	167,121	1,070,274	110,634	1,886,379	370,315	1,200	82,387	2,340,281	15,254
2009	543,602	167,488	1,086,020	111,085	1,908,195	372,570	1,200	83,232	2,365,197	15,390
2010	549,195	167,801	1,092,567	111,492	1,921,055	374,964	1,200	83,818	2,381,037	15,518
2011	554,677	168,162	1,101,274	111,902	1,936,015	377,322	1,200	84,451	2,398,988	15,666
2012	560,357	168,619	1,114,689	112,311	1,955,976	379,791	1,200	85,295	2,422,262	15,791
2013	565,810	168,861	1,117,557	112,564	1,964,792	382,113	1,200	85,682	2,433,787	15,887
2014	571,498	169,061	1,119,762	112,775	1,973,096	384,538	1,200	86,107	2,444,941	15,977
2015	577,114	169,141	1,118,687	112,928	1,977,870	386,900	1,200	86,359	2,452,329	16,061
2016	582,431	169,325	1,120,872	113,075	1,985,703	389,166	1,200	86,764	2,462,833	16,135
2017	587,325	169,403	1,121,000	113,167	1,990,895	391,235	1,200	87,032	2,470,362	16,220
2018	592,495	169,558	1,123,261	113,257	1,998,571	393,435	1,200	87,414	2,480,620	16,304
GROWTH RATES										
1998-2003	0.7%	0.3%	1.1%	1.0%	0.9%	0.3%	0.0%	4.1%	0.9%	1.1%
1998-2008	0.8%	0.4%	1.4%	0.8%	1.1%	0.4%	0.0%	2.7%	1.1%	1.2%
1998-2018	1.8%	0.5%	1.9%	1.1%	1.7%	1.0%	0.0%	3.3%	1.6%	1.9%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST

GA-84

(DRI Forecast February [illegible])

GA-85

LAWRENCEBURG GAS COMPANY

GAS CUSTOMERS BY MAJOR CLASSIFICATIONS
ANNUAL AVERAGES

	TOTAL RESIDENTIAL	COMMERCIAL	INDUSTRIAL	O.P.A.	WHOLE-SALE	TOTAL CUSTOMERS	ANNUAL INCREASE	GAS - MCF RESIDENTIAL USE PER CUSTOMER
1993	4,461	528	29	46	1	5,065	162	103
1994	4,619	545	26	50	1	5,241	176	100
1995	4,752	559	26	55	1	5,393	152	97
1996	4,909	569	28	60	1	5,567	174	105
1997	5,038	589	27	63	1	5,718	151	95
1998	5,179	572	29	57	1	5,838	121	96
1999	5,277	587	29	59	1	5,953	115	94
2000	5,378	597	30	61	1	6,067	114	93
2001	5,477	605	31	63	1	6,177	110	92
2002	5,579	613	32	64	1	6,289	112	91
2003	5,675	621	33	66	1	6,396	107	90
2004	5,768	628	33	68	1	6,498	102	90
2005	5,861	635	34	69	1	6,600	102	89
2006	5,946	641	35	71	1	6,694	94	89
2007	6,025	647	35	72	1	6,780	86	89
2008	6,105	652	36	73	1	6,867	87	88
2009	6,188	658	37	74	1	6,958	91	88
2010	6,271	664	37	76	1	7,049	91	88
2011	6,351	669	37	76	1	7,134	85	87
2012	6,428	675	38	77	1	7,219	85	87
2013	6,503	680	38	77	1	7,299	80	87
2014	6,578	685	38	77	1	7,379	80	87
2015	6,652	689	38	78	1	7,458	79	87
2016	6,719	693	38	77	1	7,528	70	87
2017	6,781	697	38	77	1	7,594	66	87
2018	6,843	701	38	76	1	7,659	65	87
GROWTH RATE								
1998-2003	1.8%	1.7%	2.6%	3.0%	0.0%	1.8%		-1.1%
1998-2008	1.7%	1.3%	2.2%	2.5%	0.0%	1.6%		-0.8%
1998-2018	1.4%	1.0%	1.4%	1.4%	0.0%	1.4%		-0.5%

NOTE: 1998 FIGURES REPRESENT TWELVE MONTHS FORECAST OF CUSTOMERS

(DRI Forecast February 1998)

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Supply-Side Screening Curves

The following pages contain the screening curves and associated data discussed in Chapter 5 of this filing. Because the specific technologies within each class were adjusted using the EPRI TAG-Supply™ software to reflect representative capital, labor, and fuel costs for Cinergy's service territory, the adjusted technologies were saved under different names than those utilized for the baseline case for each technology in TAG-Supply™. For example, technology 4001.1A with the name Adj. 1.1A in Figure GA-5-1 corresponds to technology 1.1A from TAG-Supply™ listed in Figure 5-6.

The EPRI TAG-Supply™ is licensed material that is a trade secret and is proprietary and confidential to EPRI. The redacted information will be made available to appropriate parties upon execution of an appropriate confidentiality agreement or protective order. Please contact Diane Jenner at (317) 838-2183 for more information.

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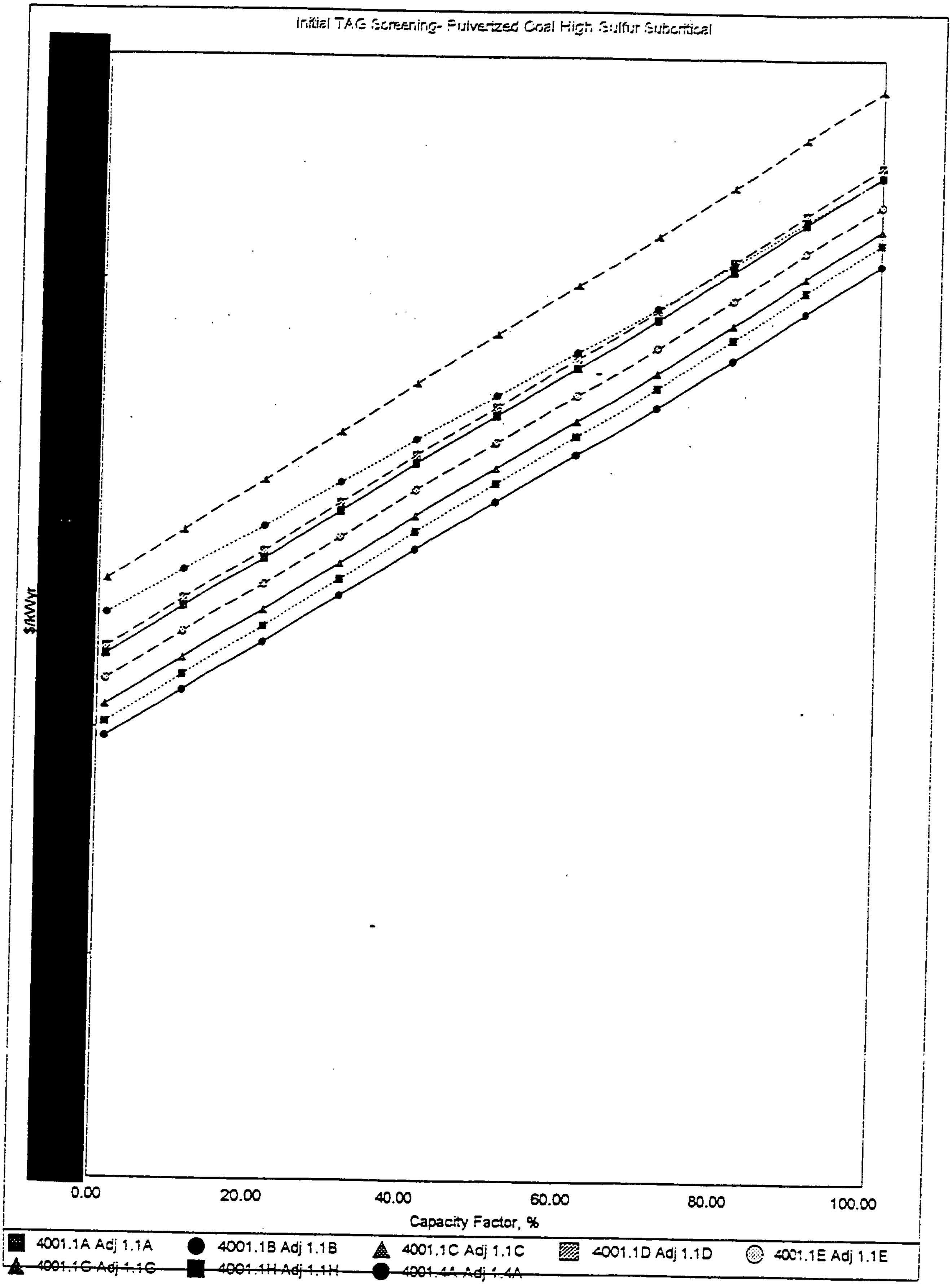

Initial TAG Screening- Pulverized Coal High Sulfur Subcritical
$/kWyr
[redacted]
0.00
20.00
40.00
60.00
80.00
100.00
Capacity Factor, %
4001.1A Adj 1.1A
4001.1B Adj 1.1B
4001.1C Adj 1.1C
4001.1D Adj 1.1D
4001.1E Adj 1.1E
4001.1G Adj 1.1G
4001.1H Adj 1.1H
4001.4A Adj 1.4A

Figure GA-5-2

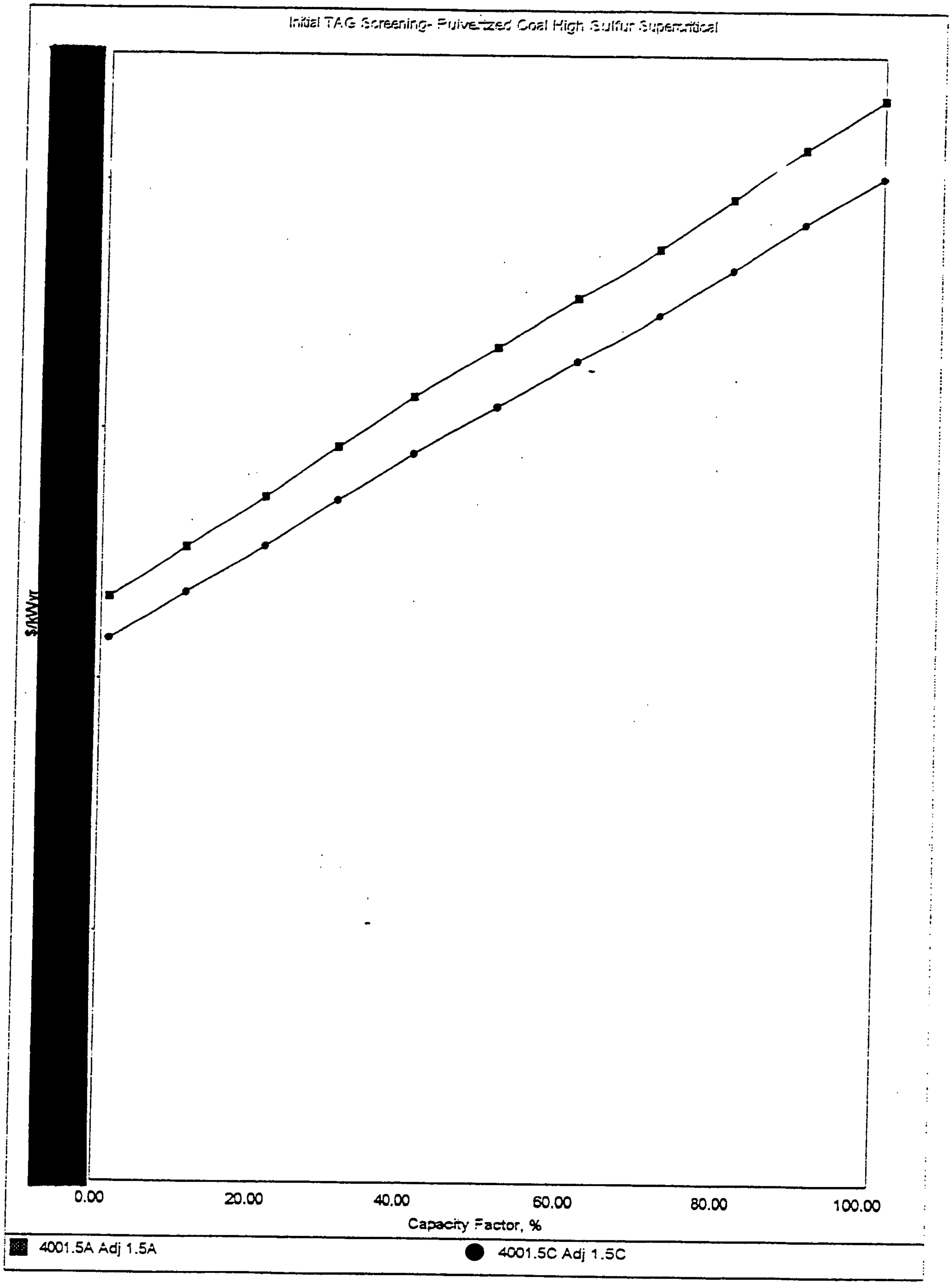

Initial TAG Screening- Pulverized Coal High Sulfur Supercritical
$/kWyr
[redacted]
0.00
20.00
40.00
60.00
80.00
100.00
Capacity Factor, %
4001.5A Adj 1.5A
4001.5C Adj 1.5C

Figure GA-5-3

CONFIDENTIAL

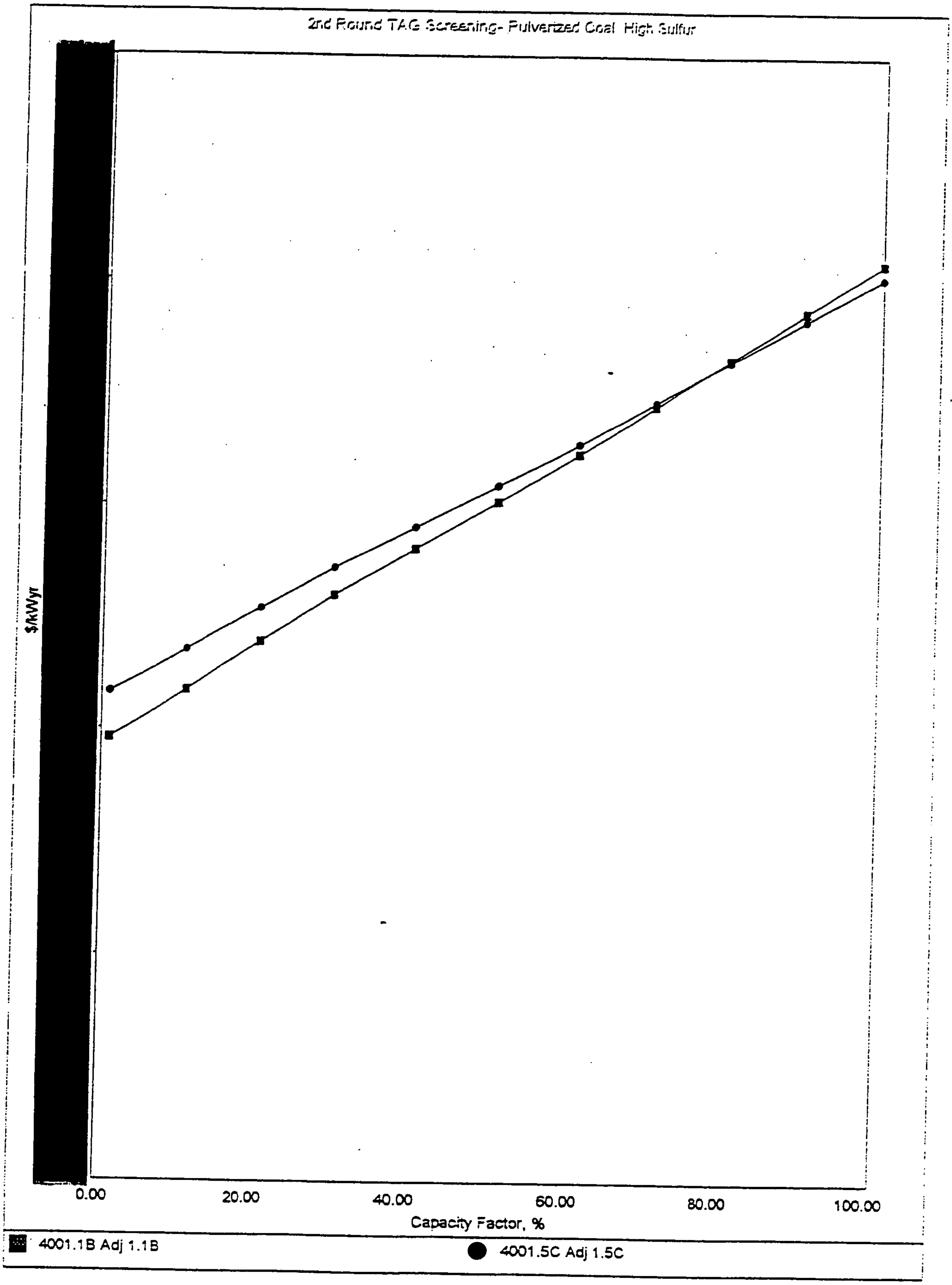
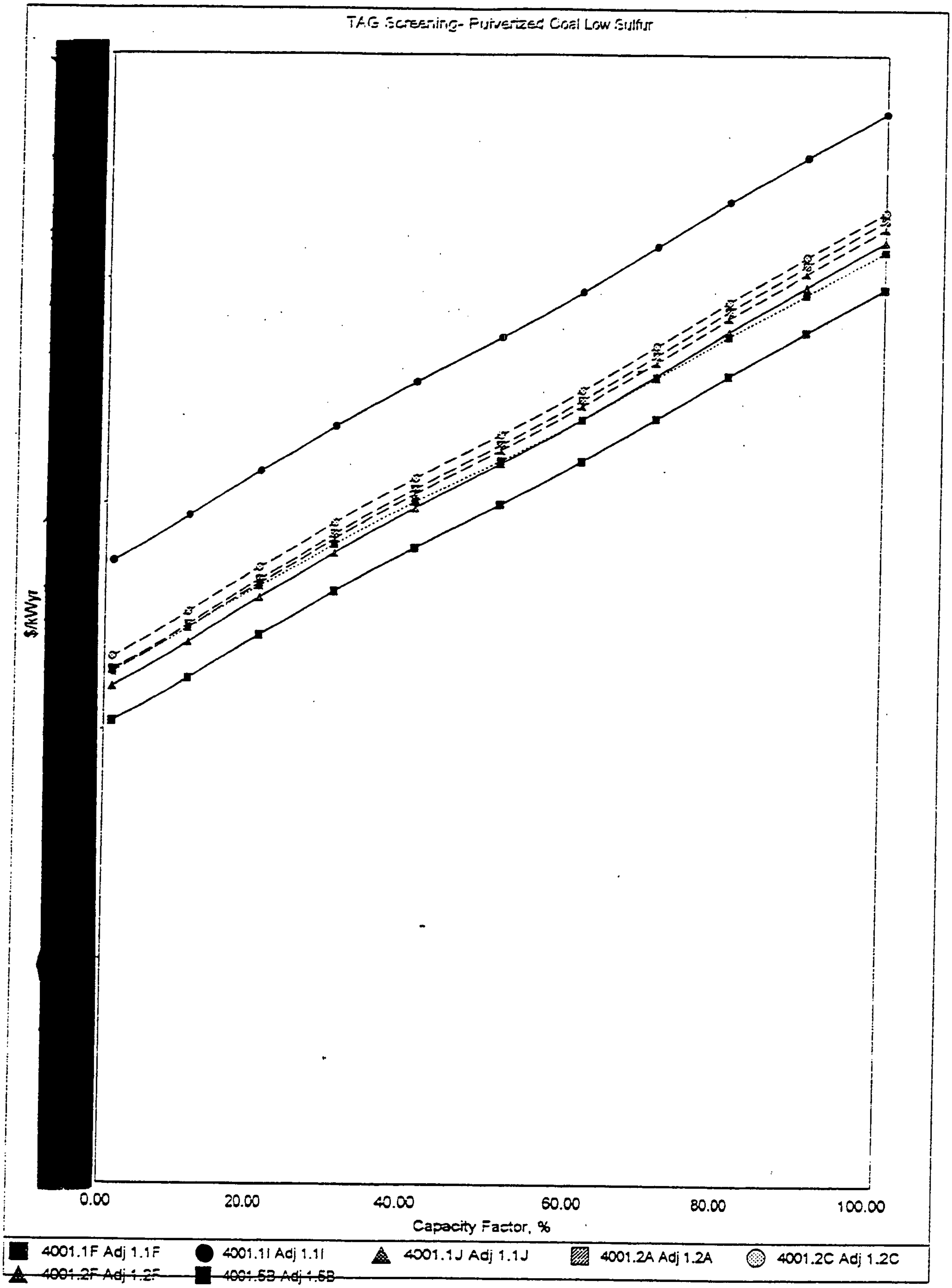
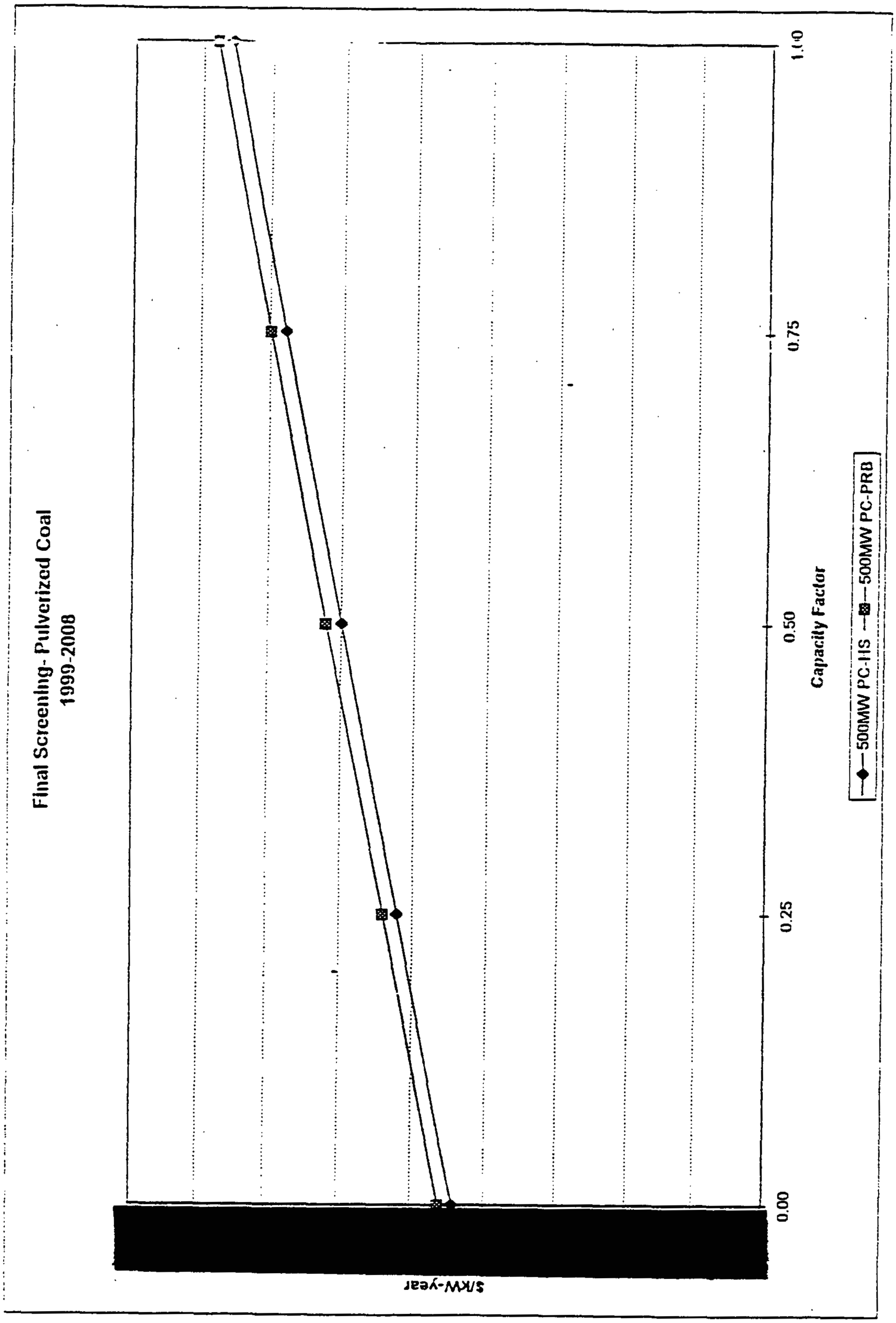
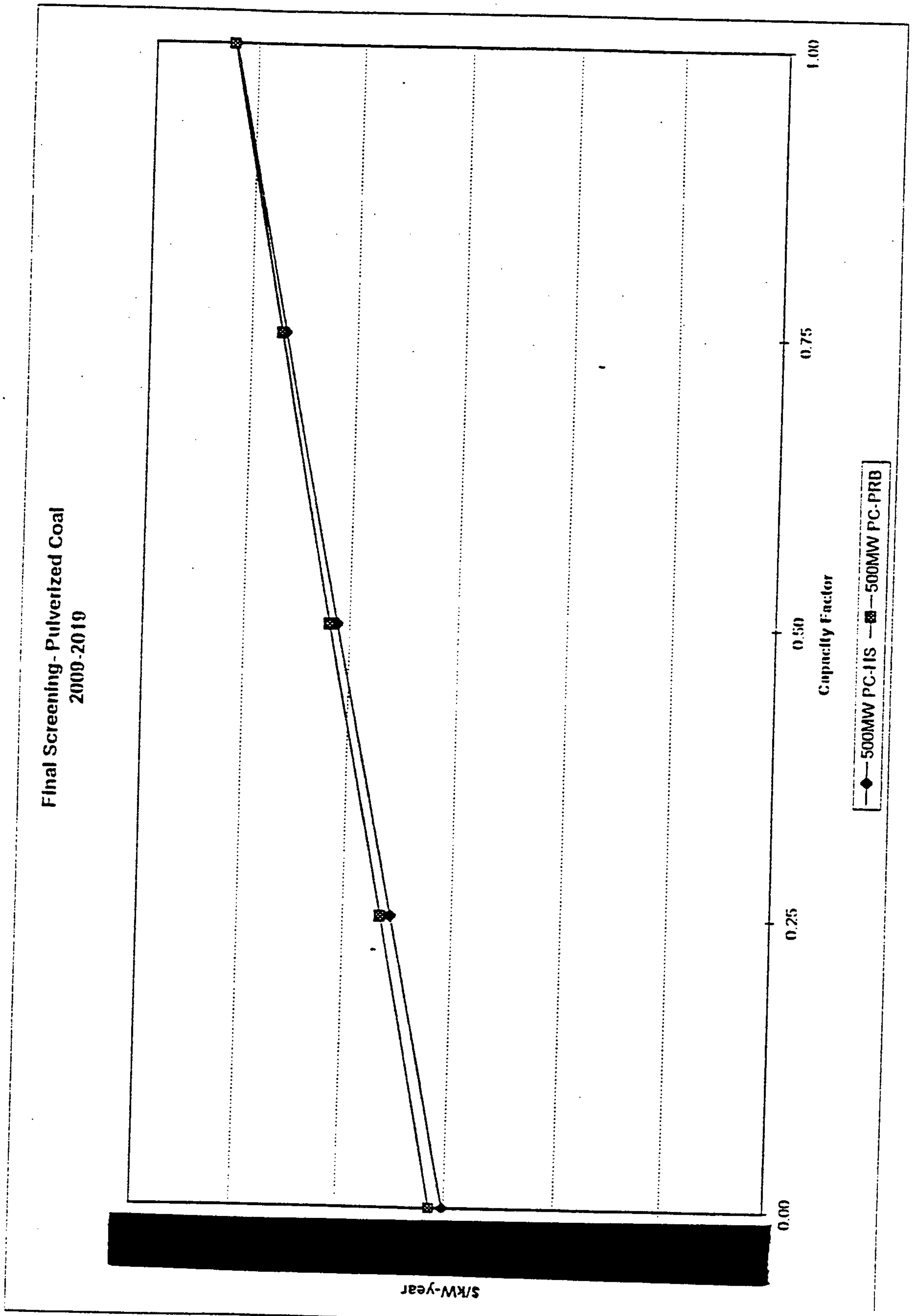


Figure GA-5-4

CONFIDENTIAL




Final Screening- Pulverized Coal
1999-2008
$/KW-year
[redacted]
0.00
0.25
0.50
0.75
1.00
Capacity Factor
500MW PC-HS
500MW PC-PRB


Final Screening- Pulverized Coal
2009-2019
$/KW-year
[redacted]
0.00
0.25
0.50
0.75
1.00
Capacity Factor
500MW PC-HS
500MW PC-PRB

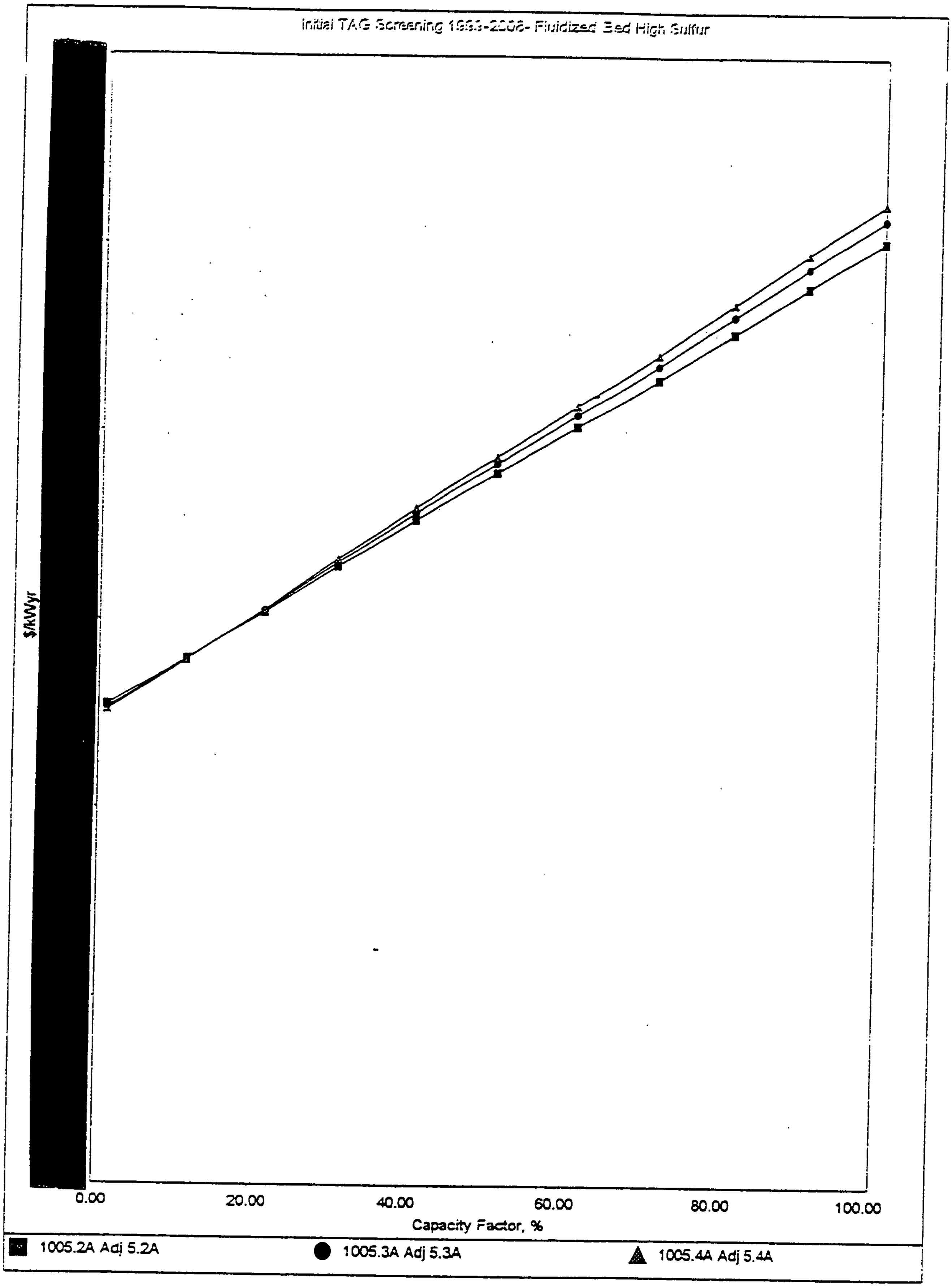

Initial TAG Screening 1993-2008- Fluidized Bed High Sulfur
$/kW/yr
[redacted]
0.00
20.00
40.00
60.00
80.00
100.00
Capacity Factor, %
1005.2A Adj 5.2A
1005.3A Adj 5.3A
1005.4A Adj 5.4A

Figure GA-5-8

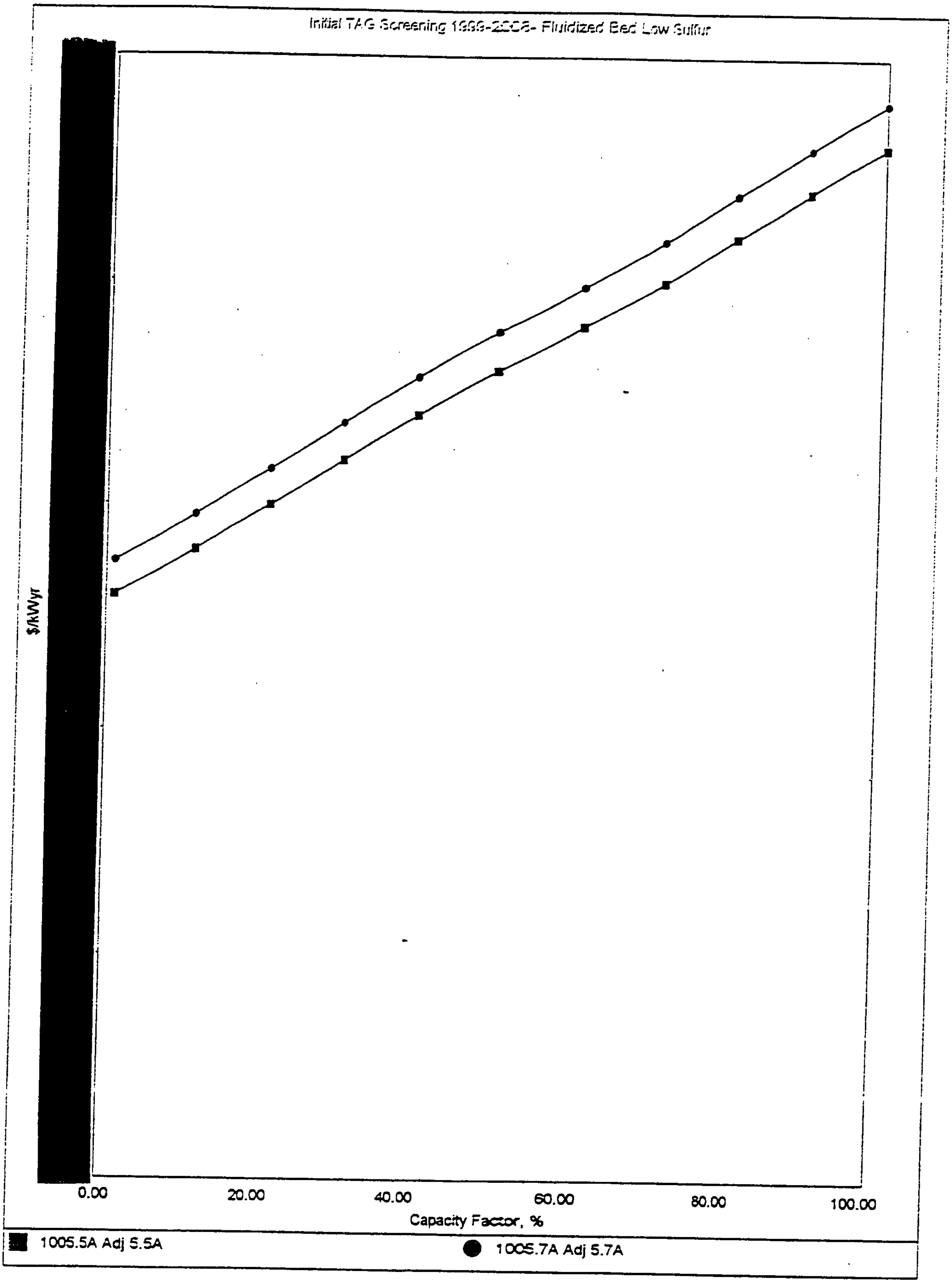

Initial TAG Screening 1999-2008- Fluidized Bed Low Sulfur
$/kWyr
[redacted]
0.00
20.00
40.00
60.00
80.00
100.00
Capacity Factor, %
1005.5A Adj 5.5A
1005.7A Adj 5.7A

Figure GA-5-9

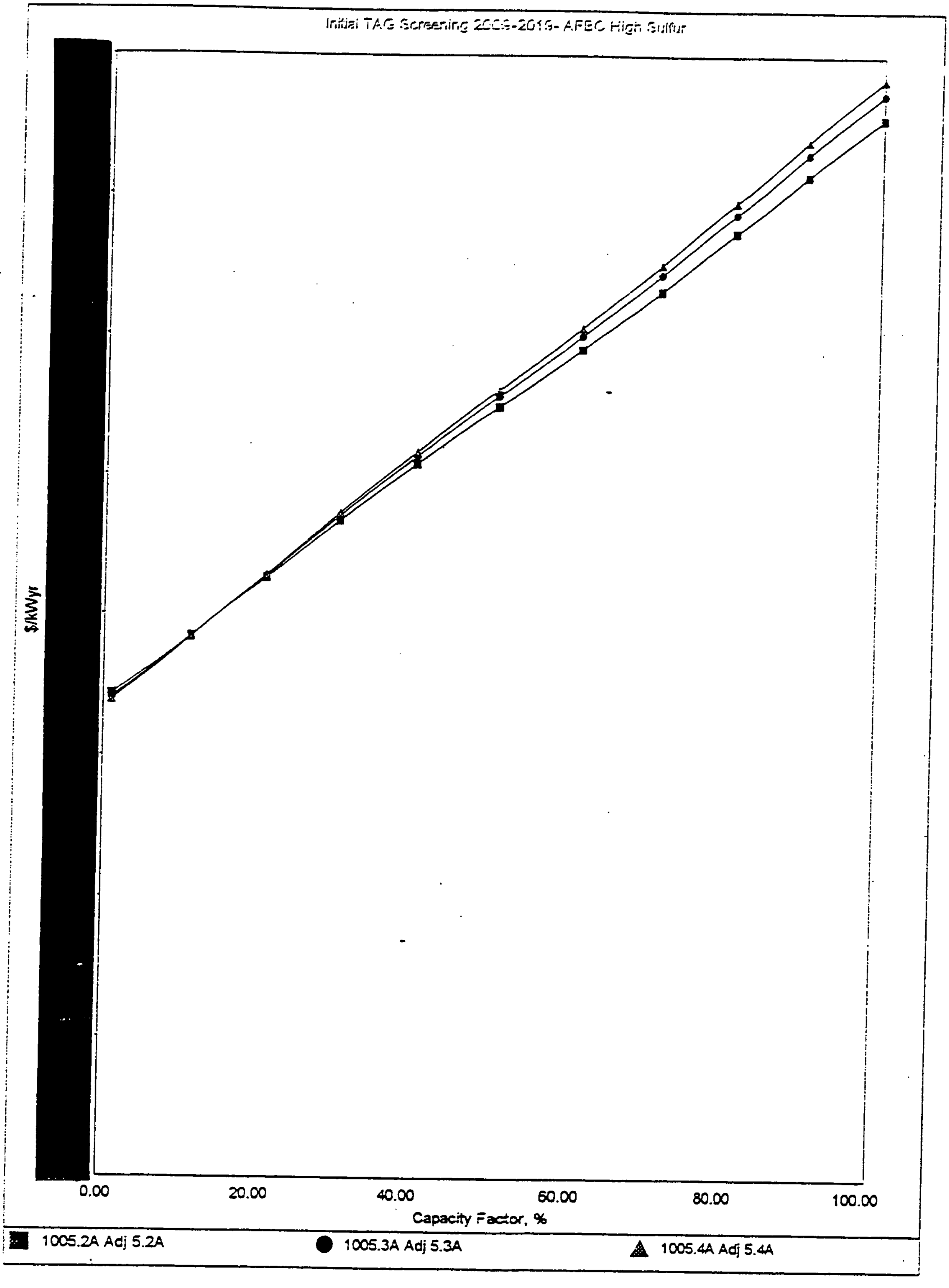

Initial TAG Screening 2009-2019- AFBC High Sulfur
$/kWyr
[redacted]
0.00
20.00
40.00
60.00
80.00
100.00
Capacity Factor, %
1005.2A Adj 5.2A
1005.3A Adj 5.3A
1005.4A Adj 5.4A

Figure GA-5-10

CONFIDENTIAL

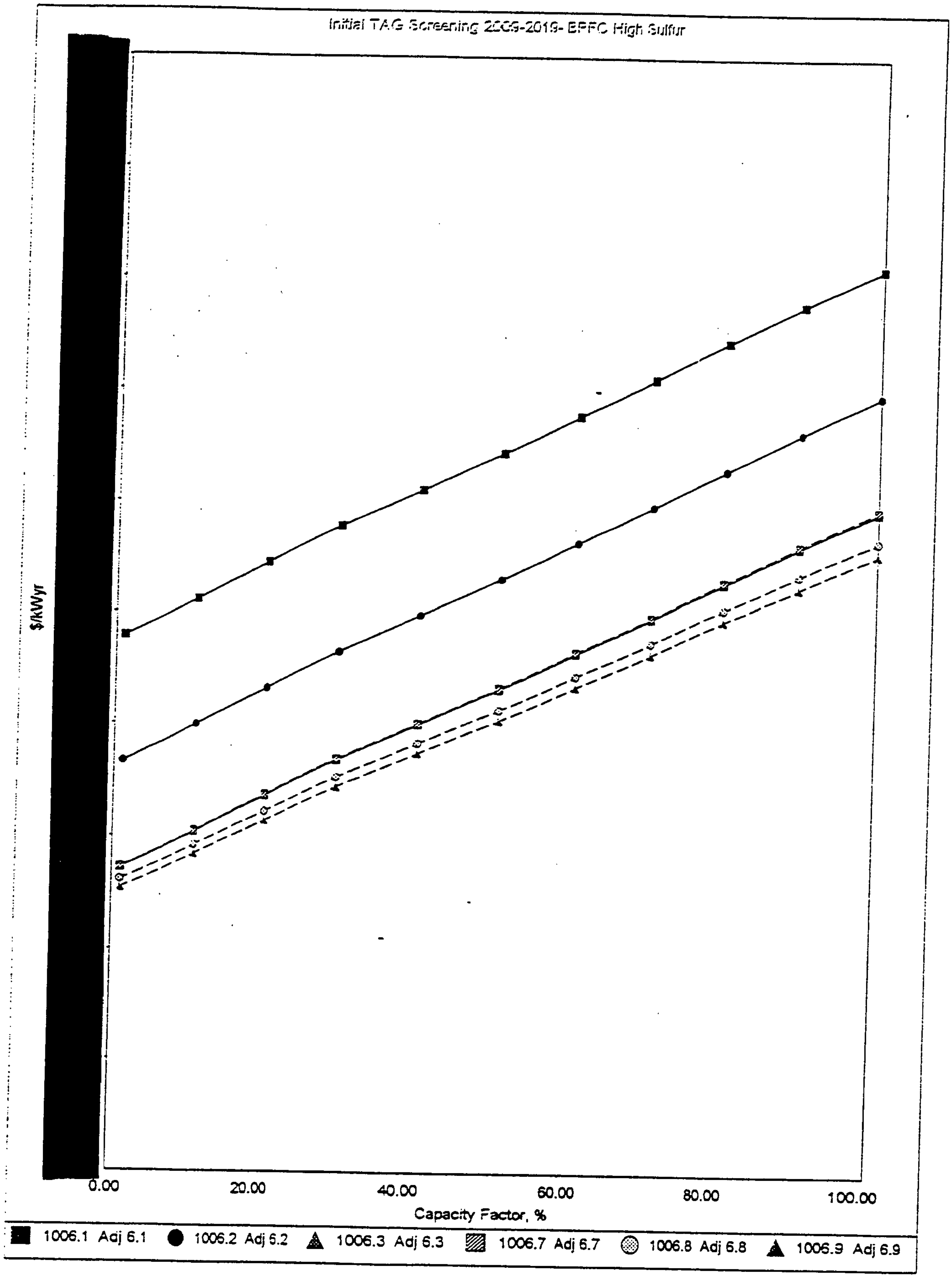
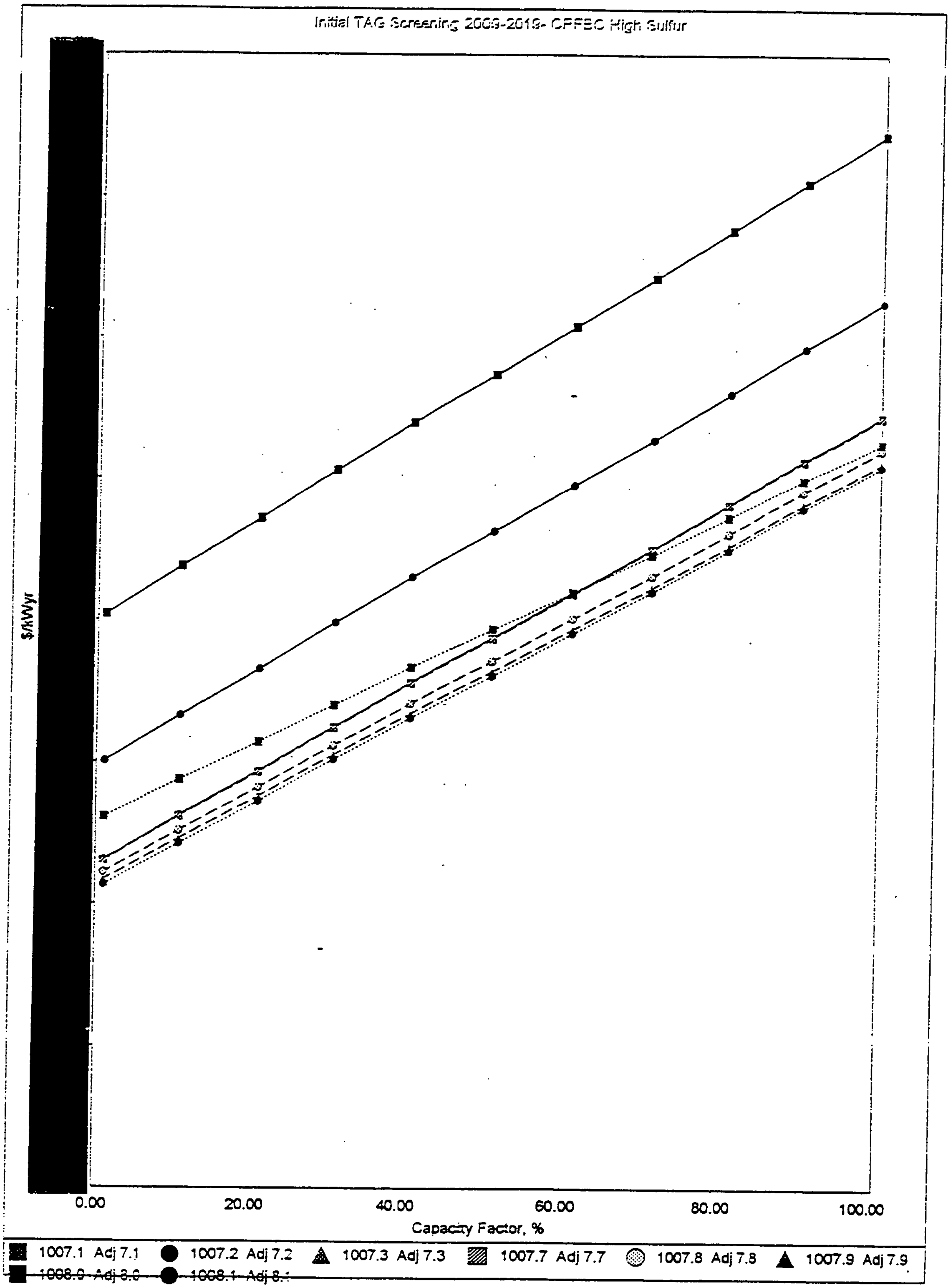
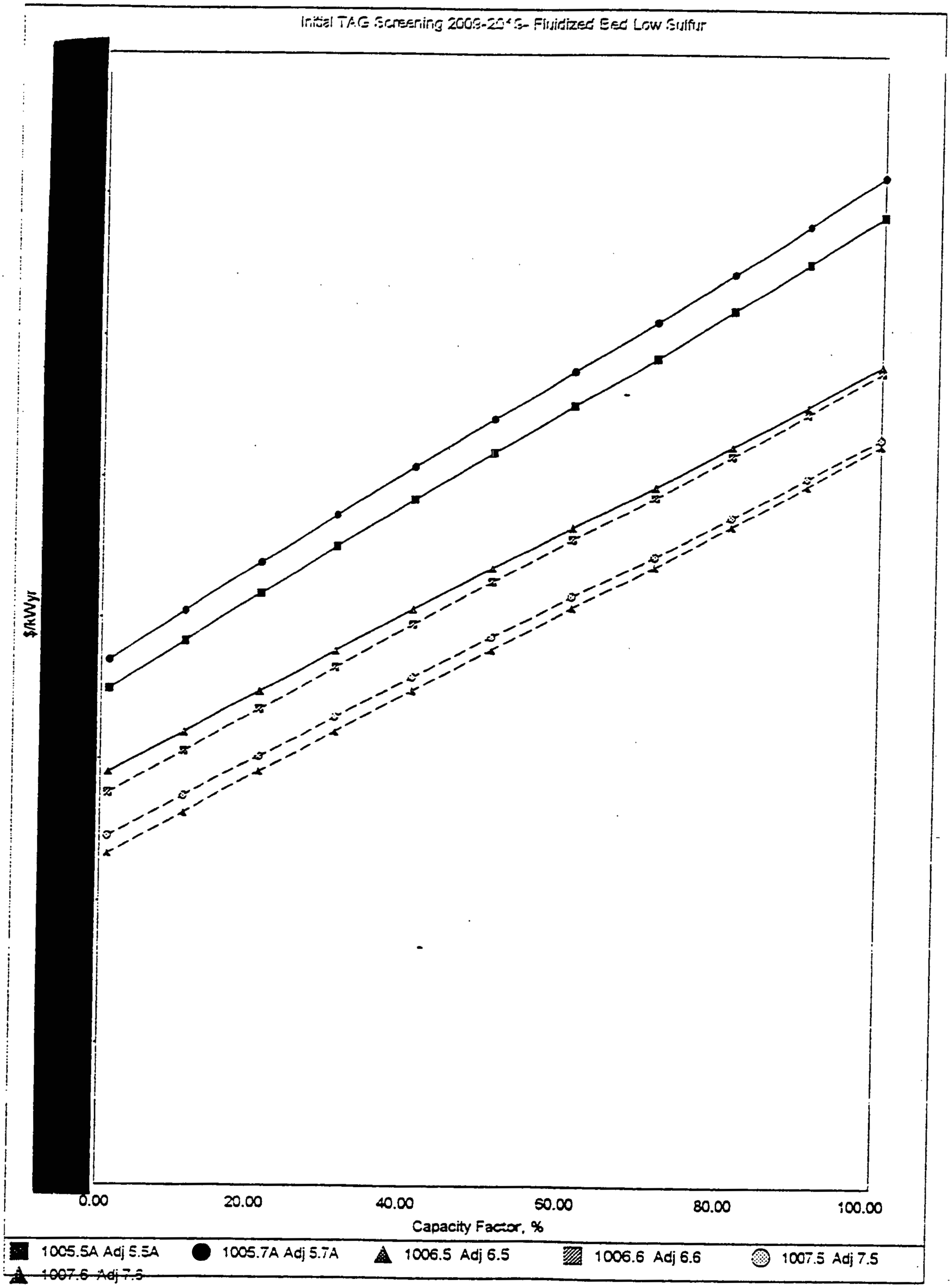
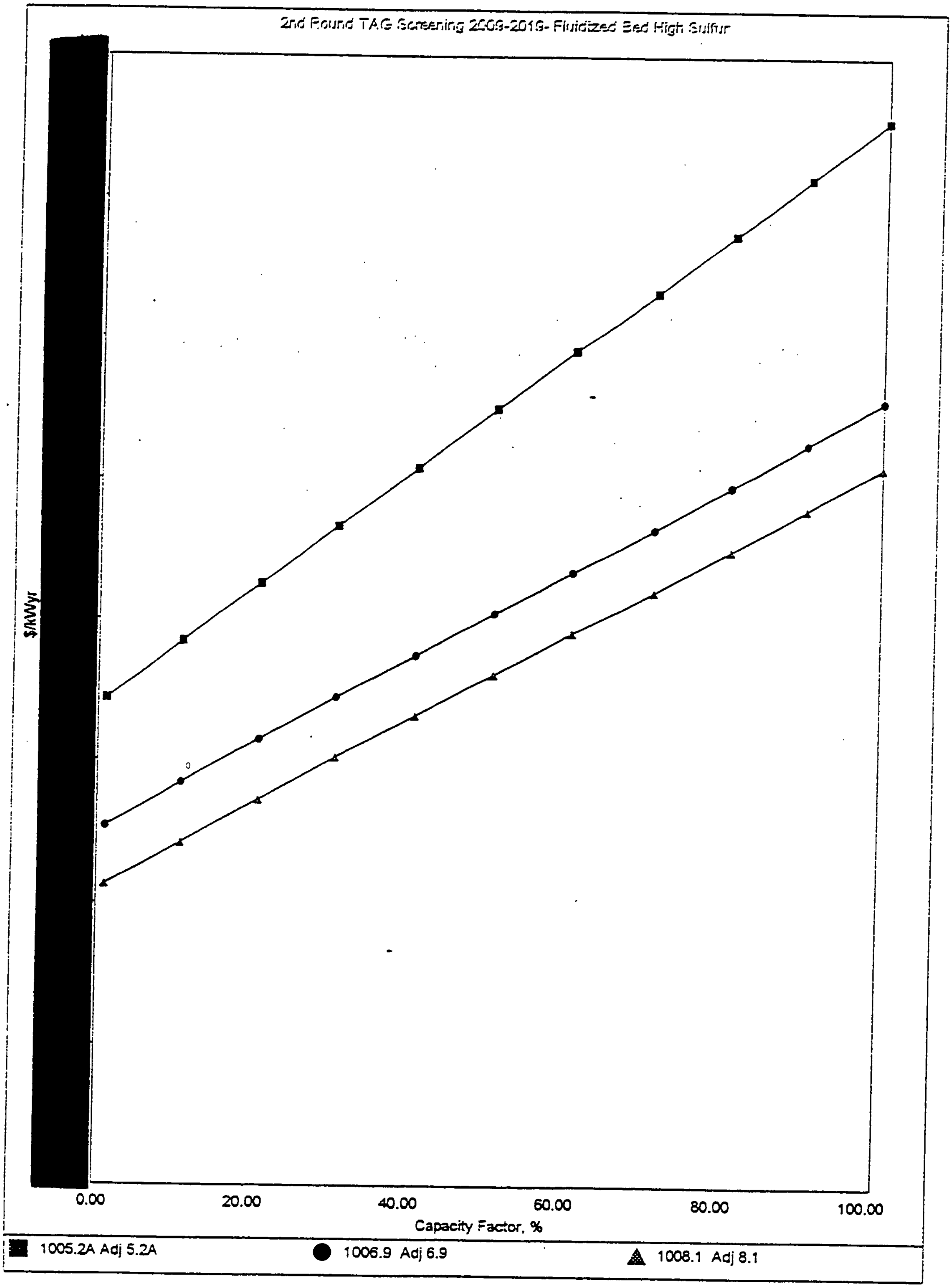


Figure GA-5- CONFIDENTIAL




Initial TAG Screening
Fluidized Bed Low Sulfur
$/kWyr
0.00
20.00
40.00
60.00
80.00
100.00
Capacity Factor, %
1005.5A Adj 5.5A
1005.7A Adj 5.7A
1006.5 Adj 6.5
1006.6 Adj 6.6
1007.5 Adj 7.5
~~1007.6 Adj 7.6~~


2nd Round TAG Screening 2009-2019- Fluidized Bed High Sulfur
$/kWyr
[redacted]
0.00
20.00
40.00
60.00
80.00
100.00
Capacity Factor, %
1005.2A Adj 5.2A
1006.9 Adj 6.9
1008.1 Adj 8.1

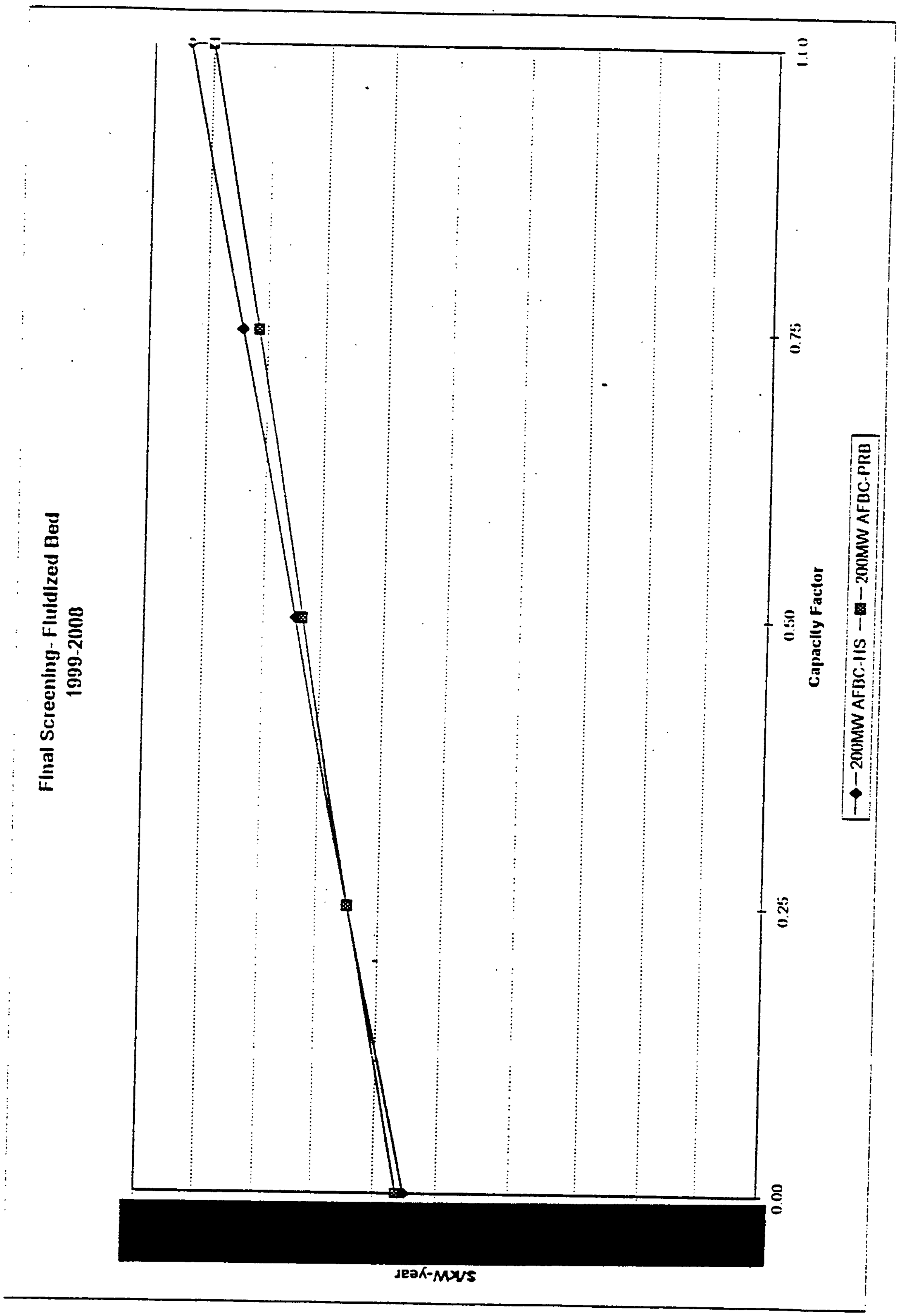
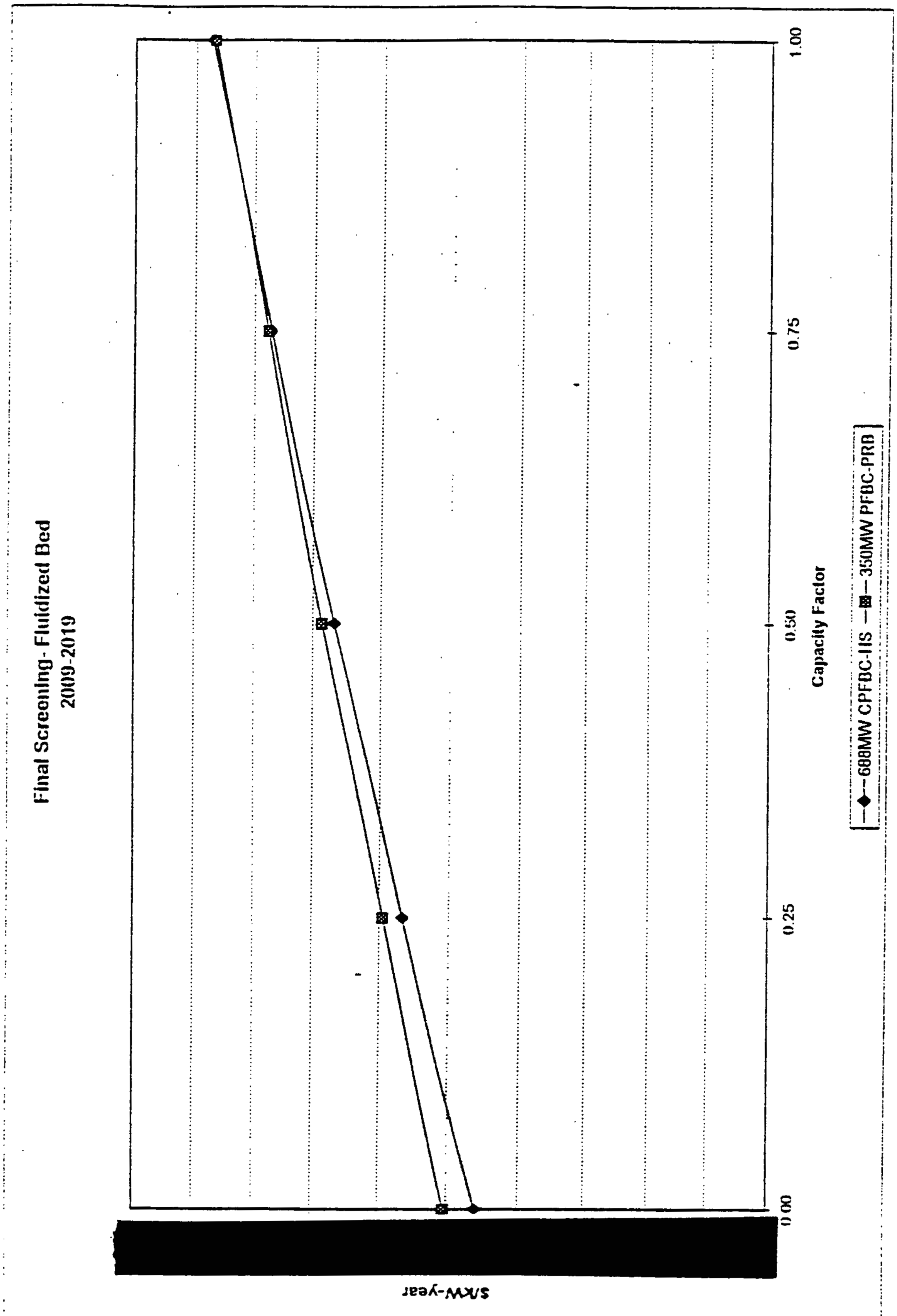

Final Screening- Fluidized Bed
1999-2008
$/KW-year
[redacted]
0.00
0.25
0.50
0.75
1.00
Capacity Factor
200MW AFBC-HS
200MW AFBC-PRB

Figure GA-5-15



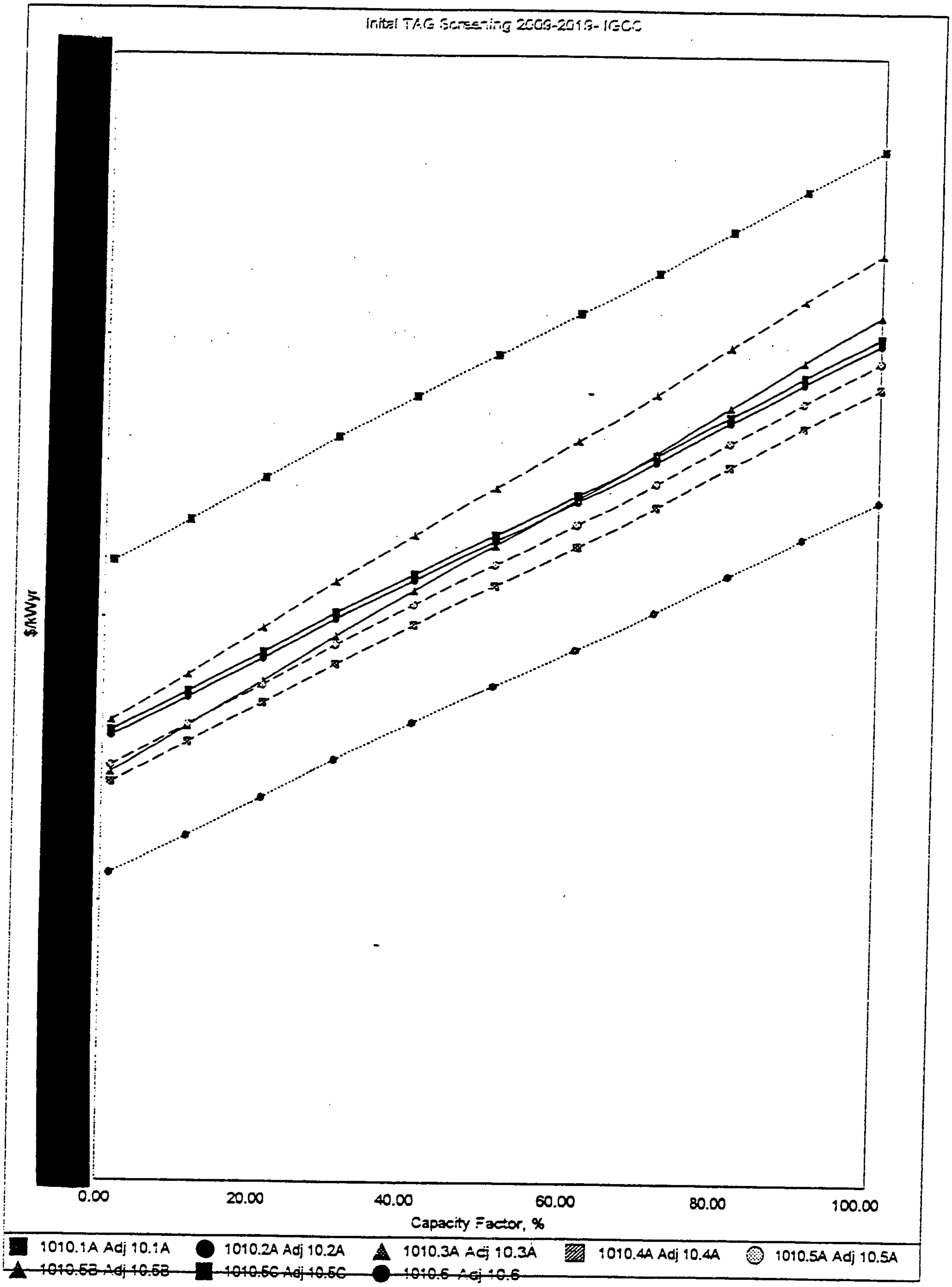
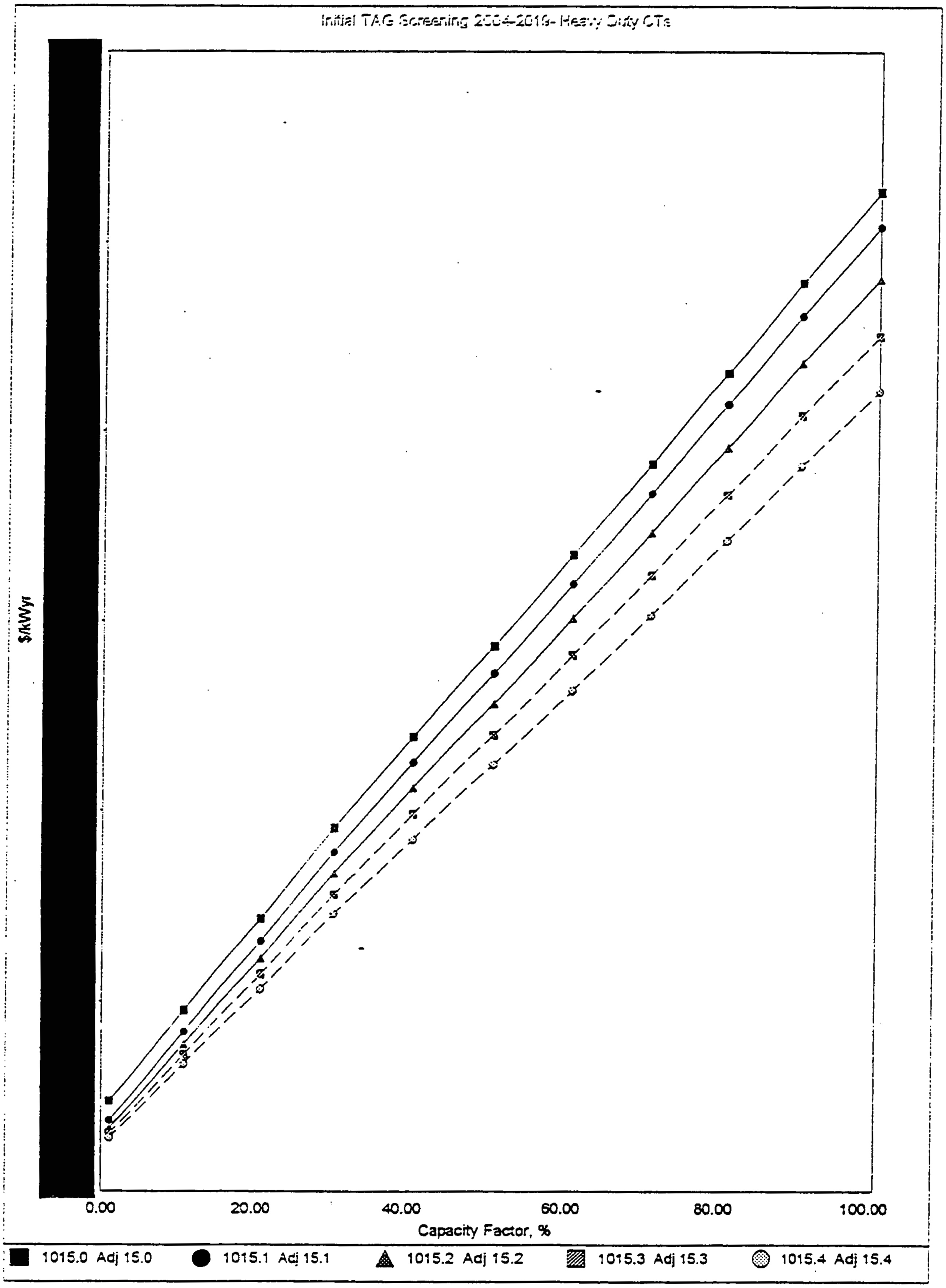

Inital TAG Screening
IGCC
$/kWyr
[redacted]
0.00
20.00
40.00
60.00
80.00
100.00
Capacity Factor, %
1010.1A Adj 10.1A
1010.2A Adj 10.2A
1010.3A Adj 10.3A
1010.4A Adj 10.4A
1010.5A Adj 10.5A
~~1010.5B Adj 10.5B~~
~~1010.5C Adj 10.5C~~
~~1010.6 Adj 10.6~~

Figure GA-5-17

CONFIDENTIAL



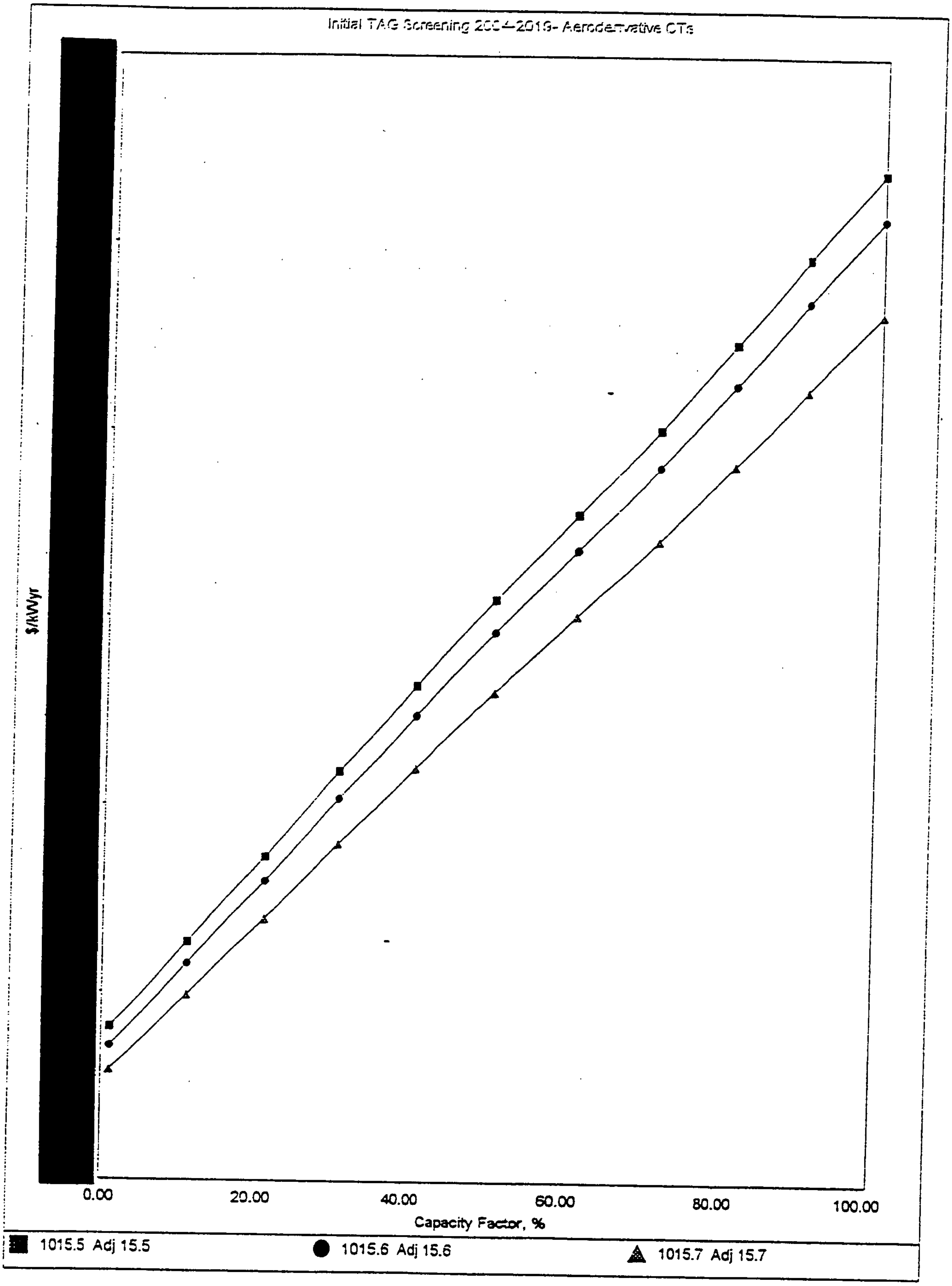
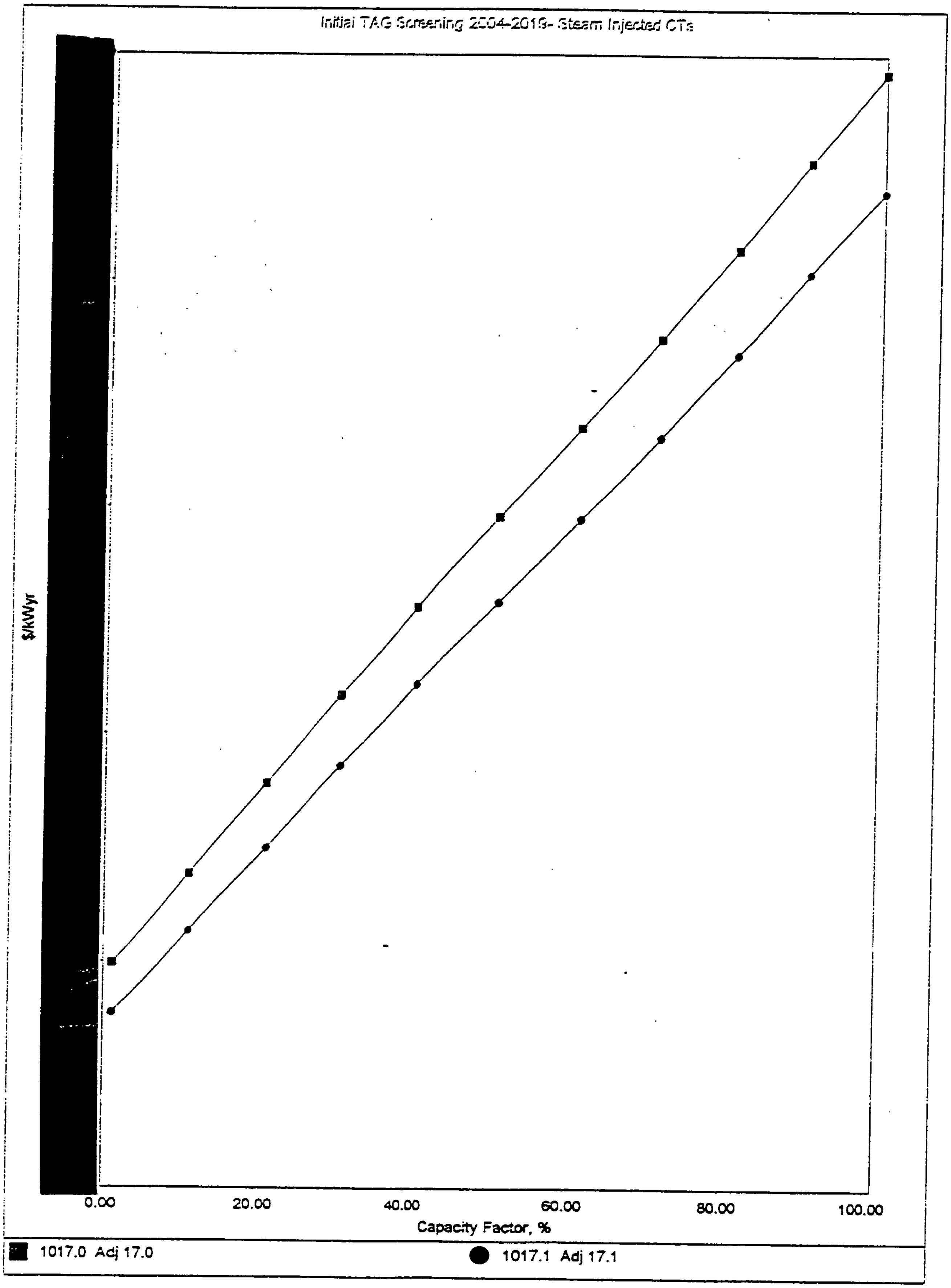
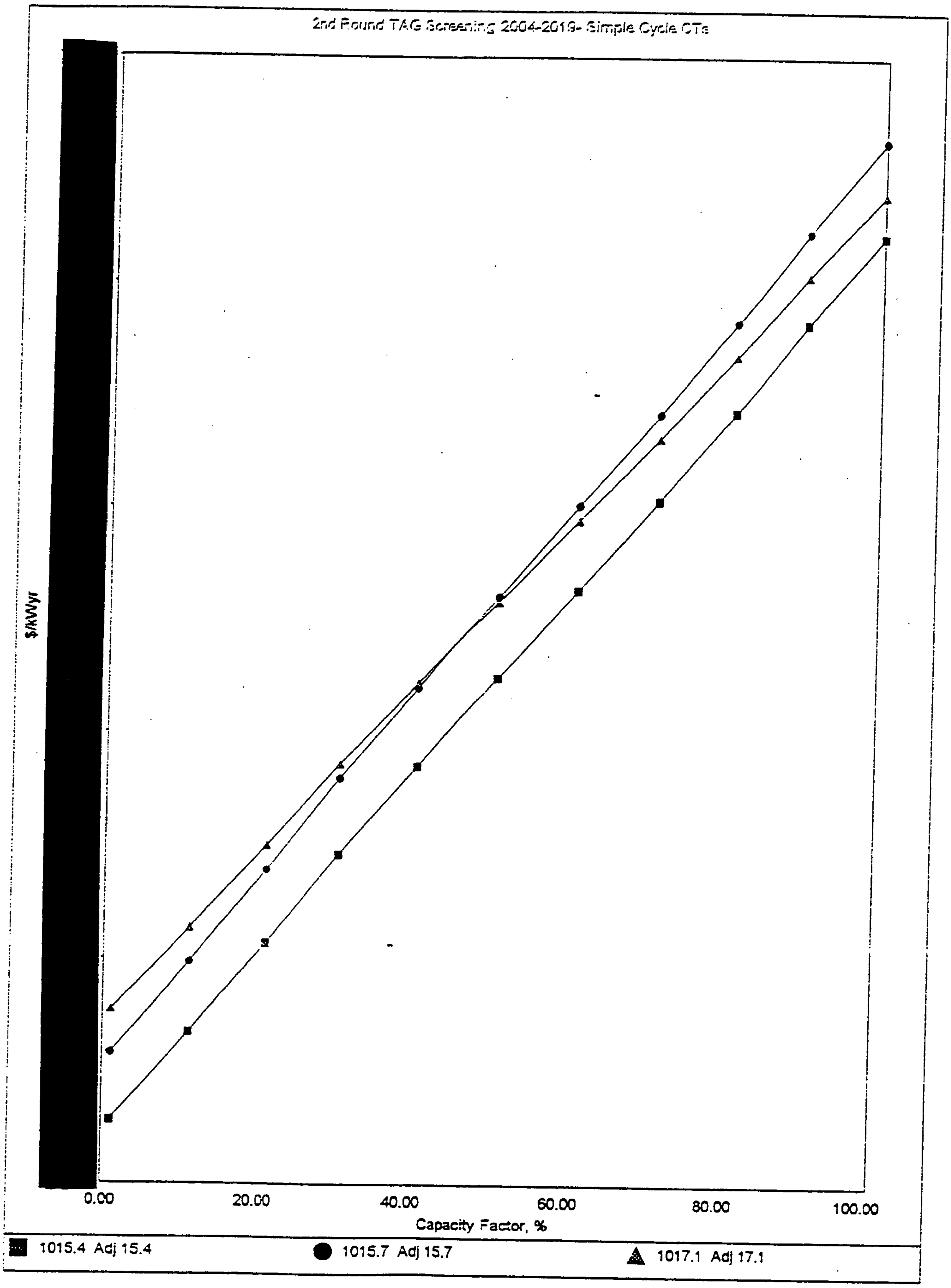

Initial TAG Screening 2004-2019- Aeroderivative CTs
$/kWyr
[redacted]
0.00
20.00
40.00
60.00
80.00
100.00
Capacity Factor, %
1015.5 Adj 15.5
1015.6 Adj 15.6
1015.7 Adj 15.7

Figure GA-5-19




2nd Round TAG Screening 2004-2019- Simple Cycle CTs
$/kWyr
[redacted]
0.00
20.00
40.00
60.00
80.00
100.00
Capacity Factor, %
1015.4 Adj 15.4
1015.7 Adj 15.7
1017.1 Adj 17.1

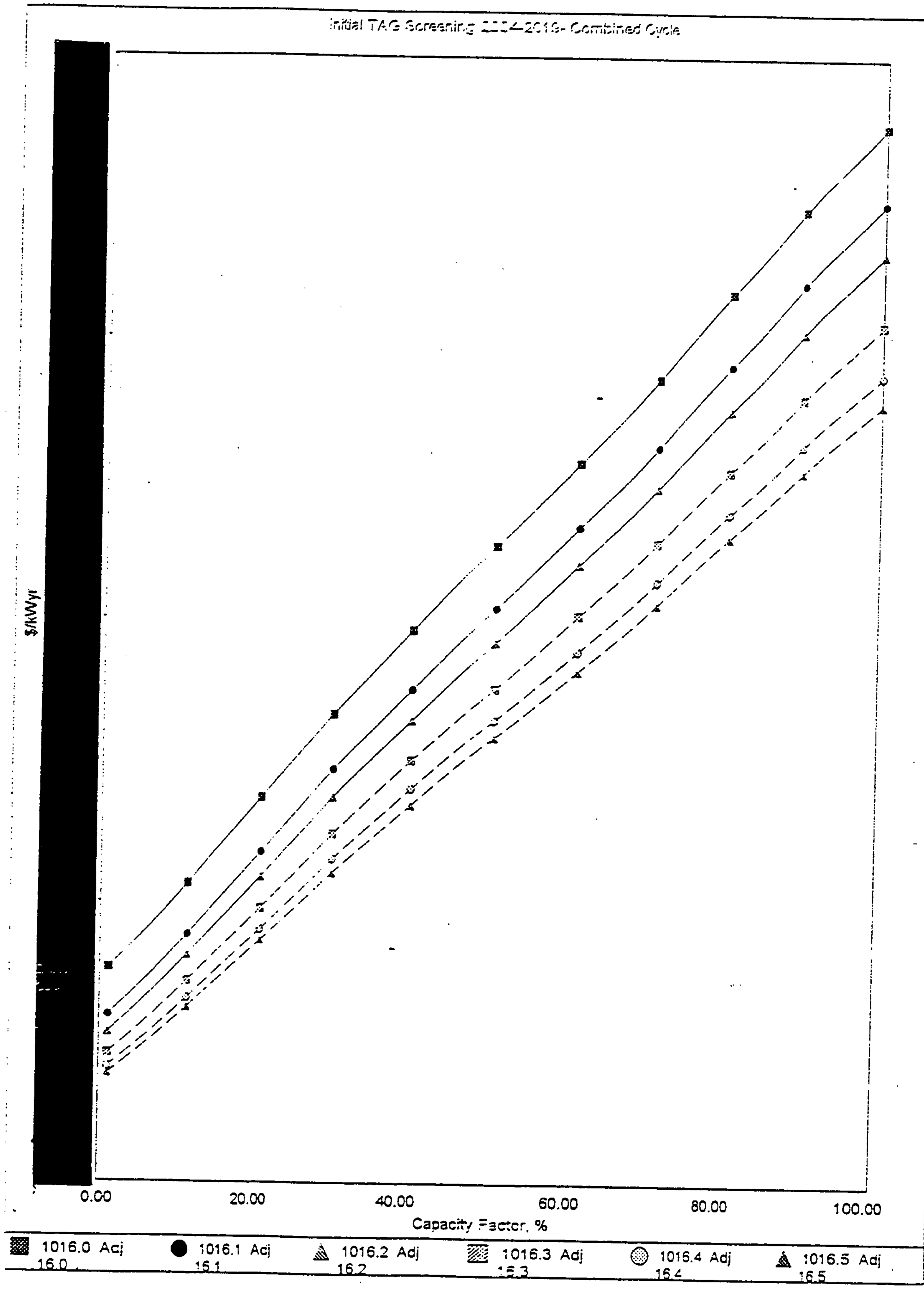

Initial TAG Screening
Combined Cycle
$/kWyr
[redacted]
0.00
20.00
40.00
60.00
80.00
100.00
Capacity Factor, %
1016.0 Adj 16.0
1016.1 Adj 16.1
1016.2 Adj 16.2
1016.3 Adj 16.3
1016.4 Adj 16.4
1016.5 Adj 16.5

Figure GA-5-22

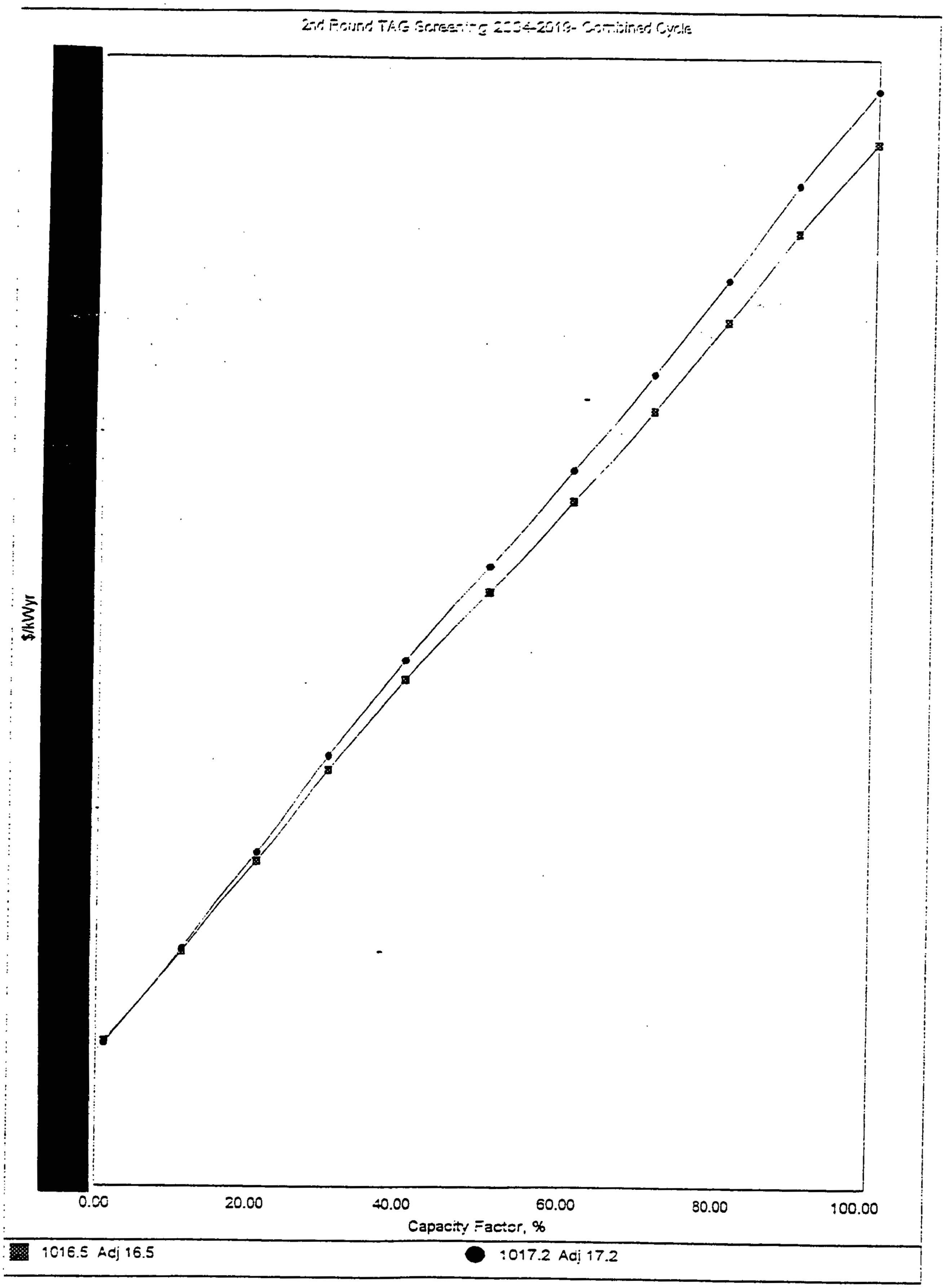


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Figure GA-5-23

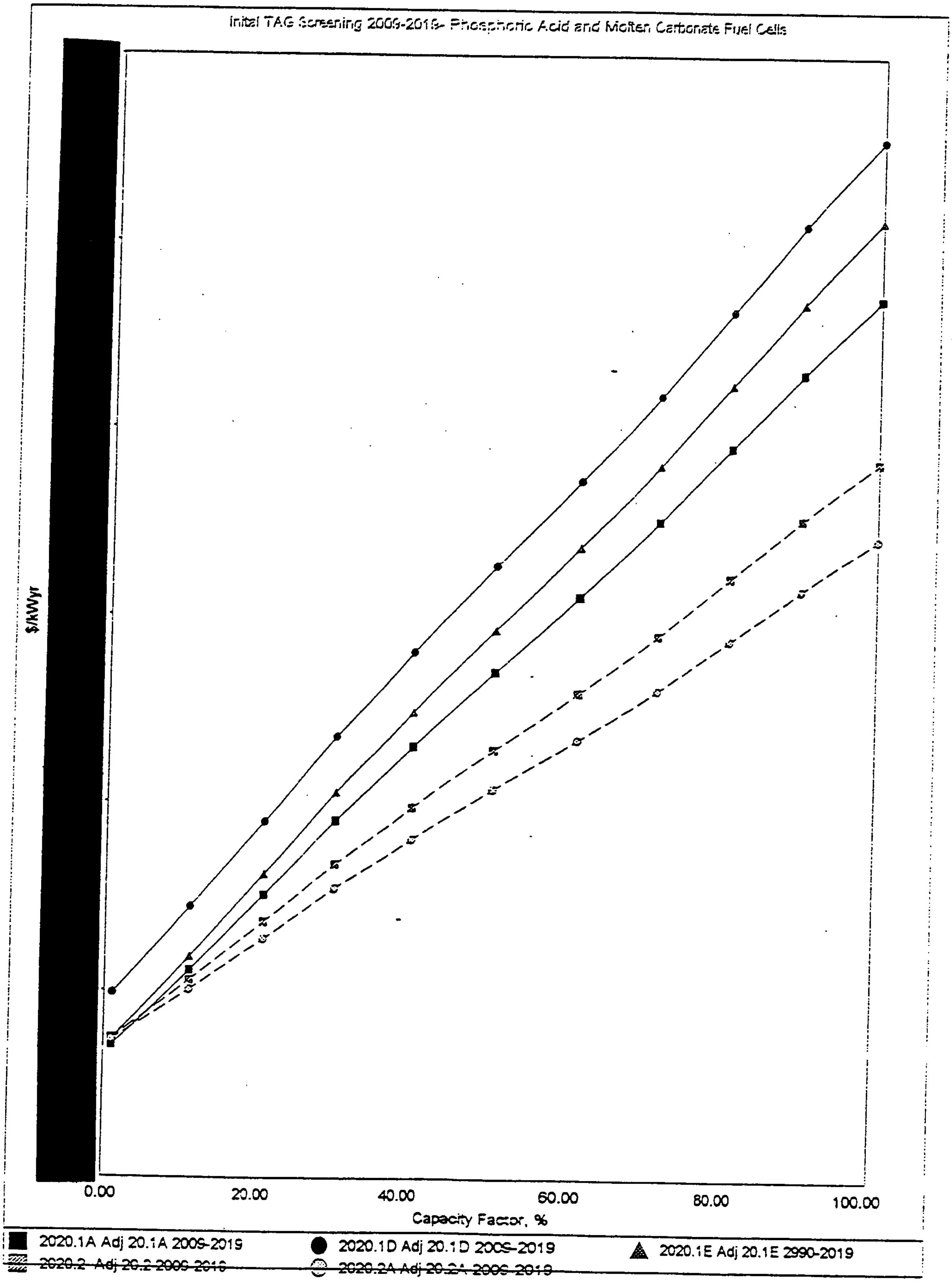


Figure GA-5-24

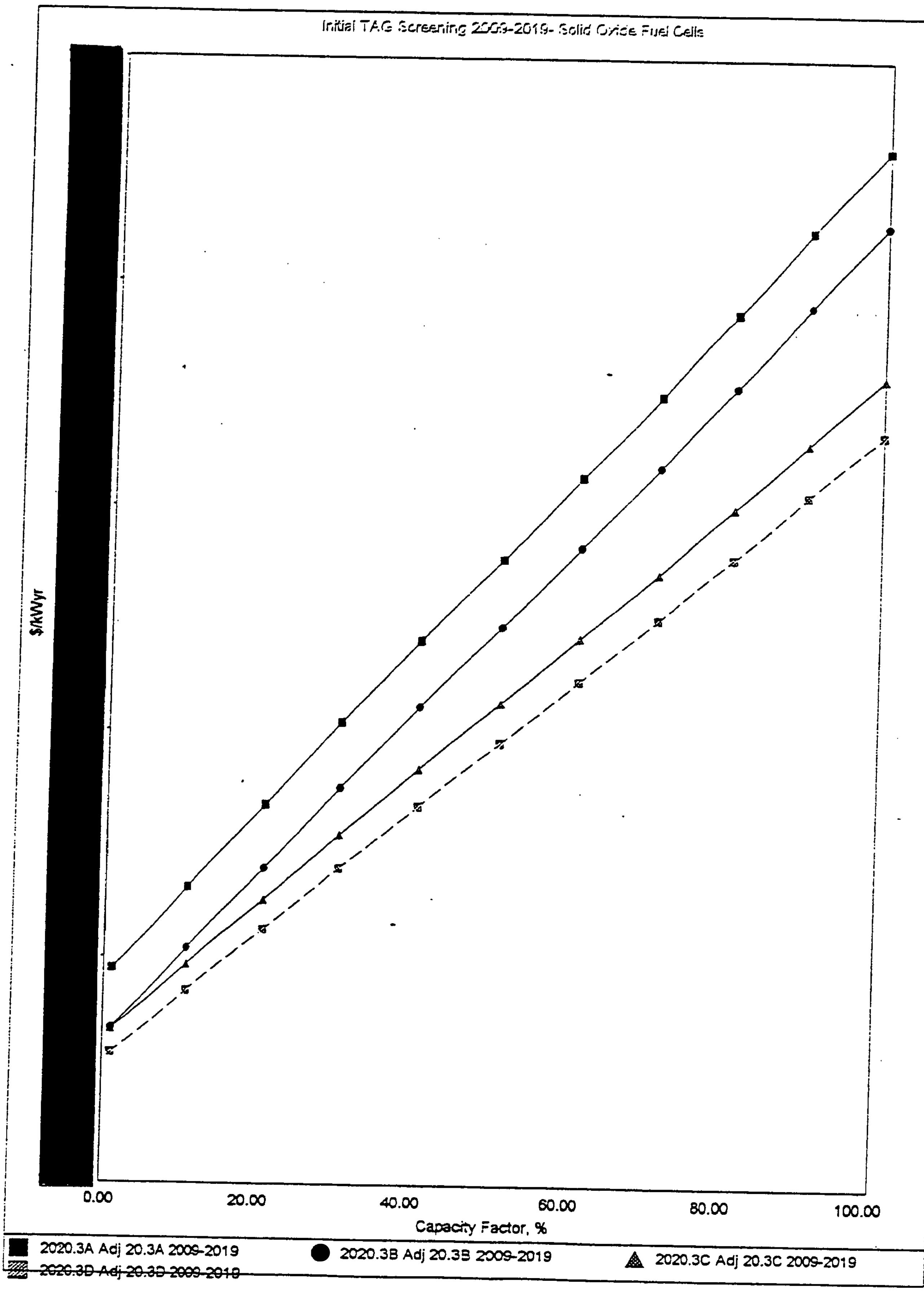


Figure GA-5-25

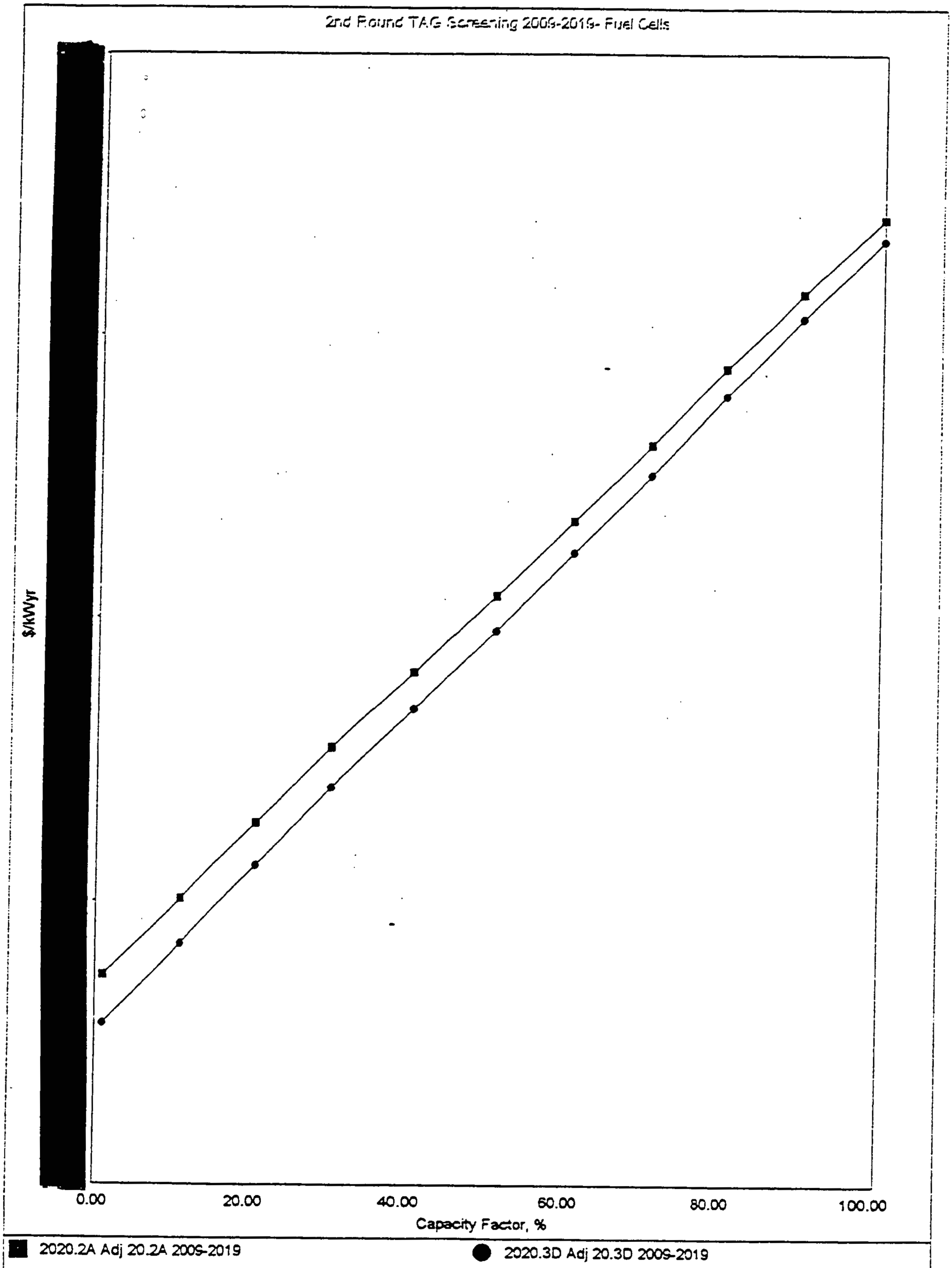


Figure GA-5-26

CONFIDENTIAL

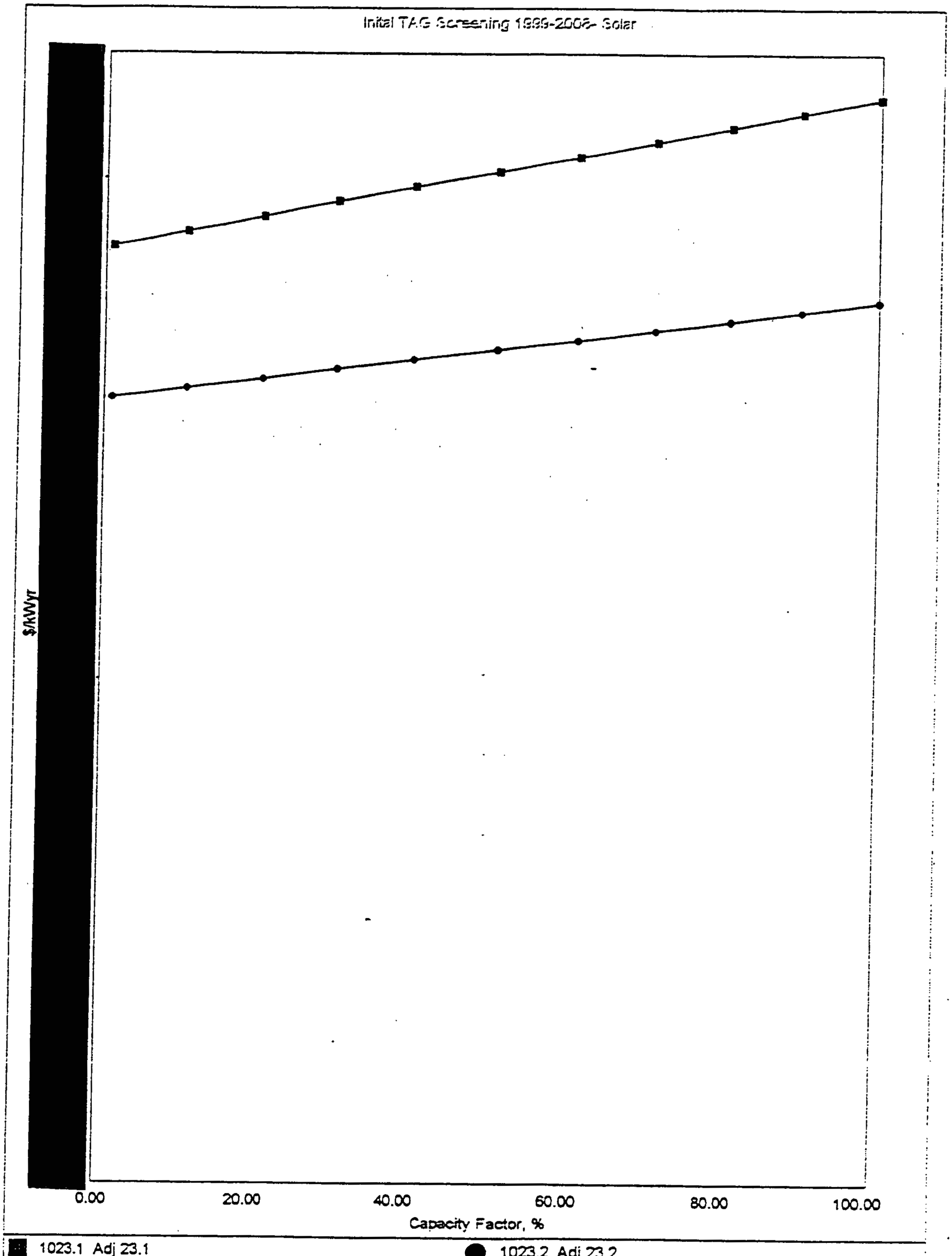
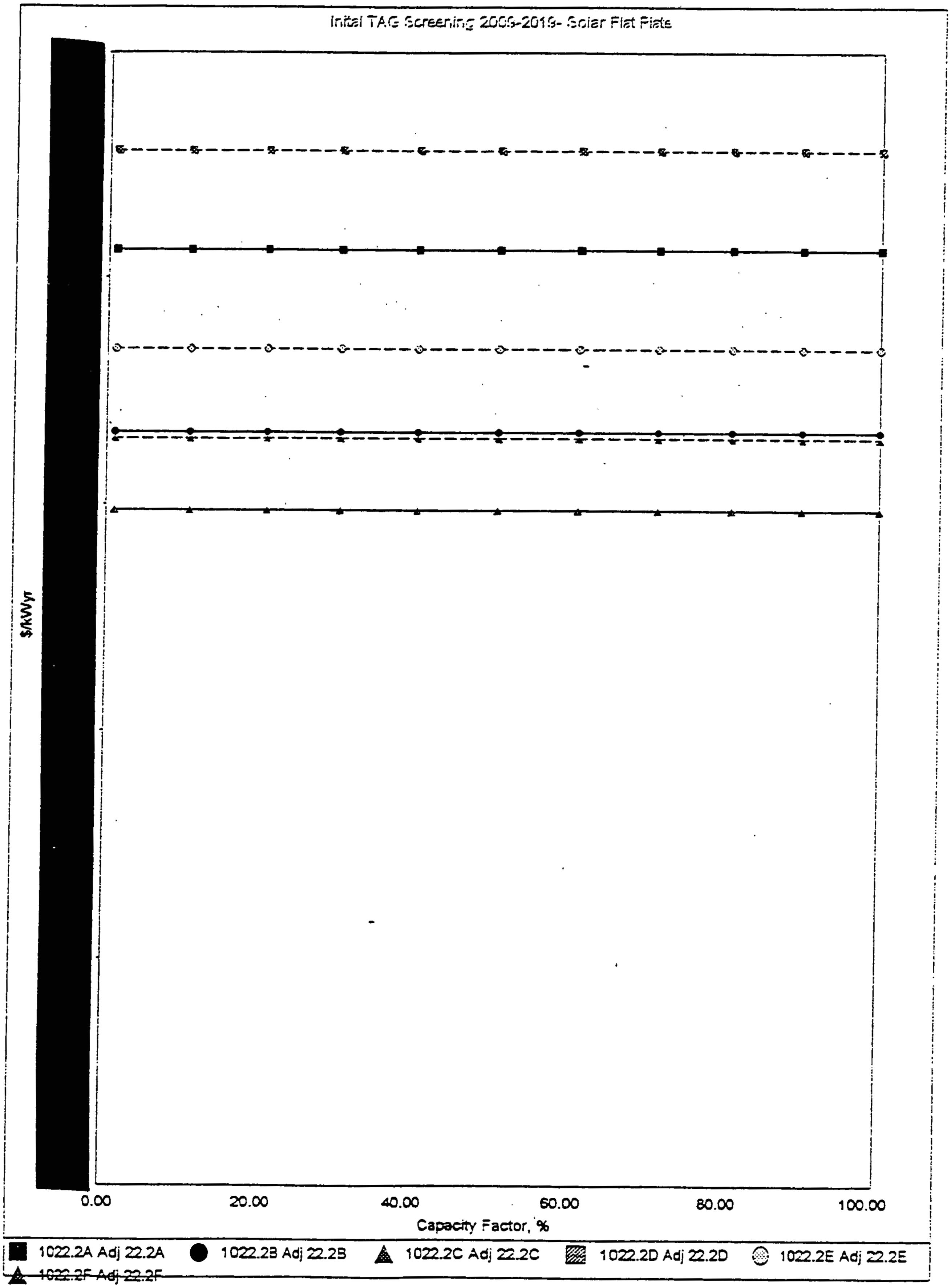
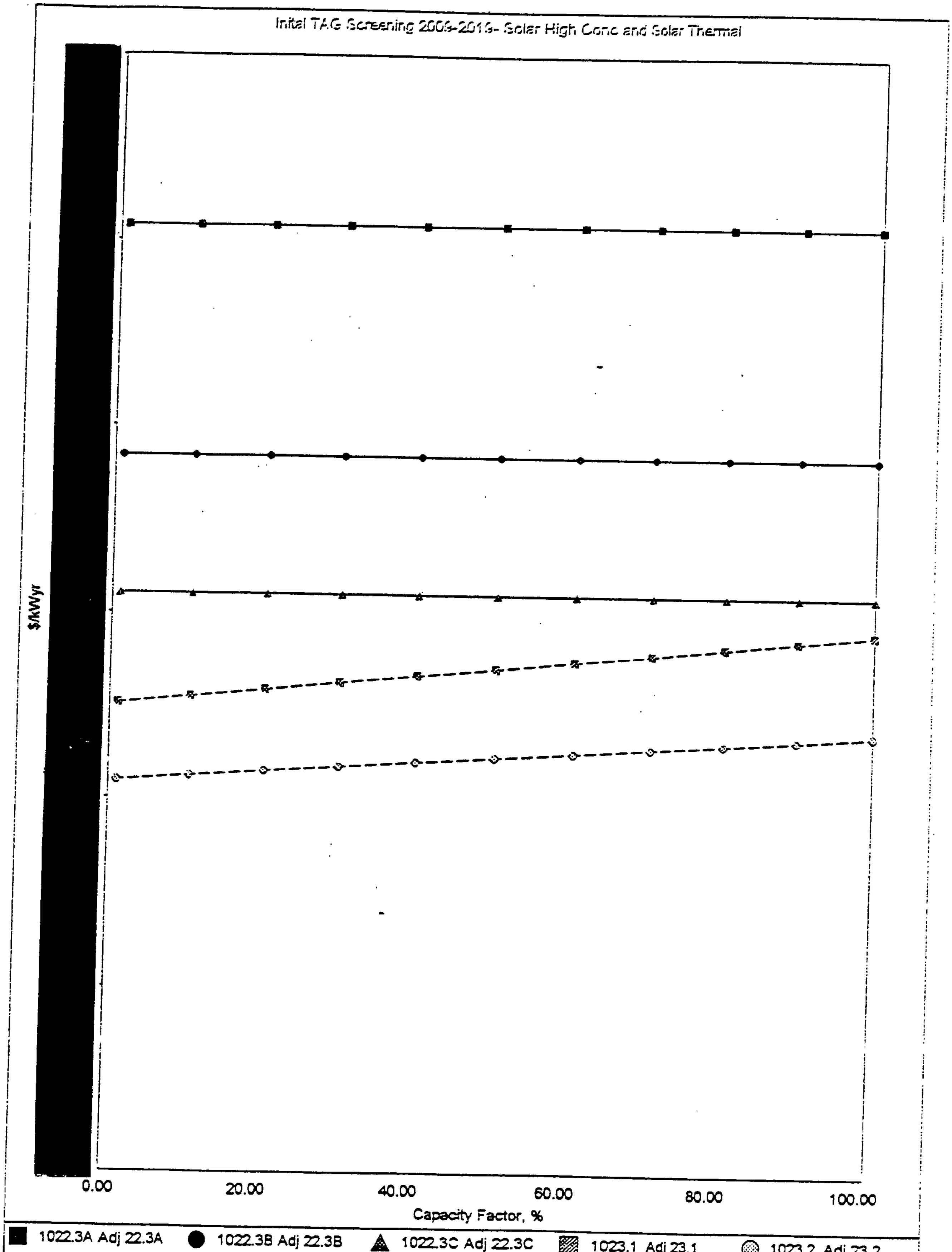
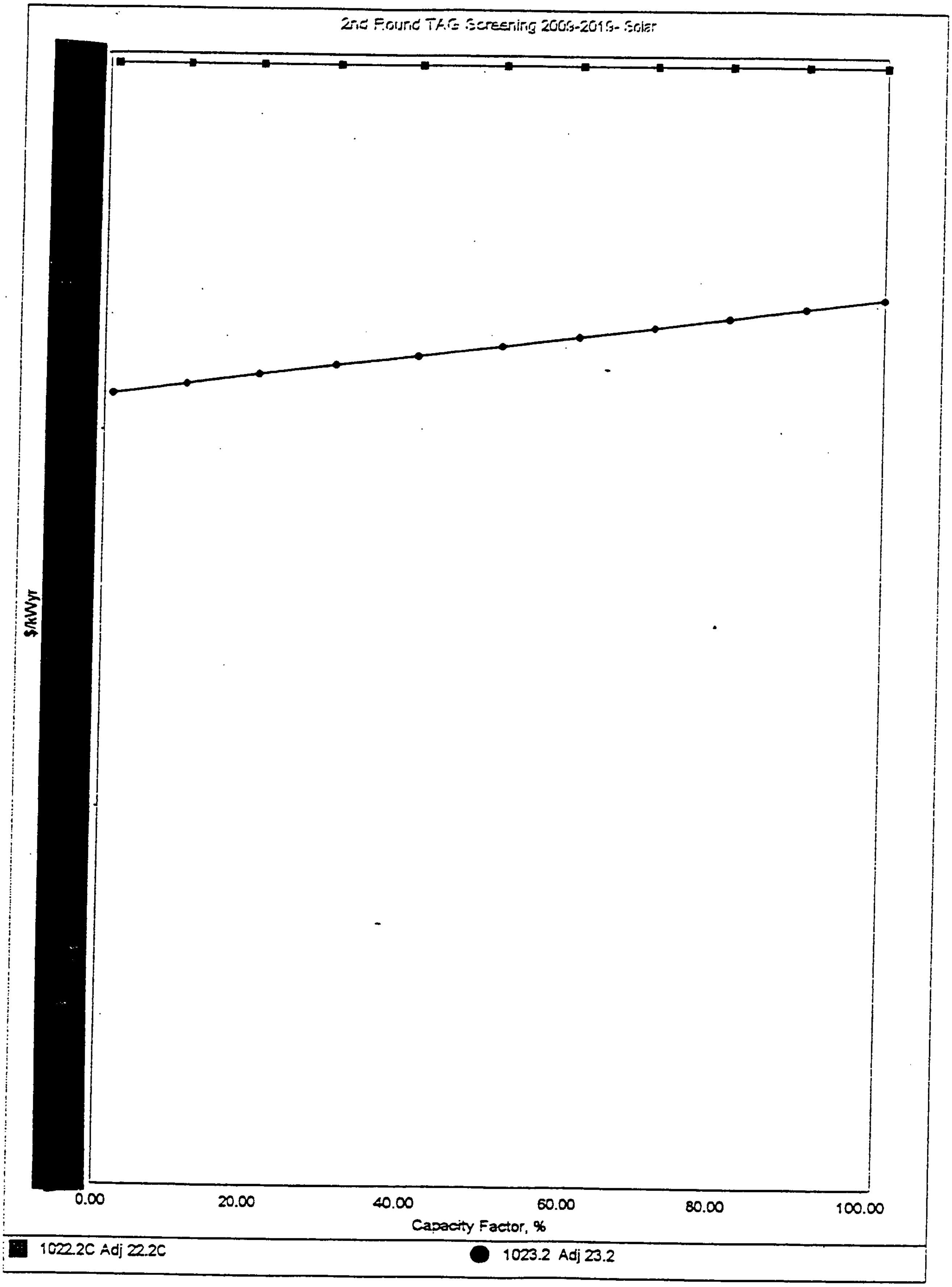
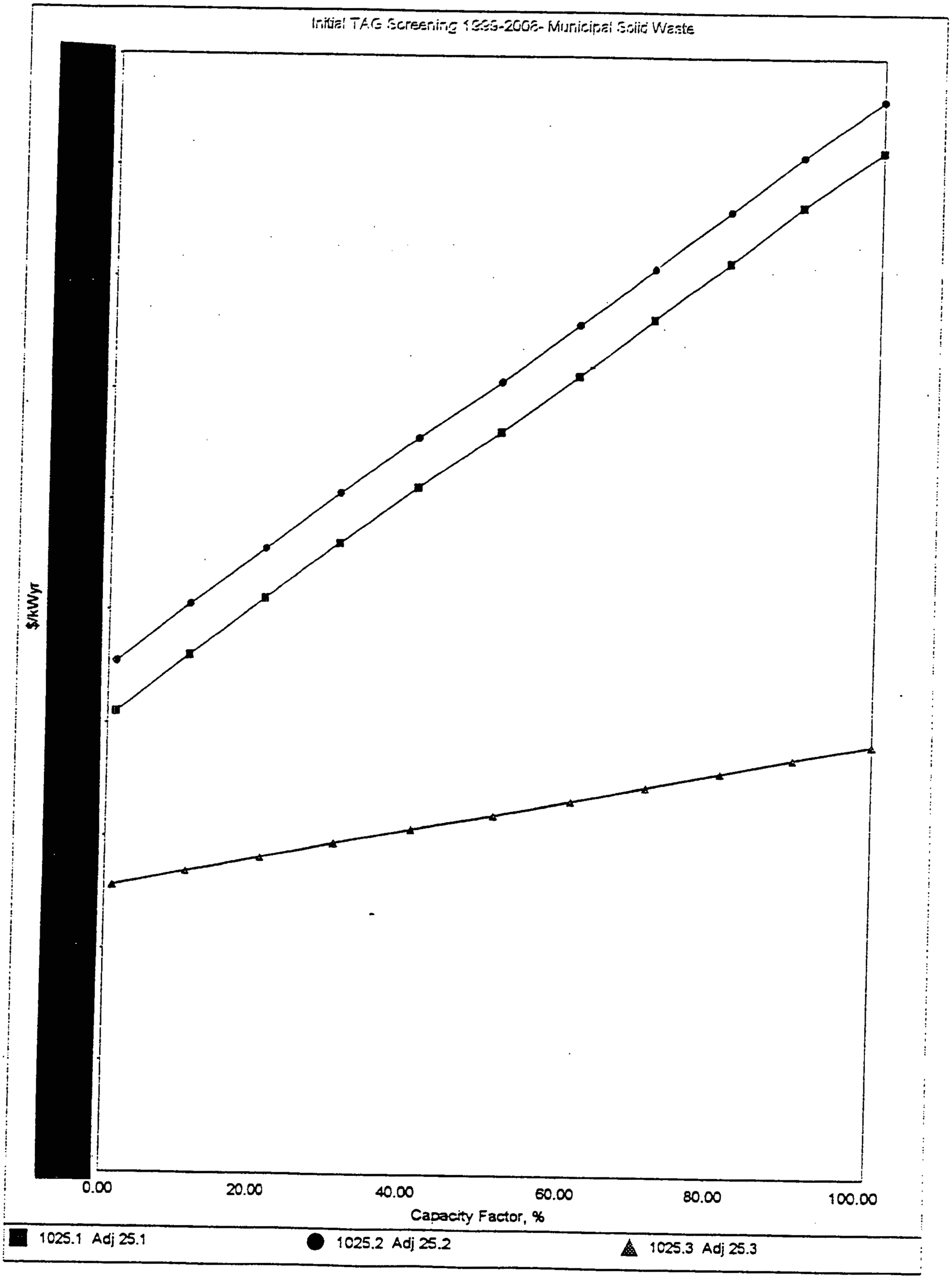


Figure GA-5-27




Inital TAG Screening 2009-2019- Solar High Conc and Solar Thermal
$/kWyr
[redacted]
0.00
20.00
40.00
60.00
80.00
100.00
Capacity Factor, %
1022.3A Adj 22.3A
1022.3B Adj 22.3B
1022.3C Adj 22.3C
1023.1 Adj 23.1
1023.2 Adj 23.2


2nd Round TAG Screening 2009-2019- Solar
$/kWyr
[redacted]
0.00
20.00
40.00
60.00
80.00
100.00
Capacity Factor, %
1022.2C Adj 22.2C
1023.2 Adj 23.2


Initial TAG Screening - Municipal Solid Waste
$/kWyr
[redacted]
0.00
20.00
40.00
60.00
80.00
100.00
Capacity Factor, %
1025.1 Adj 25.1
1025.2 Adj 25.2
1025.3 Adj 25.3

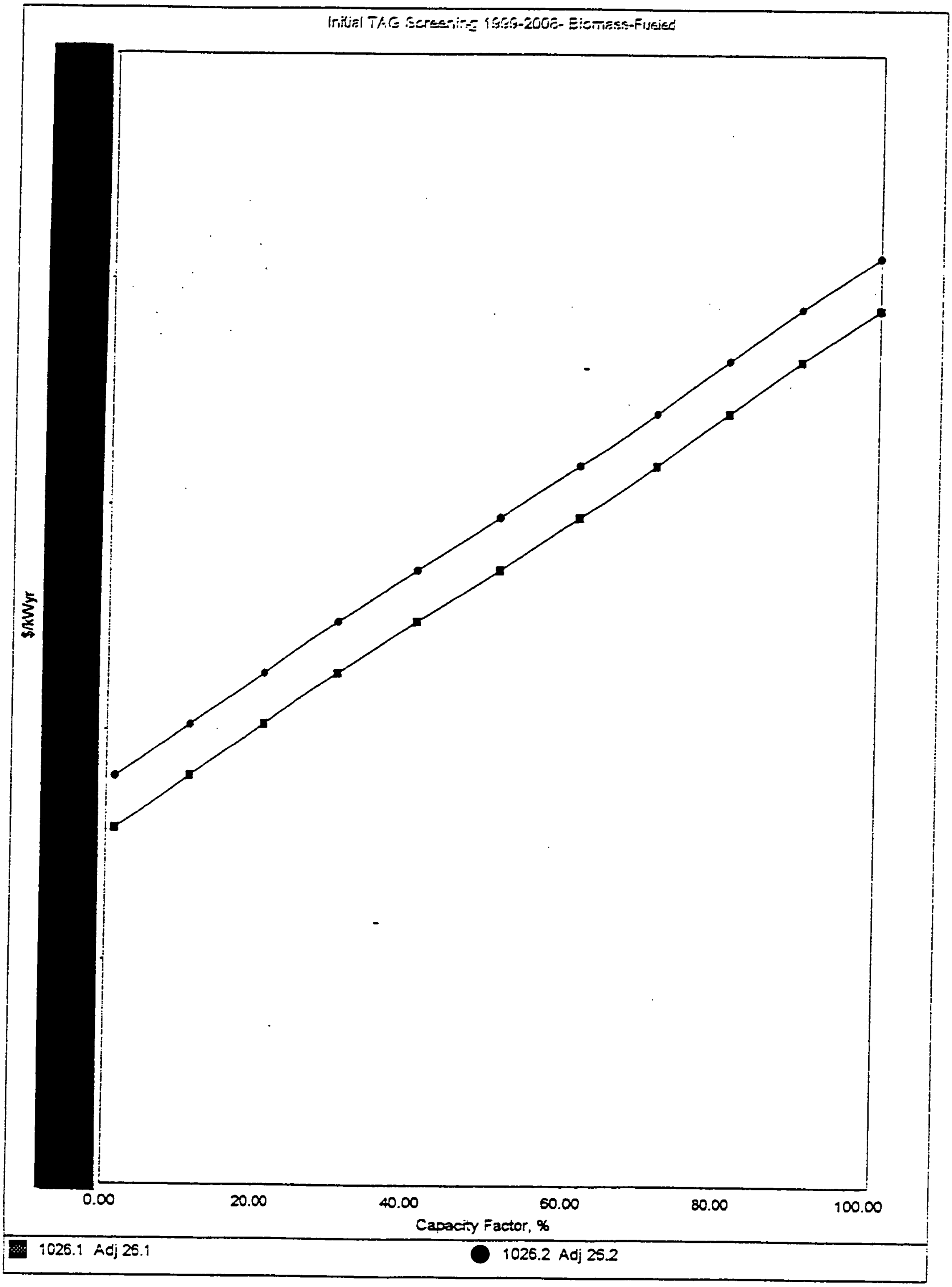
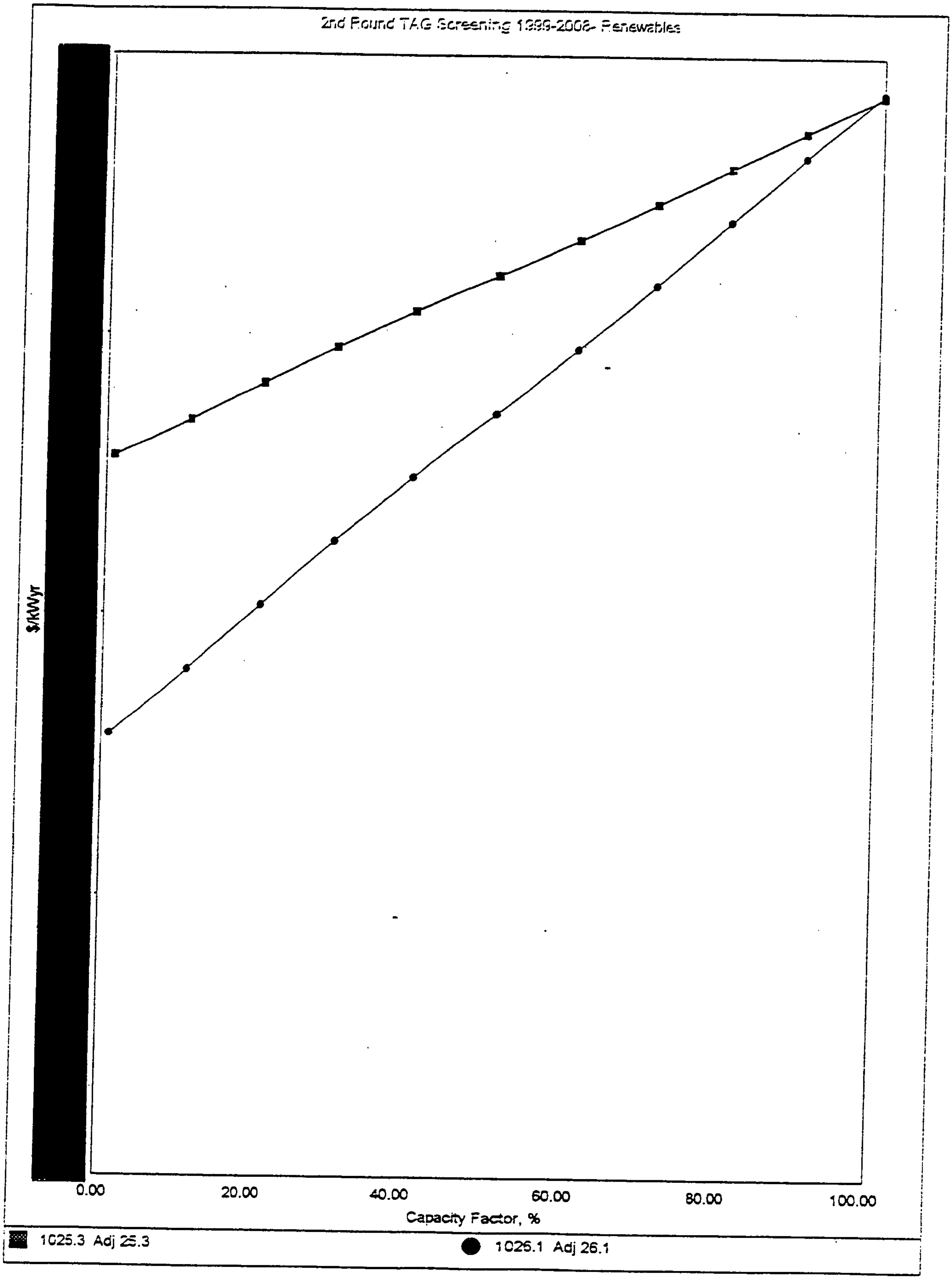

Initial TAG Screening 1999-2008- Biomass-Fueled
[redacted]
$/kWyr
0.00
20.00
40.00
60.00
80.00
100.00
Capacity Factor, %
1026.1 Adj 26.1
1026.2 Adj 26.2

Figure GA-5-32



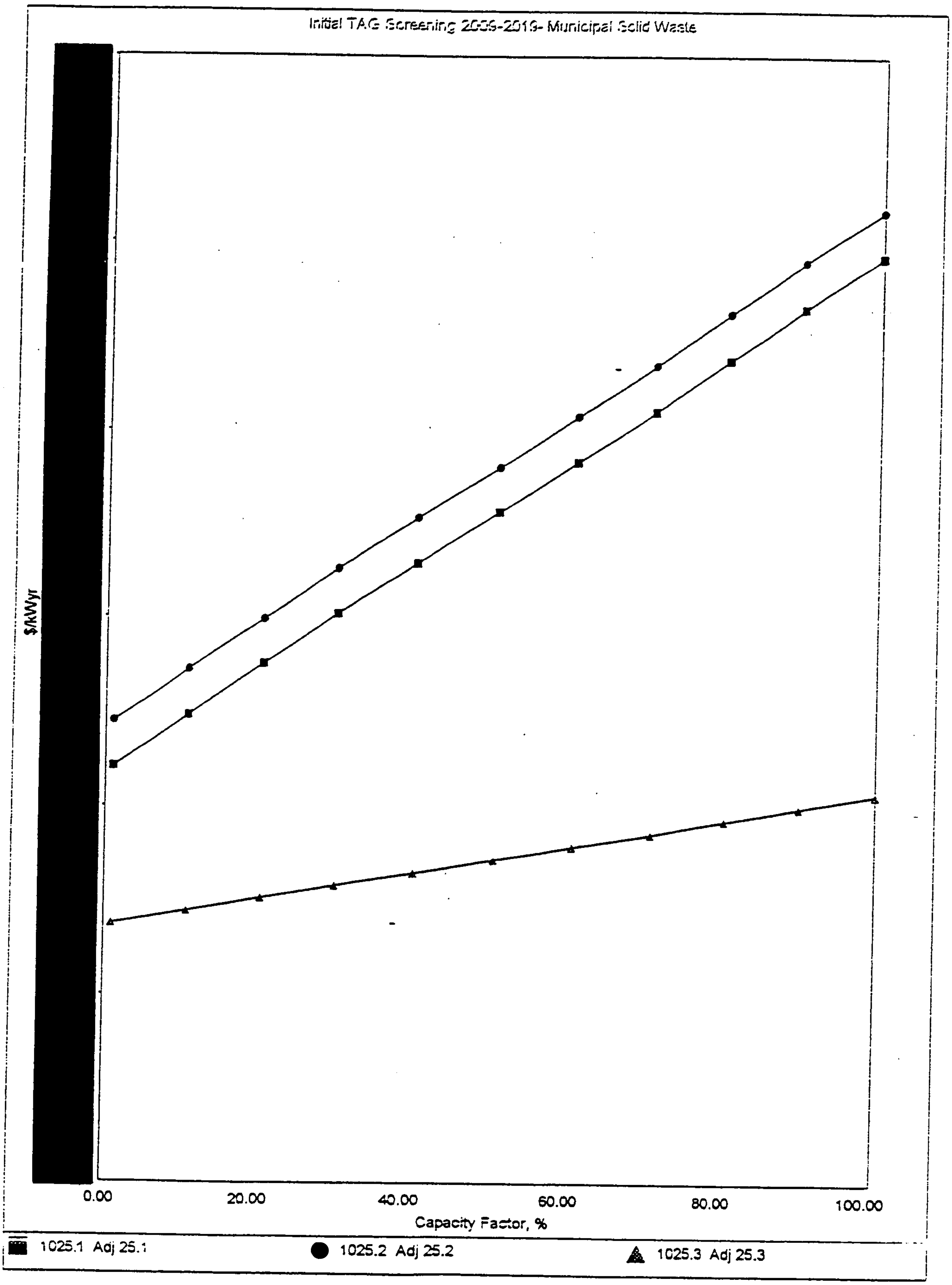

Initial TAG Screening 2009-2019- Municipal Solid Waste
$/kWyr
[redacted]
0.00
20.00
40.00
60.00
80.00
100.00
Capacity Factor, %
1025.1 Adj 25.1
1025.2 Adj 25.2
1025.3 Adj 25.3

Figure GA-5-34 CONFIDENTIAL

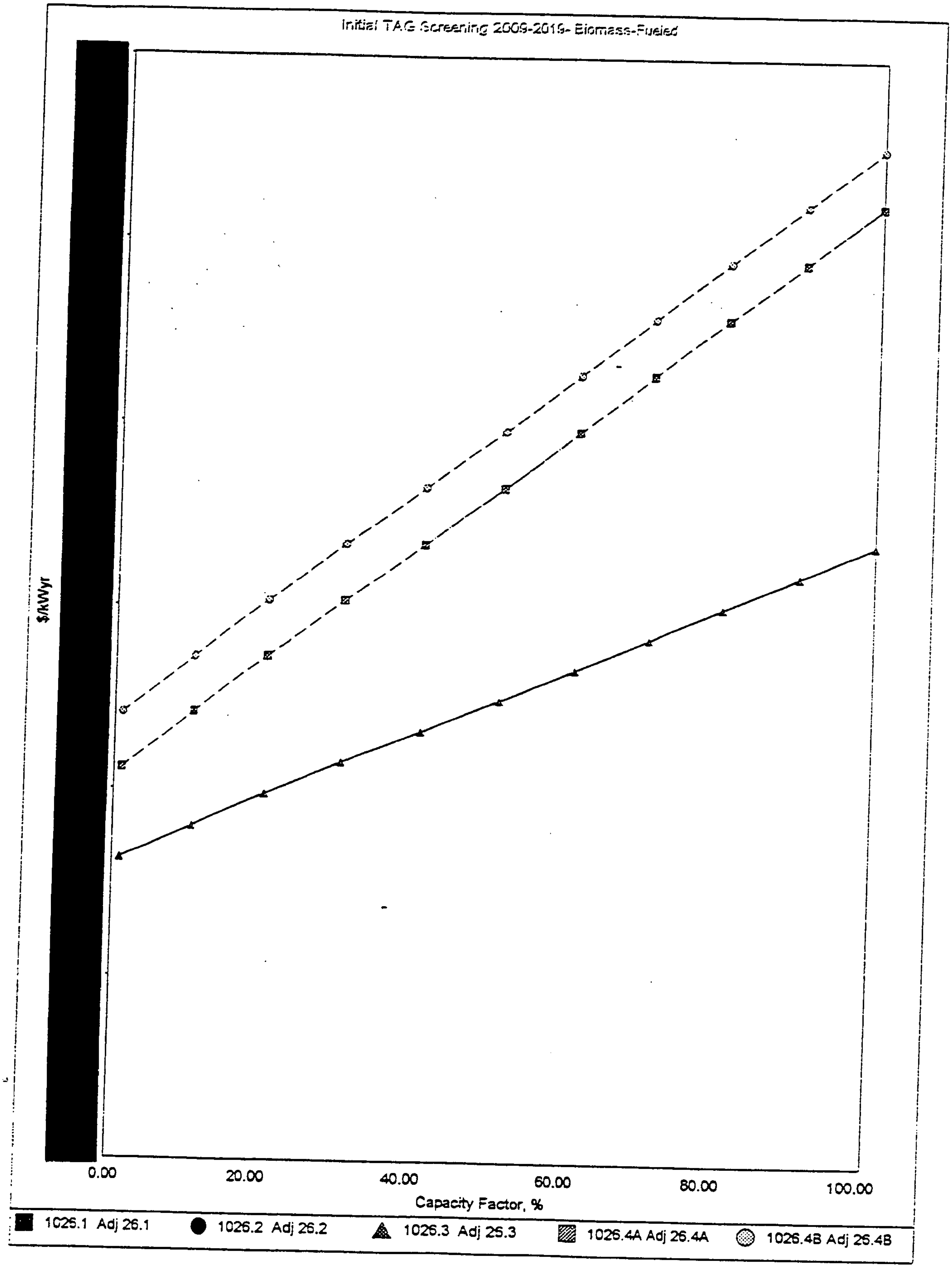
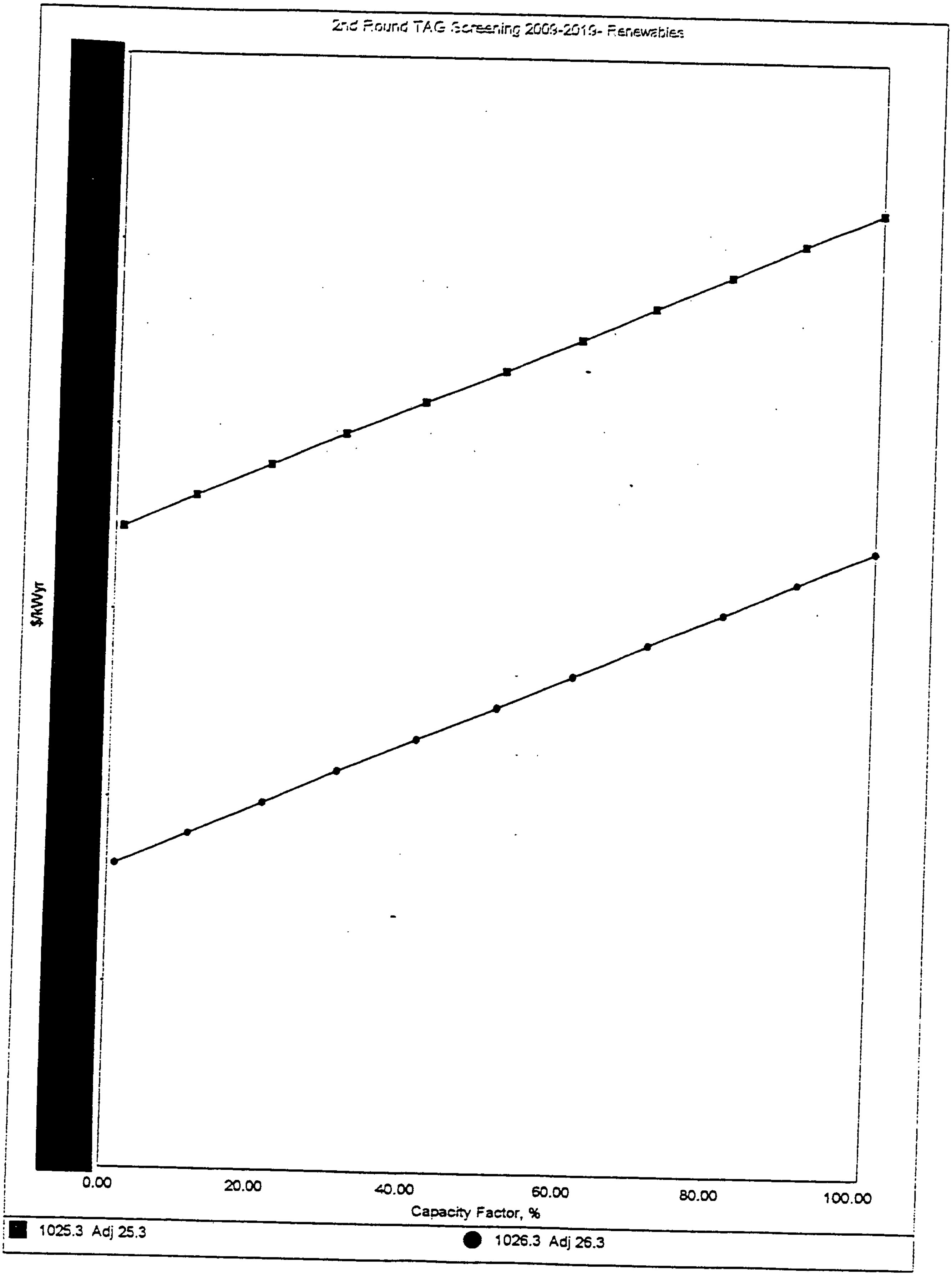
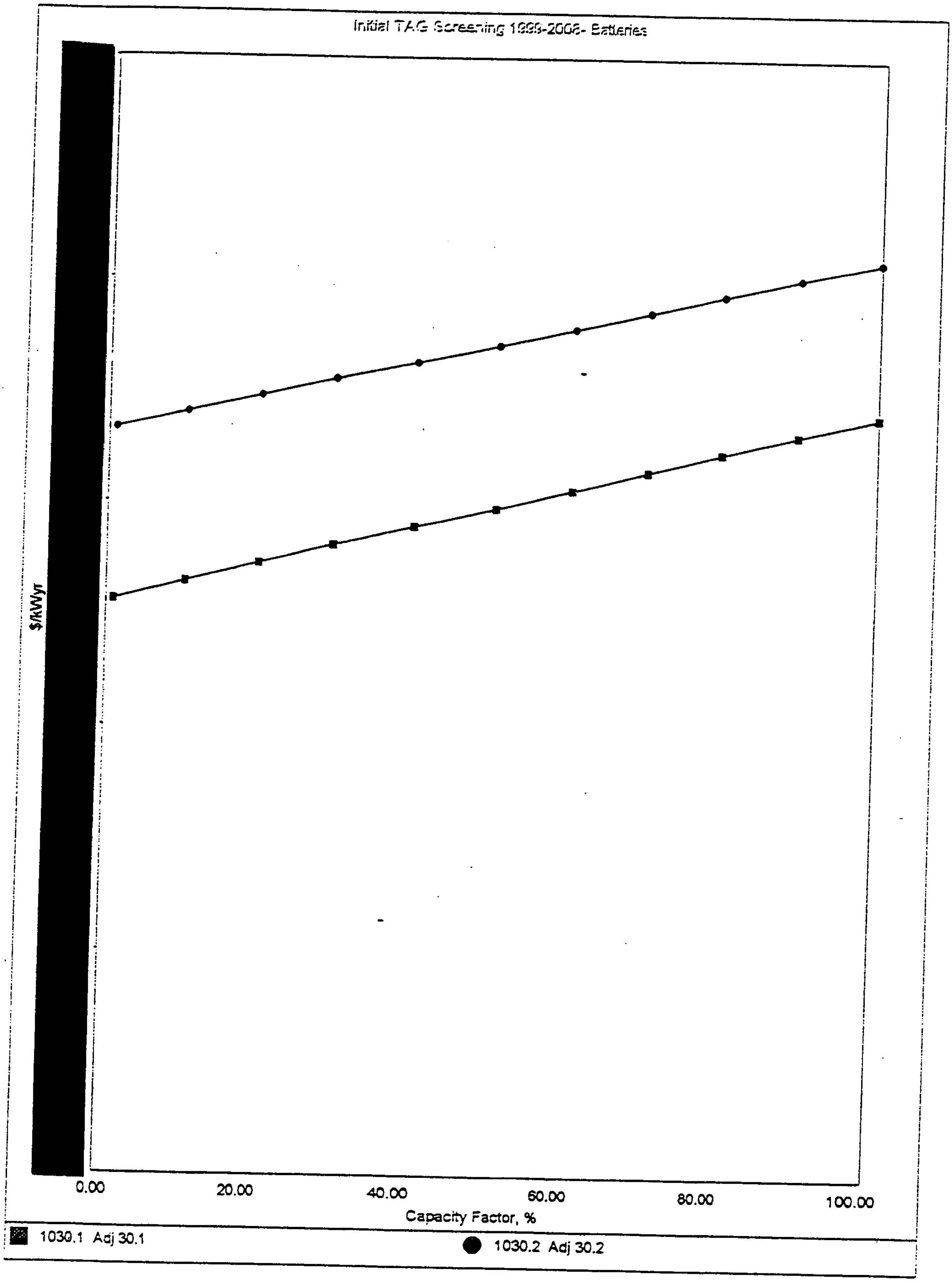


Figure GA-5-35

CONFIDENTIAL




Initial TAG Screening 1999-2008- Batteries
$/kWyr
0.00
20.00
40.00
60.00
80.00
100.00
Capacity Factor, %
1030.1 Adj 30.1
1030.2 Adj 30.2

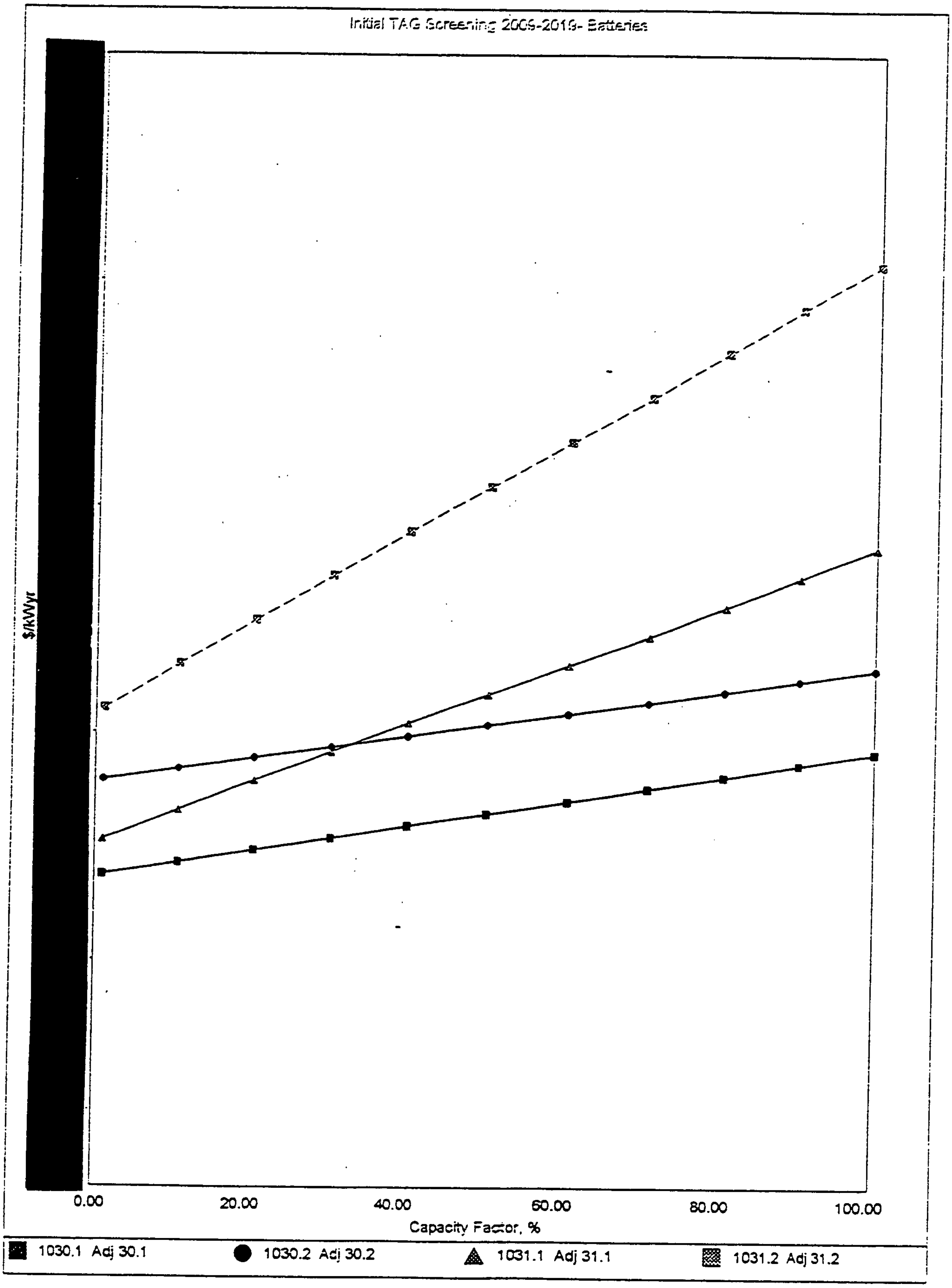
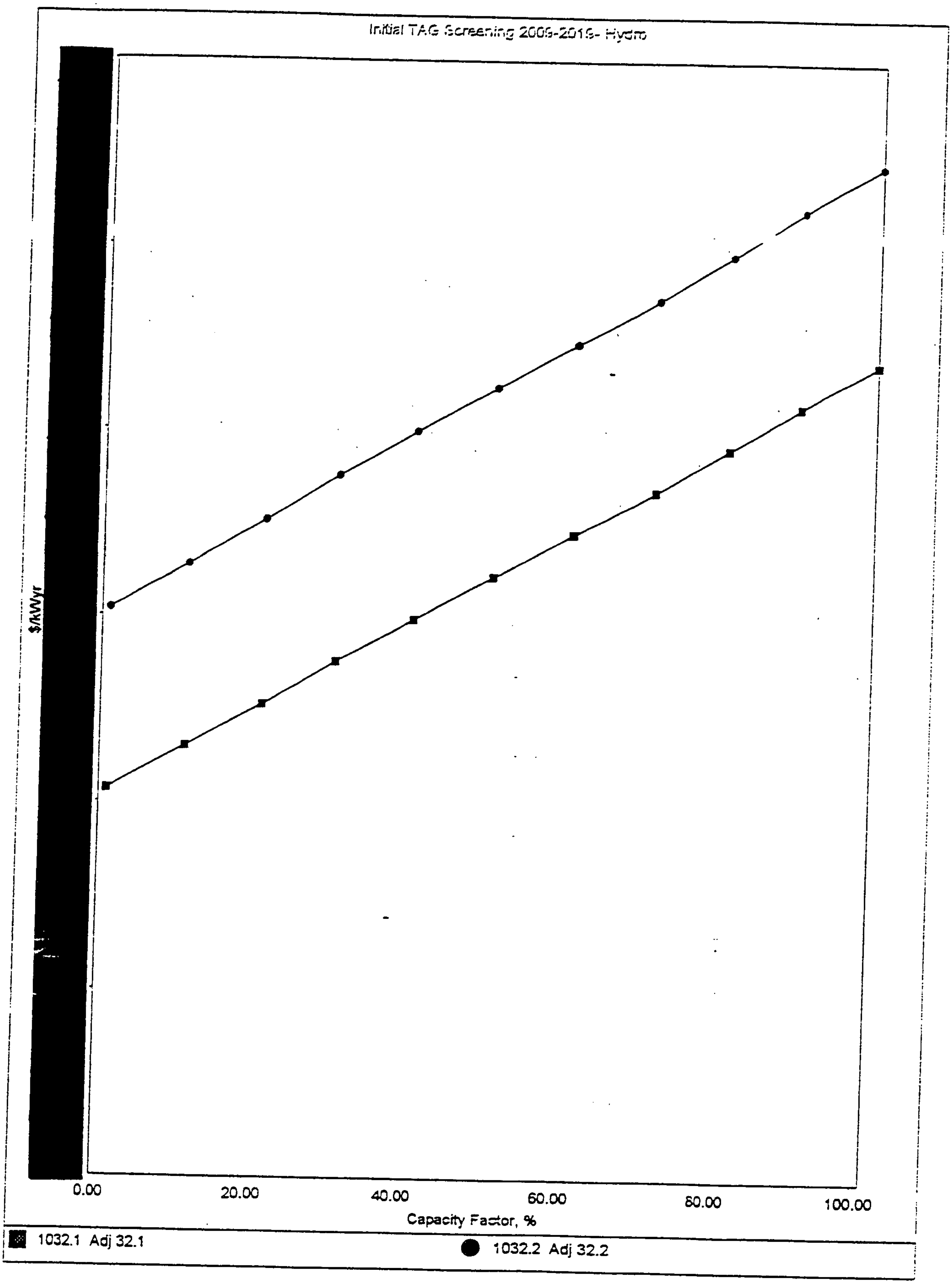

Initial TAG Screening 2009-2019- Batteries
[redacted]
$/kWyr
0.00
20.00
40.00
60.00
80.00
100.00
Capacity Factor, %
1030.1 Adj 30.1
1030.2 Adj 30.2
1031.1 Adj 31.1
1031.2 Adj 31.2

Figure GA-5-38



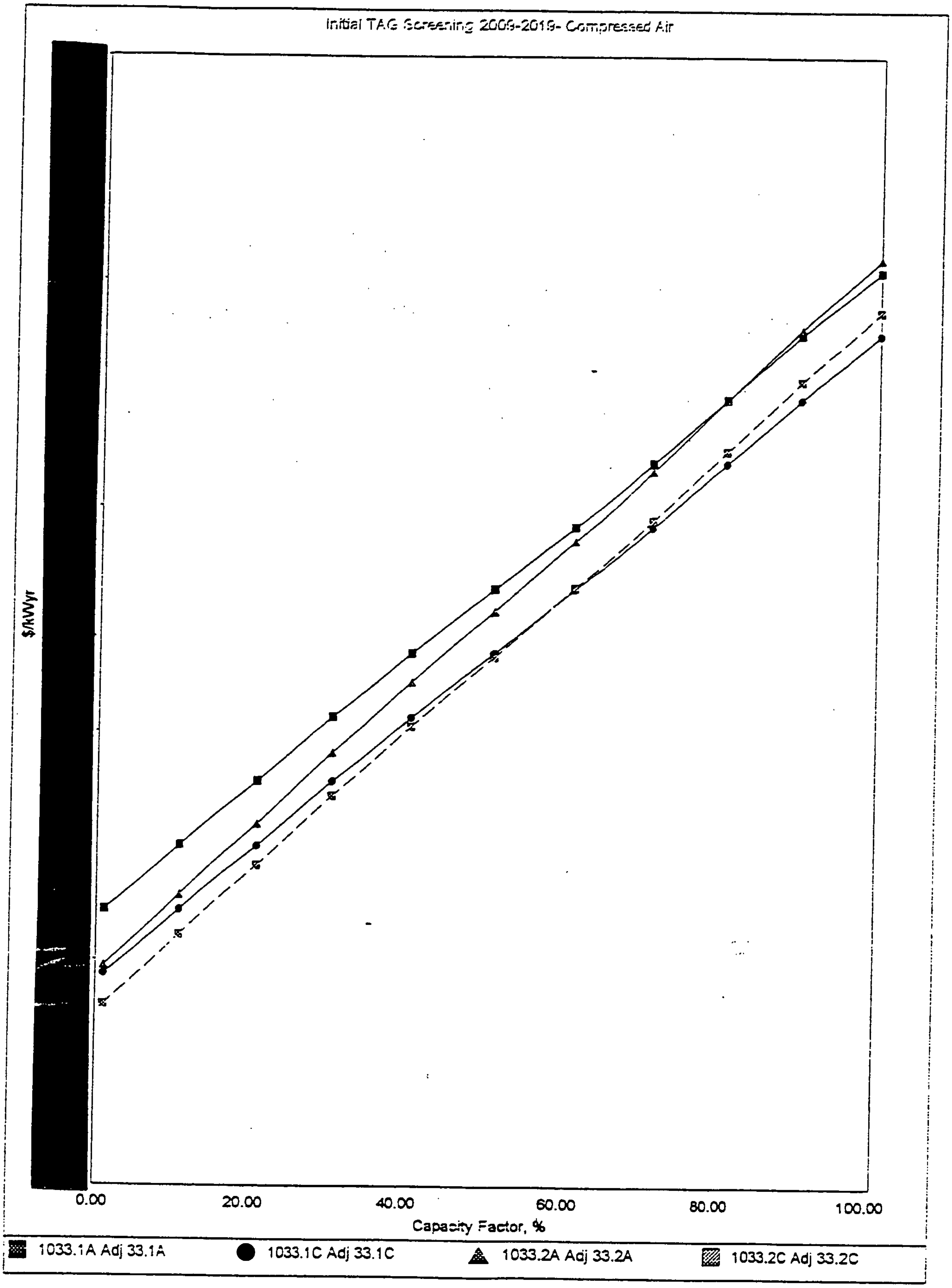

Initial TAG Screening 2009-2019- Compressed Air
$/kWyr
[redacted]
0.00
20.00
40.00
60.00
80.00
100.00
Capacity Factor, %
1033.1A Adj 33.1A
1033.1C Adj 33.1C
1033.2A Adj 33.2A
1033.2C Adj 33.2C

Figure GA-5-40

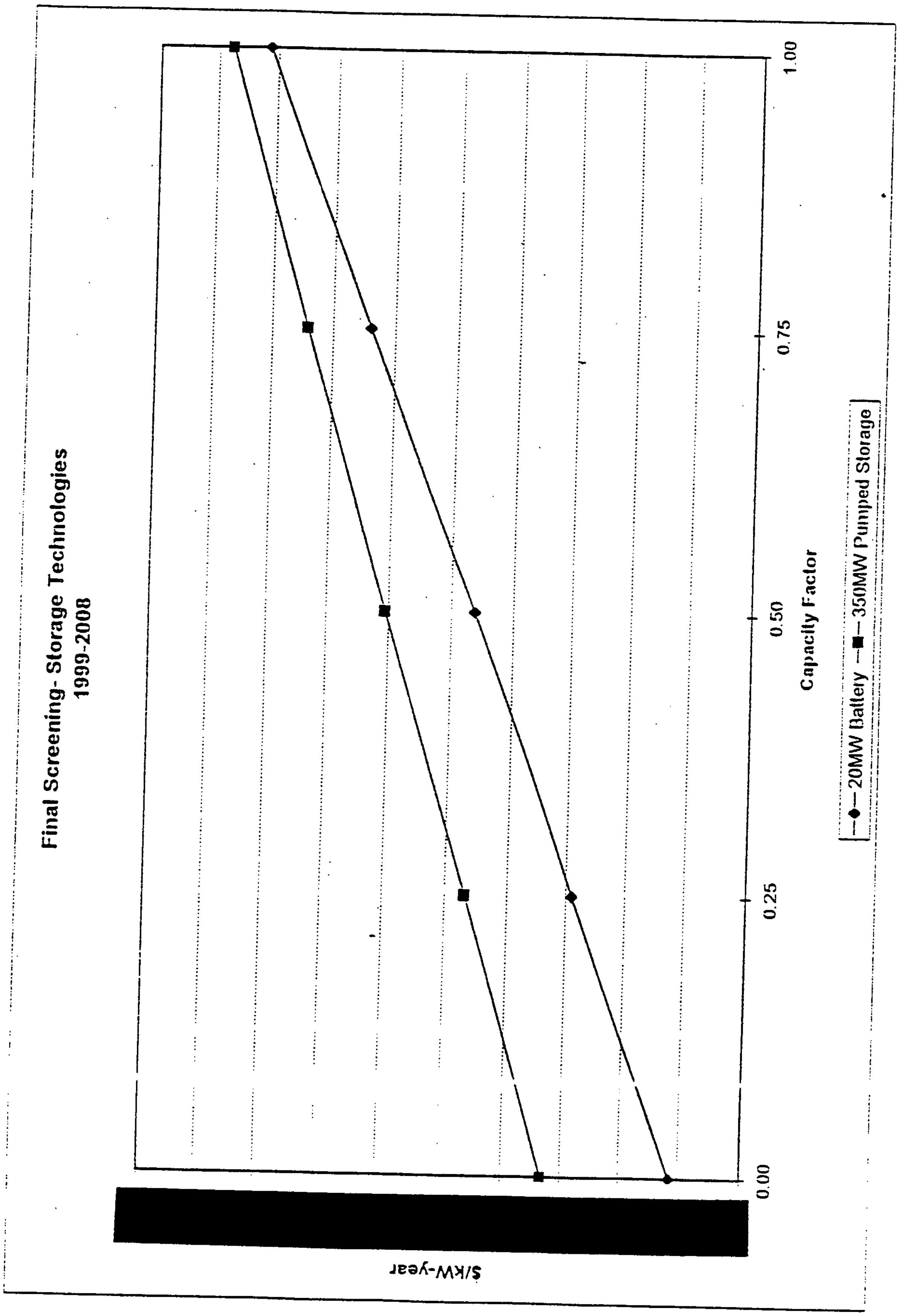


Figure GA-5-41

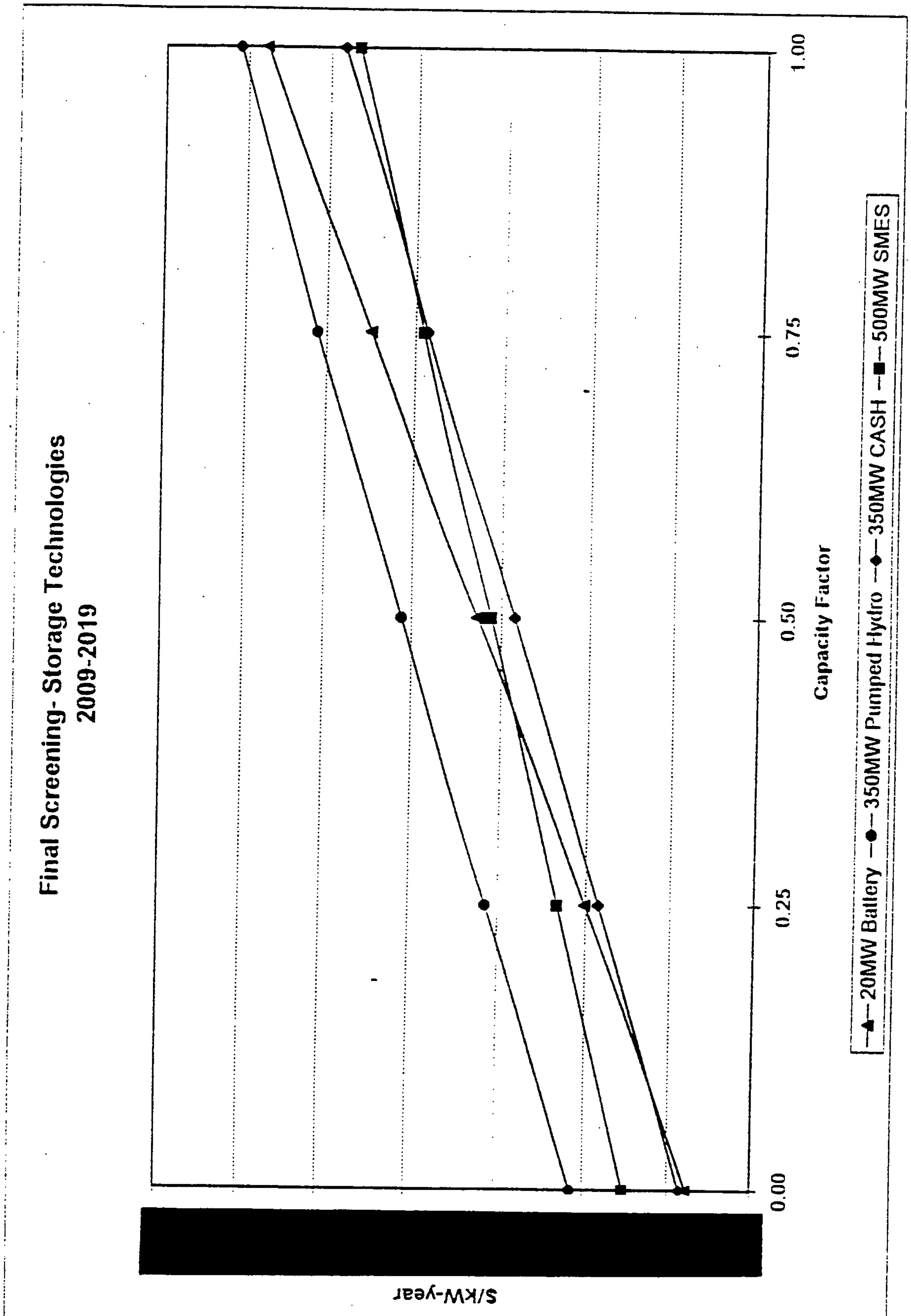


Figure GA-5-42

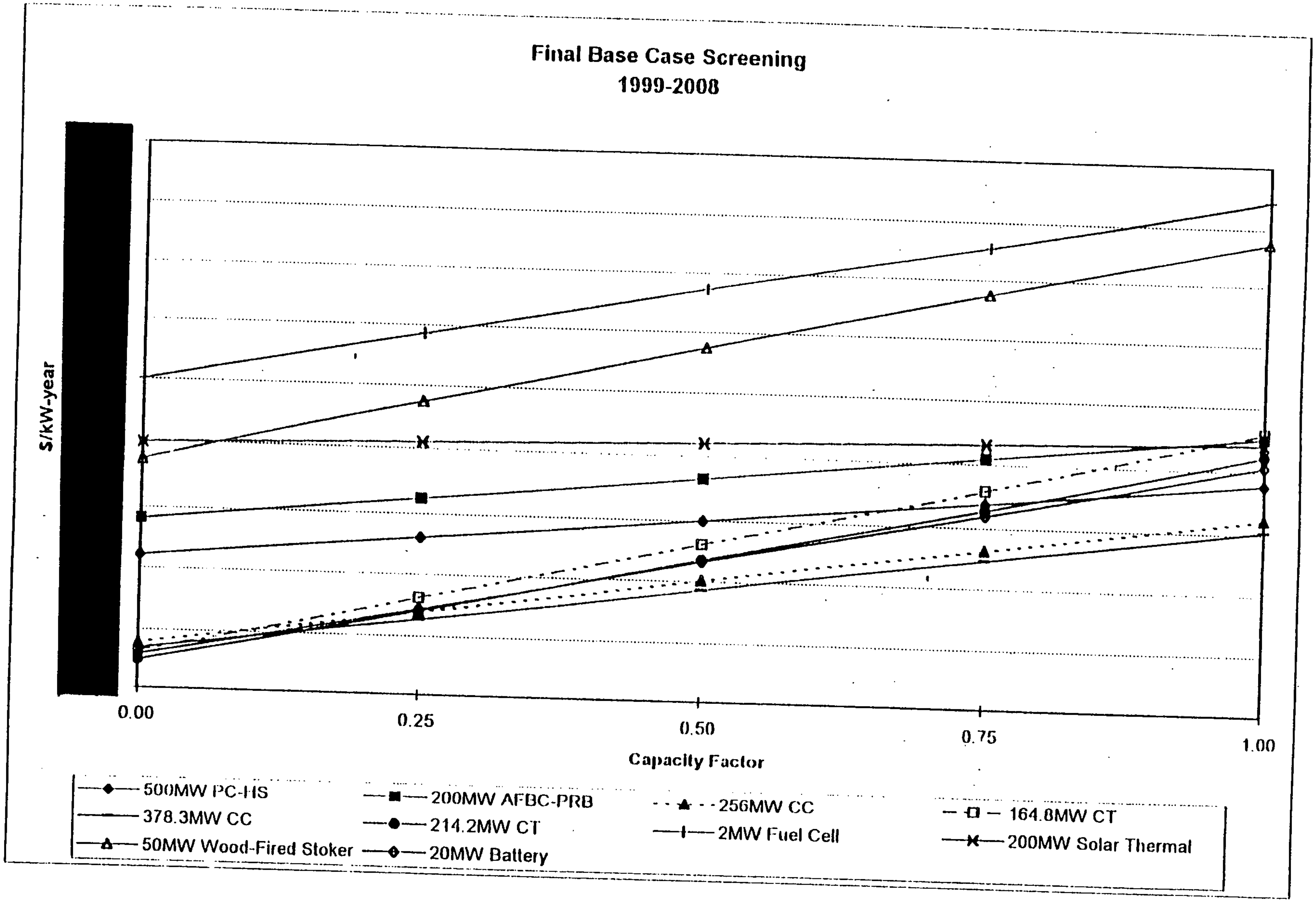


Figure GA-5-43

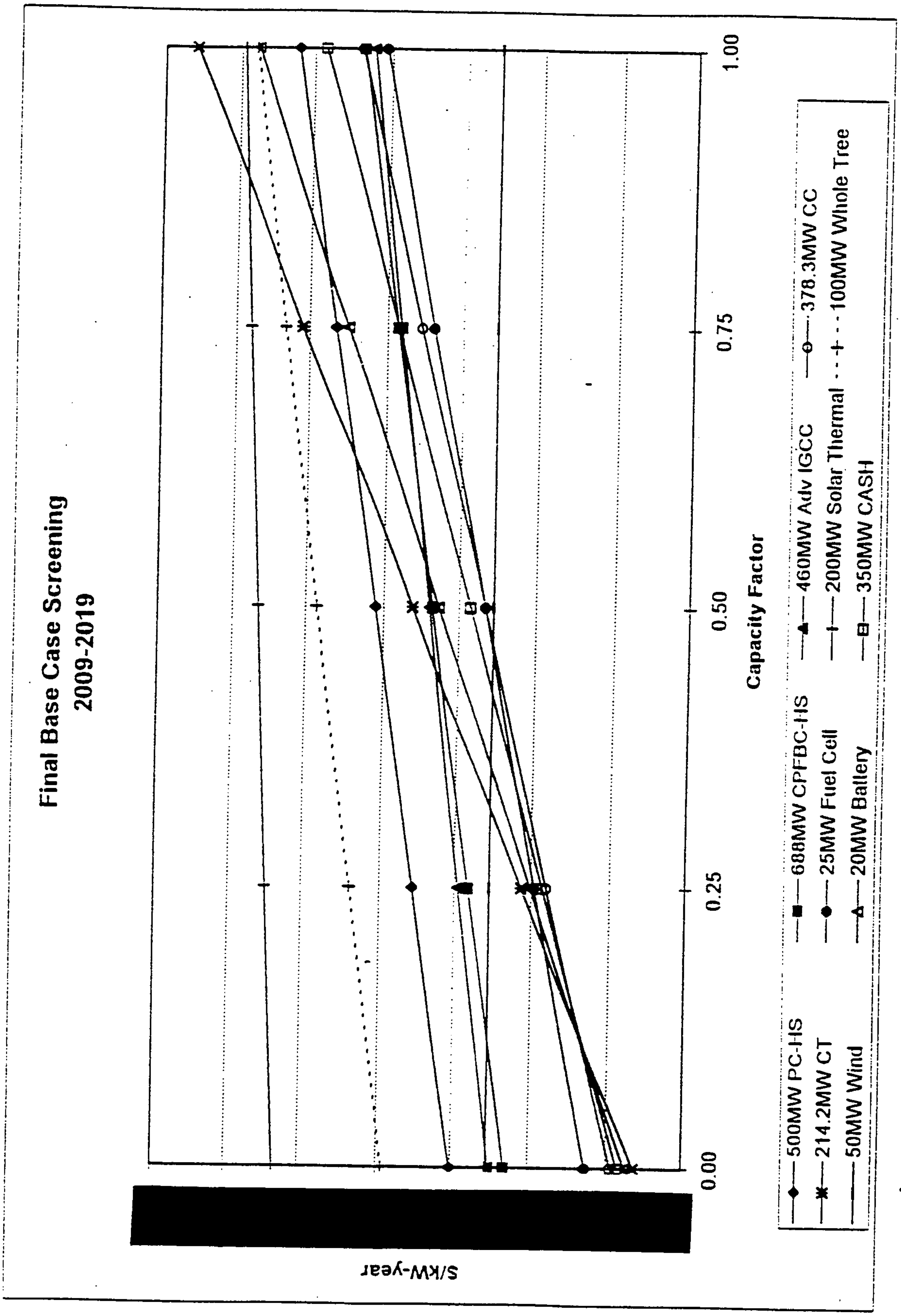


Figure GA-5-44

1999-2008 SCREENING CURVE DATA

SO2 Allowance ($/ton): [redacted] Annual Allowance Escalation

Discount Rate: 7.62%

1999 Dollars	Plant A	Plant B	Plant C	Plant D	Plant E	Plant F	Plant G	Plant H	Plant I	Plant J
GRAPH LEGEND:	500MW PC-HS	200MW AFBC-PRB	256MW CC	164.8MW CT	378.3MW CC	214.2MW CT	2MW Fuel Cell	200MW Solar Thermal	50MW Wood-Fired Stoker	20MW Battery
Size (MWe)	500.0	200.0	256.0	164.8	378.3	214.2	2.0	200.0	50.0	20.0
Capital Cost ($/kWe)	[redacted]									
Annual Fixed Charge Rate	12.50%	12.50%	11.90%	11.90%	11.90%	11.90%	12.50%	12.50%	12.50%	12.50%
Book Life (yrs)	30	30	30	30	30	30	30	30	30	30
Heat Rate (Btu/kWh)	[redacted]									
Var. O&M ($/MWh)										
Fixed O&M ($/kW-yr)										
Fuel Cost ($/MMBtu)										
Fuel Escalation Rate										
O&M Escalation Rate										
SO2 Emission Rate (lbs./MMbtu)										

NOTE: The values shown are relative values used for planning purposes. Absolute values may vary considerably depending on many factors, including but not limited to: unit MW size, seasonal deratings, specific site requirements, equipment vendor(s), ultimate number of units planned on a specific site, and future and/or unforseen regulatory requirements. An EPRI TAO estimate of AFUDC is included in the capital costs.

Levelized $/kwyr = [redacted]

Figure [illegible]-5-45

2009-2019 SCREENING CURVE DATA

SO2 Allowance ($/ton): [redacted] Annual Allowance Escalation

Discount Rate: 7.62%

2009 Dollars	Plant A	Plant B	Plant C	Plant D	Plant E	Plant F	Plant G	Plant H	Plant I	Plant J	Plant K
GRAPH LEGEND:	500MW PC-HS	688MW CPFBC-HS	460MW Adv IGCC	378.3MW CC	214.2MW CT	25MW Fuel Cell	200MW Solar Thermal	100MW Whole Tree	50MW Wind	20MW Battery	350MW CASH
Size (MWe)	500.0	688.0	460.0	378.3	214.2	25.0	200.0	100.0	50.0	20.0	350.0
Capital Cost ($/kWe)	[redacted]										
Annual Fixed Charge Rate	12.50%	12.50%	12.50%	11.90%	11.90%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Book Life (yrs)	30	30	30	30	30	30	30	30	30	30	30
Heat Rate (Btu/kWh)	[redacted]										
Var. O&M ($/MWh)											
Fixed O&M ($/kW-yr)											
Fuel Cost ($/MMBtu)											
Fuel Escalation Rate											
O&M Escalation Rate											
SO2 Emission Rate (lbs./MMbtu)											

NOTE: The values shown are relative values used for planning purposes. Absolute values may vary considerably depending on many factors, including but not limited to: unit MW size, seasonal deratings, specific site requirements, equipment vendor(s), ultimate number of units planned on a specific site, and future and/or unforseen regulatory requirements. An EPRI TAG estimate of AFUDC is included in the capital costs.

Levelized $/kwyr = [redacted]

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Figure GA-5-46

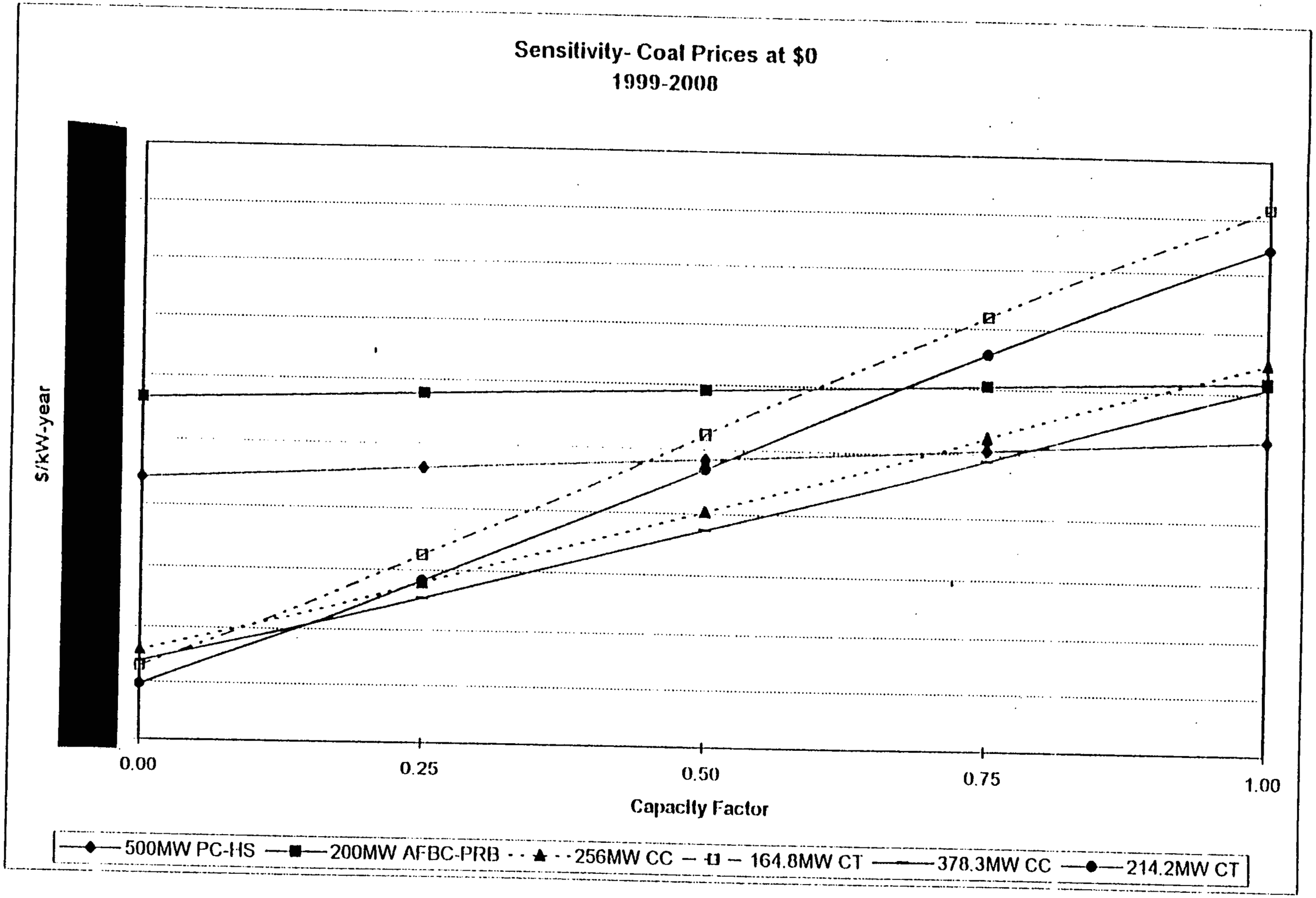

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Figure GA-5-47

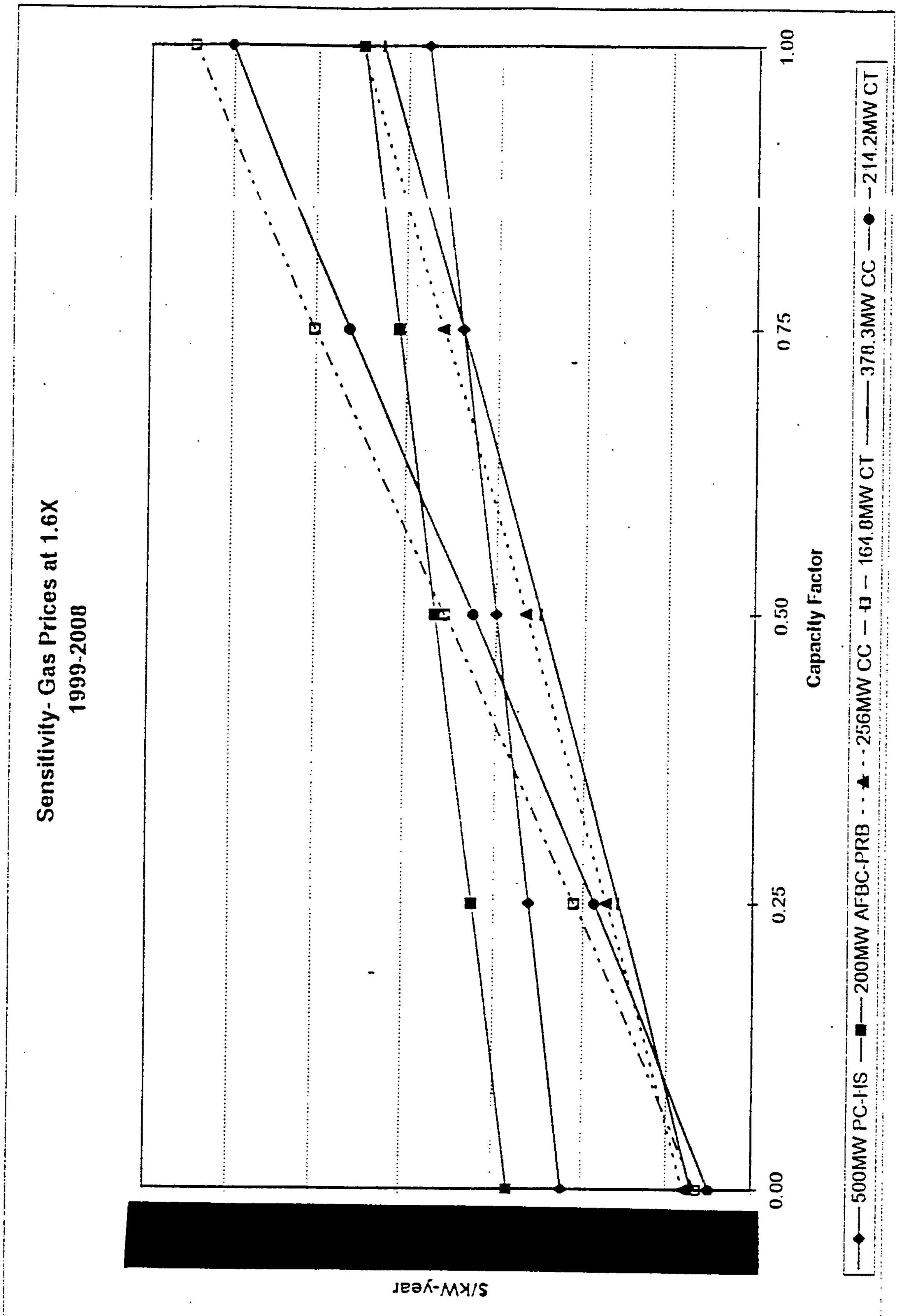
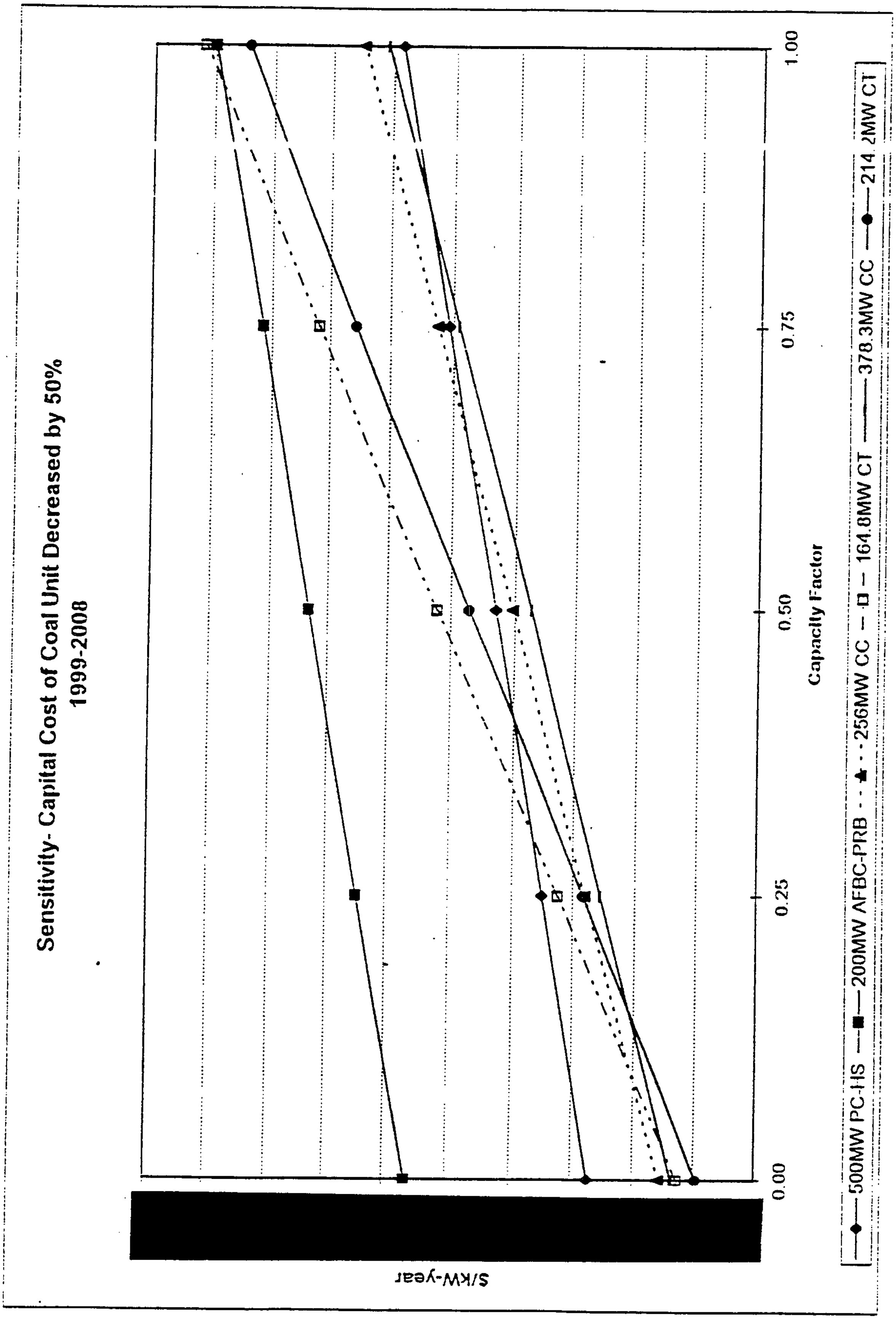


Figure GA-5-48



Sensitivity- Capital Cost of Coal Unit Decreased by 50%
1999-2008

Figure GA-5-49

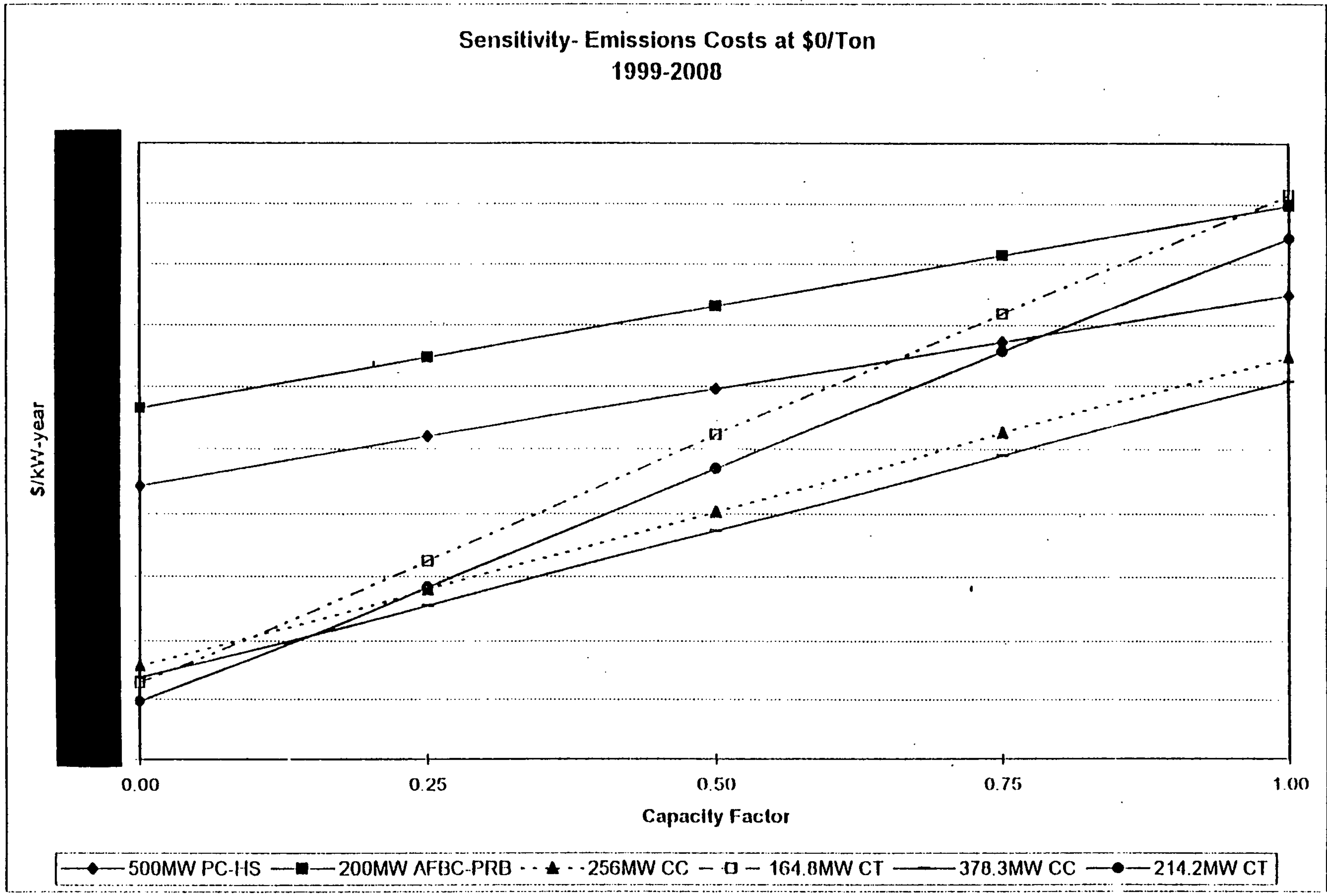
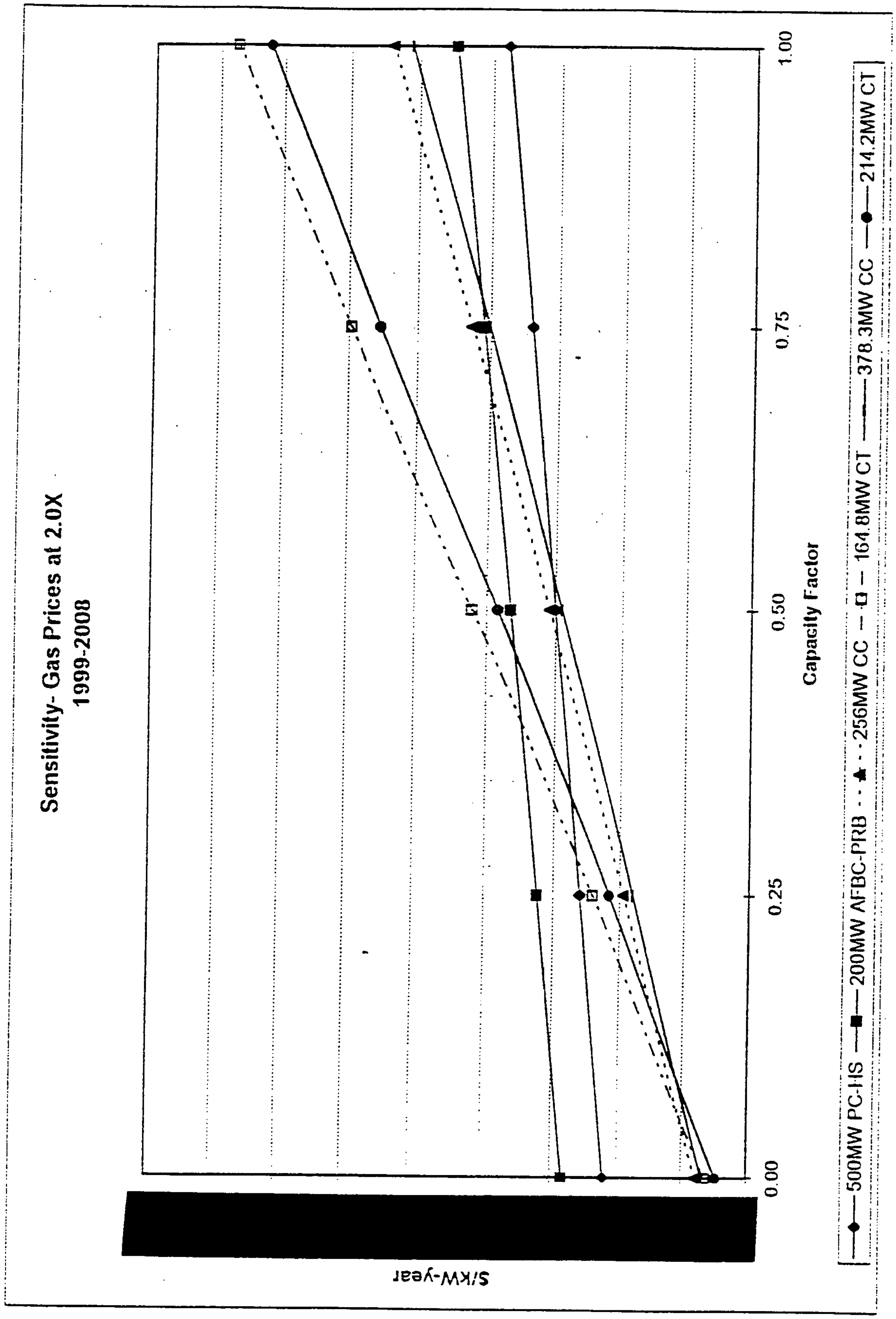


Figure GA-5-50



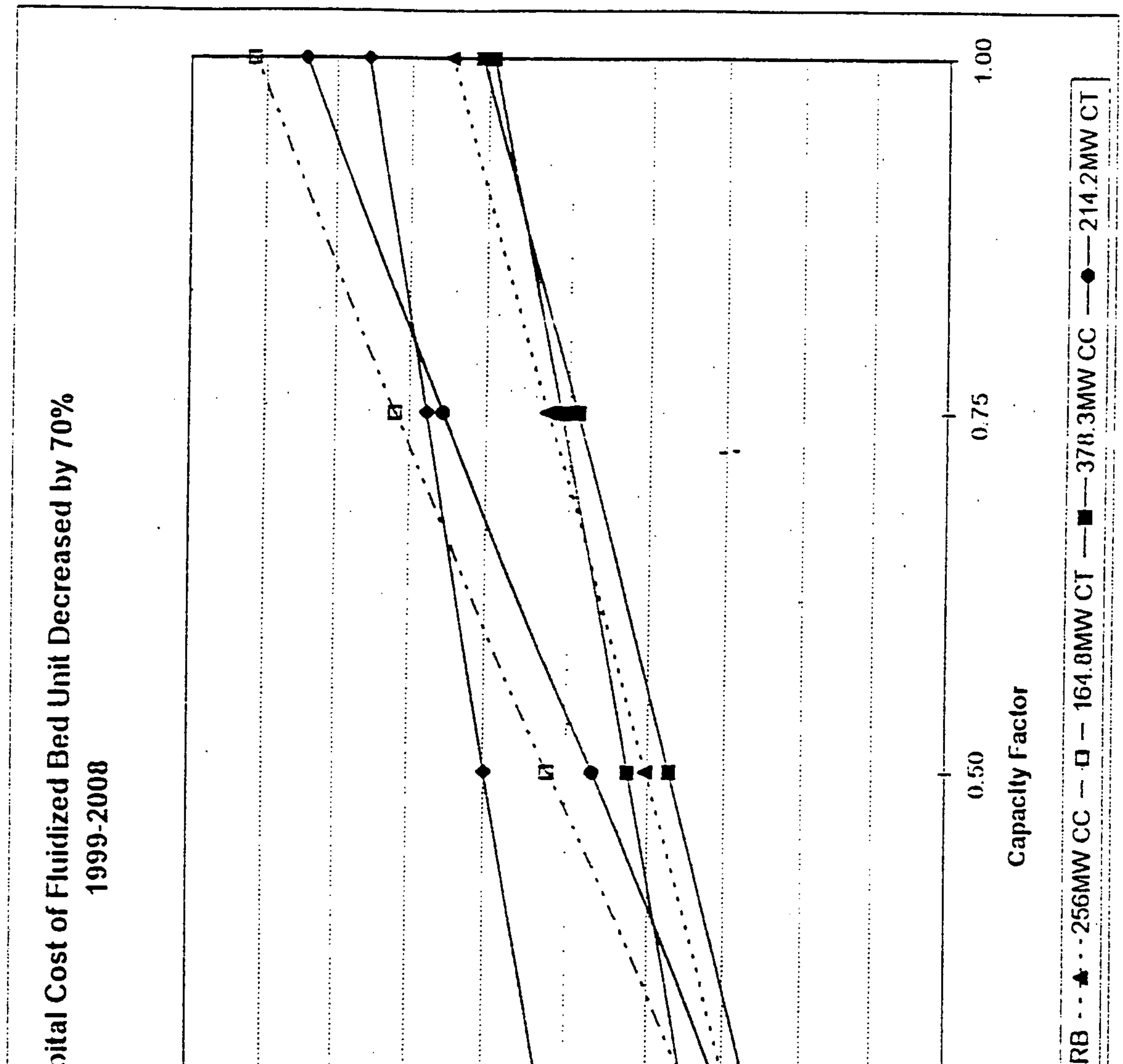

Sensitivity- Capital Cost of Fluidized Bed Unit Decreased by 70%
1999-2008
$/KW-year
0.00
0.25
0.50
0.75
1.00
Capacity Factor
500MW PC-HS
200MW AFBC-PRB
256MW CC
164.8MW CT
378.3MW CC
214.2MW CT

Figure GA-5-52

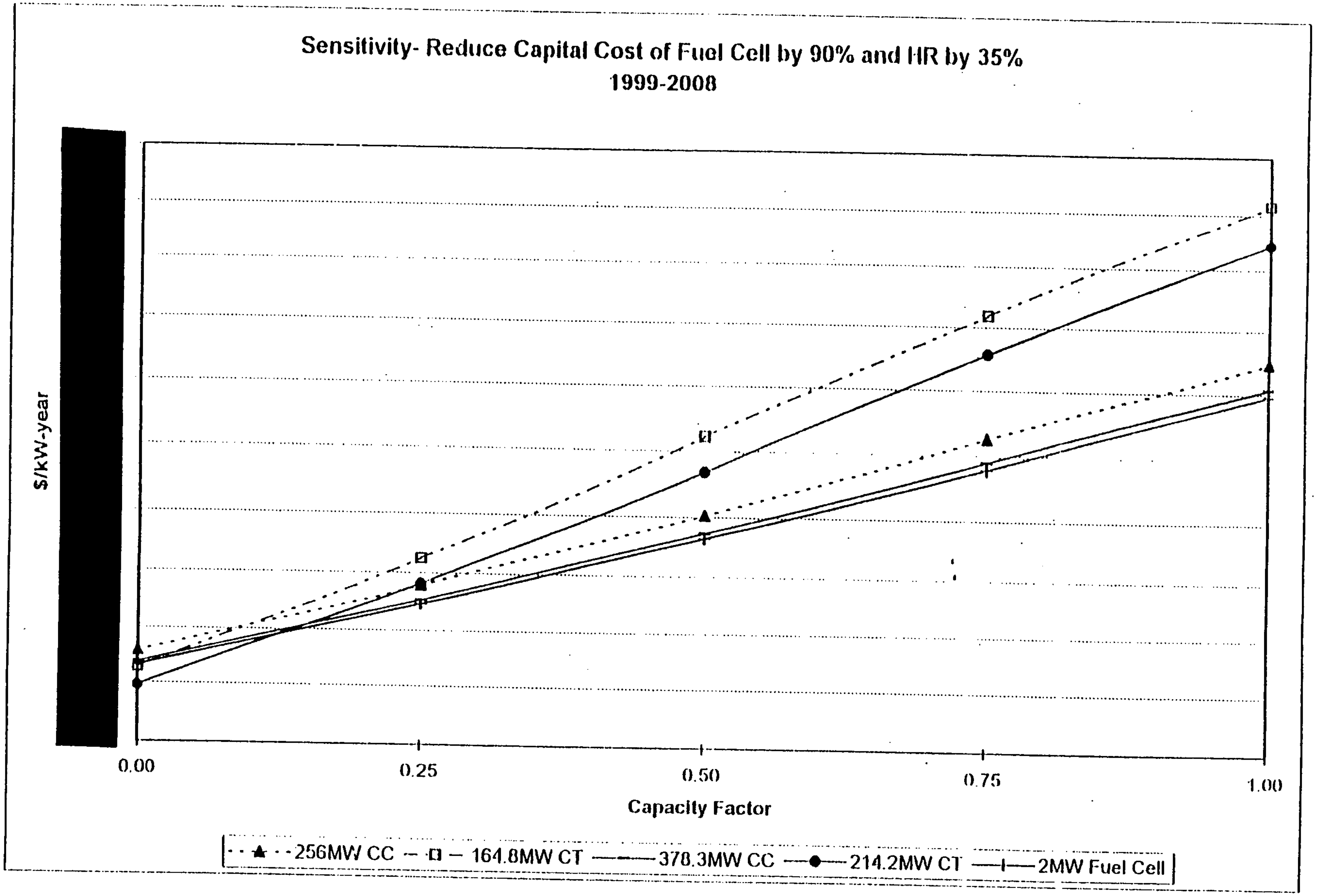


Figure GA-5-53

Sensitivity- Reduce Solar Capital Cost by 95%
1999-2008

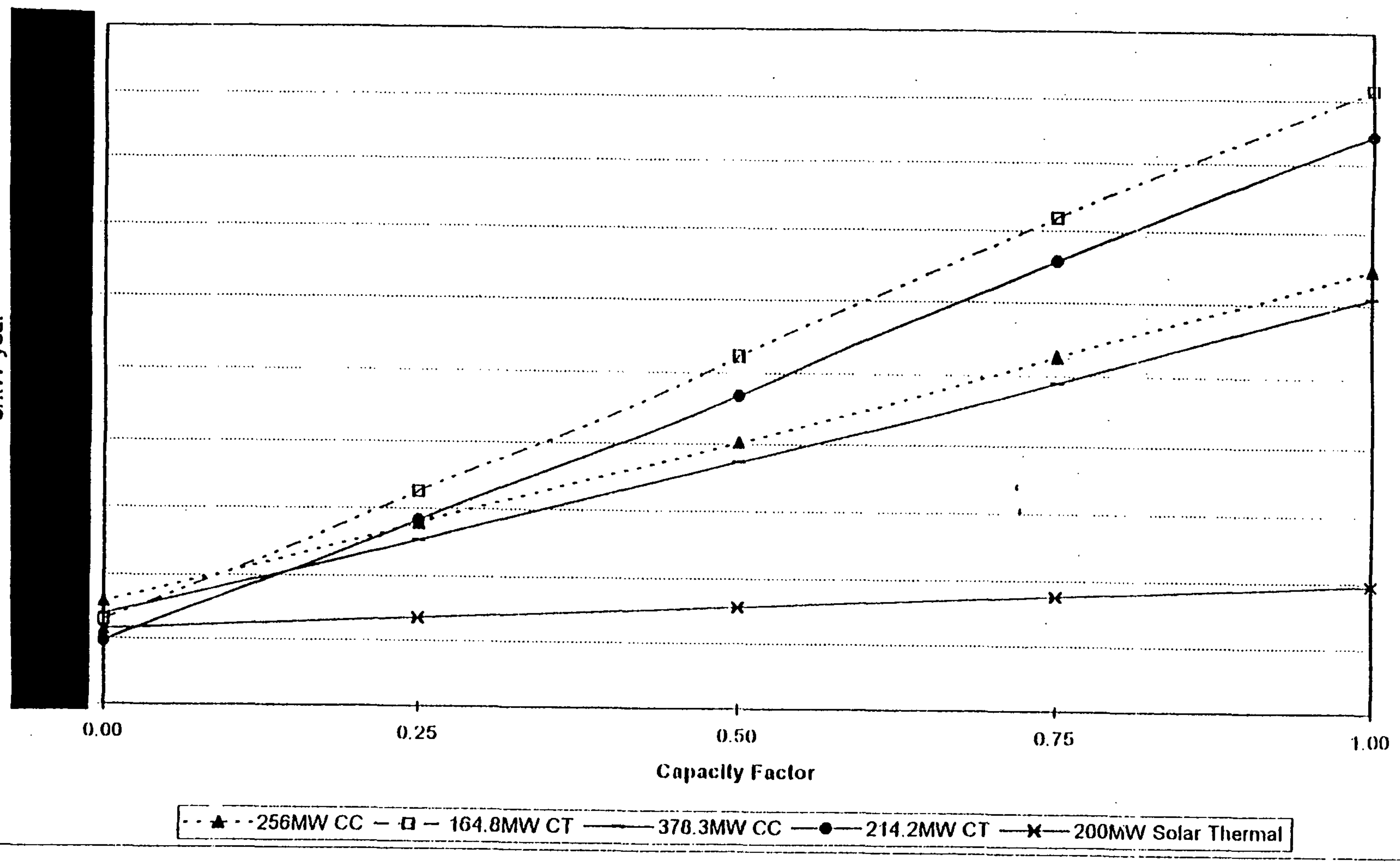


Figure GA-5-54

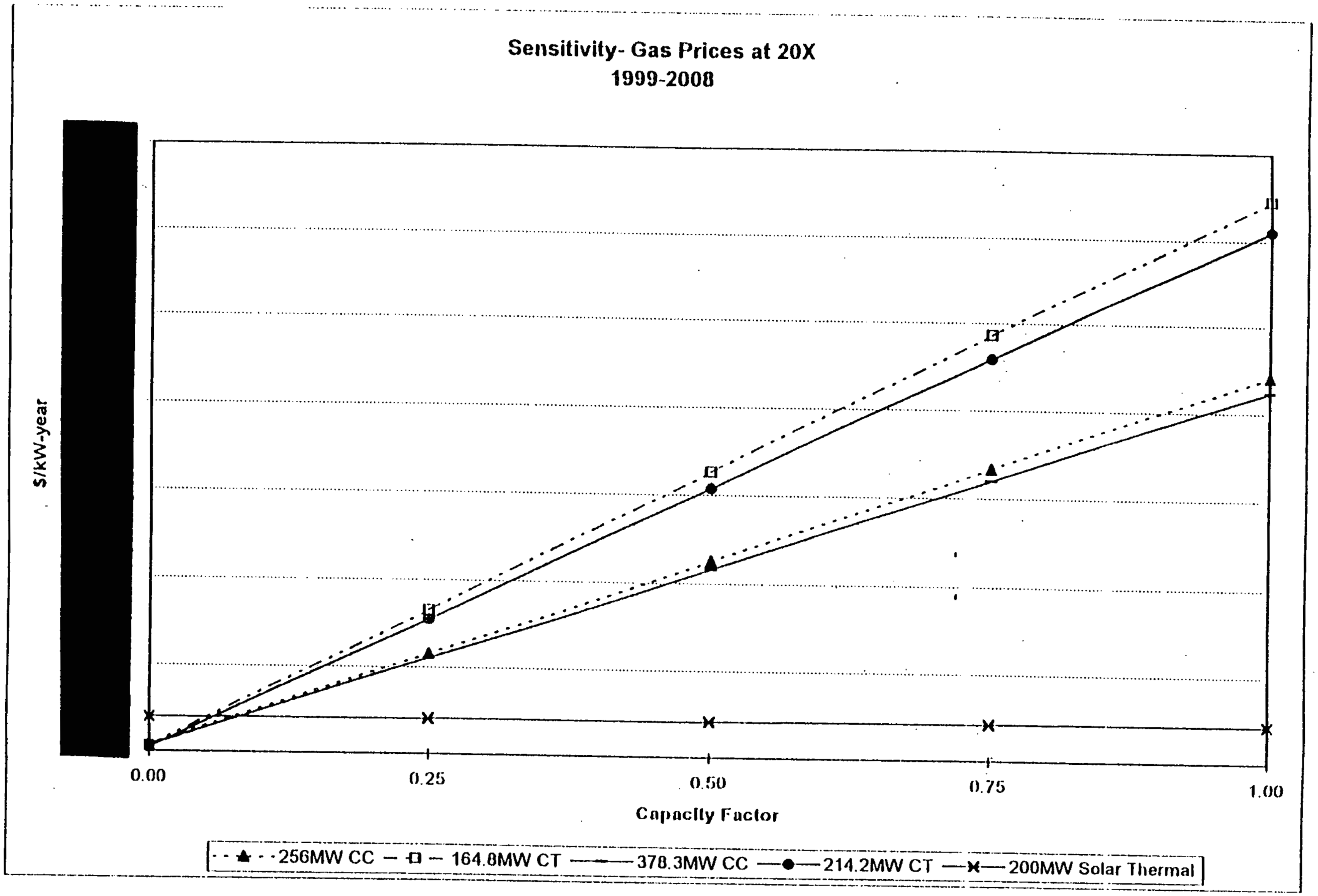


Figure GA-5-55

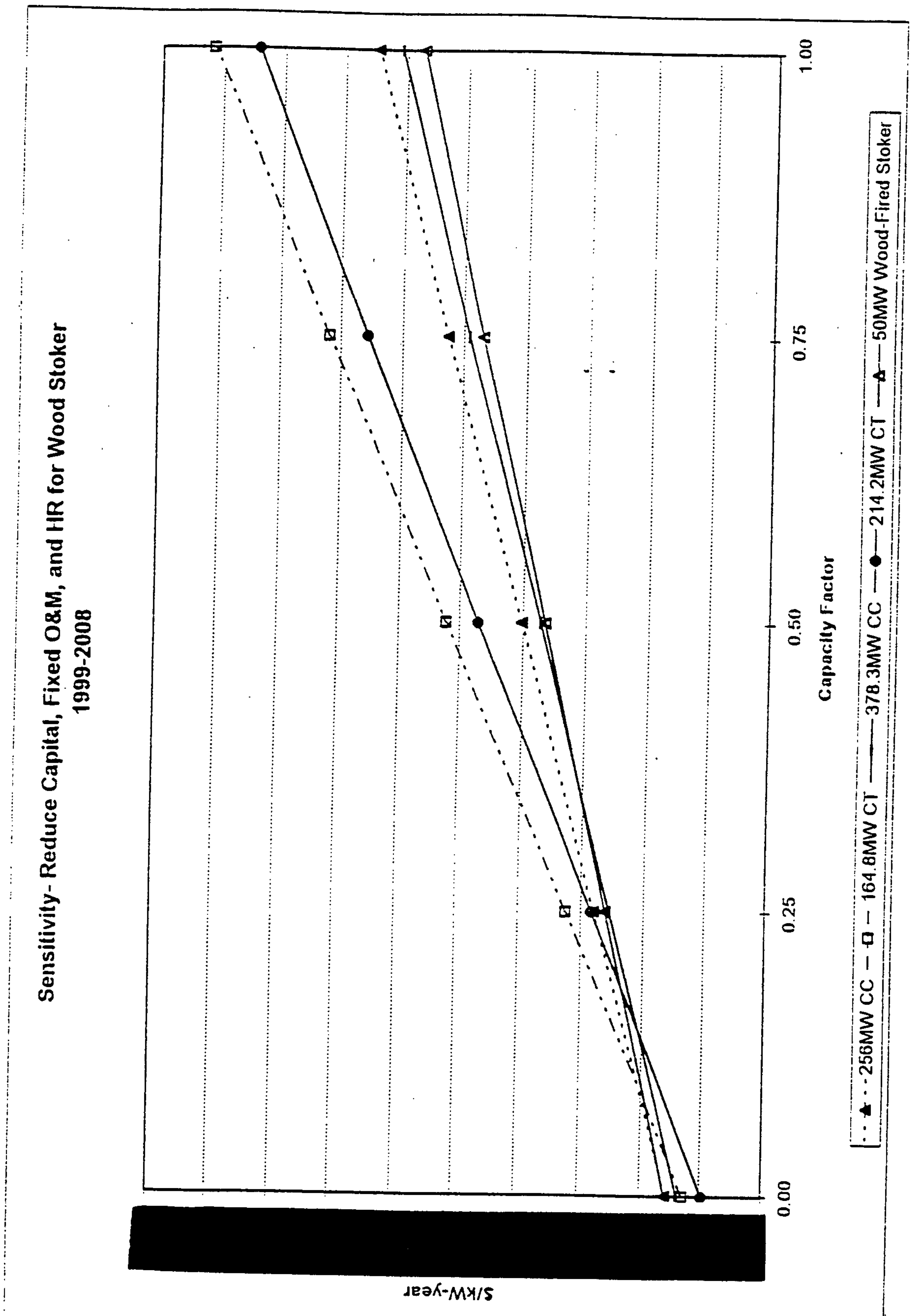


Figure GA-5-56

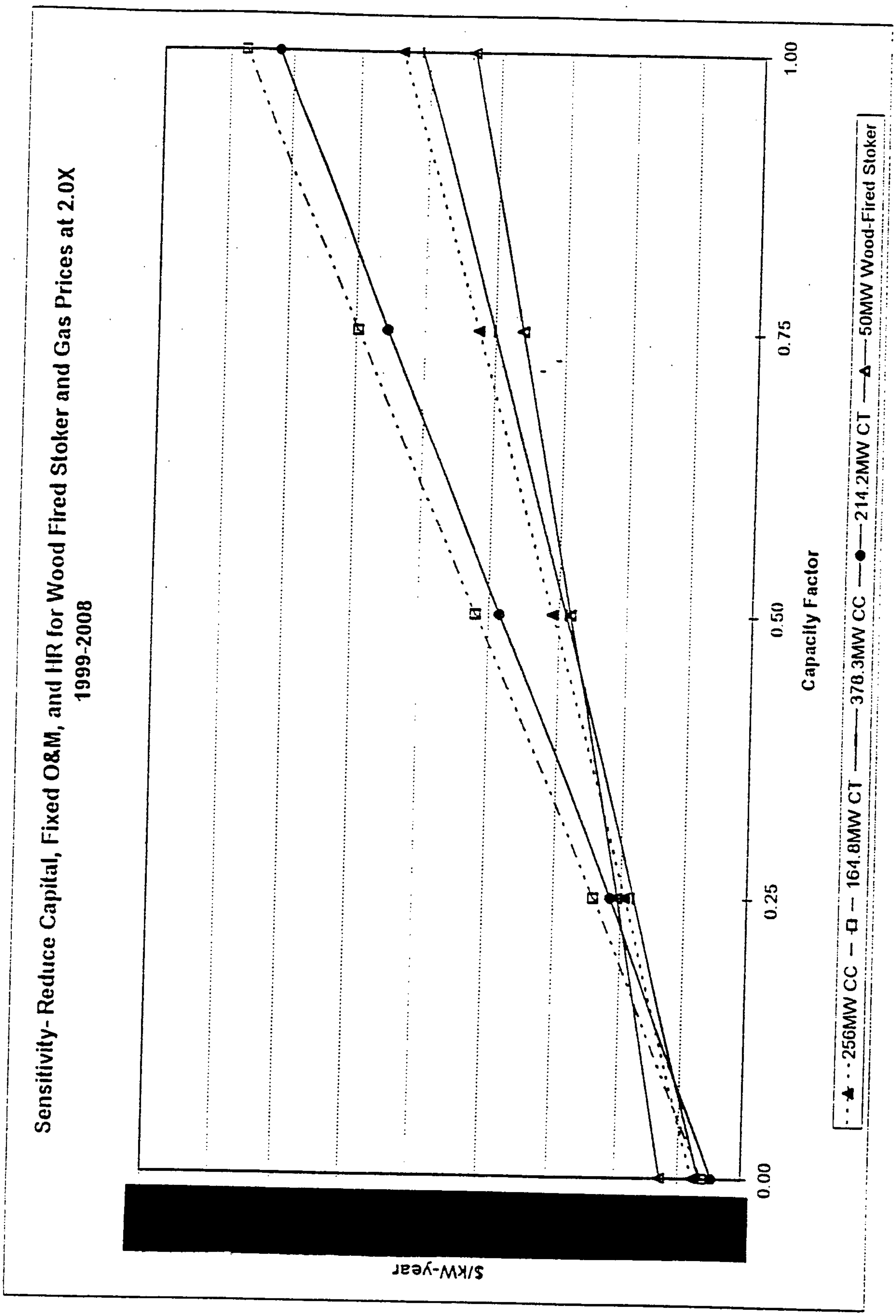


Figure GA-5-57

Sensitivity- Reduce Capital Cost of Battery by 20%
1999-2008

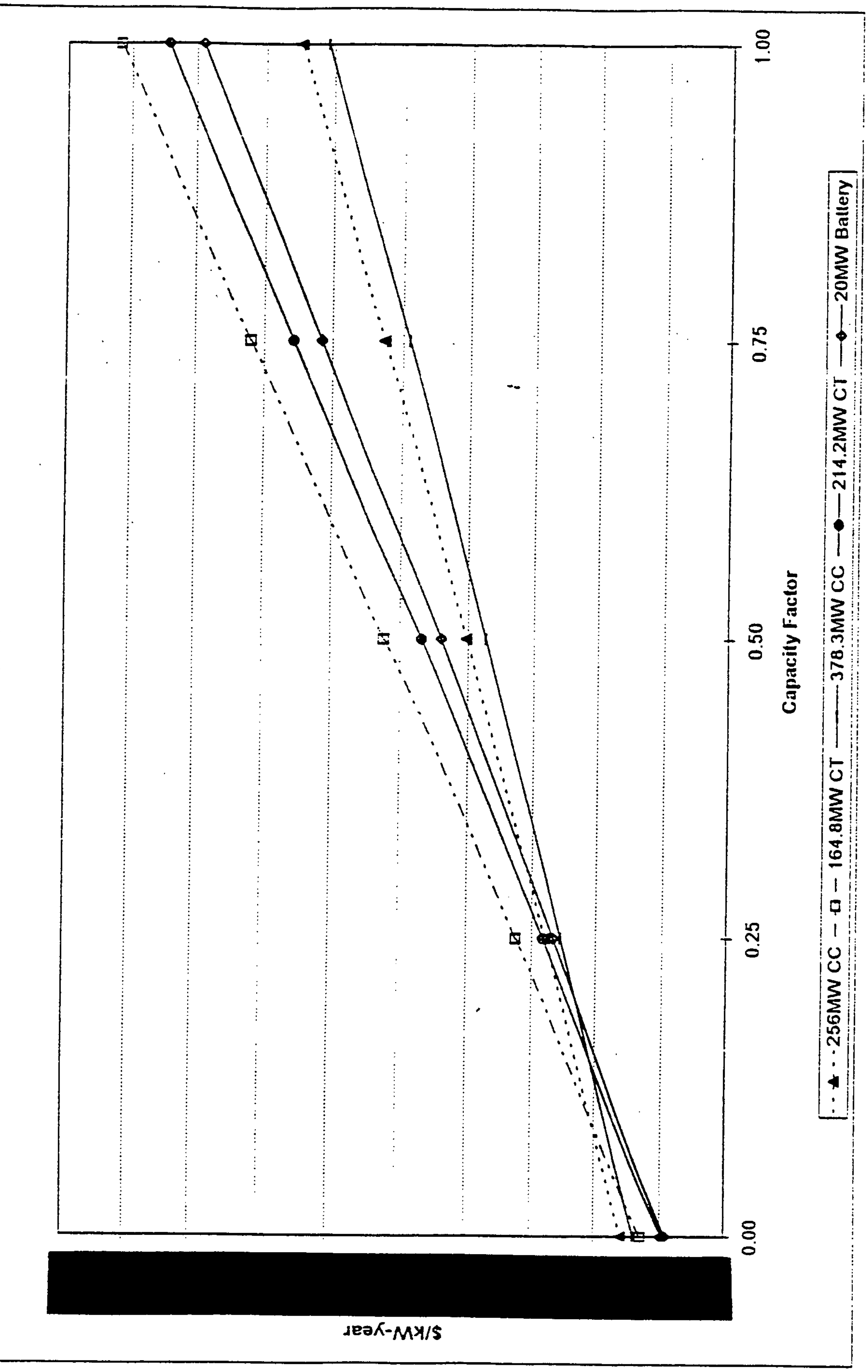


Figure GA-5-58

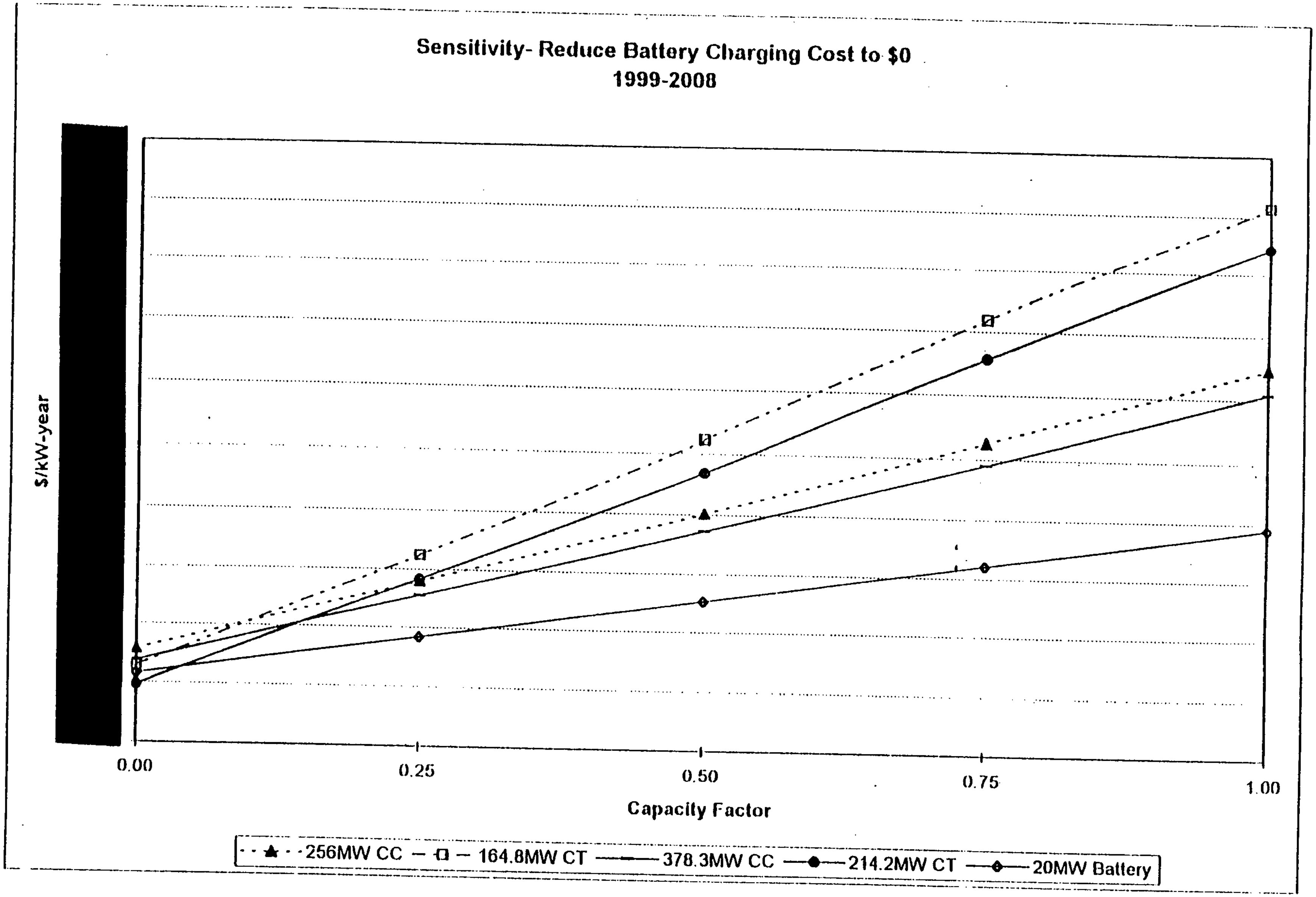


Figure GA-5-59

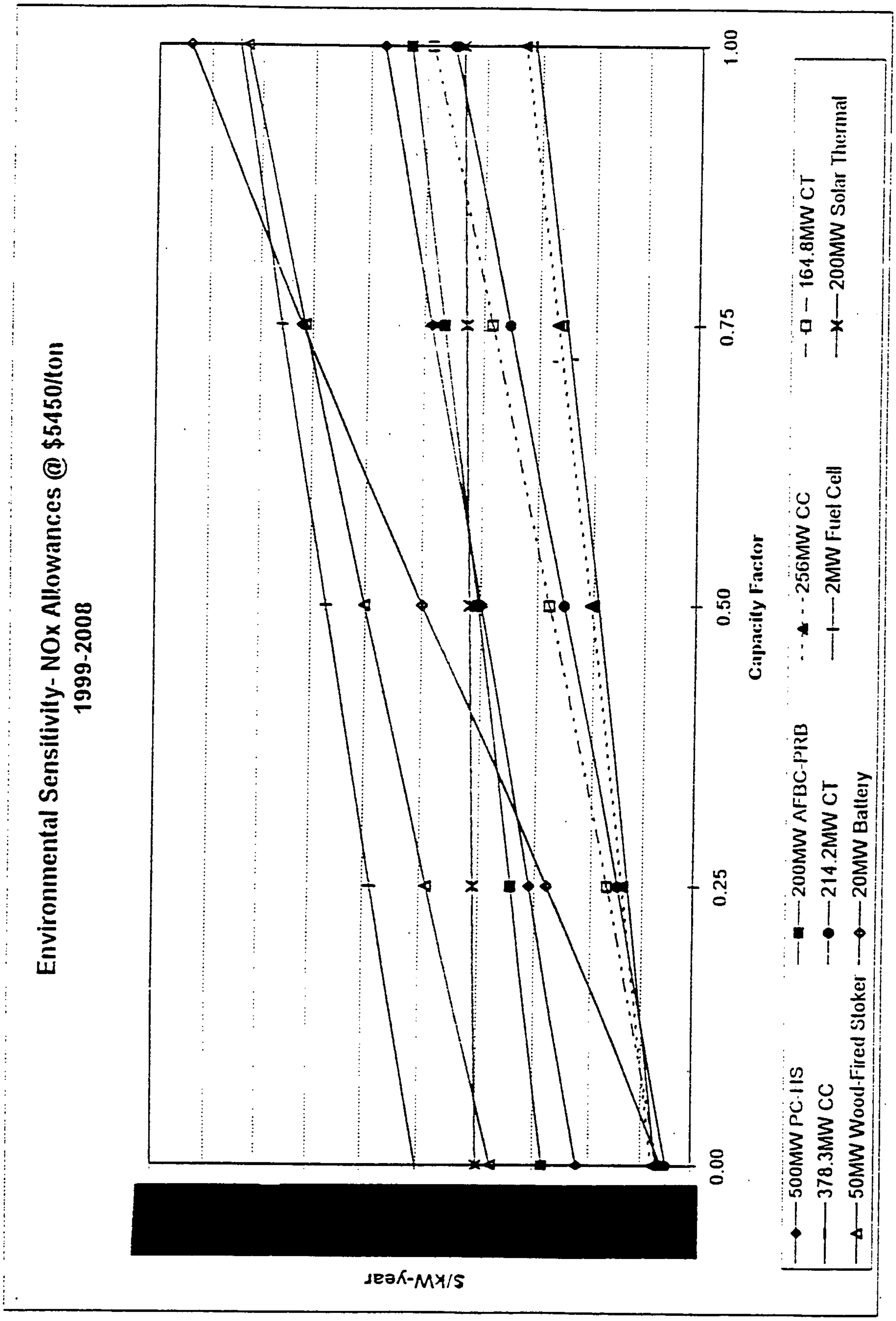


Figure GA-5-60

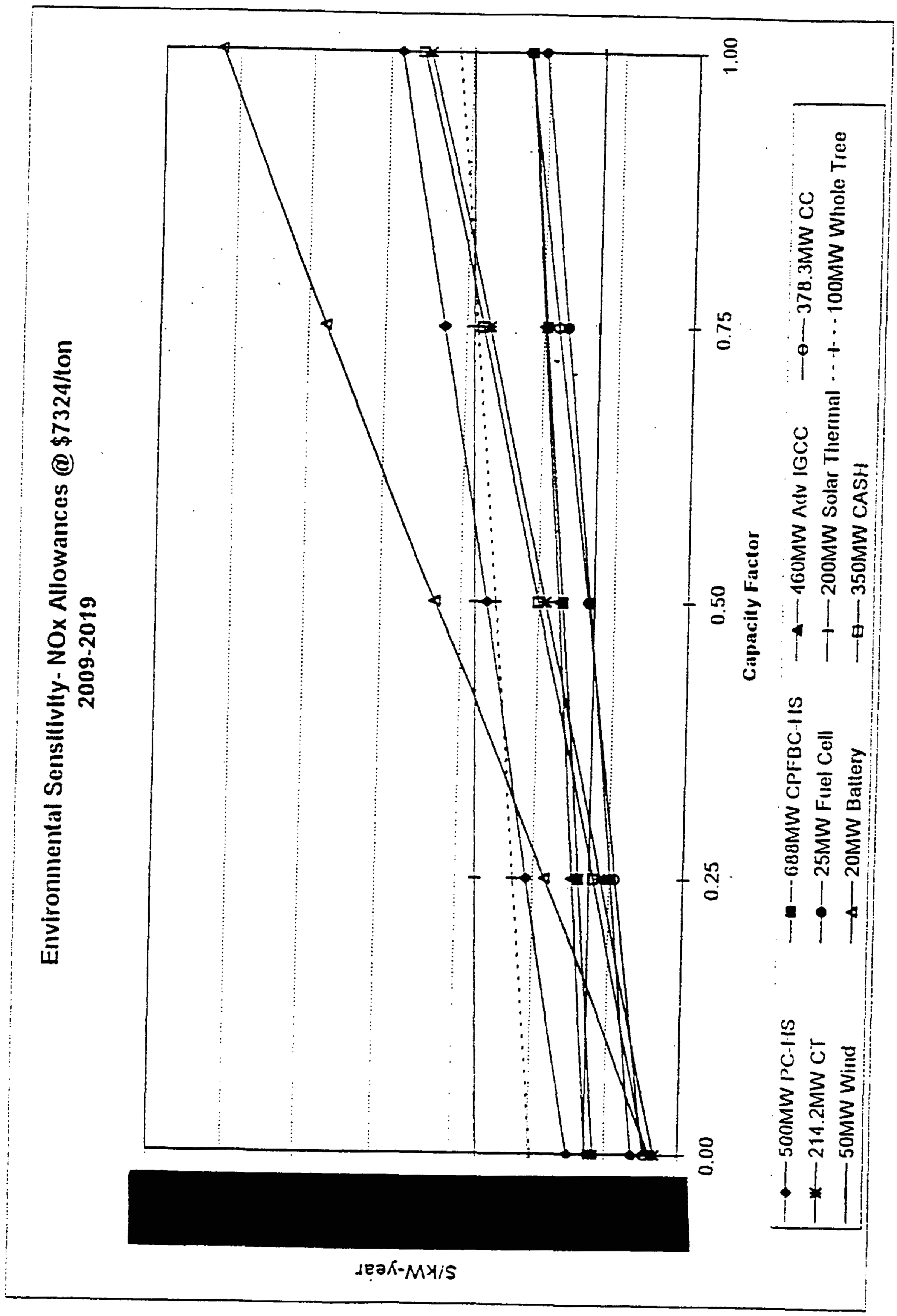


Figure GA-5-61

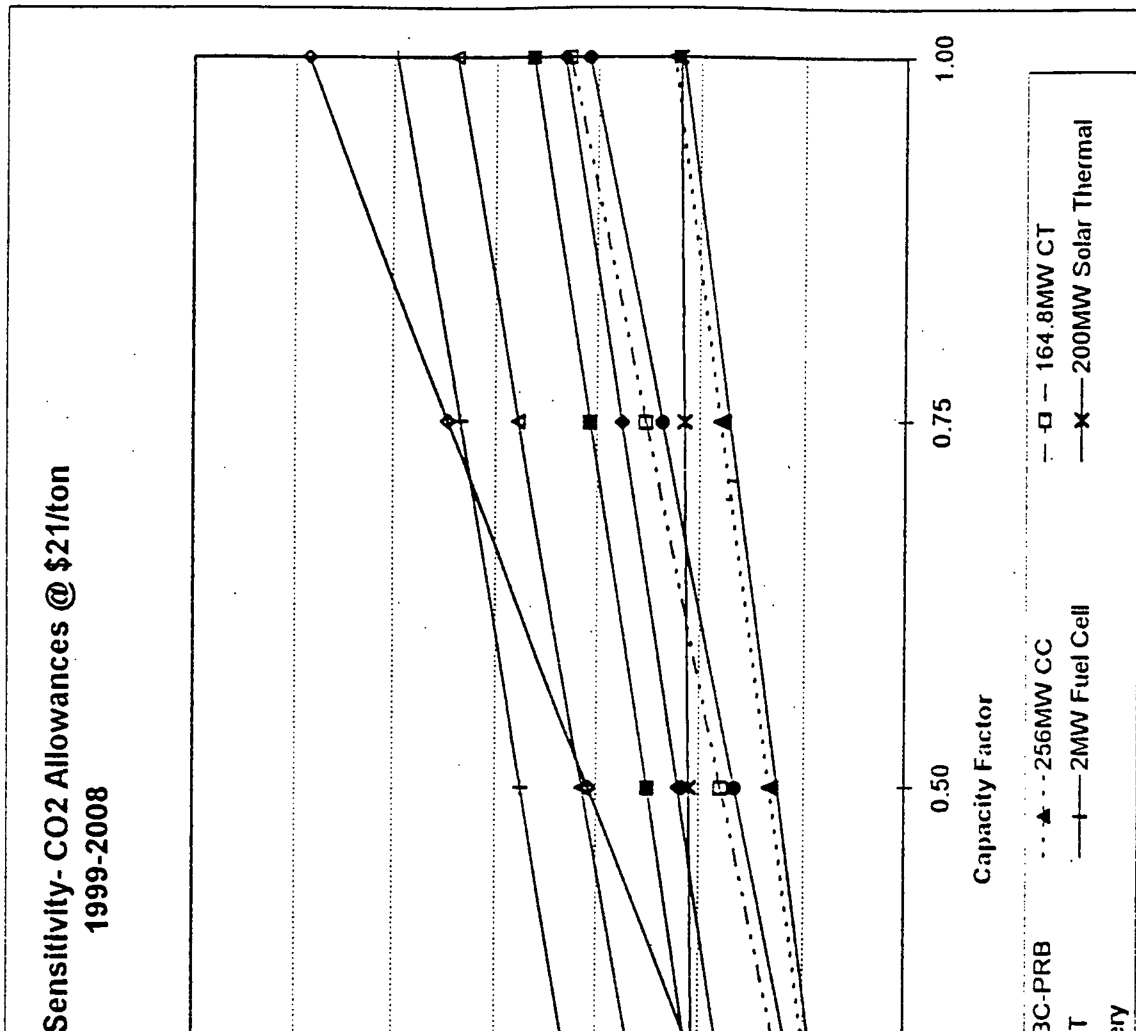


Figure GA-5-62

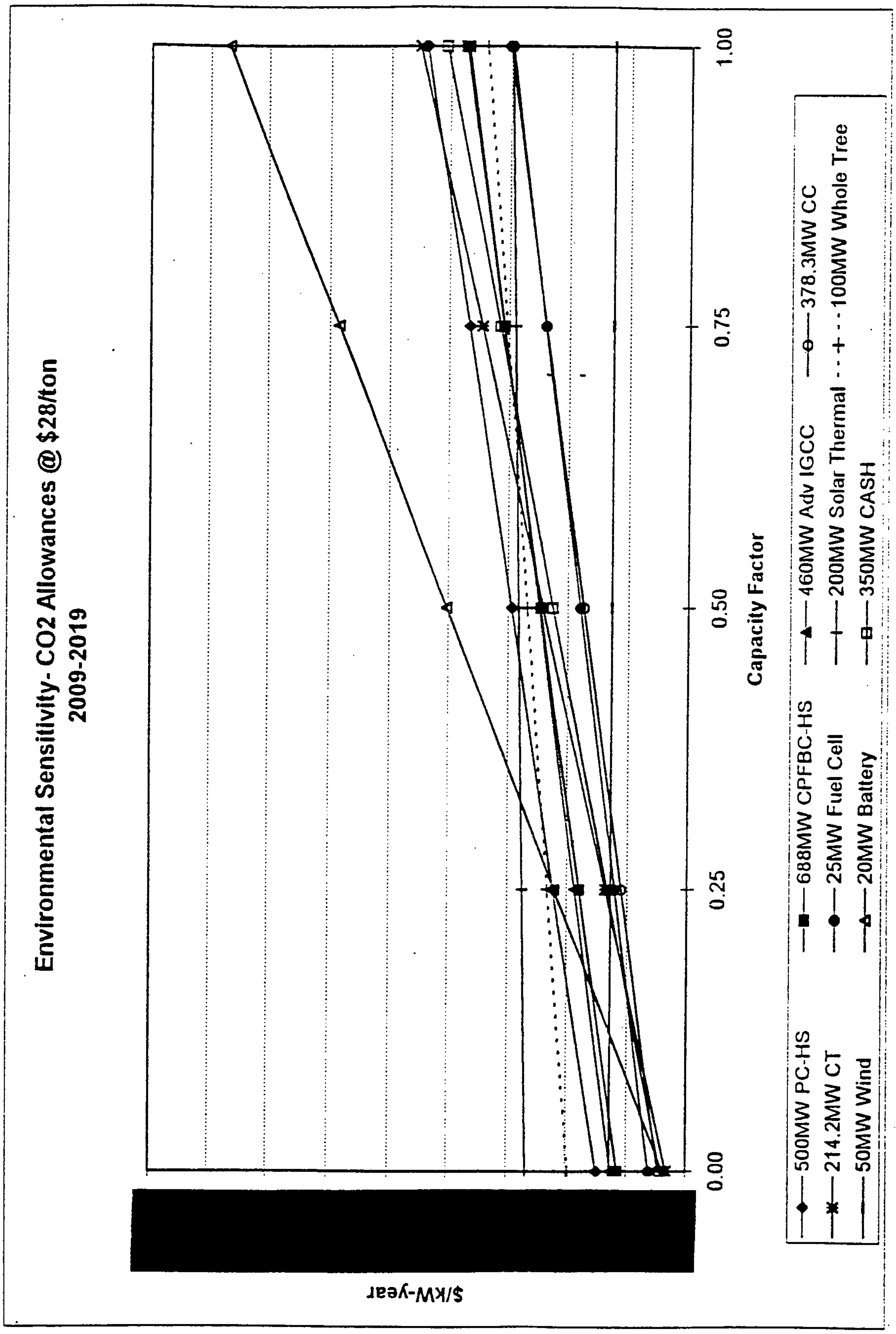


Figure GA-5-63

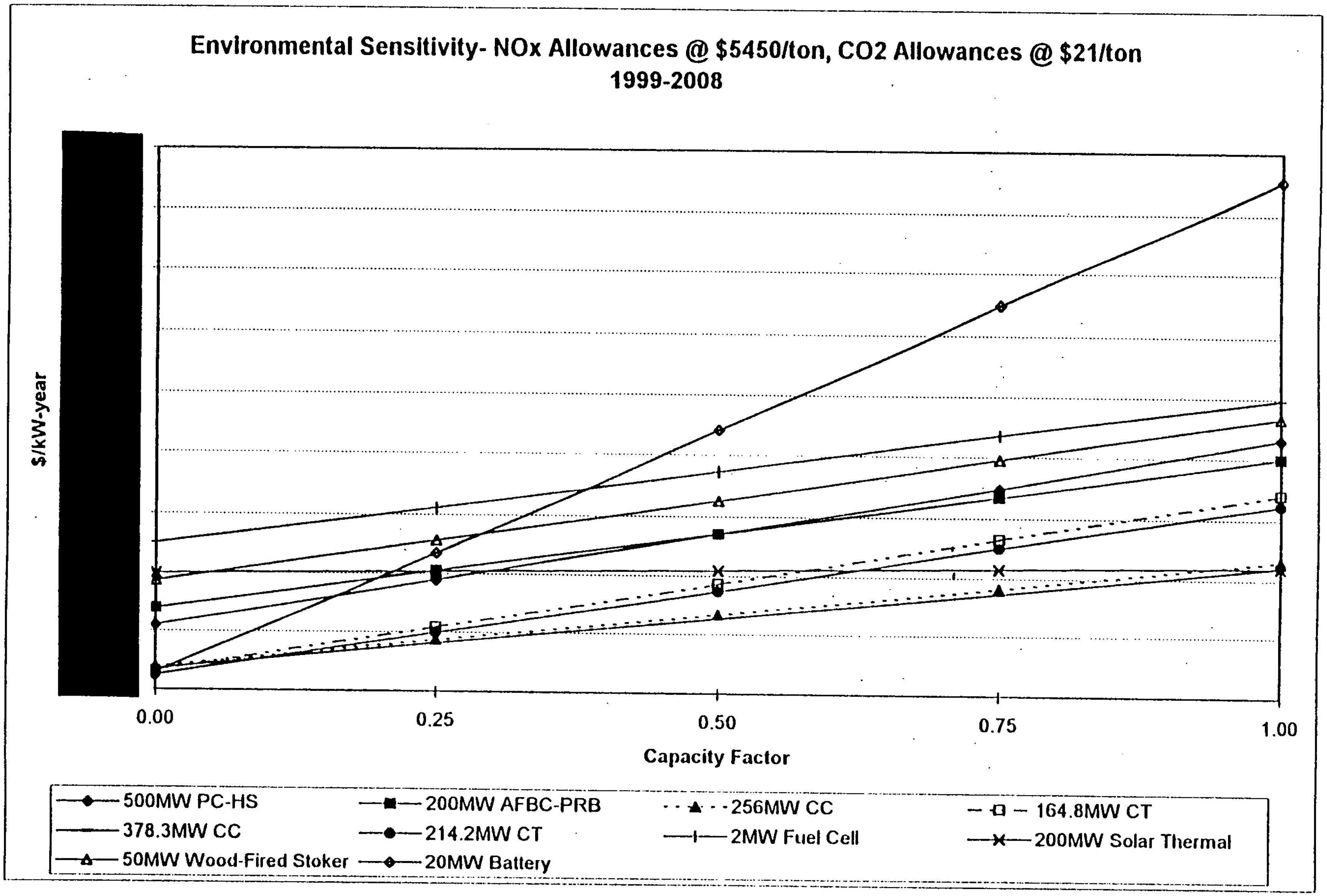
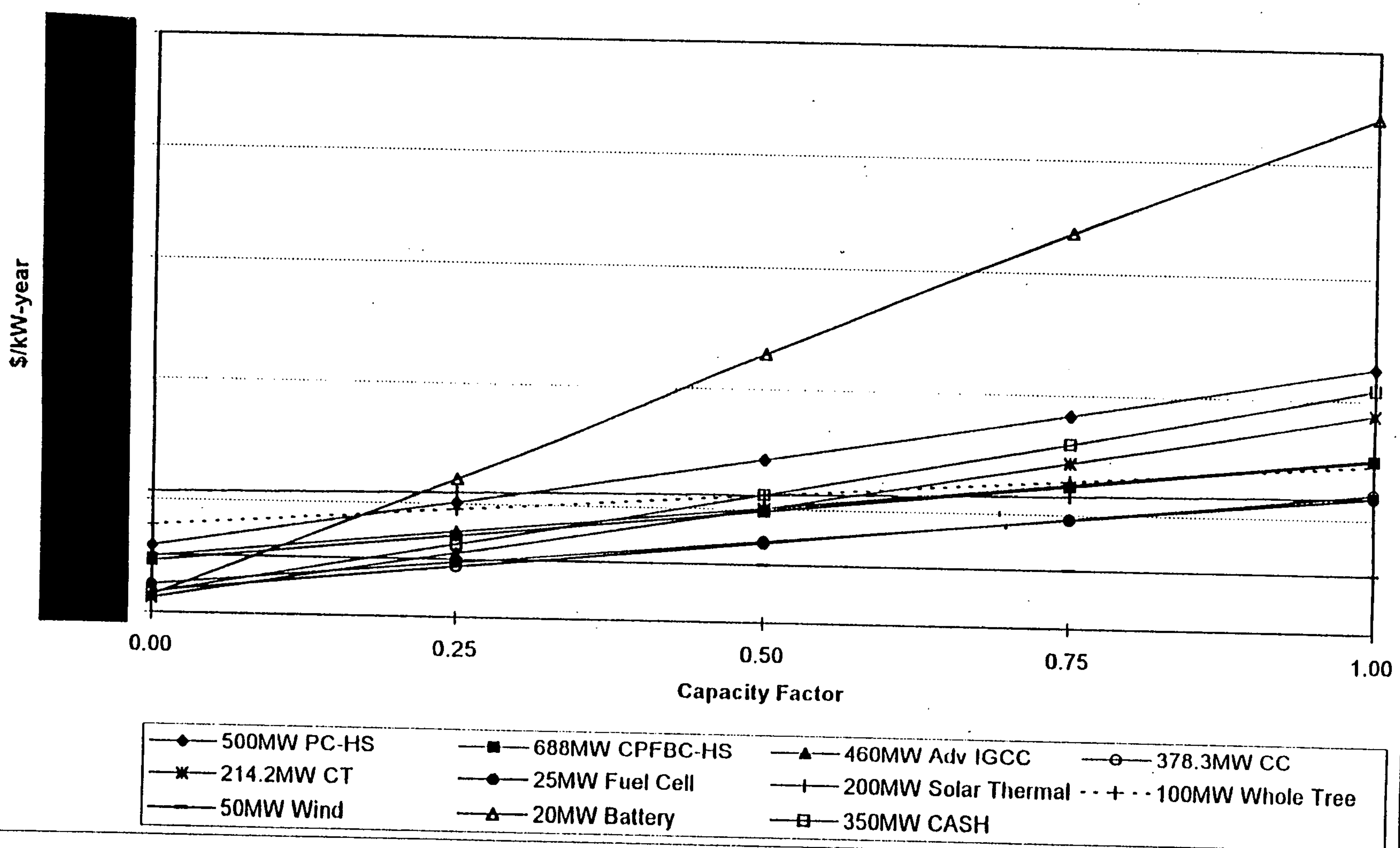


Figure GA-5-64

Environmental Sensitivity- NOx Allowances @ $7324/ton, CO_2 Allowances @ $28/ton
2009-2019



Fuel and O&M Costs

The fuel costs and annual fixed and variable O&M costs for each unit (both existing and new) in the IRP are voluminous. Cinergy also considers them to be trade secrets and confidential and competitive information. They will be made available to appropriate parties for viewing at Cinergy offices during normal business hours upon execution of an appropriate confidentiality agreement or protective order. Please contact Diane Jenner at (317) 838-2183 for more information.

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SO_2 Compliance Supply Curve Data

The following pages contain the SO_2 compliance screening curve data discussed in Chapter 6 of this filing. Cinergy considers this specific marginal compliance cost information to be a trade secret and confidential, competitive information. The redacted information will be made available to appropriate parties upon execution of an appropriate confidentiality agreement or protective order. Please contact Diane Jenner at (317) 838-2183 for more information.

SO_2 Compliance Plan

The following page contains the SO_2 compliance plan discussed in Chapter 6 of this filing. Cinergy considers this information to be a trade secret and confidential, competitive information. The redacted information will be made available to appropriate parties upon execution of an appropriate confidentiality agreement or protective order. Please contact Diane Jenner at (317) 838-2183 for more information.

Figure GA-6-3

1999 IRP Economic CAAA Compliance Options											
	Option in Indicated Years										
Units	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
[redacted]											

SO_2 Allowance Price Forecast

The following page contains the SO_2 allowance price forecast discussed in Chapter 6 of this filing. These forecasts are trade secrets and are proprietary to EVA and ICF. The redacted information will be made available to appropriate parties upon execution of appropriate confidentiality agreements or protective orders. Please contact Diane Jenner at (317) 838-2183 for more information.

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SO_2 Allowance Price Forecast

Nominal Cost Per Allowance ($)

Year	Base	High	Low
1999	[redacted]		
2000	[redacted]	[redacted]	[redacted]
2001	[redacted]		
2002	[redacted]		
2003	[redacted]		
2004	[redacted]		
2005	[redacted]	[redacted]	[redacted]
2006	[redacted]		
2007	[redacted]		
2008	[redacted]		
2009	[redacted]	[redacted]	[redacted]
2010	[redacted]		
2011	[redacted]		
2012	[redacted]		
2013	[redacted]		
2014	[redacted]		
2015	[redacted]		
2016	[redacted]		
2017	[redacted]		
2018	[redacted]		
2019	[redacted]		

Notes:

1) The values were adjusted internally with inflation numbers from DRI/McGraw-Hill Review of the US Economy Long-Range Focus, 1998 Edition.
2) The high and low price forecasts from ICF Resources Inc. were used for the EA price sensitivities. The base price forecast is from Energy Ventures Analysis, Inc.

NO_x Compliance Plan

The following page contains the NO_x compliance plan discussed in Chapter 6 of this filing. Cinergy considers this information to be a trade secret and confidential, competitive information. The redacted information will be made available to appropriate parties upon execution of an appropriate confidentiality agreement or protective order. Please contact Diane Jenner at (317) 838-2183 for more information.

Figure GA-6-4
Summary of Base Case NOx Compliance Plan

Unit	Recommended NOx Compliance Plan
Cayuga 1	[redacted]
Cayuga 2	
East Bend 2	
Edwardsport 6	
Edwardsport 7	
Edwardsport 8	
Gallagher 1	
Gallagher 2	
Gallagher 3	
Gallagher 4	
Gibson 1	
Gibson 2	
Gibson 3	
Gibson 4	
Gibson 5	
Miami Fort 5	
Miami Fort 6	
Miami Fort 7	
Miami Fort 8	
Noblesville 1	
Noblesville 2	
Wabash River 1	
Wabash River 2	
Wabash River 3	
Wabash River 4	
Wabash River 5	
Wabash River 6	
W.C. Beckjord 1	
W.C. Beckjord 2	
W.C. Beckjord 3	
W.C. Beckjord 4	
W.C. Beckjord 5	
W.C. Beckjord 6	
W.H. Zimmer 1	
Key	
SCR	- Selective Catalytic Reduction
SNCR	- Selective Noncatalytic Reduction
LNB	- Low NOx Burners
OFA	- Overfired Air Ports
LNCDS II	- Low NOx Concentric Firing System Level II

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FORM FE2-2 PART 4: PROJECTED GENERATING CAPABILITY CHANGES [In MegaWatts]

				CAPABILITY CHANGES		SEASONAL TOTAL	
YEAR	UNIT DESIGNATION	NOTES	COMMENT	SUMMER	WINTER	SUMMER	WINTER
1999	Beckjord GT - Unit 1	[1]		4.6			
	Beckjord GT - Unit 2	[1]		4.6			
	Beckjord GT - Unit 3	[1]		4.6			
	Beckjord GT - Unit 4	[1]		4.6			
	Cayuga GT - Unit 4	[1]		6.8			
	Wabash River - Unit 1	[1]		14.3			
	Woodsdale GT - Unit 1	[1]		6.4			
	Woodsdale GT - Unit 2	[1]		6.4			
	Woodsdale GT - Unit 3	[1]		6.4			
	Woodsdale GT - Unit 4	[1]		6.4			
	Woodsdale GT - Unit 5	[1]		6.4			
	Woodsdale GT - Unit 6	[1]		6.4			
	Dicks Creek GT - Unit 1	[2]			-110.0		
	Dicks Creek GT - Unit 4	[2]			-21.4		
	Dicks Creek GT - Unit 5	[2]			-21.4		
						78.2	-152.8
2000	Wabash River - Unit 1	[3]		5.0	5.0		
						5.0	5.0
2001							
						0.0	0.0
2002							
						0.0	0.0
2003	[redacted]						
	CT - Unit 1	[5]		165.0	184.0		
	CT - Unit 2			165.0	184.0		
						[redacted]	
2004	NCT - Unit 1	[6]		214.0	239.0		
	NCT - Unit 2			214.0	239.0		
	NCT - Unit 3			214.0	239.0		
	NCT - Unit 4			214.0	239.0		
	NCT - Unit 5			214.0	239.0		
	NCT - Unit 6			214.0	239.0		
	NCT - Unit 7			214.0	239.0		
	NCT - Unit 8			214.0	239.0		
	NCT - Unit 9			214.0	239.0		
	NCT - Unit 10			214.0	239.0		
	NCT - Unit 11			214.0	239.0		
						2354.0	2629.0

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FORM FE2-2 PART 4: PROJECTED GENERATING CAPABILITY CHANGES [In MegaWatts]

				CAPABILITY CHANGES		SEASONAL TOTAL	
YEAR	UNIT DESIGNATION	NOTES	COMMENT	SUMMER	WINTER	SUMMER	WINTER
2005	NCT - Unit 12			214.0	239.0		
	NCT - Unit 13			214.0	239.0		
						428.0	478.0
2006	NCT - Unit 14			214.0	239.0		
						214.0	239.0
2007							
						0.0	0.0
2008							
						0.0	0.0
2009	NFC -Unit 1	[7]		25.0	25.0		
	NFC -Unit 2			25.0	25.0		
	NFC -Unit 3			25.0	25.0		
	NFC -Unit 4			25.0	25.0		
	NFC -Unit 5			25.0	25.0		
	NFC -Unit 6			25.0	25.0		
	NFC -Unit 7			25.0	25.0		
	NFC -Unit 8			25.0	25.0		
						200.0	200.0
2010	NFC -Unit 9			25.0	25.0		
	NFC -Unit 10			25.0	25.0		
	NFC -Unit 11			25.0	25.0		
	NFC -Unit 12			25.0	25.0		
	NFC -Unit 13			25.0	25.0		
	NFC -Unit 14			25.0	25.0		
	NFC -Unit 15			25.0	25.0		
	NFC -Unit 16			25.0	25.0		
						200.0	200.0
2011	NCC -Unit 1	[8]		378.0	415.0		
						378.0	415.0
2012							
						0.0	0.0
2013	NFC -Unit 17			25.0	25.0		
	NFC -Unit 18			25.0	25.0		
	NFC -Unit 19			25.0	25.0		
	NFC -Unit 20			25.0	25.0		
	NFC -Unit 21			25.0	25.0		
	NFC -Unit 22			25.0	25.0		
	NFC -Unit 23			25.0	25.0		
	NFC -Unit 24			25.0	25.0		
						200.0	200.0
2014	NFC -Unit 25			25.0	25.0		
	NFC -Unit 26			25.0	25.0		
	NFC -Unit 27			25.0	25.0		
	NFC -Unit 28			25.0	25.0		
	NFC -Unit 29			25.0	25.0		
	NFC -Unit 30			25.0	25.0		
	NFC -Unit 31			25.0	25.0		
	NFC -Unit 32			25.0	25.0		
						200.0	200.0
2015	NCT - Unit 15			214.0	239.0		
						214.0	239.0

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FORM FE2-2 PART 4: PROJECTED GENERATING CAPABILITY CHANGES [In MegaWatts]

				CAPABILITY CHANGES		SEASONAL TOTAL	
YEAR	UNIT DESIGNATION	NOTES	COMMENT	SUMMER	WINTER	SUMMER	WINTER
2016	NCT - Unit 16			214.0	239.0	214.0	239.0
2017	NCT - Unit 17			214.0	239.0	214.0	239.0
2018	NCT - Unit 18			214.0	239.0	214.0	239.0
2019						0.0	0.0

[1] Inlet cooling was added to these combustion turbine units to improve performance during summer months. The estimated MWs were used for modeling purposes only. The actual MWs will depend on the results of testing yet to be finalized. These estimated capacity changes have already been reflected in the capability in Form FE2-1 (Figure 5-1).

[2] Dicks Creek units 1, 4 and 5 are temporarily unavailable to burn the oil backup fuel needed for operation during the winter months.

[3] Wabash River unit 1 backup fuel will be converted from oil to natural gas with the addition of an auxiliary boiler. The estimated MWs were used for modeling purposes only. The actual MWs will depend on the results of testing yet to be finalized. The values reported here are incremental to the Unit 1 existing capability.

[redacted]

[5] The Combustion Turbine units are generic. The parameters modeled are representative values. The exact unit characteristics will depend on the site and equipment vendor selected.

[6] The New Combustion Turbine units are generic. The parameters modeled are representative values. The exact unit characteristics will depend on the site and equipment vendor selected.

[7] The New Fuel Cell units are generic. The parameters modeled are representative values. The exact unit characteristics will depend on the site and equipment vendor selected.

[8] The New Combined-Cycle unit is generic. The parameters modeled are representative values. The exact unit characteristics will depend on the site and equipment vendor selected.

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Cinergy Corp. *1998 Summary Annual Report*

Committed people.

Building a Growth Energy Company: 1998 Progress Report

Our Vision

Cinergy's vision is "people making history by making a difference." Cinergy people will make history by achieving the company's mission: to create one of the top five companies in their industry. As one of the handful of companies that will shape the future of that rapidly changing industry, Cinergy will create premier value for its stakeholders. And Cinergy people will achieve their mission by making a difference with demonstrated, measurable performance.

For a discussion of Cinergy's objectives — and performance — in achieving its vision, please turn this report over to the 1998 progress report.

Company Profile

CINERGY CORP. PROVIDES ELECTRICITY, NATURAL GAS, AND OTHER ENERGY SERVICES THROUGH ITS SUBSIDIARIES AND FOUR BUSINESS UNITS: ENERGY COMMODITIES, ENERGY DELIVERY, ENERGY SERVICES, AND INTERNATIONAL. CINERGY IS THE PARENT COMPANY OF THE CINCINNATI GAS & ELECTRIC COMPANY (CINERGY/CG&E) AND PSI ENERGY, INC. (CINERGY/PSI) — UTILITIES SERVING 1.4 MILLION ELECTRIC CUSTOMERS AND 470,000 GAS CUSTOMERS IN A 25,000-SQUARE-MILE AREA OF OHIO, INDIANA, AND KENTUCKY. CINERGY IS THE LARGEST NONNUCLEAR ELECTRIC GENERATING COMPANY IN THE UNITED STATES, WITH 11,000 MEGAWATTS OF OWNED CAPACITY. CINERGY IS A REGISTERED HOLDING COMPANY UNDER THE PUBLIC UTILITY HOLDING COMPANY ACT OF 1935. THROUGH A SUBSIDIARY, CINERGY OWNS 50 PERCENT OF MIDLANDS ELECTRICITY PLC, A REGIONAL ELECTRIC COMPANY SERVING 2.2 MILLION CUSTOMERS IN THE UNITED KINGDOM. OTHER CINERGY SUBSIDIARIES ARE ENGAGED IN OTHER ENERGY-RELATED BUSINESSES.

Financial Highlights

(In millions, except as noted)	**1998**	*% Change*	*1997*	*1996*	*1995*	*1994*
OPERATING RESULTS						
Operating Revenues	**$5 876**	33.9	$4 387	$3 276	$3 023	$2 888
Operating Income	**566**	(26.1)	766	764	587	444
Net Income [(a)(d)]	**261**	(28.1)	363	335	347	191
Return on Average Common Equity (percent) [(a)(c)(d)]	**10.3**		14.2	13.0	14.0	8.2
PER SHARE OF COMMON STOCK						
Basic Earnings [(a)(c)(d)]	**$ 1.65**	(28.3)	$ 2.30	$ 2.12	$ 2.22	$ 1.30
Diluted Earnings [(a)(c)(d)]	**1.65**	(27.6)	2.28	2.11	2.20	1.29
Dividends Declared	**1.80**	0.0	1.80	1.74	1.72	1.50
Book Value at Year-end	**16.02**	(0.6)	16.10	16.39	16.17	15.56
Market Price at Year-end	**34.38**	(10.3)	38.31	33.38	30.63	23.50
CAPITALIZATION AT YEAR-END						
Common Equity	**$2 541**	0.1	$2 539	$2 584	$2 549	$2 414
Preferred Stock	**93**	(47.8)	178	194	388	478
Debt [(b)]	**3 644**	8.8	3 350	3 389	2 898	3 005
OTHER						
Common Equity/Total Capital	**40.5%**		41.9%	41.9%	43.7%	40.9%
Employees	**8 794**	15.6	7 609	7 973	8 602	8 868

(a) 1994 includes charges for merger-related and other expenditures which cannot be recovered from customers under the merger savings sharing mechanisms authorized by regulators.

(b) Includes long-term debt due within one year, notes payable, and other short-term obligations.

(c) 1996 does not include costs of reacquisition of preferred stock of subsidiary of $18 million ($.12 per share, basic and diluted).

(d) 1997 does not include extraordinary item for equity share of windfall profits tax of $109 million ($.69 per share, basic and diluted).


Aiken
Barnwell
Waynesboro
Allendale
Sylvania
Hampton
Ridgeland
Springfield
Hilton Head Island
Savannah

Through Cadence, an energy services joint venture, Cinergy helps Winn-Dixie *manage energy use* at almost 1,200 supermarkets in 14 states.

The Energy Services Business Unit is responsible for relationships with retail customers, inside and outside the Cinergy service area, and for managing the development and sale of new products.

Continued progress.

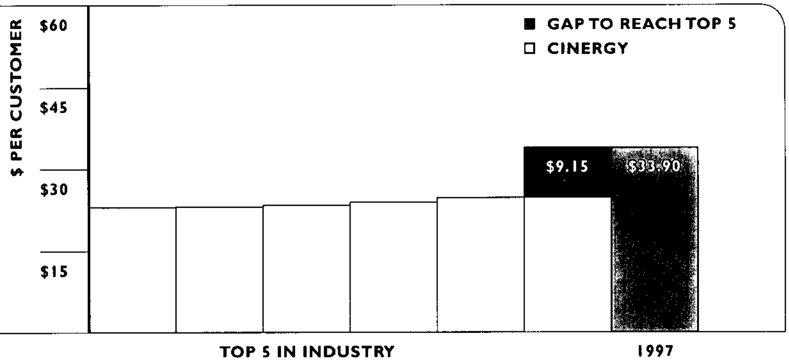
REACHING NEW CUSTOMERS CADENCE — CINERGY'S JOINT VENTURE WITH TWO OTHER ENERGY COMPANIES, NEW CENTURY ENERGIES AND FLORIDA PROGRESS — PROVIDES ENERGY COST REDUCTION SERVICES TO WINN-DIXIE SUPERMARKETS. SINCE APRIL 1998, CADENCE HAS HELPED WINN-DIXIE IDENTIFY SIGNIFICANT UTILITY COST SAVINGS. CADENCE REVIEWS ELECTRIC, WATER, GAS, AND SEWER BILLS FOR ALL 1,200 WINN-DIXIE FACILITIES SITES IN 14 STATES — AS MANY AS 4,000 BILLS PER MONTH. CINERGY IS USING JOINT VENTURES SUCH AS CADENCE TO REACH NEW CUSTOMERS IN EMERGING ENERGY SERVICES MARKETS.

"5 in 3 on 5" Performance Update

Low costs are critical to securing home base in competition. Cinergy's customer service expense per customer is below the industry average, but the company must close a significant gap to reach the top five. Although it is not a "5 in 3 on 5" measure, the quality of customer service is also key to securing home base. Data on customer complaints to regulatory agencies provide a means of comparing Cinergy's performance with that of other regional utilities.

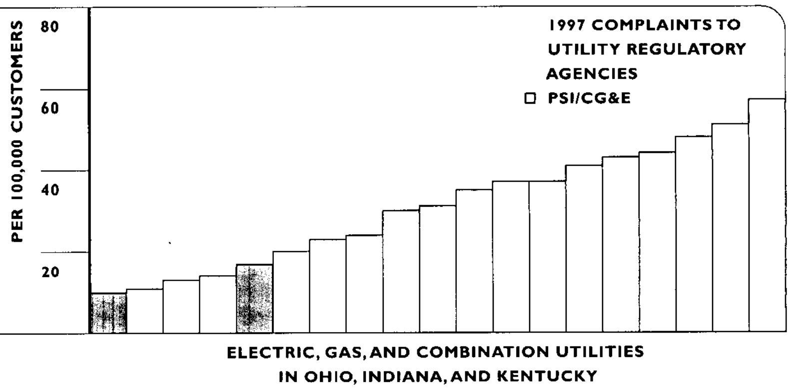
PRODUCTIVITY: ELECTRIC CUSTOMER SERVICE EXPENSE PER CUSTOMER

Cinergy ranked 17th in the industry in the productivity of its electric customer service operations, as measured by expense per customer, excluding uncollectible accounts. To reach the top five in productivity, Cinergy's electric customer service operations would have to reduce expense per customer by 27%. *(Source: 1997 FERC Form 1 Reports; Cinergy figure adjusted for an accounting reclassification.)*



CUSTOMER SERVICE: CONSUMER COMPLAINTS TO REGULATORY AGENCIES

Cinergy/PSI ranked first, with the lowest rate of consumer complaints/inquiries to state regulatory agencies, and Cinergy/CG&E ranked fifth-lowest, among 19 investor-owned electric, gas, and combination utilities in Ohio, Indiana, and Kentucky. Cinergy ranked second among holding companies, with a rate of 14 complaints per 100,000 customers. *(Source: Public Utilities Commission of Ohio, Indiana Utility Regulatory Commission, Kentucky Public Service Commission, 1997.)*



With three years remaining in Cinergy's "5 in 5 on 5" mission, it is now "5 in 3 on 5." Cinergy tracks its performance on "5 in 3 on 5" measures against the top five in the benchmark group. The graphs above show the most recent periods for which complete comparable data are available.

Objectives | *1998 Progress*

Key objectives of the Energy Services Business Unit are to secure home base and to reach new customers. In 1998, Cinergy developed new products and services for both new and existing customers. The company acquired new customers outside the service area through existing joint ventures and expanded on this strategy with a new joint venture.

SECURE HOME BASE:
ENHANCE CUSTOMER SERVICE

CUSTOMER MODEL IMPLEMENTED, NEW SERVICES OFFERED

New offerings included targeted energy services from Cinergy Business Solutions, for industrial and institutional customers, and Cinergy Integrated Energy Services, for small and mid-size business and governmental customers. More than 2,000 employees participated in training on the "customer model" aimed at providing superior service.

REACH NEW CUSTOMERS:
BUILD START-UP ENERGY SERVICES BUSINESSES

NEW CUSTOMERS FOR CADENCE AND TRIGEN-CINERGY SOLUTIONS

Existing joint ventures added new customers in 1998. Trigen-Cinergy Solutions signed seven agreements to build and/or operate industrial and municipal energy systems, bringing projected annual revenue to $67 million. Cadence manages energy information for thousands of customer sites in all 50 states (see page B-3).

REACH NEW CUSTOMERS:
CONTINUE TO PURSUE JOINT-VENTURE STRATEGY

CENTRUS JOINT VENTURE CREATED

With our Cadence partners, Cinergy launched a new joint venture called Centrus. Centrus will offer customers a combined package of energy and communications services.


POWER
F12

Cinergy created a *fiber-optic network*

The Energy Delivery Business Unit plans, builds, operates and maintains transmission and distribution systems to deliver energy to customers safely, reliably, and economically.

for Mill Creek schools, so students and staff can share resources — and we maximize value from ours.

Continued progress.

MAXIMIZING ASSET VALUE FIBER OPTICS LINKS THE BUILDINGS OF MILL CREEK SCHOOL CORPORATION IN INDIANA, CREATING A HIGH-SPEED NETWORK FOR SHARING EDUCATIONAL RESOURCES AND DATA. THE NETWORK, CREATED WITH CINERGY'S EXPERTISE AND ITS UTILITY DISTRIBUTION FACILITIES, IS JUST ONE EXAMPLE OF INITIATIVES TO MAXIMIZE THE VALUE OF CINERGY'S ENERGY DELIVERY ASSETS AND SKILLS. THE ENERGY DELIVERY BUSINESS UNIT HAS ALSO ENTERED INTO TWO JOINT VENTURES THAT LEVERAGE CINERGY'S ASSETS AND EXPERTISE.

"5 in 3 on 5" Performance Update

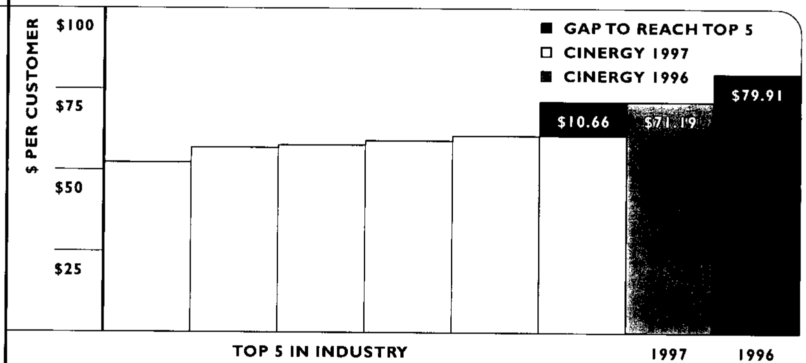
Electric and gas distribution productivity is critical for operations that will continue to be regulated. Cinergy's operation and maintenance cost per customer is improving against its peer groups, but additional cost reductions are necessary to achieve top-five productivity. Cost reductions in electric distribution are being achieved without sacrificing reliability.

PRODUCTIVITY: ELECTRIC T&D

EXPENSE PER CUSTOMER

Between 1996 and 1997, Cinergy's electric transmission and distribution (T&D) operations reduced operation and maintenance expense per customer by 11%, from $79.91 to $71.19, and narrowed the gap with the top five companies in the industry. To reach the top five in productivity, Cinergy's electric T&D operations would have to reduce operation and maintenance expense per customer an additional 15%.

(Source: 1997 FERC Form 1 Reports.)

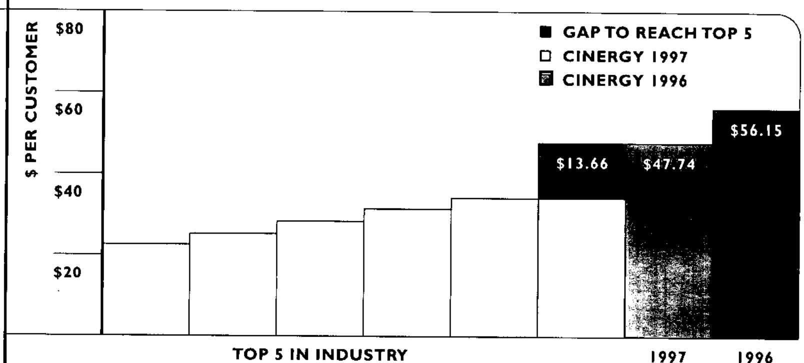


PRODUCTIVITY: GAS DISTRIBUTION

EXPENSE PER CUSTOMER

Between 1996 and 1997, Cinergy's gas distribution operations reduced operation and maintenance expense per customer by 15%, from $56.15 to $47.74, and narrowed the gap with the top five companies in the industry. To reach the top five in productivity, Cinergy's gas distribution operations would have to reduce operation and maintenance expense per customer an additional 28.6%.

(Source: 1997 FERC Form 2 Reports and 1997 EIA-176.)



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Objectives	*1998 Progress*
	The Energy Delivery Business Unit is primarily a regulated asset management business. The company has made progress in reducing costs of regulated utility operations, in the belief that constructive regulation will reward efficient service. The company has also pursued nonregulated initiatives to maximize the value of its assets.
SECURE HOME BASE: REDUCE COSTS OF REGULATED BUSINESS	**SIGNIFICANT COST REDUCTIONS ACHIEVED** Both gas and electric operations are implementing 12 initiatives in a second wave of reengineering, with a combined five-year savings potential of $52 million. Since 1996, electric and gas operations have closed the gap in achieving top-five productivity.
MAXIMIZE ASSET VALUE: LEVERAGE EXPERTISE IN ASSET MANAGEMENT	**LATTICE COMMUNICATIONS AND RELIANT JOINT VENTURES LAUNCHED** Initiatives included joint ventures that will, pending regulatory approvals, purchase Cinergy communications towers and lease space for wireless communications (Lattice Communications) and construct and locate underground utilities (Reliant Services). Efforts were initiated to install fiber-optic links along our distribution system (see page B-7).
MANAGE THE TRANSITION: CREATE MIDWEST ISO	**FEDERAL APPROVAL GAINED** In September, the Federal Energy Regulatory Commission approved the Midwest Independent System Operator (ISO) for the operation of combined transmission systems in our region. Cinergy led the creation of the Midwest ISO, which will facilitate a reliable, efficient market for electric power.

ProEnergy — now a Cinergy company — *provides wholesale gas supplies*

The Energy Commodities Business Unit markets and trades electricity, natural gas, and related commodities, in regulated and nonregulated markets, and it operates Cinergy's electric generation facilities.

to Northern States Power, warming the hearts and homes of 400,000 Midwestern families.

Continued progress.

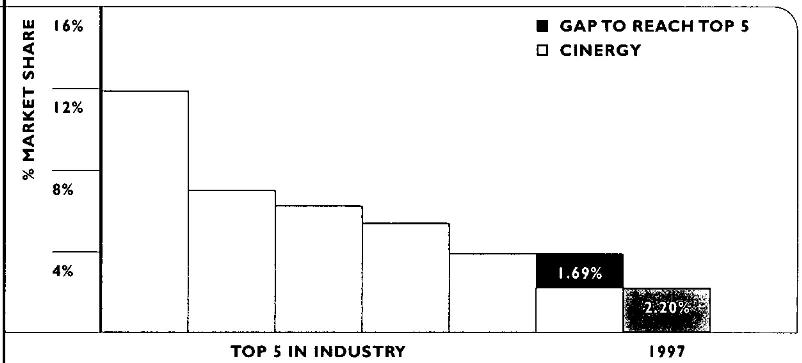
EXPANDING TRADING/MARKETING MINNEAPOLIS-BASED NORTHERN STATES POWER IS ONE OF THE LARGEST WHOLESALE GAS CUSTOMERS OF PROENERGY — NOW CINERGY GAS TRADING OPERATIONS — WHICH JOINED CINERGY IN JUNE 1998. THE ACQUISITION OF PROENERGY IS PART OF A STRATEGY TO BUILD THE PHYSICAL GAS CAPABILITIES OF OUR ENERGY MARKETING AND TRADING BUSINESS. WITH PROENERGY, CINERGY GAINED PHYSICAL GAS MARKETING CAPACITY OF 1.8 BILLION CUBIC FEET (BCF) PER DAY, AND A STRONG WHOLESALE CUSTOMER BASE OF 40 LOCAL DISTRIBUTION COMPANIES AND 160 INDUSTRIAL, COMMERCIAL, AND MARKETER ACCOUNTS.

"5 in 3 on 5" Performance Update

Cinergy maintained a position near the top five in electric commodity trading, despite a decrease in market share. Although gas trading volumes remained small, Cinergy created a beachhead in gas marketing with the acquisition of ProEnergy. Cinergy maintained a top-five position in electric generation productivity.

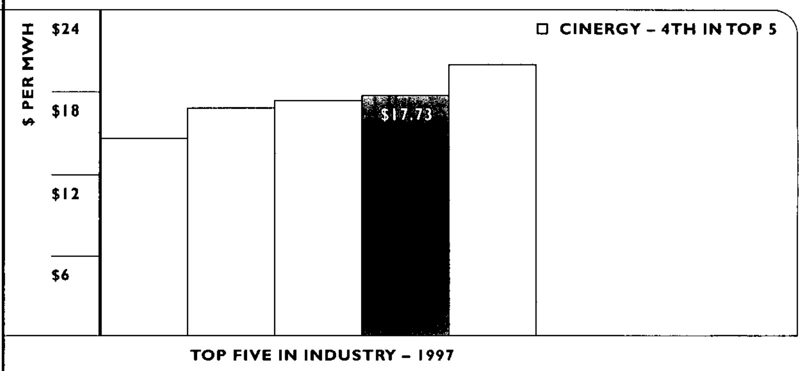
ELECTRIC COMMODITY TRADING MARKET SHARE

Cinergy ranked 10th among electric commodity trading companies, as measured by market share of purchases from power marketers in megawatt-hours (mwh). This figure captures electric power trading by utility operations as well as licensed power marketers. Volumes in the chart are for the first nine months of 1998, the latest figures available. (Source: Power Markets Week *and Cinergy.)*



PRODUCTIVITY: GENERATION EXPENSES PER MEGAWATT-HOUR (MWH)

Cinergy ranks 4th in generation productivity, as measured by cost per megawatt-hour, a sum of fuel expense, nonfuel operation and maintenance (O&M) expenses, incremental capital expenditures, and a carrying cost for fuel and O&M inventories. The benchmark group includes the 25 largest gas and electric utilities measured by revenue. (Source: 1997 FERC Form 1 Reports and 1997 EIA-176.)



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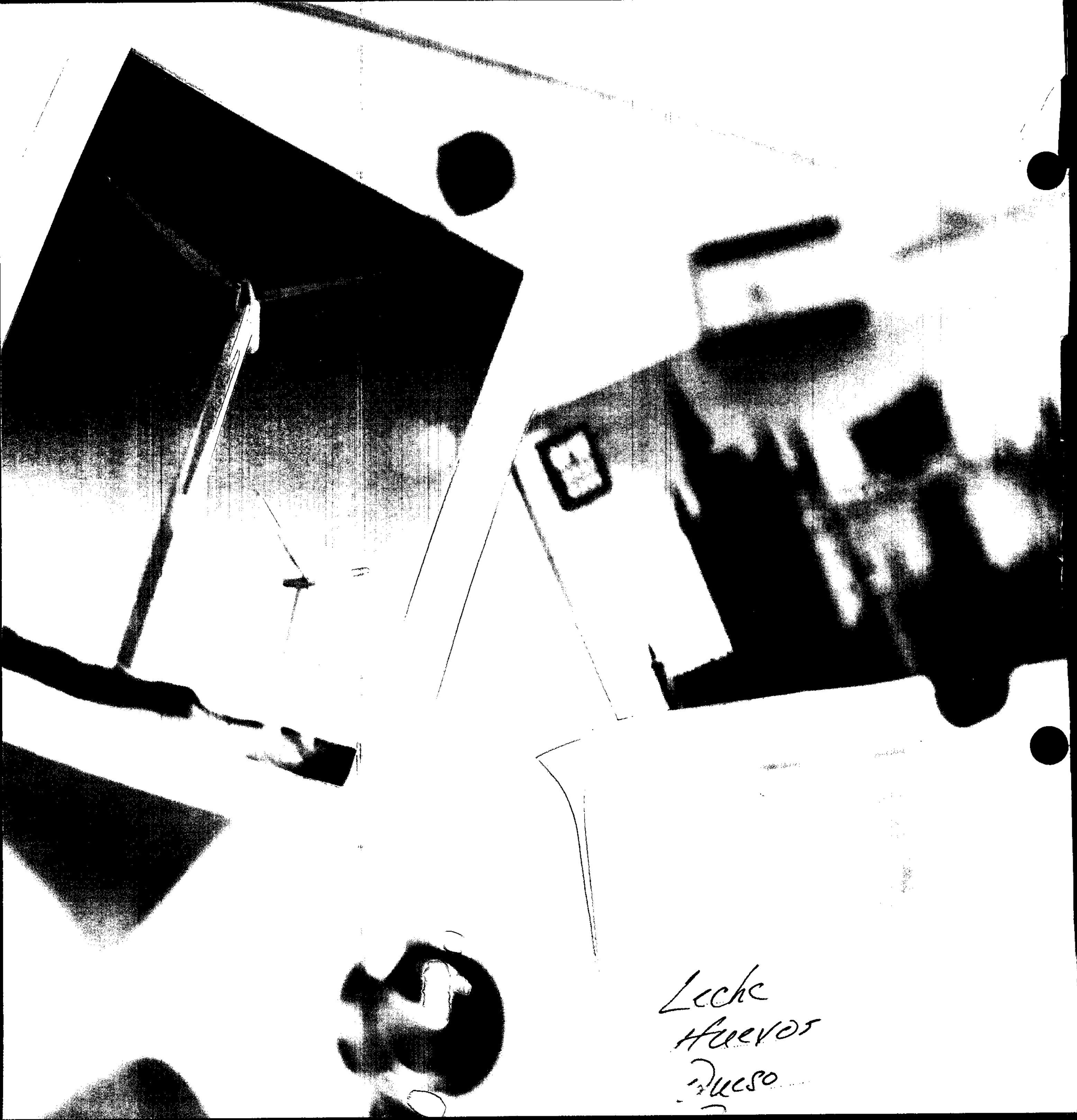
Objectives	1998 Progress
	The Energy Commodities Business Unit continued to assemble the capabilities to reach the top five in electric and gas commodity trading, adding physical gas marketing capacity, and building the necessary support infrastructure. Cinergy also took steps to maximize the value of its low-cost generation.
EXPAND TRADING/MARKETING: ACQUIRE PHYSICAL GAS MARKETING CAPABILITY	**PROENERGY ACQUIRED** Cinergy acquired ProEnergy, with physical gas marketing capacity of 1.8 Bcf per day, to build gas commodity capabilities and to complement the financial trading capability gained with the 1997 acquisition of Greenwich Energy Partners (see page B-11).
EXPAND TRADING/MARKETING: BUILD TRADING AND RISK-MANAGEMENT SYSTEMS	**NYMEX HUB ESTABLISHED, TRADING FACILITY OPENED** In July, the New York Mercantile Exchange (NYMEX) began trading electricity futures at a hub on the Cinergy transmission system, one of four in the United States. Cinergy realigned marketing and trading operations, refocused trading in the Midwest, and opened a state-of-the-art trading facility.
MAXIMIZE ASSET VALUE: INCREASE VALUE OF CINERGY GENERATION	**CHANGES IN TRADING AND OPERATIONS** In 1998, marketing and trading were refocused to maximize the value of the second call (after Cinergy utility customers) on Cinergy's 11,000 megawatts of generation. Plant operations have been refined to allow more rapid increases and decreases in output to take advantage of market conditions.
BUILD GROWTH BUSINESSES: START-UP COMMODITY BUSINESSES	**CINERGY CAPITAL SERVICES DEALS CLOSED** Cinergy Capital & Trading (CC&T) completed its first transaction, restructuring an existing power purchase agreement in July 1998. It closed a distressed asset acquisition in early 1999. CC&T was also instrumental in restructuring the agreement between Dynegy and PSI Energy related to the Wabash River coal gasification facility.



Leche
Huevos
Queso

A wind farm in Spain demonstrates how *Cinergy Global Resources* uses renewable sources of energy to provide electricity to consumers in Europe.

The International Business Unit directs power development activities through Cinergy Global Resources, as well as other offshore investments and operations, including Cinergy's stake in Midlands Electricity.

Continued progress.

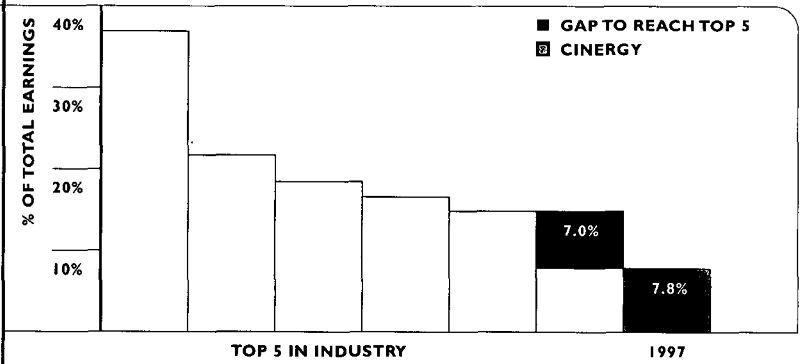
BUILDING GROWTH BUSINESSES DEVELOPMENT OF RENEWABLE ENERGY IN EUROPE AND ELSEWHERE IS ONE OF THREE STRATEGIC PRIORITIES OF CINERGY GLOBAL RESOURCES. CINERGY GLOBAL HAS COMMITTED OR INVESTED $40 MILLION IN A RENEWABLES PORTFOLIO THAT INCLUDES A TOTAL OF 145 MEGAWATTS OF CAPACITY OPERATING OR UNDER CONSTRUCTION IN SPAIN, THE UNITED STATES, AND ENGLAND. PROJECTS INCLUDE WIND, HYDRO, AND BIOMASS. CINERGY GLOBAL IS DEVELOPING THE SKILLS TO REPLICATE THESE PROJECTS ELSEWHERE.

"5 in 3 on 5" Performance Update

Earnings from international operations — essential to Cinergy's mission to become a growth energy company — have increased from 10 cents in 1996, to 18 cents in 1997 (before extraordinary item for equity share of windfall profits tax of $.69 per share), to 20 cents in 1998. Although it is not a "5 in 3 on 5" goal, Cinergy also tracks international revenue as a share of total operating revenue. According to available data, Cinergy believes it is in the top five on this measure.

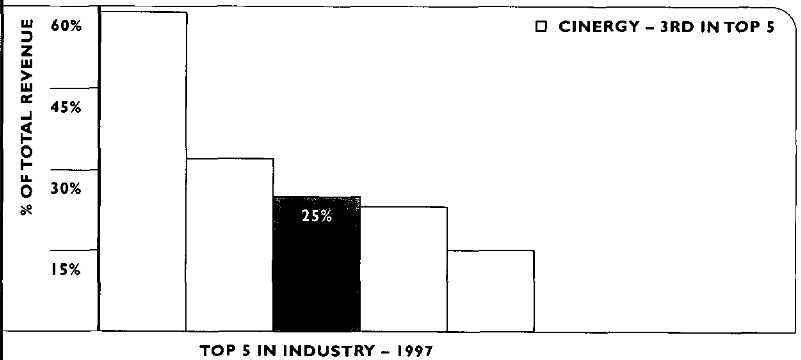
SHARE OF EARNINGS FROM INTERNATIONAL OPERATIONS

International operations contributed 18 cents per share to Cinergy earnings in 1997 (before extraordinary item for equity share of windfall profits tax of $.69 per share). The share of 1997 earnings from international operations was 7.8%. (Source: Cinergy.)



SHARE OF REVENUE FROM INTERNATIONAL OPERATIONS

Cinergy currently ranks among the top five electric, natural gas, and combination utilities with significant U.S. operations in the percentage of operating revenue from international operations. (Source: company annual reports.)



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Objectives	*1998 Progress*
	In 1998, the International Business Unit created Cinergy Global Resources to manage all of Cinergy's international businesses. Midlands Electricity, which represents Cinergy's largest international investment, took steps to improve its financial performance. Cinergy Global invested more than $100 million in international energy projects.
SECURE HOME BASE: ENHANCE VALUE OF MIDLANDS INVESTMENT	**REENGINEERING IMPLEMENTED, MIDLANDS POSITIONED FOR COMPETITION** Successful reengineering at Midlands Electricity allows reinstatement of the Midlands dividend to Cinergy two years earlier than expected. In a first-of-its-kind transaction in the United Kingdom, an agreement was reached to sell Midlands' supply business in order to concentrate on Midlands' profitable distribution business.
BUILD GROWTH BUSINESSES: RAISE FOREIGN INVESTMENT LIMIT TO 100%	**SEC APPROVAL RECEIVED IN MARCH 1998** Cinergy gained flexibility in pursuing an international strategy with approval from the Securities and Exchange Commission, under the Public Utility Holding Company Act, to invest up to 100% of its retained earnings in foreign utility companies and exempt wholesale generators. The company continues to seek greater financing flexibility.
BUILD GROWTH BUSINESSES: SUCCESSFULLY PURSUE DEVELOPMENT STRATEGY	**19 PROJECTS OPERATING OR UNDER CONSTRUCTION, INCLUDING MIDLANDS** Cinergy Global ended 1998 with interests in over 5,500 megawatts of heating and electric capacity operating or under construction, including investments made through Midlands Electricity. Cinergy Global holds interests in operations with 2.24 million transmission and distribution customers and 16,500 retail district heating customers (served through 275 wholesale customers). The strategy focuses on refurbishment projects in Europe, fuel-to-power projects in developing countries, and renewable energy projects (see page B-15).

A transforming transaction

remained a

The corporate center provides strategic direction, performance measurement, and shared services to Cinergy's business units.

at year end, with

intense but patient pursuit

of strategic initiatives.

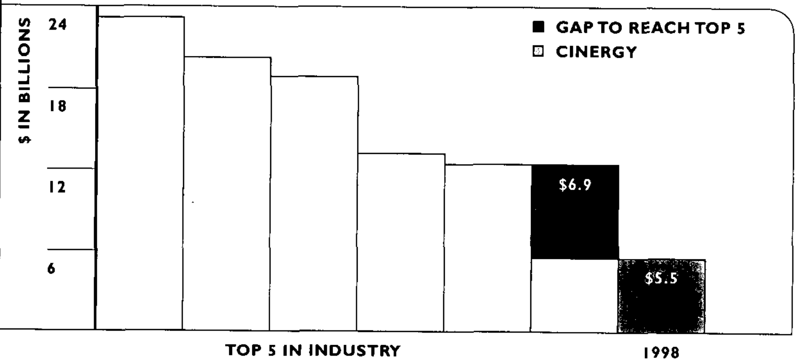
Objectives	1998 Progress
	While continuing to pursue merger and acquisition opportunities, Cinergy addressed two key uncertainties: industry transition legislation, particularly in Ohio, and new restrictions on emissions from generating plants. Cinergy is also continuing to reduce corporate center costs.
TRANSFORMING TRANSACTION	A transforming transaction — a major acquisition or merger — is a critical element in Cinergy's "5 in 3 on 5" mission, and necessary to achieving top-five scale in market capitalization and number of customers.
SECURE HOME BASE: IDENTIFY AND ACHIEVE OPERATING EFFICIENCIES	**REDUCTIONS IN CORPORATE CENTER COSTS** On a year-to-year comparison, reductions in utility operation and maintenance expenses accounted for earnings of 7 cents per share in 1998. More than half of these reductions were achieved in administrative and general expenses in the corporate center. Further corporate center savings will be a high priority of the Focus 2000 program launched in January 1999.
MANAGE THE TRANSITION: SHAPE REGULATORY REFORM	**CONSENSUS BILL PROPOSED IN OHIO** Cinergy made progress toward clear, fair industry reforms, with a consensus proposal for customer choice by Ohio's investor-owned utilities. Cinergy maintained efforts in Indiana and Kentucky, and at the Federal level — with improved prospects for repeal of the Public Utility Holding Company Act.
MANAGE THE TRANSITION: ADDRESS PROPOSED ENVIRONMENTAL REQUIREMENTS	**CINERGY INVOLVED IN DEBATE ON NITROGEN OXIDES, GLOBAL WARMING** Cinergy's coal-fired generation faces potential restrictions on carbon dioxide and nitrogen oxides emissions. Proposed NOx limits could require five-year capital costs currently estimated at \$500 million to \$700 million. Cinergy is committed to helping shape environmental solutions for cost-effective, environmentally benign use of coal to generate electricity.

(Corporate Center) "5 in 3 on 5" Performance Update

While Cinergy has made progress on a number of "5 in 3 on 5" goals, significant progress toward the top five in market capitalization and number of customers will require a transforming transaction. Because Cinergy believes that scale is critical to its mission to become a growth energy company, the company will continue to pursue strategic initiatives to achieve greater scale.

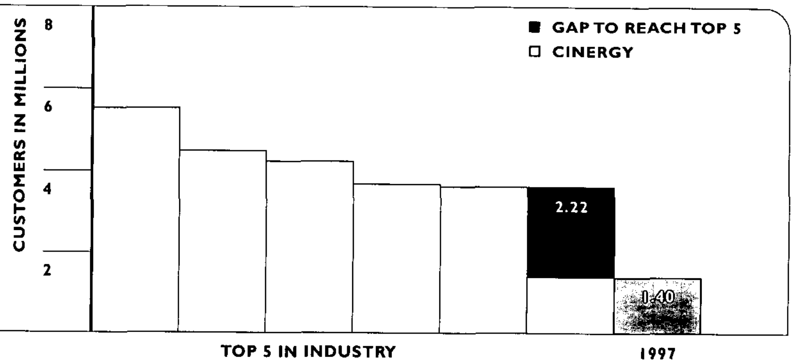
MARKET CAPITALIZATION

Cinergy's market capitalization — the total value of Cinergy stock outstanding — was $5.5 billion at the end of 1998. By comparison, the average capitalization for the five largest companies in the industry was $17.6 billion. The gap to reach the top five in market capitalization increased from $4.7 billion to $6.9 billion in 1998. (Source: Bloomberg.)



NUMBER OF DOMESTIC CUSTOMERS

According to the latest data available, Cinergy ranked 29th among energy companies in the United States in the number of domestic customers. To reach the top five, Cinergy would have to more than double its customer base. (Source: FERC Form 1 Reports and Cinergy.)



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The accompanying summary financial presentation is intended to present capsule information in an easy-to-read format and should not be considered a substitute for the full financial statements provided to all shareholders in the Appendix to the Proxy Statement. A copy of the Appendix to the Proxy Statement or the annual report on Form 10-K (1998 Form 10-K) to the Securities and Exchange Commission (SEC) can be obtained by contacting Cinergy Corp.'s (Cinergy) Shareholder Services. Please review the full financial statements in the Appendix to the Proxy Statement or 1998 Form 10-K before making any investment decisions.

Results of Operations

OPERATING REVENUES AND EXPENSES

Operating revenues for the year increased $1.5 billion (34%) in 1998. This is primarily the result of a 21% increase in electric kwh sales reflecting an increase in energy marketing and trading volumes. This increase also reflects the effects of an increase in mcf sales resulting from the acquisition of Producers Energy Marketing, LLC (ProEnergy), a gas marketing and trading firm, in mid-1998. Operating expenses for the year increased by $1.7 billion, primarily reflecting corresponding increases in purchased and exchanged power expense for energy marketing and trading and gas purchased expense for ProEnergy. Also contributing to the increase in operating expenses is a one-time charge of $80 million ($50 million after tax or $.32 per share basic and diluted) recorded during 1998, reflecting the implementation of a 1989 settlement of a dispute with Wabash Valley Power Association, Inc.

INCOME TAXES

Income taxes decreased $96 million (45%) in 1998 due to a decrease in taxable income compared to the prior year and the increased utilization of foreign tax credits.

EXTRAORDINARY ITEM – EQUITY SHARE OF WINDFALL PROFITS TAX

During the third quarter of 1997, a windfall profits tax was enacted into law in Great Britain. This tax was levied against a limited number of British companies, including Midlands Electricity plc (Midlands), which had previously been owned and operated by the government. The tax was intended to be a recovery of funds by the government due to the undervaluing of companies, such as Midlands, when they were privatized by the government via public stock offerings several years ago. Cinergy's share of the tax was approximately 67 million pounds sterling ($109 million or $.69 per share, basic and diluted) and was recorded as an extraordinary item in Cinergy's Condensed Consolidated Statement of Income in 1997.

Other Matters

YEAR 2000

The Year 2000 issue generally exists because many computer systems and applications may not properly recognize dates including and beyond the year 2000 or accurately process data in which such dates are included, potentially causing data miscalculations and inaccuracies or operational malfunctions and failures, which could materially affect Cinergy's financial condition, results of operations, and cash flows. To identify, evaluate, and address Year 2000 issues, the Cinergy Year 2000 Readiness Program has been established. This program is focused on three elements: (1) business continuity; (2) risk management; and (3) regulatory compliance.

Cinergy currently estimates that the total cost of assessment, remediation, testing, and upgrading its systems is approximately $13 million. Approximately $11 million has been incurred through December 31, 1998, for external labor, hardware and software upgrades, and for Cinergy employees who are dedicated full-time to the Cinergy Year 2000 Readiness Program.

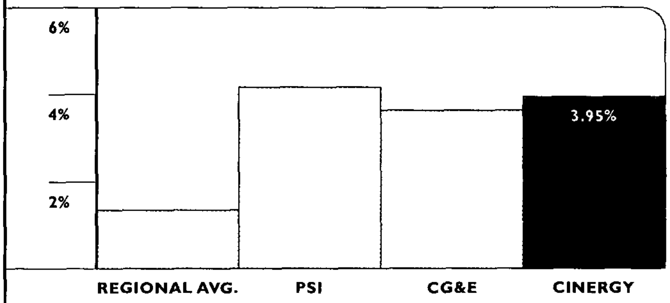
RETENTION OF GAS OPERATIONS

In its 1994 order approving the merger of PSI Resources, Inc. and The Cincinnati Gas & Electric Company (CG&E), the SEC reserved judgment over Cinergy's ownership of CG&E's gas operations for three years, at the end of which period Cinergy would be required to address the matter. In November 1998, the SEC issued an order unconditionally approving the retention of CG&E's gas businesses.

Additional Operational Measures

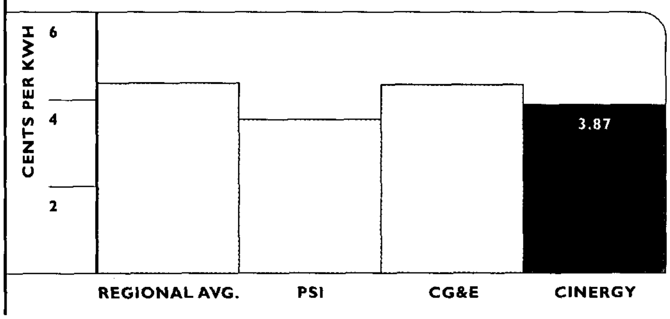
INDUSTRIAL ELECTRIC SALES GROWTH RATE (1992-1997)

Growth in Cinergy's industrial sales reflects a healthy economy in the service area as well as aggressive economic development by Cinergy/CG&E and Cinergy/PSI to attract new business and help existing businesses expand. (Source: FERC Form 1 Reports.)



1997 INDUSTRIAL ELECTRIC RATES

In a competitive environment, the price of power may be the single most important factor determining whether an industrial customer remains on a system or opts for another supplier. Industrial rates for both Cinergy/CG&E and Cinergy/PSI compared favorably with those of regional competitors in the most recent period for which comparable figures are available. (Source: FERC Form 1 Reports.)



Report of Management & Report of Independent Public Accountants

To the Shareholders of Cinergy Corp.:

The management of Cinergy Corp. is responsible for the condensed consolidated financial statements and related information in this summary annual report. These condensed consolidated financial statements and related information were derived from the consolidated financial statements that appear in the Appendix to the Proxy Statement for the 1999 Annual Meeting of Shareholders. The consolidated financial statements in the Appendix to the Proxy Statement are prepared in conformity with generally accepted accounting principles and have been audited by Arthur Andersen LLP, independent accountants, whose report on the condensed consolidated financial statements appears herein.

James E. Rogers,
President and Chief Executive Officer

Charles J. Winger,
Vice President and Chief Financial Officer

To the Board of Directors of Cinergy Corp.:

We have audited the consolidated balance sheets of Cinergy Corp. and subsidiaries as of December 31, 1998 and 1997 and the related consolidated statements of income, changes in common stock equity and cash flows for each of the three years in the period ended December 31, 1998. Such consolidated financial statements and our report thereon dated January 28, 1999 expressing an unqualified opinion (which are not presented herein) are included in the Appendix to the Proxy Statement for the 1999 Annual Meeting of Shareholders of the Company. Our report dated January 28, 1999, contained an explanatory paragraph calling attention to a change in accounting principle as discussed in Note 1 to those consolidated financial statements. The accompanying condensed consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on such condensed consolidated financial statements in relation to the complete consolidated financial statements.

In our opinion, the information set forth in the accompanying condensed consolidated balance sheets as of December 31, 1998 and 1997 and the related condensed consolidated statements of income and cash flows for each of the three years in the period ended December 31, 1998, is fairly stated, in all material respects, in relation to the complete consolidated financial statements from which it has been derived.

Arthur Andersen LLP
Cincinnati, Ohio
January 28, 1999

Condensed Consolidated Statements of Income

(In millions, except per share amounts)	**1998**	*1997*	*1996*
OPERATING REVENUES	**$5 876.3**	$4 387.1	$3 276.2
OPERATING EXPENSES			
Fuel, purchased and exchanged power, and gas purchased	**3 703.3**	2 178.9	1 121.2
Other operating expenses	**1 606.6**	1 442.5	1 391.5
	5 309.9	3 621.4	2 512.7
OPERATING INCOME	**566.4**	765.7	763.5
INTEREST AND OTHER INCOME AND EXPENSES – NET	**181.7**	177.5	206.8
INCOME BEFORE TAXES	**384.7**	588.2	556.7
INCOME TAXES	**117.2**	213.0	198.7
PREFERRED DIVIDEND REQUIREMENTS OF SUBSIDIARIES	**6.5**	12.6	23.2
NET INCOME BEFORE EXTRAORDINARY ITEM	**$ 261.0**	$ 362.6	$ 334.8
EXTRAORDINARY ITEM – EQUITY SHARE OF WINDFALL PROFITS TAX (LESS APPLICABLE INCOME TAXES OF $0)	**–**	(109.4)	–
NET INCOME	**261.0**	253.2	334.8
COSTS OF REACQUISITION OF PREFERRED STOCK OF SUBSIDIARY	**–**	–	(18.4)
NET INCOME APPLICABLE TO COMMON STOCK	**$ 261.0**	$ 253.2	$ 316.4
AVERAGE COMMON SHARES OUTSTANDING	**158.2**	157.7	157.7
EARNINGS PER COMMON SHARE			
Net income before extraordinary item	**$ 1.65**	$ 2.30	$ 2.00
Extraordinary item	**–**	.69	–
Net income	**1.65**	1.61	2.00
EARNINGS PER COMMON SHARE – ASSUMING DILUTION			
Net income before extraordinary item	**$ 1.65**	$ 2.28	$ 1.99
Extraordinary item	**–**	.69	–
Net income	**1.65**	1.59	1.99
DIVIDENDS DECLARED PER COMMON SHARE	**$ 1.80**	$ 1.80	$ 1.74

See the accompanying Notes to the Condensed Consolidated Financial Statements.

Condensed Consolidated Balance Sheets

(In millions) December 31	**1998**	*1997*
ASSETS		
Current assets		
Cash and temporary cash investments	**$ 100.2**	$ 53.3
Energy risk management assets	**969.0**	–
Other current assets	**861.5**	617.3
Total current assets	**1 930.7**	670.6
Utility plant, net of accumulated depreciation of $4,040.2 at December 31, 1998, and $3,800.3 at December 31, 1997	**6 344.4**	6 297.1
Other assets	**2 023.7**	1 890.5
	$10 298.8	$8 858.2
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Energy risk management liabilities	**$ 1 117.1**	$ –
Other current liabilities	**2 082.0**	2 000.6
Total current liabilities	**3 199.1**	2 000.6
Long-term debt	**2 604.5**	2 150.9
Other liabilities	**1 861.3**	1 989.5
Total liabilities	**7 664.9**	6 141.0
Cumulative preferred stock of subsidiaries		
Not subject to mandatory redemption	**92.7**	178.0
Common stock equity		
Common stock (158.7 shares outstanding at December 31, 1998)	**1.6**	1.6
Paid-in capital	**1 595.2**	1 573.1
Retained earnings	**945.2**	967.4
Accumulated other comprehensive loss	**(.8)**	(2.9)
	$10 298.8	$8 858.2

See the accompanying Notes to the Condensed Consolidated Financial Statements.

Condensed Consolidated Statements of Cash Flows

(In millions)	**1998**	*1997*	*1996*
OPERATING ACTIVITIES			
Net income	**$ 261.0**	$ 253.2	$ 334.8
Items providing or (using) cash:			
Wabash Valley Power Association, Inc. settlement	**80.0**	–	(80.0)
Unrealized loss from energy risk management activities	**135.0**	15.0	–
Extraordinary item – equity share of windfall profits tax	**–**	109.4	–
Changes in current assets and current liabilities	**.8**	(70.6)	265.1
Other items – net	**247.2**	426.6	290.8
Net cash provided by operating activities	**724.0**	733.6	810.7
FINANCING ACTIVITIES			
Issuance of common stock and long-term debt	**789.3**	102.1	150.5
Redemption of long-term debt	**(384.5)**	(336.3)	(237.2)
Retirement of preferred stock of subsidiaries	**(85.3)**	(16.3)	(212.5)
Dividends on common stock	**(283.9)**	(283.8)	(274.3)
Other financing activities	**(245.4)**	191.8	573.4
Net cash used in financing activities	**(209.8)**	(342.5)	(.1)
INVESTING ACTIVITIES			
Construction expenditures	**(368.6)**	(328.1)	(323.0)
Acquisition of businesses (net of cash acquired)	**(63.4)**	–	–
Investments in unconsolidated subsidiaries	**(35.3)**	(29.0)	(503.3)
Net cash used in investing activities	**(467.3)**	(357.1)	(826.3)
Net increase (decrease) in cash and temporary cash investments	**46.9**	34.0	(15.7)
Cash and temporary cash investments at beginning of period	**53.3**	19.3	35.0
Cash and temporary cash investments at end of period	**$ 100.2**	$ 53.3	$ 19.3

See the accompanying Notes to the Condensed Consolidated Financial Statements.

1. *Summary of Significant Accounting Policies*

CONSOLIDATION POLICY The accompanying Condensed Consolidated Financial Statements include the accounts of Cinergy Corp. (Cinergy), and its wholly-owned subsidiaries. Cinergy uses the equity method of accounting for entities in which Cinergy does not have control, but can exercise significant influence over operating and financial policies. Cinergy is a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA). Cinergy's utility subsidiaries are The Cincinnati Gas & Electric Company (CG&E), a combination electric and gas utility serving the southwestern portion of Ohio and the adjacent areas in Kentucky and Indiana, and PSI Energy, Inc. (PSI), an electric utility serving the north central, central, and southern portions of Indiana. Numerous subsidiaries are engaged in non-utility operations.

Cinergy conducts its operations through four business units. The business units are Energy Commodities, Energy Delivery, Energy Services, and International.

PRESENTATION The Condensed Consolidated Statements of Income in this report have been reclassified in order to present the operations of all consolidated, non-regulated entities as a component of operating income. Prior to this reclassification, the operations of such entities were reflected in "Interest and Other Income and Expenses – Net." Similarly, "Income Taxes" now includes the income taxes associated with the non-regulated entities. These changes had no effect on net income. Additionally, the Condensed Consolidated Balance Sheets have been reformatted. Prior years' data has been reclassified to conform with the current year's presentation.

ENERGY MARKETING AND TRADING Cinergy's energy marketing and trading operations actively market and trade over-the-counter forward and option contracts for the purchase and sale of electricity, natural gas, and other energy products. With respect to power marketing and trading, contracts which are intended to be physically delivered through use of the company's generation assets are accounted for on the settlement basis. All other contracts for electricity are considered to be trading activities and are accounted for using the mark-to-market method of accounting. Prior to 1998, these contracts were accounted for using the aggregate lower of cost or market method. Revenues and costs for substantially all transactions are recorded gross in the Condensed Consolidated Statements of Income as contracts are settled. Natural gas and other energy product contracts are generally considered to be part of trading activities and are accounted for using the mark-to-market method. Revenues and costs from physical marketing are recorded gross while non-physical transactions are recorded net in the Condensed Consolidated Statements of Income. At December 31, 1998, energy risk management assets of $969 million and energy risk management liabilities of $1,117 million are recorded in the Condensed Consolidated Balance Sheets. At December 31, 1997, reserves provided under the aggregate lower of cost or market were not significant.

FINANCIAL DERIVATIVES Cinergy and its subsidiaries use derivative financial instruments to hedge exposures to foreign currency exchange rates, lower funding costs, and manage exposures to fluctuations in interest rates. Instruments used as hedges must be designated as a hedge at the inception of the contract and must be effective at reducing the risk associated with the exposure being hedged. Accordingly, changes in market values of designated hedge instruments must be highly correlated with changes in market values of the underlying hedged items at inception of the hedge and over the life of the hedge contract.

Cinergy utilizes foreign exchange forward contracts and currency swaps to hedge certain of its net investments in foreign operations. Accordingly, any translation gains or losses related to the foreign exchange forward contracts or the principal exchange on the currency swaps are recorded in "Accumulated other comprehensive loss", which is a separate component of Common stock equity. Aggregate translation losses related to these instruments are reflected in "Current liabilities" in the Condensed Consolidated Balance Sheets.

Interest rate swaps are accounted for under the accrual method. Accordingly, gains and losses based on any interest differential between fixed-rate and floating-rate interest amounts, calculated on agreed upon notional principal amounts, are recognized in the Condensed Consolidated Statements of Income as a component of "Interest and Other Income and Expenses – Net" as realized over the life of the agreement.

REGULATION Cinergy, its utility subsidiaries, and certain of its non-utility subsidiaries are subject to regulation by the Securities and Exchange Commission (SEC) under the PUHCA. Cinergy's utility subsidiaries are also subject to regulation by the Federal Energy Regulatory Commission and the state utility commissions of Ohio, Kentucky, and Indiana.

The accounting policies of Cinergy's utility subsidiaries conform to the accounting requirements and ratemaking practices of these regulatory authorities and to generally accepted accounting principles, including the provisions of Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (Statement 71) which requires that the effects of the ratemaking process be recorded. Accordingly, Cinergy records various regulatory assets and liabilities to reflect the actions of regulators. Significant regulatory assets include income taxes recoverable from customers, post-in-service carrying costs and deferred operating expenses, coal contract buyout costs, and deferred demand-side management costs. The total regulatory assets at December 31, 1998 and 1997 were $971 million and $1,077 million, respectively. PSI and CG&E, in total, have previously received regulatory orders authorizing the recovery of approximately $887 million of their regulatory assets.

Based on Cinergy's current regulatory orders and the regulatory environment in which it operates, the recognition of its regulatory assets as of December 31, 1998, is fully supported. However, in light of recent trends in customer choice legislation, the potential for future losses resulting from discontinuance of Statement 71 does exist.

OPERATING REVENUES AND FUEL COSTS Cinergy's utility subsidiaries record revenues for electric and gas service provided during the month, including sales unbilled at the end of each month. The costs of electricity and gas purchased and fuel used in electric production are expensed as recovered through revenues, and any portion of these costs recoverable or refundable in future periods is deferred in the accompanying Condensed Consolidated Balance Sheets.

2. Notes Payable and Other Short-term Obligations

As of December 31, 1998, Cinergy's Condensed Consolidated Balance Sheet reflects total notes payable and other short-term obligations outstanding of $904 million. Also, Cinergy and its subsidiaries had credit arrangements in place at year end which would permit additional borrowings of approximately $966 million.

3. Commitments and Contingencies

CONSTRUCTION Aggregate expenditures for the construction programs of PSI and CG&E for 1999 through 2003 are forecasted to be $2.3 billion. This forecast includes capital expenditures required to comply with proposed nitrogen oxide (NOx) limits.

ENVIRONMENTAL

(i) Manufactured Gas Plant (MGP) Sites Prior to the 1950s, gas was produced at MGP sites through a process that involved the heating of coal and/or oil. The gas produced from this process was sold for residential, commercial, and industrial uses. Coal tar residues, related hydrocarbons, and various metals associated with MGP sites have been found at

former MGP sites in Indiana. PSI has received claims from Indiana Gas Company, Inc. (IGC) and Northern Indiana Public Service Company (NIPSCO) that PSI is a Potentially Responsible Party under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) with respect to these MGP sites. PSI has reached various agreements with IGC and NIPSCO that settle allocation of CERCLA liability for past and future costs between the three companies. These agreements conclude all CERCLA and similar claims between the three companies relative to MGP sites. Pursuant to the agreements and applicable laws, the parties are continuing to investigate and remediate the sites as appropriate.

CG&E and its utility subsidiaries are aware of sites where MGP activities have occurred at some time in the past. None of these sites is known to present a risk to the environment. CG&E and its utility subsidiaries have undertaken preliminary site assessments to obtain more information about some of these MGP sites.

Based upon the work performed to date, costs have been accrued for the MGP sites related to investigation, remediation, and groundwater monitoring. Estimated costs of certain remedial activities are accrued when such costs are reasonably estimable. Cinergy does not believe it can provide an estimate of the reasonably possible total remediation costs for any site prior to completion of a remedial investigation/feasibility study and the development of some sense of the timing for the implementation of the potential remedial alternatives, to the extent such remediation may by required. Accordingly, the total costs that may be incurred in connection with the remediation of all sites, to the extent remediation is necessary, cannot be determined at this time. These future costs at the MGP sites, based on information currently available, are not material to Cinergy's financial condition or results of operations. However, as further investigation and remediation activities are undertaken at these sites, the potential liability for MGP sites could be material.

(ii) Ozone Transport Rulemaking In October 1998, the United States Environmental Protection Agency (EPA) finalized its Ozone Transport Rule (NOx SIP Call). It applies to 22 states in the eastern half of the United States, including the three states in which Cinergy operates electric utilities. This rule recommends that states reduce NOx emissions from primarily industrial and utility sources to a certain limit by May 2003. Ohio, Indiana, six other states, and various industry groups, including Cinergy, filed legal challenges to the NOx SIP Call in late 1998. Under the current provisions of the NOx SIP Call, Cinergy's estimate for compliance with the EPA limits is currently $500 million to $700 million (in 1998 dollars) in capital expenditures between now and 2003.

4. Investments in Unconsolidated Subsidiaries

Except for Cinergy's 50% investment in Avon Energy Partners Holdings (Avon Energy), investments in unconsolidated subsidiaries are not significant. Cinergy's investment in Avon Energy was $556 million and $505 million at December 31, 1998 and 1997, respectively. For the years ended December 31, 1998 and 1997, Cinergy's equity in earnings of Avon Energy was $57 million and $63 million (before extraordinary item), respectively. Avon Energy had assets totaling $4,653 million at December 31, 1998 and $4,714 million at December 31, 1997.

5. Wabash Valley Power Association, Inc. (WVPA) Settlement

In February 1989, PSI and WVPA entered into a settlement agreement to resolve all claims related to Marble Hill, a nuclear project canceled in 1984. Implementation of the settlement was contingent upon a number of events. During 1998, PSI reached an agreement on all matters with the relevant parties. As a result, PSI recorded a liability to the Rural Utilities Service. Assumption of the liability (recorded as long-term debt in the Condensed Consolidated Balance Sheet) resulted in a charge against earnings of $80 million ($50 million after tax or $.32 per share basic and diluted) in 1998.

Executive Officers

JACKSON H. RANDOLPH
Chairman of the Board

JAMES E. ROGERS
Vice Chairman, President, and Chief Executive Officer

JOHN BRYANT
Vice President of Cinergy and Managing Director of Cinergy Global Power Services Ltd.

MICHAEL J. CYRUS
Vice President of Cinergy and Chief Operating Officer of the Energy Commodities Business Unit

CHERYL M. FOLEY
Vice President, General Counsel, and Secretary of Cinergy, and President of the International Business Unit

WILLIAM J. GREALIS
Vice President, Corporate Services, and Chief Strategic Officer of Cinergy, and President of Cinergy Investments

J. JOSEPH HALE, JR.
Vice President, Corporate Communications

M. STEPHEN HARKNESS
Vice President of Cinergy and Executive Vice President and Chief Operating Officer of Trigen-Cinergy Solutions LLC

DONALD B. INGLE, JR.
Vice President of Cinergy and President of the Energy Services Business Unit

JERRY W. LIGGETT
Vice President, Human Resources Strategy

MADELEINE W. LUDLOW
Vice President of Cinergy and President of the Energy Commodities Business Unit

JOHN M. MUTZ
Vice President of Cinergy and President of PSI Energy

WILLIAM L. SHEAFER
Vice President and Treasurer

JOHN P. STEFFEN
Vice President and Comptroller

LARRY E. THOMAS
Vice President of Cinergy and President of the Energy Delivery Business Unit

JAMES L. TURNER
President of CG&E

CHARLES J. WINGER
Vice President and Chief Financial Officer

NEIL A. ARMSTRONG (1,4)
Mr. Armstrong is chairman of AIL Systems, Inc., Deer Park, New York. He has been a director since 1994.

JAMES K. BAKER (1,4*)
Mr. Baker is the retired chairman and chief executive officer of Arvin Industries, Inc., Columbus, Indiana. He has served as a director since 1994.

MICHAEL G. BROWNING (3,6)
Mr. Browning is chairman and president of Browning Investments, Inc., Carmel, Indiana. He has served as a director since 1994.

PHILLIP R. COX (3,5)
Mr. Cox is president and chief executive officer of Cox Financial Corp., Cincinnati. He has been a director since 1994.

KENNETH M. DUBERSTEIN (5)
Mr. Duberstein is chairman and chief executive officer of The Duberstein Group, Inc., Washington, D.C. He has been a director since 1994.

CHERYL M. FOLEY
Ms. Foley, vice president, general counsel and secretary of Cinergy and president of the International Business Unit, has been a director since 1998.

JOHN A. HILLENBRAND II (2,5*)
Mr. Hillenbrand is chairman, president, and chief executive officer of Glynnadam, Inc., Batesville, Indiana. He has served as a director since 1994.

GEORGE C. JUILFS (5,6)
Mr. Juilfs is president and chief executive officer of SENCORP, Newport, Kentucky. He has been a director since 1994.

MELVIN PERELMAN, PH.D. (2,3)
Dr. Perelman is the retired executive vice president of Eli Lilly and Company, Indianapolis, Indiana. He has been a director since 1994.

THOMAS E. PETRY (1,4)
Mr. Petry is the retired chairman and chief executive officer of Eagle-Picher Industries, Inc., Cincinnati. He has been a director since 1994.

JACKSON H. RANDOLPH (1)
Mr. Randolph, chairman of Cinergy, has been a director since 1993.

JAMES E. ROGERS (1*,3)
Mr. Rogers, vice chairman, president, and chief executive officer of Cinergy, has been a director since 1993.

MARY L. SCHAPIRO (2,4)
Ms. Schapiro is president of NASD Regulation, Inc., Washington, D.C. She has been a director since 1999.

JOHN J. SCHIFF, JR. (6)
Mr. Schiff is chairman of Cincinnati Financial Corporation and The Cincinnati Insurance Company, Cincinnati. He has been a director since 1994.

PHILIP R. SHARP, PH.D. (4)
Dr. Sharp is a lecturer in public policy at the John F. Kennedy School of Government at Harvard University in Cambridge, Massachusetts. He has been a director since 1995.

VAN P. SMITH (1,6*)
Mr. Smith is chairman of Ontario Corporation, Muncie, Indiana. He has served as a director since 1994.

DUDLEY S. TAFT (3*)
Mr. Taft is president and chief executive officer of Taft Broadcasting Co., Cincinnati. He has been a director since 1994.

OLIVER W. WADDELL (2*)
Mr. Waddell is the retired chairman and chief executive officer of Star Banc Corporation, Cincinnati (now Firstar Corporation, Milwaukee, Wisconsin). He has been a director since 1994.

(1) Executive Committee
(2) Finance Committee
(3) Corporate Governance Committee
(4) Audit Committee
(5) Public Policy Committee
(6) Compensation Committee
(*) Indicates Committee Chairperson

INVESTOR CONTACT

Steven E. Schrader
General Manager,
Investor Relations and
Strategic Planning
139 East Fourth Street
Cincinnati, Ohio 45202
(513) 287-1083

E-mail:
sschrader@cinergy.com

DIVIDEND REINVESTMENT AND STOCK PURCHASE PLAN

Cinergy's Dividend Reinvestment and Stock Purchase Plan lets investors accumulate shares of Cinergy common stock without incurring brokerage fees. The plan is open to all shareholders of record. Shareholders may automatically reinvest all or a portion of their cash dividends in Cinergy common stock at prevailing market prices.

Shareholders may also purchase additional shares by making payments of at least $25 at any one time, but not more than $100,000 per calendar year. Currently, approximately 35,000 shareholders participate in the plan.

Complete details about the plan are contained in the plan's prospectus. To receive a copy of the prospectus and an enrollment form, contact Shareholder Services.

DIRECT DEPOSIT OF DIVIDENDS

Shareholders can have their dividends electronically transferred to their checking or savings accounts. To receive an enrollment form, contact Shareholder Services.

OTHER INFORMATION

Transfer agent for Cinergy common and CG&E and PSI preferred shares:

Cinergy Corp.
Shareholder Services
P.O. Box 900
Cincinnati, Ohio
45201-0900

Registrar for Cinergy common and CG&E and PSI preferred shares:

Fifth Third Bank
Corporate Trust Services
38 Fountain Square Plaza
Cincinnati, Ohio 45263

QUARTERLY STOCK DATA

Quarter	*1st*	*2nd*	*3rd*	*4th*
1998				
High	$38 11/16	$37 5/16	$38 7/8	$39 7/8
CLOSE	**$36 7/8**	**$35**	**$38 1/4**	**$34 3/8**
Low	$33	$31 5/8	$30 13/16	$33 3/4
Dividends per share	.45	.45	.45	.45
1997				
High	$35 3/4	$35 5/8	$35 1/4	$39 1/8
CLOSE	**$34 1/2**	**$34 13/16**	**$33 7/16**	**$38 5/16**
Low	$32 5/8	$32	$32 5/16	$32
Dividends per share	.45	.45	.45	.45

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CINERGY®

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION Matters discussed in this summary report reflect and elucidate Cinergy's corporate vision of the future and, as a part of that, outline goals and aspirations, as well as specific projections. These goals and projections are considered forward-looking statements and are based on management's beliefs, as well as certain assumptions made by management. Forward-looking statements involve risks and uncertainties which may cause actual results to differ materially from the forward-looking statements. In addition to any assumptions and other factors that are referred to specifically in connection with these statements, other factors that could cause actual results to differ materially from those indicated in any forward-looking statements include, among others: factors generally affecting operations — such as unusual weather conditions, unusual maintenance or repairs, or unanticipated changes in fuel costs; legislative and regulatory initiatives regarding deregulation and restructuring of the industry; the extent and timing of the entry of additional competition in our markets and the effects of continued industry consolidation through the pursuit of mergers, acquisitions and strategic alliances; challenges related to Year 2000 readiness; regulatory factors, including the failure to obtain anticipated regulatory approvals; changes in accounting principles or policies; political, legal and economic conditions and developments in the United States and in foreign countries in which we operate; changing market conditions; the performance of projects undertaken by the non-traditional business and the success of efforts to invest in and develop new opportunities; availability or cost of capital; employee workforce factors; costs and effects of legal and administrative proceedings; changes in legislative requirements; and other risks indicated in filings with the Securities and Exchange Commission (SEC). The SEC's rules do not require forward-looking statements to be revised or updated, and Cinergy does not intend to do so.

CORPORATE HEADQUARTERS

Cinergy Corp.
139 East Fourth Street
Cincinnati, Ohio 45202
Web site: www.cinergy.com

ANNUAL MEETING

The annual meeting of shareholders will be held at the Omni Netherland Plaza Hotel, Hall of Mirrors, 35 West Fifth Street, Cincinnati, Ohio, on Wednesday, April 21, 1999, at 11:00 a.m., Eastern time.

COMMON STOCK

Cinergy's common stock, which is traded under the ticker symbol CIN, is listed on the New York Stock Exchange, and has unlisted trading privileges on the Boston, Chicago, Cincinnati, Pacific, and Philadelphia exchanges. As of December 31, 1998, there were 69,326 common stock shareholders of record.

FORM 10-K

Shareholders may obtain a copy of Cinergy's annual report to the Securities and Exchange Commission (Form 10-K), without charge, by contacting Shareholder Services.

SHAREHOLDER INQUIRIES

Please direct all requests and communications pertaining to your account to:

Cinergy Corp.
Shareholder Services
P.O. Box 900
Cincinnati, Ohio
45201-0900

E-mail:
shareholders@cinergy.com

You may call Cinergy toll-free from anywhere in the United States between 8:00 a.m. and 5:00 p.m. Eastern time, Monday through Friday.
The numbers are as follows:

Greater Cincinnati:
287-1940

United States:
1-800-325-2945

skill sets, and capabilities from outside our industry — is just one part of this process. We're also reinforcing change through new processes and structures.

Over the past several years, we have built a performance-based culture. A business unit structure creates a laser focus on accountability, with incentive compensation tied to execution of fully developed business plans as measured by Key Performance Indicators (KPIs) for each unit. Last year, I stepped up my emphasis on business unit performance, personally conducting quarterly performance reviews to build a sense of urgency.

In addition, this year I'm going to identify about 25 people in our company who have the potential to have a great impact on our future. I'm going to teach a leadership development course and take personal responsibility for the development of these individuals, including job rotation and building new skills. If this is successful, I will expand it to others in the company in future years.

Conclusion

Nobody knows exactly how the energy business will unfold over the next five to ten years, so how can you identify the potential winners? In my judgment, the three key factors are:

- the right mission, pursued with a strategy that maximizes options and flexibility;
- a premier combination of people and skills; and
- a clear demonstration that those people are successfully executing that strategy.

It's a tribute to the committed people at Cinergy that they have responded to our ambitious mission as a personal challenge. In 1998, we lived up to our vision of "people making history by making a difference." Cinergy played a key role in two major events that will facilitate competitive markets for electric power.

- In July, the New York Mercantile Exchange (NYMEX) began trading electricity futures at a hub on the Cinergy transmission system.
- In September, the Federal Energy Regulatory Commission approved the Midwest Independent System Operator (ISO) for a combined transmission system in our region. Cinergy led the creation of the ISO, which will help ensure that electric power transactions will be efficient and reliable.

Cinergy employees are contributing to "5 in 3 on 5" with efforts around the world. In a year when the ultimate achievement is not clearly in sight, I thank them for their perseverance and the continued progress they have made possible.

I also want to thank Van Smith, who is retiring from our board of directors, for his many years of distinguished service to Cinergy and PSI. I deeply appreciate Van's counsel and his leadership on the board. We welcome two new Board members: Cheryl Foley, our general counsel and president of the International Business Unit; and Mary Schapiro, president of the National Association of Securities Dealers Regulation, former chair of the Commodity Futures Trading Commission, and former commissioner on the Securities and Exchange Commission.

And I thank Cinergy shareholders for your patience as we reposition our company to become a growth energy company in the new competitive world. I promise that your management team will continue to pursue an aggressive but realistic strategy, to focus on performance, and to make the tough decisions. I am committed to achieving our mission and expanding our capacity to create value for all stakeholders.

Best,

James E. Rogers

James E. Rogers
President and Chief Executive Officer
February 12, 1999

So we are focusing more than ever on this issue: Do we have a coherent strategy to develop, acquire, and retain talent, and are we effectively executing our strategy?

The primary constraint we face is not a lack of capital or opportunities, but competition for talent. This means, first and foremost, that we must recognize and develop the talent we have. It also means that we must be able to attract and retain talent with a value proposition that goes beyond the financial incentives anyone could offer. We must offer the opportunity to work with a company recognized for its leadership and innovation.

Several elements of our talent strategy have existed for some time. These include our stakeholder approach, our commitment to diversity, and policies that allow employees to balance their work and personal lives. In 1998, these policies were recognized by *Working Mother* magazine for the second consecutive year.

During the past year, we began to link our talent strategy directly to our growth strategy. What became clear is that our growth must be built upon Cinergy's characteristic style and value proposition: operational excellence. The success of our legacy utility business is based on premier operations, such as top-five productivity in electric generation.

Our talent strategy must develop and utilize the operational skills of our people, adding necessary skills to unlock their full potential. This approach is working at Cinergy Business Solutions (CBS), one of our start-up businesses. CBS is an energy services company, or ESCO, serving industrial and institutional customers. Building on Cinergy's strong engineering skills, CBS is adding people who have ESCO experience developing comprehensive energy solutions for customers. Adding these capabilities gives our engineers new opportunities to create value. It also creates a cadre to train other Cinergy employees in these hard-to-find skills.

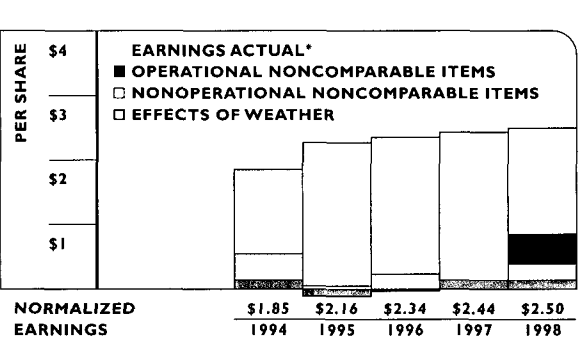
Talent is a key factor in every acquisition or start-up business we pursue in our growth strategy. We have gained critical talent from our acquisitions of Greenwich Energy Partners, ProEnergy, and Midlands Power International. We have extended our skill sets through joint ventures such as Trigen-Cinergy Solutions. And we have added critical skills to enter new markets in start-ups such as Cinergy Business Solutions. We are leveraging these skills across the entire Cinergy organization. For example, we're leveraging our reengineering expertise at Midlands and origination skills across wholesale and retail markets.

Another key element in our talent strategy is the restructuring of our "genetic code" — how we make decisions, work together, manage risk, and set expectations for performance. Adding new "genes" — mindsets,

EARNINGS COMPARISON

In 1998, basic earnings per share were $1.65, compared with $2.30 in 1997, $2.12 in 1996, $2.22 in 1995, and $1.30 in 1994. After adjusting for the effects of weather and noncomparable items, an apples-to-apples comparison shows a 2.5% increase in normalized earnings per share in 1998, from $2.44 to $2.50.

**1997 does not include extraordinary item for equity share of windfall profits tax of $.69 per share; 1996 does not include costs of reacquisition of preferred stock of subsidiary of $.12 per share.*



to pursue opportunities for our own clean-energy initiatives, with wind, hydro, and biomass projects in Europe, Africa, and the United States.

Although the Kyoto Treaty may not be ratified in its present form by the U.S. Senate, we're continuing to pursue cost-effective greenhouse gas reduction and offsetting activities, including land restoration projects and encouraging the use of alternative fuels for vehicles.

We're demonstrating Cinergy's commitment to innovative, voluntary actions to reduce our impact on the environment in a project at our Zimmer generating plant. We'll convert waste ash from the plant into artificial gypsum and sell it to a wall board manufacturer. The project will generate income and eliminate the need to ship as much as 1.7 million tons of ash to the Zimmer landfill.

We cannot predict how these issues will be resolved, but we can say this: Cinergy will be at the table to help shape the resolution of these issues, because we have made a credible and recognized commitment to being part of the solution. That solution will require 21st-century thinking. We intend to achieve the most cost-effective, environmentally benign use of coal to generate electricity, while exploring new and emerging generation technologies — such as solar and wind power and distributed generation — that may well be the eventual future of our industry.

EMERGING MARKETS. The greatest unknown lies in the shape of emerging energy markets. That fact was driven home during the Midwest heat wave last June, when prices for power spiked at levels never before imagined.

Technological and economic changes are driving emerging energy markets in unforeseeable directions. We are monitoring and participating in the development of new ideas and technologies that could transform our business. For example, Cinergy is the only U.S. electric utility participating in an international forum on technology to transmit data and communications via power lines. The technology, which holds the potential for dramatically higher data transmission speeds, could indeed transform our business — and the world's communications.

While efforts on such a visionary level are not easily captured in an annual report, we believe they are critical to our long-term growth in a rapidly changing world. As we manage uncertainty, we are guided by Peter Drucker, who has said that the best way to deal with an unpredictable future is to make the future happen.

Talent: Are we building a winning team?

In the ten years since I became a CEO, I've come to realize that talent is the most critical element in success. Today, competition is intensifying our need to develop new skills and to make the most of the skills we have.

Committed people.

CRAIG AND RUTHANN WEIDA TRANSFERRED THEIR REENGINEERING EXPERIENCE FROM CINERGY TO MIDLANDS — AND BACK AGAIN. CRAIG DIRECTED PROCESS IMPROVEMENT EFFORTS THAT FOLLOWED THE CINERGY MERGER. IN 1997-1998, HE LED A TEAM OF MIDLANDS EMPLOYEES WHO IDENTIFIED FIVE-YEAR SAVINGS ESTIMATED AT $450 MILLION. IN REENGINEERING AT CINERGY, RUTHANN'S CORPORATE CENTER TEAM FOCUSED ON FINANCIAL MANAGEMENT PROCESSES; AT MIDLANDS, SHE LED A SIMILAR TEAM THAT DESIGNED AND IMPLEMENTED FINANCIAL MANAGEMENT SYSTEMS AND PLANNING PROCESSES. BOTH CRAIG AND RUTHANN HAVE APPLIED EXPERIENCE FROM MIDLANDS IN REENGINEERING AND PLANNING AT CINERGY.

CRAIG WEIDA — VICE PRESIDENT, REENGINEERING AND SHARED SERVICES. RUTHANN WEIDA — MANAGER, BUSINESS PLANNING, ENERGY COMMODITIES BUSINESS UNIT.

petition. By using joint ventures to enter the energy services market, we position ourselves to compete while limiting our up-front investment. Similarly, we continue to take a conservative approach to branding. We seize opportunities to build the Cinergy name, but avoid the huge expenditures others have made years ahead of the market.

We continue to take advantage of opportunities to gain experience in competitive markets in the United States and abroad. At the same time, we are carefully targeting and monitoring our exposure in competitive markets. Specific profit centers focus exclusively on various regulated and competitive segments of the business.

We are also working to achieve greater certainty about the path of restructuring. We advocate clear, fair rules in regulatory and legislative reform of our industry. In 1998, we made significant progress in Ohio, achieving a consensus among the state's investor-owned utilities on a proposal for customer choice. We continue to participate actively in reform efforts in Indiana and Kentucky, and at the Federal level — where there are renewed hopes for repeal of the Public Utility Holding Company Act. And we resolved a major uncertainty under PUHCA, when the Securities and Exchange Commission approved retention of CG&E's gas business.

ENVIRONMENTAL ISSUES. In the years ahead, Cinergy faces a number of challenges in meeting our environmental responsibilities — challenges greater than the Clean Air Act limits on sulfur dioxide emissions.

In 1998, the focus shifted from acid rain to ozone, and from sulfur dioxide to nitrogen oxides (NOx). To comply with proposed NOx limits announced last fall by the Environmental Protection Agency, we could face capital costs currently estimated at $500 million to $700 million over the next five years, just at the time we expect our generation to be deregulated.

Even before the EPA action, Cinergy volunteered reductions at our generating stations and announced a demonstration of advanced technology to reduce NOx emissions at one of our plants. And we joined with others in the Alliance for Constructive Air Policy to advance constructive and cost-effective solutions to the ozone transport issue.

Implementation of the proposed global warming treaty — the Kyoto Treaty — could also have a major impact on our company — and our economy. We believe that voluntary programs are the most cost-effective means to limit greenhouse gas emissions. As a participant in the U.S. Department of Energy Climate Challenge Program, we have achieved nearly 10 million tons of carbon dioxide equivalent reductions and offsets since 1991. We are continuing

Committed people.

LELAND SMITH AND SHERRI KEMPF ARE BRINGING ENERGY SERVICE EXPERTISE TO CINERGY BUSINESS SOLUTIONS, WHICH IMPLEMENTED A MONEY-SAVING ENERGY RETROFIT FOR CINCINNATI WATER WORKS. LELAND WAS ATTRACTED TO CINERGY IN 1998 AFTER 18 YEARS AT HONEYWELL, WHERE HE DIRECTED WORLDWIDE INDUSTRIAL SERVICES AND SYSTEMS. A TEN-YEAR VETERAN OF CG&E AND CINERGY, SHERRI HAS APPLIED SKILLS FROM UTILITY DEMAND-SIDE MANAGEMENT PROGRAMS TO START UP NON-REGULATED ENERGY SERVICES BUSINESSES. WHILE AT CINERGY, SHERRI EARNED AN M.B.A. FROM THE UNIVERSITY OF CHICAGO. LELAND SMITH — PRESIDENT, CINERGY BUSINESS SOLUTIONS. SHERRI KEMPF — DIRECTOR, STRATEGIC MARKETING, CINERGY BUSINESS SOLUTIONS.

Midwest, where we have generating assets, and we continued to make the essential investments in systems to support our trading operations.

In the Energy Services Business Unit, our start-up businesses successfully closed deals and acquired major customers. Trigen-Cinergy Solutions signed seven agreements to build or operate industrial and municipal energy systems, bringing projected annual revenue to $67 million. Cadence manages energy information for thousands of customer sites in all 50 states. We also launched a new joint venture called Centrus, which offers retail consumers a one-stop utility and telecommunications bundle of products.

Energy Services also stepped up efforts to secure our position with current customers by developing new products and services and by reducing costs. More than 2,000 employees have completed training in delivering superior customer service.

The Energy Delivery Business Unit, which is engaged primarily in regulated operation of pipes and wires, is pursuing a number of initiatives to maximize the value of our assets and expertise. These include a joint venture that will, pending regulatory approval, purchase Cinergy, CG&E, and PSI communications towers and then lease space to wireless communications providers. A second joint venture, also pending approvals, will construct and locate underground electric, gas, telephone, cable, and water facilities. And another proactive effort is aimed at installing fiber-optic links on our distribution poles.

To support these initiatives in the business units, the corporate center is managing the transition to competition, developing and advancing Cinergy's position on electric utility reform and environmental policy. We are also managing the transition to the new millennium, with a Year 2000 readiness program for all of our systems, including generation, transmission, gas and electric distribution, billing, and trading.

Strategy: Can we manage uncertainty, and grow?

As the industry landscape continues to change, can any strategy be sufficiently robust to manage the uncertainties we face? We must deal not only with "known uncertainties" but also with the unknown — uncertainties we haven't even identified yet. Among those we know, the most important are the direction and timing of industry transition and regulatory reform, the impact of evolving environmental regulations, and the shape of emerging energy markets.

INDUSTRY TRANSITION. We have adopted a number of strategies to deal with the uncertain timing of com-

Committed people.

UDAY NARANG AND JOE HOPF BRING COMPLEMENTARY SKILLS AND EXPERIENCE TO CINERGY'S TRADING FLOOR. UDAY JOINED CINERGY IN 1997, AFTER FIVE YEARS IN COMMODITY DERIVATIVES TRADING IN NEW YORK AND HOUSTON. WITH EXPERTISE IN FINANCIAL INSTRUMENTS, HE MANAGES CINERGY'S LONG-TERM POWER TRADING PORTFOLIO. JOE WAS HIRED AS A MECHANIC AT PSI'S GIBSON STATION IN 1981. BY 1995, HE WAS SUPERVISOR OF CINERGY'S CONTROL CENTER AND WAS ASSIGNED TO CREATE THE TRADING FLOOR. JOE BRINGS KNOWLEDGE OF GENERATING PLANTS AND THE TRANSMISSION SYSTEM TO HIS RESPONSIBILITIES FOR PHYSICAL POWER TRADING. UDAY NARANG — MANAGING DIRECTOR, PORTFOLIO MANAGEMENT, ENERGY COMMODITIES SERVICES.

C. JOE HOPF, JR. — MANAGING DIRECTOR, POWER TRADING/OPERATIONS, ENERGY COMMODITIES SERVICES.

JULY/AUGWEST
SEPTEMBER WEST
12 JAN
12 JAN
6 JAN
12 JAN
12 JAN
8 JAN
12 JAN
7 JAN
12 JAN
BID/ASK

- We've increased revenues by $2.9 billion, or 94 percent, between 1995 and 1998.
- We've committed $700 million in capital investments to nonregulated growth and value opportunities — 44 percent of all investments in the past three years.
- We've leveraged our position in emerging energy services markets by entering into 15 joint ventures.
- We've expanded our international footprint, from $20 million in two Argentine projects, to $640 million in investments and operations in more than ten countries.

Each of our four business units has spawned start-up businesses, testing their ability to create value in emerging energy markets. This is, of course, in addition to the business units' responsibilities for premier performance in their traditional regulated markets. Elsewhere in this report, we detail measurable progress on these initiatives. I believe that this progress is bringing us closer to our goal — a new level of value creation capacity.

In 1998, the International Business Unit took key steps to reposition Midlands and to create a whole new international energy business, Cinergy Global Resources. Building on the core staff we brought in from Midlands Power International (MPI) last year, we assembled the essential elements of an international energy development team. Even as we put the pieces in place, Cinergy Global moved forward on a three-pronged development strategy:

- to acquire and modernize existing energy assets in Central and Nordic Europe, using our operational and reengineering expertise;
- to own and operate clean energy sources, developing the skills to replicate these projects elsewhere; and
- to participate in privatization or greenfield energy projects in developing countries, building on MPI's knowledge and relationships.

In November, we entered into an agreement to sell the supply business of Midlands Electricity. By making the first move to separate supply from distribution, we're staying ahead of inevitable changes in the UK electricity market, and we can concentrate on Midlands' profitable distribution business. The transaction is subject to regulatory approval. It is expected to close in the second quarter of 1999, resulting in a gain to Cinergy. In addition, successful reengineering of Midlands' operations allows reinstatement of the Midlands dividend to Cinergy two years earlier than expected.

The Energy Commodities Business Unit took a number of critical steps to solidify its energy trading business, as the expected industry shakeout materialized. With the acquisition of ProEnergy, we gained physical gas marketing capacity of 1.8 billion cubic feet per day — a long way from the top five, but a significant entry into the market. We also took action to reorganize our electric trading operations and to refocus on the

Committed people.

VLADIMIR PRERAD BRINGS 28 YEARS OF EXPERIENCE IN ENGINEERING, INTERNATIONAL BUSINESS DEVELOPMENT, AND CORPORATE MANAGEMENT TO CINERGY GLOBAL RESOURCES. VLADIMIR LEADS THE "ROM" STRATEGY — REFURBISH, OPERATE, AND MAINTAIN. CINERGY GLOBAL ACQUIRES EXISTING OPERATIONS IN EMERGING COUNTRIES WHERE SIGNIFICANT VALUE CAN BE ADDED BY RESTRUCTURING, REPOWERING, EXPANDING, OR REENGINEERING. IN 1998, HE COMPLETED TWO ACQUISITIONS IN THE CZECH REPUBLIC; IN PLZEN, FOR EXAMPLE, CINERGY GLOBAL IS REENGINEERING A UTILITY WITH 36 PRODUCTS AND SERVICES TO FOCUS ON FIVE CORE BUSINESSES. A NATIVE OF PRAGUE, VLADIMIR SPEAKS FIVE LANGUAGES. VLADIMIR PRERAD — VICE PRESIDENT, CINERGY GLOBAL RESOURCES.

I believe it also reflects a candid assessment of our capabilities and constraints.

Having demonstrated success in a major merger transaction, a joint-venture acquisition of a major foreign utility, and other growth initiatives, Cinergy can create value through an even more aggressive growth strategy. Our mission entails higher near-term risk than a niche strategy, but it's a far better option for long-term earnings growth. Indeed, continuing as a vertically integrated, franchise utility is not an option at all, given the reforms that are coming.

We face some significant constraints. As a mid-size, regional energy company, we lack the balance sheet, cash flow, and resources of some of our larger competitors. As a registered holding company under the Public Utility Holding Company Act (PUHCA), we are limited in pursuing investments or partners outside our core business or region.

But we believe that top-tier earnings growth can be achieved. This will translate over time into an increase in our price/earnings multiple. A higher P/E will give us the currency to acquire or merge with other companies in the region or across the country, further expanding our capacity to create value. We also remain hopeful that PUHCA will be repealed — and that prospect intensifies the urgency of overcoming other constraints to position ourselves for a wider range of opportunities.

To reach our potential, we must clearly assess our capabilities: our assets, our skill sets, the scope and scale of our operations, and the need to maintain current earnings. Then, we must use our capabilities to pursue a multi-path growth strategy, which includes:

- maximizing the value of our existing operations and assets;
- targeting opportunities in emerging regional and national markets for gas, electricity, and related services; and
- pursuing similar opportunities in markets outside the United States.

Such a multi-path strategy gives us greater flexibility and optionality to manage uncertainties in our industry. Exiting any part of the value chain — generation, transmission, and distribution — at this time would unduly limit us.

Growth initiatives: Are we gaining traction?

To achieve our goals, we must pursue growth along multiple paths. Are we gaining "traction" on our growth initiatives, or spinning our wheels? The results show traction.

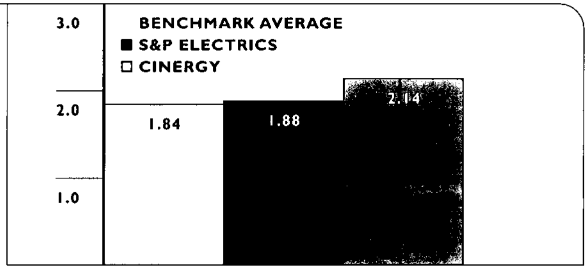
Since mid-1996, when we embarked on our mission to create a growth energy company, we have aggressively pursued growth.

Committed people.

LEIGH PEFLEY IS APPLYING 19 YEARS OF EXPERIENCE AT PSI AND CINERGY AS SHE EXPLORES NEW BUSINESS OPPORTUNITIES FOR THE ENERGY DELIVERY BUSINESS UNIT. LEIGH'S BACKGROUND INCLUDES FUELS AND MINING, BUDGETS AND FORECASTS, RATES, STRATEGIC PLANNING, ACCOUNTING, INVESTOR RELATIONS, AND REENGINEERING. NOW, AS CHAIR OF RELIANT SERVICES, A JOINT VENTURE WITH INDIANA ENERGY, SHE IS LEADING AN INITIATIVE IN UNDERGROUND UTILITY LOCATING AND CONSTRUCTION. SHE IS ALSO ANALYZING THE FINANCIAL AND BUSINESS ASPECTS OF WIRELESS COMMUNICATIONS FOR CINERGY'S PARTICIPATION IN ANOTHER JOINT VENTURE, LATTICE COMMUNICATIONS. LEIGH PEFLEY — VICE PRESIDENT, FINANCIAL OPERATIONS, ENERGY DELIVERY BUSINESS UNIT.

MARKET-TO-BOOK RATIO

The market-to-book ratio reflects the market's expectations of future performance. On December 31, 1998, Cinergy had a market-to-book ratio of 2.14, above the average of a benchmark group consisting of the largest 25 electric utilities and the average of the companies included in Standard & Poor's electric index. (Source: Bloomberg.)



for 1998 also reflect a reduction of $.14 per share for the effects of milder-than-normal weather.

Earnings of $1.65 per share in 1998 compared with $1.59 per share in 1997. Earnings in 1997 reflected a one-time extraordinary charge of $.69 per share for the windfall profits tax levied against Midlands Electricity plc, our 50 percent-owned subsidiary in the United Kingdom, and a reduction of $.14 per share for the effects of mild weather. After adjusting for the effects of weather and noncomparable items in both years, an apples-to-apples comparison shows that earnings per share were essentially flat from 1997 to 1998.

We are taking important steps to create opportunities for sustainable growth in future earnings by investing in new domestic and international initiatives. In fact, we could have reported earnings growth in line with earlier years, had we not incurred $.20 per share in net expenses for these initiatives. We have sought to balance near-term earnings with necessary investments in long-term growth.

In 1998, Cinergy acquired a major gas marketing firm, ProEnergy, which added physical gas supply and trading to our commodity portfolio. And we made investments of more than $110 million in other countries, including the Czech Republic, Estonia, Spain, and the United Kingdom.

We also demonstrated an ability to bring home the value of our investments, with the profitable sale of Cinergy's interest in Edesur SA, an electric distribution network in Argentina. In 1998, Cinergy recorded the highest profit margin ever realized from its Midwest trading operations, on the highest-ever revenues and volume of kilowatt-hours traded, even though we increased trading liabilities for future periods.

Indeed, notwithstanding charges and growth spending in 1998, our underlying earnings were strong, about $2.70 per share. Both our traditional businesses and new initiatives, such as gas marketing and trading, are contributing to our revenue growth. Results for 1998 also reflect cost-reduction efforts across the company, which are continuing with particular emphasis on the corporate center.

But clearly, we are dissatisfied with the earnings Cinergy produced in 1998 — and with a negative total shareholder return for the year. The fact is, from the Cinergy merger until last year, Cinergy significantly outpaced the industry in both earnings growth and shareholder return. We are determined to regain momentum for strong growth in earnings and shareholder value.

Mission: Do we have the right aspirations?

Is "5 in 3 on 5" a motivating vision or a mission impossible? Our mission reflects a strategic decision to pursue scale and scope, rather than retreat to a niche business.

company. They will build on the hard lessons we learned in 1998 — a year when we did not achieve the top-tier performance that we have in the past, and that we intend to achieve in the future.

Two years ago, we established our "5 in 5 on 5" mission. Its goals are to reach the top five in our industry within five years on five key dimensions — market capitalization, number of customers, electric and gas commodity trading, international presence, and productivity — while accepting nothing less than being No. 1 in customer and shareholder value.

As we enter 1999, our mission is now "5 in 3 on 5," and industry events and trends remind us every day just how ambitious our goals are. The financial community clearly believes that the size of a company's market capitalization and customer base will make a difference in its ability to create superior earnings growth. They are less certain at this time, however, about the contribution to future success that comes from building commodity trading and international businesses. Clearly, there is doubt as to whether a mid-cap company, such as Cinergy, can successfully reposition itself to produce a higher-than-average earnings trajectory in the future.

In my judgment, we can do just that, and our "5 in 3 on 5" mission is the best way in uncertain times to create the platforms for superior long-term earnings growth. I am confident that we are on the right track, but I also know that we must successfully execute to build growth platforms for the future. And we will.

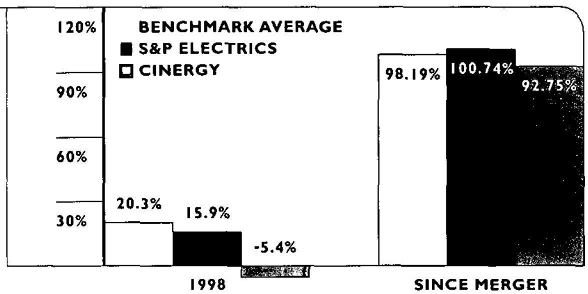
While we have been actively pursuing a transaction that will help us reach the top five in market capitalization and number of customers, we have made significant progress toward other "5 in 3 on 5" goals. Again this year, our annual report provides extensive measures of Cinergy's position in a growing universe of peer companies and our progress toward each of the five goals. As we near the halfway point in our five-year mission, my letter will focus on the strategies and talent we need to drive that progress. Before turning to these issues, let me review Cinergy's performance in 1998.

Review of 1998

Cinergy's 1998 earnings were $1.65 per share. Reported earnings reflect charges that resolve uncertainties and provide a more solid footing for future growth. A charge of $.32 per share was related to a settlement with Wabash Valley Power Association — which closes the books on PSI Energy's Marble Hill nuclear plant. We also recorded total charges of $.54 per share in our energy marketing and trading business for the establishment of net trading liabilities. These adjustments were based primarily on projections of future prices for transactions entered into prior to April 1998. Earnings

TOTAL SHAREHOLDER RETURN

Total return to Cinergy shareholders in 1998 was -5.4%, down from 21.2% in 1997. From the Cinergy merger in October 1994 until December 31, 1998, total return to Cinergy shareholders was 92.75%, below the average of a benchmark group consisting of the largest 25 electric utilities and the average of the companies included in Standard & Poor's electric index. From the merger through 1997, Cinergy total shareholder return outperformed both those averages. (Source: Bloomberg.)



James E. Rogers,
President and
Chief Executive Officer

Dear Stakeholder,

We are committed to making the transition from a vertically integrated, franchised utility to a growth energy company in emerging competitive markets. In 1998, we came face-to-face with the challenges of repositioning our company in a world where the rules are still unknown and the energy markets are embryonic. We gained a deeper, more profound understanding of our strengths and the constraints that we must overcome to be a growth energy company in this new competitive world.

Many of our people are fired up by the challenges and uncertainties we face. With their commitment, drive, and passion we will successfully move into this new world. It is the talents and efforts of these uncommon people that will allow us to make uncommon progress in transforming our

Our Mission: "5 in 3 on 5"

1998 was the second year of Cinergy's mission to be among the top five companies in the industry in five years — now three years — on five key measures: market capitalization, number of customers, electric and gas commodity trading, international presence, and productivity in key operational areas — while accepting nothing less than being No. 1 in customer and shareholder value. The following pages measure Cinergy's progress in 1998, for each of the four business units and the corporation as a whole.

For a discussion of the strategy, and the people, driving the achievement of Cinergy's mission, please turn this report over to the Letter to Stakeholders from CEO Jim Rogers.

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Continued progress.

Building a Growth Energy Company: 1998 Progress Report

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proxy & *Financial Report*

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NOTICE OF ANNUAL MEETING OF SHAREHOLDERS TO BE HELD ON APRIL 21, 1999

To the Shareholders of Cinergy Corp.:

NOTICE IS HEREBY GIVEN that the Annual Meeting of Shareholders of Cinergy Corp. will be held in the HALL OF MIRRORS of the OMNI NETHERLAND PLAZA HOTEL, 35 West Fifth Street, Cincinnati, Ohio, on Wednesday, April 21, 1999 at 11:00 a.m., eastern daylight saving time, for purposes of:

(1) electing six Class II directors to serve for three-year terms expiring in 2002;
(2) approving the Amended and Restated Cinergy Corp. Retirement Plan for Directors, as described at pages 20-22 in the Proxy Statement and set forth in Appendix A;
(3) approving the Cinergy Corp. Directors' Equity Compensation Plan, as described at pages 22-23 in the Proxy Statement and set forth in Appendix B;
(4) adopting an amendment to ARTICLE III, Section 3.1, of the Cinergy Corp. By-Laws, as described at pages 23-24 in the Proxy Statement;

and transacting such other business as may legally come before the meeting, or any adjournment or postponement thereof.

Only shareholders of record at the close of business on Monday, February 22, 1999, will be entitled to vote at the meeting, or any adjournment or postponement thereof. It is important that your shares be represented at this meeting in order that the presence of a quorum may be assured. Whether or not you now expect to be present at the meeting, you are requested to vote by toll-free telephone as described in the enclosed telephone voting instructions, or to mark, date and sign the enclosed proxy and return it promptly. A shareholder giving a proxy by either means has the power to revoke it at any time before the authority granted by the proxy is exercised.

By Order of the Board of Directors,

Cheryl M. Foley
Vice President, General Counsel and Secretary

Dated: March 15, 1999

March 15, 1999

Dear Shareholder:

You are cordially invited to attend the Annual Meeting of Shareholders of Cinergy Corp. to be held on Wednesday, April 21, 1999, at 11:00 a.m., eastern daylight saving time, in the Hall of Mirrors of the Omni Netherland Plaza Hotel, 35 West Fifth Street, Cincinnati, Ohio. At the meeting, the shareholders will be asked to vote for the election of six Class II directors, approval of the Amended and Restated Retirement Plan for Directors, approval of the new Directors' Equity Compensation Plan and the adoption of an amendment to ARTICLE III, Section 3.1 of the Company's By-Laws, and to consider any other business that may legally come before the meeting.

It is important to your interests that all shareholders, regardless of the number of shares owned, participate in the affairs of the Company. Last year, over 85% of the Company's shares were represented in person or by proxy at the annual meeting.

Even if you plan to attend this year's meeting, we urge you to take prompt action to assure that your shares will be voted. You may wish to vote your shares by using the toll-free telephone number as described in the enclosed telephone voting instructions. Or, you can mark, date and sign the proxy form and return it using the enclosed envelope, on which no postage stamp is necessary if mailed in the United States. Either way, your response is greatly appreciated.

Thank you for your continued interest in Cinergy.

Sincerely yours,

Jackson H. Randolph
Chairman of the Board

James E. Rogers
Vice Chairman, President and
Chief Executive Officer

Cinergy Corp.
139 East Fourth Street
Cincinnati, Ohio 45202
(513) 421-9500

PROXY STATEMENT

INTRODUCTION

Cinergy Corp., a Delaware corporation (the "Company"), is a registered holding company under the Public Utility Holding Company Act of 1935, as amended (the "1935 Act"), and the parent company of The Cincinnati Gas & Electric Company ("CG&E"), PSI Energy, Inc. ("PSI"), Cinergy Services, Inc. ("Services"), Cinergy Global Resources, Inc. ("Global Resources") and Cinergy Investments, Inc. ("Investments"). CG&E is an operating utility primarily engaged in providing electric and gas service in the southwestern portion of Ohio and, through its principal subsidiary, The Union Light, Heat and Power Company ("ULH&P"), in adjacent areas in Kentucky. PSI is an operating utility primarily engaged in providing electric service in north central, central and southern Indiana. Services provides management, financial, administrative, engineering, legal and other services to the Company and its subsidiaries. The Company conducts its international businesses through Global Resources and its subsidiaries, and its non-regulated businesses through Investments and its subsidiaries.

SOLICITATION

This Proxy Statement and the enclosed form of proxy are first being mailed on or about March 15, 1999, to holders of the common stock of the Company in connection with the solicitation of proxies by the Board of Directors (the "Board") of the Company for use at the Annual Meeting of Shareholders to be held on April 21, 1999, or any adjournment or postponement of such meeting (the "Annual Meeting"). Included as Appendix C to this Proxy Statement are the Company's consolidated financial statements and accompanying notes for the calendar year ended December 31, 1998, and other information relating to the Company's financial results and position. The Company's Summary Annual Report to Shareholders also accompanies the mailing of this proxy solicitation material.

The Board recommends voting: (i) FOR the election of all nominees as directors; (ii) FOR the Amended and Restated Cinergy Corp. Retirement Plan for Directors; (iii) FOR the Cinergy Corp. Directors' Equity Compensation Plan; and (iv) FOR the amendment to Article III, Section 3.1, of the Company's By-Laws. Shares of the Company's common stock represented by properly voted proxies received by telephone or mail at or prior to the Annual Meeting will be voted in accordance with the instructions indicated. If no instructions are indicated, the proxies will be voted in accordance with the recommendations of the Board. It is not anticipated that any other matters will be brought before the Annual Meeting. However, a shareholder giving a proxy grants discretionary authority to the named proxy holders should any other matters be presented at the Annual Meeting, and it is the intention of the proxy holders to act on any other matters in accordance with their best judgment.

A shareholder giving a proxy may revoke it at any time before it is voted by delivering to the Secretary of the Company written notice of revocation bearing a later date than the proxy, by delivering a duly executed proxy bearing a later date, by using the telephone voting procedures, or by attending the Annual Meeting and voting in person.

The Company will bear the cost of the solicitation of proxies by the Board. The Company has engaged Corporate Investor Communications, Inc. to assist in the solicitation of proxies for a fee estimated to be $8,500 plus reimbursement of reasonable out-of-pocket expenses. In addition to the solicitation of proxies by mail, officers and employees of the Company may solicit proxies personally or by telephone; such persons will receive no additional compensation for these services.

The Company has requested that brokerage houses and other custodians, nominees and fiduciaries forward solicitation materials to the beneficial owners of shares of the Company's common stock held of record by such persons, and will reimburse the brokers and other fiduciaries for their reasonable out-of-pocket expenses for forwarding the materials.

The solicitation of proxies has been approved by the Securities and Exchange Commission (the "SEC") under the 1935 Act. An application has been filed with the SEC requesting approval of the items set forth in this Proxy Statement as Item 2 and Item 3.

VOTING PROCEDURES AND RIGHTS

Only holders of record of the Company's common stock at the close of business on February 22, 1999 (the "Record Date") will be entitled to vote at the Annual Meeting. A majority of such holders, present in person or represented by proxy, constitutes a quorum. The number of shares of the Company's common stock outstanding as of the Record Date was 158,732,798. Each share of common stock entitles its owner to one vote upon each matter to come before the meeting.

The vote required for the election of directors, approval of the Amended and Restated Cinergy Corp. Retirement Plan for Directors, approval of the Cinergy Corp. Directors' Equity Compensation Plan, and adoption of the amendment to Article III, Section 3.1, of the Company's By-Laws is set forth within the respective discussion of each such item.

Any other matter to be presented at the Annual Meeting will be determined by the affirmative vote of the majority of the shares present in person or represented by proxy at the meeting and entitled to vote on the proposal. In tabulating the vote on any other matter, abstentions will have the same effect as votes cast against the matter; broker non-votes will be deemed absent shares and have no effect on the outcome of the vote.

Votes at the Annual Meeting will be tabulated preliminarily by the Company acting as its own transfer agent. Inspectors of election, duly appointed by the presiding officer of the Annual Meeting, will definitively count and tabulate the votes and determine and announce the results at the meeting.

ITEM 1. ELECTION OF DIRECTORS

In accordance with the provisions of the By-Laws of the Company, the Board is divided into three classes (*i.e.*, Class I, Class II and Class III), with one class of directors ordinarily being elected at each annual meeting of shareholders for a three-year term. Melvin Perelman, Thomas E. Petry, Jackson H. Randolph, Mary L. Schapiro, Philip R. Sharp and Dudley S. Taft have been nominated by the Board for election as Class II directors at the Annual Meeting for terms of three years each and until their respective successors are duly elected and qualified. The Company would like to acknowledge Mr. Van P. Smith, who is retiring after 17 years of combined service as a member of the boards of directors of the Company and PSI. His support, valued counsel and many contributions during his years of devoted and distinguished service to the Company and PSI are immeasurable and greatly appreciated.

In accordance with the General Corporation Law of the State of Delaware and the Company's By-Laws, directors will be elected at the Annual Meeting by a plurality of the votes. Duly executed and returned proxies representing shares held on the Record Date will be voted, unless otherwise specified, in favor of the nominees for the Board. Each nominee and continuing director is a member of the Company's present Board. All nominees have consented to serve if elected, but if any becomes unavailable to serve, the persons named as proxies may exercise their discretion to vote for a substitute nominee.

Except as otherwise noted, the principal occupation or employment of each individual set forth below has been such individual's principal occupation or employment for at least the past five years. All nominees and continuing directors, other than Messrs. Randolph and Rogers and Ms. Foley, are otherwise unaffiliated with the Company and its subsidiaries.

The Board Recommends Voting FOR ALL Nominees, Designated in the Proxy as Item 1.

CLASS II DIRECTOR NOMINEES FOR TERMS TO EXPIRE IN 2002

Melvin Perelman, Ph.D.

Director of the Company since 1994; Member of the Corporate Governance Committee and of the Finance Committee. Director of PSI from 1980 to 1995. Age 68.

Dr. Perelman is retired as Executive Vice President of Eli Lilly and Company, which is engaged in the manufacturing of pharmaceuticals. Prior to his retirement, he also served as a member of the board of directors of Eli Lilly, and as President of Lilly Research Laboratories. Dr. Perelman is a director of The Immune Response Corporation and Inhale Therapeutic Systems, Inc.

Thomas E. Petry

Director of the Company since 1994; Member of the Audit Committee and of the Executive Committee. Director of CG&E from 1986 to 1995. Age 59.

Mr. Petry served as Chairman of the Board and Chief Executive Officer of Eagle-Picher Industries, Inc., a diversified manufacturer of industrial and automotive products, from December 1994 until his retirement in February 1998. He was Chairman of the Board, President and Chief Executive Officer of Eagle-Picher from April 1992 until December 1994; he previously served as Chairman of the Board and Chief Executive Officer. Mr. Petry is a director of Eagle-Picher Industries, Inc., Firstar Corporation, and The Union Central Life Insurance Company.

Jackson H. Randolph

Director of the Company since 1993; Member of the Executive Committee. Director of CG&E since 1983 and of PSI since 1994. Age 68.

Mr. Randolph has served as Chairman of the Board of the Company, Investments, Services, CG&E, PSI and ULH&P since December 1995. He served as Chairman of the Board and Chief Executive Officer of the Company, Investments, Services, CG&E and PSI from October 1994, and of ULH&P from January 1995, through November 1995. Mr. Randolph was Chairman of the Board, President and Chief Executive Officer of CG&E from May 1993 until October 1994, and of ULH&P from June 1993 until January 1995; he previously served as President and Chief Executive Officer of CG&E and ULH&P. Mr. Randolph is a director of Cincinnati Financial Corporation and PNC Bank Corp.

Mary L. Schapiro

Director of the Company since 1999; Member of the Audit Committee and of the Finance Committee. Age 43

Ms. Schapiro has served as the President and as a member of the board of NASD Regulation, Inc. in Washington, D.C. since 1996. NASD Regulation is the independent regulatory subsidiary of the National Association of Securities Dealers, Inc., and is responsible for regulating all member brokerage firms and individual registered representatives and oversight for The Nasdaq Stock Market. Ms. Schapiro served as Chair of the Commodity Futures Trading Commission from 1994 to 1996. From 1988 until 1994, she served as a Commissioner of the Securities and Exchange Commission. Ms. Schapiro is also a member of the Board of Governors of the National Association of Securities Dealers, Inc.

Philip R. Sharp, Ph.D.

Director of the Company since 1995; Member of the Audit Committee. Age 56.

Dr. Sharp is a Lecturer in Public Policy at the John F. Kennedy School of Government at Harvard University in Cambridge, Massachusetts. He also serves as a member of the Secretary of Energy's Advisory Board and as Chairman of the Secretary's Electric System Reliability Task Force. Dr. Sharp is also Vice Chairman of the Energy Board of The Keystone Center, a not-for-profit public policy, scientific and educational organization with locations in Keystone, Colorado, and Washington, D.C. He previously served as a member of the U. S. House of Representatives from 1975 until January 1995, representing the second Congressional district of the State of Indiana. Dr. Sharp was a ranking member of the House Energy and Commerce Committee, where he chaired the Energy and Power Subcommittee and served on the Transportation and Hazardous Materials Subcommittee, and of the House Natural Resources Committee, where he served on the Energy and Mineral Resources and the Oversight and Investigations Subcommittees.

Dudley S. Taft

Director of the Company since 1994; Chairman of the Corporate Governance Committee. Director of CG&E from 1985 to 1995. Age 58.

Mr. Taft is President and Chief Executive Officer of Taft Broadcasting Company, which holds investments in media-related activities. He is a director of Fifth Third Bancorp, The Fifth Third Bank, Tribune Company, The Union Central Life Insurance Company and U.S. Playing Card Company.

CLASS III DIRECTORS WHOSE TERMS EXPIRE IN 2000

Michael G. Browning

Director of the Company since 1994; Member of the Compensation Committee and of the Corporate Governance Committee. Director of PSI since 1990. Age 52.

Mr. Browning is Chairman and President of Browning Investments, Inc., which is engaged in real estate ventures. He also served as President of Browning Real Estate, Inc., the general partner of various real estate investment partnerships, through December 30, 1994.

Phillip R. Cox

Director of the Company since 1994; Member of the Corporate Governance Committee and of the Public Policy Committee. Director of CG&E from 1994 to 1995. Age 52.

Mr. Cox is President and Chief Executive Officer of Cox Financial Corporation, a provider of financial and estate planning services. He is a director of Cincinnati Bell Inc., the Cincinnati office of the Federal Reserve Bank of Cleveland, PNC Bank, Ohio, N.A., and Touchstone Mutual Funds.

Kenneth M. Duberstein

Director of the Company since 1994; Member of the Public Policy Committee. Director of PSI from 1990 to 1995. Age 54.

Mr. Duberstein is Chairman and Chief Executive Officer of The Duberstein Group, Inc., a provider of strategic planning and consulting services. He is a director of The Boeing Company, Federal National Mortgage Association, Global Vacation Group, Inc. and St. Paul Companies, and is also a member of the Board of Governors of the American Stock Exchange and the National Association of Securities Dealers, Inc.

James E. Rogers

Director of the Company since 1993; Chairman of the Executive Committee and Member of the Corporate Governance Committee. Director of PSI since 1988 and of CG&E since 1994. Age 51.

Mr. Rogers has served as Vice Chairman, President and Chief Executive Officer of the Company and Services, and as Vice Chairman and Chief Executive Officer of CG&E, PSI, Investments and ULH&P, since December 1995. He also has served as Chief Executive Officer and Director of Global Resources since May 1998. Mr. Rogers served as Vice Chairman, President and Chief Operating Officer of the Company and Services, and as Vice Chairman and Chief Operating Officer of CG&E, PSI and Investments, from October 1994 through November 1995. He also served as Vice Chairman and Chief Operating Officer of ULH&P from January 1995 through November 1995. Mr. Rogers served as Chairman, President and Chief Executive Officer of PSI from August 1990 until October 1994; he previously served as Chairman and Chief Executive Officer. He also served as Chairman and Chief Executive Officer of PSI Resources, Inc., the former parent company of PSI, from October 1993 until October 1994; he previously served as Chairman, President and Chief Executive Officer. Mr. Rogers is a director of Duke Realty Investments, Inc., Fifth Third Bancorp and The Fifth Third Bank.

John J. Schiff, Jr.

Director of the Company since 1994; Member of the Compensation Committee. Director of CG&E from 1986 to 1995. Age 55.

Mr. Schiff is Chairman of the Board of Cincinnati Financial Corporation, an insurance holding company, and of The Cincinnati Insurance Company. He also served as Chairman and Chief Executive Officer of John J. & Thomas R. Schiff & Co., Inc., an insurance agency, through December 1996. Mr. Schiff is a director of Fifth Third Bancorp, The Fifth Third Bank and The Standard Register Company.

Oliver W. Waddell

Director of the Company since 1994; Chairman of the Finance Committee. Director of CG&E from 1989 to 1995. Age 68.

Mr. Waddell is the retired Chairman of the Board of Star Banc Corporation (now Firstar Corporation, a bank holding company). Prior to his retirement, he held various executive officer positions during his career with Star, including Chairman, President and Chief Executive Officer of the holding corporation and its lead bank, Star Bank, N.A. Mr. Waddell is a director of Chiquita Brands International, Inc. and Firstar Corporation.

CLASS I DIRECTORS WHOSE TERMS EXPIRE IN 2001

Neil A. Armstrong

Director of the Company since 1994; Member of the Audit Committee and of the Executive Committee. Director of CG&E from 1973 to 1995. Age 68.

Mr. Armstrong is Chairman of the Board of AIL Systems Inc., which is engaged in the manufacturing of electronic devices and systems. He is a director of Cordant Technologies, Inc., Milacron Inc., RTI International Metals, Inc., and USX Corp.

James K. Baker

Director of the Company since 1994; Chairman of the Audit Committee and Member of the Executive Committee. Director of PSI since 1986. Age 67.

Mr. Baker served as Vice Chairman of Arvin Industries, Inc., a worldwide supplier of automotive parts, from February 1996 until his retirement in April 1998. He served as Chairman of the Board of Arvin Industries from November 1986 through January 1996 and as Chief Executive Officer from 1981 until June 1993. Mr. Baker is a director of Amcast Industrial Corp., Geon Company and Tokheim Corporation.

Cheryl M. Foley

Director of the Company since 1998. Age 51.

Ms. Foley serves as Vice President and General Counsel of the Company and Services (since October 1994), of PSI (since April 1991), and of each of Investments, CG&E and ULH&P (since January 1995). She holds the additional office of Secretary at the Company and PSI, and previously held this additional office at CG&E (until April 1998) and at each of Investments, Services and ULH&P (until May 1998). She also previously served as Vice President, General Counsel and Secretary of PSI Resources, Inc., the former parent company of PSI (from April 1991 until October 1994). Ms. Foley also serves as a director and as the President of Global Resources (since May 1998), having overall responsibility for the Company's international business operations, and is also a director of Investments, Services and ULH&P.

John A. Hillenbrand II

Director of the Company since 1994; Chairman of the Public Policy Committee and Member of the Finance Committee. Director of PSI since 1985. Age 67.

Mr. Hillenbrand principally serves as Chairman, President and Chief Executive Officer of Glynnadam, Inc., a personal investment holding company. He is also Chairman of Able Body Corporation and Nambe' Mills, Inc., and Vice Chairman of Pri-Pak, Inc. Mr. Hillenbrand is a director of Hillenbrand Industries, Inc. and National City Bank, Indiana.

George C. Juilfs

Director of the Company since 1994; Member of the Compensation Committee and of the Public Policy Committee. Director of CG&E from 1980 to 1995. Age 59.

Mr. Juilfs is President and Chief Executive Officer of SENCORP, an international holding company with subsidiaries that manufacture fastening systems, finance and lease capital equipment, and commercialize health-care technologies. He is a director, serving as chairman of the board, of the Cincinnati office of the Federal Reserve Bank of Cleveland.

MEETINGS AND COMMITTEES OF THE BOARD

During the calendar year ended December 31, 1998, the Board held six meetings. All directors attended more than 75% of the aggregate number of Board meetings and meetings of committees on which they serve, with the exception of Mr. Schiff who attended 70%. In accordance with the provisions of the By-Laws of the Company, the Board has six standing committees which facilitate the carrying out of its responsibilities.

The Audit Committee, which met three times during 1998, recommends to the Board a firm of independent certified public accountants to conduct audits of the accounts and affairs of the Company and its subsidiaries; reviews with the independent certified public accountants the scope and results of audits, as well as the accounting procedures, internal controls, and accounting and financial reporting policies and practices of the Company and its subsidiaries; and makes such reports and recommendations to the Board as it deems appropriate.

The Compensation Committee met four times during 1998. The nature and scope of the Compensation Committee's responsibilities are described in the "Board Compensation Committee Report on Executive Compensation" (see page 10).

The Corporate Governance Committee, which met twice during 1998, recommends to the Board the slate of nominees of directors to be elected by the shareholders, and presents to the Board, whenever vacancies occur, names of individuals who would make suitable directors of the Company and consults with appropriate officers of the Company on matters relating to the organization of the Board and its committees. The Committee has no established procedures for consideration of nominees recommended by shareholders.

Other standing committees of the Board include the Executive Committee, the Finance Committee and the Public Policy Committee.

COMPENSATION OF DIRECTORS

Directors who are not employees (the "non-employee directors") receive an annual retainer fee of $30,000 plus a fee of $1,500 for each Board meeting attended. Non-employee directors who also serve on one or more standing committees of the Board receive an annual retainer fee of $3,000 for each committee membership plus a fee of $1,500 for each committee meeting attended. The fee for any Board or committee meeting held via conference call is $750. In consideration for their additional responsibilities and time commitments, non-employee directors serving as chairpersons of the committees of the Board receive an additional annual retainer of $3,000. Directors who are also employees of the Company receive no remuneration for their services as directors.

Under the Company's Directors' Deferred Compensation Plan, each non-employee director of the Company or any of its subsidiaries may defer fees and have them accrued either in cash or in units representing shares of the Company's common stock. If deferred in units, dividends are credited to the individual director's plan account and thereby acquire additional units, at the same time and rate as dividends are paid to holders of the Company's common stock. The deferred units are distributed to the director as shares of the Company's common stock at the time of retirement from the appropriate board. Amounts deferred in cash earn interest at the rate per annum, adjusted quarterly, equivalent to the interest rate for a one-year certificate of deposit as quoted in The Wall Street Journal for the first business day of the calendar quarter, and are paid to the director at the time of retirement from the appropriate board.

Under the Company's Stock Option Plan, each non-employee director is granted a non-qualified stock option to purchase 12,500 shares of the Company's common stock when he or she first is elected to the Board. The price per share at which options are granted must be no less than 100% of the fair market value of the Company's common stock on the New York Stock Exchange ("NYSE") on the date of the grant. Options vest at the rate of 20% per year over a five-year period from the date of grant and may be exercised over a ten-year term.

The Company has maintained a Retirement Plan for Directors under which non-employee directors of the Company, Services, PSI and CG&E have accrued retirement benefits based upon their years of service. In December 1998, the Board amended and restated this plan to eliminate future benefit accruals and adopted a new Cinergy Corp. Directors' Equity Compensation Plan under which future benefits for non-employee directors are expected to be equity-based. Each of these plans is subject to shareholder approval at the Annual Meeting. Please refer to pages 20-22 and Appendix A of this Proxy Statement for a description and the text of the amended and restated Retirement Plan for Directors, and to pages 22-23 and Appendix B for a description and the text of the new Directors' Equity Compensation Plan.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The only persons or groups known to the Company to be the beneficial owners of more than 5% of the Company's common stock, the only voting security, as of December 31, 1998, are set forth in the following table. This information is based on the most recently available reports filed with the SEC pursuant to the requirements of Sections 13(d) or 13(g) of the Securities Exchange Act of 1934, as amended (the "1934 Act"), and transmitted to the Company by the persons or groups named.

Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Scudder Kemper Investments, Inc. 345 Park Avenue New York, NY 10154	9,969,386 shares (1)	6.3%
U.S. Trust Company, N.A. 515 South Flower Street Los Angeles, CA 90071	9,181,572 shares (2)	5.8%

(1) Holder reports having sole voting power with respect to 2,160,339 shares, shared voting power with respect to 5,804,022 shares, sole dispositive power with respect to 9,899,864 shares, and shared dispositive power with respect to 69,522 shares.

(2) Shares held as trustee of benefit plans for employees of the Company and its subsidiaries. Under the terms of the plans, participants have the right to vote the shares credited to their accounts; however, the trustee may, at its discretion, vote those shares not voted by participants. Holder reports having shared voting and dispositive powers with respect to all shares, and sole voting and dispositive powers with respect to none of these shares.

The beneficial ownership of the Company's common stock held by each nominee, continuing director and named executive officer (as defined on page 14), and of units representing shares of the Company's common stock paid as compensation to non-employee directors, as of December 31, 1998, is set forth in the following table.

Name of Beneficial Owner (1)	Amount and Nature of Beneficial Ownership (2)	Units (3)
Neil A. Armstrong	10,750 shares	
James K. Baker	23,605 shares	5,901
Michael G. Browning	28,835 shares	9,495
Phillip R. Cox	10,238 shares	
Kenneth M. Duberstein	22,991 shares	
Cheryl M. Foley	81,306 shares	
William J. Grealis	109,649 shares	
John A. Hillenbrand II	33,472 shares	9,542
George C. Juilfs	13,750 shares	
John M. Mutz	113,145 shares	
Melvin Perelman	23,423 shares	8,918
Thomas E. Petry	12,000 shares	
Jackson H. Randolph	209,609 shares	
James E. Rogers	398,526 shares	
Mary L. Schapiro	0 shares	
John J. Schiff, Jr.	51,059 shares (4)	
Philip R. Sharp	6,000 shares	
Dudley S. Taft	13,000 shares	
Larry E. Thomas	131,737 shares	
Oliver W. Waddell	15,253 shares	
All directors and executive officers as a group	1,650,504 shares	

(1) Beneficial ownership of directors and executive officers as a group represents 1.04% of the outstanding shares of common stock; individual beneficial ownership by any director, nominee or executive officer does not exceed 0.252% of the outstanding shares of common stock.

(2) Includes shares which there is a right to acquire within 60 days pursuant to the exercise of stock options in the following amounts: Mr. Armstrong–10,000; Mr. Baker–10,000; Mr. Browning–22,787; Mr. Cox–10,000; Mr. Duberstein–15,287; Ms. Foley–20,000; Mr. Grealis–73,237; Mr. Hillenbrand–10,000; Mr. Juilfs–10,000; Mr. Mutz–80,000; Dr. Perelman–10,000; Mr. Petry–10,000; Mr. Randolph–91,258; Mr. Rogers–195,629; Mr. Schiff–10,000; Dr. Sharp–5,000; Mr. Taft–10,000; Mr. Thomas–62,516; and all directors and executive officers as a group–792,981.

(3) Each unit represents one share of the Company's common stock credited to the account of the respective director as of December 31, 1998 under the Company's Directors' Deferred Compensation Plan.

(4) Includes 15,000 shares owned of record by a trust of which Mr. Schiff is one of three trustees who share voting and investment power equally. Does not include 1,791,000 shares, as to which Mr. Schiff disclaims any beneficial interest, held by Cincinnati Financial Corporation and certain of its subsidiaries.

BOARD COMPENSATION COMMITTEE REPORT ON EXECUTIVE COMPENSATION

The Compensation Committee of the Board (the "Committee"): (i) establishes the Company's compensation policy; (ii) recommends, oversees and administers compensation plans for all executive officers and key employees; (iii) determines compensation for the chief executive officer; and (iv) reviews and approves compensation for the Company's remaining executive officers. During 1998, the Committee was composed of Messrs. Van P. Smith (Chairman), Michael G. Browning, George C. Juilfs, and John J. Schiff, Jr., each of whom was an independent, "non-employee director" of the Company, within the meaning of Rule 16b-3 under the 1934 Act, and an "outside director" within the meaning of Section 162(m) of the Internal Revenue Code of 1986, as amended (the "Code").

Compensation Policy

The Company's executive compensation program is designed to attract, retain and motivate the high quality employees needed to provide superior service to its customers and to maximize returns to its shareholders. The Company's compensation program for executive officers consists of base salary, annual cash incentives, and long-term incentives.

Base salaries for the executive group are targeted at the median of comparably sized utility companies based on kilowatt-hours ("kwh") sold. Because of the Company's low-cost position, kwh sales are considered to be a better measure than revenues for constructing a comparative group. Base salary levels are reviewed annually, and any increases are based on such factors as competitive industry salaries, the Company's financial results and a subjective assessment of each individual's performance, role and skills.

The Company's executive compensation program also seeks to link executive and shareholder interests through cash-based and equity-based incentive plans, in order to reward corporate and individual performance. Annual and long-term incentive plans are structured to provide opportunities that are competitive with general industry companies.

This emphasis on incentive compensation results in a compensation mix for the chief executive officer and the remaining executive officers consisting of annual and long-term incentives accounting for at least 50% of the employee's annual compensation. It is the Committee's view that short-term and long-term incentive opportunities that distinguish between short-term and long-term corporate goals can assist in motivating the type of behavior crucial to managing successfully in an increasingly competitive environment.

Consistent with its belief that a well-planned and well-implemented executive incentive compensation program, with meaningful and measurable performance targets and competitive award opportunities, sends a strong, positive message to the financial markets, the Committee has implemented an executive long-term incentive compensation program (the "LTIP") within the parameters of the Company's 1996 Long-Term Incentive Compensation Plan (the "Umbrella Plan"). The LTIP combines the interests of the Company's shareholders, customers, and management to enhance the Company's value. (Specifics of the program are discussed below under the heading "Long-Term Incentive Compensation and Stock Options.")

The Committee also has two non-qualified deferred compensation plans for executive officers of the Company, as follows: (i) the Deferred Incentive Compensation Plan allows deferral of receipt of all or a portion of cash awards otherwise payable under the Company's Annual Incentive Plan; and (ii) the Excess 401(k) Plan allows deferral of receipt of a portion of base salaries that otherwise could not be deferred under the Company's qualified 401(k) plan, due to federal government limitations on the amount of compensation that can be deferred into qualified plans.

Annual Incentive Compensation

Approximately 425 management employees, including all executive officers, are eligible to participate in the Company's Annual Incentive Plan. The plan provides for incentive cash awards or bonuses tied to the achievement of pre-determined corporate and individual goals. For 1998, the Company's corporate goal was based on earnings per share. Achievement of the corporate goal for 1998 and achievement of individual goals each accounted for 50% of the total possible award.

For 1998, the potential awards ranged from 2.5% to 90% of the participant's annual base salary, depending upon the achievement levels and the participant's position. Graduated standards for achievement were developed to encourage each employee's contribution. The Committee reviewed and approved both the plan goals at the beginning of the year and the achievements at the end of the year.

Although the corporate goal was not achieved for 1998, the Committee, in the exercise of its discretion reserved under the plan, determined that awarding a partial payout for corporate performance was appropriate. Upon reviewing the Company's significant progress toward achieving its strategic mission (*i.e.*, to be one of the top five energy companies in five years in five key areas – market capitalization, number of customers, electric and gas commodity trading, international presence, and productivity) in 1998, the Committee determined that the Company's employees – both management and non-management – should be rewarded for their commitment, dedication and achievements. The Committee recognizes that the Company's mission is most challenging in light of the numerous uncertainties facing the Company and the industry in this era of change.

Accomplishments in 1998 that were considered by the Committee included:

- A 10.3% return on equity;
- A 21.2% increase in total electric kwh sales over 1997 reflecting an increase in energy marketing and trading volumes;
- Investments of more than $110 million in international markets;
- Sale of the Company's interest in Edesur SA, an electric distribution network in Argentina;
- The agreement by Midlands Electricity, the Company's 50%-owned regional electric distribution company located in England, to sell its supply business to National Power plc;
- The acquisition of Producers Energy Marketing LLC, a major gas marketing firm, thus adding physical gas supply and trading to the Company's commodity portfolio;
- Agreements between Trigen-Cinergy Solutions and seven major corporations and/or governmental entities for the supply of energy-related systems and services;
- The implementation of electricity futures trading on the New York Mercantile Exchange, with the Company as one of only four delivery points in the United States;
- The SEC's approval of the retention of CG&E's natural gas business; and
- Continued progress with respect to the Company's cost reduction efforts.

For 1998, the Committee determined the achievement level for each named executive officer, which involved an assessment of both individual objective goals and subjective evaluation of individual performance. The Committee believed that its assessment accurately measured the performance of each such officer and determined that the achievement level for individual goals ranged from 2.75 to 3.0 on a scale ranging from 1.0 to 3.0. Individual performance goals varied for each executive officer; however, all related to the achievement of the Company's overall strategic vision of becoming a premier energy services company.

For 1999, the Company's Annual Incentive Plan corporate goal will again be based on earnings per share. For all employees except business unit presidents, the corporate goal will account for 40% of the total possible award and achievement of individual key performance indicators will account for the remaining 60%. For business unit presidents, 40% of the total possible award will be based on the corporate goal, 10% will be based on business unit earnings per share targets, and the remaining 50% will be based on individual key performance indicators.

Long-Term Incentive Compensation and Stock Options

The LTIP ties a significant portion of the participants' pay to long-term performance of the Company, provides a greater upside potential for outperforming peer companies as well as downside risk for underperforming, focuses on creating shareholder value through increasing total shareholder return, and provides a significant portion of total compensation opportunity through the use of the Company's common stock to create an ownership mindset. Approximately 85 management employees, including all executive officers except the chairman of the board, are eligible for participation in the LTIP.

The LTIP consists of two elements: (1) stock options, and (2) performance-based restricted stock and performance shares (this second portion is called the "Value Creation Plan"). "Performance-based restricted stock" means grants of the Company's common stock that are subject to transfer restrictions and risk of forfeiture for a specified restriction period, and the vesting of which are conditional upon the attainment of Performance Measures. Stock options comprise 25% of the total award opportunity under the plan, and the Value Creation Plan comprises the other 75%. The annualized target award opportunity as a percent of base salary ranges from 15% to 100% depending on the participant's position. With respect to the named executive officers eligible for participation in the LTIP, the target LTIP award values are 100% of base salary for the chief executive officer and 70% of the respective base salary for each of the remaining named executive officers. The LTIP operates on three-year, non-overlapping performance periods or cycles. The first performance period covers October 1, 1996, through December 31, 1999.

The first portion of the LTIP consists of annual grants of stock options, which commenced effective January 1, 1997, and continue effective each January 1 thereafter. The number of options granted to a participant is determined by taking 25% of the participant's target LTIP award value and dividing it by the projected stock price appreciation of an option, to arrive at the number of options granted to a participant for each year of the three-year cycle. The stock options vest three years from the date of grant. Information with respect to stock options granted during 1998 to the named executive officers is set forth in the Summary Compensation Table and the Option/SAR Grants Table.

The second portion of the LTIP consists of the Value Creation Plan. The Value Creation Plan consists of a target grant of performance-based restricted stock and performance shares, both of which can be earned based on the Company's total shareholder return ("TSR") vs. the TSR of the peer group. TSR is defined as share price appreciation plus dividends. For the three-year performance cycle, the Company's average TSR is measured against the average TSR of the peer group. The peer companies are the 25 largest utility companies, based on kwh sales.

At the end of the performance period, participants will earn an award based upon the Company's performance relative to its peer group. If the Company's TSR equals the TSR of the peer group, participants will earn the target number of restricted shares. Participants will earn the target number of restricted shares plus a greater number of non-restricted shares (called "performance shares") if the Company's TSR exceeds that of the peer group. However, if the Company's TSR is lower than that of the peer group, participants will not earn some of the target restricted shares or any performance shares and could lose all of the restricted shares if the Company's performance falls dramatically below that of the peer companies. The maximum that can be earned under the Value Creation Plan by a participant for the performance cycle is three times the total LTIP target value less the value of any stock options.

Except in the case of disability, death, voluntary termination, or retirement on or after age 50 during the three-year performance cycle, a participant must be employed by the Company on January 1 following the end of a performance cycle to receive any earned award. The earned target restricted shares become unrestricted (or vested) as soon as practicable after the end of a performance cycle, but no later than April 1 following the end of a performance cycle. The earned performance shares (based on the added incremental value created during the cycle), if any, will be paid in two equal, annual installments. One-half will be paid as soon as practicable after the first anniversary date (*i.e.*, January 1, 2001 with respect to the performance cycle ending December 31, 1999), but no later than three months subsequent to that anniversary date, following the end of a performance cycle. The remaining half will be paid as soon as practicable after the second anniversary date (*i.e.*, January 1, 2002 with respect to the performance cycle ending December 31, 1999), but no later than three months subsequent to that anniversary date, following the end of a performance cycle.

Because grants under the Value Creation Plan are made at the beginning of the three-year performance cycle, there were no grants made during 1998 to any of the named executive officers.

Chief Executive Officer

Mr. Rogers' 1998 base salary was determined by the Committee after giving consideration to his employment agreement with the Company (see "Employment Agreements and Severance Arrangements" on page 17), competitive salaries of chief executive officers of both peer companies and general industry, and a subjective assessment of his performance. For 1998, Mr. Rogers was awarded incentive compensation under the Annual Incentive Plan in the amount of $619,200. This was based, in part, upon the Committee's determination that a partial payment under the plan was appropriate, even though the Company's corporate target goal was not achieved, and upon the Committee's determination of Mr. Rogers' achievement of individual goals. Under the Annual Incentive Plan, Mr. Rogers' maximum potential award is equal to 90% of his annual base salary (including deferred compensation).

Effective January 1, 1998, the Committee granted Mr. Rogers an option to purchase 55,400 shares of the Company's common stock, at the fair market value of $38.59375 per share, as the second annual option grant under the first performance period of the LTIP. Effective March 24, 1998, the Committee granted Mr. Rogers an option to purchase 480,000 shares of the Company's common stock, at the fair market value of $36.875 per share, under the Stock Option Plan. The Committee believed that the March 1998 grant signified Mr. Rogers' importance to the current and future success of the Company and further demonstrated its support and commitment to him. Information with respect to these grants is set forth in the Summary Compensation Table and the Option/SAR Grants Table.

In September 1998, the Committee approved an amended and restated employment agreement for Mr. Rogers, which incorporated previous amendments made to his agreement and the substantive terms of his prior severance agreement. The substantive terms of the restated employment agreement are discussed under "Employment Agreements and Severance Arrangements."

Code Section 162(m)

Code Section 162(m) generally limits the Company's tax deduction to one million dollars for compensation paid to each of the named executive officers. However, the statute exempts qualifying performance-based compensation from the deduction limit if certain conditions are met. The Committee currently intends under most circumstances to structure performance-based compensation, including stock option grants and restricted stock grants under the LTIP and a significant portion of the award opportunity under the

Annual Incentive Plan, to executive officers who may be subject to Code Section 162(m) in a manner that satisfies those requirements.

However, for 1998 the Committee exercised its discretion (as discussed above) to permit a payout for the corporate goal portion of the Annual Incentive Plan even though the minimum earnings per share goal was not achieved. The Committee realizes that its action affects the tax deductibility of a part of Mr. Rogers' compensation under Code Section 162(m).

The Committee intends to continue basing its executive compensation decisions primarily upon performance achieved, both corporate and individual, but retains the right to make subjective decisions and to award compensation that might be subject to the tax deductibility limitation under Code Section 162(m).

The tables which follow, and accompanying footnotes, reflect the decisions covered by the above discussion.

Compensation Committee
Van P. Smith, Chairman
Michael G. Browning
George C. Juilfs
John J. Schiff, Jr.

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SUMMARY COMPENSATION TABLE

The following table sets forth the compensation of the chief executive officer and each of the other four most highly compensated executive officers (these five executive officers are sometimes collectively referred to as the "named executive officers") for services to the Company and its subsidiaries during the calendar years ended December 31, 1998, 1997 and 1996.

		Annual Compensation			Long-Term Compensation: Awards		Long-Term Compensation: Payouts	
(a) Name and Principal Position	(b) Year	(c) Salary ($)	(d) Bonus (1) ($)	(e) Other Annual Compen-sation ($)	(f) Restricted Stock Awards (2) ($)	(g) Securities Underlying Options/SARs (#)	(h) LTIP Payouts (3) ($)	(i) All Other Compen-sation (4) ($)
James E. Rogers	1998	810,000	619,200	47,041	0	535,400	0	138,329
Vice Chairman, President and	1997	700,008	337,504	17,039	1,951,169	55,400	0	126,956
Chief Executive Officer	1996	625,000	607,518	3,697	0	0	849,750	108,108
Jackson H. Randolph	1998	585,000	321,750	13,405	0	0	0	98,157
Chairman of the Board	1997	585,000	321,750	14,575	0	0	0	88,181
	1996	535,000	321,750	10,675	0	0	675,212	120,512
John M. Mutz	1998	415,188	199,290	5,574	0	21,700	0	23,611
Vice President of the Company,	1997	395,412	118,624	3,763	761,985	21,700	0	22,162
and President of PSI	1996	376,584	150,634	2,431	0	0	339,108	14,993
William J. Grealis	1998	396,900	180,590	25,643	0	20,700	0	34,313
Vice President, Corporate	1997	378,000	113,400	13,094	728,443	20,700	0	15,550
Services, and Chief Strategic Officer of the Company	1996	343,200	205,920	8,828	0	0	246,048	35,611
Larry E. Thomas	1998	352,848	169,367	9,678	0	18,400	0	16,594
Vice President of the Company,	1997	336,048	100,814	11,502	647,575	18,400	0	15,809
and President of the Energy Delivery Business Unit	1996	294,350	176,610	5,030	0	0	252,285	36,162

(1) Amounts appearing in this column reflect the Annual Incentive Plan award earned during the year listed and paid in the following year.

(2) Amounts appearing in this column reflect the dollar values of restricted stock awards, determined by multiplying the number of shares in each award by the closing market price of the Company's common stock as of the effective date of grant. The aggregate number of all restricted stock holdings and values at calendar year ended December 31, 1998, determined by multiplying the number of shares by the year end closing market price, are as follows: Mr. Rogers–58,462 shares ($2,009,631); Mr. Mutz–22,831 shares ($784,816); Mr. Grealis–21,826 shares ($750,269); and Mr. Thomas–19,403 shares ($666,978). Dividends are retained by the Company for the duration of the three-year performance cycle; upon settlement of the restricted stock awards, dividends will be paid in shares of the Company's common stock based on the number of shares of restricted stock actually earned and the fair market value of the Company's common stock on the settlement date.

(3) Amounts appearing in this column reflect the values of the shares earned under the Company's Performance Shares Plan during the 1994-1997 and 1996-1999 performance cycles that were ended during 1996 in transition to the Valuation Creation Plan.

(4) Amounts appearing in this column for 1998 include for Messrs. Rogers, Randolph, Mutz, Grealis and Thomas, respectively: (i) employer matching contributions under 401(k) plan and related excess benefit plan of $24,300, $17,550, $12,456, $11,907 and $10,585; and (ii) insurance premiums paid with respect to executive/group-term life insurance of $245, $752, $11,155, $22,406 and $6,009. Also includes for Mr. Rogers deferred compensation in the amount of $50,000, and for Messrs. Rogers and Randolph, respectively, above-market interest on amounts deferred pursuant to deferred compensation agreements of $48,955 and $63,447, and benefits under split dollar life insurance agreements of $14,829 and $16,408.

OPTION/SAR GRANTS TABLE

The following table sets forth information concerning individual grants of options to purchase the Company's common stock made to the named executive officers during 1998.

	Individual Grants				Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation for Option Term	
(a)	(b)	(c)	(d)	(e)	(f)	(g)
Name	Number of Securities Underlying Options/SARs Granted (#)	% of Total Options/SARs Granted to Employees in Fiscal Year	Exercise or Base Price ($/Sh)	Expiration Date	5% ($)	10% ($)
James E. Rogers	55,400	5.82%	38.59375	1/1/2008	1,344,558	3,407,654
	480,000	50.45%	36.875	3/24/2008	11,424,000	28,675,200
John M. Mutz	21,700	2.28%	38.59375	1/1/2008	526,659	1,334,767
William J. Grealis	20,700	2.18%	38.59375	1/1/2008	502,389	1,273,257
Larry E. Thomas	18,400	1.93%	38.59375	1/1/2008	446,568	1,131,784

AGGREGATED OPTION/SAR EXERCISES AND YEAR END OPTION/SAR VALUES TABLE

The following table sets forth information concerning: (i) stock options exercised by the named executive officers during 1998, including the value realized (*i.e.*, the spread between the exercise price and market price on the date of exercise); and (ii) the numbers of shares for which options were held as of December 31, 1998, including the value of "in-the-money" options (*i.e.*, the positive spread between the exercise prices of outstanding stock options and the closing market price of the Company's common stock on December 31, 1998, which was $34.375 per share).

(a)	(b)	(c)	(d) Number of Securities Underlying Unexercised Options/SARs at Year End (#)	(e) Value of Unexercised In-The-Money Options/SARs at Year End ($)
Name	Shares Acquired on Exercise (#)	Value Realized ($)	Exercisable/ Unexercisable	Exercisable/ Unexercisable
James E. Rogers	0	N/A	195,629/640,800	2,249,734/623,475
Jackson H. Randolph	8,742	102,992	91,258/50,000	1,049,467/575,000
John M. Mutz	12,787	225,356	82,660/60,740	922,328/246,660
William J. Grealis	2,650	28,156	73,237/61,400	736,947/219,363
Larry E. Thomas	31,588	478,800	62,516/56,800	718,934/246,100

PENSION BENEFITS

The pension benefits payable at retirement to each of the named executive officers are provided under the terms of the Cinergy Corp. Non-union Employees' Pension Plan, a non-contributory, defined benefit pension plan (the "Cinergy Pension Plan"), plus certain supplemental plans or agreements. Pension benefits previously earned under the terms of the former CG&E and PSI pension plans are fully preserved for participants under the terms of the Cinergy Pension Plan.

Under the terms of the Cinergy Pension Plan, the retirement income payable to a pensioner is 1.1% of final average pay plus 0.5% of final average pay in excess of covered compensation, times the number of years of plan participation through 35 years, plus 1.4% of final average pay times the number of years of plan participation over 35 years. Final average pay is the average annual salary, based upon retirement anniversary date, during the employee's three consecutive years producing the highest such average within the last ten anniversary years immediately preceding retirement, plus any short-term incentive and/or deferred compensation. Covered compensation is the average social security taxable wage base over a period of up to 35 years. The Internal Revenue Service annually establishes a dollar limit, indexed to inflation, of the amount of pay permitted for consideration under the terms of such plans, which for 1998 was $160,000.

The Cinergy Excess Pension Plan is designed to restore pension benefits to those individuals whose benefits under the Cinergy Pension Plan would otherwise exceed the limits imposed by the Code. Each of the named executive officers is covered under the terms of the Cinergy Excess Pension Plan.

The pension plan table set forth below illustrates the estimated annual benefits payable as a straight-life annuity under both Cinergy plans to participants who retire at age 62. Such benefits are not subject to any deduction for social security or other offset amounts.

The accrued annual benefit payable to Messrs. Randolph and Mutz upon their retirement is based upon credited service of 40 years and 4 years, respectively. The estimated credited years of service at age 62 for each of the remaining named executive officers are as follows: Mr. Rogers, 20 years; Mr. Grealis, 12 years; and Mr. Thomas, 37 years.

Effective January 1, 1999, the Cinergy Supplemental Retirement Plan was amended, restated and renamed the Cinergy Supplemental Executive Retirement Plan (the "SERP"). One part of the SERP, the "Mid-career Benefit," is designed to provide coverage to executives who will not qualify for full retirement benefits under the Cinergy Pension Plan. For retirement on or after age 62, the Mid-career Benefit is an amount equal to that which a covered employee with 35 years of participation would have received under the Cinergy Pension Plan and the Cinergy Excess Penison Plan, reduced by the actual benefit provided by these plans, and further reduced by 50% of the employee's age 62 social security benefit. Messrs. Rogers, Mutz and Grealis are covered under the terms of the Mid-career Benefit portion of the SERP.

The second part of the SERP, the "Senior Executive Supplement," is designed to provide selected senior officers of the Company an opportunity to earn a retirement benefit that will replace 60% of their final pay. Each participant accrues a retirement income replacement percentage at the rate of 4% per year from date of hire (maximum of 15 years). The Senior Executive Supplement is an amount equal to a maximum of 60% of the employee's final average pay

	Years of Service							
Compensation	5	10	15	20	25	30	35	40
$ 500,000	$ 39,045	$ 78,085	$ 117,130	$ 156,170	$ 195,215	$ 234,255	$ 273,300	$ 312,340
600,000	47,045	94,085	141,130	188,170	235,215	282,255	329,300	376,340
700,000	55,045	110,085	165,130	220,170	275,215	330,255	385,300	440,340
800,000	63,045	126,085	189,130	252,170	315,215	378,255	441,300	504,340
900,000	71,045	142,085	213,130	284,170	355,215	426,255	497,300	568,340
1,000,000	79,045	158,085	237,130	316,170	395,215	474,255	553,300	632,340
1,100,000	87,045	174,085	261,130	348,170	435,215	522,255	609,300	696,340
1,200,000	95,045	190,085	285,130	380,170	475,215	570,255	665,300	760,340
1,300,000	103,045	206,085	309,130	412,170	515,215	618,255	721,300	824,340
1,400,000	111,045	222,085	333,130	444,170	555,215	666,255	777,300	888,340
1,500,000	119,045	238,085	357,130	476,170	595,215	714,255	833,300	952,340
1,600,000	127,045	254,085	381,130	508,170	635,215	762,255	889,300	1,016,340
1,700,000	135,045	270,085	405,130	540,170	675,215	810,255	945,300	1,080,340
1,800,000	143,045	286,085	429,130	572,170	715,215	858,255	1,001,300	1,144,340

(as defined in the Cinergy Pension Plan) or the final 12 months of base pay and Annual Incentive Plan pay, reduced by the actual benefits provided under the Cinergy Pension Plan, the Cinergy Excess Pension Plan and the Mid-career Benefit, and further reduced by 50% of the employee's estimated age 62 social security benefit. Messrs. Rogers, Mutz, Grealis and Thomas are covered under the terms of the Senior Executive Supplement, and the estimated retirement income replacement percentage for each is 60%, 20%, 48% and 60%, respectively.

Moreover, Mr. Randolph has a Supplemental Executive Retirement Income Agreement under which he or his beneficiary will receive an annual supplemental retirement benefit of $511,654, in monthly installments of $42,638 for 180 months beginning December 1, 2000.

The Cinergy Executive Supplemental Life Insurance Program provides key management personnel, including the named executive officers, with additional life insurance coverage during employment and with post-retirement deferred compensation. At the later of age 50 or retirement, the participant's life insurance coverage under the program is canceled. At that time, the participant receives the total amount of coverage in the form of deferred compensation payable in ten equal annual installments of $15,000 per year.

EMPLOYMENT AGREEMENTS AND SEVERANCE ARRANGEMENTS

Mr. Rogers has an employment agreement which was effective October 24, 1994, and was amended and restated in its entirety effective September 22, 1998. Pursuant to the terms of his agreement, Mr. Rogers served as Vice Chairman, President and Chief Operating Officer of the Company until November 30, 1995, and, since that time, has served as Vice Chairman, President and Chief Executive Officer. Mr. Rogers' agreement currently is automatically extended for an additional year on each annual anniversary date, unless either the Company or Mr. Rogers gives timely notice otherwise. During the term of his agreement, Mr. Rogers receives a minimum annual base salary of $810,000. Under the terms of his employment agreement, Mr. Rogers was credited with 25 years of participation in the Mid-career Benefit portion of the SERP as of his 50th birthday. He has been or will be credited with an additional two years of participation on each birthday through his 55th, provided that he is employed by the Company as of each birthday.
Mr. Rogers' employment agreement also provides that if he retires on or after age 55 he will be entitled to receive annual retirement income for his lifetime equal to the greater of 60% of his final average pay, or 60% of his base pay and Annual Incentive Plan pay for the final 12 months immediately preceding his retirement.

Mr. Randolph has an employment agreement which commenced on October 24, 1994. Pursuant to the terms of his agreement, Mr. Randolph served as Chairman and Chief Executive Officer of the Company until November 30, 1995, at which time he relinquished the position of Chief Executive Officer. He will continue to serve as Chairman of the Board of the Company until November 30, 2000, the expiration date of his agreement. During the term of his agreement, Mr. Randolph receives a minimum annual base salary of $465,000.

If the employment of Messrs. Rogers or Randolph (each sometimes individually referred to as the "executive") is terminated as a result of death, his beneficiary will receive a lump sum cash amount equal to the sum of (a) the executive's annual base salary through the termination date to the extent not previously paid, (b) a pro rata portion of the benefit under the Company's Annual Incentive Plan calculated based upon the termination date, and (c) any compensation previously deferred but not yet paid to the executive (with accrued interest or earnings thereon) and any unpaid accrued vacation pay. Mr. Rogers' beneficiary will also receive an amount equal to his vested accrued benefit under the Value Creation Plan. In addition to these accrued amounts, if the Company terminates the executive's employment without "cause" or the executive terminates his employment for "good reason" (as each is defined in the employment agreements), the Company will pay to the executive (a) a lump sum cash amount equal to the present value of his annual base salary and benefit under the Company's Annual Incentive Plan payable through the end of the term of employment, at the rate and applying the same goals and factors in effect at the time of notice of such termination, (b) the value of all benefits to which the executive would have been entitled had he remained in employment until the end of the term of employment under the Company's Executive Supplemental Life Insurance Program (and also including the Value Creation Plan in the case of Mr. Rogers), (c) the value of all deferred compensation and all executive life insurance benefits whether or not then vested or payable, and (d) medical and welfare benefits for the executive and his family through the end of the term of employment. If the executive's employment is terminated by the Company for cause or by the executive without good reason, the executive will receive unpaid annual base salary accrued through the termination date and any accrued deferred compensation.

Mr. Mutz has an employment agreement which commenced on October 4, 1993, and was amended most recently effective as of December 31, 1998.

Pursuant to the terms of his agreement, Mr. Mutz serves as President, and is nominated for election as a director, of PSI until May 31, 1999, the expiration date of his agreement. During the term of his agreement, Mr. Mutz receives a minimum annual base salary of $330,000. Under his employment agreement, Mr. Mutz is fully vested in the Mid-career Benefit portion of the SERP, without offset for prior employers' retirement benefits, and is guaranteed a benefit thereunder based on its current terms even if the plan subsequently is amended to reduce benefits or is terminated. Mr. Mutz's employment agreement further provides that in connection with the Senior Executive Supplement portion of the SERP, Mr. Mutz will be credited with a pay replacement percentage of 60% as of his retirement date.

Mr. Grealis has an employment agreement which commenced on January 16, 1995, and currently is automatically extended for an additional year on each January 1, unless either the Company or Mr. Grealis gives timely notice otherwise. During the term of his agreement, Mr. Grealis receives a minimum annual base salary of $288,000. Under his employment agreement, Mr. Grealis will receive annual retirement income of no less than $283,000 payable as a straight-life annuity at age 62.

Mr. Thomas has an employment agreement which currently is automatically extended for an additional year on each January 1, unless either the Company or Mr. Thomas gives timely notice otherwise. During the term of his agreement, Mr. Thomas receives a minimum annual base salary of $240,000. Under his employment agreement, if Mr. Thomas retires on or after age 55 he will be entitled to receive annual retirement income equal to that which a covered employee with 35 years of participation would have received under Cinergy's Pension Plan and its Excess Pension Plan.

If the employment of Messrs. Mutz, Grealis or Thomas (each sometimes individually referred to as the "officer") is terminated as a result of death, for cause, or by the officer without good reason, the officer or the officer's beneficiary will be paid a lump sum cash amount equal to (a) the officer's unpaid annual base salary through the termination date, (b) a pro rata portion of the officer's award under the Company's Annual Incentive Plan, (c) the officer's vested accrued benefits under the Value Creation Plan (and also including the Cinergy Pension Plan, Excess Pension Plan, and Mid-career Benefit portion of the SERP in the case of Mr. Mutz), and (d) any unpaid deferred compensation (including accrued interest or earnings) and unpaid accrued vacation pay. If, instead, the officer's employment is terminated prior to a change in control (as defined) without cause or by the officer for good reason, the officer will be paid (a) a lump sum cash amount equal to the present value of the officer's annual base salary and target annual incentive cash award payable through the end of the term of the agreement, at the rate and applying the same goals and factors in effect at the time of notice of such termination, (b) the present value of all benefits to which the officer would have been entitled had the officer remained in employment until the end of the term of the agreement under the Value Creation Plan and Executive Supplemental Life Insurance Program (and also including the Cinergy Pension Plan, Excess Pension Plan, and Mid-career Benefit portion of the SERP in the case of Mr. Mutz), (c) the value of all deferred compensation and all executive life insurance benefits whether or not vested or payable, and (d) continued medical and welfare benefits through the end of the term of the agreement. In addition to the above, under Mr. Mutz's employment agreement the Company has waived its right to challenge Mr. Mutz in the event he elects to terminate his employment agreement for good reason.

Each of the named executive officers participates in the Company's Annual Incentive Plan, Stock Option Plan, LTIP, Excess Pension Plan, SERP, and Executive Supplemental Life Insurance Program (with the exception of Mr. Randolph who does not participate in the LTIP or SERP), participates in all other retirement and welfare benefit plans applicable generally to Company employees and executives, and receives other fringe benefits.

If the employment of any named executive officer is terminated after a change in control, the officer will be paid a lump sum cash payment equal to the greater of (i) three times the sum of his annual base salary immediately prior to the date of his termination of employment or, if higher, the date of the change in control, plus all incentive compensation or bonus plan amounts in effect prior to the date of his termination of employment or, if higher, prior to the change in control, and (ii) the present value of all annual base salary, bonuses and incentive compensation and retirement benefits that would otherwise be due under the agreement, plus deferred compensation and executive life insurance benefits. In addition, the officer will be provided life, disability, accident and health insurance benefits for thirty-six months, reduced to the extent comparable benefits are received, without cost, by the officer. In addition to the above, Messrs. Rogers and Randolph will receive their benefits under their deferred compensation agreements (discussed below) and split dollar life insurance agreements.

DEFERRED COMPENSATION AGREEMENTS

Mr. Randolph and CG&E, and Mr. Rogers and PSI, entered into deferred compensation agreements effective as of January 1, 1992, which were assumed by the Company effective as of October 24, 1994.

Pursuant to the terms of his deferred compensation agreement, Mr. Randolph was credited annually with a $50,000 base salary increase in the form of deferred compensation for the five-year period from January 1, 1992 through December 31, 1996, and when his employment terminates he will receive an annual cash benefit of $179,000 payable for a 15-year period beginning January 2001.

Pursuant to the terms of his deferred compensation agreement, Mr. Rogers was credited annually with a $50,000 base salary increase in the form of deferred compensation for the five-year period from January 1, 1992 through December 31, 1996, and is credited annually the same amount for the additional five-year period from January 1, 1997 through December 31, 2001. Mr. Rogers' deferred compensation agreement further provides that when his employment terminates for any reason, other than death, he will receive an annual cash benefit over a 15-year period beginning the first January following termination of his employment, but in no event earlier than January 2003 nor later than January 2010. The annual cash benefit amount payable for such 15-year period ranges from $179,000 per year, if payment begins in January 2003, to $554,400 per year if payment commences in January 2010. Comparable amounts are payable to Mr. Rogers if he dies before commencement of payment of the 15-year payments described above. In addition, if Mr. Rogers' employment terminates before January 1, 2002 for any reason other than death or disability, he will receive a lump sum cash payment equal to the total amount deferred during the second five-year period described above plus interest; if his employment terminates on or after January 1, 2002 for any reason other than death or disability, he will receive an additional annual benefit for a 15-year period beginning the first January following termination of his employment, but in no event earlier than January 2008 nor later than January 2010. The annual cash benefit amount payable for such period ranges from $179,000 per year, if payment begins in January 2008, to $247,000 per year if payment begins in January 2010. Comparable amounts are payable to Mr. Rogers in the event his employment is terminated for disability prior to January 1, 2002 or if he dies (i) prior to January 1, 2002 while employed or disabled, or (ii) on or after January 1, 2002 but before commencement of payment of benefits; provided, however, if Mr. Rogers becomes disabled prior to the completion of the second award period, his payments will be proportionately reduced in the same manner as described above for disability during the first award period.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

Mr. Schiff, Chairman of the Board of Cincinnati Financial Corporation, serves on the Company's Compensation Committee and Mr. Randolph, Chairman of the Board of the Company, serves on the board of directors of Cincinnati Financial Corporation.

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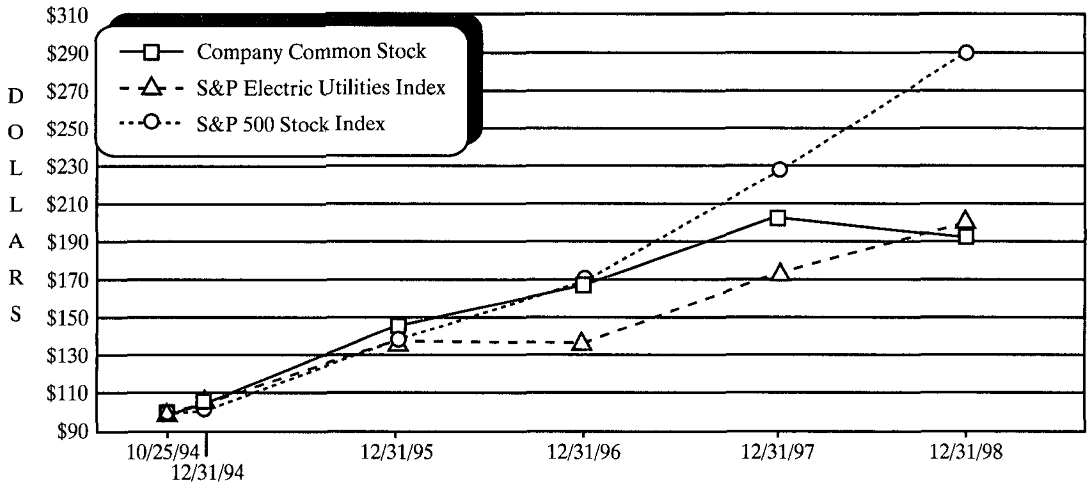
PERFORMANCE GRAPH

The following line graph compares the cumulative total average shareholder return of the common stock of the Company with the cumulative total returns during the same time period of the Standard & Poor's ("S&P") Electric Utilities Index and the S&P 500 Stock Index. The graph tracks performance from October 25, 1994, the initial trading date of the Company's common stock, through December 31, 1998, and assumes a $100 investment on such initial trading date and dividend reinvestment.

	10/25/94	12/31/94	12/31/95	12/31/96	12/31/97	12/31/98
Company Common Stock	$100.00	$104.40	$145.30	$167.70	$203.30	$192.40
S&P Electric Utilities Index	$100.00	$104.80	$137.40	$137.20	$173.20	$200.00
S&P 500 Stock Index	$100.00	$100.10	$137.70	$169.30	$225.80	$290.30



ITEM 2. APPROVAL OF AMENDED AND RESTATED CINERGY CORP. RETIREMENT PLAN FOR DIRECTORS

INTRODUCTION

Effective October 24, 1994, the Company adopted the Cinergy Corp. Retirement Plan for Directors (the "Retirement Plan"), an unfunded retirement plan for non-employee directors of the Company, Services, PSI and CG&E. Under the terms of this plan, non-employee directors with five or more years of service have been entitled to receive annual retirement compensation in an amount equal to the annual Board retainer fee in effect at the time of termination of service as a director, plus the product of the fee paid for attendance at a Board meeting multiplied by five, with the compensation paid for as many years as the person served as a director.

Effective January 1, 1999, and subject to shareholder approval, the Company amended and restated the Retirement Plan (the "Amended Retirement Plan") to eliminate the future accrual of benefits and to provide for the conversion of currently accrued benefits to units payable at retirement in shares of the Company's common stock. The Company estimates that a maximum of 175,000 shares of its common stock will be issued under the Amended Retirement Plan. The Amended Retirement Plan is also subject to SEC approval under the 1935 Act.

The Company believes that the approval of the Amended Retirement Plan is in the best interests of the shareholders because, in effectively terminating a cash-based retirement program for directors, it promotes the accomplishment of long-term corporate goals by aligning the interests of directors with those of the Company's shareholders. However, should the Amended Retirement Plan not be approved by shareholders, the original Retirement Plan will continue as it previously has existed.

VOTE REQUIRED

Assuming the presence of a quorum at the Annual Meeting, approval of the Amended Retirement Plan will require the affirmative vote of the holders of a majority of the shares of the Company's common stock present in person or represented by proxy and entitled to vote on the proposal. Abstentions will have the same effect as votes against the proposal. Broker non-votes will be deemed absent shares and will not effect the outcome of the vote.

SUMMARY OF PLAN FEATURES

The full text of the Amended Retirement Plan is included as Appendix A to this Proxy Statement. The following description summarizes the material features of the Plan.

Participants. Non-employee directors with five or more years of service on the board of directors of the Company, Services, PSI or CG&E prior to December 31, 1998, as well as all non-employee directors serving on one or more of those boards as of December 31, 1998 regardless of years of service, will participate in the Amended Retirement Plan. The total number of participants is 24, of which 14 are current directors and 10 are former directors.

Retirement Benefits. The Amended Retirement Plan provides for three categories of benefits:

- Category 1—each participant who retires as a director, or dies while serving as a director, after January 1, 1999 and who has elected to be included in this category will have his "Accrued Benefit" converted to units representing shares of the Company's common stock;
- Category 2—each participant who retires as a director, or dies while serving as a director, after January 1, 1999 and who has elected to be included in this category will receive an annual cash payment equal to the fees in effect on December 31, 1998; and
- Category 3—each participant who retired as a director prior to January 1, 1999 will receive an annual cash payment equal to the fees in effect on the date preceding his or her retirement as a director.

"Fees" have the same meaning under the Amended Retirement Plan as under the original Retirement Plan, *i.e.*, the Company's annual Board retainer fee plus five times the meeting fee. "Accrued Benefit" means a participant's total benefit entitlement as of December 31, 1998 reduced to a present value. The Accrued Benefit of each participant eligible to participate in Category 1 or 2 above is set forth on page A-6.

Each participant named on page A-6, other than Mr. Hillenbrand (who defers his director's fees into stock units under the Company's Directors' Deferred Compensation Plan) has elected to participate in Category 1 of the Amended Retirement Plan. The initial number of deferred stock units ("Deferred Units") into which each Category 1 participant's Accrued Benefit will be converted will equal the dollar amount of the Accrued Benefit divided by $34.375, the closing market price per share of the Company's common stock on December 31, 1998.

Unit Accounts. In addition to the initial number of Deferred Units credited to a Category 1 participant's account ("Unit Account"), the Unit Account will be credited with additional Deferred Units equal in value to the cash dividends which would have been paid on the number of shares represented by Deferred Units in the Account on any dividend payment date. Unit Accounts also will be proportionately adjusted for any stock split, stock dividend, combination or exchange of shares or similar change affecting the Company's common stock.

Unit Accounts will be paid out in shares of the Company's common stock, with each credited unit being equal to one share of stock.

Payment and Duration of Benefits. Generally, whether paid in cash or stock, benefit payments under the Amended Retirement Plan will begin in February following the later of (a) the date a participant ceases to be a director or (b) the participant's attainment of age 55.

The Category 1 participants may choose to have benefits paid either in a lump sum or in annual installments over a period of two to ten years. A Category 2 participant will receive benefits for a term equal to the number of full years of service completed as of December 31, 1998. Each Category 3 participant will receive benefits for a term equal to the number of full years for which he or she served as a non-employee director.

Payments under the Amended Retirement Plan will continue to a participant's beneficiary after the participant's death.

Shares of the Company's common stock distributed under the Amended Retirement Plan may be newly issued or treasury shares or shares purchased on the open market, as determined by the Company.

As of December 31, 1998, the present value of the accrued retirement benefits under the Plan for the 14 current directors was $3,910,245. As to the 10 former directors who are participants, annual cash payments of $18,750 to $32,500 will be paid for periods of 5 to 25 years, depending upon the number of years the recipient had served prior to his or her retirement as a director.

Assignment. Benefits and amounts credited to a director's Unit Account under the Plan may not be assigned, transferred, pledged, encumbered or otherwise disposed of prior to their distribution.

Amendment and Termination. The Board may amend or terminate the Amended Retirement Plan at any time. However, no termination or amendment may deprive any participant (or beneficiary) of any benefits accrued under the Plan prior to the termination or amendment without his or her consent.

Administration. The Amended Retirement Plan will be administered by the Company's Board. In addition to having the right to interpret and otherwise regulate the Plan, the Board is specifically authorized to reverse any action under the Plan which would adversely affect the ability of the Company to use pooling of interests accounting in a merger or other corporate transaction. If the Board were to exercise its discretion in this regard, it also has the authority to provide appropriate cash or other substitute compensation.

Effects of a Change in Control of the Company. In the event of a "change in control" (as defined in the Amended Retirement Plan) of the Company, each participant (or beneficiary, if appropriate) will be entitled to receive a lump sum payment of the actuarial equivalent of benefits accrued and remaining unpaid as of the date of the "change in control." The lump sum equivalent will be calculated assuming the interest rate used by the Pension Benefit Guaranty Corporation in determining the value of immediate benefits as of the immediately preceding January 1.

The Board Recommends Voting FOR this Proposal, which is Designated in the Proxy as Item 2.

ITEM 3. APPROVAL OF CINERGY CORP. DIRECTORS' EQUITY COMPENSATION PLAN

INTRODUCTION

To replace the Retirement Plan on a going-forward basis, the Company has adopted, effective January 1, 1999 and subject to shareholder approval, the Cinergy Corp. Directors' Equity Compensation Plan (the "Directors' Equity Plan"). The Plan is also subject to SEC approval under the 1935 Act.

The Company believes that the approval of the Directors' Equity Plan is in the best interests of the shareholders because the Plan aligns the long-term interests of the Company's non-employee directors with those of its shareholders, thus providing further incentive to enhance the financial success of the Company and increase shareholder value.

The Directors' Equity Plan is an unfunded plan under which each non-employee director of the Company will receive, beginning December 31, 1999, an annual award equivalent to 450 shares of the Company's common stock. Although the Plan permits the payment of cash awards at the Board's discretion, *the Board fully anticipates that all awards under the Directors' Equity Plan will be paid in shares of the Company's common stock.*

Shares of the Company's common stock distributed under the Directors' Equity Plan may be newly issued or treasury shares or shares acquired on the open market or otherwise. A maximum of 75,000 shares are authorized for issuance under the Plan, subject to adjustments for changes in the Company's capitalization.

VOTE REQUIRED

Assuming the presence of a quorum at the Annual Meeting, approval of the Directors' Equity Plan will require the affirmative vote of the holders of a majority of the shares of the Company's common stock present in person or represented by proxy and entitled to vote on the proposal. Abstentions will have the same effect as votes against the proposal. Broker non-votes will be deemed absent shares and will not effect the outcome of the vote.

SUMMARY OF PLAN FEATURES

The full text of the Directors' Equity Plan is included as Appendix B to this Proxy Statement. The following description summarizes the material features of the Plan.

Eligibility. Each non-employee director of the Company on January 1 of any year, commencing January 1, 1999, and each person who after January 1, 1999 is elected or appointed for the first time to be a non-employee director of the Company during the course of any year, is eligible to receive an award under the Directors' Equity Plan for that year. All current non-employee directors of the Company are eligible to participate in the Directors' Equity Plan. The ultimate number of participants will depend upon the number of non-employee directors of the Company over the life of the Plan, which has no set expiration date.

Awards. Commencing December 31, 1999, and on each following December 31, each eligible non-employee director during the just-completed year will be granted either a "Stock Award" or a "Cash Award," as determined by the Board in its discretion. A Stock Award will consist of 450 units ("Units"), with each Unit representing one share of the Company's common stock. Any Cash Award will be an amount in cash equal to the market value of 450 shares of the Company's common stock on the date of grant. As indicated above, *the Board fully anticipates that all Plan awards will be Stock Awards.*

Awards to directors who retire from the Board during the course of a year will be prorated based upon their lengths of service during the year.

Accounts. Stock Awards and any Cash Awards under the Directors' Equity Plan will be credited to individual bookkeeping accounts ("Accounts") maintained for each participant. A director's Account will be credited with additional full and fractional Units equal in value to the cash dividends which would have been paid on the number of shares represented by Units in the Account on any dividend payment date. Accounts also will be proportionately adjusted for any stock split, stock dividend, combination or exchange of shares or similar change affecting the Company's common stock. Any cash amounts in an Account will be credited with interest at the rate quoted for a one year $100,000 certificate of deposit. The Board has discretion, at any time, to convert Cash Awards and accrued interest in a director's Account to Units by dividing the amount of cash credited to the Account by the market value of the Company's common stock on the conversion date.

Payment of Benefits. All whole Units in a director's Account will be distributed in the form of shares of the Company's common stock (with cash paid in lieu of any fractional share). Unless converted to Units, any cash in an Account will be paid out in cash. A director may elect to have his or her Account paid out in a single lump sum or in annual installments over a period of two to ten years. In either case, payment will be made, or begin, on the first business day of the calendar year following the date of the director's retirement from the Board. Upon the death of a Plan participant, any amounts remaining in his or her Account will be paid in a lump sum, within 90 days, to the participant's designated beneficiary or estate.

Assignment. Awards and other amounts credited to a director's Account under the Plan may not be assigned, transferred, pledged, encumbered or otherwise disposed of prior to their distribution.

Duration, Amendment and Termination. The Directors' Equity Plan has no expiration date. The Board may amend or terminate the Plan at any time. However, no termination or amendment may adversely affect the balance in a director's Account or permit early payment of an Account.

Administration. The Directors' Equity Plan will be administered by the Company's Board. In addition to having the right to interpret and otherwise regulate the Plan, the Board is specifically authorized to reverse any Award under the Plan which would adversely affect the ability of the Company to use pooling of interests accounting in a merger or other corporate transaction. If the Board were to exercise its discretion in this regard, it also has the authority to provide appropriate cash or other substitute compensation.

Effects of a Change in Control of the Company. In the event of a "change in control" (as defined in the Directors' Equity Plan) of the Company, each participant (or beneficiary, if appropriate) will be entitled to receive a lump sum payment of the actuarial equivalent of benefits accrued and remaining unpaid as of the date of the "change in control." The lump sum equivalent will be calculated assuming the interest rate used by the Pension Benefit Guaranty Corporation in determining the value of immediate benefits as of the immediately preceding January 1.

The Board Recommends Voting FOR this Proposal, which is Designated in the Proxy as Item 3.

ITEM 4. ADOPTION OF AMENDMENT TO ARTICLE III, SECTION 3.1, OF THE COMPANY'S BY-LAWS

INTRODUCTION

ARTICLE III, Section 3.1, of the Company's By-Laws currently provides that the Board shall consist of 17 directors, and that this number may be changed to an odd number ranging between 15 and 23 by the affirmative vote of not less than 75% of the full Board.

The proposed amendment will reduce the lower end of the range to 7 (rather than the current 15, while keeping the higher number of the range at 23) and provide the Board more flexibility in establishing its size by eliminating the requirement that there be an odd number of directors. The proposed amendment gives the Board the ability to reduce its size if a lesser number of directors is desired, having no effect on the term of any current director or nominee.

The Board deems it advisable and in the best interests of the Company and its shareholders that the proposed amendment be adopted. Accordingly, effective October 15, 1998, the Board duly adopted the resolution recommending that the Company's shareholders duly adopt a certain amendment to ARTICLE III, Section 3.1, of the Company's By-Laws as set forth at the top of the next page, with the amended provisions shown in *italics* and the deleted provisions lined through.

Section 3.1 Number of Directors. The Board of Directors shall consist of ~~17 directors. This~~ *a* number *of directors* ~~may be changed to an odd number~~ not less than *seven (7)* ~~15~~ and not more than twenty-three (23) *as determined* by a vote of not less than 75% of the full Board of Directors ("Supermajority Vote"). Any such determination made by the Board of Directors shall continue in effect unless and until changed by the Board of Directors by Supermajority Vote, but no such change shall affect the term of any director then in office.

VOTE REQUIRED

Assuming the presence of a quorum at the Annual Meeting, adoption of the proposed amendment will require the affirmative vote of the holders of at least 80% of the issued and outstanding shares of the Company's common stock. Abstentions will have the same effect as votes against the proposal. In the absence of specific instructions from beneficial owners, brokers will retain authority to vote in their discretion with respect to this matter.

The Board Recommends Voting FOR this Proposal, which is Designated in the Proxy as Item 4.

RELATIONSHIP WITH INDEPENDENT PUBLIC ACCOUNTANTS

Arthur Andersen LLP served as independent public accountants for the Company and its subsidiaries for the year 1998. On January 21, 1999, upon recommendation of its Audit Committee, the Board engaged Arthur Andersen LLP as independent public accountants for the Company and its subsidiaries for the year 1999. Representatives of Arthur Andersen LLP are expected to be present at the Annual Meeting with the opportunity to make a statement if they desire to do so, and will be available to respond to appropriate questions.

PROPOSALS AND BUSINESS BY SHAREHOLDERS

In order to be considered for inclusion in the Company's proxy statement for the 2000 annual meeting of shareholders, proposals from shareholders must be received by November 16, 1999.

In addition, in order for a shareholder properly to introduce business for action by shareholders at the Company's 2000 annual meeting (other than business specified in the Notice of the meeting), the Company must be given written notice, which complies with all requirements of the Company's By-Laws, no earlier than December 23, 1999 and no later than January 21, 2000. The Company will retain discretionary authority to vote proxies on matters of which it is not properly notified and also may retain such authority under other circumstances.

Any proposal or notice should be directed to the Secretary of the Company at 139 East Fourth Street, Cincinnati, Ohio 45202.

By Order of the Board of Directors,

Cheryl M. Foley
Vice President, General Counsel and Secretary

Dated: March 15, 1999

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APPENDIX A

CINERGY CORP.
RETIREMENT PLAN FOR DIRECTORS
(As Amended and Restated Effective January 1, 1999)

INTRODUCTION

Effective October 24, 1994, Cinergy Corp. ("Cinergy") established the "Cinergy Corp. Retirement Plan for Directors," a retirement plan for non-employee directors of Cinergy Corp., Cinergy Services, Inc., PSI Energy, Inc., and The Cincinnati Gas & Electric Company.

As amended and restated effective January 1, 1999, the Cinergy Corp. Retirement Plan for Directors (the "Plan") is set forth in its entirety below.

ARTICLE 1

DEFINITIONS

When used in this document, the following terms shall have the respective meanings set forth below, unless a different meaning is plainly required by the context:

1.1 "Accrued Benefit" means a Participant's total benefit under the Plan as of December 31, 1998, reduced to a present value using a discount rate and other assumptions approved by the Compensation Committee of Cinergy's Board of Directors, as set forth on Schedule A (on page A-6).

1.2 "Beneficiary" means the person or persons designated by a Participant to receive benefits under the Plan after the Participant's death.

1.3 "CG&E" means The Cincinnati Gas & Electric Company, an Ohio corporation, and its successors.

1.4 "CG&E's Board of Directors" means the duly constituted board of directors of CG&E on the applicable date.

1.5 "Cinergy" means Cinergy Corp., a Delaware corporation, and its successors.

1.6 "Cinergy Services" means Cinergy Services, Inc., a Delaware corporation, and its successors.

1.7 "Cinergy's Board of Directors" means the duly constituted board of directors of Cinergy on the applicable date.

1.8 "Cinergy Services' Board of Directors" means the duly constituted board of directors of Cinergy Services on the applicable date.

1.9 "Cinergy's Secretary" means the person holding the position of Secretary of Cinergy on the applicable date.

1.10 "Common Stock" means the common stock, par value $.01 per share, of Cinergy.

1.11 "Deferred Unit" means a bookkeeping unit representing one share or a fractional share of Common Stock, ultimately payable in Common Stock as provided in this Plan.

1.12 "Director" means any person duly selected to serve as a member of Cinergy's Board of Directors, Cinergy Services' Board of Directors, PSI's Board of Directors, or CG&E's Board of Directors.

1.13 "Fees" means (a) the amount of the annual retainer compensation paid to a non-employee Director of Cinergy, plus (b) five times the compensation paid to a non-employee Director of Cinergy upon attending a meeting of Cinergy's Board of Directors.

1.14 "Market Value Per Share" means the closing price of the Common Stock, as reported by the "NYSE–Composite Transactions" published in The Wall Street Journal, on the appropriate date of reference or on the preceding trading day if that date was not a trading date.

1.15 "1934 Act" means the Securities Exchange Act of 1934, as amended from time to time, and the rules and regulations under such Act.

1.16 "Participant" means any Director or former Director who meets the eligibility requirements for participation described in Article 3.

1.17 "Plan" means this retirement plan for Directors known as the "Cinergy Corp. Retirement Plan for Directors," as amended and restated effective January 1, 1999 and as it may be further amended from time to time.

1.18 "PSI" means PSI Energy Inc., an Indiana corporation, and its successors.

1.19 "PSI's Board of Directors" means the duly constituted board of directors of PSI on the applicable date.

1.20 "PSI Resources" means PSI Resources, Inc., an Indiana corporation, and its successors.

1.21 "Unit Account" means the individual bookkeeping account maintained for a Participant who has made the election provided for in Section 5.2, to which Deferred Units are credited and debited.

The uses of singular and masculine words are for practical purposes only and shall be deemed to include the plural and feminine, respectively, unless the context plainly indicates a distinction. Certain other definitions, as required, appear in the following Articles of the Plan.

ARTICLE 2

EFFECTIVE DATE OF PLAN

The provisions of this Plan are, unless the context indicates otherwise, effective January 1, 1999.

ARTICLE 3

ELIGIBILITY

With the exception of any Director who, as of February 1, 1990, was a former employee of PSI Resources or PSI, each Director who is not also an employee or former employee of Cinergy, its subsidiaries, or affiliates with vested rights under a pension plan sponsored by Cinergy, its subsidiaries, or affiliates is eligible to participate in the Plan. No Director elected on or after January 1, 1999, shall be eligible to participate in the Plan.

An eligible Director shall become a Participant in the Plan commencing with the sixth year of service as a Director. Service as a Director of Cinergy, Cinergy Services, PSI, CG&E, or Resources prior to October 24, 1994, shall be applied in determining eligibility. Notwithstanding anything in this Article to the contrary, anyone who is an eligible Director on December 31, 1998, shall become a Participant in the Plan on January 1, 1999, irrespective of whether the Director has completed five years of service as of December 31, 1998.

ARTICLE 4

VESTING

Each eligible Director shall be fully vested in his benefits under the Plan immediately upon becoming a Participant.

ARTICLE 5

AMOUNT OF RETIREMENT BENEFITS

5.1 Each Participant who retires as a Director prior to January 1, 1999, shall be entitled to receive an annual cash payment in an amount equal to the Fees in effect on the day preceding the date of the Participant's retirement as a Director.

5.2 Each Participant who retires as a Director, or dies while a Director, on or after January 1, 1999, and who has signed the written consent and election described below, shall be entitled to receive his Accrued Benefit, which shall be converted into Deferred Units by dividing the dollar amount of the Accrued Benefit by the Market Value Per Share on December 31, 1998. The Accrued Benefit will be payable to the Director in Common Stock as set forth in Article 7.

In order for a Director to receive his Accrued Benefit in Common Stock, he must affirmatively consent, in writing, by filing with Cinergy's Secretary, on or before December 31, 1998, an election form requesting that his Accrued Benefit be converted to Deferred Units. If the Participant does not so consent, his benefit under the Plan will be paid as provided in Section 5.3.

5.3 Each Participant who retires as a Director, or dies while a Director, on or after January 1, 1999 and who has not consented to receiving his Accrued Benefit in the form of Deferred Units shall be entitled to receive an annual cash payment in an amount equal to the Fees in effect on December 31, 1998.

ARTICLE 6

UNIT ACCOUNTS

6.1 In addition to Deferred Units credited to a Participant's Unit Account as a result of the initial conversion of the Participant's Accrued Benefit, the Participant's Unit Account shall be credited with additional Deferred Units in amounts equal to:

(a) the amount of any cash dividend (or the fair market value of a dividend paid in property, other than a dividend paid in Common Stock) which the Participant would have received if on the record date for the dividend the Participant had been the owner of record of a number of shares of Common Stock equal to the number of Deferred Units (including fractions) then credited to the Participant's Unit Account divided by

(b) the Market Value Per Share on the date the dividend is paid.

From time to time, additional Deferred Units shall be credited to the Participant's Unit Account in amounts equal to the number of full and fractional shares of Common Stock which the Participant would have received if on the record date for a dividend which is to be paid in Common Stock the Participant had been the owner of record of a number of shares of Common Stock equal to the number of Deferred Units (including fractions) then credited to the Participant's Unit Account.

6.2 A Participant's Unit Account shall be proportionately adjusted, if and to the extent appropriate, for any change in the Common Stock by reason of any stock split, combination or exchange of shares, recapitalization, reorganization, merger, consolidation, or any similar change affecting the Common Stock.

ARTICLE 7

PAYMENT OF BENEFITS

7.1 *Benefits Paid in Cash*

A. *Payment to the Participant if Living*
The annual benefit shall be payable on the first business day of February each year, beginning with the February following the later of (a) the date the Participant ceases to be a Director, or (b) the Participant's attainment of age 55.

B. *Payment to the Participant's Beneficiary*
If a Participant dies before the payment of benefits has commenced under Section 7.1A, then the annual benefit shall be payable on the first business day of February each year, beginning with the February following the Participant's date of death.

7.2 *Benefits Paid in Common Stock*

A. *Payment to the Participant if Living*
The Participant's Unit Account shall be payable on the first business day of February each year, beginning with the February following the later of (a) the date the Participant ceases to be a Director, or (b) the Participant's attainment of age 55.
Prior to retirement, a Participant shall elect the method of payment by filing with Cinergy's Secretary an appropriate election form. At the Participant's election, the Unit Account shall be distributed either in a single lump sum payment or in annual installments of two to ten years.
If the Participant elects to have the Unit Account paid in a single lump sum, the number of shares of Common Stock to be transferred to the Participant shall be the number of whole Deferred Units credited to the Participant's Unit Account as of the distribution date.
If the Participant elects to have his Unit Account paid in installments, the number of shares of Common Stock to be distributed each year shall be equal to the number of Deferred Units credited to the Participant's Unit Account on the day preceding the date of payment of the installment, divided by the number of installments remaining to be paid, and reduced, if necessary, to the nearest whole Deferred Unit.

B. *Payment to the Participant's Beneficiary*
If a Participant dies before the payment of benefits has commenced under Section 7.2A, then the Participant's Unit Account shall be paid to the Participant's Beneficiary either in a single lump sum or in annual installments (of two to ten years) as determined by the Participant's Beneficiary. If paid in annual installments, the amount distributed each year shall be computed as provided in Section 7.2A and shall be payable on the first business day of February each year, beginning with the February following the Participant's date of death. If the benefit is payable in a single lump sum, the benefit shall be payable as soon as administratively feasible following the Participant's death.

C. *Manner of Payment of Common Stock*
Shares of Common Stock distributed under the Plan may be newly issued or treasury shares or shares purchased on the open market, as determined by Cinergy. Cash shall be paid in lieu of any fractional share.

ARTICLE 8

DURATION OF BENEFITS

For a Participant who retires as a Director prior to January 1, 1999, the annual benefit shall be payable for a term certain equal to the number of completed full years the Participant served as a Director as of the date of the Participant's retirement as a Director.

For a Participant who retires as a Director, or who dies while a Director, on or after January 1, 1999 and who has not elected to receive his Accrued Benefit in the form of Deferred Units, the annual benefit shall be payable for a term certain equal to the number of completed full years the Participant served as a Director as of December 31, 1998.

ARTICLE 9

DESIGNATION OF BENEFICIARY AND PAYMENT OF BENEFIT UPON DEATH

9.1 *Designation of Beneficiary*

A Participant may designate a Beneficiary or Beneficiaries (which may be an entity other than a natural person) to receive any benefit payments to be made under this Plan upon the Participant's death. A Participant may change or cancel his Beneficiary designation at any time without the consent of the Beneficiary. Any Beneficiary designation, change, or cancellation must be by written notice filed with Cinergy's Secretary and shall not be effective until received by Cinergy's Secretary. If the Participant designates more than one Beneficiary, any payments under this Plan to a Beneficiary shall be made in equal shares unless the Participant has designated otherwise, in which case the payments shall be made in shares designated by the Participant. If no Beneficiary has been named by the Participant, payment shall be made to the Participant's estate.

9.2 *Payments Upon Death of Participant*

A. *Payments Made in Cash*
Upon the death of a Participant who retires as a Director prior to January 1, 1999, payment shall be made to the Participant's Beneficiary for the balance of the number of completed full years the Participant served as a Director for which the Participant had not received payment at the date of his death.
Upon the death of a Participant who retires as a Director, or dies while a Director, on or after January 1, 1999 and who has not provided the written consent described in Section 5.2, payment shall be made to the Participant's Beneficiary for the balance of the number of completed full years the Participant served as a Director as of December 31, 1998 for which the Participant had not received payments at the date of his death.
Upon a Beneficiary's death, any remaining benefit shall be paid in a lump sum to the Beneficiary's estate.

B. *Payments Made in Common Stock*
Upon the death of a Participant who retires as a Director, or who dies while a Director, on or after January 1, 1999 and who has provided the written consent described in Section 5.2, payment shall be made to the Participant's Beneficiary in a single lump sum or for the remaining number of installments designated by the Participant. Upon the Beneficiary's death, any remaining benefit shall be paid in a lump sum to the Beneficiary's estate.

ARTICLE 10

NONALIENATION OF BENEFITS

The Plan shall not in any manner be liable for, or subject to, the debts and liabilities of any Participant or Beneficiary. No payee may assign the benefit payments due him under the Plan. No benefits at any time payable under the Plan shall be subject in any manner to anticipation, alienation, sale, transfer, assignment, pledge, attachment, garnishment, levy, execution, or other legal or equitable process or covenants of any kind.

ARTICLE 11

SHAREHOLDER APPROVAL

The Plan shall be subject to approval by a majority of the shares present in person or represented by proxy and entitled to vote thereon at a duly held shareholders' meeting of Cinergy at which a quorum exists.

ARTICLE 12

FUNDING POLICY

The Plan shall be totally unfunded so that Cinergy is under merely a contractual duty to make benefit payments when due under the Plan. The promise to pay shall not be represented by notes and shall not be secured in any way. No contributions to the Plan by Participants shall be required or permitted under the Plan.

ARTICLE 13

AMENDMENT AND TERMINATION

Cinergy, by resolution duly adopted by Cinergy's Board of Directors, shall have the right, authority and power to alter, amend, modify, revoke or terminate the Plan at any time. However, subject to the provisions of Section 14.6, without his, her or its written consent, no termination or amendment shall deprive any Participant (or Beneficiary, in the event of the Participant's death prior to the date of such action) of any benefits accrued under the Plan prior to the termination or amendment.

ARTICLE 14

MISCELLANEOUS

14.1 *Forfeitability*

If a Director or former Director becomes a director, proprietor, officer, partner or employee of, or otherwise becomes affiliated with, any utility in the

States of Indiana, Ohio or Kentucky that competes with Cinergy, its subsidiaries or affiliates, or if a former Director shall refuse a reasonable request from Cinergy, its subsidiaries or affiliates to perform consulting services after he retires from Cinergy's Board of Directors, Cinergy Services' Board of Directors, PSI's Board of Directors or CG&E's Board of Directors, any payments remaining payable to the Participant under this Plan shall be forfeited.

14.2 *No Right to Continue as a Director*
Nothing in this Plan shall be construed as conferring upon a Participant any right to continue as a member of Cinergy's Board of Directors, Cinergy Services' Board of Directors, PSI's Board of Directors or CG&E's Board of Directors.

14.3 *No Right to Corporate Assets*
Nothing in this Plan shall be construed as giving the Participant, any Beneficiary or any other person any equity or interest of any kind in the assets of Cinergy, Cinergy Services, PSI or CG&E or creating a trust of any kind or a fiduciary relationship of any kind between Cinergy, Cinergy Services, PSI or CG&E and any person. As to any claim for payments due under the provisions of the Plan, a Participant, a Beneficiary and any other persons having claim for payments shall be unsecured creditors of Cinergy, Cinergy Services, PSI or CG&E.

14.4 *Governing Law*
The Plan shall be construed and administered according to the laws of the State of Delaware to the extent that those laws are not preempted by the laws of the United States of America.

14.5 *Headings*
The headings of articles, sections, subsections, paragraphs, or other parts of the Plan are for convenience of reference only and do not define, limit, construe or otherwise affect the Plan's contents.

14.6 *Pooling of Interests Accounting*
In the event any action under this Plan would adversely affect the ability of Cinergy to use pooling of interests accounting in a subsequent merger or other corporate transaction, Cinergy's Board of Directors may, in its sole discretion, reverse any such action effective as of the effective date of the action and provide cash or such other substitute compensation as it deems appropriate and as may be necessary to cure the adverse effect on pooling.

ARTICLE 15

ADMINISTRATION

Cinergy's Board of Directors shall be responsible for the administration of the Plan. Cinergy's Board of Directors reserves the right to interpret and regulate the Plan, by exercise of discretionary authority, and its interpretation and regulation shall be effective and binding on all parties concerned.

ARTICLE 16

PAYMENTS UPON CHANGE IN CONTROL

Notwithstanding anything contained in this Plan to the contrary, following a Change in Control of Cinergy, each Participant (or Beneficiary, if appropriate) shall be entitled to receive a lump sum payment of the actuarial equivalent of benefits accrued and remaining unpaid as of the date of the Change in Control. The lump sum equivalent shall be calculated assuming the interest rate used by the Pension Benefit Guaranty Corporation in determining the value of immediate benefits as of the immediately preceding January 1.

A "Change in Control" of Cinergy shall be deemed to have occurred if the event set forth in any one of the following paragraphs shall have occurred:

(1) Any "person" or "group" (within the meaning of Sections 13(d) and 14(d)(2) of the 1934 Act) is or becomes the beneficial owner (as defined in Rule 13d-3 under the 1934 Act), directly or indirectly, of securities of Cinergy (not including in the securities beneficially owned by such person any securities acquired directly from Cinergy or its affiliates) representing 50% or more of the combined voting power of Cinergy's then outstanding securities, excluding any person who becomes such a beneficial owner in connection with a transaction described in clause (i) of paragraph (2) below; or

(2) There is consummated a merger or consolidation of Cinergy or any direct or indirect subsidiary of Cinergy with any other corporation, other than (i) a merger or consolidation which would result in the voting securities of Cinergy outstanding immediately prior to such merger or consolidation continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent thereof) at least 50% of the combined voting power of the securities of Cinergy or such surviving entity or any parent thereof outstanding immediately after such merger or consolidation, or (ii) a merger or consolidation

effected to implement a recapitalization of Cinergy (or similar transaction) in which no person is or becomes the beneficial owner, directly or indirectly, of securities of Cinergy (not including in the securities beneficially owned by such person any securities acquired directly from Cinergy or its affiliates other than in connection with the acquisition by Cinergy or its affiliates of a business) representing 25% or more of the combined voting power of Cinergy's then outstanding securities; or

(3) During any period of two consecutive years, individuals who at the beginning of that period constitute Cinergy's Board of Directors and any new director (other than a director whose initial assumption of office is in connection with an actual or threatened election contest, including but not limited to a consent solicitation, relating to the election of directors of Cinergy) whose appointment or election by Cinergy's Board of Directors or nomination for election by Cinergy's shareholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were directors at the beginning of that period or whose appointment, election or nomination for election was previously so approved or recommended cease for any reason to constitute a majority of Cinergy's Board of Directors; or

(4) The shareholders of Cinergy approve a plan of complete liquidation or dissolution of Cinergy or there is consummated an agreement for the sale or disposition by Cinergy of all or substantially all of Cinergy's assets, other than a sale or disposition by Cinergy of all or substantially all of Cinergy's assets to an entity, at least 60% of the combined voting power of the voting securities of which are owned by shareholders of Cinergy in substantially the same proportions as their ownership of Cinergy immediately prior to such sale.

Notwithstanding the provisions of Article 13, the provisions of this Article may not be amended by an amendment to the Plan effected within three years following a Change in Control.

Schedule A

SCHEDULE OF CALCULATIONS OF ACCRUED BENEFITS FOR CURRENT DIRECTORS

Active Participants as of January 1, 1999

Director's Name	Present Value of Vested Accrued Benefit
Armstrong, Neil A.	$ 447,959
Baker, James K.	$ 304,975
Browning, Michael G.	$ 208,466
Cox, Phillip R.	$ 128,495
Duberstein, Kenneth M.	$ 212,624
Hillenbrand II, John A.	$ 320,212
Juilfs, George C.	$ 365,159
Perelman, Melvin	$ 384,397
Petry, Thomas E.	$ 288,570
Schiff, Jr., John J.	$ 278,933
Sharp, Philip R.	$ 110,132
Smith, Van P.	$ 304,975
Taft, Dudley S.	$ 301,793
Waddell, Oliver W.	$ 253,555
Total	$3,910,245

Assumptions:	
Discount rate	6.00%
Mortality	None
Increase rate	5.00%

APPENDIX B

CINERGY CORP. DIRECTORS' EQUITY COMPENSATION PLAN

INTRODUCTION

On December 16, 1998, Cinergy Corp., subject to the approval of its shareholders, adopted a compensation plan known as the "Cinergy Corp. Directors' Equity Compensation Plan" (the "Plan") for the exclusive benefit of eligible non-employee directors of Cinergy Corp. Under the Plan, eligible non-employee directors of Cinergy are granted as of December 31 of each calendar year beginning in 1999 either a stock award consisting of 450 deferred units of Cinergy common stock or a cash award equal to the fair market value of 450 shares of Cinergy common stock, as determined by Cinergy's Board of Directors. The Plan, effective as of January 1, 1999, is set forth in its entirety below.

ARTICLE 1

DEFINITIONS

When used in this document, the following terms shall have the respective meanings set forth below, unless a different meaning is plainly required by the context:

1.1 "Account" means the individual bookkeeping account maintained for a Non-employee Director to which Awards, other amounts provided for in this Plan and distributions under this Plan are credited or debited.

1.2 "Award" means a Cash Award or a Stock Award granted to a Non-employee Director pursuant to this Plan.

1.3 "Beneficiary" means the recipient designated by a Non-employee Director who is, upon the Non-employee Director's death, entitled in accordance with the Plan's terms to receive the benefits to be paid with respect to the Non-employee Director.

1.4 "Board" means the duly constituted board of directors of Cinergy on the applicable date.

1.5 "Cash Award" means the grant of cash compensation to a Non-employee Director pursuant to Article 7 of the Plan. A Cash Award will be equal to the fair market value of 450 shares of Common Stock (subject to adjustment as provided in Section 6.2) on the Grant Date. The fair market value is determined by multiplying 450 (subject to adjustment) by the Market Value Per Share on the Grant Date.

1.6 "Cinergy" means Cinergy Corp., a Delaware corporation, and any successor to its business.

1.7 "Cinergy's Secretary" means the person holding the position of Secretary of Cinergy on the applicable date.

1.8 "Common Stock" means the common stock, par value $.01 per share, of Cinergy.

1.9 "Current Interest Rate" means the interest rate in effect for the period during which Cash Awards are held in a Non-employee Director's Account. The Current Interest Rate, until changed by action of the Board, shall be that percent per annum equivalent to the quoted interest rate for a one year certificate of deposit of $100,000 as quoted in The Wall Street Journal for the first business day of the particular calendar quarter. The Current Interest Rate shall be adjusted quarterly.

1.10 "Disability" shall have the meaning ascribed to it in Cinergy's Long-Term Disability Plan.

1.11 "Grant Date" means December 31 of each calendar year beginning December 31, 1999.

1.12 "Market Value Per Share" means the closing price of the common stock, as reported by the "NYSE–Composite Transactions" published in The Wall Street Journal, on the appropriate date of reference or on the preceding trading day if that date was not a trading date.

1.13 "1934 Act" means the Securities Exchange Act of 1934, as amended from time to time, and the rules and regulations under such Act.

1.14 "Non-employee Director" means a member of the Board who is not an employee of Cinergy or of any of its subsidiaries or affiliates.

1.15 "Plan" means this compensation plan known as the "Cinergy Corp. Directors' Equity Compensation Plan," as amended from time to time.

1.16 "Stock Award" means the grant on a Grant Date of 450 whole Units of Common Stock (subject to adjustment as provided in Section 6.2) to a Non-employee Director pursuant to Article 7 of the Plan.

1.17 "Unit" means a bookkeeping unit representing one share or a fractional share of Common Stock on the applicable date.

For a detailed discussion of Cinergy's short-term indebtedness, refer to Note 5 of the Notes to Consolidated Financial Statements.

LONG-TERM DEBT

Under the authority mentioned above, Cinergy had long-term debt authorization of $400 million, of which $200 million was issued and outstanding at December 31, 1998. CG&E has filed an application with the PUCO requesting authorization to issue up to $200 million of additional long-term debt. As of December 31, 1998, PSI and ULH&P had state regulatory authority for additional long-term debt issuance of $350 million and $10 million, respectively. Regulatory approval to issue additional amounts of securities will be requested as needed.

SALE OF ACCOUNTS RECEIVABLE

For a detailed discussion of the sale of accounts receivable, refer to Note 6 of the Notes to Consolidated Financial Statements.

MARKET RISK SENSITIVE INSTRUMENTS AND POSITIONS

ENERGY COMMODITIES SENSITIVITY

The transactions associated with the energy marketing and trading activities give rise to various risks, including market risk. Market risk represents the potential risk of loss from changes in the market value of a particular commitment arising from adverse changes in market rates and prices. These operations subject Cinergy to the risks and volatilities associated with the energy commodities (primarily electricity and natural gas) which it markets and trades. The wholesale energy marketing and trading business continues to be very competitive. As the ECBU continues to develop and expand its energy marketing and trading business, its exposure to movements in the price of electricity and other energy commodities will become greater. As a result, Cinergy is likely to be subject to future earnings volatility.

The energy marketing and trading activities of the ECBU principally consist of CG&E's and PSI's power marketing and trading operation which markets and trades over-the-counter contracts for the purchase and sale of electricity primarily in the Midwest region of the US, where owned generation is located. These activities are conducted by Services on behalf of CG&E and PSI. The power marketing and trading operation consists of both physical and trading activities. Transactions are designated as physical when there is intent and ability to physically deliver the power from company-owned generation. All other transactions are considered trading transactions. Substantially all of the contracts in both the physical and trading portfolios commit Cinergy, CG&E, and/or PSI to purchase or sell electricity at fixed prices in the future (i.e., fixed-price forward purchase and sales contracts, full requirements contracts). The ECBU also markets and trades over-the-counter option contracts. Substantially all of the contracts in the physical portfolio require settlement by physical delivery of electricity. Contracts within the trading portfolio generally require settlement by physical delivery or are netted out in accordance with industry trading standards. The use of these types of physical commodity instruments is designed to allow the ECBU to manage and hedge contractual commitments, reduce exposure relative to the volatility of cash market prices, and take advantage of selected arbitrage opportunities.

The ECBU structures and modifies its net position to capture expected changes in future demand, seasonal market pricing characteristics, overall market sentiment, and price relationships between different time periods and trading regions. Therefore, at times, a net open position is created or allowed to continue when it is believed future changes in prices and market conditions will make the positions profitable. Position imbalances may also occur because of the basic lack of liquidity in the wholesale power market. To the extent net open positions exist, there is the risk that fluctuating market prices of electric power may potentially impact Cinergy's financial condition or results of operations adversely if prices do not move in the manner or direction expected.

The ECBU measures the risk inherent in the trading portfolio utilizing value-at-risk analysis and other methodologies, which utilize forward price curves in electric power markets to quantify estimates of the magnitude and probability of potential future losses related to open contract positions. Predominantly all of the contracts in the physical portfolio require physical delivery of electricity and generally do not allow for net cash settlement. Therefore, these contracts are not included in the value-at-risk analysis. The value-at-risk expresses the potential loss in fair value of the trading portfolio over a particular period of time, with a specified likelihood of occurrence, due to an adverse market movement. The value-at-risk is reported as a percentage of operating income, based on a 95% confidence interval, utilizing one-day holding periods. On a one day basis as of December 31, 1998, the value-at-risk for the power trading activities was less than 1% of Cinergy's 1998 Consolidated Operating Income. The average value-at-risk, on a one-day basis at the end of each quarter in 1998, for the power trading portfolio was less than 2% of Cinergy's 1998 Consolidated Operating Income. The daily value-at-risk for the power trading portfolio as of December 31, 1997, was also less than 2% of Cinergy's 1998 Consolidated Operating Income. The value-at-risk model uses the variance-covariance statistical modeling technique and historical volatilities and correlations over the past 200-day period. The estimated market prices used to value these transactions for value-at-risk purposes reflect the use of established pricing models and various factors including quotations from exchanges and over-the-counter markets, price volatility factors, the time value of money, and location differentials.

The ECBU, through Cinergy's acquisitions of ProEnergy and Greenwich Energy Partners, in 1998 and 1997, respectively, actively markets physical natural gas and actively trades derivative commodity instruments, customarily settled in cash, including futures, forwards, swaps, and options. The ESBU, through CRI, utilizes derivative commodity instruments, customarily settled in cash, primarily to hedge purchases and sales of natural gas. The aggregated value-at-risk amounts associated with these trading and hedging activities, utilizing 95% confidence intervals and one-day holding periods, were less than $1 million as of December 31, 1998 and 1997. The market risk exposures of these trading activities is not considered significant to Cinergy's financial condition or results of operations.

Credit risk represents the risk of loss which would occur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations with the Company. Concentrations of credit risk relate to significant customers or counterparties, or groups of customers or counterparties, possessing similar economic or industry characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in economic or other conditions.

Concentration of credit risk with respect to the ESBU's trade accounts receivable from electric and gas retail customers is limited due to the large number of customers and diversified customer base of residential, commercial, and industrial customers. Contracts within the physical portfolio of the ECBU's power marketing and trading operations are primarily with traditional electric cooperatives and municipalities and other IOUs.

Contracts within the trading portfolio of the power marketing and trading operations are primarily with power marketers and other IOUs. As of December 31, 1998, approximately 73% of the activity within the trading portfolio represents commitments with 10 counterparties. The majority of these contracts are for terms of one year or less. As a result of the extreme volatility experienced in the Midwest power markets during 1998, several new entrants into the market began experiencing financial difficulties and failed to perform their contractual obligations. As a result, the bad debt provisions of approximately $13 million with respect to settled transactions were recorded during the year. Counterparty credit exposure within the power trading portfolio is routinely factored into the mark-to-market valuation. At December 31, 1998, credit exposure within the power trading portfolio is not believed to be significant. Prior to 1998, credit exposure due to nonperformance by counterparties was not significant. As the competitive electric power market continues to develop, counterparties will increasingly include new market entrants, such as other power marketers, brokers, and commodity traders. This increased level of new market entrants, as well as competitive pressures on existing market participants, could increase the ECBU's exposure to credit risk with respect to its power marketing and trading operation. As of December 31, 1998, approximately 37% of the activity within the ECBU's physical gas marketing and trading portfolio represents commitments with 10 counterparties. Credit risk losses related to the ECBU's gas and other commodity physical and trading operations have not been significant. Based on the types of counterparties and customers with which transactions are executed, credit exposure within the gas and other commodity trading portfolios at December 31, 1998, is not believed to be significant.

Cinergy has established a risk management function and has implemented active risk management policies and procedures to manage and minimize corporate and business unit exposure to price risks and associated volatilities, other market risks, and credit risk. Cinergy maintains credit policies with regard to its counterparties in order to manage and minimize its exposure to credit risk. These policies include requiring parent company guarantees and various forms of collateral under certain circumstances and the use of mutual netting/closeout agreements. Cinergy manages, on a portfolio basis, the market risks inherent in its energy marketing and trading transactions subject to parameters established by Cinergy's Risk Policy Committee. Market and credit risks are monitored by the risk management and credit function, which operates separately from the business units which originate or actively manage the market and credit risk exposures, to ensure compliance with Cinergy's stated risk management policies and procedures. These policies and procedures are periodically reviewed and monitored to ensure their responsiveness to changing market and business conditions. In addition, efforts are ongoing to develop systems to improve the timeliness and quality of market and credit risk information.

EXCHANGE RATE SENSITIVITY

Cinergy has exposure to fluctuations in the US dollar/UK pound sterling exchange rate through its investment in Midlands. Cinergy used dollar denominated variable interest rate debt to fund this investment, and has hedged the exchange rate exposure related to this transaction through a currency swap. Under the swap, Cinergy exchanged $500 million for 330 million pounds sterling. When the swap terminates in the year 2002, these amounts will be re-exchanged; that is, Cinergy will be repaid $500 million and will be obligated to repay to the counterparty 330 million pounds sterling. To fund this repayment, Cinergy could buy 330 million pounds sterling in the foreign exchange market at the prevailing spot rate or enter into a new currency swap.

The purpose of this swap is to hedge the value of Cinergy's investment in Midlands against changes in the dollar/pound sterling exchange rate. When the pound sterling weakens relative to the dollar, the dollar value of Cinergy's investment in Midlands as shown on its books declines; however, the value of the swap increases, offsetting the decline in the investment. The reverse is true when the pound sterling appreciates relative to the dollar. The translation gains and losses related to the principal exchange on the swap and on Cinergy's original investment in Midlands are recorded in "Accumulated other comprehensive loss", which is reported as a separate component of common stock equity in the Consolidated Financial Statements.

In connection with this swap, Cinergy must pay semi-annual interest on its pound sterling obligation and will receive semi-annual interest on the dollar notional amount. At December 31, 1998, the estimated fair value of this swap was $(59) million. This was partially offset by a $46 million currency translation gain to date on Cinergy's investment in Midlands.

Cinergy also has exposure to fluctuations in the US dollar/Czech koruna exchange rate through its investments in the Czech Republic. Cinergy has hedged the exchange rate exposure related to certain of its Czech koruna ("CZK") denominated investments through foreign exchange forward contracts. The contracts require Cinergy to exchange 1,447 million Czech korunas for $40 million. When the Czech koruna strengthens relative to the dollar, the dollar value of Cinergy's investment increases; however, the value of the foreign exchange forward contracts decreases, offsetting the increase in the investment. The reverse is true when the Czech koruna declines relative to the dollar. Translation losses related to the contracts are recorded in "Accumulated other comprehensive loss", which is reported as a separate component of common stock equity in the Consolidated Financial Statements. At December 31, 1998, the estimated aggregate fair value of these foreign exchange forward contracts was $(7) million.

Cinergy has investments in various other countries where the net investments are not hedged. The Company does have exposure to fluctuations in exchange rates between the US dollar and the currencies of these countries. At December 31, 1998, Cinergy does not believe it has a material exposure to the currency risk attributable to these investments.

The following table summarizes the details of the swap and the foreign exchange forward contracts. (For presentation purposes, the pound sterling payment obligation has been converted to US dollars using the dollar/pound sterling spot exchange rate at December 31, 1998, of 1.66000. The interest rates are based on the six-month LIBOR implied forward rates at December 31, 1998.)

($US Equivalent in millions)	1999	2000	2001	Expected Maturity Date 2002	2003	Thereafter	Total
Currency Swap							
Receive principal ($US)	$ –	$–	$–	$500	$–	$–	$ 500
Average interest receive rate (variable)	–%	–%	–%	5.3%	–%	–%	5.3%
Pay principal (£UK)	$ –	$–	$–	$548	$–	$–	$ 548
Average interest pay rate (partially variable, partially fixed)	–%	–%	–%	6.0%	–%	–%	6.0%
Foreign Exchange Forward Contracts							
Receive $US/Pay CZK	$ 40	$–	$–	$ –	$–	$–	$ 40
Average contractual exchange rate (CZK/$US)	36.2	–	–	–	–	–	36.2

INTEREST RATE SENSITIVITY

Cinergy's net exposure to changes in interest rates primarily consists of short-term debt instruments with floating interest rates that are benchmarked to US short-term money market indices. At December 31, 1998, this included (i) short-term bank loans and commercial paper totaling $637 million, (ii) $267 million of pollution control related debt which is classified as "Notes payable and other short-term obligations" on Cinergy's Consolidated Balance Sheets, and (iii) a $253 million sale of accounts receivable (Cinergy's Consolidated Balance Sheets are net of amounts sold). At December 31, 1997, this included (i) short-term bank loans and commercial paper totaling $870 million, (ii) $244 million of pollution control related debt which is classified as "Notes payable and other short-term obligations" on Cinergy's Consolidated Balance Sheets, and (iii) a $252 million sale of accounts receivable (Cinergy's Consolidated Balance Sheets are net of the amounts sold). At December 31, 1998 and 1997, interest rates on bank loans, commercial paper, and the sale of accounts receivable approximated 6%, and the interest rate on the pollution control debt approximated 4%. Current forward yield curves project no significant change in applicable short-term interest rates over the next five years.

The following table presents the principal cash repayments and related weighted average interest rates by maturity date for Cinergy's long-term fixed-rate debt, other debt and capital lease obligations as of December 31, 1998:

(in millions)	1999	2000	2001	Expected Maturity Date 2002	2003	Thereafter	Total	Fair Value
Liabilities								
Long-term Debt [(a)]								
Fixed rate	$137	$ 32	$ 90[(d)]	$124	$177[(e)]	$2 097	$2 657	$2 830
Average interest rate[(b)]	6.0%	5.7%	5.2%	7.3%	6.2%	7.0%	6.8%	
Other[(c)]	$ –	$ –	$ –	$ –	$ –	$ 100	$ 100	$ 104
Average interest rate[(b)]	–%	–%	–%	–%	–%	6.5%	6.5%	
Capital Lease								
Variable rate	$ –	$ –	$ 22	$ –	$ –	$ –	$ 22	$ 22
Average interest rate[(b)]	–%	–%	5.3%	–%	–%	–%	5.3%	

(a) Includes amounts reflected as long-term debt due within one year.
(b) For the long-term debt obligations, the weighted average interest rate is based on the coupon rates of the debt that is maturing in the year reported. For the capital lease, the interest rate is based on a spread over 3-month LIBOR, and averaged to be approximately 6% in 1998. For the variable rate Liquid Asset Notes with Coupon Exchange ("LANCEs"), the current forward yield curve suggests the interest rate on these notes would be fixed at 6.50% commencing October 1, 1999.
(c) Variable rate LANCEs.
(d) 6.00% Debentures due December 14, 2016, reflected as maturing in 2001 as the interest rate resets on December 14, 2001.
(e) 6.35% Debentures due June 15, 2038, reflected as maturing in 2003 as the interest rate resets on June 15, 2003.

To manage Cinergy's exposure to fluctuations in interest rates and to lower funding costs, Cinergy constantly evaluates the use of, and has entered into, several interest rate swaps. Under these swaps, Cinergy or its subsidiaries agree with counterparties to exchange, at specified intervals, the difference between fixed-rate and floating-rate interest amounts calculated on an agreed notional amount. This interest differential paid or received is recognized in the Consolidated Statements of Income as a component of interest expense.

Through one interest rate swap agreement, Cinergy has effectively fixed the interest rate on the pound sterling denominated obligation created by the currency swap discussed above. This contract requires Cinergy to pay semi-annually a fixed rate and receive a floating rate through February 2002. The notional amount of the swap is 280 million pounds sterling.

The fair value of the swap was approximately $(19) million at December 31, 1998. Translation gains and losses related to Cinergy's interest obligation, which is payable in pounds sterling, are recognized as a component of interest expense in the Consolidated Statements of Income. At December 31, 1998, the fair value of this swap decreased from $(3) million at December 31, 1997 primarily due to a projected decline in the average variable interest rate received on the dollar denominated leg of the swap over its remaining term.

At December 31, 1998, CG&E had an interest rate swap agreement outstanding related to its sale of accounts receivable. The contract has a notional amount of $100 million and requires CG&E to pay a fixed rate and receive a floating rate. PSI had three interest rate swap agreements outstanding with notional amounts of $100 million each. One contract, with two years remaining of a four-year term, requires PSI to pay a floating rate and receive a fixed rate. The other two contracts, with six-month terms, require PSI to pay a fixed rate and receive a floating rate. The floating rate is based on applicable LIBOR. At December 31, 1998 and 1997, the fair values of these interest rate swaps were not significant. The following table presents notional principal amounts and weighted average interest rates by contractual maturity dates for the interest rate swaps of Cinergy, CG&E, and PSI. The variable rates are the average implied forward rates during the contracts based on a December 31, 1998 one month commercial paper index yield curve for CG&E and the six month LIBOR yield curve at December 31, 1998 for Cinergy and PSI. Although Cinergy's swaps require payments to be made in pounds sterling, the table reflects the dollar equivalent notional amounts based on spot market foreign currency exchange rates at December 31, 1998.

	Expected Maturity Date							
($US Equivalent in millions)	1999	2000	2001	2002	2003	Thereafter	Total	Fair Value
Interest Rate Derivatives								
Interest Rate Swaps								
Receive fixed/pay variable ($US)	$ –	$100	$ –	$ –	$ –	$ –	$100	$ 2
Average pay rate	5.2%	5.1%	–%	–%	–%	–%	5.1%	
Average receive rate	6.1%	6.1%	–%	–%	–%	–%	6.1%	
Receive variable/pay fixed ($US)	$200	$ –	$ –	$ –	$ –	$ –	$200	$ (1)
Average pay rate	5.5%	–%	–%	–%	–%	–%	5.5%	
Average receive rate	5.1%	–%	–%	–%	–%	–%	5.1%	
Receive variable/pay fixed (£UK)	$ –	$ –	$ –	$465[(a)]	$ –	$ –	$465[(a)]	$(19)
Average pay rate	–%	–%	–%	7.1%	–%	–%	7.1%	
Average receive rate	–%	–%	–%	6.0%	–%	–%	6.0%	

(a) Notional converted to US dollars using the Sterling spot exchange rate at December 31, 1998, of 1.66000.

ACCOUNTING CHANGES

During the second quarter of 1998, the FASB issued Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities ("Statement 133"). Statement 133 requires companies to record derivative instruments, as defined in Statement 133, as assets or liabilities, measured at fair value. The statement requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that a company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. The standard is effective for fiscal years beginning after June 15, 1999, and Cinergy expects to adopt the provisions of Statement 133 in the first quarter of 2000. The Company has not yet quantified the impact of adopting Statement 133 on its consolidated financial statements. However, Statement 133 could increase volatility in earnings and other comprehensive income.

INFLATION

Cinergy believes that the recent inflation rates do not materially affect its financial condition or results of operations. However, under existing regulatory practice, only the historical cost of plant is recoverable from customers. As a result, cash flows designed to provide recovery of historical plant costs may not be adequate to replace plant in future years.

DIVIDEND RESTRICTIONS

See Note 2(b) of the Notes to Consolidated Financial Statements.

RESULTS OF OPERATIONS

OPERATING REVENUES

Electric Operating Revenues

The components of electric operating revenues and the related kilowatt-hour ("kwh") sales are shown below:

($ and kwh in millions)	Revenue			Kwh Sales		
	1998	1997	1996	**1998**	1997	1996
Retail	**$2 553**	$2 455	$2 438	**46 983**	45 327	45 121
Sales for resale	**2 140**	1 368	297	**77 558**	57 454	12 399
Other	**54**	39	34	**—**	—	—
Total	**$4 747**	$3 862	$2 769	**124 541**	102 781	57 520

Electric operating revenues increased $885 million (23%) for 1998, when compared to 1997. This increase was primarily due to increased volumes and a higher average price per kwh received on non-firm power sales for resale transactions related to the energy marketing and trading operations. There was also an increase in the average price per kwh paid for the corresponding purchases of purchased and exchanged power described below. Also contributing to the increase were higher retail kwh sales due to the warmer weather during 1998 when compared to 1997 and growth in the average number of residential and commercial customers.

Higher non-firm power sales for resale due to increased activity in the energy marketing and trading operations significantly contributed to the $1.1 billion (39%) increase in electric operating revenues in 1997, when compared to 1996. Also contributing to the increase was a full year's effects of PSI's retail rate increases approved in the September 1996 Order, as amended in August 1997, the December 1996 DSM Order, and the return of approximately $13 million to customers in 1996 in accordance with an order issued in February 1995 by the IURC. This order required all retail operating income above a certain rate of return to be refunded to customers. Partially offsetting these increases was the reduction in fuel revenue due to a lower average cost of fuel used in electric production.

Gas Operating Revenues

The components of gas operating revenues and the related thousand cubic feet ("mcf") sales are shown below:

($ and mcf in millions)	Revenue			Mcf Sales		
	1998	1997	1996	**1998**	1997	1996
Sales for resale	**$ 659**	$ —	$ —	**338**	—	—
Retail	**357**	454	440	**55**	69	75
Transportation	**41**	32	28	**58**	54	49
Other	**4**	5	6	**—**	—	—
Total	**$1 061**	$ 491	$ 474	**451**	123	124

Gas operating revenues increased $570 million in 1998, as compared to 1997. This increase was primarily due to the gas operating revenues of ProEnergy, which was acquired in June 1998. Partially offsetting this increase was a decline in retail sales due to lower mcf volumes reflecting, in part, the milder weather during the first quarter of 1998, and a reduction in the average number of full-service residential, commercial and industrial customers. Transportation revenues increased as full-service customers continued the move away from full service to purchasing gas directly from suppliers, using transportation services provided by CG&E.

The gas rate increase of 2.5% (approximately $9 million annually) approved by the PUCO in the December 1996 Order and a higher average cost per mcf of gas purchased contributed to the $17 million (4%) increase in gas operating revenues in 1997, as compared to 1996. These increases were partially offset by a decline in retail sales due to lower mcf volumes reflecting milder weather during 1997.

Other Revenues

Other revenues increased $34 million in 1998, as compared to 1997. This increase was primarily the result of increased sales and new initiatives by the non-regulated businesses operated by the various business units.

OPERATING EXPENSES

Fuel and Purchased and Exchanged Power

The components of fuel and purchased and exchanged power are shown below:

(in millions)	**1998**	1997	1996
Fuel	**$ 723**	$ 693	$ 713
Purchased and exchanged power	**2 123**	1 220	159
Total	**$2 846**	$1 913	$ 872

Electric fuel costs increased $30 million (4%) in 1998, when compared to 1997, and declined $20 million (3%) in 1997, when compared to 1996.

An analysis of these fuel costs is shown below:

(in millions)	**1998**	1997
Previous year's fuel expense	**$693**	$713
Increase (Decrease) due to change in:		
Price of fuel	**(23)**	7
Deferred fuel cost	**22**	(55)
Kwh generation	**28**	28
Other	**3**	—
Current year's fuel expense	**$723**	$693

Purchased and exchanged power expense increased $903 million (74%) and $1.1 billion in 1998 and 1997, respectively. These increases primarily reflect increased purchases of non-firm power for resale to others as a result of increased activity in the energy marketing and trading operations and an increase in the average price paid per kwh. Also recorded in 1998 were $135 million of unrealized losses related to the power marketing and trading operations. (See Note 1(c) of the Notes to Consolidated Financial Statements and the "Market Risk Sensitive Instruments and Positions" section for discussions on Cinergy's energy marketing and trading operations.)

Gas Purchased

Gas purchased increased $591 million in 1998, as compared to 1997. This is primarily due to the gas purchased expenses of ProEnergy, which was acquired in June 1998. Slightly offsetting this increase was a decrease in the volumes of gas purchased by CG&E, due to lower demand, and a lower average cost per mcf of gas purchased by CG&E.

The increase in gas purchased expense of $17 million (7%) in 1997, as compared to 1996, reflects a higher average cost per mcf of gas purchased. This increase was partially offset by a decline in the volumes of gas purchased.

Other Operation and Maintenance

The components of other operation and maintenance expenses are shown below:

(in millions)	**1998**	1997	1996
Other operation	**$ 814**	$693	$644
Maintenance	**192**	177	194
Total	**$1 006**	$870	$838

Other operation expenses increased $121 million (17%) in 1998, as compared to 1997. This increase is primarily due to the one-time charge of $80 million recorded during the second quarter of 1998, reflecting the implementation of a 1989 settlement of a dispute with the Wabash Valley Power Association, Inc. ("WVPA"). (See Note 18 of the Notes to Consolidated Financial Statements.) This increase was also the result of increased growth and new initiatives by the non-regulated businesses operated by the various business units. Maintenance expenses increased $15 million (8%) in 1998, as compared to 1997. This increase is due to an increase in boiler plant maintenance, an increase in general plant expenses, and an increase in distribution line maintenance costs resulting from storm damage during the second quarter of 1998.

Other operation expenses increased $49 million (8%) in 1997, as compared to 1996. This increase is primarily due to higher other operation expenses relating to the PSI Clean Coal Project, amortization of deferred DSM expenses, and amortization of deferred expenses associated with the Clean Coal Project, all of which are being recovered in revenues. The effect of discontinuing deferral of certain DSM-related costs also added to the increase. Maintenance expenses decreased $17 million (9%) in 1997, as compared to 1996. This decrease is primarily attributable to reduced outage related charges and other maintenance costs associated with the electric production facilities. Reduced maintenance costs associated with the electric transmission and distribution facilities in the PSI territory also contributed to the decrease for 1997.

Depreciation and Amortization

Depreciation and amortization increased $19 million (6%) in 1998, as compared to 1997. This increase is primarily attributable to amortization of phase-in deferrals reflecting the PUCO ordered phase-in plan for the William H. Zimmer Generating Station ("Zimmer"). (See Note 1(f) of the Notes to Consolidated Financial Statements.)

EQUITY IN EARNINGS OF UNCONSOLIDATED SUBSIDIARIES

The decrease in equity in earnings of unconsolidated subsidiaries of $9 million (15%) for 1998, as compared to 1997, is partially due to a decline in the earnings of Midlands, as a result of milder weather conditions and a penalty imposed on each electric distribution company caused by the delay in opening the electricity supply business to competition.

The increase in equity in earnings of unconsolidated subsidiaries of $35 million for 1997, as compared to 1996, primarily reflects a full year's effect of the investment in Midlands. Midlands was purchased during the second quarter of 1996.

OTHER INCOME AND (EXPENSES) — NET

The $12 million change in other income and (expenses)—net for 1998, as compared to 1997, is primarily due to a gain on the sale of Cinergy's interest in a foreign subsidiary. This gain is partially offset by a litigation settlement.

The $15 million change in other income and (expenses)—net for 1997, as compared to 1996, is due, in part, to charges in 1996 of approximately $14 million associated with the disallowance of information system costs related to the December 1996 Order, a gain of approximately $4 million in 1997 on the sale of a PSI investment, and a loss of approximately $5 million in 1996 on the sale of a foreign subsidiary. These items were partially offset by gains of approximately $6 million in 1996 related to the sale of certain CG&E assets, approximately $2 million of increased expenses in 1997 associated with the sales of accounts receivable for PSI, CG&E, and ULH&P.

INTEREST

The $21 million (10%) increase in interest expense in 1997, as compared to 1996, is due to higher short-term borrowings used to fund the redemption of first mortgage bonds by CG&E and Cinergy's investments in non-regulated companies, including Avon Energy.

INCOME TAXES

Income taxes decreased $96 million (45%) in 1998, as compared to 1997, due to a decrease in taxable income over the prior year and the increased utilization of foreign tax credits.

PREFERRED DIVIDEND REQUIREMENTS OF SUBSIDIARIES

The decrease in preferred dividend requirements of subsidiaries of $6 million (48%) for 1998, as compared to 1997, is primarily attributable to PSI's redemption of all outstanding shares of its 7.44% Series Cumulative Preferred Stock on March 1, 1998.

Preferred dividend requirements of subsidiaries decreased $11 million (46%) in 1997, when compared to 1996. This decrease is primarily attributable to the reacquisition of approximately 90% of the outstanding preferred stock of CG&E, pursuant to Cinergy's tender offer. (See Note 3(b) of the Notes to Consolidated Financial Statements.)

EXTRAORDINARY ITEM

Extraordinary item–equity share of windfall profits tax represents the one-time charge for the windfall profits tax levied against Midlands as recorded in 1997. (See Note 17 of the Notes to Consolidated Financial Statements.)

(in thousands, except per share amounts)	1998	1997	1996
Operating Revenues			
Electric	**$4 747 235**	$3 861 698	$2 768 706
Gas	**1 060 664**	491 145	474 035
Other	**68 395**	34 258	33 446
	5 876 294	4 387 101	3 276 187
Operating Expenses			
Fuel and purchased and exchanged power	**2 846 323**	1 912 793	872 088
Gas purchased	**857 010**	266 158	249 116
Other operation and maintenance	**1 006 382**	869 867	838 218
Depreciation and amortization	**325 515**	306 922	294 852
Taxes other than income taxes	**274 635**	265 693	258 375
	5 309 865	3 621 433	2 512 649
Operating Income	**566 429**	765 668	763 538
Equity in Earnings of Unconsolidated Subsidiaries	**51 484**	60 392	25 430
Other Income and (Expenses)—Net	**10 346**	(1 534)	(16 652)
Interest	**243 587**	236 319	215 603
Income Before Taxes	**384 672**	588 207	556 713
Income Taxes (Note 11)	**117 187**	213 000	198 736
Preferred Dividend Requirements of Subsidiaries	**6 517**	12 569	23 180
Net Income Before Extraordinary Item	**$ 260 968**	$ 362 638	$ 334 797
Extraordinary Item—Equity Share of Windfall Profits Tax (Less Applicable Income Taxes of $0) (Note 17)	—	(109 400)	—
Net Income	**$ 260 968**	$ 253 238	$ 334 797
Average Common Shares Outstanding	**158 238**	157 685	157 678
Earnings Per Common Share (Note 16)			
Net income before extraordinary item	**$1.65**	$2.30	$2.00
Net income	**$1.65**	$1.61	$2.00
Earnings Per Common Share—Assuming Dilution (Note 16)			
Net income before extraordinary item	**$1.65**	$2.28	$1.99
Net income	**$1.65**	$1.59	$1.99
Dividends Declared Per Common Share	**$1.80**	$1.80	$1.74

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

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(dollars in thousands) December 31	1998	1997
ASSETS		
Current Assets		
Cash and temporary cash investments	**$ 100 154**	$ 53 310
Restricted deposits	**3 587**	2 319
Notes receivable	**64**	110
Accounts receivable less accumulated provision for doubtful accounts of $25,622 at December 31, 1998, and $10,382 at December 31, 1997 (Note 6)	**580 305**	413 516
Materials, supplies, and fuel–at average cost	**202 747**	163 156
Prepayments and other	**74 849**	38 171
Energy risk management assets (Note 1(c))	**969 000**	–
	1 930 706	670 582
Utility Plant–Original Cost		
In service		
Electric	**9 222 261**	8 981 182
Gas	**786 188**	746 903
Common	**186 364**	186 078
	10 194 813	9 914 163
Accumulated depreciation	**4 040 247**	3 800 322
	6 154 566	6 113 841
Construction work in progress	**189 883**	183 262
Total utility plant	**6 344 449**	6 297 103
Other Assets		
Regulatory assets (Note 1(f))	**970 767**	1 076 851
Investments in unconsolidated subsidiaries (Note 10)	**574 401**	537 720
Other	**478 472**	275 897
	2 023 640	1 890 468
	$10 298 795	$8 858 153

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

(dollars in thousands) December 31	1998	1997
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	**$ 668 860**	$ 488 716
Accrued taxes	**228 347**	187 033
Accrued interest	**51 679**	46 622
Notes payable and other short-term obligations (Note 5)	**903 700**	1 114 028
Long-term debt due within one year (Note 4)	**136 000**	85 000
Energy risk management liabilities (Note 1(c))	**1 117 146**	–
Other	**93 376**	79 193
	3 199 108	2 000 592
Non-Current Liabilities		
Long-term debt (Note 4)	**2 604 467**	2 150 902
Deferred income taxes (Note 11)	**1 091 075**	1 248 543
Unamortized investment tax credits	**156 757**	166 262
Accrued pension and other postretirement benefit costs (Note 9)	**315 147**	297 142
Other	**298 370**	277 523
	4 465 816	4 140 372
Total liabilities	**7 664 924**	6 140 964
Cumulative Preferred Stock of Subsidiaries (Note 3)		
Not subject to mandatory redemption	**92 640**	177 989
Common Stock Equity (Note 2)		
Common stock–$.01 par value; authorized shares–600,000,000; outstanding shares–158,664,532 in 1998 and 157,744,658 in 1997	**1 587**	1 577
Paid-in capital	**1 595 237**	1 573 064
Retained earnings	**945 214**	967 420
Accumulated other comprehensive loss	**(807)**	(2 861)
Total common stock equity	**2 541 231**	2 539 200
Commitments and Contingencies (Note 12)		
	$10 298 795	$8 858 153

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY

(dollars in thousands)	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Comprehensive Income	Total Common Stock Equity
Balance at December 31, 1995	$1 577	$1 597 050	$ 951 290	$(1 074)		$2 548 843
Comprehensive income						
Net income			334 797		$334 797	334 797
Other comprehensive income, net of tax effect of $179						
Foreign currency translation adjustment					(131)	(131)
Minimum pension liability adjustment					(179)	(179)
Other comprehensive loss total				(310)	(310)	
Comprehensive income total					$334 487	
Issuance of 8,988 shares of common stock–net		311				311
Treasury shares purchased	(4)	(14 887)				(14 891)
Treasury shares reissued	4	8 599				8 603
Dividends on common stock (see page C-20 for per share amounts)			(274 358)			(274 358)
Costs of reacquisition of preferred stock of subsidiary			(18 391)			(18 391)
Other		(338)	188			(150)
Balance at December 31, 1996	$1 577	$1 590 735	$ 993 526	$(1 384)		$2 584 454
Comprehensive income						
Net income			253 238		$253 238	253 238
Other comprehensive income, net of tax effect of $1,595						
Foreign currency translation adjustment					(394)	(394)
Minimum pension liability adjustment					(1 083)	(1 083)
Other comprehensive loss total				(1 477)	(1 477)	
Comprehensive income total					$251 761	
Issuance of 65,529 shares of common stock–net		2 066				2 066
Treasury shares purchased	(11)	(46 199)				(46 210)
Treasury shares reissued	11	26 729				26 740
Dividends on common stock (see page C-20 for per share amounts)			(283 866)			(283 866)
Other		(267)	4 522			4 255
Balance at December 31, 1997	$1 577	$1 573 064	$ 967 420	$(2 861)		$2 539 200
Comprehensive income						
Net income			**260 968**		**$260 968**	**260 968**
Other comprehensive income, net of tax effect of $(1,813)						
Foreign currency translation adjustment					**2 160**	**2 160**
Minimum pension liability adjustment					**(106)**	**(106)**
Other comprehensive income total				**2 054**	**2 054**	
Comprehensive income total					**$263 022**	
Issuance of 919,874 shares of common stock–net	**10**	**30 225**				**30 235**
Treasury shares purchased	**(3)**	**(15 426)**				**(15 429)**
Treasury shares reissued	**3**	**7 325**				**7 328**
Dividends on common stock (see page C-20 for per share amounts)			**(284 703)**			**(284 703)**
Other		**49**	**1 529**			**1 578**
Balance at December 31, 1998	**$1 587**	**$1 595 237**	**$ 945 214**	**$ (807)**		**$2 541 231**

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)	1998	1997	1996
Operating Activities			
Net income	**$ 260 968**	$ 253 238	$ 334 797
Items providing or (using) cash currently:			
Depreciation and amortization	**325 515**	306 922	294 852
Wabash Valley Power Association, Inc. settlement	**80 000**	–	(80 000)
Deferred income taxes and investment tax credits–net	**(107 835)**	67 638	47 912
Unrealized loss from energy risk management activities	**135 000**	15 000	–
Equity in earnings of unconsolidated subsidiaries	**(45 374)**	(35 239)	(25 430)
Extraordinary item–equity share of windfall profits tax	**–**	109 400	–
Allowance for equity funds used during construction	**(1 668)**	(98)	(1 225)
Regulatory assets–net	**46 856**	33 605	(17 135)
Changes in current assets and current liabilities			
Restricted deposits	**(1 268)**	(598)	(358)
Accounts and notes receivable	**(45 811)**	(217 157)	132 749
Materials, supplies, and fuel	**(33 484)**	21 817	44 005
Accounts payable	**44 535**	183 296	37 281
Accrued taxes and interest	**46 371**	(21 414)	(1 289)
Other current assets and liabilities	**(9 495)**	(36 582)	52 749
Other items–net	**29 698**	53 750	(8 161)
Net cash provided by operating activities	**724 008**	733 578	810 747
Financing Activities			
Change in short-term debt	**(245 413)**	191 811	572 417
Issuance of long-term debt	**785 554**	100 062	150 217
Redemption of long-term debt	**(384 520)**	(336 312)	(237 183)
Funds on deposit from issuance of long-term debt	**–**	–	973
Retirement of preferred stock of subsidiaries	**(85 299)**	(16 269)	(212 487)
Issuance of common stock	**3 724**	2 066	311
Dividends on common stock	**(283 884)**	(283 866)	(274 358)
Net cash used in financing activities	**(209 838)**	(342 508)	(110)
Investing Activities			
Construction expenditures (less allowance for equity funds used during construction)	**(368 609)**	(328 055)	(323 013)
Acquisition of businesses (net of cash acquired)	**(63 412)**	–	–
Investments in unconsolidated subsidiaries	**(35 305)**	(29 032)	(503 349)
Net cash used in investing activities	**(467 326)**	(357 087)	(826 362)
Net increase (decrease) in cash and temporary cash investments	**46 844**	33 983	(15 725)
Cash and temporary cash investments at beginning of period	**53 310**	19 327	35 052
Cash and temporary cash investments at end of period	**$ 100 154**	$ 53 310	$ 19 327
Supplemental Disclosure of Cash Flow Information			
Cash paid during the year for:			
Interest (net of amount capitalized)	**$ 229 501**	$ 235 948	$ 207 393
Income taxes	**179 677**	140 655	141 917

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) NATURE OF OPERATIONS

Cinergy Corp., a Delaware corporation, ("Cinergy" or "Company"), is a registered holding company under the Public Utility Holding Company Act of 1935 ("PUHCA"). Cinergy was created in the October 1994 merger of The Cincinnati Gas & Electric Company ("CG&E") and PSI Resources, Inc. ("Resources"). Cinergy's utility subsidiaries are CG&E and PSI Energy, Inc. ("PSI"). CG&E, an Ohio combination electric and gas public utility company, and its five wholly-owned utility subsidiaries (including The Union Light, Heat and Power Company, a Kentucky combination electric and gas utility ("ULH&P")), are primarily engaged in the production, transmission, distribution, and sale of electric energy and/or the sale and transportation of natural gas in the southwestern portion of Ohio and adjacent areas in Kentucky and Indiana. PSI, an Indiana public electric utility and previously Resources' utility subsidiary, is engaged in the production, transmission, distribution, and sale of electric energy in north central, central, and southern Indiana. The majority of Cinergy's operating revenues is derived from the sale of electricity and the sale and transportation of natural gas.

Cinergy's non-utility subsidiaries are Cinergy Investments, Inc. ("Investments"), Cinergy Services, Inc. ("Services"), and Cinergy Global Resources, Inc. ("Global Resources"). Investments, a Delaware corporation, is a non-utility subholding company that holds virtually all of Cinergy's domestic non-utility businesses and interests. Services, a Delaware corporation, is the service company for the Cinergy system, providing member companies with a variety of administrative, management, and support services. Global Resources, a Delaware corporation, was formed in May 1998, and holds Cinergy's international businesses and certain other interests.

Cinergy conducts its operations through various subsidiaries and affiliates. The Company is functionally organized into four business units through which many of its activities are conducted: Energy Commodities Business Unit ("ECBU"), Energy Delivery Business Unit ("EDBU"), Energy Services Business Unit ("ESBU"), and the International Business Unit ("IBU"). The traditional, vertically-integrated utility functions have been realigned into the ECBU, EDBU, and ESBU. Each of these business units is described in detail along with certain financial information by business unit as of December 31, 1998, in Note 15. As the industry continues its evolution, Cinergy will continually analyze its operating structure and make adjustments as appropriate. In early 1999, certain organizational changes were begun to further align the business units to reflect Cinergy's strategic vision.

(b) PRESENTATION

The accompanying Consolidated Financial Statements include the accounts of Cinergy and its wholly-owned subsidiaries. Investments in business entities in which the Company does not have control, but has the ability to exercise significant influence over operating and financial policies (generally, 20% to 50% ownership) are accounted for using the equity method. All significant intercompany transactions and balances have been eliminated.

The preparation of financial statements in conformity with generally accepted accounting principles ("GAAP") requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities and the disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

The Consolidated Statements of Income have been reclassified in order to present the operations of all consolidated, non-regulated entities as a component of operating income. Prior to this reclassification, the operations of such entities were reflected in "Other Income and Expenses–Net." Similarly, "Income Taxes" now includes the income taxes associated with the non-regulated entities. These changes had no effect on net income. Additionally, the Consolidated Balance Sheets have been reformatted. Prior years' data has been reclassified to conform to the current year's presentation.

(c) ENERGY MARKETING AND TRADING

Cinergy's energy marketing and trading operations, conducted primarily through its ECBU, markets and trades electricity, natural gas, and other energy-related products. The power marketing and trading operation has both physical and trading activities. Generation not required to meet native load requirements is available to be sold to third parties, either under long-term contracts, such as full requirements transactions or firm forward sales contracts, or in short-term and spot market transactions. When transactions are entered into, each transaction is designated as either a physical or trading transaction. In order for a transaction to be designated as physical, there must be intent and ability to physically deliver the power from company-owned generation. Physical transactions are accounted for on a settlement basis. All other transactions are considered trading transactions and

The use of singular words is for practical purposes only and shall be deemed to include the plural unless the context clearly indicates a distinction. Certain other definitions, as required, appear in the following Articles of the Plan.

ARTICLE 2

EFFECTIVE DATE OF PLAN

Subject to Article 11, this Plan is effective as of January 1, 1999.

ARTICLE 3

PURPOSE OF PLAN

The Plan's purposes are to benefit Cinergy's shareholders by encouraging and enabling the acquisition of a proprietary interest, or increasing the proprietary interest, in Cinergy by Non-employee Directors thereby promoting the achievement of long-term corporate objectives by linking the personal interests of Non-employee Directors to those of Cinergy's shareholders, and to aid Cinergy in attracting and retaining qualified Non-employee Directors of outstanding competence.

ARTICLE 4

ADMINISTRATION

The Plan shall be administered by the Board. The Board is authorized to establish any rules and regulations and appoint any agents as it deems appropriate for the Plan's proper administration and to make any determinations under and to take any steps in connection with the Plan as it deems necessary or advisable. Each determination or other action taken pursuant to the Plan, including interpretation of the Plan and the specific conditions and provisions of the Awards granted under the Plan, shall be final and conclusive for all purposes and upon all persons including, without limitation, each Non-employee Director, Beneficiary, legal representative, and any other interested parties.

ARTICLE 5

ELIGIBILITY

Each Non-employee Director on January 1 of any year, commencing January 1, 1999, and each person who after January 1, 1999 is elected or appointed for the first time to be a Non-employee Director during the course of any year, is eligible to receive an Award under this Plan in respect of that year.

ARTICLE 6

STOCK

6.1 *Stock Subject to the Plan*

Stock to be issued or transferred under the Plan shall be shares of Common Stock. Cinergy may use authorized and unissued shares of Common Stock, treasury shares or shares acquired on the open market, in private transactions or otherwise, or a combination of the foregoing, for purposes of granting or settling an Award. Subject to adjustment as provided below, the aggregate maximum number of shares that may be issued or transferred in payment of Awards is 75,000.

6.2 *Adjustment in the Number of Shares*

If there is any change in the shares of Common Stock as a result of a stock dividend, stock split, recapitalization, merger, consolidation, combination or exchange of shares, spin-off, other significant distribution of assets, or similar change in capitalization, the Board shall make such equitable and proportionate adjustment, if any, as it deems appropriate in the total number of shares of Common Stock available for Awards under this Plan, as well as in the number of shares of Common Stock underlying a Stock Award or used as a basis for calculating the amount of a Cash Award.

ARTICLE 7

AWARDS

7.1 *Grant of Awards*

Each eligible Non-employee Director during any year shall be granted automatically on December 31st of that year, commencing December 31, 1999, either a Cash Award or a Stock Award, as determined by the Board in its discretion. Awards granted under this Plan shall be credited to each Non-employee Director's Account.

Notwithstanding anything in the Plan to the contrary, the amount of the Award to any Non-Employee Director who retires from the Board prior to December 31 of any calendar year shall be prorated based on the period of time the Non-employee Director served on the Board during that calendar year.

7.2 *Cash Awards*

Cash Awards held in an Account shall be credited with interest at the Current Interest Rate until distributed. Interest credited to the Account will bear interest (compounded quarterly) at the same rate.

The Board, in its discretion, may elect at any time to convert Cash Awards and accrued interest thereon credited to a Non-Employee Director's Account to Units by dividing the amount of cash credited to the Account on the applicable date by the Market Value Per Share on the date the conversion is made.

7.3 *Stock Awards*

Stock Awards held in an Account shall be credited, until distributed, with additional Units in amounts equal to:

(a) the amount of any cash dividend (or the fair market value of a dividend paid in property, other than a dividend paid in Common Stock) which the Non-employee Director would have received if on the record date for the dividend the Non-employee Director had been the owner of record of a number of shares of Common Stock equal to the number of Units (including fractions) then credited to the Non-employee Director's Account divided by

(b) the Market Value Per Share on the date the dividend is paid.

From time to time, additional Units shall be credited to the Non-employee Director's Account in amounts equal to the number of full and fractional shares of Common Stock which the Non-employee Director would have received if, on the record date for a dividend which is to be paid in Common Stock, the Non-employee Director had been the owner of record of a number of shares of Common Stock equal to the number of Units (including fractions) then credited to the Non-employee Director's Account. At the time any adjustment is made in accordance with Section 6.2, the Units in a Non-employee Director's Account also shall be appropriately adjusted.

ARTICLE 8

PAYMENT

8.1 *Method and Time*

A Non-employee Director's Account, together with imputed earnings thereon, shall be distributed in a single lump sum payment or in equal annual installments of two to ten years, provided that the Non-employee Director has properly elected the installment method. A single lump sum payment and, where applicable, the first installment payment shall be payable on the first business day of the calendar year immediately following the year in which the Non-employee Director ceases to be a director, and any additional installments shall be payable on the first business day of each succeeding year. The election described in this paragraph shall be made by the Non-employee Director at least one year prior to the date in which the Non-Employee Director ceases to be a director by filing with Cinergy's Secretary a written election form.

8.2 *Lump Sum*

If payment of the Non-employee Director's Account is made in a single lump sum, (i) the number of shares of Common Stock to be transferred to the Non-employee Director shall be the number of whole Units credited to the Non-employee Director's Account as of the close of business on the last business day of the calendar year in which the Non-employee Director ceases to be a director, and any fractional share shall be paid in cash, and (ii) the full amount of Cash Awards, and interest thereon, credited to the Non-employee Director's Account as of the close of business on that date shall be paid in cash.

8.3 *Installments*

If the Non-employee Director's Account is paid in installments, (i) the number of whole shares of Common Stock distributed on the date an installment is payable shall be equal to the number of Units credited to the Account as of the close of business on the last business day of the calendar year preceding the payment date, divided by the number of installments remaining to be paid, with any fractional share paid in cash and (ii) the amount of cash shall be equal to the cash balance credited to the Account as of the close of business on the last business day of the calendar year preceding the payment date, divided by the number of installments remaining to be paid.

ARTICLE 9

EFFECT OF DISABILITY OR DEATH

In the event of a Non-employee Director's Disability, the Board may take any action that it deems to be equitable under the circumstances or in the best interests of Cinergy, including, without limitation, accelerating the payment of the Non-employee Director's Account and prorating the Award that otherwise may have been awarded on the Grant Date based on the Non-employee Director's period of service during the calendar year.

If a Non-employee Director dies while a member of the Board or prior to the full payment of the Non-employee Director's Account, a number of whole shares of Common Stock equal to the number of whole Units credited to the Non-employee Director's Account (plus cash in lieu of any fractional share), and any cash allocated to the Account, shall be paid in a single lump sum payment to the Non-employee Director's designated Beneficiary or Beneficiaries, if any, or to the Non-employee Director's estate if no Beneficiaries are designated. The single lump sum payment shall be made within 90 days from the date of the Non-employee Director's death.

A Non-employee Director may designate a Beneficiary or Beneficiaries (which may be an entity other than a natural person) to receive any payments to be made under this Plan upon the Non-employee Director's death. At any time, and from time to time, any designation may be changed or canceled by a Non-employee Director without the consent of any Beneficiary. Any designation, change or cancellation must be by written notice filed with Cinergy's Secretary and shall not be effective until received by Cinergy's Secretary. If the Non-employee Director designates more than one Beneficiary, payments to each Beneficiary shall be made in equal shares unless the Non-employee Director has designated otherwise, in which case payment shall be made in the shares designated by the Non-employee Director.

ARTICLE 10

NO TRANSFER OR ASSIGNMENT

Awards and other amounts credited to a Non-employee Director's Account shall not be subject to assignment, conveyance, transfer, anticipation, pledge, alienation, sale, encumbrance or charge, whether voluntary or involuntary, by the Non-employee Director or any Beneficiary of the Non-employee Director, even if directed under a qualified domestic relations order or other divorce order. An interest in an Award or the amount represented thereby shall not provide collateral or security for a debt of a Non-employee Director or Beneficiary or be subject to garnishment, execution, assignment, levy or any other form of judicial or administrative process or to the claim of a creditor of a Non-employee Director or Beneficiary, through legal process or otherwise. Any attempt to anticipate, alienate, sell, transfer, assign, pledge, encumber, charge or to otherwise dispose of benefits payable, before actual receipt of the benefits, or a right to receive benefits, shall be void and shall not be recognized.

ARTICLE 11

SHAREHOLDER APPROVAL

The Plan shall be subject to approval by the holders of a majority of the shares present in person or represented by proxy and entitled to vote thereon at a duly held shareholders' meeting of Cinergy at which a quorum exists.

ARTICLE 12

FUNDING

12.1 *Unsecured Creditor Status*

The Plan shall be an unfunded plan within the meaning of the Internal Revenue Code of 1986, as amended. Benefits provided for in the Plan constitute only an unsecured contractual promise to pay in accordance with the terms of the Plan by Cinergy. The right of any Non-employee Director or Beneficiary to be paid any benefit under the Plan shall be no greater than the right of any other general, unsecured creditor of Cinergy.

12.2 *No Trust or Fiduciary Relationship*

Cinergy shall be responsible for the payment of all benefits provided under the Plan. Nothing contained in the Plan shall be deemed to create a trust or fiduciary relationship of any kind for the benefit of any Non-employee Director or Beneficiary. Although, at its discretion, Cinergy may establish one or more trusts for the purpose of providing for the payment of such benefits, the assets of any such trust shall be subject to the claims of Cinergy's creditors and, to the extent any benefits provided for under the Plan are not paid from any such trust, they shall remain the obligation of, and shall be paid by, Cinergy.

ARTICLE 13

MISCELLANEOUS

13.1 *No Right of Nomination*

Nothing in this Plan shall be deemed to create any obligation on the part of the Board to nominate any Non-employee Director for re-election by Cinergy's shareholders.

13.2 *No Individual Liability*

It is declared to be the express purpose and intention of the Plan that, except as otherwise required by law, no individual liability whatever shall attach to, or be incurred by, Cinergy, its shareholders, officers, employees, or members of the Board, or any representatives appointed by the Board, under or by reason of any of the Plan's terms or conditions.

13.3 *Governing Laws*

The Plan shall be construed and administered according to the laws of the State of Delaware (without giving effect to the conflict of law principles of that State) to the extent that those laws are not preempted by the laws of the United States of America.

13.4 *Amendment; Termination*

The Plan may at any time or from time to time be amended, modified or terminated by the Board; provided that, except as previously specified in the Plan, without a Non-employee Director's consent, no amendment, modification or termination shall (i) adversely affect the balance in a Non-employee Director's Account or (ii) permit payment of such balance prior to the date(s) specified by the Non-employee Director or provided for in the Plan.

13.5 *Headings*

The headings of articles and sections of the Plan are for convenience of reference only and do not define, limit, construe or otherwise effect the contents thereof.

13.6 *Change in Control*

Notwithstanding anything in this Plan to the contrary, in the event of a Change in Control of Cinergy, each Non-employee Director's Account shall be immediately payable.

A "Change in Control" of Cinergy shall be deemed to have occurred if the event set forth in any one of the following paragraphs shall have occurred:

(1) Any "person" or "group" (within the meaning of Sections 13(d) and 14(d)(2) of the 1934 Act) is or becomes the beneficial owner (as defined in Rule 13d-3 under the 1934 Act), directly or indirectly, of securities of Cinergy (not including in the securities beneficially owned by such person any securities acquired directly from Cinergy or its affiliates) representing 50% or more of the combined voting power of Cinergy's then outstanding securities, excluding any person who becomes such a beneficial owner in connection with a transaction described in clause (i) of paragraph (2) below; or

(2) There is consummated a merger or consolidation of Cinergy or any direct or indirect subsidiary of Cinergy with any other corporation, other than (i) a merger or consolidation which would result in the voting securities of Cinergy outstanding immediately prior to such merger or consolidation continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent thereof) at least 50% of the combined voting power of the securities of Cinergy or such surviving entity or any parent thereof outstanding immediately after such merger or consolidation, or (ii) a merger or consolidation effected to implement a recapitalization of Cinergy (or similar transaction) in which no person is or becomes the beneficial owner, directly or indirectly, of securities of Cinergy (not including in the securities beneficially owned by such person any securities acquired directly from Cinergy or its affiliates other than in connection with the acquisition by Cinergy or its affiliates of a business) representing 25% or more of the combined voting power of Cinergy's then outstanding securities; or

(3) During any period of two consecutive years, individuals who at the beginning of that period constitute the Board and any new director (other than a director whose initial assumption of office is in connection with an actual or threatened election contest, including but not limited to a consent solicitation, relating to the election of directors of Cinergy) whose appointment or election by the Board or nomination for election by Cinergy's shareholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were directors at the beginning of that period or whose appointment, election or nomination for election was previously so approved or recommended cease for any reason to constitute a majority of the Board; or

(4) The shareholders of Cinergy approve a plan of complete liquidation or dissolution of Cinergy or there is consummated an agreement for the sale or disposition by Cinergy of all or substantially all of Cinergy's assets, other than a sale or disposition by Cinergy of all or substantially all of Cinergy's assets to an entity, at least 60% of the combined voting power of the voting securities of which are owned by shareholders of Cinergy in substantially the same proportions as their ownership of Cinergy immediately prior to such sale.

13.7 *Pooling of Interests Accounting*

In the event any Award under this Plan would adversely affect the ability of Cinergy to participate in a subsequent merger or other corporate transaction that involves the use of pooling of interests accounting, the Board may, in its discretion, reverse any such Award, effective as of its Grant Date, and replace it with a Cash Award or provide other substitute compensation or take any other action which it deems necessary or appropriate to allow the transaction to proceed on a pooling of interests basis.

ARTICLE 14

CONTINUANCE BY A SUCCESSOR

In the event that Cinergy shall be reorganized by way of merger, consolidation, transfer of assets or otherwise, so that a corporation, partnership or person other than a subsidiary or affiliate of Cinergy shall succeed to all or substantially all of Cinergy's business, the successor may be substituted for Cinergy under the Plan by adopting the Plan.

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APPENDIX C

CINERGY CORP. 1998 FINANCIAL REPORT

TABLE OF CONTENTS

CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING INFORMATION

Matters discussed in this report reflect and elucidate management's corporate vision of the future and, as a part of that, outline goals and aspirations, as well as specific projections. These goals and projections are considered forward-looking statements and are based on management's beliefs, as well as certain assumptions made by management. Forward-looking statements involve risks and uncertainties which may cause actual results to differ materially from the forward-looking statements. In addition to any assumptions and other factors that are referred to specifically in connection with these statements, other factors that could cause actual results to differ materially from those indicated in any forward-looking statements include, among others:

- Factors affecting operations such as unusual weather conditions; catastrophic weather-related damage; unscheduled generation outages; unusual maintenance or repairs; unanticipated changes to fossil fuel costs, gas supply costs, or availability constraints due to higher demand, shortages, transportation problems or other developments; environmental incidents; or electric transmission or gas pipeline system constraints.
- Legislative and regulatory initiatives regarding deregulation and restructuring of the industry.
- The extent and timing of the entry of additional competition in electric or gas markets and the effects of continued industry consolidation through the pursuit of mergers, acquisitions, and strategic alliances.
- Challenges related to Year 2000 readiness, including success in implementing the Cinergy Year 2000 Readiness Program, the effectiveness of the Cinergy Year 2000 Readiness Program, and the Year 2000 readiness of outside entities.
- Regulatory factors such as unanticipated changes in rate-setting policies or procedures, recovery of investments made under traditional regulation, and the frequency and timing of rate increases.
- Financial or regulatory accounting principles or policies imposed by the Financial Accounting Standards Board ("FASB"), the Securities and Exchange Commission ("SEC"), the Federal Energy Regulatory Commission ("FERC"), state public utility commissions, state entities which regulate natural gas transmission, gathering and processing, and similar entities with regulatory oversight.
- Political, legal, and economic conditions and developments in the United States ("US") and the foreign countries in which Cinergy Corp. ("Cinergy" or "Company") or its subsidiaries or affiliates operate, including inflation rates and monetary fluctuations.
- Changing market conditions and a variety of other factors associated with physical energy and financial trading activities including, but not limited to, price, basis, credit, liquidity, volatility, capacity, transmission, currency exchange, interest rate, and warranty risks.
- The performance of projects undertaken by the non-traditional business and the success of efforts to invest in and develop new opportunities.
- Availability or cost of capital, resulting from changes in: Cinergy and its subsidiaries, interest rates, and securities ratings or market perceptions of the utility industry and energy-related industries.
- Employee workforce factors, including changes in key executives, collective bargaining agreements with union employees, or work stoppages.
- Legal and regulatory delays and other obstacles associated with mergers, acquisitions, and investments in joint ventures.
- Costs and other effects of legal and administrative proceedings, settlements, investigations, claims, and other matters, including, but not limited to, those described in Note 12 of the Notes to Consolidated Financial Statements.
- Changes in international, federal, state, or local legislative requirements, such as changes in tax laws or rates; environmental laws and regulations.

Cinergy undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of changes in actual results, changes in assumptions, or other factors affecting such statements.

REVIEW OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

THE COMPANY

Cinergy, a Delaware corporation, is a registered holding company under the Public Utility Holding Company Act of 1935 ("PUHCA"). Cinergy was created in the October 1994 merger of The Cincinnati Gas & Electric Company ("CG&E") and PSI Resources, Inc. Cinergy is the parent holding company of PSI Energy, Inc. ("PSI"), CG&E, Cinergy Investments, Inc. ("Investments"), Cinergy Global Resources, Inc. ("Global Resources"), and Cinergy Services, Inc. ("Services"). PSI is a public utility primarily engaged in providing electric service in north central, central, and southern Indiana. CG&E is a public utility primarily engaged in providing electric and gas service in the southwestern portion of Ohio and through its subsidiaries in adjacent areas in Kentucky and Indiana. CG&E's principal subsidiary, The Union Light, Heat and Power Company ("ULH&P"), is an operating utility primarily engaged in providing electric and gas service in northern Kentucky. Investments holds virtually all of Cinergy's domestic non-utility businesses and interests. Global Resources, formed in 1998, holds Cinergy's international businesses and certain other interests. Services provides Cinergy companies with a variety of administrative, management, and support services.

Cinergy conducts its operations through various subsidiaries and affiliates. The Company is functionally organized into four business units through which many of its activities are conducted: Energy Commodities Business Unit ("ECBU"), Energy Delivery Business Unit ("EDBU"), Energy Services Business Unit ("ESBU"), and the International Business Unit ("IBU"). The traditional, vertically-integrated utility functions have been realigned into the ECBU, EDBU, and ESBU. As the industry continues its evolution, Cinergy will continually analyze its operating structure and make adjustments as appropriate. In early 1999, certain organizational changes were begun to further align the business units to reflect Cinergy's strategic vision. Reference is made to Note 15 of the Notes to Consolidated Financial Statements for a discussion on financial information by business unit as of December 31, 1998.

FINANCIAL CONDITION

COMPETITIVE PRESSURES

Electric Utility Industry

Introduction The electric utility industry is continuing to transition from a monopoly cost-of-service regulated environment to an industry in which companies will ultimately compete to be the retail customers' energy provider. This transition will continue to impact the operations, structure, and profitability of Cinergy.

Energy companies are positioning themselves for full competition through the pursuit of mergers and acquisitions, strategic alliances, and the development of energy products and services. Cinergy's success in this transition is in large part dependent on legislative and regulatory outcomes with respect to electricity deregulation in its three franchise states: Ohio, Indiana, and Kentucky, as well as other regions in the US where Cinergy chooses to compete in the retail and wholesale markets.

Restructuring Process

Wholesale Markets The wholesale electric markets have been open to competition since 1996 when the FERC issued Orders 888 and 889. These rules provided for mandatory filing of open access/comparability transmission tariffs, functional unbundling of all services, utilities' use of these filed tariffs for their own bulk power transactions, establishment of an electronic bulletin board for transmission availability and pricing information, and establishment of a contract-based approach to recover stranded investments as a result of customer choice at the wholesale level.

Competitors within the wholesale market include traditional utilities and non-utility competitors such as exempt wholesale generators ("EWGs"), independent power producers, and power marketers. Cinergy, through its ECBU, is involved in wholesale power marketing and trading.

During late June 1998, Midwestern wholesale electric power markets experienced unprecedented price volatility due to several factors, including unseasonably hot weather, unplanned generating unit outages, transmission constraints, and defaults by certain power marketers on their supply obligations. The simultaneous occurrence of these events resulted in temporary but extreme price spikes in the Midwestern electricity markets. During this period, Cinergy's subsidiaries met both their statutory obligation to serve retail franchise customers and contractual obligations with wholesale customers. Since the events of June 1998, the Midwestern markets have continued to experience price volatility and illiquidity. For further discussion, see the "Market Risk Sensitive Instruments and Positions" section herein.

During 1998, the New York Mercantile Exchange ("NYMEX") began trading contracts with delivery points located in the Midwest and Southern regions of the country. Cinergy's transmission system is the delivery point for the Midwest region and one of only four NYMEX delivery points in the US.

Retail Markets Regulation and the transition to competition at the retail (i.e., end-user) level currently remains under the jurisdiction of individual states. (See State Developments for a discussion on the current status of customer choice in each of Cinergy's franchise states.) In most states where restructuring legislation has been enacted, all customers have been given the right to choose an electricity supplier. The incumbent utility has retained the right and obligation to provide the distribution and transmission of electricity, which continues to remain a regulated service. Significant issues facing state legislators, regulators, and incumbent franchise utilities in the restructuring to a competitive retail market include:

- The responsibility for unrecovered costs of the utilities in excess of the amounts which would be recovered under competitive market prices and the mechanism to recover these costs.
- The period allowed for transition to full competition.
- The extent to which incumbent utilities continue to have the obligation to serve during the transition period, or in the alternative, the extent to which competitive bidding for existing franchise customers is required or allowed.
- Default supplier responsibility following the transition period and the compensation for the associated risk.
- The extent to which utilities are granted the flexibility to position themselves for competition during the transition period, including the right to sell assets and retain the proceeds from such sales.
- Resolution of potential market power issues either through forced divestiture of generation and/or participation in a regional transmission organization.
- The need for a power exchange or similar mechanism to establish a market clearing price.
- Codes of conduct regarding the separation of the monopoly and non-monopoly functions of a utility and the treatment of affiliate transactions.
- Restructuring of state tax laws applicable to utilities necessitated by the disproportionate allocation of state tax liability to public utilities.

The anticipated restructuring of retail electric markets will create risks as well as opportunities for utilities, e.g., the risks and opportunities arising from the termination of the regulated Fuel Adjustment Clause, which provides protection against escalation in fuel and purchased power costs. Additionally, a number of implementation issues, including enhancements or replacements to existing customer information and billing systems, will be required. Cinergy will continue to focus on reducing costs and maintaining its status as a low-cost provider of electricity as well as identifying and addressing the likely implementation issues associated with retail customer choice. Additionally, Cinergy will continue to execute its strategy of developing and offering a portfolio of energy products and services for the retail market.

Cinergy continues to be an advocate of competition in retail electricity markets and continues to pursue customer-choice legislation at both the state and federal levels. Cinergy believes that the transition to competition can best meet the interests of all stakeholders where the rules are prescribed to the fullest extent possible in legislation that embodies the following:

- Price freezes that provide an opportunity for the utility to recover its transition costs and provide immediate flexibility for the utility to restructure its portfolio of supply assets in preparation for competition, keeping any proceeds from the sale or other disposition of assets to offset transition costs.
- A transition period with choice immediately available to all. During this period customers can adapt to the rights and responsibilities associated with choosing an alternative electricity supplier.
- Mitigation of market power issues through participation in a large, regional transmission organization.
- Adequate recovery of regulatory assets.

State Developments At present, a number of states have enacted legislation that will lead to complete retail electric competition over the next several years. These states generally have required up-front rate reductions and the opportunity for all customer classes to choose an electricity provider in return for recovery of utility stranded costs, including the ability to securitize revenue streams associated with such stranded costs.

Every state that has passed legislation has included a mechanism for the recovery of some stranded investment. However, states have varied on the methodology to be applied in determining the level of stranded investment, with divestiture of generating assets being one such method.

As discussed below, the three states in which Cinergy operates electric utilities are in various stages of addressing customer choice. None of these states has yet passed legislation, but policymakers and stakeholders continue to work to resolve the issues.

Indiana Customer-choice legislation was introduced in the Indiana General Assembly in 1998 by a coalition of customer organizations and two investor-owned utilities ("IOUs"), including Cinergy. After hearing and consideration by a Senate committee, the bill was defeated in the full Senate.

Legislation proposed by a group of large industrial customers was introduced in January 1999. At present, Cinergy continues to work with IOUs in Indiana and other stakeholders to develop customer-choice legislation that can be enacted into law in Indiana. The outcome of this effort is uncertain.

Ohio Electric restructuring legislation was introduced in the Ohio legislature during 1998. This legislation, "companion" electric restructuring bills (SB 237 and HB 732), proposed to afford choice to all retail electric customers in Ohio beginning January 1, 2000. Neither bill was passed during the 1998 legislative session.

During the third quarter of 1998, Ohio's IOUs, including CG&E, released a draft bill that sets forth the utilities' proposed approach to comprehensive electric restructuring in Ohio. Under the IOUs' proposal, choice to all retail electric customers would be introduced by January 1, 2001. Rates would be frozen during a transition period, a fixed charge for certain transition costs would continue after the freeze period for a set time, and customers would be provided a market-based "shopping credit" to stimulate the development of a competitive market. The proposal also included a restructuring of the tax laws with respect to electric utilities. In January 1999, a "place holder" bill was introduced in both the House and Senate. These bills set forth a legislative intent to develop comprehensive electric restructuring legislation in Ohio during 1999. Key policymakers in the state continue to meet with the IOUs and other stakeholders to see whether compromise legislation can be developed. It is uncertain whether this effort will produce legislation in Ohio in 1999.

Kentucky House Joint Resolution 95, which required the formation of an executive task force comprised of members from the Governor's office and the Kentucky General Assembly to further study electric restructuring, was passed by the Kentucky General Assembly and signed by the Governor in April 1998. Task force members will study electric restructuring in anticipation of the next legislative session, which occurs in January 2000.

United Kingdom Transition to full competition in the United Kingdom's ("UK") electric utility industry began with the industry's privatization in 1991. As a result of the transition plan, larger users of electricity have been free to choose their supplier since as early as 1991. In September 1998, a phase-in of choice for all remaining customers commenced and is to be completed by March 1999. The power suppliers sell power into a "pool" from which Regional Electric Companies ("RECs") purchase power for their customers through the supply segment of their business. Midlands Electricity plc ("Midlands") is one of twelve RECs in the UK. In November 1998, Midlands entered into an agreement to sell its power supply business to one of the UK's primary power generation companies. The sale is contingent upon UK government and regulatory approvals. Midlands' power supply business purchases, markets, and supplies electricity to 2.2 million customers in the UK.

After the sale, Midlands will continue to own and operate its electric distribution business, which will remain regulated by the Office of Electricity Regulation. Midlands' electric distribution business accounted for approximately 90% of its net income before interest and income taxes for the fiscal year ended March 1998. All the RECs, including Midlands, are in the process of a distribution price review. This process occurs every five years and is scheduled to take effect April 1, 2000. The public must be notified six months prior to any price changes; therefore, prices must be set and announced by October 1, 1999. (See Note 10 of the Notes to Consolidated Financial Statements for an additional discussion of Cinergy's investment in Midlands.)

Other Matters

Midwest ISO During 1998, the FERC approved the formation of a Midwest Independent System Operator ("Midwest ISO"). The Midwest ISO is the result of Cinergy's collaboration with other Midwestern utility companies to form an Independent System Operator ("ISO") that will assume functional control of their combined transmission systems and facilitate a reliable, efficient market for electric power. The ISO will provide non-discriminatory open transmission access consistent with FERC Order No. 888. The ISO will also be responsible for system reliability and administration of a regional transmission tariff, which will eliminate "pancaking" of transmission rates in the region. The Midwest ISO will be governed by a recently-elected, disinterested Board of Directors.

In addition to the ISO concept, other utilities have proposed to transfer their transmission assets to a "for profit" independent regional transmission company ("Transco"). Although Cinergy is not opposed to the formation of Transcos in the long run, it believes that an ISO is a more efficient and effective interim measure to immediately address market power issues and improve system reliability.

Currently, there are 10 utility members participating in the Midwest ISO. The Midwest ISO consists of 45,000 miles of transmission lines and covers portions of 11 states, and includes over $6.5 billion of transmission investment, forming one of the largest ISOs in the country. The Midwest ISO plans on beginning operations in the year 2000.

Repeal of the PUHCA PUHCA limits registered public utility holding companies such as Cinergy from competing for growth opportunities both domestically and internationally. Under PUHCA, registered public utility holding companies are limited in the amount of foreign investments and in domestic investments in generation they can make. It also restricts business combinations through its requirement that the electric systems of combining entities be "integrated."

Past efforts to repeal PUHCA have not been successful. In February 1999, a bill to repeal significant parts of PUHCA—S. 313, was introduced in the US Senate. Recently, the bill was voted out of the Senate Banking Committee without markup, and now goes to the full Senate. While it is uncertain whether this bill will be enacted into law, Cinergy continues to support the repeal of this act either as part of comprehensive reform of the electric industry or as separate legislation.

Substantial Accounting Implications Historically, regulated utilities have applied the provisions of Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation ("Statement 71"). The accounting afforded regulated utilities in Statement 71 is based on the fundamental premise that rates authorized by regulators allow recovery of a utility's costs. These principles have allowed the deferral of costs (i.e., regulatory assets) based on assurances of a regulator as to the future recoverability of the costs in rates charged to customers. Certain criteria must be met for the continued application of the provisions of Statement 71, including regulated rates designed to recover the specific utility's costs. Failure to satisfy the criteria in Statement 71 would eliminate the basis for recognition of regulatory assets.

Based on Cinergy's current regulatory orders and the regulatory environment in which it currently operates, the recognition of its regulatory assets as of December 31, 1998, is fully supported. However, in light of recent trends in customer-choice legislation, the potential for future losses resulting from discontinuance of Statement 71 does exist. Such potential losses, if any, cannot be determined until such time as a legislated plan has been approved by each state in which Cinergy operates a franchise territory. Cinergy intends to continue its pursuit of competitive strategies which mitigate the potential impact of these issues on the financial condition and results of operations of the Company.

Gas Utility Industry

Customer Choice Choice of gas supplier or pilot customer-choice programs are operating in several states. CG&E currently participates in a gas customer-choice program in Ohio. This program, which made customer choice available to all residential and small commercial customers in November 1997, was extended during 1998. Gas customers in approximately two-thirds of the state of Ohio are now eligible to participate in this voluntary program. Large industrial, commercial, and educational institution customers already had the ability to select their own gas supplier. Cinergy Resources, Inc. ("CRI"), Cinergy's gas retail marketing subsidiary, is one of many entities competing for customer gas supply business in these programs.

CG&E continues to provide gas transportation services for substantially all customers within its franchise territory without regard to the supplier of the gas commodity. CG&E receives a transportation charge from customers, which is based on its current regulated rates.

Acquisition of ProEnergy In June 1998, Cinergy, through Cinergy Capital & Trading, Inc. ("CC&T"), acquired Producers Energy Marketing, LLC ("ProEnergy") from Apache Corporation ("Apache") and Oryx Energy Company ("Oryx"). ProEnergy has exclusive marketing rights to North American gas production owned or controlled by Apache and Oryx, which represents approximately 1.1 billion cubic feet per day of dedicated natural gas supply. These supplies, combined with the active marketing of third-party gas, are geographically diverse and are spread through the Southwest, Rocky Mountains, Gulf Coast, Gulf of Mexico, and Michigan. The acquisition was funded with cash and the issuance of 771,258 new shares of Cinergy common stock.

SECURITIES RATINGS

The ratings as of February 28, 1999, provided by the major credit rating agencies—Duff & Phelps Credit Rating Co. ("D&P"), Fitch IBCA ("Fitch"), Moody's Investors Service ("Moody's"), and Standard & Poor's Ratings Services ("S&P")—are included in the following table:

	D&P	Fitch	Moody's	S&P
Cinergy				
Corporate Credit	BBB+	BBB+	Baa2	BBB+
Commercial Paper	D-2	F-2	P-2	A-2
CG&E				
Secured Debt	A-	A-	A3	A-
Senior Unsecured Debt	BBB+	BBB+	Baa1	BBB+
Junior Unsecured Debt	BBB	BBB+	Baa2	BBB+
Preferred Stock	BBB	BBB+	baa1	BBB
Commercial Paper	D-1-	F-1	P-2	Not rated
PSI				
Secured Debt	A-	A	A3	A-
Senior Unsecured Debt	BBB+	A-	Baa1	BBB+
Junior Unsecured Debt	BBB	BBB+	Baa2	BBB+
Preferred Stock	BBB	BBB+	baa1	BBB
Commercial Paper	D-1-	F-1	P-2	Not rated
ULH&P				
Secured Debt	A-	Not rated	A3	A-
Unsecured Debt	Not rated	Not rated	Baa1	BBB+

These securities ratings may be revised or withdrawn at any time, and each rating should be evaluated independently of any other rating.

RATE ORDERS AND OTHER REGULATORY MATTERS

Indiana

Indiana Utility Regulatory Commission ("IURC") Orders — PSI's Retail Rate Order and Demand-Side Management ("DSM") Order In September 1996, the IURC issued an order ("September 1996 Order") approving an overall average retail rate increase for PSI of 7.6% ($75.7 million annually). The order reflects a return on common equity of 11.0% and an overall rate of return on net original rate base of 8.21%. In settlement of a challenge by consumer groups to the September 1996 Order, the IURC approved a settlement agreement which reduced the original rate increase by $2.1 million in August 1997.

In a separate order issued by the IURC in December 1996 ("December 1996 DSM Order"), PSI was granted permission to recover $35 million per year for the four years ending December 31, 2000, through a non-bypassable charge in PSI's retail rates for previously incurred DSM costs and associated carrying costs. Further, PSI is authorized to spend up to $8 million annually on ongoing DSM programs through the year 1999 and to collect such amounts currently in retail rates.

Coal Contract Buyout Costs In August 1996, PSI entered into a coal supply agreement with Eagle Coal Company ("Eagle") for the supply of approximately three million tons of coal per year. The agreement, which expires December 31, 2000, provides for a buyout fee of $179 million (including interest) to be included in the price of coal to PSI over the term of the contract. This fee represents the costs to Eagle of the buyout of a previous coal supply agreement between PSI and Exxon Coal and Minerals Company. The buyout charge, excluding the portion applicable to joint owners, is being recovered through the wholesale and retail fuel adjustment clauses, with carrying costs on unrecovered amounts, through December 2002. (See Note 1(f) of the Notes to Consolidated Financial Statements.)

Coal Gasification Contract Buyout Costs In November 1995, PSI and Destec Energy Inc. ("Destec") entered into a 25-year contractual agreement for the provision of coal gasification services at PSI's Wabash River Generating Station. The agreement requires PSI to pay Destec a base monthly fee including certain monthly operating expenses. PSI received authorization in the September 1996 Order for the inclusion of these costs in retail rates. In addition, PSI received authorization to defer, for subsequent recovery in retail rates, the base monthly fees and expenses incurred prior to the effective date of the September 1996 Order. Over the next five years, the base monthly fees and expenses for the coal gasification service agreement are expected to total $212 million.

In September 1998, PSI reached agreement with Dynegy Inc. (Dynegy Inc. purchased Destec in June 1997) to purchase the remainder of its 25-year contract for coal gasification services for approximately $266 million. The proposed purchase, which is contingent upon regulatory approval satisfactory to PSI, could be completed in 1999. PSI is investigating its financing alternatives. The transaction, if approved as proposed, is not expected to have a material impact on PSI's earnings.

Currently, natural gas prices have fallen to a level which causes the synthetic gas supply taken under the current gasification services agreement to be substantially above market. If the buyout of the gasification services agreement is approved, the combustion turbine will be fired with natural gas, or with synthetic gas if it can be produced at a cost competitive with natural gas. In nominal dollars, it is estimated that the total savings, primarily as a result of the purchase, would be approximately $270 million over the life of the contract.

Ohio

Public Utilities Commission of Ohio ("PUCO") Order — CG&E's Gas Rate Order In December 1996, the PUCO issued an order ("December 1996 Order") approving an overall average increase in gas revenues for CG&E of 2.5% ($9.3 million annually). The PUCO established an overall rate of return of 9.7%, including a return on common equity of 12.0%. The PUCO disallowed certain of CG&E's requests, including the requested working capital allowance, recovery of certain capitalized information systems development costs, and certain merger-related costs. These disallowances resulted in a pretax charge to earnings during the fourth quarter of 1996 of $20 million ($15 million net of taxes or $.10 per share basic, $.09 per share diluted). CG&E's request for a rehearing on the disallowed information systems costs and other aspects of the order was denied.

In April 1997, CG&E filed a notice of appeal with the Supreme Court of Ohio challenging the disallowance of information systems costs and the imputation of certain revenues. Cinergy and CG&E cannot predict what action the Supreme Court of Ohio may take with respect to this appeal.

Kentucky

In exchange for the Kentucky Public Service Commission's ("KPSC") support of the merger, in May 1994, ULH&P accepted the KPSC's request for an electric rate moratorium commencing after ULH&P's next retail rate case (which has not yet been filed) and extending to January 1, 2000. In addition, the KPSC has authorized concurrent recovery of costs related to various DSM programs of ULH&P.

ULH&P has deferred its portion of Merger Costs incurred through December 31, 1996, for future recovery in customer rates.

SEC Order Authorizing the Retention of Gas Operations

In its 1994 order approving the merger, the SEC reserved judgment over Cinergy's ownership of CG&E's gas operations for three years, at the end of which period Cinergy would be required to address the matter. In November 1998, the SEC issued an order unconditionally approving the retention of CG&E's gas businesses.

ENVIRONMENTAL ISSUES

Clean Air Act Amendments of 1990 ("CAAA")

The 1990 revisions to the Clean Air Act require reductions in both sulfur dioxide ("SO_2") and nitrogen oxide ("NO_x") emissions from utility sources. Reductions of these emissions are to be accomplished in two phases. Compliance under Phase I was required by January 1, 1995, and Phase II compliance is required by January 1, 2000. To achieve the SO_2 reduction objectives of the CAAA, emission allowances have been allocated by the US Environmental Protection Agency ("EPA") to affected sources (e.g., Cinergy's electric generating units operated by the ECBU). Each allowance permits one ton of SO_2 emissions. The CAAA allows compliance to be achieved on a national level, which provides companies the option to achieve this compliance by reducing emissions and/or purchasing emission allowances.

All required modifications to Cinergy's generating units to implement the Phase I compliance plans were completed prior to January 1, 1995. To comply with Phase II SO_2 emission requirements, Cinergy's current strategy includes a combination of switching to lower-sulfur coal blends and utilizing an emission allowance banking strategy to the extent a viable emission allowance market exists. This cost-effective strategy will allow for meeting the Phase II SO_2 reduction requirements while maintaining optimal flexibility to meet changes in output due to increased customer choice, as well as potentially significant future environmental requirements. To meet NO_x reductions required by Phase II, additional burner modifications are planned on certain affected units in addition to using a system-wide NO_x emission averaging strategy.

Capital expenditures are forecast to be less than $10 million to comply with the Phase II NO_x reductions, substantially all of which are expected to be incurred during 1999. These expenditures are included in the amounts provided in the "Capital Requirements" section herein.

Ozone Transport Rulemaking

In June 1997, the 37-state collaborative known as the Ozone Transport Assessment Group made a wide range of recommendations to the EPA to address the impact of ozone transport on serious nonattainment areas in the Northeast, Midwest, and South. In late 1997, in response to this recommendation, the EPA published its proposed call for revisions to State Implementation Plans ("SIPs") for statewide reductions in NO_x emissions. In October 1998, the EPA finalized its Ozone Transport Rule ("NO_x SIP Call"). It applies to 22 states in the eastern half of the US, including the three states in which the Cinergy electric utilities operate, and also proposes a model NO_x trading program. This rule recommends that states reduce NO_x emissions from primarily industrial and utility sources to a certain limit by May 2003. The EPA gave the affected states until September 30, 1999, to incorporate utility NO_x reductions with a trading program into their SIPs. If the states fail to revise their SIPs accordingly, the EPA has proposed to implement a federal plan to accomplish NO_x reductions by May 2003.

Ohio, Indiana, a number of other states, and various industry groups, including some of which Cinergy is a member, filed legal challenges to the NO_x SIP Call in late 1998. Ohio and Indiana have also provided preliminary indications that they will seek fewer NO_x reductions from the utility sector in their implementing regulations than the EPA has budgeted in its rulemaking. The state implementing regulations will need the EPA's approval. The current estimate of capital expenditures required for compliance with the EPA limits in the new NO_x SIP Call is between $500 million and $700 million (in 1998 dollars) between now and 2003. This estimate is significantly dependent on several factors, including the final determination regarding both the timing and stringency of the final required NO_x reductions, the output of Cinergy's generating units, the availability of adequate supplies of resources to construct the necessary control equipment, and the extent to which a NO_x allowance trading market develops, if any.

Ambient Air Standards and Regional Haze

During 1997, the EPA revised the National Ambient Air Quality Standards for ozone and fine particulate matter and proposed rules for regional haze. The EPA is scheduled to finalize new regional haze rules by the summer of 1999 and Congress, as part of the funding bill for the Surface Transportation Act, combined the schedules for fine particulates and regional haze implementation. These new rules increase the pressure for additional NO_x and SO_2 emissions reductions. Depending on the ultimate outcome of the NO_x SIP Call, additional NO_x reductions may be required from states by 2007 to address the new eight-hour ozone standard.

The EPA estimates it will take up to five years to collect sufficient ambient air monitoring data to determine nonattainment areas. The states will then determine the sources of these particulates and determine a regional emission reduction plan. The ultimate effect of the new standard could be requirements for newer and cleaner technologies and additional controls on conventional particulates and/or reductions in SO_2 and NO_x emissions from utility sources. At this time, the exact amount and timing of required reductions cannot be predicted.

Global Climate Change

In December 1997, delegates to the United Nations' climate summit in Japan adopted a landmark environmental treaty ("Kyoto Protocol") to deal with global warming. The Kyoto Protocol establishes legally binding greenhouse gas emission targets for developed nations. On November 12, 1998, the US signed the Kyoto Protocol. However, for the Kyoto Protocol to enter into force within the US it will have to be ratified by a two-thirds vote of the US Senate. The Kyoto Protocol, in its present form, is unlikely to be ratified by the US Senate since it does not contain provisions requiring participation of developing countries.

Significant uncertainty exists concerning both the science of climate change and the Clinton Administration's environmental and energy policies and how it intends to reduce greenhouse gas emissions. Cinergy's plan for managing the potential risk and uncertainty of climate change includes: (1) implementing cost-effective greenhouse gas emission reduction and offsetting activities; (2) encouraging the use of alternative fuels for transportation vehicles (a major source of greenhouse gases); (3) funding research of more efficient and alternative electric generating technologies; (4) funding research to better understand the causes and consequences of climate change; and (5) encouraging a global discussion of the issues and how best to manage them. The ECBU believes that voluntary programs, such as the US Department of Energy ("DOE") Climate Challenge Program, which Cinergy joined in 1995, are the most cost-effective means to limit greenhouse gas emissions.

Air Toxics

The air toxics provisions of the CAAA exempted fossil-fueled steam utility plants from mandatory reduction of air toxics until the EPA completed a study. The final report, issued in February 1998, confirmed utility air toxic emissions pose little risk to public health. It stated mercury is the pollutant with the greatest potential threat, while others require further study. A Mercury Study Report, issued in December 1997, stated that mercury is not a risk to the average American and expressed uncertainty whether reductions in current domestic sources would reduce human mercury exposure. US utilities are a large domestic source, but they are negligible compared to global mercury emissions. The EPA was unable to show a feasible mercury control technology for coal-fired utilities. In November 1998, the EPA finalized its Mercury Information Collection Request ("ICR"). Pursuant to the ICR, all generating units must provide detailed information about coal use and mercury content. The EPA will also select about 100 generating units for one-time stack sampling. At that time, the EPA also announced that it would make its regulatory determination on the need for additional regulation by the fourth quarter of 2000. It will utilize the new information from the ICR, a new study by the National Academy of Sciences, and other additional information. If more air toxics regulations are issued, the compliance cost could be significant. The outcome or effects of the EPA's determination cannot currently be predicted.

Other

As more fully discussed in Note 12(b)(ii) of the Notes to Consolidated Financial Statements, PSI has received claims from Indiana Gas Company, Inc. ("IGC") and Northern Indiana Public Service Company ("NIPSCO") that PSI is a Potentially Responsible Party under the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") with respect to certain manufactured gas plant ("MGP") sites, and therefore is responsible for the costs of investigating and remediating these sites.

In November 1998, NIPSCO, IGC, and PSI entered into an agreement which settled the allocation of CERCLA liability for past and future costs among the three companies, at seven MGP sites in Indiana. Similar agreements were reached between IGC and PSI which allocate CERCLA liability at 14 MGP sites with which NIPSCO had no involvement. These agreements conclude all CERCLA and similar claims between the three companies relative to MGP sites. Pursuant to the agreements, the parties are continuing to investigate and remediate the sites as appropriate. In the case of some sites, the parties have applied to the Indiana Department of Environmental Management for inclusion of such sites in the Indiana Voluntary Remediation Program.

Reserves recorded, based on information currently available, are not material to Cinergy's financial condition or results of operations. However, as further investigation and remediation activities are undertaken at these sites, the potential liability for MGP sites could be material to Cinergy's financial condition or results of operations.

Refer to Notes 12(b) and (c) of the Notes to Consolidated Financial Statements for a more detailed discussion of the status of certain environmental issues.

CAPITAL REQUIREMENTS

CONSTRUCTION AND OTHER INVESTING ACTIVITIES

The regulated businesses of Cinergy forecast construction expenditures for 1999 to be approximately $386 million and over the next five years (1999–2003) to be approximately $1.7 billion. The timing and amount of investments by Cinergy's non-regulated businesses is dependent upon the development and favorable evaluation of opportunities.

The above forecast excludes the estimated expenditures necessary to comply with the EPA's proposed stricter NO_x emission control standards associated with the 22-state NO_x SIP Call. Cinergy estimates that the capital costs for additional NO_x controls at its facilities could range between $500 million and $700 million (in 1998 dollars) over the next five years. The above forecast also excludes any capital expenditures that may be required for the construction of new generating facilities.

In order to meet the power supply demands of its customers, the ECBU must constantly assess the adequacy of its supply portfolio and determine which supply alternatives to pursue to most effectively meet demands, hedge risks, and satisfy regulatory requirements. Supply alternatives include investments in existing facilities, investments in new facilities, and/or acquisitions of power supply from the market. In addition, Cinergy's present demand requirements could be impacted if customer-choice legislation is passed in any of the states in which Cinergy has a regulated franchise. (*All forecasted amounts, excluding NO_x compliance amounts, are in nominal dollars and reflect assumptions as to the economy, capital markets, construction programs, legislative and regulatory actions, frequency and timing of rate increases, and other related factors, all or any of which may change significantly.*)

Cinergy's mission is to reach the top five in our industry within three years on five key dimensions—market capitalization, number of customers, electric and gas commodity trading, international presence, and productivity. Cinergy has entered into various growth initiatives in its pursuit of these goals. These initiatives include, among others, energy marketing and trading, retail energy products and services, and additional international investment. In addition, Cinergy is working toward maximizing the value of its existing operations and assets and continues to explore the potential for mergers, acquisitions, and strategic alliances.

Certain legal and regulatory requirements, including PUHCA, limit Cinergy's ability to invest in growth initiatives. PUHCA restricts the amount which can be invested outside the regulated utility, including foreign utility company ("FUCO") investments and investments in domestic power plants that qualify as "qualifying facilities" ("QFs") under the Public Utility Regulatory Policies Act of 1978 or are certified as EWGs by the FERC. Under these restrictions, Cinergy may invest or commit to invest (i) an amount equal to 100% of consolidated retained earnings (defined under applicable SEC regulations as the average of Cinergy's consolidated retained earnings for the four most recent quarterly periods) in EWGs and FUCOs (equal to $949 million at December 31, 1998), and (ii) an amount equal to 15% of consolidated capitalization ($942 million at December 31, 1998) in QFs and other "energy-related" nonutility investments (as defined in the applicable SEC regulation).

At December 31, 1998, under these SEC restrictions, Cinergy had available capacity for additional EWG/FUCO investments of $332 million and available capacity for additional QFs and "energy-related" nonutility investments of $524 million.

OTHER COMMITMENTS

Securities Redemptions

Mandatory redemptions of long-term debt total $410 million during the period 1999 through 2003.

The maintenance and replacement fund provisions contained in PSI's first mortgage bond indenture require cash payments, bond retirements, or pledges of unfunded property additions each year based on an amount related to PSI's net revenues. Cinergy will continue to evaluate opportunities for the refinancing of outstanding securities beyond mandatory redemption requirements.

Guarantees

At December 31, 1998, Cinergy had issued $286 million in guarantees primarily related to the energy marketing and trading activities of its subsidiaries and affiliates. In addition, Cinergy had guaranteed $258 million of the debt securities of its subsidiaries and affiliates.

Year 2000

The Year 2000 issue generally exists because many computer systems and applications, including those embedded in equipment and facilities, use two digit rather than four digit date fields to designate an applicable year. As a result, the systems and applications may not properly recognize dates including and beyond the year 2000 or accurately process data in which such dates are included, potentially causing data miscalculations and inaccuracies or operational malfunctions and failures, which could materially affect a business's financial condition, results of operations, and cash flows.

Cinergy has established a centrally-managed, company-wide initiative, known as the Cinergy Year 2000 Readiness Program, to identify, evaluate, and address Year 2000 issues. The Cinergy Year 2000 Readiness Program, which began in the fourth quarter of 1996, is generally focused on three elements that are integral to this initiative: (1) business continuity; (2) risk management; and (3) regulatory compliance. Business continuity includes providing reliable electric and gas supply and service in a safe and cost-effective manner. This element encompasses mission-critical generation, transmission, and distribution systems and related infrastructure, as well as operational and financial information technology ("IT") systems and applications, end-user computing resources, and building systems (such as security, elevator, and heating and cooling systems). Risk management includes a review of the Year 2000 readiness efforts of Cinergy's critical suppliers, key customers and other principal business partners, and, as appropriate, the development of joint business support, contingency plans, and the inclusion of Year 2000 concerns as a regular part of the due diligence process in any new business venture. Regulatory compliance includes communications with regulatory agencies, other utilities, and various industry groups. While this initiative is broad in scope, it has been structured to identify and prioritize efforts for mission-critical electric and gas systems and services and key business partners.

Under the Cinergy Year 2000 Readiness Program, Cinergy has established a target date of June 30, 1999, for the remediation and testing of its mission-critical generation, transmission, and distribution systems (gas and electric). An innovative remediation and testing effort which Cinergy has initiated involves operating several electric-generating units with post Year 2000 dates. Cinergy's experience has been that those units have continued to operate without any material adverse result relating to a Year 2000 issue. Cinergy's progress to date ranges from approximately 90% regarding IT systems to approximately 75% regarding assessment of critical suppliers.

Cinergy has also reviewed its existing contingency and business continuity plans and modified them in light of the Year 2000 issue. Contingency planning to maintain and restore service in the event of natural and other disasters (including software and hardware-related problems) has been part of Cinergy's standard operation for many years, and Cinergy is working to leverage this experience in the review of existing plans to address Year 2000-related challenges. These reviews have assessed the potential for business disruption in various scenarios, including the most reasonably likely worst-case scenario, and to provide for key operational back-up, recovery, and restoration alternatives.

Cinergy cannot guarantee that third parties on whom it depends for essential goods and services (those where the interruption of the supply of such goods and services could lead to issues involving the safety of employees, customers, or the public, the continued reliable delivery of gas and/or electricity, and the ability to comply with applicable laws or regulations) will convert their mission-critical systems and processes in a timely manner. Failure or delay by any of these third parties could significantly disrupt business. However, to address this issue, Cinergy has established a supplier compliance program, and is working with its critical suppliers in an effort to minimize such risks.

In addition, Cinergy is coordinating its findings and other issues with other utilities and various industry groups via the Electric Power Research Institute Year 2000 Embedded Systems Project and the Year 2000 Readiness Assessment Program of the North American Electric Reliability Council ("NERC"), acting at the request of the DOE. The DOE has asked NERC to report on the integrity of the transmission system for North America and to coordinate and assess the preparation of the electric systems in North America for the Year 2000. NERC submitted its initial quarterly status report and coordination plan to the DOE in September 1998, and a second quarterly status report for the fourth quarter of 1998 was submitted on January 11, 1999.

Cinergy currently estimates that the total cost of assessment, remediation, testing, and upgrading its systems as a result of the Year 2000 effort is approximately $13 million. Approximately $11 million in expenses have been incurred through December 31, 1998, for external labor, hardware and software upgrades, and for Cinergy employees who are dedicated full-time to the Cinergy Year 2000 Readiness Program. The timing of these expenses may vary and is not necessarily indicative of readiness efforts or progress to date. Cinergy anticipates that a portion of its Year 2000 expenses will not be incremental costs, but rather, will represent the redeployment of existing IT resources. Since its formation, Cinergy has incurred, and will continue to incur, significant capital improvement costs related to planned system upgrades or replacements required in the normal course of business. These costs have not been accelerated as a result of the Year 2000 issue.

The above information is based on Cinergy's current best estimates, which were derived using numerous assumptions of future events, including the availability and future costs of certain technological and other resources, third-party modification actions, and other factors. Given the complexity of these issues and possible unidentified risks, actual results may vary materially from those anticipated and discussed above. Specific factors that might cause such differences include, among others, the ability to locate and correct all affected computer code, the timing and success of remedial efforts of third-party suppliers, and similar uncertainties.

The above information is a Year 2000 Readiness Disclosure pursuant to the Federal Year 2000 Information and Readiness Disclosure Act.

CAPITAL RESOURCES

The regulated businesses of Cinergy forecast that their need for external funds during the 1999 through 2003 period will primarily be for the refinancing of existing securities. It is currently expected that funds required to pursue the various non-regulated growth initiatives underway will be obtained primarily through short-term borrowing and the issuance of long-term debt and/or equity securities. (*This forecast reflects nominal dollars and assumptions as to the economy, capital markets, construction programs, legislative and regulatory actions, frequency and timing of rate increases, and other related factors, all or any of which may change significantly.*)

INTERNAL FUNDS

Currently, a substantial portion of Cinergy's revenues and corresponding cash flows are derived from cost-of-service regulated operations. Cinergy believes it is likely that the generation component of the electric utility industry will ultimately be deregulated. However, the timing and nature of the deregulation and restructuring of the industry is uncertain. In the interim, revenues provided by cost-of-service regulated operations are anticipated to continue as the primary source of funds for Cinergy. As a result of its low-cost position and market strategy, over the long term, Cinergy believes it will be successful in a more competitive environment. However, as the industry becomes more competitive, future cash flows from operations could be subject to a higher degree of volatility than under the present regulatory structure.

COMMON STOCK

During 1998, 1997, and 1996, Cinergy issued approximately 194,000; 66,000; and 15,000 new shares, respectively, of common stock pursuant to various stock-based employee plans. In addition, Cinergy purchased approximately 861,000 and 1.7 million shares on the open market to satisfy the majority of its 1998 and 1997 obligations, respectively, under these plans. Cinergy currently plans to continue using market purchases of common stock to satisfy the majority of its obligations under these plans; however, given its future capital requirements, it will continue to re-evaluate this decision. In the event Cinergy begins issuing shares of common stock to satisfy these obligations, it has authority under PUHCA to issue and sell through December 31, 2000, up to approximately 22 million additional shares of Cinergy common stock.

SHORT-TERM DEBT

Cinergy has authority under PUHCA to issue and sell, through December 31, 2002, short-term notes, long-term unsecured debentures, and commercial paper in an aggregate principal amount not to exceed $2 billion. The entire amount may be outstanding as short-term debt; however, long-term unsecured debentures outstanding may not exceed $400 million at any time. In connection with this authority, Cinergy has established committed and uncommitted lines of credit, of which $305 million remained unused and available at December 31, 1998.

Also at year-end, Global Resources had $100 million available under its revolving credit facility.

As of December 31, 1998, Cinergy's utility subsidiaries had regulatory authority to borrow up to $853 million. Pursuant to this authority, committed and uncommitted lines of credit have been established for CG&E and PSI of which, $310 million and $249 million, respectively, remained unused and available at December 31, 1998.

are accounted for using the mark-to-market method of accounting. Under the mark-to-market method of accounting, these trading transactions are reflected at fair value as "Energy risk management assets" and "Energy risk management liabilities". Changes in fair value, resulting in unrealized gains and losses, are reflected in "Fuel and purchased and exchanged power". Revenues and costs for all transactions are recorded gross in the Consolidated Statements of Income as contracts are settled. Revenues are recognized in "Operating Revenues–Electric" and costs are recorded in "Fuel and purchased and exchanged power".

Although physical transactions are entered with the intent and ability to settle the contract with company-owned generation, it is likely, that from time to time, due to numerous factors such as generating station outages, native load requirements, and weather, power used to settle the physical transactions will be required to be purchased on the open market. Depending on the factors giving rise to these open market purchases, the cost of such purchases could be in excess of the associated revenues. Losses such as this will be recognized as the power is delivered. In addition, physical contracts are subject to permanent impairment tests. At December 31, 1998, management has concluded that no physical contracts are impaired.

At December 31, 1998, the trading portfolio consisted of "Energy risk management assets" of $969 million and "Energy risk management liabilities" of $1,117 million. Prior to December 31, 1998, the transactions now included in the trading portfolio were accounted for and valued at the aggregate lower of cost or market. Under this method, only the net value of the entire portfolio was recorded as a liability in the Consolidated Balance Sheets. The net liability was not significant at December 31, 1997.

Contracts in the trading portfolio are valued at end-of-period market prices, utilizing factors such as closing exchange prices, broker and over-the-counter quotations, and model pricing. Model pricing considers time value and volatility factors underlying any options and contractual commitments. Management expects that some of these obligations, even though considered as trading contracts, will ultimately be settled from time to time by using company-owned generation. The cost of this generation is typically below the market prices at which the trading portfolio has been valued.

Because of the volatility currently experienced in the power markets, and the factors discussed above pertaining to both the physical and trading activities, volatility in future earnings (losses) from period to period in the ECBU is likely.

As a result of the acquisitions of Producers Energy Marketing, LLC ("ProEnergy") in 1998 and Greenwich Energy Partners in 1997, the ECBU also physically markets natural gas and trades natural gas and other energy-related products. All of these operations are accounted for on the mark-to-market method of accounting. Revenues and costs from physical marketing are recorded gross in the Consolidated Statements of Income as contracts are settled due to the exchanging of title to the natural gas throughout the earnings process. Realized revenues for 1998 were approximately $650 million. There were no such revenues prior to 1998. All non-physical transactions are recorded net in the Consolidated Statements of Income. Energy risk management assets and liabilities and gross margins from trading activities were not significant at December 31, 1998 and 1997 or for each of the three years ended December 31, 1998.

(d) FINANCIAL DERIVATIVES

Cinergy and its subsidiaries use derivative financial instruments to hedge exposures to foreign currency exchange rates, lower funding costs, and manage exposures to fluctuations in interest rates. Instruments used as hedges must be designated as a hedge at the inception of the contract and must be effective at reducing the risk associated with the exposure being hedged. Accordingly, changes in market values of designated hedge instruments must be highly correlated with changes in market values of the underlying hedged items at inception of the hedge and over the life of the hedge contract.

Cinergy and its subsidiaries utilize foreign exchange forward contracts and currency swaps to hedge certain of their net investments in foreign operations. Accordingly, any translation gains or losses related to the foreign exchange forward contracts or the principal exchange on the currency swaps are recorded in "Accumulated other comprehensive loss", which is a separate component of Common Stock Equity. Aggregate translation losses related to these instruments are reflected in Current Liabilities in the Consolidated Balance Sheets.

Interest rate swaps are accounted for under the accrual method. Accordingly, gains and losses based on any interest differential between fixed-rate and floating-rate interest amounts, calculated on agreed upon notional principal amounts, are recognized in the Consolidated Statements of Income as a component of "Interest" as realized over the life of the agreement.

(e) FEDERAL AND STATE INCOME TAXES

Under the provisions of Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes ("Statement 109"), deferred tax assets and liabilities are recognized for the income tax consequences of transactions treated differently for financial reporting and tax return purposes, measured on the basis of statutory tax rates. Investment tax credits utilized to reduce federal income taxes payable have been deferred for financial reporting purposes and are being amortized over the useful lives of the property which gave rise to such credits.

(f) REGULATION

Cinergy, its utility subsidiaries, and certain of its non-utility subsidiaries are subject to regulation by the Securities and Exchange Commission ("SEC") under the PUHCA. Cinergy's utility subsidiaries are also subject to regulation by the Federal Energy Regulatory Commission ("FERC") and the state utility commissions of Indiana, Kentucky, and Ohio.

The accounting policies of Cinergy's utility subsidiaries conform to the accounting requirements and ratemaking practices of these regulatory authorities and to GAAP, including the provisions of Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation ("Statement 71").

Under the provisions of Statement 71, regulatory assets represent probable future revenue associated with deferred costs to be recovered from customers through the ratemaking process. Certain criteria must be met for regulatory assets to be recorded and for the continued application of the provisions of Statement 71, including regulated rates designed to recover the specific utility's costs. Failure to satisfy the criteria in Statement 71 would eliminate the basis for recognition of regulatory assets.

Based on Cinergy's current regulatory orders and the regulatory environment in which it currently operates, the recognition of its regulatory assets as of December 31, 1998, is fully supported. However, in light of recent trends in customer-choice legislation, the potential for future losses resulting from discontinuance of Statement 71 does exist. The regulatory assets of CG&E and its utility subsidiaries and PSI as of December 31 are as follows:

	1998			1997		
(in millions)	**CG&E(1)**	**PSI**	**Cinergy**	CG&E(1)	PSI	Cinergy
Amounts due from customers–income taxes(2)	**$331**	**$ 26**	**$357**	$350	$ 24	$ 374
Post-in-service carrying costs and deferred operating expenses	**128**	**43**	**171**	135	44	179
Coal contract buyout costs	**–**	**99**	**99**	–	122	122
Deferred demand-side management ("DSM") costs	**40**	**43**	**83**	39	71	110
Phase-in deferred return and depreciation(3)	**75**	**–**	**75**	90	–	90
Deferred merger costs	**16**	**69**	**85**	16	74	90
Unamortized costs of reacquiring debt	**34**	**29**	**63**	36	30	66
Coal gasification services expenses	**–**	**19**	**19**	–	22	22
Other	**3**	**16**	**19**	2	22	24
Total	**$627**	**$344**	**$971**	$668	$409	$1 077

(1) Includes $11 million related to ULH&P (for DSM, unamortized costs of reacquiring debt and other regulatory assets) at both December 31, 1998, and 1997.

(2) Income tax provisions reflected in customer rates are regulated by the various regulatory commissions overseeing the regulated business operations of CG&E and its utility subsidiaries and PSI. In accordance with the provisions of Statement 71, Cinergy, CG&E, and PSI have recorded a net regulatory asset representing the probable recovery from customers of additional income taxes established under Statement 109. ULH&P has recorded a regulatory liability representing the probable repayment to customers of income taxes established under Statement 109 to the extent deferred income taxes recovered in rates exceed amounts payable in future periods.

(3) Pursuant to an order from the Public Utilities Commission of Ohio, CG&E is recovering this asset over a seven-year period which began in May 1995.

CG&E has previously received regulatory orders authorizing the recovery of $553 million of its total regulatory assets at December 31, 1998. PSI has previously received regulatory orders authorizing the recovery of $334 million of its total regulatory assets at December 31, 1998. The recovery of these assets is being reflected in rates charged to customers over a period ranging from 1 to 33 years. Both CG&E and PSI will request recovery of additional amounts in future proceedings. These proceedings, if any, may be related to the transition to customer choice in each applicable jurisdiction.

(g) UTILITY PLANT

Utility plant is stated at the original cost of construction, which includes an allowance for funds used during construction ("AFUDC") and a proportionate share of overhead costs. Construction overhead costs include salaries, payroll taxes, fringe benefits, and other expenses.

Substantially all utility plant is subject to the lien of each applicable company's first mortgage bond indenture.

(h) AFUDC

In accordance with the uniform systems of accounts prescribed by regulatory authorities, Cinergy's utility subsidiaries capitalize AFUDC, a non-cash income item, which is defined by the FERC as including "the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used." The borrowed funds component of AFUDC, which is recorded on a pre-tax basis was $7.5 million, $5.4 million, and $6.2 million for 1998, 1997, and 1996, respectively. AFUDC accrual rates are compounded semi-annually and averaged 6.6% in 1998, 6.3% in 1997, and 7.1% in 1996.

(i) DEPRECIATION AND MAINTENANCE

Provisions for depreciation are determined by using the straight-line method applied to the cost of depreciable plant in service. The rates are based on periodic studies of the estimated service lives and net cost of removal of the properties. The average depreciation rates for utility plant are:

	1998	1997	1996
CG&E and its utility subsidiaries			
Electric	**2.9%**	2.9%	2.9%
Gas	**2.9**	2.9	2.8
Common	**2.6**	3.0	3.0
PSI	**3.0**	3.0	3.0

For Cinergy's utility subsidiaries, maintenance and repairs of property units and replacements of minor items of property are charged to maintenance expense. The costs of replacements of property units are capitalized. The original cost of the property retired and the related costs of removal, less salvage recovered, are charged to accumulated depreciation.

(j) OPERATING REVENUES AND FUEL COSTS

Cinergy's utility subsidiaries record revenues for electric and gas service provided during the month, including sales unbilled at the end of each month. The costs of electricity and gas purchased and fuel used in electric production are expensed as recovered through revenues and any portion of these costs recoverable or refundable in future periods is deferred in either "Accounts receivable" or "Accounts payable" in the accompanying Balance Sheets. Indiana law subjects the recovery of fuel costs to a determination that such recovery will not result in earning a return in excess of that allowed by the Indiana Utility Regulatory Commission ("IURC") in its last general rate order.

(k) STATEMENTS OF CASH FLOWS

All temporary cash investments with maturities of three months or less, when acquired, are reported as cash equivalents. See Note 8(a)(i) for information concerning non-cash investing transactions and Note 18 for information concerning a non-cash financing transaction.

(l) TRANSLATION OF FOREIGN CURRENCY

All assets and liabilities reported in the balance sheets of foreign subsidiaries whose functional currency is other than the United States ("US") dollar are translated at year-end exchange rates; income and expense items are translated at the average exchange rate prevailing during the month the respective transactions occur. Translation gains and losses are recorded in "Accumulated other comprehensive loss", which is a separate component of common stock equity.

(m) ACCOUNTING CHANGES

Effective with the first quarter of 1998, Cinergy and its subsidiaries adopted the provisions of Statement of Financial Accounting Standards No. 130, Reporting Comprehensive Income ("Statement 130"). Statement 130 establishes standards for reporting and displaying comprehensive income and its components in a full set of general-purpose financial statements. Comprehensive income per Statement 130 is defined as "the change in equity of a business enterprise during a period from transactions and other events and circumstances from nonowner sources."

In December 1998, the Company implemented the provisions of the Emerging Issues Task Force Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." For a detailed discussion of the Company's energy trading and risk management activities, refer to Note 1(c).

2. COMMON STOCK

(a) CHANGES IN COMMON STOCK OUTSTANDING

The following table reflects the shares of Cinergy common stock reserved for issuance at December 31, 1998, and shares issued in 1998, 1997, and 1996 for the Company's stock-based plans.

	Shares Reserved at Dec. 31, 1998	Shares Issued 1998	1997	1996
1996 Long-term Incentive Compensation Plan ("LTIP")	**6 956 386**	**–**	43 614	–
Stock Option Plan	**4 366 186**	**192 591**	22 219	15 007
Performance Shares Plan ("PSP")	**771 301**	**–**	–	492
Employee Stock Purchase and Savings Plan	**1 931 378**	**1 006**	–	–
401(k) Savings Plans	**6 469 373**	**–**	–	–
Dividend Reinvestment and Stock Purchase Plan	**1 798 486**	**–**	–	–
Directors' Deferred Compensation Plan	**200 000**	**–**	–	–

Cinergy retired 44,981; 304; and 6,511 shares of common stock in 1998, 1997, and 1996, respectively, primarily representing shares tendered as payment for the exercise of previously granted stock options.

In June 1998, Cinergy issued 771,258 shares of new common stock to acquire ProEnergy.

(b) DIVIDEND RESTRICTIONS

Cinergy owns all of the common stock of CG&E and PSI. The ability of Cinergy to pay dividends to holders of its common stock is principally dependent on the ability of CG&E and PSI to pay common dividends to Cinergy. CG&E and PSI cannot purchase or otherwise acquire for value or pay dividends on their common stock if dividends are in arrears on their preferred stock. The amount of common stock dividends that each company can pay also may be limited by certain capitalization and earnings requirements. Currently, these requirements do not impact the ability of either company to pay dividends on common stock.

(c) STOCK-BASED COMPENSATION PLANS

Cinergy has four stock-based compensation plans: the LTIP, the Stock Option Plan, the PSP, and the Employee Stock Purchase and Savings Plan. Cinergy ceased accrual of incentive compensation under the PSP as of December 31, 1996, and on January 1, 1997, implemented the LTIP.

Cinergy accounts for its stock-based compensation plans under Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees, under which stock option-type awards are recorded at intrinsic value. For 1998, 1997, and 1996, compensation cost related to Cinergy's stock-based compensation plans, before income taxes, recognized in the Consolidated Statements of Income was $1 million, $6 million, and $2 million, respectively.

Net income and earnings per share ("EPS") for 1998, 1997, and 1996, assuming compensation cost for these plans had been determined at fair value, consistent with the provisions of Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation ("Statement 123"), would have been as follows:

(in millions, except per share amounts)		**1998**	1997	1996
Net income	– as reported	**$ 261**	$ 253	$ 335
	– pro forma	**$ 258**	$ 251	$ 334
EPS	– as reported	**$1.65**	$1.61	$2.00
	– pro forma	**$1.63**	$1.59	$1.99
Diluted EPS	– as reported	**$1.65**	$1.59	$1.99
	– pro forma	**$1.62**	$1.58	$1.99

In accordance with the provisions of Statement 123, in estimating the pro forma amounts, the fair value method of accounting was not applied to options granted prior to January 1, 1995. As a result, the pro forma effect on net income and EPS may not be representative of future years. In addition, the pro forma amounts reflect certain assumptions used in estimating fair values. These fair value assumptions are described under each applicable plan discussion below.

(i) LTIP

In 1996, Cinergy adopted the LTIP. Under this plan, certain key employees may be granted stock options and restricted shares of Cinergy common stock. Stock options are granted at the fair market value of the shares on the date of grant. These options vest in three years and expire in 10 years from the date of grant with the exception of participants that retire. Their shares become vested upon retirement. Participants' shares that are not vested become forfeited when the participant leaves Cinergy. Restricted shares are granted at the fair market value of the shares on the date of grant, discounted to reflect the inability to sell the shares during the three-year restriction period. In addition to the stock options and restricted shares, participants may earn additional shares if Cinergy's Total Shareholder Return ("TSR") exceeds that of the average annual median TSR of a selected peer group. Conversely, if Cinergy's TSR falls below that of the peer group, participants would lose some or all of the restricted shares. Dividends on any restricted stock awards and additional performance shares will be paid in shares of common stock during the payout period in the years 2000 to 2002. No stock-based awards were made under the LTIP prior to 1997. In 1998 and 1997, 41,129 and 425,938 performance-based restricted shares at a weighted average price of $34.69 and $29.95, respectively, were granted to certain key employees. As of December 31, 1998, Cinergy held a total of 442,941 performance-based restricted shares. The number of shares of common stock to be awarded under the LTIP is limited in the aggregate to 7,000,000 shares.

LTIP stock option activity for 1998 and 1997 is summarized as follows:

	1998		1997	
	Number	**Weighted Average Exercise Price**	Number	Weighted Average Exercise Price
Outstanding, beginning of year	**369 600**	**$33.60**	–	–
Granted	**471 400**	**38.19**	369 600	$33.60
Forfeited	**(68 000)**	**36.06**	–	–
Outstanding, end of year	**773 000**	**$36.19**	369 600	$33.60
Exercisable, end of year	**11 600**	**$36.05**	–	–
Weighted average fair value of options granted during the year	**$4.68**		$3.54	

The fair values of options granted were estimated as of the date of grant using a Black-Scholes option-pricing model. The weighted averages for the assumptions used in determining the fair values of options granted were as follows:

	1998	1997
Risk-free interest rate	**5.6%**	6.2%
Expected dividend yield	**4.8%**	5.4%
Expected lives	**5.6 yrs.**	5.4 yrs.
Expected common stock variance	**1.8%**	1.7%

The price range for the options outstanding under the LTIP at December 31, 1998, was $33.50–$38.59 and the weighted average contractual life was 8.7 years.

(ii) Stock Option Plan

The Cinergy Stock Option Plan is designed to align executive compensation with shareholder interests. Under the Stock Option Plan, incentive and non-qualified stock options, stock appreciation rights ("SARs"), and SARs in tandem with stock options may be granted to key employees, officers, and outside directors. The activity under this plan has predominantly consisted of the issuance of stock options. Options are granted at the fair market value of the shares on the date of grant. Options generally vest over five years at a rate of 20% per year and expire 10 years from the date of grant. The total number of shares of common stock available under the Stock Option Plan may not exceed 5,000,000 shares. No stock options may be granted under the plan after October 24, 2004.

Stock Option Plan activity for 1998, 1997, and 1996 is summarized as follows:

	1998		1997		1996	
	Number	**Weighted Average Exercise Price**	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
Outstanding, beginning of year	**2 954 475**	**$23.79**	3 334 637	$23.57	3 653 085	$22.47
Granted	**480 000**	**36.88**	–	–	220 000	29.75
Exercised	**(430 961)**	**21.62**	(380 162)	21.71	(513 448)	18.16
Forfeited	**(100 000)**	**26.92**	–	–	(25 000)	–
Outstanding, end of year	**2 903 514**	**$26.17**	2 954 475	$23.79	3 334 637	$23.57
Exercisable, end of year	**1 535 514**	**$23.61**	1 389 975	$22.58	1 131 637	$21.34
Weighted average fair value of options granted during the year		**$4.53**		$ –		$3.07

The fair values of options granted were estimated as of the date of grant using a Black-Scholes option-pricing model. The weighted averages for the assumptions used in determining the fair values of options granted in 1998 and 1996 (no options were granted during 1997), were as follows:

	1998	1996
Risk-free interest rate	**5.6%**	6.3%
Expected dividend yield	**4.8%**	5.8%
Expected lives	**6.5 yrs.**	6.5 yrs.
Expected common stock variance	**2.0%**	1.8%

Price ranges, along with certain other information, for options outstanding under the Stock Option Plan at December 31, 1998, are as follows:

	Outstanding			**Exercisable**	
Exercise Price Range	**Number**	**Weighted Average Exercise Price**	**Weighted Average Contractual Life**	**Number**	**Weighted Average Exercise Price**
$13.15–$17.35	**99 638**	**$15.35**	**1.1 yrs.**	**99 638**	**$15.35**
$22.88–$25.19	**2 034 213**	**$23.61**	**6.0 yrs.**	**1 286 213**	**$23.73**
$28.44–$36.88	**769 663**	**$29.15**	**7.1 yrs.**	**149 663**	**$34.00**

(iii) PSP

Cinergy's PSP is a long-term incentive plan developed to reward officers and other key employees for achieving corporate and individual goals. Under the PSP, participants are granted contingent shares of common stock. A percentage of these contingent shares is earned with respect to each participant based on the level of goal attainment at the completion of a performance cycle. Performance cycles consist of overlapping four-year periods, beginning every two years. Awards earned under the PSP are paid in two installments: one-half of the award is paid in the year immediately following the end of the performance cycle and one-half of the award is paid in the subsequent year. The most recently commenced four-year performance cycle under the PSP began January 1, 1996, and was scheduled to end December 31, 1999. As previously discussed, Cinergy implemented the LTIP effective January 1, 1997, and ceased accrual of incentive compensation under the PSP as of December 31, 1996. The total number of shares of common stock available under this plan may not exceed 800,000 shares. Final payouts for performance cycle four that began January 1, 1992, were made in 1997. Final payouts for cycles five and six, which began in January 1994 and January 1996, respectively, will be made in 1999.

The following table provides certain information regarding contingent shares granted under the PSP for the performance cycle which began January 1, 1996:

	1996
Number of contingent shares granted	166 280
Fair value at date of grant (dollars in thousands)	$3 508
Weighted average per share amounts	$24.47

The fair values of contingent shares and the weighted average per share amounts are measured at the market price of a share of common stock as if it were vested and issued on the date of grant, adjusted for expected forfeitures and the estimated present value of dividends foregone during the related performance cycle.

(iv) Employee Stock Purchase and Savings Plan

Cinergy's Employee Stock Purchase and Savings Plan allows essentially all full-time, regular employees to purchase shares of common stock pursuant to a stock option feature. Under the Employee Stock Purchase and Savings Plan, after-tax funds are withheld from a participant's compensation during a 26-month offering period and are deposited in an interest-bearing account. At the end of the offering period, participants may apply amounts deposited in the account, plus interest, toward the purchase of shares of common stock at a purchase price equal to the fair market value of a share of common stock on the first date of the offering period, less 5%. Any funds not applied toward the purchase of shares are returned to the participant. A participant may elect to terminate participation in the plan at any time. Participation also will terminate if the participant's employment with Cinergy ceases. Upon termination of participation, all funds, including interest, are returned to the participant without penalty. The current offering period began January 1, 1997, and ended February 28, 1999. The purchase price for all shares under this offering is $31.83. The previous offering period ended December 31, 1996, with a purchase price of $21.73. The total number of shares of common stock available under the Employee Stock Purchase and Savings Plan may not exceed 2,000,000.

Employee Stock Purchase and Savings Plan activity for 1998, 1997, and 1996 is summarized as follows:

	1998		1997		1996	
	Number	**Weighted Average Exercise Price**	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
Outstanding, beginning of year	**326 367**	**$31.83**	–	$ –	490 787	$21.73
Granted	**–**	**31.83**	338 947	31.83	–	–
Exercised	**(3 342)**	**31.83**	(95)	31.83	(414 284)	21.73
Forfeited	**(25 651)**	**31.83**	(12 485)	31.83	(76 503)	21.73
Outstanding, end of year	**297 374**	**$31.83**	326 367	$31.83	–	$ –
Weighted average fair value of options granted during the year	**$ –**		$3.08		$ –	

The fair values of options granted were estimated as of the date of grant using a Black-Scholes option-pricing model. The weighted averages for the assumptions used in determining the fair values of options granted were as follows:

	1997
Risk-free interest rate	5.9%
Expected dividend yield	5.4%
Expected lives	2.0 yrs.
Expected common stock variance	1.6%

3. PREFERRED STOCK OF SUBSIDIARIES

(a) SCHEDULE OF CUMULATIVE PREFERRED STOCK

(dollars in thousands)		December 31	1998	1997
CG&E	Not subject to mandatory redemption	Par value $100 per share–authorized 6,000,000 shares–outstanding		
		4% Series 169,834 shares in 1998 and 1997	**$16 983**	$ 16 983
		4¾% Series 37,335 shares in 1998 and 38,096 shares in 1997	**3 734**	3 810
		Total	**20 717**	20 793
PSI	Not subject to mandatory redemption	Par value $25 per share–authorized 5,000,000 shares–outstanding		
		4.32% Series 169,161 shares in 1998 and 1997	**4 229**	4 229
		4.16% Series 148,763 shares in 1998 and 1997	**3 719**	3 719
		7.44% Series 3,408,712 shares in 1997	**–**	85 218
		Par value $100 per share–authorized 5,000,000 shares–outstanding		
		3½% Series 39,748 shares in 1998 and 40,302 shares in 1997	**3 975**	4 030
		6⅞% Series 600,000 shares in 1998 and 1997	**60 000**	60 000
		Total	**71 923**	157 196
Total–Cinergy				
	Total not subject to mandatory redemption		**$92 640**	$177 989

(b) CHANGES IN CUMULATIVE PREFERRED STOCK OUTSTANDING

(dollars in thousands)					Shares Retired	Par Value
1998 Not Subject to Mandatory Redemption	**Par value**	**$100 per share**				
	CG&E	**4¾%**	**Series**		**761**	**$ 76**
	PSI	**3½%**	**Series**		**554**	**55**
	Par value	**$25 per share**				
	PSI	**7.44%**	**Series**		**3 408 712**	**85 218**
1997 Not Subject to Mandatory Redemption	Par value	$100 per share				
	CG&E	4%	Series		1	$ 1
		4¾%	Series		3 525	352
	PSI	7.15%	Series		158 640	15 864
		3½%	Series		265	26
	Par value	$25 per share				
	PSI	4.32%	Series		1	–
1996 Not Subject to Mandatory Redemption	Par value	$100 per share				
	CG&E	4%	Series		100 165	$10 016
		4¾%	Series		88 379	8 838
	PSI	3½%	Series		276	29
	Par value	$25 per share				
	PSI	7.44%	Series		591 288	14 782
Subject to Mandatory Redemption	Par value	$100 per share				
	CG&E	7⅞%	Series		800 000	$80 000
		7⅜%	Series		800 000	80 000

During the third quarter of 1996, Cinergy commenced an offer to purchase any and all outstanding shares of preferred stock of CG&E. Cinergy purchased 1,788,544 shares of preferred stock, made a capital contribution to CG&E of all the shares, and CG&E subsequently canceled the shares. The cost of reacquiring the preferred stock, totaling $18 million, represents the difference between the par value of the preferred stock purchased and the price paid (including fees paid to tender agents) and is reflected as a charge to "Retained Earnings" in the Consolidated Statements of Changes in Common Stock Equity and as a deduction from "Net Income" in the Consolidated Statements of Income for purposes of determining net income and EPS applicable to common stock.

4. LONG-TERM DEBT

(a) SCHEDULE OF LONG-TERM DEBT (EXCLUDING AMOUNTS REFLECTED IN CURRENT LIABILITIES)

(dollars in thousands)			December 31	1998	1997
Cinergy	Other Long-term Debt	6.53%	Debentures due December 16, 2008	**$ 200 000**	$ –
	Unamortized Discount			**(87)**	–
			Total–Cinergy	**199 913**	–
Global Resources					
	Other Long-term Debt	6.20%	Debentures due November 3, 2008	**150 000**	–
		Other		**9 443**	–
			Total Other Long-term Debt	**159 443**	–
	Unamortized Premium and Discount–Net			**(326)**	–
			Total–Global Resources	**159 117**	–
CG&E and Subsidiaries					
CG&E	First Mortgage Bonds	5.80%	Series due February 15, 1999	**–**	110 000
		7⅜%	Series due May 1, 1999	**–**	50 000
		7⅜%	Series due November 1, 2001	**–**	60 000
		7¼%	Series due September 1, 2002	**100 000**	100 000
		6.45%	Series due February 15, 2004	**110 000**	110 000
		8½%	Series due September 1, 2022	**–**	100 000
		7.20%	Series due October 1, 2023	**300 000**	300 000
		5.45%	Series due January 1, 2024 (Pollution Control)	**46 700**	46 700
		5½%	Series due January 1, 2024 (Pollution Control)	**48 000**	48 000
			Total First Mortgage Bonds	**604 700**	924 700
	Pollution Control Notes	6.50%	due November 15, 2022	**12 721**	12 721
	Other Long-term Debt		Variable rate Liquid Asset Notes with Coupon Exchange ("LANCEs") due October 1, 2007 *(Redeemable at the option of CG&E)* *(Variable interest rate sets at 6.50% commencing October 1, 1999)* *(Holders of not less than 66⅔% in an aggregate principal amount of the LANCEs have the one-time right to convert from the 6.50% fixed rate to a London Interbank Offered Rate ("LIBOR")-based floating rate at any interest rate payment date between October 1, 1999 and October 1, 2002)*	**100 000**	100 000
		6.40%	Debentures due April 1, 2008	**100 000**	–
		6.90%	Debentures due June 1, 2025 *(Redeemable at the option of the holders on June 1, 2005)*	**150 000**	150 000
		8.28%	Junior Subordinated Debentures due July 1, 2025	**100 000**	100 000
		6.35%	Debentures due June 15, 2038	**100 000**	–
			Total Other Long-term Debt	**550 000**	350 000
	Unamortized Premium and Discount–Net			**(3 396)**	(8 860)
			Total–CG&E	**1 164 025**	1 278 561

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(a) SCHEDULE OF LONG-TERM DEBT (EXCLUDING AMOUNTS REFLECTED IN CURRENT LIABILITIES)–CONTINUED

(dollars in thousands)			December 31	1998	1997
ULH&P	First Mortgage Bonds	6½%	Series due August 1, 1999	–	20 000
		8%	Series due October 1, 2003	–	10 000
			Total First Mortgage Bonds	–	30 000
	Other Long-term Debt	6.11%	Debentures due December 8, 2003	**20 000**	–
		6.50%	Debentures due April 30, 2008	**20 000**	–
		7.65%	Debentures due July 15, 2025	**15 000**	15 000
			Total Other Long-term Debt	**55 000**	15 000
	Unamortized Premium and Discount–Net			**(447)**	(329)
			Total–ULH&P	**54 553**	44 671
Lawrenceburg Gas Company	First Mortgage Bonds	9¾%	Series due October 1, 2001	**1 200**	1 200
			Total–CG&E and Subsidiaries	**1 219 778**	1 324 432
PSI	First Mortgage Bonds	Series S,	7%, due January 1, 2002	–	26 429
		Series Y,	7⅝%, due January 1, 2007	–	24 140
		Series QQ,	8¼%, due June 15, 2013 (Pollution Control)	–	23 000
		Series TT,	7⅜%, due March 15, 2012 (Pollution Control)	**10 000**	10 000
		Series UU,	7½%, due March 15, 2015 (Pollution Control)	**14 250**	14 250
		Series YY,	5.60%, due February 15, 2023 (Pollution Control)	**29 945**	29 945
		Series ZZ,	5¾%, due February 15, 2028 (Pollution Control)	**50 000**	50 000
		Series AAA,	7⅛%, due February 1, 2024	**50 000**	50 000
		Total First Mortgage Bonds		**154 195**	227 764
	Secured Medium-term Notes	Series A,	7.15% to 8.88%, due January 6, 1999 to June 1, 2022	**284 000**	290 000
		Series B,	5.22% to 8.26%, due September 19, 2000 to August 22, 2022 *(Series A and B, 7.83% weighted average interest rate and 14 year weighted average remaining life)*	**195 000**	195 000
		Total Secured Medium-term Notes		**479 000**	485 000
	Other Long-term Debt	Series 1994A Promissory Note, non-interest bearing, due January 3, 2001		**19 825**	19 825
		6.35%	Debentures due November 15, 2006 *(Redeemable in whole or in part at the option of the holders on November 15, 2000)*	**100 000**	100 000
		6.00%	Debentures due December 14, 2016 *(Redeemable in whole or in part at the option of the holders on December 14, 2001)*	**50 000**	–
		6.50%	Synthetic Putable Yield Securities due August 1, 2026	**50 000**	–
		7.25%	Junior Maturing Principal Securities due March 15, 2028	**100 000**	–
		6.00%	Rural Utilities Service ("RUS") Obligation payable in annual installments	**85 620**	–
		Total Other Long-term Debt		**405 445**	119 825
	Unamortized Premium and Discount–Net			**(12 981)**	(6 119)
		Total–PSI		**1 025 659**	826 470
		Total–Cinergy and Subsidiaries		**$2 604 467**	$2 150 902
Total–Cinergy Corp. Consolidated					
		First Mortgage Bonds		**$ 760 095**	$1 183 664
		Secured Medium-term Notes		**479 000**	485 000
		Pollution Control Notes		**12 721**	12 721
		Other Long-term Debt		**1 369 888**	484 825
		Unamortized Premium and Discount–Net		**(17 237)**	(15 308)
		Total Long-term Debt		**$2 604 467**	$2 150 902

(b) MANDATORY REDEMPTION AND OTHER REQUIREMENTS

Long-term debt maturities for the next five years (excluding callable and/or putable debt) are as follows:

(in millions)	Mandatory Redemptions
1999	$137
2000	32
2001	40
2002	124
2003	77
	$410

Maintenance and replacement fund provisions contained in PSI's first mortgage bond indenture require cash payments, bond retirements, or pledges of unfunded property additions each year based on an amount related to PSI's net revenues.

5. NOTES PAYABLE AND OTHER SHORT-TERM OBLIGATIONS

Notes payable and other short-term obligations and weighted average interest rates were as follows:

	December 31, 1998			December 31, 1997		
(in millions)	**Established Lines**	**Outstanding**	**Weighted Average Rate**	Established Lines	Outstanding	Weighted Average Rate
Cinergy						
Committed lines						
Acquisition line	**$ 160**	**$160**	**5.61%**	$ 350	$ 350	6.25%
Revolving line	**600**	**245**	**5.68**	400	89	6.27
Commercial paper	**–**	**50**	**5.78**	–	161	6.19
Uncommitted lines	**45**	**50***	**5.84**	–	–	–
Utility subsidiaries						
Committed lines	**300**	**–**	**–**	270	30	6.09
Uncommitted lines	**410**	**95**	**5.90**	360	206	6.19
Pollution control notes	**267**	**267**	**3.83**	244	244	4.08
Non-utility subsidiary	**138**	**37**	**13.11**	115	34	7.20
Total	**$1 920**	**$904**	**5.20%**	$1 739	$1 114	5.78%

* Excess over Established Line represents amount sold by dealers to other investors.

Cinergy and its utility subsidiaries have arranged committed lines (''unsecured lines of credit''), as well as uncommitted lines (short-term borrowings on an ''as offered'' basis) with various banks. The established committed lines include $106 million designated as backup for certain of the uncommitted lines at December 31, 1998. Further, the committed lines are maintained by commitment fees, which were immaterial during the 1996 through 1998 period.

Cinergy's committed lines are comprised of an acquisition line and a revolving line. The established revolving line also provides credit support for Cinergy's commercial paper program, which is limited to a maximum outstanding principal amount of $400 million. The proceeds from the commercial paper sales were used for general corporate purposes. Proceeds from the sale of Cinergy's 6.53% debentures were used to reduce the acquisition line to the year-end level of $160 million.

Global Resources established a $100 million revolving credit agreement in 1998, which is due to expire in March 1999.

CG&E and PSI also have the capacity to issue commercial paper that must be supported by committed lines of the respective company. Neither CG&E nor PSI issued commercial paper in 1998 or 1997.

Amounts outstanding under the committed lines for Cinergy, the utility subsidiaries, and the non-utility subsidiary would become immediately due upon an event of default, which includes non-payment, default under other agreements governing company indebtedness, bankruptcy, or insolvency. Certain of the uncommitted lines have similar default provisions.

Both CG&E and PSI have issued variable rate pollution control notes. Holders of these pollution control notes have the right to put their notes on any business day. Accordingly, these issuances are reflected in the Consolidated Balance Sheets as ''Notes payable and other short-term obligations.''

6. SALE OF ACCOUNTS RECEIVABLE

In 1996, CG&E, PSI, and ULH&P entered into an agreement to sell, on a revolving basis, undivided percentage interests in certain of their accounts receivable up to an aggregate maximum of $350 million. As of December 31, 1998, $253 million, net of reserves, has been sold. The Consolidated Balance Sheets are net of the amounts sold at December 31, 1998 and 1997.

7. LEASES

(a) OPERATING LEASES

Cinergy and its subsidiaries have entered into operating lease agreements covering various facilities and properties, including computer, communications, and transportation equipment and office space. Total rental payments on operating leases were $42 million for 1998, $36 million for 1997, and $31 million for 1996.

Future minimum lease payments required under operating leases with remaining, non-cancelable lease terms in excess of one year as of December 31, 1998, are as follows:

(in millions)	Minimum Payments
1999	$ 38
2000	31
2001	22
2002	14
2003	10
After 2003	36
Total	$151

(b) CAPITAL LEASE

In 1996, CG&E entered into a sale-leaseback agreement for certain equipment at Woodsdale Generating Station. The lease is a capital lease with an initial lease term of five years. At the end of the initial lease term, the lease may be renewed at mutually agreed upon terms or the equipment may be repurchased by CG&E at the original sale amount. The monthly lease payment, comprised of interest only, is based on the applicable LIBOR and, therefore, the capital lease obligation will not be amortized over the initial lease term. The property under the capital lease is depreciated at the same rate as if the property were still owned by CG&E. CG&E recorded a capital lease obligation, included in Non-Current Liabilities, of $22 million, which represented the net book value of the equipment at the beginning of the lease.

8. FINANCIAL INSTRUMENTS

(a) FINANCIAL DERIVATIVES

Cinergy has entered into financial derivative contracts for the purposes described below.

(i) Foreign Exchange Hedging Activity

Cinergy has hedged its pound sterling denominated investment in Midlands through a currency swap. The currency swap requires Cinergy to exchange a series of pound sterling denominated cash flows for a series of dollar denominated cash flows based on Cinergy's initial exchange of $500 million for 330 million pounds sterling. Cinergy has also hedged certain of its net investments in the Czech Republic utilizing foreign exchange forward contracts. Translation gains and losses related to the forward foreign exchange contracts and the principal exchange on the currency swap have primarily been recorded in "Accumulated other comprehensive loss", which is reported as a separate component of common stock equity in the Consolidated Financial Statements. At December 31, 1998, aggregate translation losses of approximately $49 million, related to the foreign exchange forward contracts and the principal exchange of the currency swap, have been reflected in Current Liabilities in the Consolidated Balance Sheets. At December 31, 1998, the fair value of these contracts was approximately $(66) million.

(ii) Interest Rate Risk Management

Cinergy and its subsidiaries enter into interest rate swaps to lower funding costs and manage exposures to fluctuations in interest rates. Under these interest rate swaps, Cinergy and its subsidiaries agree with counterparties to exchange, at specified intervals, the difference between fixed-rate and floating-rate interest amounts calculated on an agreed notional principal amount. Cinergy has effectively fixed the interest rate applicable to the pound sterling denominated leg of its currency swap for its remaining term through an interest rate swap agreement. This contract requires Cinergy to pay a fixed rate and receive a floating rate. This contract has a total notional principal amount of 280 million pounds sterling. Translation gains and losses related to Cinergy's interest obligation, which is payable in pounds sterling, are recognized as a component of interest expense in the Consolidated Statements of Income. The fair value of this interest rate swap agreement at December 31, 1998, was approximately $(19) million.

At December 31, 1998, CG&E had an interest rate swap agreement outstanding related to its sale of accounts receivable. The contract has a notional amount of $100 million and requires CG&E to pay a fixed rate and receive a floating rate. PSI had three interest rate swap agreements outstanding with notional amounts of $100 million each. One contract, with two years remaining of a four-year term, requires PSI to pay a floating rate and receive a fixed rate. The other two contracts, with six-month terms, require PSI to pay a fixed rate and receive a floating rate. The floating rate is based on applicable LIBOR. At December 31, 1998, the fair values of these interest rate swap agreements were not significant.

(b) FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

The estimated fair values of Cinergy's and its subsidiaries' other financial instruments were as follows (this information does not purport to be a valuation of the companies as a whole):

	December 31, 1998		December 31, 1997	
(in millions)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial Instruments				
First mortgage bonds and other long-term debt (includes amounts reflected as long-term debt due within one year)	**$2 740**	**$2 934**	$2 236	$2 337

The following methods and assumptions were used to estimate the fair values of each major class of financial instruments:

Cash and Temporary Cash Investments, Restricted Deposits, and Notes Payable and Other Short-Term Obligations Due to the short period to maturity, the carrying amounts reflected on the Consolidated Balance Sheets approximate fair values.

First Mortgage Bonds and Other Long-Term Debt The fair values of long-term debt issues were estimated based on the latest quoted market prices or, if not listed on the New York Stock Exchange, on the present value of future cash flows. The discount rates used approximate the incremental borrowing costs for similar instruments.

(c) CONCENTRATIONS OF CREDIT RISK

Credit risk represents the risk of loss which would occur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations with the Company. Concentrations of credit risk relate to significant customers or counterparties, or groups of customers or counterparties, possessing similar economic or industry characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in economic or other conditions.

Concentration of credit risk with respect to the ESBU's trade accounts receivable from electric and gas retail customers is limited due to the large number of customers and diversified customer base of residential, commercial, and industrial customers. Contracts within the physical power portfolio of the ECBU's power marketing and trading operations are primarily with traditional electric cooperatives and municipalities and other investor-owned utilities.

Contracts within the trading portfolio of the power marketing and trading operations are primarily with power marketers and other investor-owned utilities. As of December 31, 1998, approximately 73% of the activity within the trading portfolio represents commitments with 10 counterparties. The majority of these contracts are for terms of one year or less. As a result of the extreme volatility experienced in the Midwest power markets during 1998, several new entrants into the market began experiencing financial difficulties and failed to perform their contractual obligations. As a result, the bad debt provisions of approximately $13 million with respect to settled transactions were recorded during the year. Counterparty credit exposure within the power trading portfolio is routinely factored into the mark-to-market valuation. At December 31, 1998, credit exposure within the power trading portfolio is not believed to be significant. Prior to 1998, credit exposure due to nonperformance by counterparties was not significant. As the competitive electric power market continues to develop, counterparties will increasingly include new market entrants, such as other power marketers, brokers, and commodity traders. This increased level of new market entrants, as well as competitive pressures on existing market participants, could increase the ECBU's exposure to credit risk with respect to its power marketing and trading operation. As of December 31, 1998, approximately 37% of the activity within the ECBU's physical gas marketing and trading portfolio represents commitments with 10 counterparties. Credit risk losses related to the ECBU's gas and other commodity physical and trading operations have not been significant. Based on the types of counterparties and customers with which transactions are executed, credit exposure within the gas and other commodity trading portfolios is not believed to be significant.

Potential exposure to credit risk also exists from Cinergy's use of financial derivatives such as currency swaps, foreign exchange forward contracts, and interest rate swaps. Because these financial instruments are transacted only with highly rated financial institutions, Cinergy does not anticipate nonperformance by any of the counterparties.

9. PENSION AND OTHER POSTRETIREMENT BENEFITS

Cinergy's defined benefit pension plans cover substantially all US employees meeting certain minimum age and service requirements. Plan benefits are determined under a final average pay formula with consideration of years of participation, age at retirement, and the applicable average Social Security wage base or benefit amount.

Effective January 1, 1998, Cinergy reconfigured its defined benefit pension plans. The reconfigured plans cover the same employees as the previous plans and established a uniform final average pay formula for all employees. The reconfiguration of the pension plans did not have a significant impact on the Company's financial condition or results of operations.

Cinergy's pension plan funding policy for US employees is to contribute annually an amount which is not less than the minimum amount required by the Employee Retirement Income Security Act of 1974 and not more than the maximum amount deductible for income tax purposes. The pension plans' assets consist of investments in equity and fixed income securities.

Cinergy provides certain health care and life insurance benefits to retired US employees and their eligible dependents, if the retiree has met minimum age and service requirements. The health care benefits include medical coverage, dental coverage, and prescription drugs and are subject to certain limitations, such as deductibles and co-payments. Prior to January 1, 1997, CG&E and PSI employees were covered under separate plans. Effective January 1, 1997, all Cinergy active US employees are eligible to receive essentially the same postretirement health care benefits. Certain classes of employees, based on age, as well as all retirees, have been grandfathered under benefit provisions in place prior to January 1, 1997. CG&E does not pre-fund its obligations for these postretirement benefits. PSI is pre-funding its obligations as authorized by the IURC.

Cinergy's benefit plans' cost for 1998, 1997, and 1996 included the following components:

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**1998**	1997	1996	**1998**	1997	1996
Service cost	**$21.8**	$19.8	$21.2	**$ 4.1**	$ 3.1	$ 5.8
Interest cost	**71.6**	67.8	61.6	**16.1**	16.3	18.7
Expected return on plans' assets	**(66.9)**	(62.8)	(61.2)	**–**	–	–
Amortization of transition obligation/(asset)	**(1.3)**	(1.3)	(1.3)	**5.0**	5.0	8.4
Amortization of prior service cost	**4.4**	4.4	4.5	**–**	–	–
Recognized actuarial loss	**–**	(.3)	(.3)	**.4**	.3	.3
Net periodic benefit cost	**$29.6**	$27.6	$24.5	**$25.6**	$24.7	$33.2

During 1996, CG&E and its subsidiaries (including ULH&P) recognized an additional $31 million of accrued pension cost in accordance with Statement of Financial Accounting Standards No. 88, Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits ("Statement 88"). Additionally, during 1996, PSI recognized an additional $30 million of accrued pension cost in accordance with Statement 88. These amounts represent the costs associated with additional benefits extended in connection with voluntary workforce reduction programs.

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**1998**	1997	1996	**1998**	1997	1996
Actuarial Assumptions:						
Discount rate	**6.75%**	7.5%	8.0%	**6.75%**	7.5%	8.0%
Rate of future compensation increase	**3.75%**	4.5%	5.0%	**n/a**	n/a	n/a
Rate of return on plans' assets	**9.00%**	9.0%	9.0%	**n/a**	n/a	n/a

For measurement purposes, a 7% annual rate of increase in the per capita cost of covered health care benefits was assumed for 1999. The rate was assumed to decrease gradually to 5% for 2004 and remain at that level thereafter.

The following table provides a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ended December 31, 1998, and a statement of the funded status as of December 31 of both years.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**1998**	1997	**1998**	1997
Change in benefit obligation				
Benefit obligation at beginning of period	**$ 960.3**	$ 877.4	**$ 221.9**	$ 211.0
Service cost	**21.8**	19.8	**4.1**	3.1
Interest cost	**71.6**	67.8	**16.1**	16.3
Amendments	**1.0**	–	**–**	–
Actuarial gain	**53.6**	65.4	**17.4**	3.7
Benefits paid	**(56.2)**	(70.1)	**(13.0)**	(12.2)
Benefit obligation at end of period	**1 052.1**	960.3	**246.5**	221.9
Change in plan assets				
Fair value of plan assets at beginning of period	**888.1**	764.1	**–**	–
Actual return on plan assets	**9.9**	186.6	**–**	–
Employer contribution	**23.5**	7.5	**13.0**	12.2
Benefits paid	**(56.2)**	(70.1)	**(13.0)**	(12.2)
Fair value of plan assets at end of period	**865.3**	888.1	**–**	–
Funded status	**(186.8)**	(72.2)	**(246.5)**	(221.9)
Unrecognized prior service cost	**43.3**	46.6	**–**	–
Unrecognized net actuarial (gain)/loss	**(24.1)**	(134.6)	**40.3**	22.6
Unrecognized net plan assets	**(7.1)**	(8.5)	**65.8**	70.9
Accrued benefit cost at December 31	**$(174.7)**	$(168.7)	**$(140.4)**	$(128.4)

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Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

(in millions)	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total of service and interest cost components	$ 2.8	$ (2.4)
Effect on postretirement benefit obligation	26.7	(23.7)

In addition, the Company sponsors non-qualified pension plans that cover officers, certain other key employees, and non-employee directors. Cinergy's non-qualified pension plans are not currently funded. Cinergy may begin to fund certain of these plans through a rabbi trust in 1999.

The pension benefit obligations and pension expense under these plans were:

(in millions)	**1998**	1997
Pension benefit obligations	**$31.4**	$24.6
Pension expense	**4.5**	4.1

10. INVESTMENTS IN UNCONSOLIDATED SUBSIDIARIES

Except for Cinergy's 50% investment in Avon Energy Partners Holdings ("Avon Energy"), which holds Midlands Electricity plc ("Midlands"), investments in unconsolidated subsidiaries are not significant.

Summarized financial information for Avon Energy is as follows:

(in millions)	December 31 1998	1997
Assets		
Current assets	**$ 568**	$ 676
Property, plant, and equipment	**1 974**	1 890
Other assets	**2 111**	2 148
Total assets	**$4 653**	$4 714
Liabilities and Shareholders' Equity		
Other liabilities	**$1 639**	$2 175
Long-term debt	**1 896**	1 533
Total common shareholders' equity	**1 118**	1 006
Total liabilities and shareholders' equity	**$4 653**	$4 714
Cinergy's investments in unconsolidated subsidiaries:		
Avon Energy	**$ 556**	$ 505
Other companies	**18**	33
Total investments in unconsolidated subsidiaries	**$ 574**	$ 538

(in millions)	December 31 1998	1997	1996
Operating revenues	**$2 406**	$2 176	$1 132
Net income before extraordinary item	**$ 105**	$ 127	$ 50
Extraordinary item–windfall profits tax (less applicable income taxes of $0)	**$ –**	$ (219)	$ –
Net income (loss)	**$ 105**	$ (92)	$ 50
Cinergy's equity in earnings of Avon Energy before extraordinary item	**$ 57**	$ 63	$ 25
Cinergy's equity in extraordinary item	**–**	(109)	–
Cinergy's equity in earnings of:			
Avon Energy	**$ 57**	$ (46)	$ 25
Other companies	**(6)**	(3)	–
Total equity in the earnings of unconsolidated subsidiaries	**$ 51**	$ (49)	$ 25

During 1997 Cinergy received $25 million of dividends from Avon Energy.

In November 1998, Midlands announced the sale of its electric supply business to National Power PLC ("National Power"). National Power will acquire all of the assets of Midlands' supply business and assume its liabilities, including obligations under all Midlands power purchase agreements for approximately $300 million, plus an adjustment for working capital at financial closing. The sale is subject to approval by Great Britain's Department of Trade and Industry and Office of Electricity Regulation and is expected in the second quarter of 1999. Midlands will continue to own and operate its distribution business as well as interests in various generation stations.

11. INCOME TAXES

The significant components of Cinergy's net deferred income tax liability at December 31, 1998, and 1997, are as follows:

(in millions)	1998	1997
Deferred Income Tax Liability		
Utility plant	**$1 104.2**	$1 076.8
Unamortized costs of reacquiring debt	**21.2**	24.4
Deferred operating expenses and carrying costs	**73.3**	75.0
Amounts due from customers–income taxes	**121.7**	129.4
Deferred DSM costs	**22.8**	31.7
Investments in unconsolidated subsidiaries	**–**	55.0
Other	**51.0**	47.9
Total deferred income tax liability	**1 394.2**	1 440.2
Deferred Income Tax Asset		
Unamortized investment tax credits	**57.0**	60.5
Accrued pension and other benefit costs	**89.0**	63.3
Net energy risk management liabilities	**54.5**	–
RUS obligations	**29.5**	3.8
Investments in unconsolidated subsidiaries	**13.1**	–
Other	**60.0**	64.1
Total deferred income tax asset	**303.1**	191.7
Net Deferred Income Tax Liability	**$1 091.1**	$1 248.5

Cinergy and its subsidiaries will participate in the filing of a consolidated federal income tax return for the year ended December 31, 1998. The current tax liability is allocated among the members of the group pursuant to a tax sharing agreement consistent with Rule 45(c) of the PUHCA.

A summary of federal and state income taxes charged (credited) to income and the allocation of such amounts is as follows:

(in millions)	1998	1997	1996
Current Income Taxes			
Federal	**$209.0**	$133.3	$143.4
State	**16.9**	12.1	7.5
Total current income taxes	**225.9**	145.4	150.9
Deferred Income Taxes			
Federal			
Depreciation and other utility plant-related items	**25.3**	26.7	61.6
DSM costs	**(8.8)**	(8.5)	(1.9)
Pension and other benefit costs	**(3.3)**	.9	(28.2)
Litigation settlement	**–**	1.8	26.2
RUS obligations	**(22.5)**	(3.5)	–
Unrealized energy risk management losses	**(49.4)**	(1.5)	–
Fuel costs	**(1.0)**	4.4	8.8
Other items–net	**(32.0)**	54.5	(15.4)
Total deferred federal income taxes	**(91.7)**	74.8	51.1
State	**(7.4)**	2.4	6.5
Total deferred income taxes	**(99.1)**	77.2	57.6
Investment Tax Credits–Net	**(9.6)**	(9.6)	(9.8)
Total Income Taxes	**$117.2**	$213.0	$198.7

Federal income taxes, computed by applying the statutory federal income tax rate to book income before extraordinary item and federal income tax, are reconciled to federal income tax expense reported in the Consolidated Statements of Income as follows:

(in millions)	1998	1997	1996
Statutory federal income tax provision	**$129.0**	$196.4	$181.8
Increases (Reductions) in taxes resulting from:			
Amortization of investment tax credits	**(9.6)**	(9.6)	(9.8)
Depreciation and other utility plant-related differences	**10.4**	11.7	14.1
Preferred dividend requirements of subsidiaries	**2.3**	4.4	8.5
Foreign tax adjustments	**(20.0)**	(13.2)	(11.1)
Other–net	**(4.4)**	8.8	1.2
Federal income tax expense	**$107.7**	$198.5	$184.7

12. COMMITMENTS AND CONTINGENCIES

(a) CONSTRUCTION

Construction expenditures for the 1999 through 2003 period are forecast to be approximately $1.7 billion. These forecasted amounts exclude the estimated expenditures necessary to comply with the stricter nitrogen oxide ("NO_x") emission control standards proposed by the United States Environmental Protection Agency ("EPA").

(b) MANUFACTURED GAS PLANT ("MGP") SITES

(i) General

Prior to the 1950s, gas was produced at MGP sites through a process that involved the heating of coal and/or oil. The gas produced from this process was sold for residential, commercial, and industrial uses.

(ii) PSI

Coal tar residues, related hydrocarbons, and various metals associated with MGP sites have been found at former MGP sites in Indiana, including at least 21 MGP sites which PSI or its predecessors previously owned. PSI acquired four of the sites from Northern Indiana Public Service Company ("NIPSCO") in 1931 and at the same time it sold NIPSCO the sites located in Goshen and Warsaw, Indiana. In 1945, PSI sold 19 of these sites (including the four it acquired from NIPSCO) to Indiana Gas and Water Company, Inc. (now Indiana Gas Company, Inc. ("IGC")). One of the 19 sites, the one located in Rochester, Indiana, was later sold by IGC to NIPSCO.

IGC and NIPSCO both made claims against PSI, contending that PSI is a Potentially Responsible Party under the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") with respect to the 21 MGP sites, and therefore legally responsible for the costs of investigating and remediating these sites. Moreover, in August 1997, NIPSCO filed suit against PSI in federal court, claiming, pursuant to CERCLA, recovery from PSI of NIPSCO's past and future costs of investigating and remediating MGP related contamination at the Goshen MGP site.

In November 1998, NIPSCO, IGC, and PSI entered into a Site Participation and Cost Sharing Agreement by which they settled allocation of CERCLA liability for past and future costs, among the three companies, at seven MGP sites in Indiana. Pursuant to this agreement, NIPSCO's lawsuit against PSI was dismissed. The parties have assigned one of the parties lead responsibility for managing further investigation and remediation activities at each of the sites. Similar agreements were reached between IGC and PSI which allocate CERCLA liability at 14 MGP sites with which NIPSCO had no involvement. These agreements conclude all CERCLA and similar claims between the three companies relative to MGP sites. Pursuant to the agreements and applicable laws, the parties are continuing to investigate and remediate the sites as appropriate. Investigation and cleanup of some of the sites is subject to oversight by the Indiana Department of Environmental Management ("IDEM").

PSI has placed its insurance carriers on notice of IGC's, NIPSCO's, and the IDEM's claims related to MGP sites. In April 1998, PSI filed suit in Hendricks County Circuit Court against its general liability insurance carriers seeking, among other matters, a declaratory judgment that its insurance carriers are obligated to defend MGP claims against PSI or pay PSI's costs of defense and to indemnify PSI for its costs of investigating, preventing, mitigating, and remediating damage to property and paying claims associated with MGP sites. PSI cannot predict the outcome of this litigation.

Based upon the work performed to date, PSI has accrued costs for the sites related to investigation, remediation, and groundwater monitoring. Estimated costs of certain remedial activities are accrued when such costs are reasonably estimable. PSI does not believe it can provide an estimate of the reasonably possible total remediation costs for any site prior to completion of a remedial investigation/feasibility study and the development of some sense of the timing for the implementation of the potential remedial alternatives, to the extent such remediation may be required. Accordingly, the total costs that may be incurred in connection with the remediation of all sites, to the extent remediation is necessary, cannot be determined at this time. These future costs at the 21 Indiana MGP sites, based on information currently available, are not material to Cinergy's financial condition or results of operations. However, as further investigation and remediation activities are undertaken at these sites, the potential liability for the 21 MGP sites could be material to Cinergy's and PSI's financial condition or results of operations.

(iii) CG&E and its Utility Subsidiaries

CG&E and its utility subsidiaries are aware of potential sites where MGP activities have occurred at some time in the past. None of these sites is known to present a risk to the environment. CG&E and its utility subsidiaries have undertaken preliminary site assessments to obtain more information about some of these MGP sites.

(c) OZONE TRANSPORT RULEMAKING

In October 1998, the EPA finalized its Ozone Transport Rule ("NO_x SIP Call"). It applies to 22 states in the eastern half of the US, including the three states in which the Cinergy electric utilities operate. This rule recommends that states reduce NO_x emissions from primarily industrial and utility sources to a certain limit by May 2003. Ohio, Indiana, a number of other states, and various industry groups, including some of which Cinergy is a member, filed legal challenges to the NO_x SIP Call in late 1998. Ohio and Indiana have also provided preliminary indications that they will seek fewer NO_x reductions from the utility sector in their implementing regulations than the EPA has budgeted in its rulemaking. The state implementing regulations will need the EPA's approval. Under the current provisions of the NO_x SIP Call, the estimate for compliance with the EPA limits is currently $500 million to $700 million (in 1998 dollars) between now and 2003. This estimate is significantly dependent on several factors, including the final determination regarding both the timing and stringency of the final required NO_x reductions, the output of CG&E's and PSI's generating units, the availability of an adequate supply of resources to construct the necessary control equipment, and the extent to which a NO_x allowance trading market develops, if any.

(d) UCH PROJECT

Midlands (of which the Company owns 50%) has a 40% ownership interest in a 586 megawatts ("MW") power project in Pakistan ("Uch project" or "Uch") which was originally scheduled to begin commercial operation in late 1998. In July 1998, the Pakistani government-owned utility issued a notice of intent to terminate certain key project agreements relative to the Uch project. The notice asserts that various forms of corruption were involved in the original granting of the agreements to the Uch investors by a predecessor government. The Company believes that this notice is similar to notices received by a number of other independent power projects in Pakistan.

The Uch investors, including a subsidiary of Midlands, strongly deny the allegations and have pursued all available legal options to enforce their contractual rights under the project agreements. Physical construction of the project is complete; however, commercial operations have been delayed pending resolution of the dispute. In December 1998, the Pakistani government offered to withdraw its notice.

Through its 50% ownership of Midlands, the Company's current investment in the Uch project is approximately $32 million. In addition, project lenders could require investors to make additional capital contributions to the project under certain conditions. The Company's share of these additional contributions is approximately $12 million. At the present time, the Company cannot predict the ultimate outcome of this matter.

(e) EXPIRATION OF BARGAINING AGREEMENT

Our collective-bargaining agreement with the International Brotherhood of Electrical Workers Local No. 1393, covering approximately 1,470 employees, will expire on May 1, 1999. Management has developed contingency plans for service to continue in the event of a work stoppage. In the unlikely event of a work stoppage, incremental related costs would be incurred, but would not be expected to have a material impact on operating income.

13. JOINTLY-OWNED PLANT

CG&E, Columbus Southern Power Company, and The Dayton Power and Light Company have constructed electric generating units and related transmission facilities on varying common ownership bases. PSI is a joint owner of Gibson Generating Station ("Gibson") Unit 5 with Wabash Valley Power Association, Inc. ("WVPA") and Indiana Municipal Power Agency ("IMPA"). Additionally, PSI is a co-owner with WVPA and IMPA of certain transmission property and local facilities. These facilities constitute part of the integrated transmission and distribution systems which are operated and maintained by PSI. The Consolidated Statements of Income reflect CG&E's and PSI's portions of all operating costs associated with the jointly-owned facilities.

CG&E's and PSI's investments in jointly-owned plant are as follows:

	1998			
(dollars in millions)	**Share**	**Utility Plant in Service**	**Accumulated Depreciation**	**Construction Work In Progress**
CG&E				
Production				
Miami Fort Station (Units 7 and 8)	64.00%	$ 216	$120	$4
W.C. Beckjord Station (Unit 6)	37.50	41	26	1
J.M. Stuart Station	39.00	273	128	2
Conesville Station (Unit 4)	40.00	73	39	2
William H. Zimmer Station	46.50	1 218	275	5
East Bend Station	69.00	333	172	2
Killen Station	33.00	187	91	–
Transmission	Various	64	32	1
PSI				
Production				
Gibson (Unit 5)	50.05	206	102	3
Transmission and local facilities	94.62	2	1	–

14. QUARTERLY FINANCIAL DATA (unaudited)

(in millions, except per share amounts)

Quarter Ended	Operating Revenues[(a)]	Operating Income[(a)]	Net Income (Loss)	Basic Earnings (Loss) Per Share	Diluted Earnings (Loss) Per Share
1998					
March 31	**$1 348**	**$226**	**$106**	**$ .67**	**$ .67**
June 30	**1 168**	**3** [(b,d)]	**(25)** [(b,d)]	**(.16)** [(b,d)]	**(.16)** [(b,d)]
September 30	**1 976**	**204** [(e)]	**109** [(e)]	**.69** [(e)]	**.69** [(e)]
December 31	**1 384**	**133** [(f)]	**71** [(f)]	**.45** [(f)]	**.45** [(f)]
Total	**$5 876**	**$566**	**$261**	**$1.65**	**$1.65**
1997					
March 31	$1 039	$215	$114	$ .72	$ .72
June 30	872	142	56	.35	.34
September 30	1 361	183	(27) [(c)]	(.16) [(c)]	(.17) [(c)]
December 31	1 115	226	110	.70	.70
Total	$4 387	$766	$253	$1.61	$1.59

(a) For a discussion of the reclassification of amounts disclosed in prior reports, see Note 1(b).

(b) In the second quarter of 1998, Cinergy recorded charges of $65 million, pretax related to power marketing and trading operations which constitutes, after tax, $.26 per share, basic and diluted. For a discussion of the energy marketing and trading operations, see Note 1(c).

(c) For a discussion of the windfall profits tax levied against Midlands, which was recorded in the third quarter of 1997 as an extraordinary item, see Note 17. Net income, basic EPS, and diluted EPS during the third quarter of 1997, before the extraordinary item, were $83 million, $.53, and $.52, respectively. Total net income, basic EPS, and diluted EPS for 1997, before the extraordinary item, were $363 million, $2.30, and $2.28, respectively.

(d) In the second quarter of 1998, Cinergy, through PSI, recorded a charge against earnings of $80 million ($50 million after tax or $.32 per share basic and diluted) for a settlement related to the Marble Hill nuclear project. For a discussion of this settlement, see Note 18.

(e) In the third quarter of 1998, Cinergy recorded charges of $20 million, pretax related to power marketing and trading operations which constitutes, after tax, $.08 per share, basic and diluted. For a discussion of the energy marketing and trading operations, see Note 1(c).

(f) In the fourth quarter of 1998, Cinergy recorded charges of $50 million, pretax related to power marketing and trading operations which constitutes, after tax, $.20 per share, basic and diluted. For a discussion of the energy marketing and trading operations, see Note 1(c).

15. FINANCIAL INFORMATION BY BUSINESS SEGMENT

During 1998, Cinergy and its subsidiaries adopted the provisions of Statement of Financial Accounting Standards No. 131, Disclosures about Segments of an Enterprise and Related Information ("Statement 131"). Statement 131 requires disclosure about reportable operating segments in annual and interim condensed financial statements. These operating segments are based on products and services, geography, legal structure, management structure or any manner in which management disaggregates a company.

Cinergy's reportable segments are strategic business units which were formed during the second half of 1996 and began operating as separately identifiable business units in 1997. Each business unit has its own management structure, headed by a business unit president who reports directly to the chief executive officer of Cinergy. Each business unit and their responsibilities as of December 31, 1998, is described in detail below.

The ECBU operates and maintains, exclusive of certain jointly-owned plant, all of the Company's domestic electric generation facilities. In addition to the production of electric power, all energy risk management, marketing, and proprietary arbitrage trading, with the exception of electric and gas retail sales, is conducted through the ECBU. Revenues from external customers are derived from the ECBU's marketing, trading, and risk management activities. Intersegment revenues are derived from the sale of electric power to the ESBU.

The EDBU plans, constructs, operates, and maintains the Company's transmission and distribution systems. Revenues from customers other than end-users are primarily derived from the transmission of electric power through the Company's transmission system. Intersegment revenues are derived from sale of electric and gas transmission and distribution services to the ESBU.

The ESBU provides gas and electric energy as well as gas supply risk management services to end-users. The ESBU also manages the development and the sales and marketing of new end-use energy-related products and services. All of the ESBU's revenues are derived from the sales of such services and products to external customers. All electric energy sold to end-users is purchased from the ECBU. In addition to energy-related products and services, the ESBU also sells other end-use products and services, such as telephone services, through joint-venture affiliates. Other products and services offered through joint-venture affiliates include the construction and sale or lease of cogeneration and trigeneration facilities to large commercial/industrial customers and energy management services to third parties.

The IBU directs and manages all of the Company's international business holdings, which include wholly-owned subsidiaries and equity investments. Revenues and equity earnings from unconsolidated companies are primarily derived from energy-related businesses.

Transfer pricing for sales of electric energy and sales of electric and gas transmission and distribution services between the ECBU, ESBU, and EDBU are derived from the operating utilities' retail and wholesale rate structures.

The following financial information by business unit, product and service, and geographic area for the years ending December 31, 1998, 1997, and 1996, is as follows:

BUSINESS UNITS

(in millions)

	1998							
	Cinergy Business Units					All Other(1)	Reconciling Eliminations(2)	Consolidated
	ECBU	EDBU	ESBU	IBU	Total			
Operating Revenues–External Customers	$2 726	$ 34	$3 107	$ 9	$ 5 876	$ –	$ –	$ 5 876
Intersegment Revenues	1 782	724	–	–	2 506	–	(2 506)	–
Depreciation and Amortization(3)	197	123	4	2	326	–	–	326
Equity in Earnings of Unconsolidated Subsidiaries	(1)	–	(4)	56	51	–	–	51
Interest Expense (net)(4)	95	88	3	51	237	7	–	244
Income Taxes	–	–	–	–	–	117	–	117
Segment Profit (Loss)	151	225	4	16	396	(135)	–	261
Total Segment Assets	5 476	3 754	275	751	10 256	43	–	10 299
Investments in Unconsolidated Subsidiaries	–	–	8	566	574	–	–	574
Total Expenditures for Long-Lived Assets	109	227	17	–	353	17	–	370

(1) The all other category represents miscellaneous corporate items, including income taxes, which are not allocated to business units for purposes of segment profit measurement.

(2) The reconciling eliminations category eliminates the intersegment revenues of the ECBU and the EDBU.

(3) The components of Depreciation and Amortization include depreciation of fixed assets, amortization of intangible assets, amortization of phase-in deferrals, and amortization of post-in-service deferred operating expenses.

(4) Interest income is deemed immaterial.

(in millions)

1997	ECBU	EDBU	ESBU	IBU	Total	All Other(1)	Reconciling Eliminations(2)	Consolidated
	Cinergy Business Units							
Operating Revenues–External Customers	$1 287	$ 27	$3 071	$ 2	$4 387	$ –	$ –	$4 387
Intersegment Revenues	1 688	727	–	–	2 415	–	(2 415)	–
Depreciation and Amortization(3)	184	118	5	–	307	–	–	307
Equity in Earnings of Unconsolidated Subsidiaries	–	–	(3)	63	60	–	–	60
Interest Expense (net)(4)	108	86	4	38	236	–	–	236
Income Taxes	–	–	–	–	–	213	–	213
Segment Profit (Loss) Before Extraordinary Item	330	224	4	22	580	(217)	–	363
Extraordinary Item(5)	–	–	–	(109)	(109)	–	–	(109)
Segment Profit (Loss)	330	224	4	(87)	471	(217)	–	254
Total Segment Assets	4 380	3 617	279	562	8 838	20	–	8 858
Investments in Unconsolidated Subsidiaries	–	–	3	535	538	–	–	538
Total Expenditures for Long-Lived Assets	79	224	12	–	315	13	–	328

(1) The all other category represents miscellaneous corporate items, including income taxes, which are not allocated to business units for purposes of segment profit measurement.

(2) The reconciling eliminations category eliminates the intersegment revenues of the ECBU and the EDBU.

(3) The components of Depreciation and Amortization include depreciation of fixed assets, amortization of intangible assets, amortization of phase-in deferrals, and amortization of post-in-service deferred operating expenses.

(4) Interest income is deemed immaterial.

(5) Windfall Profits Tax (see Note 17).

(in millions)

1996	ECBU	EDBU	ESBU	IBU	Total	All Other(1)	Reconciling Eliminations(2)	Consolidated
	Cinergy Business Units							
Operating Revenues–External Customers	$ 210	$ 23	$3 043	$ –	$3 276	$ –	$ –	$3 276
Intersegment Revenues	1 678	733	–	–	2 411	–	(2 411)	–
Depreciation and Amortization(3)	175	115	5	–	295	–	–	295
Equity in Earnings of Unconsolidated Subsidiaries	–	–	–	25	25	–	–	25
Interest Expense (net)(4)	101	91	6	18	216	–	–	216
Income Taxes	–	–	–	–	–	199	–	199
Segment Profit (Loss)	308	208	16	7	539	(204)	–	335
Total Segment Assets	4 399	3 424	283	605	8 711	14	–	8 725
Investments in Unconsolidated Subsidiaries	–	–	–	593	593	–	–	593
Total Expenditures for Long-Lived Assets	100	206	17	593	916	1	–	917

(1) The all other category represents miscellaneous corporate items, including income taxes, which are not allocated to business units for purposes of segment profit measurement.

(2) The reconciling eliminations category eliminates the intersegment revenues of the ECBU and the EDBU.

(3) The components of Depreciation and Amortization include depreciation of fixed assets, amortization of intangible assets, amortization of phase-in deferrals, and amortization of post-in-service deferred operating expenses.

(4) Interest income is deemed immaterial.

PRODUCTS AND SERVICES

(in millions)

	Revenues							
	Traditional Utility			Energy Marketing and Trading			Other	
Year	Electric	Gas	Total	Electric	Gas	Total		Consolidated
1998	**$2 696**	**$435**	**$3 131**	**$2 066**	**$665**	**$2 731**	**$14**	**$5 876**
1997	2 579	519	3 098	1 283	–	1 283	6	4 387
1996	2 568	505	3 073	200	–	200	3	3 276

Cinergy's core products and services focus on providing traditional utility services (the supply of electric energy and gas supply) and energy marketing and trading services.

GEOGRAPHIC AREAS AND LONG-LIVED ASSETS

(in millions)

	Revenues				
		International			
Year	Domestic	UK	All Other[1]	Total	Consolidated
1998	**$5 867**	**$ –**	**$ 9**	**$ 9**	**$5 876**
1997	4 385	–	2	2	4 387
1996	3 276	–	–	–	3 276

(in millions)

	Long-Lived Assets				
		International			
Year	Domestic	UK	All Other[1]	Total	Consolidated
1998	**$7 302**	**$501**	**$209**	**$710**	**$8 012**
1997	7 267	505	42	547	7 814
1996	7 302	593	10	603	7 905

(1) During 1998, the IBU acquired the assets of two district heating plants (approximately 816 MW combined) in the Czech Republic. The assets and the results of operations of these international investments are consolidated into the company's financial statements, while the remaining international long-lived assets of the IBU are accounted for as equity method investments. As a result, revenues from the IBU are not significant.

Cinergy's core service territory and asset base is located in the southwestern portion of Ohio, including adjacent areas in Kentucky, and the north central, central, and southern regions of Indiana. Cinergy's energy marketing and trading function provides energy risk management, marketing, and trading services throughout the US. Abroad, Cinergy owns a 50% interest in Midlands, a regional electric company located in the United Kingdom ("UK"). In addition to its ownership interest in Midlands, Cinergy also has other equity investments in Europe, Africa, and Asia and is actively developing other energy-related projects.

16. EARNINGS PER SHARE

A reconciliation of earnings per common share ("basic EPS") to earnings per common share assuming dilution ("diluted EPS") is presented below:

(in millions, except per share amounts)	Income (Numerator)	Shares (Denominator)	EPS
1998			
Earnings per common share: Net income	**$261**	**158**	**$1.65**
Effect of dilutive securities: Common stock options		**1**	
EPS–assuming dilution: Net income plus assumed conversions	**$261**	**159**	**$1.65**
1997			
Earnings per common share: Net income before extraordinary item[a]	$363	158	$2.30
Effect of dilutive securities: Common stock options		1	
EPS–assuming dilution: Net income before extraordinary item plus assumed conversions[a]	$363	159	$2.28
1996			
Net income	$335		
Less: costs of reacquisition of preferred stock of subsidiary	18		
Earnings per common share: Net income applicable to common stock	317	158	$2.00
Effect of dilutive securities: Common stock options		1	
EPS–assuming dilution: Net income applicable to common stock plus assumed conversions	$317	159	$1.99

(a) The after-tax EPS impact of the extraordinary item–equity share of windfall profits tax in 1997 was $.69 for both basic and diluted EPS.

Options to purchase shares of common stock are excluded from the calculation of EPS-assuming dilution when the exercise prices of these options are greater than the average market price of the common shares during the year. For 1998, approximately one million shares, with an average exercise price of approximately $38.00 per share, were excluded from the EPS-assuming dilution calculation. For 1997 and 1996, shares excluded for this calculation were immaterial.

17. EXTRAORDINARY ITEM–EQUITY SHARE OF WINDFALL PROFITS TAX

During the third quarter of 1997, a windfall profits tax was enacted into law in Great Britain. This tax was levied against a limited number of British companies, including Midlands, which had previously been owned and operated by the government. The tax was intended to be a recovery of funds by the government due to the undervaluing of companies, such as Midlands, when they were privatized by the government via public stock offerings several years ago.

Cinergy's share of the tax was approximately 67 million pounds sterling ($109 million or $.69 per share, basic and diluted). As Cinergy's management believes this charge to be unusual in nature, and does not expect such a charge to recur, the tax was recorded as an extraordinary item in Cinergy's Consolidated Statement of Income during 1997. No related tax benefit was recorded for the charge as the windfall profits tax is not deductible for corporate income tax purposes in the UK, and Cinergy expects that benefits, if any, derived for US federal income taxes will not be significant.

18. WVPA SETTLEMENT

In February 1989, PSI and WVPA entered into a settlement agreement to resolve all claims related to Marble Hill, a nuclear project canceled in 1984. Implementation of the settlement was contingent upon a number of events. During 1998, PSI reached agreement on all matters with the relevant parties and, as a result, recorded a liability to the RUS. PSI will repay the obligation to the RUS with interest over a 35-year term. The net proceeds from a 35-year power sales agreement with WVPA will be used to fund the principal and interest on the obligation to the RUS. Assumption of the liability (recorded as long-term debt in the Consolidated Balance Sheet) resulted in a charge against earnings of $80 million ($50 million after tax or $.32 per share basic and diluted) in the second quarter of 1998.

Management is responsible for the accuracy, objectivity, and consistency of the financial statements presented in this report. The Consolidated Financial Statements of Cinergy Corp. (Cinergy) conform to generally accepted accounting principles and have also been prepared to comply with accounting policies and principles prescribed by the applicable regulatory authorities.

To assure the reliability of Cinergy's financial statements, management maintains a system of internal controls. This system is designed to provide reasonable assurance that assets are safeguarded, that transactions are executed with management's authorization, and that transactions are properly recorded so financial statements can be prepared in accordance with the policies and principles previously described.

Cinergy has established policies intended to ensure that employees adhere to the highest standards of business ethics. Management also takes steps to assure the integrity and objectivity of Cinergy's accounts by careful selection of managers, division of responsibilities, delegation of authority, and communication programs to assure that policies and standards are understood.

An internal auditing program is used to evaluate the adequacy of and compliance with internal controls. Although no cost effective internal control system will preclude all errors and irregularities, management believes that Cinergy's system of internal controls provides reasonable assurance that material errors or irregularities are prevented, or would be detected within a timely period.

Cinergy's Consolidated Financial Statements have been audited by Arthur Andersen LLP, which has expressed its opinion with respect to the fairness of the statements. The auditors' examination included a review of the system of internal controls and tests of transactions to the extent they considered necessary to render their opinion.

The Board of Directors, through its audit committee of outside directors, meets periodically with management, internal auditors, and independent auditors to assure that they are carrying out their respective responsibilities. The audit committee has full access to the internal and independent auditors, and meets with them, with and without management present, to discuss auditing and financial reporting matters.

James E. Rogers

James E. Rogers
President and
Chief Executive Officer

Charles J. Winger

Charles J. Winger
Vice President and
Chief Financial Officer

To the Board of Directors of Cinergy Corp.:

We have audited the accompanying consolidated balance sheets of Cinergy Corp. (a Delaware Corporation) and its subsidiary companies as of December 31, 1998 and 1997, and the related consolidated statements of income, changes in common stock equity and cash flows for each of the three years in the period ended December 31, 1998. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements 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 Cinergy Corp. and its subsidiary companies as of December 31, 1998 and 1997, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998, in conformity with generally accepted accounting principles.

As explained in Note 1 to the consolidated financial statements, the Company changed its method of accounting for its energy trading and risk management activities effective December 31, 1998.

Arthur Andersen LLP
Cincinnati, Ohio,
January 28, 1999

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FINANCIAL		1998	1997	1996	1995	1994
Operating Revenues (thousands)		**$ 5 876 294**	$4 387 101	$3 276 187	$3 023 431	$2 888 447
Net Income (thousands)		**$ 260 968**	$ 253 238	$ 334 797	$ 347 182	$ 191 142
Total Assets (thousands)		**$10 298 795**	$8 858 153	$8 724 934	$8 103 242	$8 037 422
Construction Expenditures (Including AFUDC) (thousands)		**$ 370 277**	$ 328 153	$ 324 238	$ 326 869	$ 486 734
Capitalization	Common Equity	**$ 2 541 231**	$2 539 200	$2 584 454	$2 548 843	$2 414 271
($-thousands)	Preferred Stock[a]					
	Subject to Mandatory Redemption	–	–	–	160 000	210 000
	Not Subject to Mandatory Redemption	**92 640**	177 989	194 232	227 897	267 929
	Long-term Debt[a]	**2 604 467**	2 150 902	2 326 378	2 346 766	2 615 269
	Total Capitalization	**$ 5 238 338**	$4 868 091	$5 105 064	$5 283 506	$5 507 469
Other Common Stock Data	Avg. Shares Outstanding (millions)	**158**	158	158	157	147
	Avg. Shares Outstanding–Assuming Dilution (millions)	**159**	159	159	158	148
	Earnings Per Share	**$ 1.65**	$ 1.61[c]	$ 2.00[b]	$ 2.22	$ 1.30
	Earnings Per Share–Assuming Dilution	**$ 1.65**	$ 1.59[c]	$ 1.99[b]	$ 2.20	$ 1.29
	Dividends Declared Per Share	**$ 1.80**	$ 1.80	$ 1.74	$ 1.72	$ 1.50
	Payout Ratio[d]	**109.1%**	111.8%[c]	87.0%[b]	77.5%	115.4%
	Book Value Per Share (year-end)	**$ 16.02**	$ 16.10	$ 16.39	$ 16.17	$ 15.56
Degree Day Data	CG&E Heating (30-year average–5,248)	**4 282**	5 271	5 611	5 323	4 937
	Cooling (30-year average–996)	**1 235**	851	916	1 216	1 026
	PSI Heating (30-year average–5,609)	**4 440**	5 680	5 891	5 578	5 194
	Cooling (30-year average–1,014)	**1 250**	871	989	1 214	1 057
Employee Data	Number of Employees (year-end)	**8 794**	7 609	7 973	8 602	8 868
GAS OPERATIONS						
Gas Revenues	Residential	**$ 240 297**	$ 284 516	$ 272 303	$ 237 576	$ 242 415
(thousands)	Commercial	**87 583**	121 345	118 994	99 708	114 854
	Industrial	**17 320**	31 168	30 409	28 979	43 490
	Other	**12 888**	18 554	20 133	19 740	23 483
	Total Sales	**358 088**	455 583	441 839	386 003	424 242
	Gas Transported	**41 050**	32 456	27 679	20 934	13 496
	Total Sales & Transported	**399 138**	488 039	469 518	406 937	437 738
	Total ProEnergy	**658 771**	–	–	–	–
	Other Gas Revenues	**2 755**	3 106	4 517	3 915	4 660
	Total Gas	**$ 1 060 664**	$ 491 145	$ 474 035	$ 410 852	$ 442 398
Gas Sales	Residential	**36 256**	41 846	44 721	43 153	39 065
(million cu. ft.)	Commercial	**13 999**	19 141	21 199	19 664	20 070
	Industrial	**2 941**	5 240	5 746	6 624	9 025
	Other	**2 449**	3 162	3 947	4 584	4 803
	Total Sales	**55 645**	69 389	75 613	74 025	72 963
	Gas Transported	**57 881**	53 448	48 560	40 543	32 579
	Total ProEnergy	**338 343**	–	–	–	–
	Total Sales, Transported, & ProEnergy	**451 869**	122 837	124 173	114 568	105 542
Gas Customers	Residential	**404 417**	407 128	397 660	389 165	379 953
(avg.)	Commercial	**39 332**	41 915	41 499	40 897	40 545
	Industrial	**1 569**	1 960	1 961	1 959	2 076
	Other	**1 227**	1 505	1 518	1 558	1 520
	Transportation	**15 626**	1 205	829	599	56
	ProEnergy	**147**	–	–	–	–
	Total	**462 318**	453 713	443 467	434 178	424 150
System Maximum Day Sendout (million cu. ft.)		**788**	932	861	813	955
Avg. Cost Per Mcf Purchased (cents)		**364.43[e]**	380.41	326.50	277.92	335.60
Load Factor–Gas		**39.5%**	36.1%	39.5%	38.7%	30.3%

Certain amounts in prior years have been reclassified to conform to the 1998 presentation.

(a) Excludes amounts due within one year.

(b) Includes $.12 per share for the cost of reacquiring 90% of CG&E's preferred stock through a tender offer.

(c) Includes $.69 per share for an extraordinary item (Midlands windfall profits tax).

(d) Based on basic earnings per share.

(e) Excludes ProEnergy purchases. Had the purchases been included, the Avg. Cost Per Mcf Purchased (cents) would have been 217.99 in 1998.

ELECTRIC OPERATIONS		1998	1997	1996	1995	1994
Electric Revenues (thousands)	Residential	**$1 028 314**	$ 984 891	$ 996 959	$ 965 278	$ 898 763
	Commercial	**722 292**	689 091	673 181	661 496	626 333
	Industrial	**702 208**	669 464	657 563	637 090	598 126
	Other	**100 017**	111 867	110 003	118 458	96 247
	Total Retail	**2 552 831**	2 455 313	2 437 706	2 382 322	2 219 469
	Sales For Resale	**2 140 431**	1 367 897	296 600	197 943	194 734
	Other	**53 973**	38 488	34 400	32 314	31 846
	Total Electric	**$4 747 235**	$3 861 698	$2 768 706	$2 612 579	$2 446 049
Electric Sales (million kwh)	Residential	**14 551**	14 147	14 705	14 366	13 578
	Commercial	**12 524**	12 034	11 802	11 648	11 167
	Industrial	**18 093**	17 321	16 803	16 264	15 547
	Other	**1 815**	1 825	1 811	1 795	1 723
	Total Retail	**46 983**	45 327	45 121	44 073	42 015
	Sales For Resale	**77 558**	57 454	12 399	7 769	7 801
	Total Electric	**124 541**	102 781	57 520	51 842	49 816
Electric Customers (avg.)	Residential	**1 257 853**	1 236 974	1 215 782	1 195 323	1 174 705
	Commercial	**153 674**	151 093	149 015	147 888	144 766
	Industrial	**6 473**	6 472	6 470	6 424	6 345
	Other	**6 500**	6 372	6 265	6 008	5 779
	Total	**1 424 500**	1 400 911	1 377 532	1 355 643	1 331 595
System Capability–Summer (mw)[(a)(b)]	Consolidated	**10 936**	10 936	11 037	11 133	10 990
	CG&E	**5 075**	5 075	5 175	5 271	5 271
	PSI	**5 861**	5 861	5 862	5 862	5 719
System Peak Load (mw)	CG&E	**4 725**	4 638	4 452	4 509	4 326
	PSI	**5 708**	5 313	5 227	5 274	4 869
Annual Load Factor–Electric	CG&E	**59.0%**	58.4%	60.5%	58.8%	58.7%
	PSI	**59.7%**	59.2%	59.0%	57.4%	59.0%
Electricity Output (million kwh)	Generated–Net					
	CG&E	**26 069**	25 329	25 844	23 959	22 432
	PSI	**30 851**	29 521	26 815	28 499	27 898
	Purchased[(c)]	**3 718**	4 073	7 990	2 576	2 449
Source of Energy Supply (%)	Coal	**90.73%**	90.74%	85.69%	93.93%	94.40%
	Hydro	**0.57%**	0.72%	0.56%	0.66%	0.58%
	Oil & Gas	**2.56%**	1.63%	0.58%	0.73%	0.38%
	Purchased	**6.13%**	6.91%	13.17%	4.68%	4.64%
Fuel Cost	Per Million Btu	**$ 1.24**	$ 1.25	$ 1.35	$ 1.37	$ 1.41
Heat Rate (Btu per kwh sendout)	Consolidated	**10 274**	10 190	10 113	10 035	10 095
	CG&E	**10 110**	9 984	9 816	9 832	9 853
	PSI	**10 414**	10 369	10 403	10 207	10 292

Certain amounts in prior years have been reclassified to conform to the 1998 presentation.

(a) Includes amounts to be purchased, subject to availability, pursuant to agreements with other utilities.

(b) Excludes foreign capacity.

(c) Excludes purchases related to Cinergy's power marketing and trading function.

CINERGY®

CINERGY CORP.
139 East Fourth Street
Cincinnati, Ohio 45202

1999

CINERGY®

Case No. 99-449

Integrated Resource Plan

TRANSMISSION INFORMATION

VOLUME III

Case No. 99-449

NOV - 1 1999

CINERGY®

PSI Energy, Inc.
The Cincinnati Gas & Electric Company
The Union Light, Heat & Power Company

1999

INTEGRATED RESOURCE PLAN

Volume III

Transmission Information

November 1, 1999

By: Cinergy Corp.
John C. Procario, Vice President
Electric Operations
139 East Fourth Street
P.O. Box 960
Cincinnati, Ohio 45201-0960

NOTICE

In order to comply with the codes of conduct in FERC Order 889, this Transmission Information Volume, Volume III, was prepared independently from the rest of the Integrated Resource Plan. However, it is an integral part of the Cinergy 1999 IRP filing. Please see the submittal letters and other specific filing attachments contained in the front of Volume I of the Cinergy 1999 Integrated Resource Plan.

TRANSMISSION VOLUME

Table of Contents

7. ELECTRIC TRANSMISSION FORECAST

A. INTRODUCTION

The Cinergy transmission system is comprised of the 138 kV and 345 kV systems of The Cincinnati Gas & Electric Company (CG&E), and the 138 kV, 230 kV, and 345 kV systems of PSI Energy, Inc. (PSI). The Cinergy Bulk Transmission Planning Department plans the transmission systems as an integrated, single system. The Bulk Transmission Planning Department and Transmission and The Distribution Planning Department continuously evaluate the performance of the transmission and distribution systems, and will take actions to ensure that the systems are adequate to support anticipated loads.

Transmission and distribution planning is a complex process which requires the evaluation of numerous factors to provide meaningful insights into the performance of the system. Cinergy's distribution system planners gather information concerning actual distribution substation transformer and line loadings. The loading trend for each transformer is examined, and a projection of future transformer bank loading is made based on the historic load growth combined with the distribution planners' knowledge of load additions within the area.

The load growth in a distribution planning area tends to be somewhat more uncertain and difficult to predict than the load forecasts made for Cinergy as a whole.

Customers' decisions can dramatically impact not only the location of future capacity, but also the timing of system improvement projects. Because of this uncertainty, distribution development plans must be under continual review to make sure the proposed specific projects remain appropriate for the area's needs. Transmission and distribution (T&D) planning generally depends on the specific location of the loads, therefore the effects of co-generation capacity on T&D planning is location-specific. To the extent that fewer new T&D resources are required to serve these customers or the local areas in which they reside, Cinergy's T&D planning will reflect this.

It typically takes 18 to 24 months to add new distribution substation capacity to an area. Factors closely related to the future customer's load, such as local knowledge of growth potential based upon zoning, highway access and surrounding development can help forecast ultimate distribution system needs.

The transmission system planners utilize the historical distribution substation transformer bank loading and trends, combined with the Cinergy load forecast and resource plan and firm service schedules, to develop models of the transmission system. These models are utilized to simulate the performance of the transmission system under a wide variety of credible conditions to ensure that the expected performance of the transmission system meets both East Central Area Reliability (ECAR) and Cinergy planning criteria. Should these simulations indicate that a violation of the planning criteria occurs, more detailed studies are conducted to determine the severity of the problem and possible measures to alleviate it. A copy of Cinergy's FERC FORM 715 ***Annual Transmission Planning and Evaluation Report***, April 1, 1999, which includes the planning criteria, is included in the General Appendix of this filing.

B. THE EXISTING TRANSMISSION SYSTEM

1. General Description

The Cinergy transmission system above 125 kV consists of 138 kV, 230 kV, and 345 kV systems. The 345 kV system generally serves to distribute power from the larger, base load generating units on the system, and to interconnect the Cinergy system with other systems. These interconnections enable the transmission of power between systems from jointly owned generating units and they provide capacity for economy and emergency power transfers. The 345 kV system is connected to the 138 kV and 230 kV systems through large transformers at a number of substations across the system. These 138 kV and 230 kV systems generally distribute power received through the transformers and also from several smaller generating units which are connected directly at these voltage levels. This power is distributed to substations, which supply lower voltage sub-transmission systems, distribution circuits, or serve a number of large customer loads directly.

As of December 1998, the transmission system of CG&E and its subsidiary companies consisted of approximately 390 circuit miles of 345 kV lines (including CG&E's share of jointly owned transmission) and 645 circuit miles of 138 kV lines. Portions of the 345 kV transmission system are jointly owned with Columbus Southern Power (CSP) and/or Dayton Power & Light (DP&L).

PSI, Indiana Municipal Power Agency (IMPA) and Wabash Valley Power Association (WVPA) own the Joint Transmission System (JTS) in Indiana. The three co-owners have rights to use the JTS. As of December 1998, PSI's wholly and jointly owned share of transmission included approximately 857 circuit miles of 345 kV lines, 780 circuit miles of 230 kV lines and 1634 circuit miles of 138 kV lines.

2. **Evaluation of Adequacy for Load Growth**

The transmission system of Cinergy is adequate to support load growth and the current level of projected long-term power purchases and sales over the next ten years. This assumes that the planned transmission system expansions are completed as currently scheduled. Cinergy's transmission system, as with the transmission system of any other utility, can be significantly affected by the actions of others. In an attempt to evaluate these effects, ECAR develops a series of power flow simulation base cases that reflect the expected transmission system configuration and transactions. Should actual conditions differ significantly from those assumed in the base cases, then a re-evaluation of the adequacy of the Cinergy transmission system would be required. Further, there is currently no in-progress or planned transmission system projects affecting any Cinergy facilities, which are intended to provide additional resources.

3. Loss Evaluation

Screening analyses were performed to determine the effect of spending capital dollars solely for the purpose of reducing losses. Since it is becoming increasingly more difficult to construct new transmission lines on new right of way, the analyses assumed that existing transmission lines would be reconductored to reduce losses. The results of the analyses showed that it is NOT economical to spend capital dollars solely for the benefit of reducing losses on a system wide basis.

For example, an analysis on the PSI system assumed average costs for reconductoring and it used a weighted, average value for the existing losses on the transmission lines. This weighted value was based on existing miles of line in service by voltage class and conductor size. A power flow case was run to determine the existing losses at system peak load by voltage class. This was used as a benchmark when calculating the amount of loss reduction by reconductoring to determine the reasonableness of the results. In this analysis, over one billion dollars would be required to reconductor the entire PSI transmission system resulting in a reduction of approximately 100 megawatts of losses during the peak loading period. The cost per kilowatt would be over $9,000.

A similar example for the CG&E system analyzed the reconductoring of a ten-mile long 138 kV line. Reconductoring with larger wire reduced the peak load losses by approximately 0.5 MW (for a 100 MVA flow on the line). The cost of such a reconductoring project would be approximately $1,500,000 or more, resulting in a cost per kilowatt of over $3,000.

These analyses clearly show that a system wide program of reducing losses on the Cinergy transmission system through transmission-related alternatives is not economical. As a result, no loss-reduction alternatives were passed to the integration process. Cinergy will continue to evaluate specific cases where it may be economical to reconductor lines based on line loss reduction. The above discussion is not to imply that power and energy losses are not considered. Loss performance is factored into the choice between alternate projects, which are intended to meet other system performance objectives.

C. DESCRIPTION OF TRANSMISSION SYSTEM EXPANSION PLANS

The transmission system expansion plans for the Cinergy system are developed for the purpose of meeting the projected future requirements of the transmission system. The basic methodology used to determine the future requirements is power flow analysis. Power flow representations of the Cinergy electric transmission system, which allow computer simulations to determine MW and MVAR flows and the voltages across the system, are maintained for the peak periods of the current year and for future years. These power flow base cases simulate the system under normal conditions with typical generation, and no transmission outages. They are used to determine the general performance of the existing and planned transmission system under normal conditions.

Contingency cases based on the peak load base cases are studied to determine system performance for planned and unplanned transmission and generation outages. The results of these studies are used as a basis to determine the need for and timing of additions to the transmission system.

The cash flows associated with the major new PSI and CG&E transmission facility projects planned can be found in Section C of the Transmission Short-Term Implementation Plan.

D. TRANSMISSION SPECIAL TOPIC

The Ohio Public Utilities Commission has required CG&E to address the following Special Topic Question in this IRP:

Distribution System Planning Process

Provide a description of the Company's distribution system planning process, including a discussion of how existing system problems are identified, how future growth is estimated and how the impact of that growth on distribution system performance is determined.

Response - On the CG&E system, the distribution function is performed by systems with nominal voltages of 4160 Volts (2400 Volts phase to ground), 12,470 Volts (7200 Volts phase to ground), and 34,500 Volts (19,920 Volts phase to ground). The 4160-Volt system is gradually diminishing in size and is no longer reinforced except in special circumstances. Reinforcements to the 12.47 kV systems and 34.5 kV systems are planned based on the same criteria utilizing the same process.

The criteria call for adequate facilities to be available to serve the peak demand on the system with all system components in service. The loading on any component is planned to be less than its assigned rating, with such ratings developed utilizing a variety of methods. Manufacturers' ratings are applied where appropriate, as are ratings based on the actual thermal performance of various components. Except for the area designated for underground network service in downtown Cincinnati, the distribution systems are not designed to necessarily enable full peak load to be served in the event of system failure(s). Mobile and spare transformers are available to restore service, if required.

The process to determine when additional system capacity is required begins with an annual assembly of the peak demands served by each distribution supply transformer and its associated feeder(s). Transformers and/or feeders, which are approaching their assigned capacities, are identified. The system is divided into load areas of contiguous or strongly tied feeder groups surrounding these more heavily loaded facilities. A load history is developed based on the aggregate demands of all transformers and feeders in these areas. From the load history, load projections are made based primarily on linear extrapolation of past history. Other inputs are also considered. The Energy Services unit of CG&E notifies the Energy Delivery area of specific large commercial, industrial and residential loads prior to their installation. These notifications typically contain an estimate of the demand to be added. The recent and pending additions for each feeder are tracked, and this data is compared with the load projections based on historical data to determine if the projected growth rate appears reasonable or should be increased or decreased. Once an appropriate growth rate is determined, the load is projected into the future to determine when the area load will exceed the total area capacity. If the need for transformer capacity appears likely to occur within approximately 2 to 3 years, a plan is devised to install the capacity, establish new feeder(s) to be supplied from the new capacity, and redistribute the area load among the new and existing facilities. Alternative locations for new transformers including existing substations and new sites are considered. The transmission system, substation, and distribution feeder changes required for each location are considered. The location which appears to allow the capacity deficiency to be remedied in the least cost manner is normally chosen for implementation, and detailed plans are developed and included in the budgeting, engineering and construction processes.

The above process is followed in cases where a capacity deficiency is identified. Often, area capacity will be sufficient although one or more transformers and/or feeders are approaching their assigned capacities. Many times, such imbalances among available existing facilities can be alleviated utilizing existing switching points to redistribute the area load. In other cases, it might be necessary to upgrade existing or build new distribution routes to allow the load to be redistributed. Such projects are identified as the second step to the above process, i.e., if total transformer capacity is sufficient, it is projected when individual transformers or feeders within the area may reach their capacities. If the need for upgraded or new distribution feeder routes appears likely within 1 to 2 years, detailed plans are developed. Again, the lowest cost reinforcements necessary to alleviate the system deficiencies are identified, developed into detailed plans, and included in the budgeting, engineering and construction processes.

Each year, the current plans are evaluated against the most recent load data and new load projections. The timing of implementation of each project will be adjusted as required to attempt to install the modifications only when required to meet the load.

Provide a description of all distribution facilities at voltages greater than or equal to 12.5 kV planned or scheduled for years zero through five.

Response - The following table lists the major distribution system reinforcement projects for the 12.47

kV and 34.5 kV distribution systems that are presently planned for the 1998-2003 period.

Project Location	Description	In Service Date
Pisgah	Erect 10.5 MVA transformer and facilities required for one 12.47 kV feeder.	06/01/2000
Simpson	Erect 22.4 MVA transformer and facilities required for two 12.47 kV feeders.	06/01/2000
Walnut Hills	Substation and feeder improvements to increase feeder capacity and replace inadequate equipment.	2000 - 2001
Bethany	Erect 22.4 MVA transformer and facilities required for two 12.47 kV feeders.	06/01/2001
Dimmick	Erect 22.4 MVA transformer and facilities required for two 12.47 kV feeders.	06/01/2002
Pleasant Valley	Erect 10.5 MVA transformer and facilities required for one 12.47 kV feeder.	06/01/2002
Locust	Erect 10.5 MVA transformer and facilities required for one 12.47 kV feeder.	06/01/2003
Mack	Erect 10.5 MVA transformer and facilities required for one 12.47 kV feeder.	06/01/2003
Mulhauser	Erect 22.4 MVA transformer and facilities required for two 12.47 kV feeders.	06/01/2003
Tri-County	Erect 10.5 MVA transformer and facilities required for one 12.47 kV feeder.	06/01/2003
Beckett	Erect 22.4 MVA transformer and facilities required for two 12.47 kV feeders.	06/01/2004
Park	Erect 22.4 MVA transformer and facilities required for two 12.47 kV feeders.	06/01/2004
Port Union	Erect 22.4 MVA transformer and facilities required for two 12.47 kV feeders.	06/01/2005

Provide a description of the Company's process for obtaining community involvement in the planning and implementation of distribution system enhancements.

Response - CG&E has no established process or procedure that calls for community involvement in the planning and implementation of distribution system improvements. Public notice is given via the ELTFR for those projects that require new connections to the 138 kV system. No public notice is given for additions to existing substations or for new substations supplied from lower voltage supply systems. Typically, local political leaders will be consulted in association with a proposed project to help judge the need for additional public involvement. Additionally, public meetings have been held related to the proposed purchase of property for a future substation project where it was felt necessary to obtain community input. In one case, it was determined that a property would not be purchased based on local community reaction. As projects are implemented, those members of the public that will be specifically impacted by a project are contacted, and attempts are made to address any concerns they may have.

OHIO APPENDIX

4901:5-5-04

4. ELECTRIC TRANSMISSION FORECAST

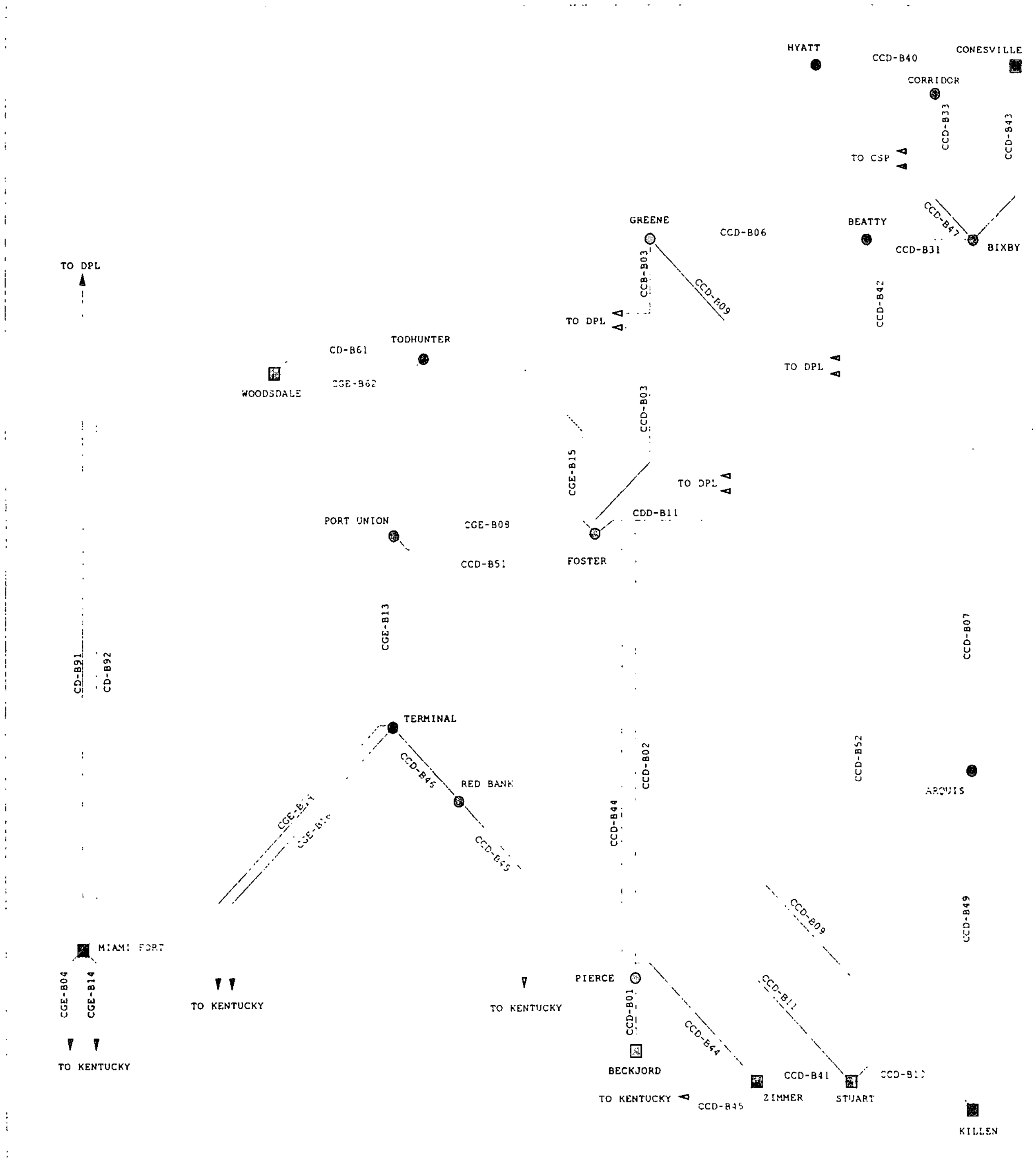
This section of the 1999 Integrated Resource Plan contains the transmission forecast forms FE3-1 through FE3-4 plus system diagrams and maps for the portions of the Cinergy network within the State of Ohio as required by OAC 4901:5-5-4.

(B)(2) EXISTING TRANSMISSION SYSTEM MAPS

(a) A schematic map of the existing 345 kV system is presented on the next page. A schematic map of the existing 138 kV system is presented on the following page.

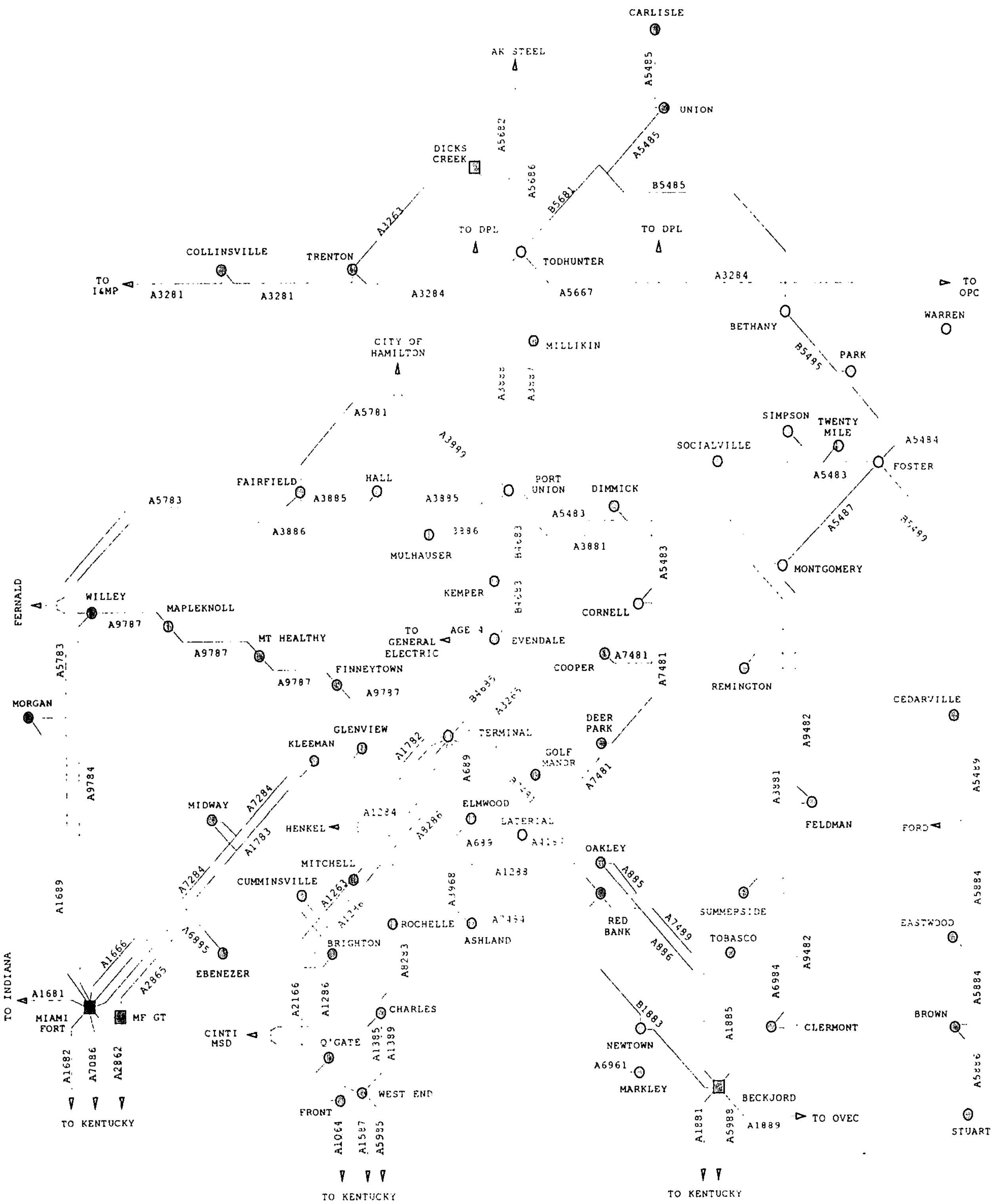
(b) A geographic map of the CG&E service area within the State of Ohio is contained in a pocket envelope located at the back of the Ohio Appendix. This map shows the CG&E 138 kV and 345 kV electric transmission lines. It includes existing lines and those presently under construction.

(c) Copies of the maps described in Paragraph (B) (2) (b) on a scale of 1:250,000 have been provided jointly by the several Ohio electric utilities.



SCHEMATIC MAP OF THE
EXISTING
CG&E 345KV SYSTEM
1999

GENERATING STATION
PROPOSED GEN. STA.
EXISTING SUBSTATION
PROPOSED SUBSTATION
CUSTOMER SUBSTATION
UC UNDER CONST
() - YEAR IN SERV



SCHEMATIC MAP OF THE
EXISTING
CG&E 138KV SYSTEM
1999

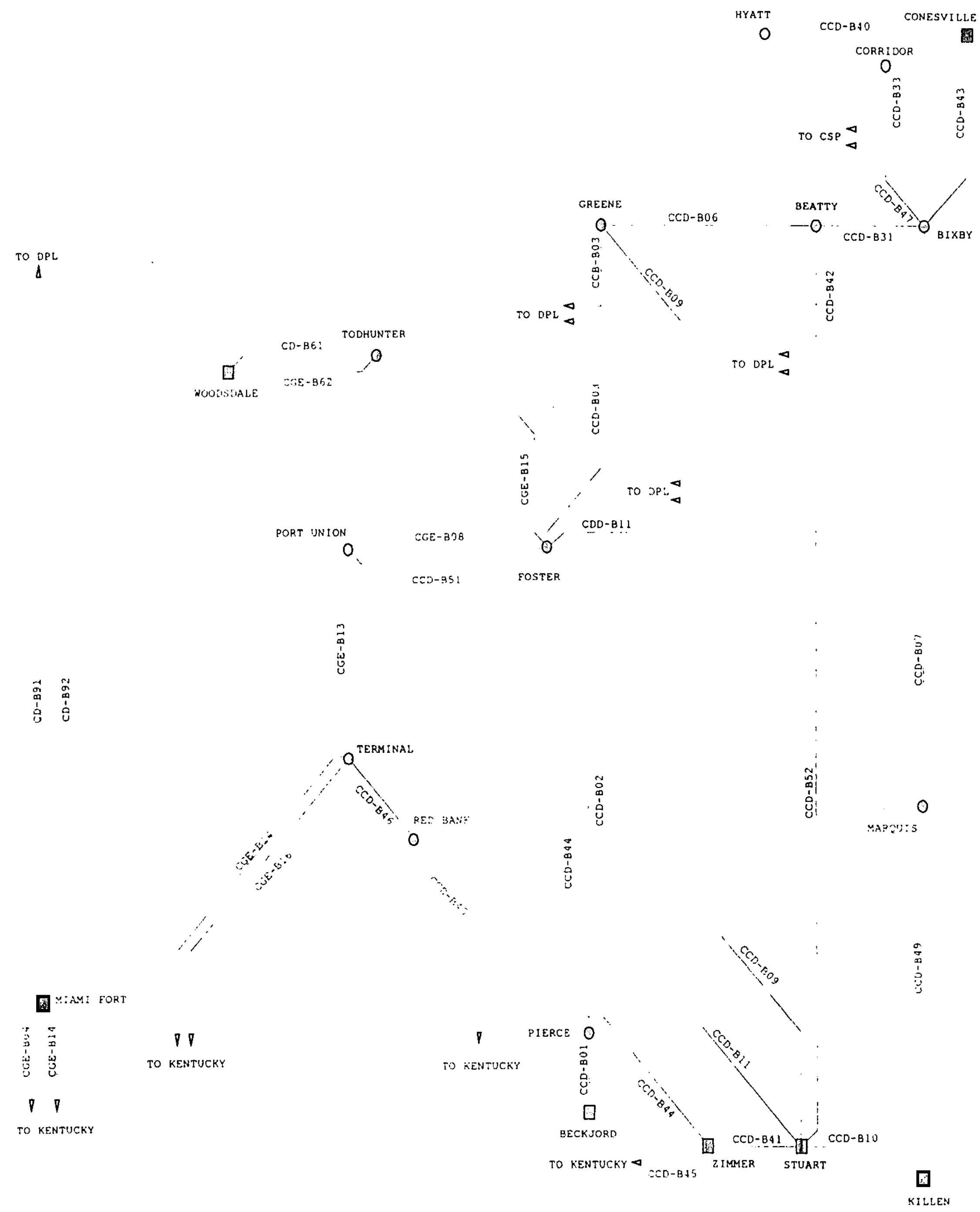
GENERATING STATION
PROPOSED GEN. STA.
EXISTING SUBSTATION
PROPOSED SUBSTATION
CUSTOMER SUBSTATION

A - 138KV CONST
B - 345KV CONST
UC UNDER CONST
() - YEAR IN SERV
ALL LINES CGE

(C) **PLANNED TRANSMISSION SYSTEM MAPS**

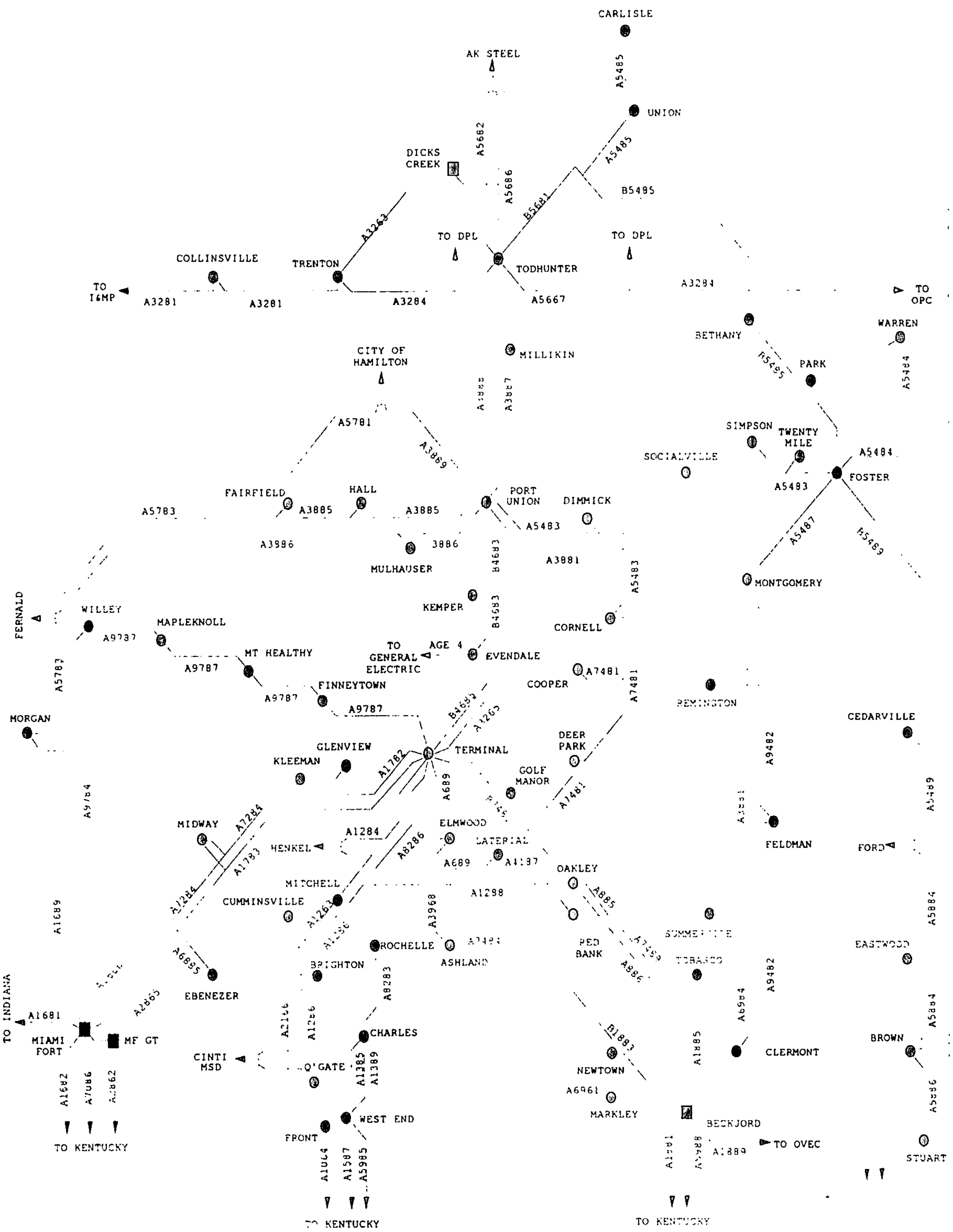
(1) Schematic maps showing the existing transmission system within the State of Ohio, and presently proposed additions to be made during years zero through ten of the forecast term are shown on the next page for the 345 kV system, and on the following page for the 138 kV system. The corresponding geographic map is contained in a pocket envelope located at the back of the Ohio Appendix.

(2) Copies of the maps described in Paragraph (C) (1) on a scale of 1:250,000 have been provided jointly by the several Ohio electric utilities.



TEN YEAR RESOURCE PLAN
SCHEMATIC MAP OF THE
CG&E 345KV SYSTEM
2000-2009

GENERATING STATION
PROPOSED GEN. STA.
EXISTING SUBSTATION
PROPOSED SUBSTATION
CUSTOMER SUBSTATION
UC UNDER CONST
() - YEAR IN SERV



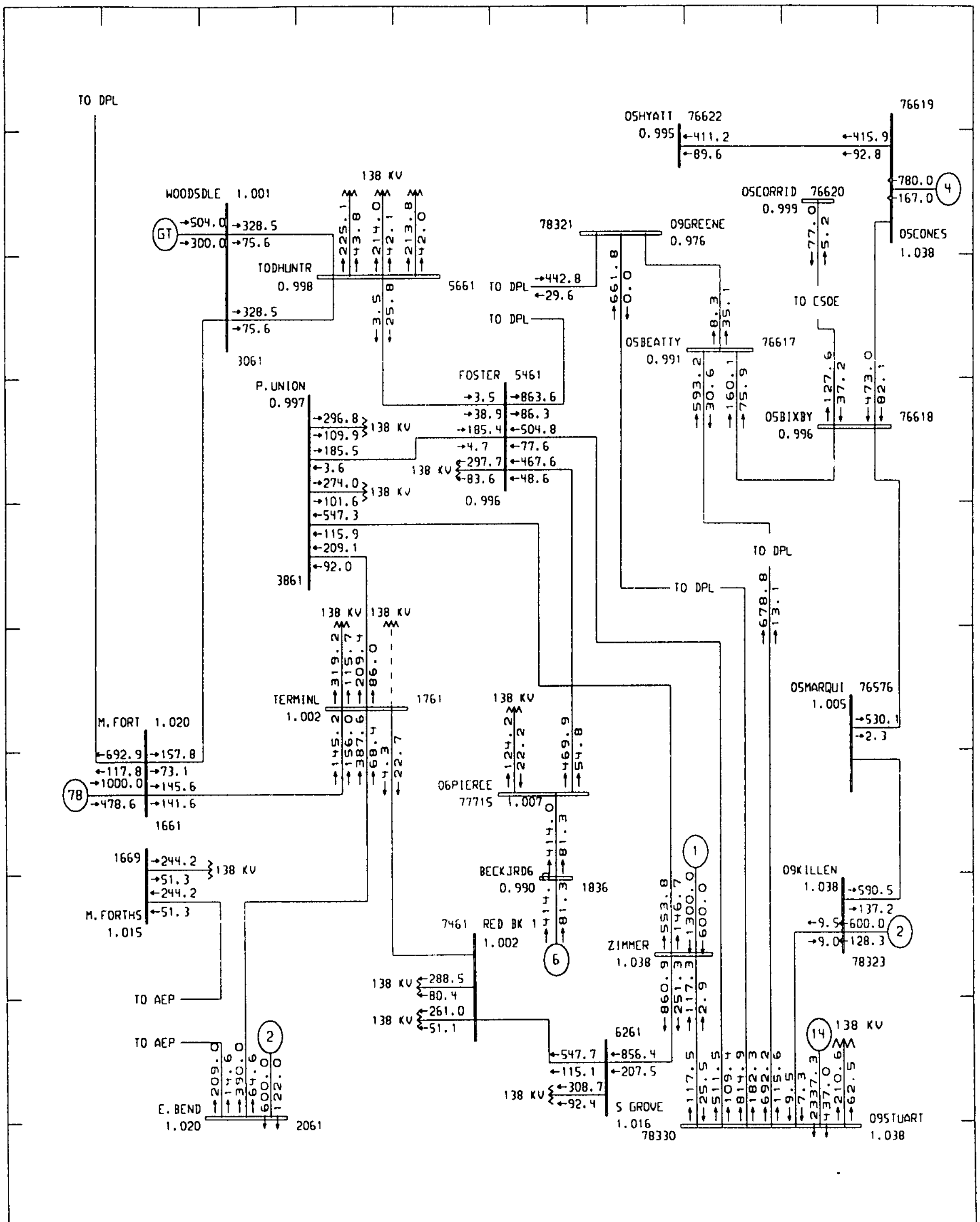
TEN YEAR RESOURCE PLAN
SCHEMATIC MAP
CG&E 138KV SYSTEM
2000 - 2009

GENERATING STATION
PROPOSED GEN. STA.
EXISTING SUBSTATION
PROPOSED SUBSTATION
CUSTOMER SUBSTATION

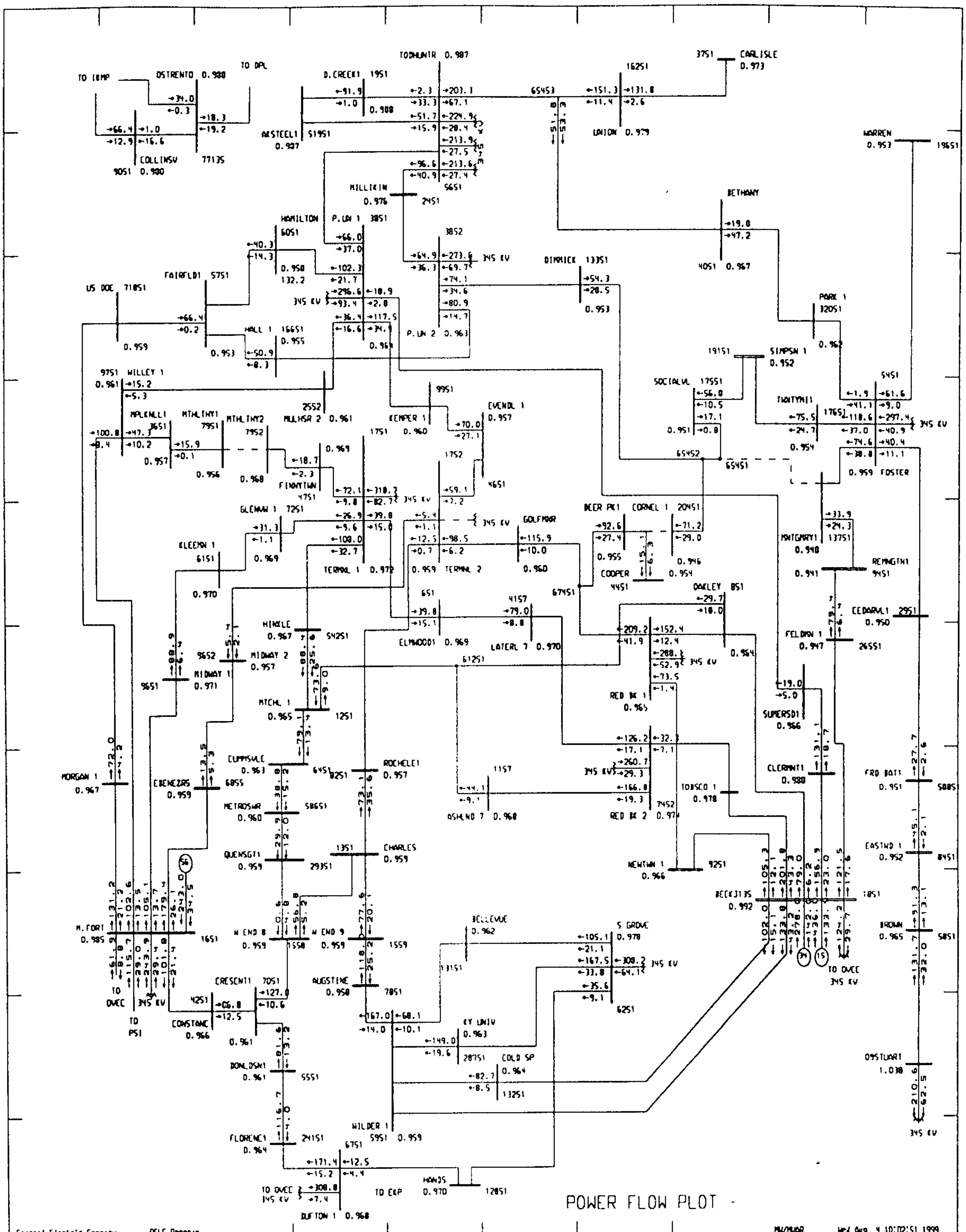
A - 138KV CONST
B - 345KV CONST
UC UNDER CONST
() - YEAR IN SERV
ALL LINES CGE

(D)(1) BASE CASE PLOTS

See IRP Chapter 7, Section C: DESCRIPTION OF TRANSMISSION SYSTEM EXPANSION PLANS, for discussion of power flow analysis of the CG&E transmission system. Graphic plots of the CG&E 138 kV and 345 kV systems that show the MW and MVAR flows and the bus voltages have been prepared. Plots of 138 kV system and 345 kV system for the 1999 summer base case are on the next page and following page, respectively. The 2003 summer base case plots are presented on the following two pages.



General Electric Company	PSLF Program		MW/MVAR Wed Aug 4 10:01:26 1999
CINERGY ELECTRIC SYSTEM PLANNING	990125-5-04 (0) (1) POWER FLOW PLOT - CG&E 345 KV SYSTEM 1999 SUMMER BASE CASE		LTFRdir/345ltfr99.drw LTFRdir/99LTFRCASE.sav

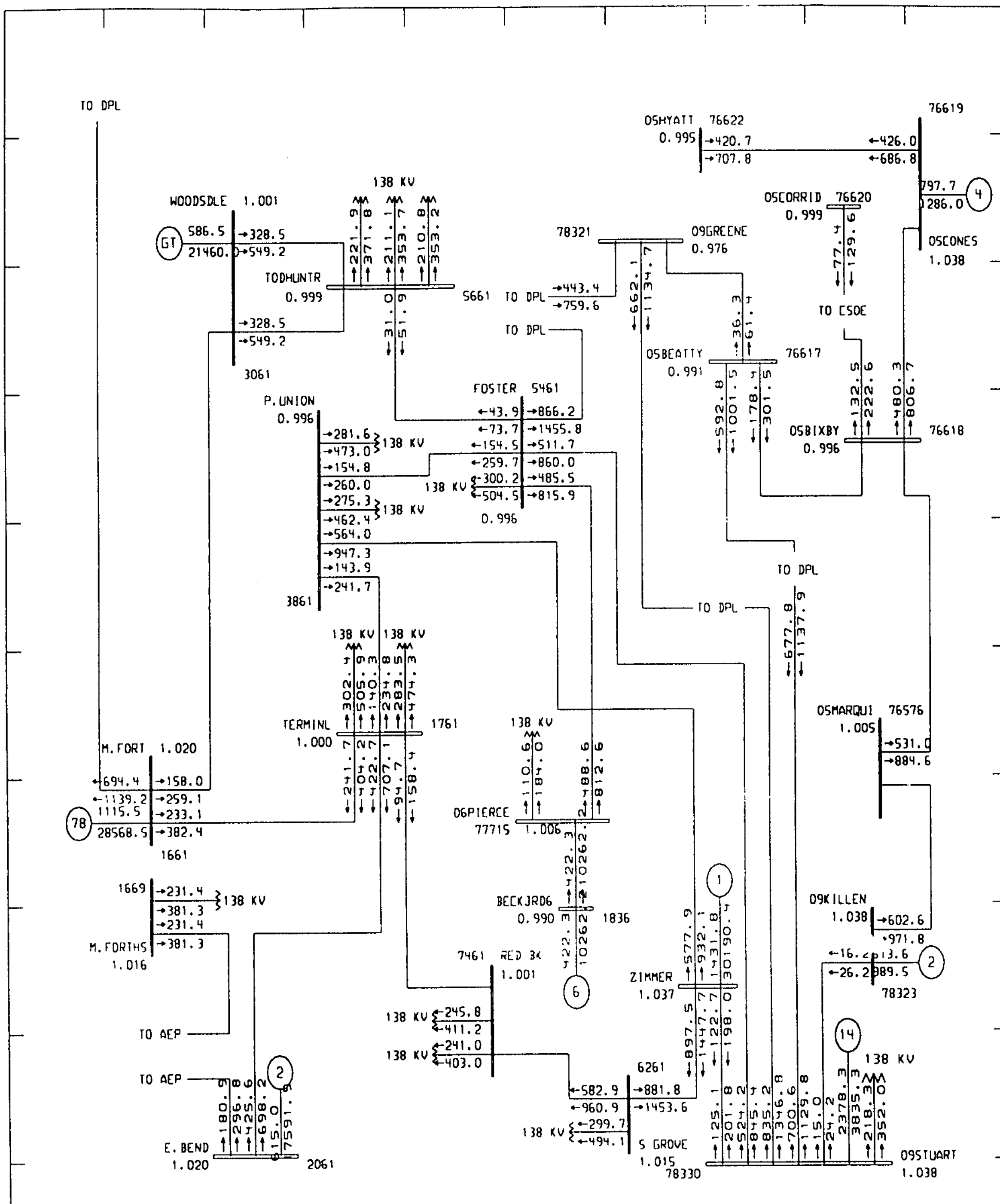


General Electric Company   PSLF Program   MW/MVAR   Wed Aug 4 10:02:51 1999

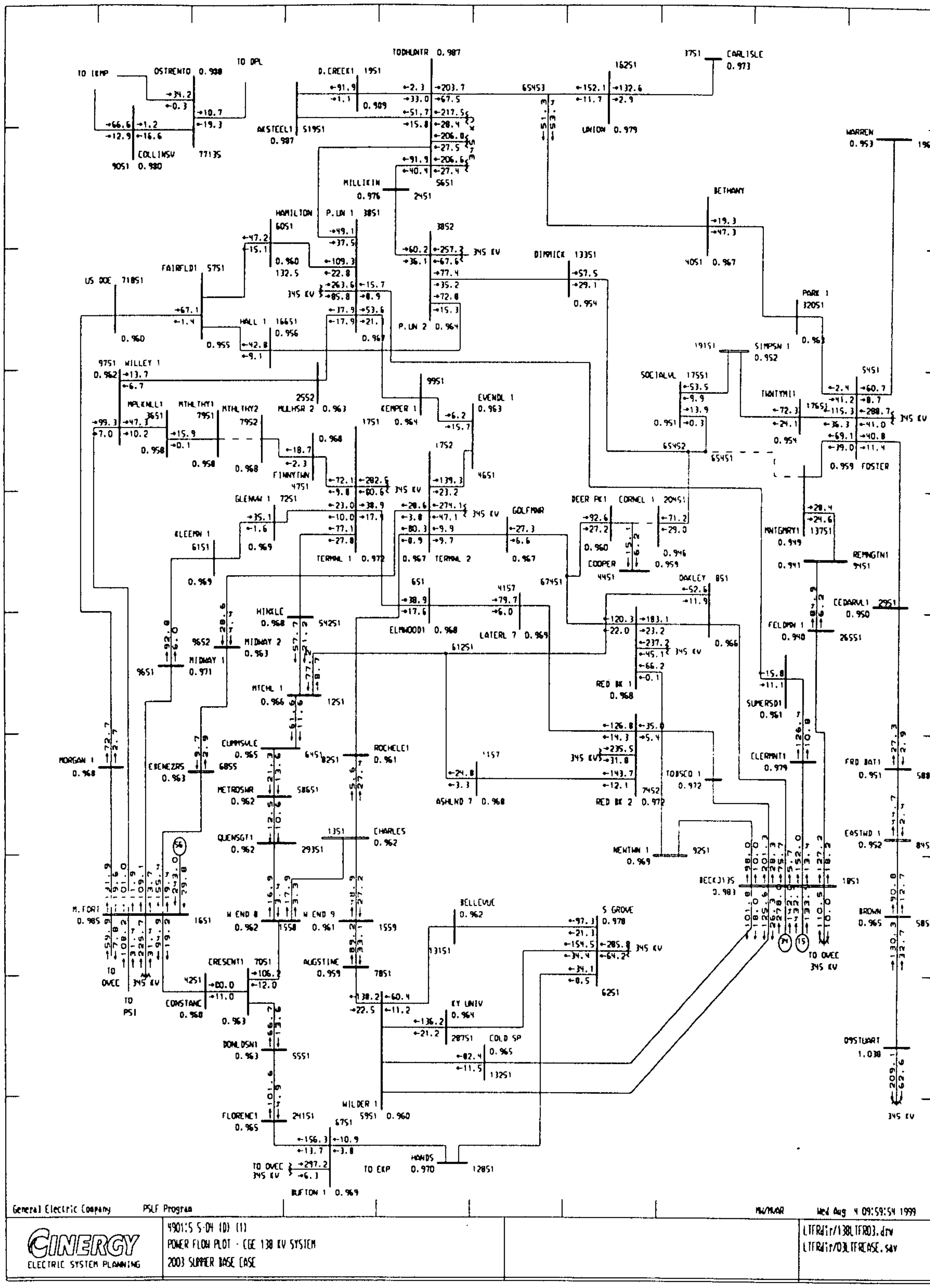
CINERGY
ELECTRIC SYSTEM PLANNING

490125-5-04 (0) (1)
POWER FLOW PLOT - CG&E 345 KV SYSTEM
1999 SUMMER BASE CASE

LTFRdir/138LTFR99.drw
LTFRdir/99LTFRCASE.sav



General Electric Company	PSLF Program	MVA/AMPS Tue Aug 17 13:46:48 1999
CINERGY ELECTRIC SYSTEM PLANNING	4901:5-5-04 (D) (1) POWER FLOW PLOT - CGE 345KV SYSTEM 2003 SUMMER BASE CASE	/home/stehlin/irp 1999/345ltr irp 1999/irp99.sav


General Electric Company
PSLF Program
MW/MVAR
Wed Aug 4 09:59:54 1999
CINERGY
ELECTRIC SYSTEM PLANNING
POWER FLOW PLOT - CGE 138 KV SYSTEM
2003 SUMMER BASE CASE

(D)(2) CONTINGENCY CASES

Contingency cases based on the peak load base cases are studied to determine system performance for generation and transmission system outages. The results of such studies are used as bases for the determination of the need for and timing of additions to the transmission system. The several power flow outage cases described below can be considered representative of the types of outages studied. All cases are based on the 1999 Summer Peak Load Power Flow Base Case, with Terminal 345-138 kV Bank 11 out of service. The cases studied and the results are as follows:

Outage Case No. 1: Outage of the 400 MVA, 345-138 kV autotransformer TB 11 at Foster Substation.

Results: In the base case, this transformer carries 302 MVA. When it is removed, this flow is redistributed on the 69 kV, 138 kV and 345 kV systems, resulting in large percentage changes in the flows on a large number of system components. The Feeder CGE-A5483 between the Port Union and Dimmick substations loads to 102% of its normal rating and 85% of the emergency rating, while Beckjord to Feldman portion of Feeder CGE-A9482 loads to 102% of its normal rating and 84% of the emergency rating of the conductor. It appears that voltage-regulating equipment at the distribution supply stations will compensate for the lowered transmission voltages. Switching could be performed on the 138 kV system to reduce the loading if necessary. Performance for this outage is acceptable.

Outage Case No. 2: Outage of the Wilder-West End circuit CGE-A5985 at the same time that the Terminal-Rochelle circuit CGE-A8286 is unavailable for service. A portion of the CGE-A8286 circuit consists of underground pipe-type cable. This type of construction is exceptionally reliable, but could require long repair time in the event of an outage.

Results: This double contingency outage represents a large disturbance to the 138 kV system. The most serious effect is the loading on two 138 kV circuits. The Charles-West End Feeder CGE-A1389 loads to 113% of its normal rating, while the Buffington-Florence portion of the Feeder CGE-A6782 loads to 101% of its normal rating. These loading correspond to 93%

and 90%, respectively, of the summer emergency ratings of the circuits. Voltages do not drop significantly for this outage scenario. These conditions are considered tolerable for a double-contingency outage condition. Reinforcement projects may be required in this area in the future to address the above overloads.

Outage Case No. 3: Outage of the 400 MVA, 345-138 kV autotransformer TB 27 at Red Bank Substation.

Results: This transformer carries 291 MVA in the base case. This outage results in many power flow shifts, on the various system components. No Facility carries load in excess of normal rating. The 138 kV Feeder CGE-A6885, between the Miami Fort and Ebenezer substations, loads to 113% of its normal rating and 93% of the emergency rating of the conductor. The 138 kV Feeder CGE-A7484, between Red Bank and Ashland substations, is loaded to 96% of normal rating and 77% of the emergency rating of the conductor. No component is loaded above its emergency rating, which is acceptable performance. Switching could be performed on the 138 kV system to reduce the loading if necessary. This outage scenario has a relatively minor effect on system voltages. The voltage drops by 1.0% or more at 5 busses.

__Outage Case No. 4__: Outage 400 MVA, 345-138 kV autotransformer, TB 11, at Foster Substation and the 138 kV Feeder CGE-A5485 between the Todhunter and Foster substations.

__Results__: This transformer carries 302 MVA in the base case, and their simultaneous outage results in many power flow shifts on the various system components. The most serious effect of this double contingency outage is Feeder CGE-A5483 loads to 145% of its normal rating and 120% of its emergency rating. Switching could be performed on the 138 kV system to reduce the loading if necessary. This double contingency outage produces a large voltage effect at the substations served by the above three feeders, and also on the underlying 69 kV system. It appears that voltage-regulating equipment, at the distribution supply stations, could compensate for the lowered transmission voltages. Performance for this outage is acceptable.

4901:5-5-04 (D)(3),(D)(4),(D)(7) RELIABILITY ANALYSIS, ADEQUACY, TRANSMISSION SYSTEM CHANGES FOR NEW RESOURCES

(D)(3) As discussed on the previous pages, a number of contingency cases, predicated on the various base cases, have been studied. These contingency cases include loss of transformer and/or loss of transmission circuit, as well as unscheduled variation of generation dispatch. These contingency cases seek to model system performance under various conditions that are common to electric system operation. The general criteria applied to these studies are that the loss of either a major transformer or transmission circuit should not cause loading on any of the remaining transformers or circuits to exceed their emergency thermal ratings. In addition, double-contingency outages, which include at least one 345 kV system component, should likewise not cause loading on any remaining components to exceed the emergency thermal ratings. Probability of occurrence, availability of mitigating procedures, and other factors are considered when these reliability analyses are performed and evaluated.

(D)(4) The contingency cases and reliability analyses described above indicate the performance of the transmission system subsequent to outages, which may be caused by natural disasters. As discussed above, the transmission system is designed to withstand certain outages without causing loading on the remaining system components to exceed emergency thermal load ratings. More severe outages may cause system components to overload. Such overloads, if not corrected by switching or other actions, may cause loss of life of the overloaded system components. Some outages may be of such a severity that all of the load could not be served. The transmission system could also be segmented to such a degree that all of the load could not be served.

(D)(7) There are currently no planned transmission system changes associated with any options identified under Rule 4901:5-5-03, Paragraph (D)(1). There may be changes to the transmission system associated with new generating units, however, depending on their location(s).

(E) (1) **TRANSMISSION FORECAST FORMS**

(a) The following forms FE3-1, ***Characteristics of Existing Transmission Lines,*** summarize the characteristics of the transmission lines existing as of the writing of this report. The forms are separated into several groups. The first group is of lines designed to operate at 138 kV. The second group is of wholly owned lines designed to operate at 345 kV. The remaining groups are of lines designed to operate at 345 kV which are jointly owned with other utilities. The line numbers correspond to those shown on the schematic diagrams and geographic maps of section 4901:5-5-04 (B).

THE CINCINNATI GAS & ELECTRIC COMPANY
4901:5-5-04(E)(1)(a)
FORM FE3-1: CHARACTERISTICS OF EXISTING TRANSMISSION LINES

WHOLLY OWNED TRANSMISSION LINES DESIGNED FOR 138 KV OPERATION

CIRCUIT NO. CGE-A	LINE NAME	ORIGIN	TERMINUS	VOLTAGE (KV) OPER. LEVEL	VOLTAGE (KV) DESIGN LEVEL	R-O-W LENGTH (MILES)	SUPPORTING STRUCTURES	NUMBER OF CIRCUITS	SUBSTATIONS ON THE LINE
GE4	Evendale-GE Ram Jet	Evendale	Tower No. 2	138	138	0.17	Steel Tower	1	
684	Elmwood-Lateral	Elmwood	Lateral						
	Section 1			138	138	1.34	Wood Pole	1	
	Section 2			138	138	2.37	Steel Tower	2	
689	Elmwood-Terminal	Elmwood	Terminal	138	138	1.40	Wood Pole	1	
885	Oakley-Red Bank	Oakley	Red Bank	138	138	1.09	Steel Tower	2	
886	Oakley-Beckjord	Oakley	Beckjord	138	138	16.45	Steel Tower	2	
1064	Front-Wilder	Front	Ohio/Ky. St. Line	69	138	0.20	Steel Tower	2	
1263	Mitchell-Brighton	Mitchell	Brighton	69	138	4.20	Steel Tower	2	
1284	Mitchell-Terminal	Mitchell	Terminal	138	138	3.61	Steel Tower	2	Henkel Corp.
1286	Mitchell-West End	Mitchell	West End	138	138	8.18	Steel Tower	2	Cumminsville, Queensgate, Metro Sewer Dist.
1288	Mitchell-Ashland-Oakley	Mitchell	Oakley, Ashland						
	Section 1			138	138	1.30	Steel Tower	1	
	Section 2			138	138	7.33	Steel Tower	2	
1385	Charles-West End	Charles	West End	138	138	1.11	Underground	1	
1389	Charles-West End	Charles	West End	138	138	1.12	Underground	1	
1587	West End-Crescent	West End	Ohio/Ky. St. Line	138	138	0.30	Steel Tower	1	
1666	Miami Fort-Monsanto	Miami Fort	Tower No. 30	69	138	6.39	Steel Tower	2	
1681	Miami Fort-Greendale	Miami Fort	Ohio/Ind. St. Line	138	138	0.86	Steel Tower & Wood Pole	1	
1682	Miami Fort-[illegible] Creek	Miami Fort	Ohio/Ky. St. Line	138	138	0.30	Wood H-Frame	1	
1688	Miami Fort-MFGT	Miami Fort	Miami Fort GT	138	138	0.34	Wood Pole	1	
1689	Miami Fort-Morgan	Miami Fort	Morgan	138	138	8.16	Steel Tower	2	
1782	Terminal-Glenview	Terminal	Glenview						
	Section 1			138	138	5.03	Steel Tower	2	
	Section 2			138	138	0.60	Wood H-Frame	1	
1783	Terminal-Ebenezer	Terminal	Ebenezer						
	Section 1			138	138	9.98	Steel Tower	2	
	Section 2			138	138	3.64	Wood Pole	1	
	Section 3			138	138	0.13	Wood H-Frame	1	Midway
1881	Beckjord-Wilder	Beckjord	Ohio/Ky. St. Line	138	138	0.32	Steel Tower	2	
1885	Beckjord-Tobasco	Beckjord	Tobasco	138	138	5.84	Steel Tower	2	
1889	Beckjord-Pierce	Beckjord	Pierce	138	138	0.22	Steel Tower	1	
2166	Brighton-Front	Brighton	Front	69	138	3.45	Steel Tower	2	
2862	Miami Fort GT-Villa	Miami Fort GT	Ohio/Ky. St. Line	69	138	0.14	Steel Tower	2	
2865	Miami Fort GT-Monsanto	Miami Fort GT	Tower No. 30	69	138	6.39	Steel Tower	2	
3263	Trenton-Middletown Oxygen	Tower No.1	Tower No. 17	69	138	2.77	Steel Tower	1	
3265	Trenton-Terminal	Trenton	Terminal						
	Section 1			69	138	0.45	Steel Tower	1	
	Section 2			69	138	1.20	Wood Pole	1	
3281	Trenton-College Corner	Trenton	Ohio/Ind. St. Line	138	138	24.11	Steel Tower	2	Collinsville
3284	Trenton-Hillsboro	Trenton	H-Frame No. 570	138	138	18.11	Wood H-Frame	1	
3881	Port Union-Summerside	Port Union	Summerside	138	138	22.74	Steel Tower	2	
3885	Port Union-Fairfield	Port Union	Fairfield	138	138	6.59	Steel Tower	2	Hall
3886	Port Union-Willey	Port Union	Willey	138	138	14.30	Steel Tower	2	Mulhauser
3887	Port Union-Todhunter	Port Union	Todhunter	138	138	9.69	Steel Tower	2	Millikin
3888	Port Union-Todhunter	Port Union	Todhunter	138	138	9.69	Steel Tower	2	
3889	Port Union-City of Hamilton	Port Union	City of Hamilton	138	138	4.65	Wood Pole	1	
3968	Central-Ashland	Tower No. 37	Tower No. 58	69	138	3.43	Steel Tower	2	
4187	Lateral-Red Bank	Lateral	Red Bank	138	138	2.90	Steel Tower	2	
4861	Ivorydale-Terminal	Tower No. 1	Tower No. 5	69	138	0.90	Steel Tower	2	
5483	Foster-Port Union	Foster	Port Union						
	Section 1			138	138	9.19	Steel Tower	2	Dimmick, Montgomery
	Section 2			138	138	8.39	Wood Pole	1	Twenty Mile, Cornell, Simpson, Socialville

THE CINCINNATI GAS & ELECTRIC COMPANY
4901:5-5-04(E)(1)(a)
FORM FE3-1: CHARACTERISTICS OF EXISTING TRANSMISSION LINES
WHOLLY OWNED TRANSMISSION LINES DESIGNED FOR 138 KV OPERATION

CIRCUIT NO. CGE-A	LINE NAME	ORIGIN	TERMINUS	VOLTAGE (KV) OPER. LEVEL	VOLTAGE (KV) DESIGN LEVEL	R-O-W LENGTH (MILES)	SUPPORTING STRUCTURES	NUMBER OF CIRCUITS	SUBSTATIONS ON THE LINE
5485	Foster-AK Steel	Foster	AK Steel						
	Section 1			138	138	2.96	Steel Tower	2	
	Section 2			138	138	9.77	Wood Pole	1	Carlisle, Union
5487	Foster-Remington	Foster	Remington						
	Section 1			138	138	13.40	Steel Tower	2	Montgomery
	Section 2			138	138	4.45	Wood Pole	1	
5489	Foster-Ford	Foster	Ford						
	Section 1			138	138	17.97	Wood Pole	1	Cedarville
	Section 2			138	138	4.86	Wood H-Frame	1	
5484	Foster-Warren	Foster	Warren	138	138	8.70	Wood pole	1	
5666	Todhunter-Manchester	Tower No. 17	Tower No. 20	69	138	0.55	Steel Tower	1	
5667	Todhunter-Kings Mills	Todhunter	Monroe	69	138	1.43	Wood H-Frame	1	
5681	Todhunter-AK Steel	Todhunter	AK Steel	138	138	2.96	Steel Tower	2	
5682	Todhunter-AK Steel	Todhunter	AK Steel	138	138	2.34	Steel Tower	2	
5686	Todhunter-AK Steel	Todhunter	AK Steel						
	Section 1			138	138	2.34	Steel Tower	2	
	Section 2			138	138	0.33	Steel Tower	1	Dicks Creek
5781	Fairfield-City of Hamilton	Fairfield	City of Hamilton	138	138	6.05	Wood Pole	1	
5783	Fairfield-Morgan	Fairfield	Morgan	138	138	16.50	Steel Tower	2	Fernald (USDOE)
5884	Brown-Ford	Brown	Ford						
	Section 1			138	138	4.91	Wood Pole	1	Eastwood
	Section 2			138	138	14.50	Wood H-Frame	1	
5886	Brown-Stuart	Brown	Stuart	138	138	21.16	Wood H-Frame	1	
5985	Wilder-West End	Ohio/Ky. St. Line	West End	138	138	0.20	Steel Tower	2	
5988	Wilder-Beckjord	Ohio/Ky. St. Line	Beckjord	138	138	0.37	Steel Tower	2	
6885	Ebenezer-Miami Fort	Ebenezer	Miami Fort						
	Section 1			138	138	10.26	Steel Tower	2	
	Section 2			138	138	4.92	Wood Pole	1	
6961	Summerside-Markley	Pole No. 601	Markley	69	138	1.70	Wood Pole	1	
6984	Summerside-Beckjord	Summerside	Beckjord	138	138	10.44	Steel Tower	2	Clermont
7086	Crescent-Miami Fort	Ohio/Ky. St. Line	Miami Fort	138	138	0.13	Steel Tower	2	
7284	Glenview-Miami Fort	Glenview	Miami Fort						
	Section 1			138	138	0.60	Wood H-Frame	1	
	Section 2			138	138	15.07	Steel Tower	2	Kleeman
	Section 3			138	138	0.12	Wood H-Frame	1	Midway
7481	Red Bank-Terminal	Red Bank	Terminal	138	138	9.10	Wood Pole	1	Deer Park
7484	Red Bank-Ashland	Red Bank	Ashland						
	Section 1			138	138	0.96	Steel Tower	2	
	Section 2			138	138	0.12	Wood Pole	1	
	Section 3			138	138	4.24	Underground	1	
7489	Red Bank-Tobasco	Red Bank	Tobasco						
	Section 1			138	138	9.64	Steel Tower	2	
	Section 2			138	138	0.07	Wood Pole	1	
8283	Rochelle-Charles	Rochelle	Charles	138	138	2.38	Underground	1	
8286	Rochelle-Terminal	Rochelle	Terminal						
	Section 1			138	138	3.56	Steel Tower	2	
	Section 2			138	138	1.25	Wood Pole	1	
	Section 3			138	138	1.32	Underground	1	
9482	Remington-Beckjord	Remington	Beckjord	138	138	19.08	Steel Tower	2	Feldman
9784	Willey-Miami Fort	Willey	Miami Fort	138	138	14.95	Steel Tower	2	
9787	Willey-Terminal	Willey	Terminal						
	Section 1			138	138	5.68	Wood H-Frame	1	Mapleknoll
	Section 2			138	138	11.71	Wood Pole	1	Mt. Healthy, Finneytown
	Section 3'			138	138	0.50	Steel Tower	2	

THE CINCINNATI GAS & ELECTRIC COMPANY
4901:5-5-04(E)(1)(a)
FORM FE3-1: CHARACTERISTICS OF EXISTING TRANSMISSION LINES
WHOLLY OWNED TRANSMISSION LINES DESIGNED FOR 345 KV OPERATION

CIRCUIT NO. CGE-B	LINE NAME	ORIGIN	TERMINUS	VOLTAGE (KV) OPER. LEVEL	VOLTAGE (KV) DESIGN LEVEL	R-O-W LENGTH (MILES)	SUPPORTING STRUCTURES	NUMBER OF CIRCUITS	SUBSTATIONS ON THE LINE
04	Miami Fort-Tanners Creek	Miami Fort	Ohio/Ky. St. Line	345	345	0.32	Steel Tower	2	
08	Port Union-Foster	Port Union	Foster						
	Section 1			345	345	11.66	Steel Tower	2	
	Section 2			345	345	0.24	Steel Tower	1	
13	Terminal-Port Union	Terminal	Port Union						
	Section 1			345	345	0.46	Steel Tower	1	
	Section 2			345	345	9.65	Steel Tower	2	
14	Miami Fort-Terminal								
	Section 1	Terminal	Ohio/Ky. St. Line	345	345	14.84	Steel Tower	2	
	Section 2	Miami Fort	Ohio/Ky. St. Line	345	345	0.32	Steel Tower	2	
15	Foster-Todhunter	Foster	Todhunter	345	345	15.79	Steel Tower	2	
16	East Bend-Terminal	Ohio/Ky. St. Line	Terminal	345	345	14.84	Steel Tower	2	
62	Woodsdale-Todhunter	Woodsdale	Todhunter	345	345	4.68	Steel Tower	2	
1883	Beckjord-Red Bank	Beckjord	Red Bank						
	Section 1			138	345	0.89	Steel Tower	1	
	Section 2			138	345	13.82	Steel Tower	2	Newtown
4683	Evendale-Port Union	Evendale	Port Union						
	Section 1			138	345	0.52	Steel Tower	1	
	Section 2			138	345	5.48	Steel Tower	2	Kemper
4685	Evendale-Terminal	Evendale	Terminal						
	Section 1			138	345	0.21	Steel Tower	1	
	Section 2			138	345	4.02	Steel Tower	2	
5485	Foster-AK Steel	Foster	AK Steel						
	Section 1			138	345	0.41	Steel Tower	1	
	Section 2			138	345	13.58	Steel Tower	2	Park, Bethany
5681	Todhunter-AK Steel	Todhunter	AK Steel	138	345	1.77	Steel Tower	2	
7481	Red Bank-Terminal	Red Bank	Terminal						
	Section 1			138	345	5.72	Steel Pole	2	Golf Manor
	Section 2			138	345	0.90	Steel Tower	2	Cooper

THE CINCINNATI GAS & ELECTRIC COMPANY
4901:5-5-04(E)(1)(a)
FORM FE3-1: CHARACTERISTICS OF EXISTING TRANSMISSION LINES
COMMONLY OWNED TRANSMISSION - CG&E, CSP AND DP&L COMPANIES
TENANTS IN COMMON WITH UNDIVIDED OWNERSHIP, TOTAL MILEAGE GIVEN

CIRCUIT NO. CCD-B	LINE NAME	ORIGIN	TERMINUS	VOLTAGE (KV) OPER. LEVEL	VOLTAGE (KV) DESIGN LEVEL	R-O-W LENGTH (MILES)	SUPPORTING STRUCTURES	NUMBER OF CIRCUITS	SUBSTATIONS ON THE LINE
01	Beckjord-Pierce	Beckjord	Pierce	345	345	0.32	Steel Tower	1	
02	Pierce-Foster	Pierce	Foster						
	Section 1			345	345	23.38	Steel Tower	2	
	Section 2			345	345	0.57	Steel Tower	1	
03	Sugarcreek-Greene	Sugarcreek	Greene	345	345	8.30	Steel Tower	1	
06	Greene-Beatty	Greene	Beatty						
	Section 1			345	345	3.66	Steel Tower	2	
	Section 2			345	345	45.34	Steel Tower	1	
07	Marquis-Bixby	Marquis	Bixby						
	Section 1			345	345	63.16	Steel Tower	1	
	Section 2			345	345	8.52	Steel Tower	2	
09	Stuart-Greene	Stuart	Greene	345	345	80.38	Steel Tower	1	
10	Stuart-Killen	Stuart	Killen Tap	345	345	13.13	Steel Tower	1	
11	Stuart-Foster	Stuart	Foster						
	Section 1			345	345	55.77	Steel Tower	1	
	Section 2			345	345	3.20	Steel Tower	2	
24	Foster-Sugarcreek	Foster	Sugarcreek						
	Section 1			345	345	3.20	Steel Tower	2	
	Section 2			345	345	24.13	Steel Tower	1	
31	Beatty-Bixby	Beatty	Bixby						
	Section 1			345	345	4.69	Steel Tower	1	
	Section 2			345	345	8.52	Steel Tower	2	
33	Kirk-Corridor	Kirk	Corridor	345	345	18.36	Wood H-Frame	1	
40	Conesville-Hyatt	Conesville	Hyatt						
	Section 1			345	345	66.07	Steel Tower	1	
	Section 2			345	345	1.78	Wood Pole	1	
	Section 3			345	345	0.48	Wood H-Frame	1	
41	Stuart-Zimmer	Stuart	Zimmer						
	Section 1			345	345	35.13	Steel Tower	1	
	Section 2			345	345	0.78	Steel Tower	2	
42	Atlanta-Beatty	Atlanta	Beatty						
	Section 1			345	345	3.68	Steel Tower	2	
	Section 2			345	345	25.22	Steel Tower	1	
43	Conesville-Bixby	Conesville	Bixby						
	Section 1			345	345	14.87	Steel Tower	2	
	Section 2			345	345	50.86	Wood H-Frame	1	
44	Zimmer-Port Union	Zimmer	Port Union						
	Section 1			345	345	35.88	Steel Tower	2	
	Section 2			345	345	10.03	Steel Tower	1	
45	Zimmer-Red Bank								
	Section 1	Zimmer	Ohio/Ky. St. Line	345	345	0.43	Steel Tower	1	
	Section 2	Red Bank	Tower No. 24	345	345	10.58	Steel Tower	2	
	Section 3	Tower No. 23	Ohio/Ky. St. Line	345	345	0.80	Steel Tower	1	
46	Red Bank-Terminal	Red Bank	Terminal						
	Section 1			345	345	5.75	Steel Pole	2	
	Section 2			345	345	0.90	Steel Tower	2	
47	Bixby-Kirk	Bixby	Kirk						
	Section 1			345	345	14.57	Steel Tower	2	
	Section 2			345	345	4.20	Wood H-Frame	1	
49	Killen-Marquis	Killen Tap	Marquis	345	345	32.01	Steel Tower	1	
52	Stuart-Atlanta	Stuart	Atlanta	345	345	65.00	Steel Tower	1	

THE CINCINNATI GAS & ELECTRIC COMPANY
4901:5-5-04(E)(1)(a)
FORM FE3-1: CHARACTERISTICS OF EXISTING TRANSMISSION LINES
COMMONLY OWNED TRANSMISSION - CG&E AND DP&L COMPANIES
TENANTS IN COMMON WITH UNDIVIDED OWNERSHIP, TOTAL MILEAGE GIVEN

CIRCUIT NO. CD-B	LINE NAME	ORIGIN	TERMINUS	VOLTAGE (KV) OPER. LEVEL	DESIGN LEVEL	R-O-W LENGTH (MILES)	SUPPORTING STRUCTURES	NUMBER OF CIRCUITS	SUBSTATIONS ON THE LINE
61	Woodsdale-Todhunter	Woodsdale	Todhunter	345	345	4.68	Steel Tower	2	
91	Miami Fort-West Milton	Miami Fort	Tower No. 173						
	Section 1			345	345	33.25	Steel Tower	2	
	Section 2			345	345	1.37	Steel Tower	1	
92	Miami Fort-Woodsdale	Miami Fort	Woodsdale						
	Section 1			345	345	33.25	Steel Tower	2	
	Section 2			345	345	4.82	Steel Tower	1	

(E)(1) TRANSMISSION FORECAST FORMS

(b) The following forms FE3-2 ***Summary of Existing Substations,*** provide a listing of the existing CG&E and customer owned substations which are connected to transmission lines designed to operate at 138 kV or 345 kV. The existing and proposed lines associated with each station are listed. The line numbers correspond to those shown on the schematic diagrams and geographic maps of section 4901:5-5-04 (B) and (C).

THE CINCINNATI GAS & ELECTRIC COMPANY
4901:5-5-04(E)(1)(b)
FORM FE3-2: SUMMARY OF EXISTING SUBSTATIONS

SUBSTATION NAME	VOLTAGE (KV)	NAME	NUMBER	EXISTING OR PROPOSED
AK Steel	138	Foster-AK Steel	5485	Existing
		Todhunter-AK Steel	15681	Existing
		Todhunter-AK Steel	15682	Existing
		Todhunter-AK Steel	15686	Existing
Ashland	138	Mitchell-Ashland-Oakley	1288	Existing
		Central-Ashland	3968	Existing
		Red Bank-Ashland	7484	Existing
Beckjord	345 & 138	Oakley-Beckjord	886	Existing
		Beckjord-Red Bank	1883	Existing
		Beckjord-Tobasco	1885	Existing
		Beckjord-Pierce	1889	Existing
		Remington-Beckjord	9482	Existing
		Beckjord-Wilder	1881	Existing
		Wilder-Beckjord	5988	Existing
		Summerside-Beckjord	6984	Existing
		Beckjord-Pierce	4501	Existing
Bethany	138	Foster-AK Steel	5485	Existing
Brighton	69	Brighton-Front	2166	Existing
		Mitchell-Brighton	1263	Existing
Brown	138	Brown-Stuart	5886	Existing
		Brown-Eastwood	5884	Existing
Carlisle	138	Foster-AK Steel	5485	Existing
Cedarville	138	Foster-Ford	5489	Existing
Charles	138	Charles-West End	1385	Existing
		Charles-West End	1389	Existing
		Rochelle-Charles	8283	Existing
Cinti. M.S.D.	138	Mitchell-West End	1286	Existing
City of Hamilton	138	Port Union-City of Ham.	3889	Existing
		Fairfield-City of Hamilton	5781	Existing
Clermont	138	Summerside-Beckjord	6984	Existing
Collinsville	138	Trenton-College Corner	3281	Existing
Cooper	138	Red Bank-Terminal	7481	Existing
Cornell	138	Red Bank-Terminal	7481	Existing
		Port Union-Foster	5483	Existing
Cumminsville	138	Mitchell-West End	1286	Existing
Deer Park	138	Red Bank-Terminal	7481	Existing
Dicks Creek	138	Todhunter-AK Steel	5686	Existing
Dimmick	138	Foster-Port Union	5483	Existing
Eastwood	138	Brown-Ford	5884	Existing
Ebenezer	138	Terminal-Ebenezer	1783	Existing
		Ebenezer-Miami Fort	6885	Existing
Elmwood	138	Elmwood-Lateral	684	Existing
		Elmwood-Terminal	689	Existing
Evendale	138	Evendale-Port Union 4683	Existing	
		Evendale-Terminal	4685	Existing
		Evendale-General Electric	GE4	Existing
Fairfield	138	Fairfield-Morgan	5783	Existing
		Port Union-Fairfield	3885	Existing
		Fairfield-City of Hamilton	5781	Existing
Feldman	138	Remington-Beckjord	9482	Existing
FERMCO	138	Fairfield-Morgan	5783	Existing
Finneytown	138	Willey-Terminal	9787	Existing
Ford	138	Foster-Ford	5489	Existing
		Brown-Ford	5884	Existing
Foster	345 & 138	Foster-Port Union	5483	Existing
		Foster-Remington	5484	Existing
		Foster-AK Steel	5485	Existing
		Foster-Cedarville	5489	Existing
		Pierce-Foster	4502	Existing
		Stuart-Foster	4511	Existing
		Port Union-Foster	4508	Existing
		Foster-Todhunter	4515	Existing
		Foster-Sugarcreek	4524	Existing
Front	69	Front-Wilder	1064	Existing
		Brighton-Front	2166	Existing

THE CINCINNATI GAS & ELECTRIC COMPANY
4901:5-5-04(E)(1)(b)
FORM FE3-2: SUMMARY OF EXISTING SUBSTATIONS

SUBSTATION NAME	VOLTAGE (KV)	NAME	NUMBER	OR PROPOSED	EXISTING
Glenview	138	Terminal-Glenview		1782	Existing
		Miami Fort-Glenview		7284	Existing
Golf Manor	138	Red Bank-Terminal		7481	Existing
Hall	138	Port Union-Fairfield		3885	Existing
Henkel Corp.	138	Mitchell-Terminal		1284	Existing
Kemper	138	Evendale-Port Union		4683	Existing
Kleeman	138	Glenview-Miami Fort		7284	Existing
Lateral	138	Elmwood-Lateral		684	Existing
		Lateral-Red Bank		4187	Existing
Mapleknoll	138	Willey-Terminal		9787	Existing
Markley	69	Summerside-Markley		6961	Existing
Miami Fort	345 & 138	Miami Fort-Greendale		1681	Existing
		Miami Fort-Clifty Creek		1682	Existing
		Miami Fort-MFGT		1688	Existing
		Miami Fort-Morgan		1689	Existing
		Ebenezer-Miami Fort		6885	Existing
		Crescent-Miami Fort		7086	Existing
		Glenview-Miami Fort		7284	Existing
		Willey-Miami Fort		9784	Existing
		Miami Fort-Miami		4591	Existing
		Miami Fort-Woodsdale		4592	Existing
		Miami Fort-Tanners Creek		4504	Existing
		Miami Fort-Terminal		4514	Existing
Miami Fort GT	138	Miami Fort-MFGT		1688	Existing
		MFGT-Villa		2862	Existing
		MFGT-Ebenezer		2865	Existing
Midway	138	Terminal-Ebenezer	1783	Existing	
		Miami Fort-Glenview	7284	Existing	
Millikin	138	Port Union-Todhunter	3887	Existing	
Mitchell	138	Mitchell-Brighton	1263	Existing	
		Mitchell-Terminal	1284	Existing	
		Mitchell-West End	1286	Existing	
		Mitchell-Ashland-Oakley	1288	Existing	
Montgomery	138	Foster-Remington		5487	Existing
		Foster-Port Union	5483	Existing	
Morgan	138	Miami Fort-Morgan	1689	Existing	
		Fairfield-Morgan		5783	Existing
Mt. Healthy		138Willey-Terminal	9787	Existing	
Mulhauser	138	Port Union-Willey	3886	Existing	
Newtown	138	Beckjord-Red .k	1883	Existing	
Oakley	138	Oakley-Red Bank		885	Existing
		Oakley-Beckjord		886	Existing
		Mitchell-Ashland-Oakley	1288	Existing	
Park	138	Foster-AK Steel		5485	Existing
Port Union	345 & 138	Port Union-Summerside		3881	Existing
		Foster-Port Union	5483	Existing	
		Port Union-Fairfield	3885	Existing	
		Port Union-Willey	3886	Existing	
		Port Union-Todhunter	3887	Existing	
		Port Union-Todhunter	3888	Existing	
		Port Union-City of Hamilton	3889	Existing	
		Evendale-Port Union	4683	Existing	
		Zimmer-Port Union	4544	Existing	
		Port Union-Foster	4508	Existing	
		Terminal-Port Union	4513	Existing	
Queensgate	138	Mitchell-West End	1286	Existing	
Red Bank	345 & 138	Red Bank-Terminal	7481	Existing	
		Lateral-Red Bank		4187	Existing
		Beckjord-Red Bank	1883	Existing	
		Red Bank-Ashland		7484	Existing
		Oakley-Red Bank		885	Existing
		Red Bank-Tobasco		7489	Existing
		Red Bank-Terminal	4546	Existing	
		Zimmer-Red Bank		4545	Existing
Remington	138	Remington-Beckjord	9482	Existing	

THE CINCINNATI GAS & ELECTRIC COMPANY
4901:5-5-04(E)(1)(b)
FORM FE3-2: SUMMARY OF EXISTING SUBSTATIONS

SUBSTATION NAME	VOLTAGE (KV)	NAME	NUMBER	OR PROPOSED	EXISTING
		Foster-Remington		5484	Existing
Rochelle	138	Rochelle-Charles		8283	Existing
		Rochelle-Terminal	8286	Existing	
Simpson	138	Foster-Port Union	5483	Existing	
Socialville	138	Foster-Port Union	5483	Existing	
Summerside	138	Port Union-Summerside		3881	Existing
		Summerside-Beckjord	6984	Existing	
Terminal	345 & 138	Elmwood-Terminal		689	Existing
		Mitchell-Terminal	1284	Existing	
		Terminal-Glenview	1782	Existing	
		Terminal-Ebenezer	1783	Existing	
		Trenton-Terminal		3265	Existing
		Evendale-Terminal	4685	Existing	
		Red Bank-Terminal	7481	Existing	
		Rochelle-Terminal	8286	Existing	
		Willey-Terminal		9787	Existing
		Terminal-Port Union	4513	Existing	
		Miami Fort-Terminal	4514	Existing	
		East Bend-Terminal	4516	Existing	
		Red Bank-Terminal	4546	Existing	
Tobasco	138	Beckjord-Tobasco		1885	Existing
		Red Bank-Tobasco		7489	Existing
Todhunter	345 &138	Port Union-Todhunter	3887	Existing	
		Port Union-Todhunter	3888	Existing	
		Todhunter-Kings Mills		5667	Existing
		Todhunter-Armco		5681	Existing
		Todhunter-Armco		5682	Existing
		Todhunter-Armco		5686	Existing
		Foster-Todhunter		4515	Existing
		Woodsdale-Todhunter	4561	Existing	
		Woodsdale-Todhunter	4562	Existing	
Trenton	138	Trenton-College Corner		3281	Existing
		Trenton-Hillsboro	3284	Existing	
		Trenton-Middletown Oxygen	3263	Existing	
Twenty Mile	138	Foster-Port Union	5483	Existing	
Union	138	Foster-Todhunter		5485	Existing
Warren	138	Foster-Warren		5484	Existing
West End	138	Mitchell-West End	1286	Existing	
	Future Charles-West End			1385	Existing
	345	Charles-West End		1389	Existing
		West End-Crescent	1587	Existing	
		Wilder-West End		5985	Existing
Willey	138	Port Union-Willey	3886	Existing	
		Willey-Miami Fort	9784	Existing	
		Willey-Terminal		9787	Existing
Woodsdale	345	Woodsdale-Todhunter	4561	Existing	
		Woodsdale-Todhunter	4562	Existing	
		Miami Fort-Woodsdale	4592	Existing	
Zimmer	345	Stuart-Zimmer		4541	Existing
		Zimmer-Port Union	4544	Existing	
		Zimmer-Red Bank		4545	Existing

(E) (2) TRANSMISSION FORECAST FORMS

(a) The following forms FE3-3, ***Specifications of Planned Electric Transmission Lines,*** present information regarding any planned new 138 kV and 345 kV transmission lines, and for other additions or changes to existing 138 kV and 345 kV transmission lines, for years zero through ten of the forecast period. Included are projects which will provide for (i) new lines requiring new rights-of-way, (ii) lines for which capacity changes in terms of voltage, current, or both are scheduled, and (iii) other changes which may be considered substantial as defined in rule 4906-1-02 of the Administrative Code. The numbers correspond to those shown on the schematic diagrams and geographic maps of section 4901:5-5-04(B) and (C). The facilities listed are those which are included in the ten-year construction schedule of the CG&E Company at the time of preparation of this report. The ten-year construction schedule is primarily used to project future financial, engineering, construction, and other requirements. It is prepared by postulating viable projects to maintain adequate system performance, based on presently known load growth forecast and other factors. Many of the listed projects have not been fully evaluated, planned, and/or budgeted, and are therefore subject to continual review and modification.

THE CINCINNATI GAS & ELECTRIC COMPANY

4901:5-5-04 (E) (2) (a)

FORM FE3-3: SPECIFICATIONS OF PLANNED ELECTRIC TRANSMISSION LINES

1. Line Name:
   Line Number:

2. Point of Origin:
   Point of Termination:

3. Right-of-Way, Length:
   Average Width:
   Number of Circuits:

4. Line Voltage:

5. Application for Certificate:

6. Construction to Commence:
   Commercial Operation:

7. Capital Investment, Estimated Line Cost:

8. Substations:

9. Supporting Structures:

10. Participation with other Utilities:

11. Purpose of Planned Line:

12. Consequence of Delay or Termination:

13. Miscellaneous:

(E) (2) **TRANSMISSION FORECAST FORMS**

(b) The following form FE3-4, ***Summary of Proposed Substations,*** lists those new substations proposed for installation during years zero through ten of the forecast period in which the highest voltage will be 138 kV or higher and any existing substations where the highest voltage is to be increased to 138 kV or higher during this time period. The existing or proposed transmission lines associated with each substation are listed, with line numbers corresponding to the schematic diagrams and geographic maps of section 4901:5-5-04 (B) and (C). The facilities listed are those which are included in the ten-year construction schedule of the CG&E Company at the time of preparation of this report. The ten-year construction schedule is primarily used to project future financial, engineering, construction, and other requirements. It is prepared by postulating viable projects to maintain adequate system performance, based on presently known load growth forecasts and other factors. Many of the listed projects have not been fully evaluated, planned, and/or budgeted, and are therefore subject to continual review and modification.

THE CINCINNATI GAS & ELECTRIC COMPANY
4901:5-5-04(E)(2)(b)
FORM FE3-4: SUMMARY OF PROPOSED SUBSTATIONS

SUBSTATION NAME	VOLTAGE (KV)	TIMING			LINE ASSOCIATION(S)	
		1	2	3		

TIMING	
1	Application Date
2	Begin Construction
3	In-Service Date

(F) ECAR

Information relating to ECAR and bulk power requirements is provided to the PUCO by ECAR on behalf of CG&E and the several Ohio electrical utilities.

STATUS

Improvements for Cinergy Reorganization

There are currently no in-progress or planned transmission system projects affecting any CG&E facilities which are intended to provide additional resource.

Section 4(15) System-Wide Reliability Measure

At the present time, there is no measure of system-wide reliability that covers the entire system (transmission, distribution, and generation). Cinergy is in the process of developing a software analysis program, in conjunction with ABB and Duke Power Company, that calculates overall system reliability indices utilizing outage rates and repair times for generating units and transmission components. Cinergy expects this program to be useful in developing overall system reliability factors.

PSI 138 kV Transmission Project Descriptions

The following transmission projects include new circuits and upgrades of existing circuits.

A new 0.3 mile 138kV loop will be constructed from the existing Gallagher - Jeffersonville 138kV circuit into the existing Clarksville substation. This line is scheduled for an in service date of 4/30/01. A new 138-69kV transformer will be installed at the Clarksville substation. This project is required to satisfy the planning criteria of withstanding a single contingency outage. The alternatives evaluated for this project involved various combinations of new 69 and 138kV facilities along with reconductoring of existing 69kV facilities.

A new 1.75 mile 138kV line will be constructed from the existing substations of Seymour O'Brien St. and Seymour Industrial Park. This line is scheduled for an in service date of 11/30/01. This project is required to satisfy the planning criteria of withstanding a single contingency outage. The alternatives evaluated for this project involved various combinations of new 138kV facilities and replacement of the 138-69-34.5kV transformers at the Seymour substation.

Alternatives for the above 138 kV projects all included, where applicable, the consideration of using DSM and DS&G to defer the timing of the projects. This was done through the tailored collaboration projects referred to in Volume I, Chapter 4, Section F.

Section 8(3)(a) Map of Facilities and Transfer Capacity

A map showing existing generation and existing and planned transmission (69kV and up) is provided in the General Appendix map section. Further, there are no transfer capacity restrictions.

Section 8(5)(c) Planning Criteria

Information pertaining to transmission planning can be found in Chapter 7 section C.

5. **PLANNED SUMMARY**

5. (4) **Planned Resource Acquisition Summary**

The Cinergy resource acquisition summary is contained in Chapter 7 Section (B)(2)&(3). Further, there is currently no in-progress or planned transmission system projects affecting any ULH&P or CG&E facilities that are intended to provide additional resource.

5. (5) **Two Year Implementation Plan Summary**

The two-year Implementation Plan Summary is contained in the Short Term Implementation Plan and Status report, on pages STIP-1 through STIP-3.

8. **RESOURCE ASSESSMENT AND ACQUISITION PLAN**

8. (2) (a) **Option Considered for Inclusion**

Information pertaining to transmission and distribution facilities can be found in Ohio appendix section 4901:5-5-01.

8. (3) (a) **Map of Facilities**

A map of transmission facilities for ULH&P is provided in the General Appendix map section. The locations of interconnections are indicated on the map. The thermal capacities of all interconnections and other lines are listed on the following pages in Table 8. (3) (a). These capacities are keyed to circuit numbers indicated on the map. The locations of generating stations are also indicated.

8. (5) (g) **Development of Plan**

This transmission volume was prepared independently by the Bulk Transmission Department, in compliance with FERC Order 889. Information pertaining to the generation facilities can be found in volumes I, II and III. Further, there are specific topics regarding FERC initiatives in the section D of chapter 7.

The Cincinnati Gas & Electric Company
The Union Light, Heat & Power Company

Thermal Capacities of
69 kV, 138 kV & 345 kV Transmission Lines

Circuit Number	Circuit Name	Operating Voltage (kV)	Normal Amperes Summer	Normal Amperes Winter	Emergency Amperes Summer	Emergency Amperes Winter
661	Elmwood-Terminal	69	695	926	841	1028
684	Elmwood-Lateral	69	946	1264	1149	1407
689	Elmwood-Terminal	138	1092	1462	1332	1631
863	Oakley-Linwood	69	695	926	841	1028
868	Oakley-Fairfax	69	695	926	841	1028
868	Fairfax-Summerside	69	389	516	466	569
885	Oakley-Red Bank	138	1180	1581	1439	1763
886	Oakley-Beckjord	138	1180	1581	1439	1763
965	Kenton-Wilder	69	695	926	841	1028
966	Kenton-Villa	69	695	926	841	1028
966	Tap to Buffington	69	695	926	841	1028
1062A	Front-Miami Fort	69	854	1141	1037	1269
1062A	Tap to Smith (EKP)	69	695	926	841	1028
1062B	Tap off 1062A to Villa	69	695	926	841	1028
1062C	Tap to Feeder 6763	69	946	1264	1149	1407
1064	Front-Wilder	69	695	926	841	1028
1263	Mitchell-Brighton	69	774	1030	936	1144
1265	Mitchell-Ivorydale	69	695	926	841	1028
1269	Mitchell-Central	69	695	926	841	1028
1284	Mitchell-Terminal	138	979	1309	1191	1458
1286	Mitchell-West End	138	964	1289	1173	1435
1288	Mitchell-Oakley	138	964	1289	1173	1435
1288	Tap to Ashland	138	964	1289	1173	1435
1385	West End-Charles	138	980	1120	1025	1160
1389	West End-Charles	138	980	1120	1025	1160
1587	West End-Crescent	138	854	1141	1037	1269
1681	Miami Fort-Greendale (PSI)	138	2092	2841	2092	2841
1682	Miami Fort-Clifty (LG&E)	138	571	760	571	760
1689	Miami Fort-Morgan	138	713	950	862	1055
1765	Terminal-Lincoln	69	695	926	841	1028
1766	Terminal-Lincoln	69	774	1030	936	1144
1782	Terminal-Glenview	138	964	1289	1173	1435
1783	Terminal to Midway Tap	138	979	1309	1191	1458
1783	Tap to Midway	138	774	1030	936	1144
1783	Tap to Ebeneezer	138	946	1264	1149	1407
1862	Beckjord GT to HLP #6	69	979	1309	1191	1458
1862	HLP #6 to South Bethel	69	695	926	841	1028
1862	Tap to Clermont	69	695	926	841	1028
1881	Beckjord-Buffington	138	695	926	841	1028
1883	Beckjord-Red Bank	138	1180	1581	1439	1763
1885	Beckjord-Tobasco	138	1180	1581	1439	1763
1889	Beckjord-Pierce	138	1180	1581	1439	1763
2166	Brighton-Front	69	774	1030	936	1144

The Cincinnati Gas & Electric Company
The Union Light, Heat & Power Company

Thermal Capacities of
69 kV, 138 kV & 345 kV Transmission Lines

Circuit Number	Circuit Name	Operating Voltage (kV)	Normal Amperes Summer	Normal Amperes Winter	Emergency Amperes Summer	Emergency Amperes Winter
2166	Tap to Ferguson	69	946	1264	1149	1407
2764	Linwood-Cincinnati Waterworks	69	695	926	841	1028
2865	Miami Fort-Neumann	69	946	1264	1149	1407
2865	Tap to Monsanto	69	946	1264	1149	1407
3163	Hamilton-Millville	69	378	499	452	551
3164	Hamilton-Port Union	69	946	1264	1149	1407
3167	Hamilton-Miller	69	695	926	841	1028
3261	Trenton-Port Union	69	695	926	841	1028
3261	Tap to Woodsdale	69	424	562	511	624
3262	Trenton-Miller	69	695	926	841	1028
3265	Trenton-Terminal	69	646	858	778	951
3281	Trenton-Collinsville	138	639	851	772	944
3281	Collinsville-College Corner (I&ME)	138	639	851	772	944
3284	Trenton-Hutchings (DP&L)	138	713	950	862	1055
3284	Hutchings-Hillsboro (OP)	138	713	950	862	1055
3762	Carlisle-Trenton	69	695	926	841	1028
3762	Tap to Mosinee	69	389	516	466	569
3763	Carlisle-Springboro	69	695	926	841	1028
3763	Springboro-Red Lion	69	389	516	466	569
3766	Carlisle-Manchester	69	695	926	841	1028
3861	Port Union-Evendale	69	695	926	841	1028
3864	Port Union-Route 4	69	946	1264	1149	1407
3864	Tap to Symmes	69	695	926	841	1028
3864	Tap to Northgreen	69	695	926	841	1028
3869	Port Union-Kings Mills	69	695	926	841	1028
3881	Port Union-Summerside	138	713	950	862	1055
3885	Port Union-Fairfield	138	713	950	862	1055
3886	Port Union-Willey	138	713	950	862	1055
3887	Port Union-Todhunter	138	713	950	862	1055
3888	Port Union-Todhunter	138	713	950	862	1055
3889	Port Union-City of Hamilton	138	1059	1417	1290	1580
3968	Central-Ashland	69	713	950	862	1055
4187	Lateral-Red Bank	138	964	1289	1173	1435
4366	Clermont-South Bethel	69	389	516	466	569
4366	Tap to Hamlet	69	389	516	466	569
4501	Beckjord-Pierce	345	1475	1992	1811	2226
4502	Pierce-Foster	345	2184	2924	2664	3262
4504	Miami Fort-Tanners Creek (I&ME)	345	2156	2886	2628	3218
4508	Foster-Port Union	345	2156	2886	2628	3218
4511	Stuart-Foster	345	2184	2924	2664	3262
4512	East Bend-Tanners Creek (I&ME)	345	2156	2886	2628	3218
4513	Port Union-Terminal	345	2156	2886	2628	3218
4514	Miami Fort-Terminal	345	2156	2886	2628	3218
4515	Foster-Todhunter	345	2156	2886	2628	3218

The Cincinnati Gas & Electric Company
The Union Light, Heat & Power Company

Thermal Capacities of
69 kV, 138 kV & 345 kV Transmission Lines

Circuit Number	Circuit Name	Operating Voltage (kV)	Normal Amperes Summer	Normal Amperes Winter	Emergency Amperes Summer	Emergency Amperes Winter
4516	East Bend-Terminal	345	2156	2886	2628	3218
4524	Foster-Sugarcreek (DP&L)	345	2184	2924	2664	3262
4541	Stuart-Zimmer	345	2156	2886	2628	3218
4544	Zimmer-Port Union	345	2118	2834	2580	3160
4545	Zimmer-Silver Grove	345	2360	3162	2878	3526
4545	Silver Grove-Red Bank	345	2156	2886	2628	3218
4546	Red Bank-Terminal	345	2156	2886	2628	3218
4561	Woodsdale-Todhunter	345	2156	2886	2628	3218
4562	Woodsdale-Todhunter	345	2156	2886	2628	3218
4591	Miami Fort-West Milton (DP&L)	345	2156	2886	2628	3218
4592	Miami Fort-Woodsdale	345	2156	2886	2628	3218
4666	Evendale-Port Union	69	646	858	778	951
4666	Tap to Northgreen	69	646	858	778	951
4683	Evendale-Port Union	138	1441	1939	1770	2169
4685	Evendale-Terminal	138	1441	1939	1770	2169
4861	Ivorydale-Terminal	69	695	926	841	1028
4861	Tap to Elmwood	69	695	926	841	1028
5367	Grant-Renaker/Munk (EKP)	69	695	926	841	1028
5483	Foster to HLP #524	138	1059	1417	1290	1580
5483	HLP #524 to Port Union	138	713	950	862	1055
5483	Tap to Cornell	138	946	1264	1149	1407
5483	Tap to Montgomery	138	1059	1417	1290	1580
5485	Foster-Todhunter	138	1078	1443	1314	1609
5485	Tap to Carlisle	138	1059	1417	1290	1580
5487	Foster-Montgomery	138	1059	1417	1290	1580
5487	Montgomery-Remington	138	713	950	862	1055
5489	Foster-Cedarville-Ford	138	1059	1417	1290	1580
5661	Todhunter-Pole 1132	69	946	1264	1149	1407
5661	Pole 1132-Trenton	69	695	926	841	1028
5661	Pole 1132-Monroe	69	695	926	841	1028
5661	Tap to Dicks Creek #19	69	695	926	841	1028
5661	Tap to Dicks Creek #269	69	389	516	466	569
5665	Todhunter-Pole 850	69	946	1264	1149	1407
5665	Tap to Manchester	69	695	926	841	1028
5665	Tap to Red Lion	69	695	926	841	1028
5666	Todhunter-Tower 17	69	946	1264	1149	1407
5666	Tap to Trenton	69	639	851	639	851
5666	Tap to Jackson	69	639	851	639	851
5667	Todhunter-Kings Mill	69	695	926	841	1028
5682	Todhunter-Armco	138	713	950	862	1055
5686	Todhunter-Armco	138	713	950	862	1055
5686	Tap to Dicks Creek	138	713	950	862	1055
5762	Fairfield-Hamilton	69	695	926	841	1028
5767	Fairfield-HLP 1177	69	946	1264	1149	1407

The Cincinnati Gas & Electric Company
The Union Light, Heat & Power Company

Thermal Capacities of
69 kV, 138 kV & 345 kV Transmission Lines

Circuit Number	Circuit Name	Operating Voltage (kV)	Normal Amperes Summer	Normal Amperes Winter	Emergency Amperes Summer	Emergency Amperes Winter
7481	Tap to Cornell	138	946	1264	1149	1407
7484	Red Bank-Ashland	138	1004	1004	1255	1255
7489	Red Bank-Tobasco	138	1180	1581	1439	1763
8286	Rochelle-Terminal	138	979	1285	1180	1330
9062	Collinsville-Locust	69	389	516	466	569
9062	Locust-Contreras	69	378	499	452	551
9064	Collinsville-Trenton	69	639	851	772	994
9482	Remington-Beckjord	138	713	950	862	1055
9784	Willey-Miami Fort	138	713	950	862	1055
9787	Willey-Terminal	138	946	1264	1149	1407

The Cincinnati Gas & Electric Company
The Union Light, Heat & Power Company

Thermal Capacities of 69 kV, 138 kV & 345 kV Transmission Lines

Circuit Number	Circuit Name	Operating Voltage (kV)	Normal Amperes Summer	Normal Amperes Winter	Emergency Amperes Summer	Emergency Amperes Winter
5767	HLP 1177-F9062	69	695	926	841	1028
5781	Fairfield-Bishop	138	1059	1417	1290	1580
5783	Fairfield-Morgan	138	695	926	841	1028
5863	Brown-South Bethel	69	695	926	841	1028
5863	Tap to Georgetown	69	389	516	466	569
5884	Brown-Eastwood-Ford	138	1059	1417	1290	1580
5886	Brown-Stuart	138	979	1309	1191	1458
5962	Wilder-Cold Spring	69	389	516	466	569
5962	Tap to Marshall	69	389	516	466	569
5966	Wilder-Joseph Co.	69	695	926	841	1028
5967	Wilder-Cold Spring	69	695	926	841	1028
5967	Tap to White Tower	69	695	926	841	1028
5983	Wilder-Bellevue	138	1059	1417	1290	1580
5985	Wilder-West End	138	1059	1417	1200	1472
5986	Wilder-Newport Steel	138	1059	1417	1290	1580
5987	Wilder-Silver Grove	138	979	1309	1191	1458
5988	Wilder-Beckjord	138	946	1264	1149	1407
6084	Bishop-City of Hamilton	138	1059	1417	1290	1580
6282	Silver Grove-Wilder	138	1078	1443	1314	1609
6365	Tobasco-HLP 318	69	946	1264	1149	1407
6365	Tap to Markley	69	695	926	841	1028
6365	Tap to Cincinnati Waterworks	69	695	926	841	1028
6761	Buffington-Grant	69	389	516	466	569
6761	Tap to White Tower	69	695	926	841	1028
6761	Tap to Devon (EKP)	69	695	926	841	1028
6763	Buffington-Limaburg	69	389	516	466	569
6763	Tap to Dixie	69	695	926	841	1028
6763	Tie to F-1062C	69	946	1264	1149	1407
6764	Buffington-Dixie	69	695	926	841	1028
6782	Buffington-Crescent	138	946	1264	1149	1407
6785	Buffington-Boone (EKP)	138	1059	1417	1290	1580
6861	Ebenezer-Monsanto	69	695	926	841	1028
6863	Ebenezer-Ferguson	69	946	1264	1149	1407
6863	Tap to Delhi	69	695	926	841	1028
6864	Ebenezer-Neumann	69	946	1264	1149	1407
6885	Ebenezer-Miami Fort	138	841	1120	958	1171
6961	Summerside-Markley	69	695	926	841	1028
6962	Summerside-Hamlet	69	389	516	466	569
6962	Tap to Tobasco	69	695	926	841	1028
6984	Summerside-Beckjord	138	713	950	862	1055
7086	Crescent-Miami Fort	138	854	1141	1037	1269
7284	Glenview-Miami Fort	138	964	1289	1173	1435
7284	Tap to Midway	138	774	1030	936	1144
7481	Red Bank-Terminal	138	1441	1939	1770	2169

Planned New Transmission Facilities

Description of Projects

See the tables below. More detailed descriptions of these projects can be found in the Indiana and Ohio Appendices.

Criteria and Objectives for Monitoring Success

Milestones and criteria used to monitor the transmission facilities projects are typical of construction projects and measured on the following factors:

- Comparison of the actual completion date to the targeted completion date
- Comparison of the actual cost to the budgeted cost

Anticipated Time Frame and Estimated Costs

The cash flows associated with the major new transmission facility projects planned are shown below. Due to the difference between state IRP regulations, the information included is not the same for PSI projects and CG&E projects.

PSI TRANSMISSION LINE PROJECTS

LINE NAME	MILE	kV	PROGRESS/ COMPLETION DATE	CASH FLOWS* ($000) 1999	2000	2001	2002
Clarksville	0.3	138	4/30/01	0.0	0.0	0.0	231.0
Seymour	1.75	138	11/30/01	0.0	0.0	0.0	500.0
Purdue Northwest	1.7	138	12/01/99	0.0 *			

*reimbursed

CG&E TRANSMISSION LINE PROJECTS

LINE NAME	MILES	kV	PROGRESS/ COMPLETION DATE	CASH FLOWS* ($000) 1999	2000	2001	2002

*Excluding AFUDC

Anticipated Project Milestones

The completion of these projects, by their planned in-service dates, is the project milestones.

United States of America

Federal Energy Regulatory Commission

FERC FORM 715

Annual Transmission Planning and Evaluation Report

CINERGY

April 1, 1999

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United States of America

Federal Energy Regulatory Commission

1999 FERC FORM 715

Annual Transmission Planning and Evaluation Report

Part 1: Identification and Certification

Transmitting Utility Name	**CINERGY SERVICES, INC on behalf of PSI Energy Inc., and The Cincinnati Gas & Electric Company(hereinafter referred to as CINERGY)[1]**
Transmitting Utility Mailing Address	**139 East Fourth Street Cincinnati, Ohio 45202**
Contact Person Name	**E. F. Kirschner**
Contact Person Title	**Principal Engineer, Bulk Transmission Planning**
Contact Person Address	**1000 East Main Street Plainfield, Indiana 46168**
Contact Person Telephone Number	**(317) 838-1455**
Contact Person Facsimile Number	**(317) 838-2607**
Certifying Official Name	**Ronald R. Jackups**
Certifying Official Title	**General Manager, Electric System Operations**
Certifying Official Signature	______________________
Date	______________________

[1] Includes transmission facilities owned by Wabash Valley Power Association(WVPA) and Indiana Municipal Power Agency(IMPA) which are operated and planned by CINERGY.

United States of America
Federal Energy Regulatory Commission

1999 FERC Form 715
Annual Transmission Planning and Evaluation Report
Part 2:

Cinergy is a Member of the East Central Area Reliability Coordination Agreement (ECAR) and participates in its regional process for consolidating and sharing of power flow information. As such, the respondent hereby authorizes the ECAR Region to release, without conditions, to FERC and to the public, the most current regional power flow data models.

By: ______________________________

Edward F. Kirschner

Title:

Principal Engineer, Bulk Transmission Planning

Date: ____________________

Regional organization name, mailing address, contact person and title, telephone and facsimile information:

East Central Area Reliability Coordination Agreement
220 Market Avenue South, Suite 501
Canton, OH 44702-2182
Jeffrey L. Mitchell, P.E.
Staff Engineer
TEL: 330-580-8007
FAX: 330-456-3648

United States of America
Federal Energy Regulatory Commission
1999 FERC Form 715
Annual Transmission Planning and Evaluation Report
Part 2:

The East Central Area Reliability Coordination Agreement (ECAR) hereby submits power flow data in response to Part 2 of FERC Form 715 for the following ECAR members:

Company Name	Power Flow Data Acronym
Allegheny Power	AP
American Electric Power	AEP
Big Rivers Electric Corporation	BREC
Cinergy Corporation	CIN
Consumers Energy	CONS
The Dayton Power and Light Company	DPL
The Detroit Edison Company	DECO
Duquesne Light Company	DLCO
East Kentucky Power Cooperative, Inc.	EKPC
FirstEnergy Corporation	FE
Hoosier Energy Rural Electric Coop., Inc.	HE
Indiana Municipal Power Agency[1]	IMPA
Indianapolis Power & Light Company	IPL
LG&E Energy Corporation	LGEE
Northern Indiana Public Service Company	NIPS
Ohio Valley Electric Corporation	OVEC
Southern Indiana Gas and Electric Company	SIGE

[1] *The Indiana Municipal Power Agency participates in ECAR base case development, but its transmission system above 100 kV is operated and planned by the PSI Energy, Inc. operating company of Cinergy Corporation.*

Each of these utilities participates in the ECAR regional process for consolidating and sharing of power flow information. Additionally, power flow base case models developed by ECAR include imbedded system representations of the following ECAR Associate Members:

Allegheny Electric Cooperative, Inc.	AEC
American Municipal Power - Ohio	AMPO
Buckeye Power, Inc.	BPI
Municipal Cooperative Coordinated Pool (Michigan)	MCCP
Midland Cogeneration Venture	MCV
Wabash Valley Power Association	WVPA

The following ECAR Associate Members have no transmission systems within ECAR and are, therefore, not represented in the ECAR portion of these models:

AES Power, Inc.
American Energy Solutions, Inc.
Amoco Energy Trading Corp.
Aquila Power Corp.
Cargill-Alliant LLC
Citizens Power LLC
CNG Energy Services Corp.
Commonwealth Edison Co.
Constellation Power Source, Inc.
Delmarva Power
Duke/Louis Dreyfus LLC
El Paso Energy Marketing Co.
Enron Power Marketing, Inc.
Enserch Energy Services, Inc.
Entergy Power Marketing Corp.
Noram Energy Services, Inc
Ontario Hydro
Pacificorp Power Marketing
PECO Energy Co-Power Team
PG&E Energy Trading Power LP
Pennsylvania Power & Light, Inc.
Proliance Energy LLC
Southern Company Energy Marketing LP
Sonat Power Marketing LP
Vitol Gas & Electric LLC
Williams Energy Services Co.

The ECAR Members have authorized the ECAR Region to release, without conditions, to FERC and to the public, the most current regional power flow data models.

Regional organization name, mailing address, contact person and title, telephone and facsimile information:

East Central Area Reliability Coordination Agreement
220 Market Avenue South, Suite 501
Canton, OH 44702-2182
Jeffrey L. Mitchell, P.E.
Staff Engineer
TEL: 330-580-8007 FAX: 330-456-3648

Process for public access to regional power flow information:

Requests should be submitted in writing with pre-paid fees to the regional contact person above. Data will be sent via first class U. S. Mail (via UPS for paper hard copies) no later than 10 working days following receipt by the regional organization contact person of a written request and pre-paid fees.

Information will be made available electronically on an as-is, non-supported basis. Each model will include:

Input data in PTI PSS/E Rev. 24, Activity RAWD card image format, or in GE PSLF (EPC) Rev. 10 format (please specify in request letter).

Corresponding solved output listing.

A data dictionary cross-referencing ECAR bus or line terminal names in the model to actual substation or switching station names commonly used by the utility.

Electronic Media: Self-decompressing MS DOS ASCII format on 3.5 inch, 1.44 MB diskettes or via electronic mail.

On-Site Inspection: Powerflow data are available for inspection by appointment only at the ECAR Executive Office, 220 Market Avenue South, Suite 501, Canton, Ohio 44702. Contact Jeffrey L. Mitchell, P.E., Staff Engineer, at (330) 580-8007 for appointments. Orders for data will be accepted during on-site inspections for shipping within ten (10) working days.

Fees: Fees must be pre-paid before requests will be honored.

Electronic Media: $70 fee for first model requested and $15 for each additional model in the same written request.

Paper Hard-copy: $250 per model requested.

Data Dictionary Hard-Copy (during on-site inspection only): $0.10 per page

Powerflow models available as of April 1, 1999 are:

Current Cases Filed April 1, 1999 with the FERC

Case Name	Case File Designator
1998/99 Winter Peak ECAR Assessment Study Case	98WSEQ
1999 Spring Peak Case	99GFEQ
1999 Summer Peak Case	99SFEQ
1999 Summer Peak ECAR Assessment Study Case	99SSEQ
1999 Fall Peak Case	99FFEQ
1999/00 Winter Peak Case	99WFEQ
1999/00 Winter Light Load (a.k.a. Y2K)	99WLFEQ
1999 Light Load Case[2]	99LFEQ
2000 Summer Peak Case	00SFEQ
2003 Summer Peak ECAR Assessment Study Case	03SSEQ
2000/01 Winter Peak Case	00WFEQ
2003 Summer Peak Case	03SFEQ
2003/04 Winter Peak Case	03WFEQ
2008 Summer Peak Case	08SFEQ

Non-Current Cases Available on Request[3]

1997/98 Winter Peak ECAR Assessment Study Case	97WS
1998 Spring Peak Case	98GF
1998 Summer Peak Case	98SF
1998 Summer Peak ECAR Assessment Study Case	98SS
1998 Fall Peak Case	98FF
1998/99 Winter Peak Case	98WF
1998 Light Load Case	98LF
1999 Summer Peak Case	99SF [1997 series]
1999 Summer Peak ECAR Assessment Study Case	99SS
1999/00 Winter Peak Case	99WF [1997 series]
2002 Summer Peak Case	02SF [1997 series]
2002/03 Winter Peak Case	02WF [1997 series]
2007 Summer Peak Case	07SF [1997 series]

[2]A Light Load case is defined as a typical early morning load level in April with pumped storage hydro units in pumping mode. The intent is to model near minimum load levels. Summer equipment ratings are used.
[3] Non-Current cases in the ECAR Base Case Library that were previously filed with the FERC, and are available on request.

Disclaimer

The East Central Area Reliability Coordination Agreement (ECAR) Region is providing this power flow base case data on behalf of its Member systems in compliance with the requirements of FERC Form 715, Part 2 (18 C.F. R. § 141.300), Annual Transmission Planning and Evaluation Report. These data were compiled in compliance with those requirements, and ECAR does not warrant or represent its use for any other purpose.

These base case data are compiled directly from information supplied to ECAR by its Members, and external system representations developed under the auspices of the North American Electric Reliability Council Multi-regional Modeling Working Group. The ECAR Region is not responsible for the accuracy of the contents other than replacement of diskettes damaged in transit.

Level of Detail
The power flow base case provided contains sufficient detail of the bulk transmission systems in the ECAR Region to perform screening analysis of the availability of transmission system capacity within the ECAR Region.

In some of the power flow cases, specific generation resources needed to meet control area load were not yet identified when the cases were created. In the NERC base cases, the needed generation was made up by other ECAR units, which were not fully dispatched. In the future year ECAR base cases, the needed generation will be made up by units that are remote to the ECAR region.

External Models
This power flow base case contains reduced or equivalent representations of systems external to the ECAR Region Member systems. Those external representations are of sufficient detail to simulate power transactions to and from those systems. However, the representations are not intended for study of the transmission capacity in those external systems.

Solution Tolerances

GE PSLF Program: Powerflow base cases are solved using the Full Solution (option 1) iteration technique of the GE PSLF (Revision 10.1) power flow program on a Digital Alpha computer. It was solved with a zero impedance cutoff value of 0.000101 p.u., and a plus or minus 1 MVA bus mismatch tolerance. Attempts at solution to stricter tolerances may not be successful.

PTI PSS/E Program: Powerflow base cases are solved using the Fixed Slope Decoupled Newton-Raphson Iteration technique on an IBM RS6000 computer. They were solved with a zero impedance cutoff value of 0.0001 p.u., and a plus or minus 1 MVA bus mismatch tolerance. Attempts at solution to stricter tolerances may not be successful.

Memory Requirements
The set of self-decompressing data files for each case requires a total up to 20 MB of disk space per case when decompressed.

United States of America

Federal Energy Regulatory Commission

1999 FERC FORM 715

Annual Transmission Planning and Evaluation Report

CINERGY

Part 3: Transmitting Utility Maps and Diagrams

Included with this filing are two copies each of the following maps for each of CINERGY's operating companies as indicated below.

<u>PSI ENERGY</u>

System map has not changed since last filing.

Switching diagrams have not changed since last filing.

<u>CINCINNATI GAS & ELECTRIC COMPANY</u>

System map dated January 1, 1999

Switching diagrams: 69 kV(2 diagrams), 138 kV(1 diagram), 345 kV(1 diagram)

(all revised 1/22/99)