Cinergy Services, Inc.
139 East Fourth Street, Rm 25 AT II
P.O. Box 960
Cincinnati, OH 45201-0960
Tel 513.287.3075
Fax 513.287.3810
michael.pahutski@cinergy.com

MICHAEL J. PAHUTSKI
Counsel

VIA OVERNIGHT MAIL

CINERGY.

April 1, 2004

Mr. Thomas Dorman
Executive Director,
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

RECEIVED
APR 0 2 2004
PUBLIC SERVICE COMMISSION

Re: Case No. 2004-00014

Dear Mr. Dorman:

Enclosed please find an original and 12 copies of *ULH&P's Integrated Resource Plan Filing and ULH&P and CG&E's Joint Petition for Confidential Treatment*, as well as an original and 10 copies (in binders) of *ULH&P's 2003 Integrated Resource Plan*, which are being submitting for filing. Please return to me two (2) file-stamped copies of the pleading in the enclosed overnight mail envelope.

If you have any questions, please feel free to contact me at (513) 287-3075.

Sincerely,

Michael J. Pahutski

Michael J. Pahutski

MJP/mak

Enclosures

2004-00014

The Union Light, Heat & Power Company

RECEIVED

APR 0 2 2004

PUBLIC SERVICE COMMISSION

2003

INTEGRATED RESOURCE PLAN

VOLUME I

April 1, 2004

By: The Union Light, Heat and Power Company.
Gregory C. Ficke, President
139 East Fourth Street
Cincinnati, OH 45202

Cinergy/ULH&P
139 East Fourth Street
P.O. Box 960
Cincinnati, OH 45201-0960
Tel 513.287.2660

Greg Ficke
President
The Union Light, Heat & Power Company

April 1, 2004

The Honorable Thomas M. Dorman, Executive Director
Public Service Commission of Kentucky
P.O. Box 615
Frankfort, KY 40602

CINERGY.
ULH&P

RE: Cinergy 2003 Integrated Resource Plan

Dear Mr. Dorman:

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 2003 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 2003 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, Environmental 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 standards of conduct in FERC Order 889, items related to transmission and distribution were prepared independently, and have been compiled in a separate volume. A Secondary Appendix is also included to address areas specific to Kentucky IRP regulations. All together, including the Secondary Appendix and the transmission information volume, each copy of the 2003 IRP consists of two volumes.

Please note that John Finnigan, Legal Department, Room 25ATII, 139 East Fourth Street, Cincinnati, OH 45202, (513) 287-3601, 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.

Very truly yours,

Gregory C Ficke

ATTACHMENT "A"

Cinergy/ULH&P

2003 INTEGRATED RESOURCE PLAN

CERTIFICATE OF SERVICE

The undersigned states that he is the President of The Union Light, Heat & Power Co. (ULH&P); 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.

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. Elizabeth E. Blackford
Assistant Attorney General
Kentucky Office of the
Attorney General
1024 Capital Center Drive, Suite 200
Frankfort, KY 40601-8204

Brian Angus
Northern Kentucky Community
Action Commission
13 West Seventy Street
Covington, KY 41012-0931

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

One copy of this Report will be kept at the principal business office of ULH&P 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.

Gregory C. Ficke, President

April 1, 2004
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 April, 2004, filed a copy of the 2003 Cinergy Integrated Resource Plan ("IRP") with the Public Service Commission of Kentucky ("KyPSC").

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 during normal business hours. A copy of this IRP will be provided, at cost, to cover expenses incurred, upon request.

KENTUCKY INDEX TO 2003 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) Secondary Appendix

Section 5. Plan Summary
(1) Chapter 1, Sections A, B
(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
Waiver received

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

	Secondary Appendix
(e)	Secondary Appendix
(5)(a)(1)	Waiver received
(2)	Waiver received
(b)(1)	Waiver received
(2)	Waiver received
(6)	No response required
(7)(a)	Secondary Appendix
(b)	Chapter 3, Section C
(c)	Chapter 3, Section B
(d)	Chapter 3, Section F
(e)(1)	Chapter 3, Section B
(2)	Chapter 3, Section B
(3)	Chapter 3, Section B
(4)	Chapter 3, Section F
(f)	Chapter 3, Section E
(g)	Chapter 3, Sections D, E

Section 8. Resource Assessment and Acquisition Plan

(1)	Chapter 4
	Chapter 5, Sections E, F, G
	Chapter 6
	Transmission Volume, Chapter 7, Section C
	Chapter 8, Sections C, D, E, F, G, H, I
(2)(a)	Chapter 5, Sections B, G
	Transmission Volume, Chapter 7, Section C
(b)	Chapter 4, Sections B, C, D, E
(c)	Chapter 5, Section F
	Chapter 8, Sections B, F, H
(d)	Chapter 5, Sections C, E, F, G
(3)(a)	Transmission Volume, Secondary Appendix
(b)(1)	Chapter 5, Figure 5-48
	Chapter 8, Figures 8-12, 8-15
(2)	Chapter 5, Figure 5-48
	Chapter 8, Figures 8-12, 8-15
(3)	Chapter 5, Figure 5-48
	Chapter 8, Figures 8-12, 8-15
(4)	Chapter 5, Figure 5-48
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(b)Secondary Appendix
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Chapter 4, Section E

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Chapter 6, Section D
Transmission Volume Chapter 7, Section C
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(d) Chapter 2, Section D
Chapter 8, Sections C, D, F

(e) Chapter 2, Section E
Chapter 5, Section F
Chapter 6, Section D
Chapter 8, Sections E, F

(f) Chapter 6
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(g) Chapter 2, Section B
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Chapter 6, Section D
Transmission Volume, Chapter 7, Section C
Chapter 8, Sections B, C, D, E, F, G, H

Section 9. Financial Information

(1) Chapter 8, Sections C, F
(2) Chapter 8, Sections C, F
(3) Secondary Appendix
(4) Secondary Appendix

Section 10. Notice

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) Secondary 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

ULH&P is a wholly owned subsidiary of CG&E that provides electric and gas service in the Northern Kentucky area contiguous to the Southwestern Ohio area served by CG&E. ULH&P serves approximately 128,000 customers in its 500 square mile service territory. ULH&P's service territory includes the cities of Covington and Newport, Kentucky.

ULH&P currently owns no generation resources, and has historically relied on its parent company, CG&E, to provide it with its full requirements of electric power. Until January 1, 2002, ULH&P received its full requirements of electric power from CG&E under a cost-of-service-based wholesale power tariff approved by the Federal Energy Regulatory Commission (FERC). Since January 1, 2002, ULH&P has received its full requirements of electric power to serve its retail customers from CG&E pursuant to a market-based, fixed price Power Sales Agreement, which expires on December 31, 2006.

ULH&P owns an electric transmission system and an electric distribution system in portions of 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. ULH&P contracts separately with the Midwest Independent

Transmission System Operator, Inc. (MISO) through Cinergy Services, Inc. for bulk transmission service to transport electric power from CG&E's plants and from outside the Cinergy system through the Cinergy transmission system to ULH&P's transmission and distribution system for ultimate delivery to ULH&P's distribution system and end-use retail customers.

The Cinergy Control Area is directly interconnected with twelve other control areas (American Electric Power, LGE Energy, Ameren, Hoosier Energy, Indianapolis Power & Light, Northern Indiana Public Service Co., Southern Indiana Gas & Electric Co., Dayton Power & Light, East Kentucky Power Cooperative, Ohio Valley Electric Corporation, Allegheny Power Wheatland, and Duke Energy Vermillion).

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 cost-effective portfolio of options intended to satisfy reliably 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.

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 (such as wholesale market risks, reliability risks, etc.)

The reliability constraints utilized for this IRP are:

1. Minimum reserve margin of fifteen percent (15%);
2. Annual loss of load hours (LOLH) less than 175; and
3. Expected unserved energy (EUE) less than 0.18 percent.

The reserve margin criterion represents a balance that must be struck between reliability needs and costs. Lower reserves may help restrain rates, but using a reserve level that is too low can result in additional costs to customers. ULH&P is continuing to examine the appropriate level of reserves for long-term planning.

C. <u>PLANNING PROCESS</u>

The injection of customer choice into various segments of the electric utility industry has resulted in the electric utility business shortening its planning horizon. The analysis performed to prepare this IRP covered the period 2003-2023, although the primary focus was on the first ten years. This technique was used in order to concentrate on the near-term while recognizing the fact that course corrections may be made along the way. While Kentucky IRP rules only require analysis of a 15-year timeframe, the unique circumstances of the expiration of ULH&P's contract with CG&E at the end of 2006 necessitated using a longer planning period to encompass a minimum of 15 years beyond the contract expiration date.

The major Base Case assumption concerning new laws and regulations is that no environmental compliance changes beyond the NO_x SIP call will be required to be implemented throughout the 2003-2012 time period. 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 analyses 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 Kentucky 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 and procurement and, to the extent allowable considering the standards 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 electric load forecast.
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 environmental compliance options.
6. Integrate the demand-side, supply-side, and environmental 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 presented herein represents the results of this extensive business planning process.

D. LOAD FORECAST

The electric energy and peak demand forecasts of the ULH&P franchised service territory are prepared each year as part of the planning process.

The general framework of the Electric Energy and Peak Load Forecast 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 is obtained from Economy.com, a national economic consulting firm.

Similarly, the history and forecast of key economic and demographic concepts for the service area economy is obtained from Economy.com. The service area economic forecast is used along with the energy and peak models to produce the electric load forecast.

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

Table 1-1 provides information on the ULH&P 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

ULH&P System

ELECTRIC ENERGY AND PEAK LOAD

FORECAST: ANNUAL GROWTH RATES

	2003-2023
Residential MWH	1.3%
Commercial MWH	1.4%
Industrial MWH	3.3%
Net Energy MWH	1.9%
Summer Peak MW	1.4%
Winter Peak MW	1.5%

The forecast of 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

ULH&P's demand-side programs, which are expected to help reduce demand on the ULH&P system during times of peak load, fall into three categories: traditional regulated DSM, customer-specific contract options, and innovative pricing programs.

DSM Programs

As a result of the Kentucky Public Service Commission's Order in Case No. 2002-00358 dated December 17, 2002, the Commission approved the continuation of and cost recovery for three current programs: the Residential Conservation and Energy Education, Residential Home Energy House Call, and Residential Comprehensive Energy Education programs for a 3-year period, through December 31, 2005. In addition, the Commission approved the implementation of a revised low-income home energy assistance program (Payment Plus) as a pilot through May 31, 2004.

On September 26, 2003, ULH&P, with the approval of the DSM Collaborative, made an application to the Commission for approval to implement a direct load control program (Power Manager) in the utility's service area. The Power Manager program subsequently received Commission approval for implementation on November 20, 2003. The incremental impacts of the DSM resource programs, including direct load control, are incorporated into the IRP analysis. The above-mentioned DSM programs were screened during this IRP process before proceeding to the integration/optimization process.

Pricing Programs

In addition to the traditional regulated DSM programs, ULH&P has two pricing programs: customer-specific contract options, and innovative pricing programs.

ULH&P has contracted with an industrial customer to reduce demand for electricity during times of peak system demand. By the term of the contract, ULH&P assumes no obligation to plan for or build to serve the customers' non-firm loads, and ULH&P can interrupt the customer at times of system peak or during times of system emergencies (up to a certain number of hours per year).

We currently expect and plan for a 3 MW reduction in our load forecasts for this "as available" load at any given point in time.

ULH&P's innovative pricing programs fall into two categories: PowerShare® and Real Time Pricing (RTP). Both programs provide customers with a market price-based incentive to alter their usage patterns. The PowerShare® program is a market-based program that provides financial incentives in the form of bill credits to our industrial and commercial customers to reduce their electric demand during periods of peak load on the ULH&P system. Customers may choose to participate in either CallOption (a contractual obligation to reduce load if requested) or QuoteOption (a pure pricing program with no contractual obligation to reduce load). With the reduction of up-front premiums under CallOption due to the drop in market prices, the amount of CallOption load reduction for summer 2003 was estimated at about 100 kW. Estimated peak reduction impacts from these programs vary based on expected market prices.

ULH&P's RTP program (Rate RTP) consists of a two-part rate: an access charge for the customer's historic or usual load, billed at standard tariff rates; and an energy charge, for the customer's incremental or decremental energy usage, billed at a real time price. The RTP rate sends price signals to participating customers that encourage usage during low cost periods and discourage consumption in high cost periods. Currently, 25 ULH&P customers participate in RTP with the estimated peak load reduction for summer 2003 at about 2 MW. While this program is scheduled to end in 2004, it was assumed to continue throughout the IRP planning horizon.

The expected impacts of the customer-specific contract options and innovative pricing programs are incorporated into the IRP analysis.

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).

Because customers make cogeneration decisions based on their particular economic situations, ULH&P does not attempt to forecast specific Megawatt levels of cogeneration activity in its service area. Cogeneration facilities built to affect customer energy and demand served by the utility are captured in the load forecast. Cogeneration built to provide supply to the electric network represent additional regional supply capability. As purchase 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® (TAG®) 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. As a result of the screening process, the following supply technologies were selected to be utilized as candidate supply-side resources in the STRATEGIST® dynamic integration computer runs: 1) 156 MW 7FA Simple Cycle Combustion Turbine (CT) units for the 2007-2023 time period, 2) 477 MW Combined Cycle (CC) units for the 2007-2023 time period, 3) 467 MW Pulverized Coal (PC) units for the 2007-2012 time period, 4) 350 MW Pressurized Circulating Fluidized Bed (PCFB) units for the 2013-2023 time period, and 5) 25 MW Fuel Cells for the 2013-2023 period. These units could represent potential non-utility generating units, purchases, or utility-constructed units. Due to the relatively small size of ULH&P's system, the larger units above (i.e., CT, CC, PC, and PCFB) were limited in size to 70 MW blocks so that no single unit would constitute more than 8% of ULH&P's load so that the 15% reserve margin criterion would be adequate.

In this IRP, ULH&P also considered the acquisition of CG&E's ownership of East Bend 2, Miami Fort 6, and Woodsdale 1-6, in conjunction with a Back-up Power Sales Agreement (PSA) for East Bend 2 and Miami Fort 6, as potential supply-side resources.

G. ENVIRONMENTAL COMPLIANCE

CAAA Phase I & Phase II Compliance

A detailed description of Cinergy's Phase I and Phase II compliance planning processes can be found in the Cinergy 1995, 1997, and 1999 IRPs.

NO_x Compliance Planning

NO_x State Implementation Plan (SIP) Call Compliance Planning must include requirements set forth by the following: 1) Federal NO_x SIP Call, 2) Kentucky NO_x SIP, and 3) Section 126 Petitions. These requirements are described in detail in Chapter 6.

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 NO_x allowance allocation.

The compliance plan that was developed assumes that trading will be permitted across state lines. This decision ultimately rested with the individual States when they developed their State Implementation Plans (SIP). Initially, it was 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 in the near term. However, the plan is structured to utilize trading should allowance prices fall below the highest marginal cost reduction projects.

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 reductions targeted at specific generating plants.

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 standards of conduct in FERC Order 889, the relevant transmission information is located in the Transmission Volume of 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 environmental compliance options were integrated into a set of resource plans, or strategies, using a consistent method of evaluation. STRATEGIST® (formerly named PROSCREEN II®) was the model utilized in this final integration process. From the optimized plans, five 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 sensitivities addressed at the integration stage were higher and lower gas price forecasts, a lower power market price forecast, and higher and lower load levels (based on extreme and mild weather conditions). Environmental risks, market volatility risks, and transmission risks were also considered.

Based upon both the quantitative and qualitative results of the screening analyses and sensitivity analyses, the plan selected to be the 2003 IRP is shown in Figure 1-3, assuming the transfer of the plants to ULH&P occurs on 7/1/04. The details of the plan including yearly capacity, purchases, capacity additions, retirements/derates, cogeneration, load, DSM, interruptible load, firm sales, and reserve margins are shown in Figure 1-4.

This IRP is the plan with the lowest Present Value Revenue Requirements (PVRR), over $640 million lower than the next lowest PVRR plan without the Plants. It contains the DSM bundle and DLC/RTP/CallOption programs. The supply-side resources consist of East Bend, Miami Fort 6, and Woodsdale, along with a Back-up Power Sale Agreement (PSA) for East Bend and Miami Fort 6. In addition, the plan contains small amounts of summer purchases (*i.e.*, 25-50 MW per year) in 2011-2012. Later on in the plan, there are PCFB units in 2013, 2018, and 2023, and Fuel Cell units in 2015 and 2017, which all currently act as "placeholders" for whatever capacity resources are the most economical at the time decisions for adding capacity need to be made. Of course, as the time approaches when final commitments have to be made for capacity in the last ten years of the plan, the plan may be adjusted – to levelize the reserve margins, or to substitute purchases for some of the new plant construction beginning in 2013 in the plan, if the economics and reliability of power purchases improve.

East Bend, Miami Fort 6, and Woodsdale are currently dispatched economically along with CG&E's other units and with PSI's generating units under a Joint Generation Dispatch Agreement (JGDA) between CG&E and PSI. Once all regulatory approvals are received, after ULH&P acquires these plants, they will continue to be dispatched economically with the other Cinergy system units under a Purchase, Sales and Operation Agreement between ULH&P and CG&E. This agreement will also allow energy transfers between ULH&P and CG&E at market price.

The IRP includes the projected SO_2 and NO_x compliance options described in past IRPs and in Chapter 6 associated with the East Bend, Miami Fort 6, and Woodsdale units. Any shortfalls between the yearly emission allowance allocation from the USEPA and the actual SO_2 and NO_x emitted will be supplied by ULH&P's allowance bank or by allowance purchases from the market.

The relative value for the 2003 Present Value Total Cost obtained from the STRATEGIST® output for the 2003 IRP is $3,313,502,200. The effective after-tax discount rate used was 8.737%.

The plan chosen has a number of distinct advantages due to the inclusion of the East Bend, Miami Fort 6, and Woodsdale as outlined below:

- Because these Plants already exist, there is no risk of construction or siting delay as would be the case with building new capacity.
- Excessive reliance on the wholesale market can pose pricing, scarcity, and non-performance (i.e., supplier credit) risks. The acquisition of these Plants greatly reduces ULH&P's reliance on the wholesale market for its reliability needs.

- Because these Plants are within the Cinergy control area and connected to the Cinergy transmission system, ULH&P can avoid the risks associated with trying to import the large amounts of purchases that would be required without these plants. In addition, ULH&P can avoid the deliverability risks associated with the acquisition of generation distant from the Cinergy transmission system.
- The inclusion of these plants in ULH&P's portfolio will provide source and price stability to Kentucky's electric supply which has been a key factor historically in economic development in the state.

In making decisions concerning what steps to take to begin the implementation of the 2003 IRP, careful consideration must be given to the rapidly changing environment in which utilities operate. Some of the key issues or uncertainties are:

- Environmental Regulatory Climate
- Volatility in the Wholesale Power Market
- Transmission Constraints

On July 21, 2003, ULH&P filed a petition with the Kentucky Public Service Commission to obtain Certificates of Public Convenience and Necessity (CPCN) to acquire the East Bend, Miami Fort 6, and Woodsdale units (Case No. 2003-00252). ULH&P also requested approval of the Back-up PSA for East Bend and Miami Fort 6. On December 5, 2003, the Kentucky Public Service Commission approved ULH&P's acquisition of the Plants and approved the Back-up PSA. Regulatory approvals are also required from the Federal Energy Regulatory Commission (FERC) and the Securities Exchange Commission (SEC).

After 2007, the purchases, fluidized bed units, and Fuel Cells in the plan represent, to a large extent, "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.

To comply with Phase II of the Acid Rain Program sulfur dioxide emission requirements, Cinergy's current strategy, as described in previous IRPs, 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. 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 described in Chapter 6. Cinergy has begun to implement its strategy (specifically by installing and operating an SCR on East Bend, as well as other Cinergy system units) in order to be ready to meet the compliance deadline of May 2004. However, Cinergy continues to study the environmental compliance alternatives and the viability of allowance purchases from the market to meet the requirements in the most cost-effective manner. 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 current 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 KY PSC approved ULH&P's current DSM programs through December 31, 2005, in an order dated December 17, 2002. Under this Agreement, ULH&P is implementing several DSM programs and RTP and the PowerShare® load interruption program as discussed in detail in Chapter 4 of this IRP and in the Short-Term Implementation Plan. In addition, ULH&P sought approval to amend its DSM program to add a Direct Load Control program. The Kentucky PSC approved the implementation of the Direct Load Control program on November 20, 2003. The incremental impacts going forward of the Interruptible customer contract and the

DSM, DLC, RTP, and CallOption programs are incorporated into the resource plan for ULH&P.

The 2003 IRP, with its proposed implementation, is consistent with ULH&P's overall planning objectives and goals. The plan that was chosen was the least cost (PVRR), provides reliable service to ULH&P's customers, is robust, and minimizes risks to customers of potential future market price spikes. In addition, monitoring of the SO_2 and NO_x emission allowance markets provide flexibility to ULH&P's environmental compliance strategy.

Figure 1-1

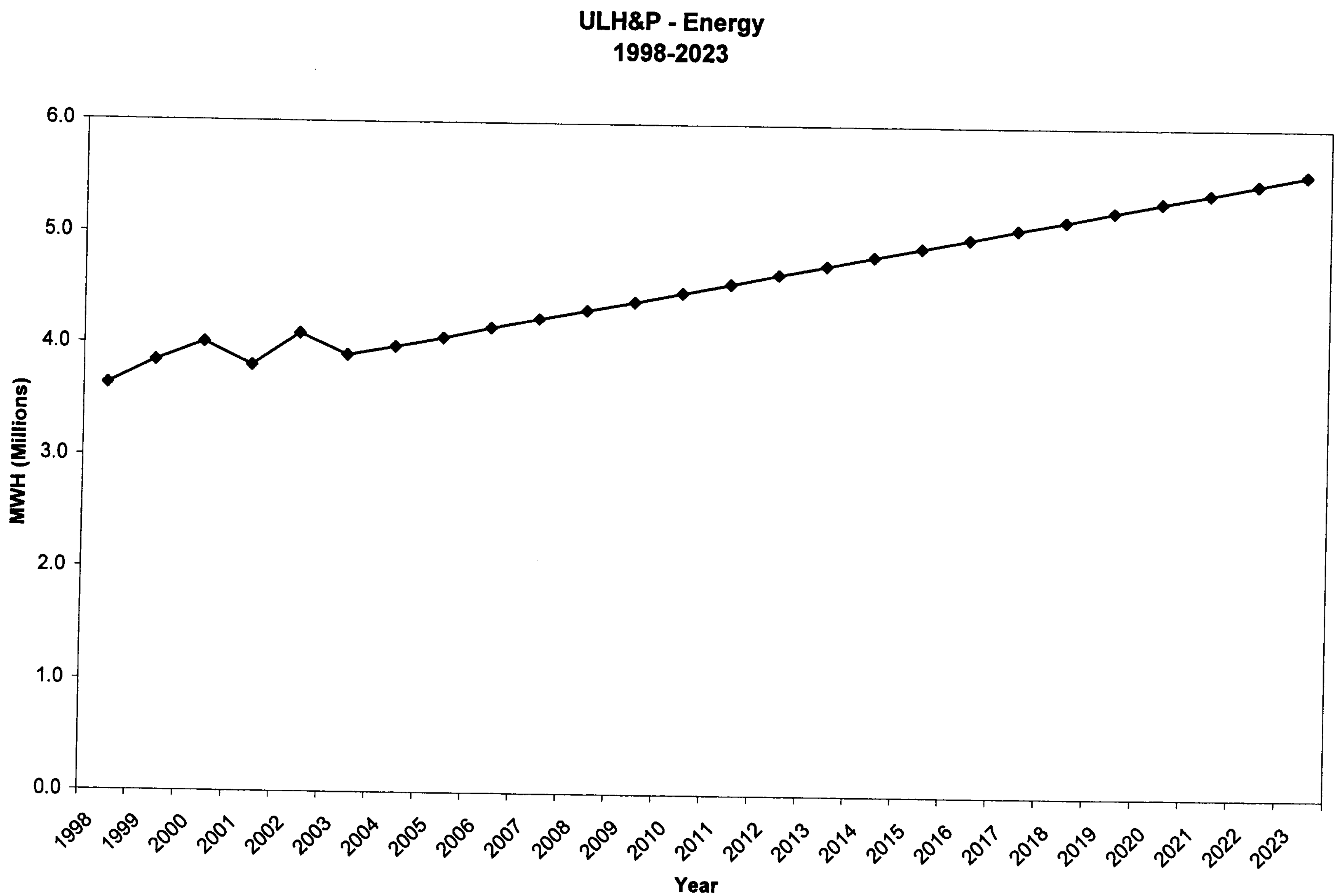
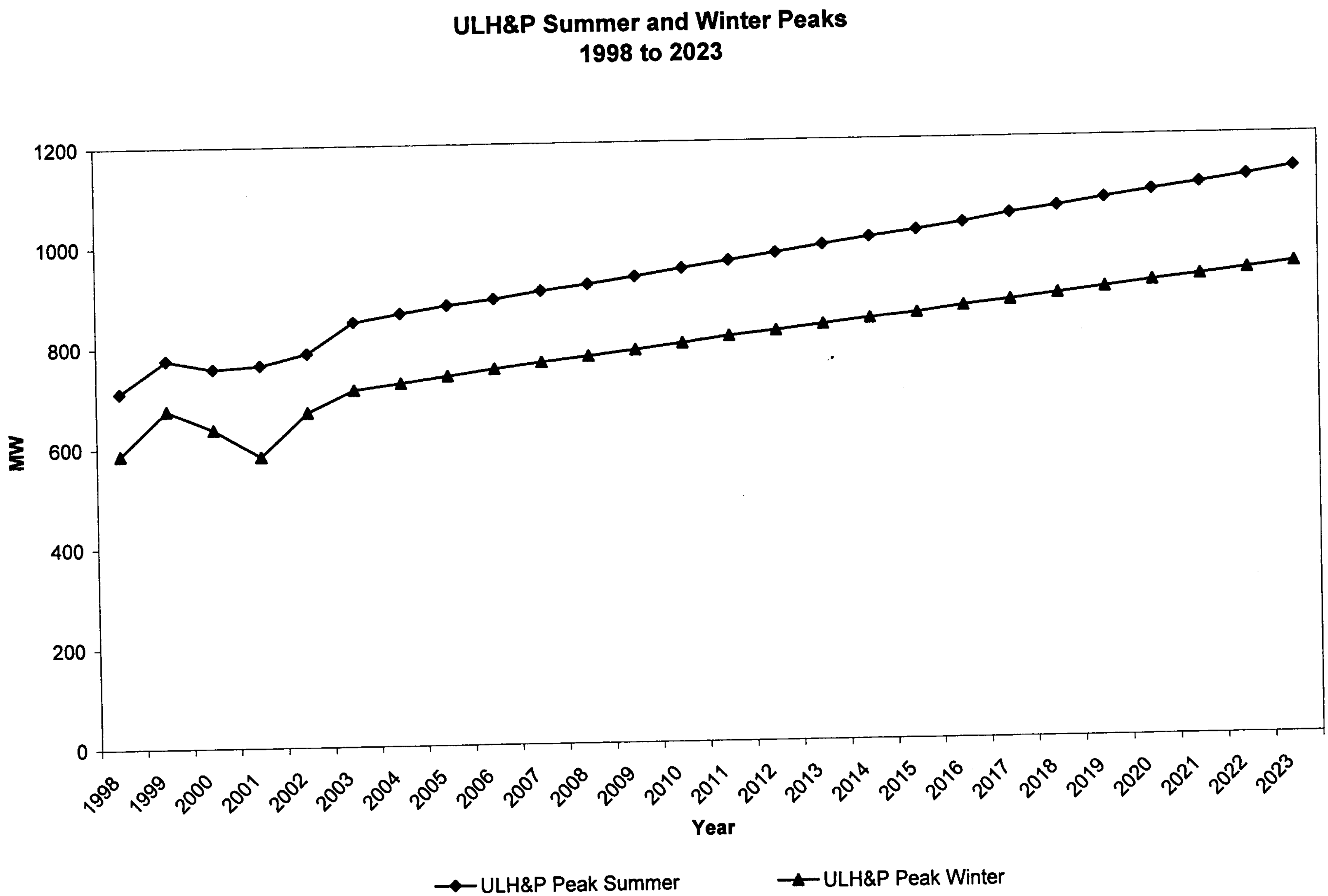

ULH&P - Energy
1998-2023
MWH (Millions)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Year

Figure 1-2



ULH&P Summer and Winter Peaks
1998 to 2023
MW
1200
1000
800
600
400
200
0
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Year
ULH&P Peak Summer
ULH&P Peak Winter

Figure 1-3

ULH&P INTEGRATED RESOURCE PLAN
2003-2023

Year	Demand-Side[1]	Purchases/Unit Additions[2]
2003	DSM Bundle Interruptible Contracts RTP/DLC/CallOption Programs	
2004		East Bend 2 with Back-up PSA Miami Fort 6 with Back-up PSA Woodsdale 1-6
2005		
2006		
2007		
2008		
2009		
2010		
2011		25 MW Summer Purchase
2012		50 MW Summer Purchase
2013		1-70 MW PCFB Unit
2014		
2015		1-25 MW Fuel Cell
2016		
2017		1-25 MW Fuel Cell
2018		1-70 MW PCFB Unit
2019		
2020		
2021		
2022		
2023		1-70 MW PCFB Unit

[1] The Demand-side resources are assumed to continue throughout the planning period (2003-2023)
[2] Capacity shown denotes summer ratings

Figure 1-4

ULH&P
INTEGRATED RESOURCE PLAN
East Bend/Miami Fort 6/Woodsdale Plan
(Summer Capacity and Loads)

YEAR	INITIAL CAPACITY	SHORT TERM PURCH.	INCR. CAPACITY ADDITIONS	INCR. CAPACITY RETIRE./ DERATES	COGEN. CAPACITY	TOTAL CAPACITY	PEAK LOAD	INCR. DSM[a]	DLC/RTP/ CALLOPTION	INDUSTRIAL INTERRUPTIBLE LOAD	FIRM SALES	NET LOAD	RES. MAR. (%)	RM CRITERION[b] (%)	MW TO ADD TO MEET RM
2003	0	843	0	0	0	843	848	-0.4	-2	-3	0	843	NA	NA	NA
2004	0	0	1077	0	0	1077	864	-0.4	-4	-3	0	857	25.7	16.7	-77
2005	1077	0	0	0	0	1077	879	-0.4	-7	-3	0	869	24.0	16.6	-64
2006	1077	0	0	0	0	1077	890	-0.4	-10	-3	0	877	22.9	16.5	-56
2007	1077	0	0	0	0	1077	905	-0.4	-13	-3	0	889	21.2	16.4	-43
2008	1077	0	0	0	0	1077	917	-0.4	-15	-3	0	899	19.8	16.3	-32
2009	1077	0	0	0	0	1077	931	-0.4	-15	-3	0	913	18.0	16.1	-17
2010	1077	0	0	0	0	1077	946	-0.4	-15	-3	0	928	16.1	16.0	-1
2011	1077	25	0	0	0	1102	960	-0.4	-15	-3	0	942	17.0	15.9	-11
2012	1077	50	0	0	0	1127	974	-0.4	-15	-3	0	956	17.9	15.7	-21
2013	1077	0	70	0	0	1147	989	-0.4	-15	-3	0	971	18.2	15.6	-25
2014	1147	0	0	0	0	1147	1003	-0.4	-15	-3	0	985	16.5	15.5	-10
2015	1147	0	25	0	0	1172	1016	-0.4	-15	-3	0	998	17.5	15.4	-21
2016	1172	0	0	0	0	1172	1030	-0.4	-15	-3	0	1012	15.8	15.2	-6
2017	1172	0	25	0	0	1197	1047	-0.4	-15	-3	0	1029	16.4	15.1	-13
2018	1197	0	70	0	0	1267	1060	-0.4	-15	-3	0	1042	21.6	15.0	-69
2019	1267	0	0	0	0	1267	1075	-0.4	-15	-3	0	1057	19.9	15.0	-52
2020	1267	0	0	0	0	1267	1089	-0.4	-15	-3	0	1071	18.3	15.0	-36
2021	1267	0	0	0	0	1267	1102	-0.4	-15	-3	0	1084	16.9	15.0	-21
2022	1267	0	0	0	0	1267	1116	-0.4	-15	-3	0	1098	15.4	15.0	-5
2023	1267	0	70	0	0	1337	1131	-0.4	-15	-3	0	1113	20.2	15.0	-57

[a] Not included in load forecast
[b] East Bend and Miami Fort 6 have a back-up contract, so Reserve Margin Criterion is the greater of 15% or 7% plus reserving for the loss of the largest unit

2. OBJECTIVES AND PROCESS

A. INTRODUCTION

In this Integrated Resource Plan (IRP) process, the modeling of ULH&P includes the electric loads and supply-side and demand-side resources associated with the ULH&P franchised service territory. The existing Power Sale Agreement (PSA) with CG&E that serves ULH&P's full requirements load through 2006 was modeled (see Chapter 5 for more details). Beginning in 2007, a number of supply-side alternatives available to ULH&P were analyzed.

In its order in Case No. 2001-00058 (the CG&E-ULH&P contract proceeding), the Kentucky Public Service Commission directed ULH&P to file a stand-alone IRP by June 30, 2004. Therefore, the planning for ULH&P was performed using ULH&P resources/contracts, ULH&P load (including the effects of ULH&P's DSM, Interruptible contracts, and innovative pricing programs) and expansion alternatives available to ULH&P.

This chapter will explain the objectives of, and the process used to develop, the 2003 ULH&P Integrated Resource Plan for the ULH&P service territory as described above.

B. <u>OBJECTIVES</u>

An IRP process generally encompasses an assessment of a variety of supply-side, demand-side, and environmental compliance alternatives leading to the formation of a diversified, long-term cost-effective portfolio of options intended to reliably 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.

The planning process itself must be dynamic and constantly adaptable to changing conditions. The resource plan presented herein represents one possible outcome based upon a snapshot in time along this dynamic continuum. While it is the most appropriate resource plan at this point in time, good business practice requires ULH&P to continue to study the options, and make adjustments as necessary and practical to reflect improved information and changing circumstances. Consequently, a good business planning analysis is truly an evolving process that can never be considered complete.

ULH&P'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 plan that is robust over a wide variety of possible futures
- Minimize risks (such as wholesale market risks, reliability risks, etc.)

C. ASSUMPTIONS

The injection of customer choice into various segments of the electric utility industry has resulted in the electric utility business shortening its planning horizon. The analysis performed to prepare this IRP covered the period 2003-2023, although the primary focus was on the first ten years. This technique was used in order to concentrate on the near-term while recognizing the fact that course corrections may be made along the way. While Kentucky IRP rules only require analysis of a 15-year timeframe, the unique circumstances of the expiration of ULH&P's contract with CG&E at the end of 2006 necessitated using a longer planning period to encompass a minimum of 15 years beyond the contract expiration date.

The major Base Case environmental assumptions for the first ten years were as follows:

- ULH&P will meet all current environmental requirements.
- Environmental regulations require meeting a 0.15 lb./MMBtu NO_x emission rate through a cap and trade program by June 2004.

- No Global Climate Change legislation or regulation mandates will be implemented before the end of the period.
- No lower emission limit or shorter averaging time requirements for SO_2 will be imposed during the period.
- No Hazardous Air Pollutant controls will be mandated and implemented during the period.
- No Mercury controls will be mandated and implemented during the period.
- No Renewable Energy Portfolio Standard will be mandated and implemented during the 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 escalation assumption was the Bureau of Labor Statistics Homepage (http://stats.bls.gov). The source of the O&M escalation assumption was the 1985-2001 historical average inflation from the Bureau of Economic Analysis, Department of Commerce. The Consumer Price Index from Economy.com was utilized to estimate general inflation for the Load Forecast. Cinergy's Financial Department provided the after-tax effective discount rate of 8.737% and the AFUDC rate of 7.00% 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

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, maintenance scheduling, and operating reserve obligations under the East Central Area Reliability Coordination Agreement (ECAR).

For the period 2003-2006, ULH&P has a firm full-requirements wholesale contract with CG&E that serves ULH&P's load. Therefore, a target reserve margin is not applicable for this period. As explained in previous IRP filings since 1995, Cinergy and ULH&P have used a 17% planning reserve margin, along with loss of load hours (LOLH) and expected unserved energy (EUE) criteria to ensure that native load needs are met. In this IRP for the period after 2006, ULH&P's reserve margin criteria consist of a 15% reserve margin (as a minimum) along with the same LOLH and EUE criteria used in past IRPs.

Reserve margins are an obligation for a number of reasons. First, the reserve margin must cover Operating Reserves. The Operating Reserve is a requirement of both

ECAR and NERC to ensure that the real time needs of the electric system are met.

The requirement is:

- one (1) percent of the projected peak load as "Load and Frequency Regulation Reserve" – to provide "on-line" generation for load and frequency regulation
- one and one-half (1½) percent of the projected peak load as "Spinning Reserve" – which is required to be "on-line" and capable of being supplied within ten minutes, and
- one and one-half (1½) percent of the projected peak load as "Supplemental Reserve" – which is required to be capable of being supplied to the system within ten minutes from "on-line" or "off-line" resources.

The total Operating Reserve requirement is 4%.

Second, the reserve margin must cover a level of unscheduled outages that inevitably occur. Even the best-maintained generating system will experience unit outages and derates, and there is always the possibility that such an outage or outages will occur when the units are most needed. ULH&P believes that 8% is a reasonable expected margin for a normal level of outages and derates.

Third, there is always the possibility that that temperatures can be abnormal, that the actual load may be different from the projected load forecast due to changed economic conditions, or that the weather may be different from the temperature on which the load forecast was based (without being "extreme"). For example, ULH&P's load forecasting personnel estimate that a 1 degree increase in temperature can result in approximately a 1.1% increase in ULH&P's load to be served. Since extreme temperatures are not used as a basis for ULH&P's load forecast (ULH&P uses approximately 93 degrees in its forecast of peak demand), ULH&P considers a minimum of 3% reserve for weather-induced load to be appropriate. History shows that temperatures in Kentucky can get above 96 degrees on a hot summer day.

Taking these reserve considerations in the aggregate, ULH&P considers 15% to be a minimum reserve margin. However, ULH&P continues to examine the appropriate level of reserves to help control costs. Lower reserves may help restrain increases in base rates, but there are clearly limits to, and trade-offs for, any gains from lower reserves, as some past summers have taught us. For example, if using a reserve level that is too low causes a utility to increase its reliance on purchases from the spot market, customers incur additional costs. These costs can be substantial if the spot market price is experiencing a spike at the time purchases are made. If shortages in the wholesale market occur such that load must be curtailed, customers incur additional costs such as loss of production and inconvenience.

Because of the relatively small size of ULH&P's system, it may be necessary to use a higher reserve margin to provide the same level of reliability that a 15% reserve margin provides to a larger system. For example, many utilities use reserve margin criteria that contain a component to cover the loss of the largest unit on the system.

Depending on the mix of resources and the sources of those resources ultimately determined to be optimal to serve ULH&P's load after 2006, a higher reserve margin may be needed. Alternatively, ULH&P may need to secure contracts to back-up a portion of its capacity. The modeling in this IRP attempts to capture the differences in reliability criteria necessary for resources with and without back-up contracts. ULH&P continues to study this issue.

To summarize, the reliability constraints utilized for this IRP are:

1. Minimum reserve margin of fifteen percent (15%);
2. Annual loss of load hours (LOLH) less than 175; and
3. Expected unserved energy (EUE) less than 0.18 percent.

Currently, the need for additional electricity resource options to satisfy 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 an increase in 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. 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 development and evaluation), environmental compliance planning, environmental, financial, power marketing and trading, fuel planning and procurement, engineering and construction, and transmission planning (to a limited extent due to the standards of conduct in FERC Order 889). It was the Team's responsibility to examine the IRP requirements contained within the Kentucky 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, supply-side options, environmental 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 and procurement, and, to the extent allowable considering the standards of conduct in FERC Order 889, transmission 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 electric load forecast. 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 environmental compliance options. More details concerning this step of the process can be found in Chapter 6.

6. Integrate the demand-side, supply-side, and environmental 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.

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.

3. ELECTRIC LOAD FORECAST

A. GENERAL

ULH&P provides electric and gas service in the Northern Kentucky area. ULH&P serves approximately 128,000 customers in its 500 square mile service territory. ULH&P's service territory includes the cities of Covington and Newport, Kentucky.

ULH&P owns an electric transmission system and an electric distribution system 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.

ULH&P does not perform joint load forecasts with non-affiliated companies. The forecast is prepared independent of the forecasting efforts of other utilities.

B. FORECAST METHODOLOGY

The forecast methodology is essentially the same as that presented in past Integrated Resource Plans filed with the Kentucky Public Service Commission (KyPSC).

Energy is a key commodity linked to 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 are key ingredients to energy forecasts.

The general framework of the Electric Energy and Peak Load Forecast 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 is obtained from Economy.com, a nationally recognized vendor of economic forecasts. In conjunction with the forecast of the national economy, the Company also obtains a forecast of the service area economy from Economy.com. The ULH&P service area is located in Northern Kentucky adjacent to the service area of the Cincinnati Gas & Electric Company. The economy of Northern Kentucky is contained within the Cincinnati Primary Metropolitan Statistical Area (PMSA) and is an integral part of the regional 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 Economy

The national and service area economic forecasts are prepared by Economy.com. The service area forecast incorporates both national and local impacts into the local economic forecast.

Economy.com provides local forecasts for income, industrial production and employment by Standard Industrial Classifications (SIC), and population. This information serves as input into the energy and peak load forecast models.

There are four major components to the service area economic forecast: employment, income, production, and demographics.

Additionally, inflation is measured by changes in the Consumer Price Index (CPI).

Employment - Total service area employment is classified into two major categories: manufacturing and non-manufacturing. In general, different elements affect employment in these two categories.

Forecasts of employment are developed for the commercial, industrial, and governmental sectors. Within the industrial sector, employment and production is forecast by SIC.

Production – Local industrial production is projected for each key SIC group by multiplying the forecast of productivity (production per employee) by the forecast of local employment by key SIC.

(1) Local Industrial $\text{Production}_i = \text{Productivity}_i * \text{Local Employment}_i$

where i represents SIC.

Income - Income is available in five distinct components, which together produce total nominal service area income. 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 as follows:

(2) 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.

Population - Population projections for the service area are provided for each five-year age-cohort by Economy.com.

2. Electric Energy Forecast

The forecast 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 projected energy requirements for ULH&P's retail electric customers are determined through econometric analysis. Econometric models are a means of representing economic behavior through the use of statistical methods, such as regression analysis.

The ULH&P forecast of energy requirements is included within the overall forecast of energy requirements of the Greater Cincinnati and Northern Kentucky region. The ULH&P sales forecast is developed by allocating percentages of the total regional forecast for each customer group. These percentages provide ULH&P forecasts for sales to the residential, commercial, industrial, government or other public authority (OPA), and street lighting energy sectors. In addition, forecasts are also prepared for three minor categories: interdepartmental use (Gas Department), Company use, and losses. In a similar fashion, the ULH&P peak load forecast is developed by allocating a share from the regional total. Historical percentages and judgment are used to develop the allocations of sales and peak demands.

The following sections provide the specifications of the econometric equations developed to forecast electricity sales for the franchised service territory.

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:

(3) Residential Sales =

Number of Residential Customers * Use per Residential Customer.

Econometric relationships are 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:

(4) Residential Customers =

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

where Real Per Capita Income = (Personal Income/Population/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 also play a role.

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

(5) Residential usage per Customer =

f (Real Income Per Capita * Efficient Appliance Stock,
Real Marginal Electricity Price * Efficient Appliance Stock,
Saturation of Electric Resistance Heating,
Saturation of Electric Heat Pump,
Saturation of Central Air Conditioning,
Saturation of Window Air Conditioning,

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 appliance saturations are discussed in the data section.

Commercial Sector - Commercial electricity usage changes with variations in commercial economic activity, conservation/energy efficiency, and energy 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, equipment efficiency, and the weather.

(6) Commercial Sales =

f (Commercial Employment,

Marginal Electric Price/Consumer Price Index,

Price of Natural Gas/Consumer Price Index,

Equipment Efficiency,

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, and heating and cooling degree days.

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 indicates that weather is becoming more important to industrial sales. This is evident from the fact that cooling degree days and heating degree days are included in several of the industrial equations.

The general form of the equation is as follows:

(7) Industrial Sales_i =

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.

<u>Other Public Authority Sector</u> - 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:

(8) 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:

(9) Non-Water Pumping Sales =

f (Governmental Employment,

Marginal Electric Energy Price/Consumer Price Index,

Marginal Electric Energy Price/Natural Gas Price,

Billed Heating and 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:

(10) 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.

Total Electric 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 electric 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 Company 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 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 the Company in this area indicated 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 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:

(11) Peak =

f (Weather Normalized Sendout,

Weather Factors).

Winter Peak - Winter peak loads are also influenced by the current level of economic activity and a 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 temperature, 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:

(12) 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 historical 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, and other public authority, 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 industrial 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.

Peak 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).

C. ASSUMPTIONS

1. General

A major risk to the national and regional economic forecasts and hence the electric load forecast is the continued economic growth in the U.S. economy. In addition, 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 or reduce interest rates to keep the economy growing. The national economy has been experiencing slow growth since the end of the recession in November 2001. The ultimate outcome in the near term is dependent upon the success of the economy moving forward out of this slow period.

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.

The economy of the ULH&P service area is expected to grow at a rate similar to the rest of the nation. With extensive economic diversity, the Cincinnati area economy, including Northern Kentucky, is well structured to make the adjustments necessary for growth. In the manufacturing sector, its major industries are food products, paper, printing, chemicals, steel, fabricated metals, machinery, and automotive and aircraft transportation equipment. In the non-manufacturing sector, its major industries are life insurance and finance. In addition, the Cincinnati area is the headquarters for major international and national market-oriented retailing establishments.

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.

2. Specific

Commercial Fuels - At the time of the forecast, the equivalent energy prices ($/MMBtu) of natural gas and fuel oils (#2 and #6) was below the price of electricity. Further, it was expected that natural gas and oil prices would change in a similar fashion but at different rates. The projected annual growth rate 2003 to 2023, in nominal terms, is 3.5 percent for the price of natural gas and 3.7 percent for the price of oil (residual fuel oils.)

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 and oil prices are expected to increase over the forecast 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 source relied upon is Economy.com.

Alternative Energy Sources – The supply of energy from alternate energy sources and technologies currently is small and will continue to have a minor effect on the 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. Commercially available wind generator units are currently not economically feasible in the 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 gas and electricity, to some extent in the residential class. The 2000 appliance saturation survey indicated that a small percentage of customers in the service area use wood as a primary source for home heating. Many, of course, use gas 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.

Pricing Policy – ULH&P's electric tariffs for residential customers have a seasonal pattern. 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.

The purpose of the seasonal characteristics of the rate schedules is to promote conservation during summer months when demand upon electric facilities is greatest.

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 service area 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 0.6 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: 1.1 percent locally versus 1.3 percent nationally.

For the forecast period, local industrial production is expected to increase at a 1.9 percent annual rate, while 2.6 percent is the expected growth rate for the nation.

Inflation Rate - The annual inflation rate projected for the forecast period is 2.3 percent.

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 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. The Company has distributed information on cogeneration to anyone that has expressed interest. The development of cogeneration on the system and its effect on the forecast will be monitored closely in the future. 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.

Year End Residential Customers - In the following table, historical and projected total year-end residential customers for the entire service area are provided.

NUMBER OF YEAR-END RESIDENTIAL CUSTOMERS

1994	99,710
1995	101,898
1996	103,708
1997	105,413
1998	107,428
1999	109,547
2000	111,631
2001	112,417
2002	111,833
2003	112,707
2004	113,782
2005	114,884
2006	116,186
2007	117,379
2008	118,495
2009	119,668
2010	120,927
2011	122,131
2012	123,302
2013	124,457
2014	125,559
2015	126,636
2016	127,696
2017	128,706
2018	129,671
2019	130,612
2020	131,529
2021	132,422
2022	133,291
2023	134,169

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 provided by Economy.com.

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.

D. DATA BASE DOCUMENTATION

Data collection is one of the first steps in the forecasting process. The data base discussion is broken into three parts: Service Area Economy, Energy and Peak Models, and Forecast Data.

1. Service Area Economy

Major groups of data used in the development of the service area economic forecast are employment, industrial production indices, population, income, prices, and wages. National and local values for these concepts are available from Economy.com, both on an historic and forecast basis.

Some of the data collected is not in the appropriate form for analysis. In the following sections, descriptions are provided of the manipulations that various groups of data must go through to develop the final data series actually used in regression analysis.

Average Hourly Earnings-Manufacturing - Average hourly earnings for total manufacturing for the Cincinnati MSA are available on a quarterly basis from Economy.com. Average hourly earnings for durable and non-durable manufacturing is computed as a weighted average of total average hourly earnings. Service area durable and non-durable employment to total manufacturing employment ratios serve as the weights used in this calculation.

Consumer Price Index - The local CPI is equivalent to the national CPI obtained from Economy.com.

Employment - Employment numbers are required on both a national and service area basis. Quarterly national and local employment series are obtained from Economy.com. Employment series are available for all SIC groups in the industrial and commercial sectors.

Employment data are essentially in the correct form except for one required aggregation. Total commercial employment is derived from the sum of employment in SICs 40 through 89.

Service area employment is available for construction, industrial SICs 20, 23, 26, 27, 28, 30, 33, 34, 35, 36, 371, 372, AOIDG (all other industrials, durable goods), and AOINDG (all other industrials, non-durable goods), commercial SICs 40 through 89, and government SIC 90 for the service area.

Population - National and local values for total population and population by age-cohort groups are obtained from Economy.com. Population aged 20 and over is derived by subtracting population aged 0 to 4 and 5 to 19 from total population. Population aged 0 to 19 is derived by adding population aged 0 to 4 and population aged 5 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 Economy.com.

Income - Local income data series are obtained from Economy.com. The data is retrieved on a county level and summed to a service area level. This includes data for personal income; dividends, interest, and rent; transfer payments; wage and salary disbursements plus other labor income; adjustment for residence; personal contributions for social insurance; and non-farm proprietors' income.

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.

Electricity and Natural Gas Prices - The average price of electricity and natural gas is available from Company 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 All Other Industries, Durable Goods (AOIDG) and All Other Industries, Non-Durable Goods (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 are obtained from Economy.com.

2. Energy and Peak Models

The electric energy and peak load forecast is prepared using a forecast of the local economy, which is obtained from Economy.com.

The majority of the data required for developing the electric energy model is obtained from either the service area economic forecast data or the Company's financial reports. Also, data on additional national variables are obtained from Economy.com. As with the economic data, 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 Company financial reports for each customer class. Sales for SIC 372 through 379 (372@9) are computed by subtracting sales for SIC 371 from sales for SIC 37. The last step is to derive sales for the all other industries (AOI) category. This is accomplished by subtracting sales for SICs 20, 26, 28, 33, 35, 36, 371, and 372@9 from 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 are derived by subtracting the respective water-pumping series from the OPA series.

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. The series is converted to a quarterly and annual series by averaging.

Residential Use Per Customer - 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 calculated on a monthly basis using temperature data from the NOAA (National Oceanic and Atmospheric Administration). The degree day series are required on a billing cycle basis for use in regression analysis.

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 on the connected load.

The appliance stock variable is calculated as follows:

(13) $\text{Appliance Stock}_t = \text{SUM}\,(K_i * SAT_{i,t} * EFF_{i,t})$ 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 load data.

Appliance Saturation and Efficiency - In general, information on historical appliance saturations for all appliances is obtained from Company 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.

Data on historical 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 Appliance Week.

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.

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

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

Peak Weather Data - 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.

Electricity Price - Data on electricity price (including fuel cost) is collected for each customer class. This information is obtained from rate schedules.

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, the Company continues 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, the Company monitors 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.

Market Research - Primary research projects continue to be conducted as part of the on-going efforts to gain knowledge about the Company'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. MODELS

Specific analytical techniques have been employed for development of the forecast models.

1. 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 energy model equations may employ 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 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.

2. 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.

3. Alternative Methodologies

The Company continues to use the current forecasting methodology since it is considered to be reasonably accurate.

4. Changes In Methodology

There were no significant changes to the forecast methodology. The Company uses the latest historical data available and relies on recent economic data and forecasts from Economy.com.

5. Computer Software

The computer software package employed in the preparation of the forecast, developed by Economic Analysis Associates, Inc., is called EAL (Economic Analysis Language). It is a licensed software product utilized on microcomputers.

F. FORECASTED DEMAND AND ENERGY

On the following pages, the loads for ULH&P are provided. The forecast data is provided before and after implementation of DSM programs.

1. Service Area Energy Forecasts

Figure 3-1 indicates ULH&P's energy demand for its service area before DSM.

Before implementation of any new DSM programs or incremental DSM impacts, Residential use for the twenty-year period of the forecast is expected to increase an average of 1.3 percent per year; Commercial use, 1.4 percent per year; and Industrial use, 3.3 percent per year.

The summation of the forecast changes in each sector results in a growth rate forecast of 1.8 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 (Figure 3-2) Residential use is expected to increase an average of 1.3 percent per year; Commercial use, 1.4 percent per year; and Industrial use, 3.3 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 an after DSM growth rate forecast of 1.8 percent for Net Energy for Load.

2. System Seasonal Peak Load Forecast

Figure 3-3 contains the forecast of summer and winter peaks for the ULH&P service area. 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.

Figure 3-4, labeled "Internal Load", summarizes 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 is 1.5 percent. Projected growth in the winter peak demand is 1.4 percent.

Peak load forecasts after implementation of DSM programs (Figure 3-5 and Figure 3-6) are shown for native and internal loads after DSM. Based on Figure 3-6, the projected growth in the summer peak is 1.4 percent. Projected growth in winter peak demand is 1.4 percent.

3. 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, 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 5 MW exists for interruption in the ULH&P service area (Interruptible customer plus RTP/CallOption). The after DSM forecast reflects the 5 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.

4. Load Factor

The numbers below represent the annual percentage load factor for the ULH&P System before any new or incremental DSM. It shows the relationship between Net Energy for Load, Figure 3-1 and the annual peak, Figure 3-4, before DSM.

YEAR	LOAD FACTOR
1998	58.49%
1999	56.67%
2000	60.51%
2001	57.02%
2002	59.48%
2003	52.61%
2004	52.62%
2005	52.80%
2006	53.37%
2007	53.57%
2008	53.87%
2009	54.04%
2010	54.21%
2011	54.42%
2012	54.65%
2013	54.81%
2014	55.01%
2015	55.22%
2016	55.40%
2017	55.47%
2018	55.64%
2019	55.79%
2020	55.96%
2021	56.10%
2022	56.28%
2023	56.41%

5. 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 Economy.com. Economy.com 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 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			
Employment			
Manufacturing	-0.6%	-0.2%	0.3%
Commercial	1.0%	1.3%	1.6%
Governmental	-0.1%	0.1%	0.3%
Total	0.5%	0.9%	1.2%
Industrial Production	1.6%	2.0%	2.3%
Real Per Capita Income	0.5%	1.3%	2.2%
Consumer Price Index	2.3%	2.3%	2.3%

Figure 3-7 provides the high, low, and most likely before DSM forecasts of electric energy and peak demand for the service area. Figure 3-8 provides similar information after implementation of the DSM programs.

Likewise, under the assumption of base economic growth, the most likely forecast of electrical energy demand and peak loads is generated using forecasts of normal weather. Ranges around the base forecast can be generated using abnormally harsh or abnormally mild weather conditions.

The level of electric sales is highly sensitive to weather conditions. As weather is represented in the forecast by the level of heating and cooling degree days, the ranges were generated using increased levels of degree days above normal (harsh) and reduced levels of degree days below normal (mild). The alternate ranges of electricity loads were projected using an estimated 80% confidence interval (90/10 probability levels) for the weather conditions.

The following table provides the range of sales under the alternate weather conditions as compared to the base forecast.

UNION LIGHT HEAT AND POWER
NET ENERGY FOR LOAD

RANGE OF FORECASTS
WEATHER BANDS

	MILD	BASE	HARSH
2003	3,766,754	3,907,910	4,069,804
2004	3,838,742	3,982,976	4,149,026
2005	3,918,698	4,065,712	4,234,723
2006	4,010,149	4,160,857	4,334,278
2007	4,093,849	4,246,751	4,422,430
2008	4,170,177	4,327,116	4,508,316
2009	4,248,500	4,407,408	4,590,405
2010	4,330,536	4,492,073	4,677,654
2011	4,411,732	4,576,717	4,767,493
2012	4,494,949	4,662,895	4,857,164
2013	4,577,003	4,748,487	4,947,157
2014	4,658,848	4,833,412	5,035,153
2015	4,737,804	4,914,256	5,117,836
2016	4,818,926	4,998,327	5,206,282
2017	4,906,026	5,087,452	5,296,684
2018	4,981,390	5,166,768	5,380,998
2019	5,064,964	5,253,634	5,471,477
2020	5,147,926	5,338,123	5,557,256
2021	5,224,436	5,415,950	5,636,486
2022	5,306,545	5,501,580	5,726,985
2023	5,391,697	5,588,766	5,815,896

6. Monthly Forecast

Figure 3-9 and Figure 3-10 contain the net monthly energy forecast and the net monthly internal peak load forecast for the total ULH&P system before DSM. Likewise, Figure 3-11 and 3-12 present the net monthly energy and internal peak load forecasts for the total ULH&P system after DSM.

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.

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Figure 3-1 Part 1

Union Light Heat and Power

Service Area Energy Forecast (Megawatt Hours/Year)

Before DSM

	YEAR	(1) RURAL AND RESIDENTIAL	(2) COMMERCIAL	(3) INDUSTRIAL	(4) STREET-HWY LIGHTING	(5) SALES FOR RESALE a	(6) OTHER
-5	1998	1,217,326	974,915	1,047,913	15,713	0	348,392
-4	1999	1,254,643	1,042,927	966,516	16,764	0	356,315
-3	2000	1,259,784	1,161,743	1,030,210	18,029	0	320,045
-2	2001	1,297,467	1,297,651	880,519	17,163	0	297,772
-1	2002	1,403,524	1,317,653	770,872	19,493	0	299,446
0	2003	1,342,657	1,270,153	815,394	20,706	0	288,627
1	2004	1,365,459	1,299,138	835,764	20,980	0	288,862
2	2005	1,386,764	1,328,709	861,589	21,255	0	290,771
3	2006	1,414,184	1,357,926	892,732	21,533	0	293,305
4	2007	1,434,518	1,378,697	928,134	21,815	0	296,047
5	2008	1,460,309	1,402,816	957,145	22,099	0	299,112
6	2009	1,477,987	1,421,684	991,810	22,389	0	301,586
7	2010	1,498,358	1,440,956	1,027,500	22,677	0	303,905
8	2011	1,520,940	1,460,621	1,066,430	22,976	0	305,973
9	2012	1,542,617	1,480,414	1,105,466	23,275	0	308,037
10	2013	1,565,979	1,501,196	1,141,936	23,581	0	309,582
11	2014	1,587,034	1,522,112	1,179,412	23,892	0	310,957
12	2015	1,605,090	1,541,952	1,216,363	24,200	0	312,265
13	2016	1,625,435	1,561,347	1,255,605	24,516	0	313,351
14	2017	1,641,966	1,579,717	1,299,740	24,835	0	314,254
15	2018	1,663,963	1,599,233	1,339,078	25,162	0	315,100
16	2019	1,684,601	1,618,066	1,382,594	25,490	0	315,777
17	2020	1,704,595	1,636,736	1,425,814	25,822	0	316,122
18	2021	1,715,614	1,651,753	1,464,255	26,160	0	316,340
19	2022	1,737,733	1,669,956	1,510,073	26,501	0	316,886
20	2023	1,752,800	1,685,119	1,558,866	26,848	0	316,883

(a) Sales for resale to municipals.

Figure 3-1 Part 2

Union Light Heat and Power

Service Area Energy Forecast (Megawatt Hours/Year)

Before DSM

	YEAR	(7) (1+2+3 +4+5+6) TOTAL CONSUMPTION	(8) LOSSES AND UNACCOUNTED FOR b	(9) (7+8) NET ENERGY FOR LOAD
-5	1998	3,604,260	33,536	3,637,796
-4	1999	3,637,166	210,364	3,847,529
-3	2000	3,789,810	222,718	4,012,529
-2	2001	3,790,572	20,458	3,811,030
-1	2002	3,810,988	284,130	4,095,119
0	2003	3,737,539	170,371	3,907,910
1	2004	3,810,203	172,773	3,982,976
2	2005	3,889,088	176,624	4,065,712
3	2006	3,979,680	181,177	4,160,857
4	2007	4,059,211	187,540	4,246,751
5	2008	4,141,481	185,635	4,327,116
6	2009	4,215,456	191,952	4,407,408
7	2010	4,293,396	198,677	4,492,073
8	2011	4,376,940	199,777	4,576,717
9	2012	4,459,809	203,086	4,662,895
10	2013	4,542,274	206,213	4,748,487
11	2014	4,623,407	210,005	4,833,412
12	2015	4,699,870	214,386	4,914,256
13	2016	4,780,254	218,073	4,998,327
14	2017	4,860,512	226,940	5,087,452
15	2018	4,942,536	224,232	5,166,768
16	2019	5,026,528	227,106	5,253,634
17	2020	5,109,089	229,034	5,338,123
18	2021	5,174,122	241,828	5,415,950
19	2022	5,261,149	240,431	5,501,580
20	2023	5,340,516	248,250	5,588,766

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

Figure 3-2 Part 1

Union Light Heat and Power

Service Area Energy Forecast (Megawatt Hours/Year)a

After DSM

		(1)	(2)	(3)	(4)	(5)	(6)
	YEAR	RURAL AND RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET-HWY LIGHTING	SALES FOR RESALE b	OTHER
-5	1998	1,217,326	974,915	1,047,913	15,713	0	348,392
-4	1999	1,254,643	1,042,927	966,516	16,764	0	356,315
-3	2000	1,259,784	1,161,743	1,030,210	18,029	0	320,045
-2	2001	1,297,467	1,297,651	880,519	17,163	0	297,772
-1	2002	1,403,524	1,317,653	770,872	19,493	0	299,446
0	2003	1,340,970	1,270,153	815,394	20,708	0	288,627
1	2004	1,362,680	1,299,138	835,764	20,980	0	288,862
2	2005	1,382,892	1,328,709	861,589	21,255	0	290,771
3	2006	1,409,813	1,357,926	892,732	21,533	0	293,305
4	2007	1,430,147	1,378,697	928,134	21,815	0	296,047
5	2008	1,455,938	1,402,816	957,145	22,099	0	299,112
6	2009	1,473,616	1,421,684	991,810	22,389	0	301,586
7	2010	1,493,987	1,440,956	1,027,500	22,677	0	303,905
8	2011	1,516,569	1,460,621	1,066,430	22,976	0	305,973
9	2012	1,538,246	1,480,414	1,105,466	23,275	0	308,037
10	2013	1,561,608	1,501,196	1,141,936	23,581	0	309,582
11	2014	1,582,663	1,522,112	1,179,412	23,892	0	310,957
12	2015	1,600,719	1,541,952	1,216,363	24,200	0	312,265
13	2016	1,621,064	1,561,347	1,255,605	24,516	0	313,351
14	2017	1,637,595	1,579,717	1,299,740	24,835	0	314,254
15	2018	1,659,592	1,599,233	1,339,078	25,162	0	315,100
16	2019	1,680,230	1,618,066	1,382,594	25,490	0	315,777
17	2020	1,700,224	1,636,736	1,425,814	25,822	0	316,122
18	2021	1,711,243	1,651,753	1,464,255	26,160	0	316,340
19	2022	1,733,362	1,669,956	1,510,073	26,501	0	316,886
20	2023	1,748,429	1,685,119	1,558,866	26,848	0	316,883

(a) Includes DSM Impacts.

(b) Sales for resale to municipals.

Figure 3-2 Part 2

Union Light Heat and Power

Service Area Energy Forecast (Megawatt Hours/Year)c

After DSM

	YEAR	(7) (1+2+3 +4+5+6) TOTAL CONSUMPTION	(8) LOSSES AND UNACCOUNTED FOR d	(9) (7+8) NET ENERGY FOR LOAD
-5	1998	3,604,260	33,536	3,637,796
-4	1999	3,637,166	210,364	3,847,529
-3	2000	3,789,810	222,718	4,012,529
-2	2001	3,790,572	20,458	3,811,030
-1	2002	3,810,988	284,130	4,095,119
0	2003	3,735,852	170,371	3,906,223
1	2004	3,807,424	172,773	3,980,197
2	2005	3,885,216	176,624	4,061,840
3	2006	3,975,309	181,177	4,156,486
4	2007	4,054,840	187,540	4,242,380
5	2008	4,137,110	185,635	4,322,745
6	2009	4,211,085	191,952	4,403,037
7	2010	4,289,025	198,677	4,487,702
8	2011	4,372,569	199,777	4,572,346
9	2012	4,455,438	203,086	4,658,524
10	2013	4,537,903	206,213	4,744,116
11	2014	4,619,036	210,005	4,829,041
12	2015	4,695,499	214,386	4,909,885
13	2016	4,775,883	218,073	4,993,956
14	2017	4,856,141	226,940	5,083,081
15	2018	4,938,165	224,232	5,162,397
16	2019	5,022,157	227,106	5,249,263
17	2020	5,104,718	229,034	5,333,752
18	2021	5,169,751	241,828	5,411,579
19	2022	5,256,778	240,431	5,497,209
20	2023	5,336,145	248,250	5,584,395

(c) Includes DSM Impacts.

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

Figure 3-3

Union Light Heat and Power

System Seasonal Peak Load Forecast (Megawatts)

Before DSM
Native Load a

		Summer			Winter d		
	YEAR	LOAD	CHANGE b	PERCENT CHANGE c	LOAD	CHANGE b	PERCENT CHANGE c
-5	1998	710			586		
-4	1999	775	65	9.2	674	88	15.0
-3	2000	757	-18	-2.3	636	-38	-5.6
-2	2001	763	6	0.8	582	-54	-8.5
-1	2002	783	20	2.6	668	86	14.8
0	2003	843	60	7.7	707	39	5.8
1	2004	859	16	1.9	719	12	1.7
2	2005	874	15	1.7	732	13	1.8
3	2006	885	11	1.3	745	13	1.8
4	2007	900	15	1.7	757	12	1.6
5	2008	912	12	1.3	768	11	1.5
6	2009	926	14	1.5	779	11	1.4
7	2010	941	15	1.6	791	12	1.5
8	2011	955	14	1.5	804	13	1.6
9	2012	969	14	1.5	814	10	1.2
10	2013	984	15	1.5	825	11	1.4
11	2014	998	14	1.4	836	11	1.3
12	2015	1,011	13	1.3	846	10	1.2
13	2016	1,025	14	1.4	859	13	1.5
14	2017	1,042	17	1.7	869	10	1.2
15	2018	1,055	13	1.2	881	12	1.4
16	2019	1,070	15	1.4	892	11	1.2
17	2020	1,084	14	1.3	903	11	1.2
18	2021	1,097	13	1.2	914	11	1.2
19	2022	1,111	14	1.3	925	11	1.2
20	2023	1,126	15	1.4	936	11	1.2

(a) Excludes interruptible load.
(b) Difference between reporting year and previous year.
(c) Difference expressed as a percent of previous year.
(d) Winter load reference is to peak loads which occur in the following winter.

Figure 3-4

Union Light Heat and Power

System Seasonal Peak Load Forecast (Megawatts)

Before DSM
Internal Load a

		Summer			Winter d		
	YEAR	LOAD	CHANGE b	PERCENT CHANGE c	LOAD	CHANGE b	PERCENT CHANGE c
-5	1998	710			586		
-4	1999	775	65	9.2	674	88	15.0
-3	2000	757	-18	-2.3	636	-38	-5.6
-2	2001	763	6	0.8	582	-54	-8.5
-1	2002	786	23	3.0	668	86	14.8
0	2003	848	62	7.9	712	44	6.6
1	2004	864	16	1.9	724	12	1.7
2	2005	879	15	1.7	737	13	1.8
3	2006	890	11	1.3	750	13	1.8
4	2007	905	15	1.7	762	12	1.6
5	2008	917	12	1.3	773	11	1.4
6	2009	931	14	1.5	784	11	1.4
7	2010	946	15	1.6	796	12	1.5
8	2011	960	14	1.5	809	13	1.6
9	2012	974	14	1.5	819	10	1.2
10	2013	989	15	1.5	830	11	1.3
11	2014	1,003	14	1.4	841	11	1.3
12	2015	1,016	13	1.3	851	10	1.2
13	2016	1,030	14	1.4	864	13	1.5
14	2017	1,047	17	1.7	874	10	1.2
15	2018	1,060	13	1.2	886	12	1.4
16	2019	1,075	15	1.4	897	11	1.2
17	2020	1,089	14	1.3	908	11	1.2
18	2021	1,102	13	1.2	919	11	1.2
19	2022	1,116	14	1.3	930	11	1.2
20	2023	1,131	15	1.3	941	11	1.2

(a) Includes interruptible load.
(b) Difference between reporting year and previous year.
(c) Difference expressed as a percent of previous year.
(d) Winter load reference is to peak loads which occur in the following winter.

Figure 3-5

Union Light Heat and Power

System Seasonal Peak Load Forecast (Megawatts) a

After DSM
Native Load b

		Summer			Winter e		
	YEAR	LOAD	CHANGE c	PERCENT CHANGE d	LOAD	CHANGE c	PERCENT CHANGE d
-5	1998	710			586		
-4	1999	775	65	9.2	674	88	15.0
-3	2000	757	-18	-2.3	636	-38	-5.6
-2	2001	763	6	0.8	582	-54	-8.5
-1	2002	783	20	2.6	668	86	14.8
0	2003	841	58	7.4	707	39	5.8
1	2004	857	16	1.9	718	11	1.6
2	2005	868	11	1.3	731	13	1.8
3	2006	876	8	0.9	744	13	1.8
4	2007	888	12	1.4	756	12	1.6
5	2008	898	10	1.1	767	11	1.5
6	2009	912	14	1.6	778	11	1.4
7	2010	927	15	1.6	790	12	1.5
8	2011	941	14	1.5	803	13	1.6
9	2012	955	14	1.5	813	10	1.2
10	2013	970	15	1.6	824	11	1.4
11	2014	984	14	1.4	835	11	1.3
12	2015	997	13	1.3	845	10	1.2
13	2016	1,011	14	1.4	858	13	1.5
14	2017	1,028	17	1.7	868	10	1.2
15	2018	1,041	13	1.3	880	12	1.4
16	2019	1,056	15	1.4	891	11	1.2
17	2020	1,070	14	1.3	902	11	1.2
18	2021	1,083	13	1.2	913	11	1.2
19	2022	1,097	14	1.3	924	11	1.2
20	2023	1,112	15	1.4	935	11	1.2

(a) Includes DSM Impacts.
(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.

Figure 3-6

Union Light Heat and Power

System Seasonal Peak Load Forecast (Megawatts) a

After DSM
Internal Load b

		Summer			Winter e		
	YEAR	LOAD	CHANGE c	PERCENT CHANGE d	LOAD	CHANGE c	PERCENT CHANGE d
-5	1998	710			586		
-4	1999	775	65	9.2	674	88	15.0
-3	2000	757	-18	-2.3	636	-38	-5.6
-2	2001	763	6	0.8	582	-54	-8.5
-1	2002	786	23	3.0	668	86	14.8
0	2003	848	62	7.9	712	44	6.6
1	2004	863	15	1.8	723	11	1.5
2	2005	878	15	1.7	736	13	1.8
3	2006	889	11	1.3	749	13	1.8
4	2007	904	15	1.7	761	12	1.6
5	2008	916	12	1.3	772	11	1.4
6	2009	930	14	1.5	783	11	1.4
7	2010	945	15	1.6	795	12	1.5
8	2011	959	14	1.5	808	13	1.6
9	2012	973	14	1.5	818	10	1.2
10	2013	988	15	1.5	829	11	1.3
11	2014	1,002	14	1.4	840	11	1.3
12	2015	1,015	13	1.3	850	10	1.2
13	2016	1,029	14	1.4	863	13	1.5
14	2017	1,046	17	1.7	873	10	1.2
15	2018	1,059	13	1.2	885	12	1.4
16	2019	1,074	15	1.4	896	11	1.2
17	2020	1,088	14	1.3	907	11	1.2
18	2021	1,101	13	1.2	918	11	1.2
19	2022	1,115	14	1.3	929	11	1.2
20	2023	1,130	15	1.3	940	11	1.2

(a) Includes DSM Impacts.
(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.

Figure 3-7

Union Light Heat and Power

Range Of Forecasts
Economic Bands

Before DSM

Year	Energy Forecast (GWH/YR) (Net Energy For Load) Low	Most Likely	High	Peak Load Forecast (MW) Low	Most Likely	High
2003	3,889	3,908	3,921	845	848	850
2004	3,956	3,983	3,998	860	864	866
2005	4,036	4,066	4,088	874	879	883
2006	4,122	4,161	4,190	884	890	895
2007	4,194	4,247	4,286	896	905	911
2008	4,265	4,327	4,388	908	917	927
2009	4,330	4,407	4,482	919	931	943
2010	4,396	4,492	4,586	931	946	961
2011	4,460	4,577	4,687	941	960	977
2012	4,525	4,663	4,792	952	974	994
2013	4,595	4,748	4,898	965	989	1,012
2014	4,661	4,833	5,005	976	1,003	1,030
2015	4,722	4,914	5,108	987	1,016	1,046
2016	4,787	4,998	5,221	998	1,030	1,065
2017	4,852	5,087	5,327	1,010	1,047	1,083
2018	4,909	5,167	5,434	1,021	1,060	1,101
2019	4,970	5,254	5,550	1,032	1,075	1,120
2020	5,027	5,338	5,663	1,042	1,089	1,138
2021	5,084	5,416	5,775	1,051	1,102	1,156
2022	5,139	5,502	5,894	1,061	1,116	1,175
2023	5,191	5,589	6,012	1,070	1,131	1,194

Figure 3-8

Union Light Heat and Power

Range Of Forecasts a
Economic Bands

After DSM

	Energy Forecast (GWH/YR) (Net Energy For Load)			Peak Load Forecast (MW)		
Year	Low	Most Likely	High	Low	Most Likely	High
2003	3,887	3,906	3,919	845	848	850
2004	3,953	3,980	3,995	859	863	865
2005	4,032	4,062	4,084	873	878	882
2006	4,118	4,156	4,186	883	889	894
2007	4,190	4,242	4,281	895	904	910
2008	4,260	4,323	4,383	907	916	926
2009	4,326	4,403	4,478	918	930	942
2010	4,391	4,488	4,582	930	945	960
2011	4,455	4,572	4,682	940	959	976
2012	4,521	4,659	4,788	951	973	993
2013	4,590	4,744	4,894	964	988	1,011
2014	4,657	4,829	5,001	975	1,002	1,029
2015	4,718	4,910	5,104	986	1,015	1,045
2016	4,782	4,994	5,216	997	1,029	1,064
2017	4,848	5,083	5,323	1,009	1,046	1,082
2018	4,905	5,162	5,430	1,020	1,059	1,100
2019	4,965	5,249	5,545	1,031	1,074	1,119
2020	5,023	5,334	5,659	1,041	1,088	1,137
2021	5,080	5,412	5,771	1,050	1,101	1,155
2022	5,134	5,497	5,889	1,060	1,115	1,174
2023	5,186	5,584	6,008	1,069	1,130	1,193

(a) Includes DSM Impacts.

Figure 3-9

Union Light Heat and Power

Net Monthly Energy Forecast (Megawatt Hours)
Before DSM

YEAR 0	2003	Kentucky
January		353,600
February		294,077
March		307,424
April		267,740
May		298,002
June		343,723
July		403,094
August		386,515
September		322,597
October		294,633
November		297,982
December		338,523

YEAR 1	2004	
January		360,178
February		299,555
March		313,749
April		272,997
May		303,013
June		350,367
July		411,224
August		394,188
September		329,165
October		300,084
November		303,653
December		344,803

Figure 3-10

Union Light Heat and Power

Net Monthly Internal Peak Load Forecast (Megawatts)
Before DSM

YEAR 0	2003	Kentucky
January		700
February		654
March		616
April		564
May		665
June		811
July		848
August		848
September		762
October		582
November		621
December		681

YEAR 1	2004	
January		712
February		665
March		627
April		574
May		677
June		826
July		864
August		864
September		776
October		593
November		632
December		693

Figure 3-11

Union Light Heat and Power

Net Monthly Energy Forecast (Megawatt Hours) a
After DSM

YEAR 0	2003	Kentucky
January		353,493
February		293,975
March		307,311
April		267,644
May		297,893
June		343,580
July		402,908
August		386,330
September		322,435
October		294,506
November		297,829
December		338,319
YEAR 1	2004	
January		359,973
February		299,366
March		313,546
April		272,829
May		302,827
June		350,129
July		410,921
August		393,892
September		328,910
October		299,887
November		303,420
December		344,497

(a) Includes DSM Impacts.

Figure 3-12

Union Light Heat and Power

Net Monthly Internal Peak Load Forecast (Megawatts) a
After DSM

YEAR 0	2003	Kentucky
--------		----------
January		700
February		654
March		616
April		564
May		665
June		811
July		848
August		848
September		762
October		582
November		621
December		681
YEAR 1	2004	

January		712
February		665
March		627
April		574
May		677
June		825
July		863
August		863
September		775
October		593
November		631
December		692

(a) Includes DSM Impacts.

4. DEMAND-SIDE MANAGEMENT RESOURCES

A. INTRODUCTION

Since the previous Integrated Resource Plan filed in 1999, ULH&P has devoted its demand-side management (DSM) efforts to the implementation of the following four programs:

Program 1: Residential Conservation and Energy Education

Program 2: Residential Home Energy House Call

Program 3: Residential Comprehensive Energy Education Program

Program 4: Residential New Construction

The Kentucky Public Service Commission has been kept appraised of the activities and progress made on these programs through annual status reports filed with the Commission on or about October 1 of each year.

As a result of the Commission's review of the 2001 status report, the Commission approved the Home Energy Assistance Plus pilot program. In the 2002 status report, ULH&P provide detailed results on the cost effectiveness of the four programs and summary evaluation of the Home Energy Assistance Plus pilot program. Based upon the analysis, ULH&P recommended that the Residential New Construction Program be discontinued and that the Home Energy Assistance Plus pilot program be extended for two more years.

In the Commission Order in Case No. 2002-00358 dated December 17, 2002, the Commission approved the continuation of and cost recovery for the Residential Conservation and Energy Education, Residential Home Energy House Call, and Residential Comprehensive Energy Education programs for a 3-year period, through December 31, 2005. The Commission approved the termination of the Residential New Construction/Renovation program. Finally, the Commission approved the implementation of a revised low-income home energy assistance program (Payment Plus) as a pilot through May 31, 2004.

B. CURRENT DSM PROGRAMS

This section provides a description of each current program and a review of the cost-benefit analyses..

Program 1: Residential Conservation and Energy Education

The Residential Conservation and Energy Education program was designed by the ULH&P DSM Collaborative to help the Company's income-qualified customers reduce their energy consumption and lower their energy cost. This program specifically focuses on customers that meet the income qualification levels of 150% of federal poverty level. This program uses the LIHEAP customer list as well as other community outreach to improve participation. The program provides direct installation of weatherization and energy-efficiency measures and educates ULH&P's income-qualified customers about their energy usage and other opportunities to reduce energy consumption and lower their cost.

The Company estimates that at least 6,000 customers (number of single family owner occupied households with income below $25,000) within ULH&P's service area would qualify for services under this program. The program has provided weatherization services to 251 homes in 2000, 283 in 2001, 203 in 2002, and 224 in 2003.

At the end of 2002, the processes and impacts of the program were evaluated to identify additional areas for improvement. This evaluation showed that the overall program structure was cost effective. However, the Tier 2 level (basic services and air sealing) was the least cost effective alternative. Thus in early 2003 another modification to the program was made to further improve cost effectiveness. The Tier 2 and Tier 3 levels were combined into one new level (Tier 2) which, using the National Energy Audit Tool (NEAT) audit, expanded the offering of services to include insulation (previously in the old Tier 3 service level). The average amount spent and maximum amount allowed are listed below for each tier.

> TIER 1 Spending = Average $350 including administration, not to exceed $550
>
> TIER 2 Spending = Average $1,370 including administration, not to exceed $4,000

The services provided within each new modified tier are described below.

The tier structure is defined as follows:

	Therm / square foot	kWh use/ square foot	Investment Allowed
Tier 1	0 < 1 therm / ft2	0 < 7 kWh / ft2	Up to $550
Tier 2	1 + therms / ft2	7 + kWh / ft2	All SIR $\geq$ 1.5 up to $4K

SIR = Savings - Investment Ratio

Tier One Services

ULH&P, through its subcontractors, provides Tier One services to a customer, if they use less than 1 therm per square foot per year and less than 7 kWh per square foot per year based on the last year of usage (weather adjusted) of Company supplied fuels. Square footage of the dwelling is based on conditioned space only, whether occupied or unoccupied. It does not include unconditioned or semi-conditioned space (non-heated basements). The total program dollars allowed per home for Tier One services is $550.00 per home.

Tier One services are as follows:

- Furnace Tune-up & Cleaning
- Furnace replacement if investment in repair over $500 (leveraged through the Gas Weatherization program)
- Venting check & repair
- Water Heater Wrap
- Pipe Wrap
- Waterbed mattress covers
- Cleaning of refrigerator coils
- Cleaning of dryer vents

- Compact Fluorescent Light (CFL) Bulbs
- Low-flow shower heads and aerators
- Weather-stripping doors & windows
- Limited structural corrections that affect health, safety, and energy up to $100
- Energy Education

Tier Two Services

ULH&P will provide Tier Two services to a customer, if they use at least 1 therm and/or 7 kWh per square foot per year based on the last year of usage of ULH&P supplied fuels.

Tier Two services are as follows:

- Tier One services plus:
- Additional cost-effective measures (with SIR $\geq$ 1.5) based upon the results of the NEAT audit. Through the NEAT audit, the utility can determine if the cost of energy saving measures pay for themselves over the life of the measure as determined by a standard heat loss/economic calculation (NEAT audit) utilizing the avoided cost of gas and electricity. Such items can include but are not limited to attic insulation, wall insulation, crawl space insulation, floor insulation and sill box insulation. Safety measures applying to the installed technologies can be included within the scope of work considered in the NEAT audit as long as the SIR is greater than 1.5 including the safety changes.

Regardless of placement in a specific tier, ULH&P provides energy education to all customers in the program.

Refrigerators

To increase the cost-effectiveness of this program and to provide more savings and bill control for the customer, the DSM Collaborative and ULH&P proposed and gained Commission approval in Case No. 2002-00358 to expand this program to include refrigerators as a qualified measure in owner occupied homes. Refrigerators consume a very large amount of electricity within the home. Through replacement of poor-performing units, customers can save an average of $96 per year. To determine replacement, the program weatherization provider performs a two-hour meter test of the existing refrigerator unit. If it is a high-energy consumer as determined by this test, the unit is replaced. Results from a similar program operated by Cinergy in Ohio have shown that the average unit replaced consumes 1,620 kWh per year. Replacing with a new Energy Star qualified refrigerator, which uses approximately 400 kWh, results in an overall savings to the average customer of 1,200 kWh per year. In the Ohio program, Cinergy has been replacing 36% of the units tested. Given the size of the KY Residential Conservation and Energy Education program, that would equate to approximately 100 refrigerators being replaced per year. Ramp up for this program began in March 2003 and in 2003 there were 121 refrigerators tested and 47 units replaced. The existing refrigerator being replaced is removed from the home and destroyed in an environmentally appropriate manner to assure that the units are not used as a second refrigerator in the home or do not end up in the secondary appliance market. The refrigerator program has been found cost-effective elsewhere.

The Commission gave approval for continuation of the Residential Conservation and Energy Education program under the requirement that efforts be made to improve the cost-effectiveness and increase the level of co-funding or leveraging with other sources of funding. ULH&P, with the cooperation of the service providers, has worked very hard to make this program cost-effective. The leveraging of other funds has increased significantly. In addition, the program was re-designed such that each measure would be installed only if cost-effective.

ULH&P believes this program is cost-effective as a DSM program. In addition, continuation of this program ensures that the Company's disadvantaged customers can participate in ULH&P's portfolio of DSM programs and other funds are leveraged.

<u>Program 2: Residential Home Energy House Call</u>

The Home Energy House Call (HEHC) program consists of three major components:

- Home Energy Survey
- Comprehensive Energy Audit & Review
- Measures Installation Opportunity

When a customer requests a HEHC service, a qualified home energy specialist visited the home to gather information about the household's energy usage. A questionnaire about the energy usage, including appliance efficiencies, was completed. The specialist also performed a walk-through audit and checks the home for air infiltration, inspected the HVAC filter, and surveyed the insulation levels in different areas of the home. A detailed report was generated on site that explained how energy is used each month and a list of prioritized action items was compiled based on energy savings and costs.

In January 2003, ULH&P signed a two-year contract with Enertouch Inc. (dba GoodCents Solutions) to implement the Home Energy House Call program. By doing so, ULH&P is able to provide a more comprehensive program to customers for less than it cost in prior years under the previous contractor. The audit process, itself, remains much the same. Enhancements to the program include a more comprehensive audit report with a stronger focus on the building envelope, and the installation of several energy saving measures at no cost to the customer. The measures include a low-flow showerhead, two aerators, outlet gaskets, two compact fluorescent bulbs, and a motion sensor night-light. Customers can begin realizing an immediate savings on their electric bill by participating in the program. The program has also taken on a more professional look. Auditors are equipped with uniforms, marked trucks, and better equipment necessary to facilitate the audit.

In 2003, a total of 507 audits were completed in Kentucky, just above the goal. The goal was achieved even though ULH&P had to shut down the program for the first two months of 2003 to allow time for putting the new audit processes in place. In September and October 2003, HEHC piggybacked on the work of some 500 students participating in the Kentucky National Energy Education Development (NEED) program. As part of the curriculum on energy conservation in the Kentucky NEED program, Home Energy House Call audits will be offered on a first-come, first-served basis. With the increased response rate to the program this year and the strategy GoodCents proposed to "catch up", the program just exceeded the 2003 annual goal of 500 audits.

Customer satisfaction ratings for the new program to-date are very positive with a rating of 4.8 on a five- point scale for program.

Since the beginning of the program in 1996, over 2,800 customers have participated of which there were 485 in 2000, 500 in 2001, 513 in 2002 and 507 in 2003.

ULH&P believes this program is cost-effective as a DSM program and that it provides tremendous value to the ratepayers.

Program 3: Residential Comprehensive Energy Education

This energy education program was developed by the DSM Collaborative and implemented in late 1997. The contract for implementation of this program was awarded to Kentucky NEED (National Energy Education Development). NEED was launched in 1980 to promote student understanding of the scientific, economic, and environmental impacts of energy. The program is currently available in 36 states, the U.S. Virgin Islands, and Guam.

The program has provided unbiased educational information on all energy sources, with an emphasis on the efficient use of energy. Energy education materials, emphasizing cooperative learning, are provided to teachers. Leadership Training Workshops are structured to educate teachers and students to return to their schools, communities, and families to conduct similar training and to implement behavioral changes that reduce energy consumption. Educational materials and Leadership Training workshops are designed to address students of all aptitudes and have been provided for students and teachers in grades 5 through 12.

The KY NEED program follows national guidelines for materials used in teaching, but also offers additional services such as: hosting teacher/student workshops, sponsoring teacher attendance at summer training conferences, sponsoring attendance at a National Youth Awards Conference for award-winning teachers and students, and providing curricula, free of charge, to teachers.

Since October 1999, 414 Teachers enrolled in the program with 127 Teacher/Student presentations, 240 Teachers attending Teacher workshops and over 2,000 students attending workshops. Overall, the program has reached teachers and students in 71 schools in the six counties served by ULH&P. There are currently 158 teachers enrolled in the program. At a minimum, these teachers have impacted over 4,000 students. In addition, many of the teachers have multiple classes, so the number is potentially higher. Students who attend workshops are encouraged to mentor other students in their schools – further spreading the message of energy conservation. Teams of high school students serve as facilitators at workshops. Through this approach, all grade levels are either directly or indirectly presented the energy efficiency and conservation message. Several of the student teams have made presentations to community groups, sharing their knowledge of energy, promoting energy conservation and demonstrating that the actions of each person impact energy efficiency. It is intended that these students will share this information with their families and reduce consumption in their homes.

As noted in ULH&P's Case No. 2002-00358, the cost-effectiveness of this program is difficult to quantify. To get a better understanding of the impacts of this program, the last evaluation recommended that a better data collection instrument be employed. This data instrument has been developed and will be used in the classroom.

An additional improvement recommended by the evaluation is the addition of energy savings "kits" as a teaching tool. These kits include actual weatherization and conservation measures for the students to install in their homes to get their families directly involved in application of conservation concepts. The actual installation of measures helps increase the directly measurable savings from this program and should increase cost effectiveness. The Collaborative recommended and received approval to include 500 kits for inclusion in the energy curriculum of selected classrooms to increase savings and to improve tracking. These kits were tested in the Spring of 2003 for full implementation in the Fall of 2003 when the science curriculum deals with these issues.

Program 4. Pilot Program: Home Energy Assistance Plus

From January to April 2002, ULH&P and the Northern Kentucky Community Action Commission (NKCAC) implemented a pilot home energy assistance program, Home Energy Assistance Plus. This pilot program was structured to test and evaluate the process and design of a home energy assistance program. The pilot program was designed to impact participants' behavior (e.g. encourage meeting utility bill payments as well as eliminate arrearages) and to generate energy conservation impacts. As reported in the previous filing, in Case 2002-00358, a process evaluation completed for the pilot revealed that it was very labor intensive with limited results.

To address these findings, the DSM Collaborative recommended and received approval for another test program that has a less labor-intensive form of energy education, budget counseling, and bill assistance. A new pilot program for 2003-2004 is in progress to help these low-income customers. The pilot program was established with three parts:

1. Energy & Budget Counseling – to help customers understand how to control their energy usage and how to manage their household bills, a combined education/counseling approach will be used.
2. Weatherization – participants in this program are required to have their homes weatherized as part of the normal Residential Conservation and Energy Education (low-income weatherization) program unless weatherized in past program years.
3. Bill Assistance – to provide an incentive for these customers to participate in the education and weatherization, and to help them get control of their bills, payment assistance credits are provided to each customer when they complete the other aspects of the program. The credits are: $200 for participating in the energy efficiency counseling, $150 for participating in the budgeting counseling, and $150 to participate in the Residential Conservation and Energy Education program. If all of the requirements are completed, a household could receive up to a total of $500. This will allow for approximately 100 homes to participate per year.

This program is offered over six winter months per year starting in November. However, for the first year after approval, the program runs February through July and November through December. Customers will be tracked and the program evaluated after two years to see if customer energy consumption dropped and changes in bill paying habits occurred.

In the first round, through August 2003, 78 customers participated in the Energy Education segment while only 60 customers continued on to receive Budget Counseling. At this point, 17 customers have completed the weatherization component and 13 additional homes are in process. The additional homes should be completed later this year. A second round of classes are scheduled to begin in November, 2003. ULH&P and NKCAC will work to acquire more customers to attend these classes for this second round to make up for the shortfall in the first round. The Company expects to provide detailed information on the impact of this pilot program in the Fall 2004 DSM status report.

C. PRICING PROGRAMS

ULH&P's innovative pricing programs fall into three categories: Interruptible Contracts, PowerShare®, and Real Time Pricing. ULH&P has one contract for interruptible service for 3 MW.

The PowerShare® program is offered under ULH&P Rider PLM. This program was implemented on January 1, 2000, following the success of a 1990s program, Energy Call Options. The PowerShare® program is a market-based program that provides financial incentives in the form of bill credits to our industrial and commercial customers to reduce their electric demand during periods of peak load on the ULH&P system. Customers may choose to participate in either CallOption or QuoteOption.

CallOption requires customers to commit to a pre-selected load reduction, based on historic or usual demand, at a selected strike price. The strike price is selected by the customer based upon the customer's willingness and ability to comply with the call for a load reduction. In return for a commitment to reduce load when called, CallOption customers receive a monthly premium payment from ULH&P as a credit to the bill; in addition, when they are called to reduce load, the customers receive an energy credit based upon the strike price. Customers are offered a day-ahead and same day notification option. The level of incentive depends upon the selected parameters: the contracted for option load and the strike price. The term of the CallOption agreement is four months, June through September, with "built-in" limitations on the number of occurrences (hours) the CallOption can be invoked during the time period.

The second option, QuoteOption, allows customers to elect whether or not to reduce load when called, at a selected minimum price. No monthly premium is paid to QuoteOption customers since they can elect not to respond when called, but an energy credit is paid for load reductions made in response to ULH&P calls.

Because customers have the right to elect whether or not to respond to a call, the QuoteOption essentially offers customers a no risk proposition. While this election feature gives us less control over, and certainty of, load reductions, it also provides us with load reduction from a group of customers that would not participate if they had to contractually commit to mandatory load reductions.

Within the current environment of lower market prices and reduced price volatility, our goal is to maintain the flexibility and optionality that the PowerShare® program provides. Our main emphasis will be retaining the existing PowerShare® base and to continue to cost-effectively add new Customers. We have positioned PowerShare® as a year round program in order to keep Customers engaged and interested in the program. We have simplified the enrollment process through the use of the PowerShare® Web site.

With the reduction of up-front premiums under CallOption due to the drop in market prices, the amount of CallOption load reduction for summer 2003 was only 100 kW. Our primary focus for the future is maintaining customers under the QuoteOption as a hedge against unforeseen changes in market prices and available supply.

ULH&P's RTP program (see Rate RTP) consists of a two-part rate: an access charge for the customer's historic or usual load, billed at standard tariff rates; and an energy charge, for the customer's incremental or decremental energy usage, billed at a real time price. The RTP rate sends price signals to participating customers that encourage usage during low cost periods and discourage consumption in high cost periods. Currently, 25 ULH&P customers participate in RTP with an expected peak load reduction for summer 2003 of about 2 MWs. While this program is scheduled to end in 2004, it was assumed to continue throughout the IRP planning horizon.

D. PLANNED NEW DSM PROGRAM

ULH&P is implementing a new program (Power Manager) that will allow the Company to shave the peak load on hot summer days. Power Manager is a direct load control (DLC) program for the cycling of residential air conditioning during the summer months. Under Power Manager, a load management control device (LM Device) will be installed on the customer's house and connected to the outside central air-conditioning compressor unit (A/C system). This LM Device will allow ULH&P to remotely cycle the A/C system during summer peak load periods (usually during a span from mid-day to early evening) thus reducing the amount of summer peak load. The program will be in effect during the period from May 1 to September 30. A paging system will be used to send load control instructions to the LM Device. It is expected that individual customers will be cycled for approximately 80-100 hours per summer, or on average about 10-12 times per summer.

Power Manager will be offered to residential customers who have a functional central air-conditioning system with an outside compressor unit. The customer (or the owner in the case of customers who rent) must agree to have the LM Device connected to their A/C system and to allow ULH&P to cycle their A/C system. The customer also must be located within the coverage area of the communication system that will be used to control the LM Device.

The initial design of Power Manager has been structured on the same basic principles as the Company's innovative PowerShare® program. Power Manager will couple direct load control with a flavor of "real time pricing" through the Variable Daily Event Incentive structure described below.

Customers who own their home (Owners) will select from two Control Options based on the amount of load reduction they agree to supply: Option A, 1 kW reduction and Option B, 1.5 kW reduction. Owners will receive an installation payment for agreeing to have the LM Device installed which will initially be set at $25.00 for Option A and $35.00 for Option B.

Customers who rent (Renters) will only be offered Option A because of the smaller-sized A/C systems that are typically installed. Additionally, in order to maintain the cost effectiveness of the program due to the high turnover rate for Renters and the fact that Renters do not own the central A/C system, Renters will not receive an installation payment.

Both Owners and Renters will receive a Variable Daily Event Incentive for each day that the A/C system is cycled. For any given day, the Variable Daily Event Incentive will be based on the kW reduction selected by the customer, the number of hours that the A/C system is cycled on any given day and the real time value of electric energy during the control event. For any given control season, the total payments for the Variable Daily Event Incentives will be at least $5.00 for Option A and $8.00 for Option B. The following illustrates the Variable Daily Event Incentive calculation assuming the value of the load reduction is $0.10:

Control Option	***Variable Daily Event Incentive***
Option A	1.0 kW X 8 Hours X $0.10 = $0.80
Option B	1.5 kW X 8 Hours X $0.10 = $1.20

Customers will be able to enroll in the program though a toll-free number and mail-in post cards. As an added benefit, customers will be offered an Event Opt-Out option that will allow them to pre-schedule a limited number of times that they are excluded from a control event under non-system emergency conditions. Customers will have one Opt-Out per month during the summer season. The Event Opt-Out will be implemented through the program's Customer Service Center via a toll free number. ULH&P also plans to have a recorded message via a toll-free number and a message on the Internet to inform customers when a control event may occur and what the price for the event incentive may be.

The enrollment of customers and the installation of the LM Device will be done by GoodCents Solutions out of Atlanta, Georgia. GoodCents currently provides customer support services for other ULH&P DSM programs and is providing customer and installation services for the IP&L and LG&E direct load control programs. Corporate Systems Engineering based in Indianapolis, Indiana, is the supplier of the LM Devices and is providing the software system used to cycle the A/C system.

The installation payment and the Variable Daily Event Incentive will be given to the customer in the form of credits on their bill. The tracking and the calculation of the bill credits will be done by GoodCents and transferred electronically to ULH&P's billing system.

E. DSM PROGRAMS AND THE IRP

The projected impact of the DSM programs discussed above have been included in the least-cost supply plan for ULH&P. The conservation DSM programs are projected to reduce energy consumption 3,100 MWH and 1 MW by the end of 2005. These impacts are included in the IRP analysis. The direct load control program is projected to reduce peak demand 12 MW by the end of 2007. Combining the direct load control projected impacts with those for the interruptible, PowerShare®, and RTP programs produces a projected load management impact of 17 MW by 2007. The following table summarizes the projected load management impacts included in this IRP analysis.

Projected Load Management Impacts
(MW)

Year	Interruptible	RTP	CallOption	Direct Load Control	Total
2003	3	2	0.1	0	5
2004	3	2	0.1	1.5	7
2005	3	2	0.1	4.6	10
2006	3	2	0.1	7.7	13
2007	3	2	0.1	10.8	16
2008	3	2	0.1	12.4	18
2009	3	2	0.1	12.4	18
2010	3	2	0.1	12.4	18
2011	3	2	0.1	12.4	18
2012	3	2	0.1	12.4	18
2013	3	2	0.1	12.4	18
2014	3	2	0.1	12.4	18
2015	3	2	0.1	12.4	18
2016	3	2	0.1	12.4	18
2017	3	2	0.1	12.4	18
2018	3	2	0.1	12.4	18
2019	3	2	0.1	12.4	18
2020	3	2	0.1	12.4	18
2021	3	2	0.1	12.4	18
2022	3	2	0.1	12.4	18
2023	3	2	0.1	12.4	18

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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

ULH&P does not currently own any generating units. Instead, it is served via a wholesale Power Sales Agreement (PSA) from CG&E as discussed in Section D below.

C. EXISTING NON-UTILITY GENERATION

ULH&P does not currently have any contracts with non-utility generators.

Some of ULH&P'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 generally is 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 ULH&P 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. Some of these customers are participants in ULH&P's PowerShare® program which was discussed in Chapter 4. In compliance with the standards 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, ULH&P does not participate in any type of power pooling because it does not own any power generating units.

ULH&P is currently a 100% wholesale requirements customer of CG&E. In recent times, up until January 1, 2002, ULH&P received its full requirements of electric power from CG&E under a FERC-approved cost-of-service-based wholesale power tariff. Under this wholesale power tariff, ULH&P paid a bundled price for transmission and generation services from CG&E. This bundled price was based on the FERC-approved costs of owning, operating and maintaining the FERC-jurisdictional portion of CG&E's transmission and generation assets.

Since January 1, 2002, ULH&P has received its full requirements of electric power to serve its retail customers from CG&E pursuant to a Power Sales Agreement approved, subject to certain conditions, by the Kentucky Public Service Commission in Case No. 2001-00058. This Power Sale Agreement is a market-based, fixed price agreement under which ULH&P is assessed a monthly demand charge of $7200 per megawatt (MW) based on its peak demand for the month, and an energy charge of $24 per megawatt-hour (MWH). ULH&P contracts separately with the Midwest Independent Transmission Operator, Inc. (MISO) through Cinergy Services, Inc. (Cinergy Services), for bulk transmission service to transport electric power from CG&E's plants and from outside the Cinergy system through the Cinergy transmission system to ULH&P's transmission system for ultimate delivery to ULH&P's distribution system and end-use retail customers. The contract for this service expires on 12/31/06. The modeling in this IRP consisted of modeling this PSA through its expiration date and then considering a number of supply-side and demand-side alternatives from 2007 forward.

Cinergy is interconnected directly with East Kentucky Power Cooperative, Inc., LGE Energy/Kentucky Utilities, American Electric Power, The Dayton Power and Light Company, Ohio Valley Electric Corporation, Ameren, Hoosier Energy, Indianapolis

Power and Light, 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.

Cinergy 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.

E. <u>NON-UTILITY GENERATION AS FUTURE RESOURCE OPTIONS</u>

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. Cinergy typically receives several requests a year for independent/small power production and cogeneration buyback rates. ULH&P does not currently have any contracts for cogeneration. However, ULH&P has two cogeneration tariffs available to customers and is in the process of updating these tariffs. ULH&P will supply any customer interested in cogeneration with a copy of these tariffs and will discuss options with that customer. ULH&P is currently in discussions with one customer.

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 ULH&P's comparatively low electricity rates and avoided cost buyback rates, cogeneration and small power production are generally uneconomical for most customers.

For these reasons, Cinergy does not attempt to forecast specific Megawatt levels of this activity in its service area. Cogeneration facilities built to affect customer energy and demand served by the utility are captured in the load forecast. Cogeneration built to provide supply to the electric network represent additional regional supply capability. As purchase 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. Cinergy Solutions, an affiliate of ULH&P, builds, owns, and operates 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 ULH&P 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 STRATEGIST® 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

Information Sources

Most of the specific technology parameters used in the screening process were based on information taken from the Technical Assessment Guide® (TAG®) - Central Stations report dated December 2000 and the Technical Assessment Guide Supply-Side Technologies program (TAG-Supply™), Version 3.11, produced by the Electric Power Research Institute (EPRI) of Palo Alto, California. The TAG® is proprietary to EPRI and 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 (S&L) prepared a study for Cinergy that contained cost and performance data for potential new pulverized coal and fluidized bed plants. Cinergy considers the S&L study to be confidential and competitive information. The

2001 report "Repowering the Midwest" by the Environmental Law & Policy Center and other groups was the source for additional renewable cost information. Cinergy-specific price estimates for Combustion Turbines and Combined Cycle Units provided by Cinergy's engineering department were also used to supplement the EPRI data. Cinergy also considers these estimates to be confidential and competitive information.

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 Cinergy service territory. 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: 2003-2012 and 2013-2023. Because the TAG® 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 2003 and 2012. All technologies (Mature, Commercial, Demonstration, and Pilot) were considered to be available beginning in 2013. The costs contained in the TAG® 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 screen economically 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 fuel prices used for the specific technologies within each class were representative fuel costs for Cinergy's service territory. The technologies were then screened using relative dollar per kilowatt-year versus capacity factor screening curves. The screening within each general class as well as the final screening across the general classes used a spreadsheet-based screening curve model developed by Cinergy.

This screening curve analysis model calculates the fixed costs associated with owning and maintaining a technology type over its lifetime and computes 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 capacity factors outside of their relevant operating range, probably will not be part of the least cost solution, and therefore can be eliminated from further analysis. Whenever the screening curves for technologies with generic cost estimates were essentially the same as technologies with more detailed Cinergy cost estimates, the technology with the more detailed cost estimate was chosen.

2. Screening Results

Figures 5-1 through 5-11 show the technologies screened within each of the ten classes 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

Figure GA-5-12 in the General Appendix shows the screening curve for the pulverized coal units. The Brownfield 467 MW Supercritical coal unit was the "Best in Class" in the relevant capacity factor range.

Fluidized Bed

Figure GA-5-13 shows the screening curve for the period 2003-2012, and Figures GA-5-14 through GA-5-16 show the results for the period after 2012. The Brownfield 459 MW unit was the "Best in Class" in the first ten years and the 350 MW PFBCPCFB unit was the "Best in Class" for installation after 2012.

Integrated Coal Gasification Combined Cycle

There were no Mature or Commercial technologies in the 2003-2012 time period. Figure GA-5-17 shows the screening curve for the time period after 2012. The "Best in Class" technology was a 460 MW Advanced GCC unit.

Simple Cycle Combustion Turbines

Cinergy's engineering department provided estimates for 156 MW (summer rating) 7FA CTs to be screened along with the TAG® technologies. Figures GA-5-18 and GA-5-19 show that the "Best in Class" CTs were the Cinergy-specific 7FA units for both time frames.

Combined Cycle

As with the Simple Cycle CTs, Cinergy's engineering department provided Cinergy-specific prices for a 477 MW (summer rating) Brownfield CC and for repowering Edwardsport as a natural gas CC plant to be screened along with the TAG® technologies (although a Brownfield CC and repowering Edwardsport are not resources that are available to ULH&P). The cost of a 477 MW Greenfield CC was also extrapolated from these estimates and used in the screening. For the period 2003-2012, the Cinegy-specific Greenfield CC, Brownfield CC, and Repowering Edwardsport units were the "Best in Class" as shown in Figure GA-5-20. For 2013-2023, the "Best in Class" Combined Cycle units were the Cinergy-specific Greenfield and Brownfield CC units, as shown in Figure GA-5-21.

Fuel Cells

The 2 MW Phosphoric Acid Ambient Pressure Fuel Cell was the only viable alternative for the 2003-2012 time frame. For the period after 2012, the Phosphoric Acid, Molten Carbonate, and the Solid Oxide Fuel Cells (including the Hybrid Fuel Cell from "Repowering the Midwest") were screened against each other as shown in Figure GA-5-22. The "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 2003 IRP. There is a very limited opportunity to apply renewable resource technologies in the Cinergy service territory. With most wind speeds averaging less than what is needed for a Class 3 wind site, generation of significant amounts of electricity using wind energy is not cost-effective relative to more conventional technologies. In addition, the actual capacity that would be available from wind resources at the time of summer peak (when the capacity is needed the most) is, at best, significantly less than the installed capacity. This means that considerably more capacity (at a correspondingly higher capital cost) would need to be installed for the wind capacity to be equivalent to the dependable capacity of a conventional technology resource. With regard to solar power, there is relatively low solar power density in this area, so generation of significant amounts of electricity using 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 remote locations or in other special applications. However, under current assumptions, they continue to be not as cost competitive or as reliable in this part of 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 small number of private companies currently collect landfill gas to burn in on-site CTs at a few different landfills within Cinergy's 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 the Cinergy utilities 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 are discussed below:

Wind

The only Mature or Commercial wind technology available during the 2003-2012 time period was a 50 MW plant in "Repowering the Midwest". The 100 MW Wind plant contained in "Repowering the Midwest" was selected for final screening for the 2013-2023 time frame as shown in Figure GA-5-23.

Solar

The flat plate Solar units in "Repowering the Midwest" were the only technologies that were either Mature or Commercial during the 2003-2012 period. During the 2013-2023 period, the "Best in Class" technology was also the Solar unit from "Repowering the Midwest" as shown in Figure GA-5-24.

Other Renewable Resources

For both time periods, the technologies were divided into the groupings of Municipal Solid Waste and Biomass-Fueled units. The screening curves for 2003-2012 and for 2013-2023 are shown in Figures GA-5-25 through GA-5-26. The 75 MW and 100 MW Biomass GCC from "Repowering the Midwest" were the "Best in Class" units for the 2003-2012 and 2013-2023 time frames, respectively.

Storage

The categories of Batteries, Pumped Hydro, Compressed Air, and Superconducting Magnetic Storage were used. The screening results for 2003-2012 are shown in Figure GA-5-27. The 20 MW Light Duty Lead Battery was the most economical. The screening curve for 2013-2023 is shown in Figure GA-5-28. The 20 MW Light Duty Lead Battery and the 350 MW Compressed Air Storage unit using Porous media unit were the most economical 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.

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). As discussed earlier, a specific cost estimate for repowering Edwardsport was included in the CC screening. In addition, since the cost estimate for Combined Cycle repowering at Edwardsport was similar to the cost of a new Combined Cycle plant, the characteristics of the new plant can act as a proxy 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 of a combined cycle facility at a new site. However, as discussed earlier, ULH&P does not currently own any generation.

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 5-29. These technologies were then screened against each other, or across all classes, to develop the final supply-side alternatives to be carried into the integration model.

The resultant final screening curve for 2003-2012, Figure GA-5-30, shows that the 7FA CT, the Greenfield CC, the Brownfield CC, Repowering Edwardsport, and the Brownfield Pulverized Coal units make up the lower envelope of the final curve. The curve for the 2013-2023 period, Figure GA-5-31, shows that the Combustion Turbine, the Combined Cycle, Solid Oxide Fuel Cell, and 350 MW fluidized bed units make up the lower envelope of the final curve over their respective capacity factor ranges. While the screening curve shows that the Wind resource might be economical relative to Combined Cycle units if it can achieve capacity factors greater than about 30%, in reality the screening curve analysis greatly overstates the value of Wind due to the reduced level of capacity actually available on peak, as discussed earlier.

As a result of the screening process, the following supply technologies were selected to be utilized as candidate supply-side resources in the STRATEGIST® dynamic integration computer runs: 1) 156 MW 7FA CT units for the 2007-2023 time period, 2) 477 MW Greenfield Combined Cycle units for the 2007-2023 time period, 3) 467 MW Brownfield PC units for the 2008-2012 time period, 4) 350 MW PFBCPCFB units for the 2013-2023 time period, and 5) 25 MW Fuel Cells for the 2013-2023 period. More detailed information on the final supply side technologies screened can be found in Figures GA-5-32 and GA-5-33. Since the SO_2 and NO_x 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 and the NO_x SIP Call 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 2003-2012 time 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 2013-2023 time frame because little additional information relevant to 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 provides a better understanding of the magnitude of changes in fuel prices, Emission Allowance prices, capital costs, etc., that will affect resource decisions. In addition, it allows the most economical technologies from each individual class to be included in the sensitivity analysis.

Fluidized Bed

The parameters that should have the greatest impact on fluidized bed unit economics are relative fuel prices (coal prices versus gas prices), capital cost, and emission allowance prices. A sensitivity study showed a reduction in coal prices of 30% is necessary before the fluidized bed unit would become competitive at between 60% and 65% capacity factor (see Figure GA-5-34). An increase of 10% in gas prices is necessary before the pulverized coal unit and fluidized bed unit would become competitive at between 60% and 65% capacity factor (see Figure GA-5-35). However, the PC unit still slightly dominates the CFBC unit, so that the CFBC unit never becomes economic. Figure GA-5-36 shows that the estimated capital cost of the fluidized bed unit would have to decrease by 15% to make the unit economical at between 60% and 65% capacity factor. The unit is insensitive to emission allowance price changes in that it did not become economical even when reducing SO_2, NO_x, or both SO_2 and NO_x allowance prices to $0/ton (see Figures GA-5-37 through GA-5-39).

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, Greenfield CC, Brownfield CC, and Repower Edwardsport units, which also use gas, were already more economical and continued to dominate it. The estimated capital cost had to be reduced by at least 90% to make the Fuel Cell competitive with the CT and CC units (see Figure GA-5-40).

Wind

For wind to be economical in a relevant capacity factor range, the estimated capital cost must be reduced by at least 20% to compete with CT and Combined Cycle units, and, even then, the wind resource is limited in Cinergy's service area as discussed earlier (see Figure GA-5-41). Because of the high capital cost of wind units, gas prices would have to be double their base case levels before the technology would be marginally competitive (see Figure GA-5-42).

Solar

For solar to be economical in a relevant capacity factor range, the estimated capital cost must be reduced by 75% to compete with Combined Cycle units, and, even then, the insolation is limited in the Midwest as discussed earlier (see Figure GA-5-43). Because of the high capital cost of solar units, even if gas, prices were 6 times their base case levels, the technology would not be competitive (see Figure GA-5-44).

Biomass

For the Biomass unit to become competitive with a Combined Cycle unit, a 70% decrease in the estimated capital cost would be necessary (see Figure GA-5-45). Alternatively, gas prices would have to be double their base case levels for the Biomass unit to be competitive (see Figure GA-5-42).

Battery

The major shortcoming of the Battery is its lack of flexibility due to its one-hour storage time in comparison with the allowable runtime of the CT. Given that the load during the hours immediately prior to and after the system peak can be almost the same magnitude as the system peak, these resources will not be able to compete with more conventional technologies for serving the system peak load until the storage times of Battery resources are increased.

6. Environmental Sensitivities

The "Best in Class" Technologies also were screened 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 CO_2 emissions from each unit as well as the estimated emission allowance price for CO_2 emissions. The costs of the CO_2 emissions were then added to the other unit costs to develop the screening curves.

CO_2

The allowance price assumed for the CO_2 sensitivity was $23.64/ton ($21/ton in 1999 dollars escalated at 3% per year), 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 $87.05/metric ton of carbon. Figure GA-5-46 shows the results of the screening for 2003-2012. 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-5-47 shows the results of the screening for 2013-2023, which utilized an allowance price of $31.76/ton in 2013 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 still the most economical choices. Although the Wind resource appears to be marginally economical according to the screening curve, this analysis is misleading due to its capacity problems that have been discussed previously.

Summary of Screening Sensitivities

Since the most economical technologies did not change for the 2003-2012 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. In addition, if specific proposals for these types of technologies are received, Cinergy will analyze them in more depth.

7. Unit Size

As described previously, various unit sizes were screened for most of the technology classes. The unit sizes selected for planning purposes generally are the largest technologies available today because they generally offer lower $/kW installed capital costs due to economies of scale. However, the true test of whether a resource is economic depends on the economics of an overall resource plan that contains that resource (including fuel costs, O&M costs, emission costs, etc.), not merely on the $/kW cost.

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® and can be obtained from vendors. Cinergy's experience also confirms their reasonability. The TAG® 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. However, the Cinergy-specific alternatives did include all costs. A listing of the projected generating facility costs from the screening curves can be found in Figures GA-5-32 and GA-5-33. The availability and performance of conventional supply-side options is also relatively well known and the TAG® 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 two to three years. For coal units, the lead time is approximately five 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 installed one of the world's first 250 kW class, natural gas-powered Fuel Cells. This unit was installed in 1999 at the Naval Surface Warfare Center located in Crane, Indiana. Cinergy also licensed 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.

11. Coordination With Other Utilities

Decisions concerning coordinating the construction and operation of new units with other utilities or entities are dependent on a number of factors including the size of the unit versus each utility's capacity requirement and whether the timing of the need for facilities is the same. To the extent that facilities that are too large to fit well into the resource plan become economically viable in a plan, co-ownership can be considered at that time. Coordination with other utilities can also be achieved through purchases and sales in the bulk power market.

G. ADDITIONAL SUPPLY-SIDE RESOURCES CONSIDERED

In this IRP, ULH&P also considered the acquisition of CG&E's ownership of East Bend 2, Miami Fort 6, and Woodsdale 1-6, in conjunction with a Back-up Power Sales Agreement (PSA) for East Bend 2 and Miami Fort 6, as potential supply-side resources.

1. Description

Figure 5-48 contains information concerning these CG&E generating units. This includes the station name and location, unit number, type of unit, installation date, tentative retirement year, net dependable summer and winter capability (CG&E share), and current environmental protection measures. For those units which are jointly owned with other utilities, Figure 5-49 shows the total capability of the unit and the share owned by each company. The approximate fuel storage capacity at each of these stations is shown in Figure 5-50. The specific analyses including these units is discussed in Chapter 8.

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. This IRP assumes that these 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. It is anticipated that future units will be governed by similar guidelines.

Scheduling Guidelines for Cinergy Units

1. Major maintenance on baseload units 400 MW and larger is to be performed at about six to ten year intervals (East Bend 2).
2. Major maintenance on intermediate-duty units between 140 MW and 400 MW is to be performed at about six to twelve year intervals (Miami Fort 6).

3. Due to the more limited run-time of other units, judgment and predictive maintenance will be used to determine the need for major maintenance (Woodsdale 1-6).

In addition to the regularly scheduled maintenance outages, beginning in 1999, a program of "availability outages" was instituted. These are unplanned, opportunistic, proactive short duration outages aimed at addressing potential summer failure situations. At opportune times, when it is economic to do so, units not scheduled for a maintenance outage may be taken out of service for up to a week in order to perform preventive maintenance activities. This enhancement in maintenance philosophy reflects Cinergy's focus on having the generation available during peak periods (e.g., the summer months). Generating station performance is now measured primarily by reference to hours of availability for the peak hours of the day. Moreover, targeted, plant-by-plant assessments of the causes of all forced outages that occurred during 1999, 2000, 2001, and 2002 have been performed to further focus actions during maintenance and availability outages. (The 2003 assessment is not yet complete). Finally, in 2000, system-wide and plant-specific contingency planning was instituted to ensure an adequate supply of labor and materials when needed, with the goal of reducing the length of any forced outages.

The general maintenance requirements for all of the existing generating units were entered into the STRATEGIST® model (described in Chapter 8) which was used to develop the IRP.

4. Fuel Supply

<u>Coal</u>

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 and inventory levels that 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.

East Bend and Miami Fort 6 customarily receive approximately 70% to 80% of their annual coal requirements under long-term coal supply agreements. 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 supply 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, market re-openers at Cinergy's sole option, contract extension options and volume flexibilities.

The remainder of its fuel needs at East Bend and Miami Fort 6 is filled 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 has generally been 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 non-economic. The gas supply for Woodsdale is managed under a Gas Supply and Management Agreement with Cinergy Marketing & Trading (CM&T), an affiliate of ULH&P. CM&T supplies the full requirements of natural gas needed by Woodsdale either by selling the gas from supplies owned or controlled by CM&T or by purchasing gas from third parties as an agent. The price paid is the market price, and then CM&T is reimbursed for the cost to transport the gas from the point where CM&T acquires the gas to Woodsdale. There is an administrative fee paid to CM&T for this service. The Gas Supply Management Agreement allows Woodsdale to obtain natural gas more economically by using CM&T as the supplier versus obtaining its own supply and paying for transportation service at CG&E's tariffed rate.

Propane

At Woodsdale, propane is used as the back-up fuel, which provides a hedge against high natural gas prices when gas is needed there. A Propane Supply Management Agreement is similar to the Gas Supply Management Agreement and provides for CM&T to supply the full requirements of propane needed by Woodsdale either from CM&T's own supplies or from supplies purchased by CM&T from third parties. Woodsdale has 100,000 barrels of propane storage space available under two separate agreements.

Oil

At East Bend and Miami Fort 6, Cinergy uses fuel oil for starting coal-fired boilers and for flame stabilization during low load periods. Oil supplies are expected to be sufficient to meet these needs for the foreseeable future.

Opportunity Fuels

Cinergy uses available non-conventional fuels where feasible to reduce generation costs. Examples of opportunity fuels include petroleum coke, "synfuels" derived from coal, waste paper, railroad ties and agricultural wastes. Cinergy has actively pursued the use of opportunity fuels for many years, having used or tested petroleum coke, synfuels, waste tires, cellulose derived from municipal solid waste, and paper pellets in various plants, always in a blend with coal. In the proposed experimental program to burn railroad ties, there would be no cost for the actual ties, thereby potentially reducing the fuel cost to the benefit of customers.

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. Gas prices were provided by ICF Consulting. Cinergy's and ICF's projected fuel prices are considered by them to be trade secrets and proprietary competitive information.

6. Condition Assessment

In the past, Cinergy has 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.

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 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. This 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: 1) flue gas scrubbers for SO_2 control; 2) larger or upgraded electrostatic precipitators with flue gas conditioning, baghouses or wet electrostatic precipitators for particulate removal; 3) selective noncatalytic reduction (SNCR) technology, selective catalytic reduction (SCR) technology, boiler optimization technology, and low NO_x burners (or modifications of existing combustion systems) for NO_x control; 4) sorbent injection (such as activated carbon) and baghouses for mercury control; and 5) cooling towers or closed cycle cooling systems for reducing the potential impact of thermal discharges. In addition to these emission specific control technologies, there are some synergistic emission control benefits across technologies. For example, an SCR for NO_x control together with a flue gas scrubber for SO_2 control is a very effective combination in reducing mercury emissions as well. Similarly, baghouses with carbon injection for mercury control are also effective in reducing particulate emissions.

East Bend 2 was constructed originally incorporating a flue gas scrubbing system. This unit has been in commercial operation since 1981. The flue gas scrubber reduces the net output capacity of these units by about 1.2% to 1.6%.

The environmental standards limiting the stack discharge of particulates have necessitated retrofitting precipitators on several existing generating units. The upgraded precipitators will generally require more "energy to function". While a detailed study has not been performed, the projected effect of these precipitators on the efficiency of the fuel cycle is a decrease in the efficiency of approximately 0.75% to 1.00%.

While detailed studies are required to determine the specific impacts of new control technologies on generating unit output and the efficiency of the fuel cycle, the following are the approximate impacts: 1) SCRs (selective catalytic reduction systems) require approximately 0.6% of the unit output and decrease the efficiency by about 0.6%; 2) SNCRs (selective non-catalytic reduction systems) require approximately 0.1% of the unit output and decrease the efficiency by about 0.1%; 3) current design FGDs (flue gas desulfurization systems) require approximately 1.8% of the unit output and decrease the efficiency about 1.8%; and 4) ACI plus PBH (activated carbon injection and polishing baghouse) systems require approximately 0.5% of the unit output and decrease the efficiency about 0.5%.

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 and the NO_x SIP Call (see Chapter 6) has increased, and will continue to increase, the cost of producing electricity. Possible future regulations such as Mercury MACT, the Interstate Air Quality Rule, the Clear Skies Initiative, or other proposed legislation to reduce air emissions will also increase the cost of electricity production (see Chapter 8). In addition, depending on the schedules and timetables associated with the implementation of any new emission control regulations, equipment availability, construction and cut-in may adversely impact both reliability and electricity prices during compliance implementation.

Cinergy supports R&D efforts concerning products and processes that cover: 1) air toxics measurement and control; 2) NO_x, SO_2 and particulate (including PM2.5) control; 3) heat rate improvement; 4) waste and effluent management; 5) pollution prevention; 6) greenhouse gas reduction; and 7) combustion by-product use.

Figure 5-1

SCREENING: PULVERIZED COAL TECHNOLOGIES

2003-2012 and 2013-2023

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
1.1I Limestone Forced Ox. Sub. 200MW
1.1J Limestone Forced Ox. Sub. 2 X 275MW
Greenfield 2960MW PC Sub.
Greenfield 467MW PC Sup.
Brownfield 2960MW PC Sub.
Brownfield 467MW PC Sup.

→ Brownfield 467MW PC Sup.

Figure 5-2

SCREENING: FLUIDIZED BED TECHNOLOGIES

2003-2012

Atmospheric Fl.-Bed Combustion (AFBC):
5.2A Circulating AFBC 200MW
5.3A Circulating AFBC 200MW
5.4A Circulating AFBC 200MW

Circulating Fl.-Bed Combusion (CFBC):
Greenfield 113MW
Greenfield 226MW
Greenfield 226MW (2X1)
Greenfield 459MW (2X1)
Brownfield 113MW
Brownfield 226MW
Brownfield 226MW (2X1)
Brownfield 459MW (2X1)

→ Brownfield 459MW (2X1)

Figure 5-3

SCREENING: FLUIDIZED BED TECHNOLOGIES (Cont.)

2013-2023

Atmospheric Fl.-Bed Combustion (AFBC):
5.2A Circulating AFBC 200MW
5.3A Circulating AFBC 200MW
5.4A 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
6.8 Supercr. 350MW
6.9 Supercr. 350MW

Circulating Pressurized Fl.-Bed Comb. (PFBC):
Brownfield 226MW
Brownfield 226MW (2X1)
Greenfield 459MW (2X1)
Brownfield 459MW (2X1)

→ 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
New Case 677MW

→ 7.9 Supercr. 350MW

→ 7.9 Supercr. 350MW

Figure 5-4

SCREENING: SIMPLE CYCLE COMBUSTION TURBINES

2003-2012

Heavy Duty:
15.0 50MW
15.1 80MW
15.2 110MW
15.3 160MW
7FA CT

Aeroderivative:
15.5 25MW
15.7 45MW

→ 7FA CT

2013-2023

Heavy Duty:
15.0 50MW
15.1 80MW
15.2 110MW
15.3 160MW
15.4 230MW
7FA CT

Aeroderivative:
15.5 25MW
15.7 45MW

→ 7FA CT

Figure 5-5

SCREENING: COMBINED CYCLE

2003-2012

Combined Cycle:
16.0 75MW
16.1 120MW
16.2 165MW
16.3 235MW
16.4 345MW
Greenfield CC-477MW
Brownfield CC-4776MW
Repower Edwardsport

→ Greenfield CC-477MW
Brownfield CC-477 MW
Repower Edwardsport

2013-2023

Combined Cycle:
16.0 75MW
16.1 120MW
16.2 165MW
16.3 235MW
16.4 345MW
16.5 400MW
Greenfield CC-4776MW
Brownfield CC-4776MW

→ Greenfield CC-477MW
Brownfield CC-477MW

Figure 5-6

SCREENING: INTEGRATED COAL GASIFICATION COMBINED CYCLE

2003-2012

No Mature or Commercial Technologies

2013-2023

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
New Case 425MW

→ 10.6 Advanced GCC 460MW

Figure 5-7

SCREENING: FUEL CELLS

2003-2012

Phosphoric Acid:
20.1D PA Ambient Pressure 2MW

2013-2023

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

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
Repowering the Midwest Hybrid 10MW

→ 20.3D SO Pressurized 25MW

Figure 5-8

SCREENING: WIND

2003-2012

Repowering the Midwest 50MW

2013-2023

24.2 Wind Turbine .35MW each
Repowering the Midwest 100MW → Repowering the Midwest 100MW

Figure 5-9

SCREENING: PV SOLAR

2003-2012

Repowering the Midwest Flat 10X100kW

2013-2023

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
22.3A PV High Conc 1MW
22.3B PV High Conc 5MW
22.3C PV High Conc 10 X 5MW
Repowering the Midwest Flat 10X100kW

→ Repowering the Midwest Flat 10X100kW

Figure 5-10

SCREENING: OTHER RENEWABLES

2003-2012

Municipal Solid Waste:
25.1 MSW Mass Burn 40MW
25.2 MSW Refuse Derived 40MW
25.3 Scrap Tire Mass Burn 40MW

Biomass-Fueled:
26.1 Wood-fired Stoker 50MW
26.2 Wood-fired Circ. FBC 50MW
Repowering the Midwest Biomass GCC

→ Repowering the Midwest Biomass GCC

2013-2023

Municipal Solid Waste:
25.1 MSW Mass Burn 40MW
25.2 MSW Refuse Derived 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
Repowering the Midwest Biomass GCC

→ Repowering the Midwest Biomass GCC

Figure 5-11

SCREENING: STORAGE

2003-2012

Batteries:
30.1 Lead Battery-LD 20MW
30.2 Lead Battery-HD 20MW

Hydro:
32.1 Pumped Hydro 350MW

→ 30.1 Lead Battery-LD 20MW

2013-2023

Batteries:
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
32.2 Underground Pumped 2000MW

Compressed Air:
33.1A CAES R350MW
33.1C CAES P350MW
33.2A CASH R350MW
33.2C CASH P350MW

Super Conducting Magnetic:
34.1 SMES 500MW

→ 30.1 Lead Battery-LD 20MW
33.1C CAES P350MW

Figure 5-29

Supply-Side Screening "Best in Class" Technologies

Category	2003-2012	2013-2023
Pulverized Coal	467 MW Brownfield	467 MW Brownfield
Fluidized Bed	459 MW CFBC	350MW PFBC
IGCC	---	460 MW Adv. GCC
Simple Cycle CT	156 MW 7FA CT	156 MW 7FA CT
Combined Cycle	477 MW Greenfield CC 477 MW Brownfield CC* 453 MW Repower Edwardsport*	477 MW Greenfield CC 477 MW Brownfield CC*
Fuel Cell	2 MW Phosphoric Acid	25 MW Solid Oxide
Wind	50 MW Repowering the Midwest	100 MW Repowering the Midwest
Solar	10X100 kW Repowering the Midwest	10X100 kW Repowering the Midwest
Other Renewables	75 MW Repowering the Midwest Biomass	100 MW Repowering the Midwest Biomass
Storage	20 MW Battery	20 MW Battery 350 MW CAES

* Not available for ULH&P.

Note: See text for explanation of individual technology types

Figure 5-48

UNION LIGHT HEAT & POWER

SUMMARY OF EXISTING ELECTRIC GENERATING FACILITIES

STATION NAME & LOCATION	FOOT NOTES	UNIT	TYPE OF UNIT*	INSTALLATION DATE MONTH & YEAR	TENTATIVE RETIREMENT YEAR	MAXIMUM GENERATING CAPABILITY (net kW) SUMMER	WINTER	ENVIRONMENTAL PROTECTION MEASURES*
East Bend Boone County Kentucky	A	2	CF-S	3-1981	Unknown	414,000	414,000	EP, LNB, CT & SO2 Scrubber, SCR
Miami Fort North Bend, Ohio		6	CF-S	11-1960	Unknown	163,000	163,000	EP & SNCR
Woodsdale Trenton, Ohio		1	GF/PF-GT	5-1993	Unknown	83,433	94,000	WI
		2	GF/PF-GT	7-1992	Unknown	83,433	94,000	WI
		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	
				SYSTEM TOTAL:		1,077,598	1,141,000	

*LEGEND:

CF = Coal Fired
OF = Oil Fired
GF = Natural Gas Fired
SF = Syngas Fired
PF = Propane Fired

S = Steam
CC = Combined-Cycle Combustion Turbine
GT = Simple-Cycle Combustion Turbine
HY = Hydro
IC = Internal Combustion

EP = Electrostatic Precipitator
CT = Cooling Towers
CL = Cooling Lake
WI = Water Injection, NOx
SI = Steam Injection, NOx
LNB = Low NOx Burners
OFA = Overfire Air
FGC = Flue Gas Conditioning
SCR = Selective Catalytic Reduction
SNCR = Selective Non-Catalytic Reduction

FOOTNOTES:

(A) 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.

Figure 5-49

Maximum Net Demonstrated Capaility 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	DP&L Share Summer	DP&L Share Winter
East Bend Boone County, KY	2	3-1981	600	600	414	414	186	186

NOTE: Totals may not add due to rounding to whole numbers.

Figure 5-50

APPROXIMATE FUEL STORAGE CAPACITY

Generating Station	Coal Capacity (Tons)	Oil Capacity (Gallons)	Propane Capacity (Barrels)
East Bend	375,000	500,000	--
Miami Fort	600,000	4,476,000	--
Woodsdale	--	--	100,000

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6. ENVIRONMENTAL COMPLIANCE

A. INTRODUCTION

The purpose of the compliance planning process is to develop an integrated resource/compliance plan that meets the future resource needs of Cinergy while at the same time meeting environmental requirements in a reliable and economic manner. Compliance planning associated with existing laws and regulations is discussed in this chapter. Risks associated with anticipated and potential changes to environmental regulations are discussed in Chapter 8, Section E. Since ULH&P does not currently own any generating units, the discussion in this chapter deals, in general, with compliance planning for the Cinergy system.

B. CAAA PHASE I COMPLIANCE

A detailed description of Cinergy's Phase I compliance planning process can be found in the Cinergy 1995, 1997, and 1999 IRPs.

C. CAAA PHASE II COMPLIANCE

A detailed description of Cinergy's Phase II compliance planning process can be found in the Cinergy 1995, 1997, and 1999 IRPs.

D. NO_x SIP CALL COMPLIANCE PLANNING

Cinergy's NO_x SIP Call compliance plan was discussed in the 1999 and 2001 IRP filings.

Cinergy's NO_x Compliance Implementation Plan

When Cinergy first created its NO_x Compliance Implementation Plan it was acting under a May 1, 2003, deadline. It was not until August 2000 that the NO_x SIP Call deadline was extended to May 31, 2004. Finally, the U.S. Supreme Court decided not to grant review of the decision to uphold the NO_x SIP Call Rule in March 2001.

The emission target that Cinergy is planning to meet for its impacted electric generating units (those over 25 megawatts) is the ozone season NO_x cap related to an emissions rate of 0.15 lb. per million Btu. Cinergy will need to reduce its NO_x emissions from current levels by approximately 63% from current emission levels. This is the level of reduction that will comply with the final U.S. EPA SIP Call rule, the individual state SIP rules, and U.S. EPA's Section 126 petitions.

While there are still some legal issues the Court of Appeals is reviewing concerning the NO_x rules at this time, Cinergy is currently required to comply with the individual state NO_x SIP rules. As such, it is absolutely necessary for Cinergy to continue construction and to plan on meeting the deadline (May 31, 2004) and emission levels (0.15 lb NO_x per million Btu input) that are currently required.

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 times a unit's heat input. EPA determined this cap using a baseline of heat input during the years 1995 and 1996. EPA then used the ICF Resources, Inc. Integrated Planning Model (IPM®) to grow this heat input to projected 2007 levels. EPA then calculated a tonnage cap using the 0.15 lb. NO_x/MMBtu emissions rate. This cap was then allocated to the individual states. In the states' individual SIP rules, each state determined how its individual NO_x emission budgets were to be allocated.

Until the individual states filed their final rules with EPA, Cinergy had to estimate the potential allocations from each state for each of its generating units. There was an expectation that the states could hold back as much as 5% of the allotments. For example, Kentucky's final rule kept 5% of the allotments from 2004-2006 in reserve for auction, and 2% thereafter. Due to these uncertainties, the Cinergy compliance plan incorporated a 5% compliance margin to allow for many of the variables that can affect operations.

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. This was required because, unlike SO_2 emissions, NO_x emissions are not linear across a generating unit's load range. Future projected operating hours provided from PROMOD IV® (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. Cinergy began by identifying the available NO_x control equipment and the most likely units for installation. Sensitivity analyses were performed to evaluate a number of emerging technologies. Cinergy concluded that there were five demonstrated types of NO_x control technologies available. They include combustion controls, such as Low NO_x Burners, Overfire Air, and Boiler Optimization Programs, and post combustion NO_x controls, such as Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR).

Selective Catalytic Reduction is capable of removing in excess of 85% of the NO_x from flue gas by a catalytic chemical process that reduces NO_x to nitrogen and water. SCRs are also the most capital intensive of the control technologies and generally take 24 to 36 months to design, procure and construct. They also require the longest unit outages for installation or "tie-in", generally up to twelve weeks, depending on existing unit configuration.

Selective Non-Catalytic Reduction is not as capital intensive as SCR technology but is only capable of reducing 20% to 30% of the NO_x emissions from a unit. SNCR technology involves placing injection nozzles in the boiler and injecting a liquid reagent to react with the NO_x. SNCRs do not require as long of a lead-time or a long unit outage for installation, but are more cost-effective on smaller units. In addition, SNCRs do not perform as well on larger units due to insufficient mixing of the reagent in the combustion gas stream.

Boiler Optimization Programs are computer control programs, which allow better monitoring and control of the combustion process in a boiler and thereby less NO_x creation. Boiler Optimization Programs are generally used in conjunction with other technologies such as Low NO_x Burners and automatic boiler controls and can help reduce NO_x in the range of 5% to 15% from uncontrolled levels. The Optimization Programs were considered for installation on virtually all of the coal-fired units in the Cinergy system. (The published March 1999 plan had Optimziation/Tuning on all the units except Miami Fort 5 and 6, units which did not have adequate combustion control systems.)

Overfire Air is a process of injecting a portion of the furnace combustion air above the burners in a boiler, reducing temperatures in that area and thereby reducing thermal NO_x production. To be most effective, overfire Air is typically used in conjunction with Low NO_x Burners.

Low NO_x Burners are burners designed to lower combustion temperatures in a boiler, thus reducing the amount of NO_x created during combustion, and can reduce uncontrolled NO_x levels by 35% to 50%.

4. Compliance Plan

Cinergy used an Excel-based spreadsheet model called the Engineering and Construction NO_x 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. The basic concept and initial model was developed externally by The NorthBridge Group and then brought in house where it was upgraded and improved. 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). Not all NO_x compliance options were analyzed for all units since Cinergy had already installed Low NO_x Burners on most of its units as a part of its acid rain compliance program, and some technologies, such as SNCR, don't work well on larger units. This approach also allowed Cinergy to schedule the less cost-effective compliance options later in the implementation process, so that if requirements are eased somewhat, or if new technologies are developed, Cinergy could take advantage of such changes.

After ranking the NO_x control 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 NO_x allowance allocation. This model may be run in a state-by-state mode or a PSI/CG&E mode using reductions in 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 NO_x 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 6-1 for East Bend, Miami Fort 6, and Woodsdale.

Cinergy recognizes that it is necessary to continuously evaluate and refine the plan as: 1) NO_x reductions requirements are finalized; 2) more experience with and knowledge about control technologies is gained; and 3) earned Early Reduction Credits can be included in the plan.

If some new compliance technology were to become available, proven, and more economical, Cinergy would consider substituting such a new technology for one of the later-scheduled projects. Finally, if Cinergy experiences better NO_x emission reductions from technologies currently planned, some future projects may be deferred or canceled.

5. Trading

The compliance plan assumes that NO_x allowance trading will be permitted across state lines. 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, at least in the near term. Unlike what was seen in Phase I of the acid rain program, Cinergy does not believe and is not aware of anyone predicting that there will be vast amounts of allowances available to achieve the high level of over compliance. The Cinergy compliance plan therefore assumes that compliance will be accomplished on system. However, the plan is structured to utilize trading should allowance availability increase or allowance prices fall below the marginal cost of reduction projects not yet implemented. There is the opportunity to defer some expenditures for significant savings, or even replace some planned equipment additions in the later part of the construction program with less expensive compliance options.

6. Non-Attainment Issues

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 and sources for reductions. As a result, Cinergy could be required to make specific reductions. These reductions may not result in the lowest cost plan based on marginal cost per ton removed.

E. EMISSION ALLOWANCE MANAGEMENT

Figure 6-2 shows the number of SO_2 allowances allotted by the USEPA for East Bend, Miami Fort 6, and Woodsdale. Figure 6-3 shows the projected number of NO_x allowances that will be allotted to these units.

The emission allowance markets impact the compliance 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.

The economics of this banking strategy, or strategic bank, are dependent upon the market price of allowances.

Cinergy has maintained an interdepartmental group to perform SO_2 and NO_x emission allowance management. Cinergy plans to manage emissions risk by utilizing a mixture of purchasing allowances, installing equipment and, when applicable, purchasing power. The most economic decision is dependent upon the current and forecasted market price of allowances, the cost and lead-time to install control equipment, and the current and forecasted market price of power. These factors will be reviewed as the markets change and the most economic emission compliance strategy will be employed.

Figure 6-1

NO_x Compliance Plan

Unit	Compliance Options
East Bend 2 *	Tuning/Optimization/Install SCR
Miami Fort 6	LNB

KEY:
SCR - Selective Catalytic Reduction
SNCR - Selective Non-Catalytic Reduction
LNB - Low NOx Burners
* Options currently installed and in-service

Figure 6-2

SO_2 ALLOWANCES ALLOCATED TO EAST BEND, MIAMI FORT 6, AND WOODSDALE

Plant Name	Unit/ Boiler No.	Percent Ownership	ALLOWANCES ALLOCATED 2000-2009	2010 & after
Miami Fort	6	100.00	4,908	4,917
East Bend	2	69.00	12,893	12,916
Woodsdale	1	100.00	294	295
Woodsdale	2	100.00	294	295
Woodsdale	3	100.00	294	295
Woodsdale	4	100.00	294	295
Woodsdale	5	100.00	294	295
Woodsdale	6	100.00	294	295
Total			19,565	19,603

Note: Number of allowances shown are Cinergy's portion for jointly owned units.

Figure 6-3

NO_x ALLOWANCES ALLOCATED TO EAST BEND, MIAMI FORT 6, AND WOODSDALE

Plant Name	Unit/ Boiler No.	Percent Ownership	ALLOWANCES ALLOCATED 2004	2005 & after
Miami Fort	6	100.00	398	398
East Bend	2	69.00	1,077	1,077
Woodsdale	1	100.00	30	30
Woodsdale	2	100.00	30	30
Woodsdale	3	100.00	39	39
Woodsdale	4	100.00	37	37
Woodsdale	5	100.00	40	40
Woodsdale	6	100.00	39	39
Total			1,690	1,690

Note:

Number of allowances shown are Cinergy's portion for jointly owned units. 2004 allocations are a hybrid of Section 126 and NOx SIP Call. 2005 allocations are from NOx SIP Call. Beyond 2006, allocations are subject to state updates.

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7. <u>ELECTRIC TRANSMISSION FORECAST</u>

In compliance with the standards 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 environmental compliance resources 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 2003 IRP, and its general implementation.

Figure 8-1 shows ULH&P's supply versus demand balance without any new supply-side resources. For 2007 (the first year after the full requirements contract expires), ULH&P has a need for about 1022 MW of resources to meet a minimum 15% Reserve Margin. ULH&P's resource requirements continue to grow over time as its load grows.

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 using a consistent method of evaluation. The tool used to perform this final integration was STRATEGIST® (formerly named PROSCREEN II®). In addition, PROMOD IV® was used to calculate generating unit capacity factors used in the development of the NO_x compliance plan (see Chapter 6).

1. Model Descriptions

STRATEGIST® is a state-of-the-art computer model developed by New Energy Associates, LLC of Atlanta, Georgia. STRATEGIST® is commercially licensed to many utilities and has been used by Cinergy 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 to select expansion plans based on Present Value Revenue Requirements (PVRR). 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 units. 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 NO_x SIP Call 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, ULH&P uses the following basic criteria for resource planning: (1) minimum reserve margin of 15%, (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 PVRR of the various plans generated by the model, ULH&P was able to evaluate the relative economics of different resource combinations.

PROMOD IV®, like STRATEGIST®, has been used by Cinergy 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 STRATEGIST®, 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 environmentally-affected 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 power market price forecast utilized in this IRP was developed by ICF using ICF's proprietary Integrated Planning Model (IPM®). IPM® simulates the wholesale power market and uses a linear programming optimization routine to project wholesale market power prices. The model forecasts how the industry will function (e.g., unit additions and retirements, economic dispatch, etc.) based on economic fundamentals rather than extrapolating from historical conditions. The North American Eastern Interconnect was modeled in IPM®, subdivided into approximately twenty-five regional or sub-regional markets. ICF's IPM® power model is widely accepted in the utility industry as well as by investment banks and rating agencies and has been used in regulatory cases and in litigation.

2. Process

Throughout the IRP process, the modeling was reviewed for accuracy. The projected market prices for electricity from ICF for Southern ECAR were included in the STRATEGIST® database to simulate the interactions between ULH&P's system and the wholesale market.

Once the supply-side, demand-side, and environmental compliance screening processes were completed, the options shown below were modeled in STRATEGIST®. 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 (DSM Settlement Agreement)	Transfer East Bend 2 to ULH&P with Back-up PSA (2007)
Interruptible Contracts (2003-2023)	Transfer Miami Fort 6 to ULH&P with Back-up PSA (2007)
DLC Program (2003-2023)	Transfer Woodsdale 1-6 to ULH&P (2007)
CallOption Program (2003-2023)	50 MW Block 5-Year Market-Based July/August 5X16 Purchases (2007)
RTP Program (2003-2023)	156 MW 7FA CT in blocks of 70 MW (2007-2023)
	Greenfield 477 MW CC in blocks of 70 MW (2007-2023)
	467 MW Pulverized Coal in blocks of 70 MW (2007-2012)
	350 MW TAG Adv. PCFB in blocks of 70 MW (2013-2023)
	25 MW Fuel Cell (2013-2023)
	25 MW Annual Market-Based July/August 5X16 Purchases (2008-2023)

Notes:
1) 5X16 = 5 days/week, 16 hours/day
2) CT = Combustion Turbine
3) CC = Combined Cycle
4) PCFB = Pressurized Circulating Fluidized Bed
5) DLC = Direct Load Control
6) RTP = Real Time Pricing
7) TAG = EPRI Technical Assessment Guide®

Due to the relatively small size of the ULH&P system, some of the generic supply-side options were modeled in blocks smaller than the normal sizes of these units. For example, the CT, CC, pulverized coal, and PCFB units were limited to blocks of 70 MW in size even though these units are normally much larger. The reasoning behind this is so that no single unit would constitute more than 8% of ULH&P's load so that the 15% reserve margin criterion would be adequate. This is a conservative assumption because the "best in class" resources from the supply-side screening generally were the largest units available, due to economies of scale. If smaller units were required for ULH&P, the capital costs on a $/kW basis would be higher than the costs used in this analysis. The only other means for ULH&P to be able to take advantage of the economies of scale of owning a larger unit would be to jointly own such a unit with another utility, purchase a back-up contract, or carry a higher level of reserves, all of which may entail additional costs.

Although the lead time for a new coal unit is such that having capacity available by 2007 would be extremely difficult, if not impossible, the coal unit alternative was nevertheless available in that year for modeling purposes. This affords a better picture of what an optimal system for ULH&P would look like at that time. In addition, it models the possibility of acquiring ownership in an existing unit(s).

For ease of modeling, the Interruptible contract and the DLC, RTP, and CallOption programs were modeled as dispatchable supply-side resources by increasing their MW demand-side contributions by 15% for the reserve margin.

Any generic CTs and CCs selected by the model can be viewed as "placeholders" for "peaking" and "intermediate" duty market purchases. Similarly, any generic pulverized coal, fluidized bed, or Fuel Cell units selected by the model can be viewed as "placeholders" for base load 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 a twenty-one year period (2003-2023), with optimization beginning in 2007 after the current full requirements contract expires.

C. IDENTIFICATION OF SIGNIFICANTLY DIFFERENT PLANS

The STRATEGIST® model is somewhat limited in the number of resource alternatives that it can consider and still reach solution because it looks at all possible combinations of all of the alternatives. Therefore, the analysis was performed in a number of steps. The first step was an optimization run that used only generic supply-side resources and purchases (i.e., East Bend, Miami Fort 6, and Woodsdale were excluded). Three plans were chosen from this run to analyze further.

A second run was performed assuming that the acquisition of East Bend, Miami Fort 6, and Woodsdale would occur in 2007, with generic resource and purchase alternatives available after that. Even though the actual acquisition of these plants would potentially occur in 2004 assuming all regulatory approvals are received, the modeling attempted to replicate the effect on ULH&P's customers. ULH&P's proposal is that ULH&P's rates would not change until 1/1/07, when new retail rates associated with fuel and wholesale generation and transmission service (including the Plants at their 1/1/07 Net Book Values) could go into effect. Therefore, 2003-2006 was modeled with ULH&P's customers continuing to pay at their current rates, followed by the acquisition of the Plants in 2007 along with their associated operating costs from then on. The least-cost plan was then chosen from this run for further analysis.

Finally, a third run was performed assuming that ULH&P's load would continue to be served by a full-requirements Purchased Power Agreement (PPA) at market prices.

The year 2007 was key In determining the significantly different plans for further analysis because this is the soonest that ULH&P's customers can be affected by these decisions, given the rate freeze that is in effect. In the optimization run using only generic new resources, the primary differences between plans in 2007 concerned the mix of capacity additions (coal units, combined cycle units, and CTs), which primarily represents a trade-off between the capital cost of the plants (*i.e.*, higher capital cost coal units versus lower capital cost CCs and CTs) and the fuel costs to operate the plants (*i.e.*, coal versus natural gas). The first plan chosen from this run was the number one-ranked (*i.e.*, lowest PVRR) plan. The other two significantly different plans from this run were chosen because they contained a different number of coal versus gas units compared to the number one plan. The second plan chosen was the lowest-ranked plan containing one less coal unit as well as a shift from peaking capacity to intermediate capacity. This plan also contained a 50 MW 5-year purchase. The third plan chosen was the lowest-ranked plan containing one additional coal unit as well as a shift from intermediate capacity to peaking capacity. The reason that the lowest-ranked plans containing either two additional or two less coal units were not chosen was that the PVRRs of such plans were significantly higher than the PVRR of the number one-ranked plan.

Figure 8-2 shows the 5 plans of interest, which were: 1) the All New Generic Units #1 Plan, 2) the 1 Less Coal Unit Plan, 3) the 1 Additional Coal Units Plan, 4) the East Bend/Miami Fort 6/Woodsdale Plan, and 5) the Full-Requirements PPA Plan.

The All New Generic Units #1 Plan (as is true for all of the plans) contains the DSM bundle, the RTP/DLC/CallOption programs, and the Interruptible load. The supply-side resources consist of eight coal units (560 MW), three combined cycle units (210 MW), and four simple cycle CT units (280 MW) in 2007. In addition, the plan contains small amounts of summer purchases (i.e., 25-50 MW per year) in 2009-2012. The remainder of the plan consists of PCFB units in 2013, 2015, 2019, and 2023 along with 25 MW purchases in 2014, 2018, and 2022. The purchases shown in the plan can represent summer 5X16 purchases, options, 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 would be made depends on the relative prices of the alternatives available at that time. The choice of the PCFB units added in the last ten years of the plan is highly dependent on whether EPRI's projections of fluidized bed capital costs and heat rates can become a reality. Therefore, these units should be viewed merely as "placeholders" for whatever capacity resources are the most economical at the time decisions for adding capacity need to be made.

For the 1 Less Coal Unit Plan, the supply-side resources consist of seven coal units (490 MW), five combined cycle units (350 MW), two simple cycle CT units (140 MW), and a 50 MW 5-year block summer purchase in 2007. In addition, the plan contains another coal unit in 2011 and small amounts of summer purchases (*i.e.*, 25-50 MW per year) in 2008-2010, and 2012. The remainder of the plan consists of PCFB units in 2013, 2016, 2021, and 2023 along with 25-50 MW purchases in 2014-2015, 2018-2020, and 2022. As discussed above, the purchases and units added in the last ten years of the plan should be viewed as "placeholders."

For the 1 Additional Coal Unit Plan, the supply-side resources consist of nine coal units (630 MW), one combined cycle unit (70 MW), and five simple cycle CT units (350 MW) in 2007. In addition, the plan contains small amounts of summer purchases (*i.e.*, 25-50 MW per year) in 2009-2012. The remainder of the plan consists of PCFB units in 2013, 2015, 2021, and 2023 along with 25-50 MW purchases in 2014, 2018-2020, and 2022. As discussed above, the purchases and units added in the last ten years of the plan should be viewed as "placeholders."

The "East Bend/Miami Fort 6/Woodsdale" Plan contains East Bend, Miami Fort 6, and Woodsdale in 2007 along with a Back-up PSA for East Bend and Miami Fort 6. In addition, the plan contains small amounts of summer purchases (*i.e.*, 25-50 MW per year) in 2011-2012. The remainder of the plan consists of PCFB units in 2013, 2018, and 2023, and Fuel Cell units in 2015 and 2017. Again, the purchases and units added in the last ten years of the plan should be viewed as "placeholders."

The reserve margin criterion used to develop the East Bend/Miami Fort 6/Woodsdale Plan was modified because of the size of the units involved. The East Bend and Miami Fort units have a back-up contract that essentially makes these units 100% reliable for ULH&P, so no outage-related reserve margin component is necessary for that portion of the load. However, the size of each of the Woodsdale units (83.4 MW) is slightly larger than the 70 MW discussed earlier that would allow the 8% outage component of the reserve margin criterion to cover the loss of the largest unit. Therefore, the criterion used for the outage component was the greater of the loss of largest unit (*i.e.*, 83.4 MW) or 8%. Of course, the ECAR Operating Reserve and weather-related components of the Reserve Margin criterion still apply. The result was that the criterion used was 16.4% in 2007, gradually decreasing as ULH&P's load grows (and the loss of the largest unit represents a smaller percentage of that load) to the minimum 15% level by 2018. The calculation of the reserve margin criterion used for this plan is shown in Figure 8-3.

The fifth significantly different plan assumes that ULH&P's load will be served by a full-requirements PPA priced at market prices.

In summary, in 2007, which is the main focus, the key differences between these plans concern the types of capacity additions and their fuel sources, and the reliance on purchases. The All New Generic Units #1 Plan and the East Bend/Miami Fort 6/Woodsdale Plan have about the same amount of coal-fired capacity versus gas-fired capacity, although the All New Generic Units #1 Plan has more intermediate and less peaking capacity. The 1 Less Coal Unit Plan has less coal-fired capacity, more intermediate capacity, less peaking capacity, and relies on a 5-year peaking purchase. The 1 Additional Coal Unit Plan has more coal-fired capacity, less intermediate capacity, and slightly more peaking capacity than the All New Generic Units #1 Plan. Of course, the Full-Requirements PPA Plan relies entirely on purchases. Overall, these plans are representative of the choices that ULH&P must make at this time.

In all of these plans, the dominant reliability constraint was the minimum reserve margin. In other words, the supply-side 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 PVRR.

The relative PVRR for the five plans obtained from the STRATEGIST® model for the Study Period (i.e., 20-year Planning Period plus infinite end effects) are as follows:

	2003 Present Value Revenue Requirements ($ Millions)	Change from EB/MF6/Wood Plan ($ Millions)	Change from EB/MF6/Wood Plan (%)
East Bend/Miami Ft 6/ Woodsdale Plan	$3313.5	$0	0.00%
Full-Requirements PPA Plan	$3957.0	+$643.5	+19.4%
All New Generic Units #1 Plan	$4062.2	+$748.7	+22.6%
1 Less Coal Unit Plan	$4075.0	+$761.5	+23.0%
1 Additional Coal Units Plan	$4083.9	+$770.4	+23.3%

The effective after-tax discount rate used was 8.74%. 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 plans.

For the 20-year Planning Period rather than the full Study Period, the East Bend/Miami Fort 6/Woodsdale Plan is over $400 million lower in cost than the Full-Requirements PPA Plan.

D. SENSITIVITY ANALYSES

A number of possible alternative futures that could have large impacts on stakeholders were identified. 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
- Changes in absolute gas prices
- Changes in market prices
- Changes in the level of service area load

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 alternative futures were addressed during the screening and the results can be found in Chapter 5. Changes in environmental regulations will be discussed below in Section E. Changes in gas prices, market prices, and service area load were addressed as sensitivities at the integration stage.

Each of the five significantly different plans was "hard-coded" through 2007 to reflect that the 2007 decisions are not alterable once these resource commitments have been made. Then, for each of the sensitivities, the model was allowed to re-optimize each of the plans after that to reflect that the remaining resource additions in the plans can and would be adjusted over time as circumstances change and new plans are developed. The lowest-ranked re-optimized significantly different plan under each sensitivity condition was chosen to perform comparisons. It should be noted that the results of the sensitivity analyses are to be used for comparison of the plans to each other on a relative basis. The results of these sensitivities are discussed in more detail below.

Higher Gas Price Forecast Sensitivity

Since the near-term capacity choices are installing or acquiring gas-fired capacity versus coal-fired units versus purchasing from the market, changes in gas prices can affect the relative economics of the plan chosen. A sensitivity using the ICF High Case gas price forecast was performed. This forecast represents a more pessimistic view (from the perspective of gas purchasers) of the gas industry's supply response compared to the Base Case forecast. Because a change in gas prices will also affect market prices, the ICF market price forecast that corresponded with the ICF High Case gas price forecast also was used in this sensitivity.

Figure 8-4 shows the resulting plans under this higher gas price sensitivity. All of the five significantly different plans remained the same as under Base Case conditions through 2009. In the last ten years, the generic unit plans show an advancement of coal-fired units and fewer purchases, as would be expected with higher gas prices and correspondingly higher market prices. The East Bend/Miami Fort 6/Woodsdale Plan was unchanged from Base Case conditions.

The values obtained from the STRATEGIST® model for relative Present Value Revenue Requirements for the five plans are as follows:

	2003 Present Value Revenue Requirements ($ Millions)	Change from EB/MF6/Wood Plan ($ Millions)	Change from EB/MF6/Wood Plan (%)
East Bend/Miami Ft 6/ Woodsdale Plan	$3474.2	$0	0.00%
Full-Requirements PPA Plan	$4003.2	+$529.0	+15.2%
All New Generic Units #1 Plan	$4133.5	+$659.3	+19.0%
1 Less Coal Unit Plan	$4148.1	+$673.9	+19.4%
1 Additional Coal Units Plan	$4132.8	+$658.6	+19.0%

Again, the figures above should be used only for the relative comparison of the five plans. The least cost plan was a plan containing the East Bend, Miami Fort 6, and Woodsdale units. However, as expected, the East Bend/Miami Fort 6/Woodsdale Plan became relatively more expensive compared to Base Case conditions than the generic unit plans because of its higher mix of gas-fired units.

Lower Gas Price Forecast Sensitivity

A sensitivity using the ICF Low Case gas price forecast was also performed. In this forecast, future gas prices were approximately equal to historical 1989 to 2002 natural gas prices in real inflation-adjusted terms. The large increases in forecasted demand for natural gas make this scenario unlikely to occur.

Because a change in gas prices will affect market prices, the ICF market price forecast that corresponded with the ICF Low Case gas price forecast also was used in this sensitivity.

Figure 8-5 shows the resulting plans under this lower gas price sensitivity. All of the significantly different plans remained the same as under Base Case conditions through 2009. In the last ten years, the generic unit plans show the addition of CT and Fuel Cell units and an elimination of the coal-fired units, while the East Bend/Miami Fort 6/Woodsdale Plan includes additional CC and Fuel Cell units and an elimination of the coal-fired units, as would be expected with lower gas prices.

The values obtained from the STRATEGIST® model for relative Present Value Revenue Requirements for the five plans are as follows:

	2003 Present Value Revenue Requirements ($ Millions)	Change from EB/MF6/Wood Plan ($ Millions)	Change from EB/MF6/Wood Plan (%)
East Bend/Miami Ft 6/ Woodsdale Plan	$2848.4	$0	0.00%
Full-Requirements PPA Plan	$3309.3	+$460.9	+16.2%
All New Generic Units #1 Plan	$3804.1	+$955.7	+33.6%
1 Less Coal Unit Plan	$3751.3	+$902.9	+31.7%
1 Additional Coal Units Plan	$3869.0	+$1020.6	+35.8%

Again, the figures above should be used only for the relative comparison of the five plans. The least cost plan was a plan containing the East Bend, Miami Fort 6, and Woodsdale units. As expected, the East Bend/Miami Fort 6/Woodsdale Plan became relatively more expensive than the Full-Requirements PPA Plan because of its lower dependence on the power market. At the same time, it became relatively less expensive compared to the generic unit plans because of its higher mix of gas-fired capacity.

Capacity Oversupply Sensitivity

A sensitivity using lower market prices than under base conditions was performed. This forecast was generated by ICF by assuming a large amount of additional power plant construction in the Eastern Interconnect in 2006 and

2007 relative to the Base Case. The amount of overbuilding assumed was roughly equal to the levels experienced in 2001 and 2002, distributed evenly among sub-regions. This case reflects that prices remain depressed for an extended period of time and do not return to supply/demand equilibrium levels until about 2011, whereas equilibrium was reached by about 2007 or 2008 in the Base Case.

Figure 8-6 shows the resulting plans under this Capacity Oversupply sensitivity. All of the plans remained the same as under Base Case conditions.

The values obtained from the STRATEGIST® model for relative Present Value Revenue Requirements for the five plans are as follows:

	2003 Present Value Revenue Requirements ($ Millions)	Change from EB/MF6/Wood Plan ($ Millions)	Change from EB/MF6/Wood Plan (%)
East Bend/Miami Ft 6/ Woodsdale Plan	$3306.3	$0	0.00%
Full-Requirements PPA Plan	$3659.5	+$353.2	+10.7%
All New Generic Units #1 Plan	$4065.1	+$758.8	+23.0%
1 Less Coal Unit Plan	$4077.8	+$771.5	+23.3%
1 Additional Coal Units Plan	$4085.4	+$779.1	+23.6%

Again, the figures above should be used only for the relative comparison of the five plans. The least cost plan was a plan containing the East Bend, Miami Fort 6, and Woodsdale units. As expected, the East Bend/Miami Fort 6/Woodsdale Plan became relatively more expensive than the Full-Requirements PPA Plan because of its lower dependence on the power market. Its economics relative to the generic unit plans remained virtually unchanged.

Higher Load Forecast Sensitivity

A sensitivity with a higher load level based on extreme weather condition assumptions was chosen. The alternate electricity loads were projected using an estimated 80% confidence interval, with the extreme load sensitivity based on the 90% probability level. Throughout the forecast, the summer and winter peak loads in this sensitivity are about 55-70 MW higher than the Base forecast. The gas prices and market prices remained at Base Case levels for this sensitivity.

Figure 8-7 shows the resulting plans under this Higher Load Forecast sensitivity. All of the non-PPA plans required additional capacity in 2007 in order to meet the reserve margin criterion due to the higher load levels. The All New Generic Units #1 Plan and the 1 Less Coal Unit Plan each added another coal unit, and then added more purchases and fewer coal units in the last ten years. The 1 Additional Coal Unit Plan added another CC unit, but then remained relatively unchanged in the last ten years. Finally, the East Bend/Miami Fort 6/Woodsdale

Plan also added another CC unit, but in the last ten years, the Fuel Cell units were eliminated and an additional coal unit was built instead.

The values obtained from the STRATEGIST® model for relative Present Value Revenue Requirements for the five plans are as follows:

	2003 Present Value Revenue Requirements ($ Millions)	Change from EB/MF6/Wood Plan ($ Millions)	Change from EB/MF6/Wood Plan (%)
East Bend/Miami Ft 6/ Woodsdale Plan	$3484.3	$0	0.00%
Full-Requirements PPA Plan	$4155.6	+$671.2	+19.3%
All New Generic Units #1 Plan	$4274.7	+$790.3	+22.7%
1 Less Coal Unit Plan	$4287.4	+$803.1	+23.0%
1 Additional Coal Units Plan	$4278.3	+$794.0	+22.8%

Again, the figures above should be used only for the relative comparison of the five plans. The least cost plan was a plan containing the East Bend, Miami Fort 6, and Woodsdale units. The East Bend/Miami Fort 6/Woodsdale Plan became relatively less expensive compared to all of the other plans.

Lower Load Forecast Sensitivity

A sensitivity with a lower load level based on mild weather assumptions was chosen. The alternate electricity loads were projected using an estimated 80% confidence interval, with the mild load sensitivity based on the 10% probability level. Throughout the forecast, the summer and winter peak loads in this sensitivity are about 55-75 MW lower than the Base forecast. The gas prices and market prices remained at Base Case levels for this sensitivity.

Figure 8-8 shows the resulting plans under this Lower Load sensitivity. None of the plans require any additional resources until 2012 due to the lower load level. The types of resources added after that in each of the plans is similar to what was added in the Base Case.

The values obtained from the STRATEGIST® model for relative Present Value Revenue Requirements for the five plans are as follows:

	2003 Present Value Revenue Requirements ($ Millions)	Change from EB/MF6/Wood Plan ($ Millions)	Change from EB/MF6/Wood Plan (%)
East Bend/Miami Ft 6/ Woodsdale Plan	$3207.2	$0	0.00%
Full-Requirements PPA Plan	$3793.7	+$586.5	+18.3%
All New Generic Units #1 Plan	$3926.1	+$718.9	+22.4%
1 Less Coal Unit Plan	$3908.0	+$700.8	+21.9%
1 Additional Coal Units Plan	$3940.3	+$733.1	+22.9%

Again, the figures above should be used only for the relative comparison of the five plans. The least cost plan was a plan containing the East Bend, Miami Fort 6, and Woodsdale units. The East Bend/Miami Fort 6/Woodsdale Plan became relatively more expensive than the other plans compared to Base Case conditions.

Figure 8-9 summarizes the results of these sensitivity analyses, showing the total PVRR for each plan, for each sensitivity. The East Bend/Miami Fort 6/Woodsdale Plan is the lowest cost plan in all cases.

Figure 8-10 shows the change in PVRR of each plan compared to its PVRR under Base Case conditions for each of the sensitivities. The East Bend/Miami Fort 6/Woodsdale Plan was more sensitive to changes in gas prices than the other plans, although it was less sensitive to higher gas prices than to lower gas prices. The Full-Requirements PPA Plan was the most sensitive to lower gas prices. The East Bend/Miami Fort 6/Woodsdale Plan, as well as the other non-PPA plans, had little sensitivity to changes in market prices as a result of capacity oversupply. Of course, the Full-Requirements PPA Plan was highly sensitive to market price changes. Finally, the East Bend/Miami Fort 6/Woodsdale Plan was less sensitive to changes in the load forecast than the other plans. In general, however, none of the alternative plans reacted in a significantly superior manner across the sensitivities. The East Bend/Miami Fort 6/Woodsdale Plan, overall, is robust and has a much lower PVRR than the alternative plans.

Figure 8-11 shows the PVRR of the alternative plans compared to the East Bend/Miami Fort 6/Woodsdale Plan for the Base Case and for each of the sensitivities. In each case, the plan containing the Plants had a lower PVRR than the alternative plans, ranging from a minimum of $353 million, or about 11%, to a maximum of over $1 billion, or about 36%.

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 Federal Legislative Affairs, Environmental Strategy, and Sustainability 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.

<u>**New Ozone National Ambient Air Quality Standard (NAAQS)**</u>

On July 19, 1997, the United States Environmental Protection Agency (USEPA or 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. EPA has suggested that controls may be mandated sometime between 2009 and 2016.

On May 14, 1999, the U.S. Circuit Court of Appeals for the District of Columbia (Court of Appeals) ruled that the EPA's final rule establishing the new eight-hour ozone standard and the fine particulate matter standard constituted an invalid delegation of legislative authority. In June 1999, the EPA appealed the decision. On October 29, 1999, the full Court of Appeals rejected the EPA's request for reconsideration. In January 2000, the EPA appealed to the U.S. Supreme Court (Supreme Court) and on February 27, 2001, the Supreme Court reversed the Court of Appeals' ruling. However, the Supreme Court invalidated the EPA's implementation procedure for the portion of the case dealing with the eight-hour ozone standard. The EPA currently is evaluating approaches for implementing the eight-hour ozone standard in accordance with the Supreme Court's opinion. On June

2, 2003, EPA published a proposed rule that sets out two different approaches for States to use to implement the 8-hour ozone health standard. EPA will review the comments on the proposed rule and make a final determination as to the requirements for States sometime in mid to late 2004.

In May 2003, the EPA entered into a consent decree with various environmental groups that required the EPA to designate by April 15, 2004, which counties in the United States are classified as being "nonattainment", or exceeding the acceptable limits for ozone. On or before July 15, 2003, Kentucky and other states submitted to EPA their list of potential nonattainment counties for ozone. On December 3, EPA replied to Kentucky and other states with revisions to and/or agreement with the proposed designations. Depending on how the outcome of the 8 hour implementation rule, states may require affected sources to implement pollution control to reduce emissions which lead to the creation of ozone in the 2009 to 2016 timeframe. Cinergy will continue to monitor these developments and their potential impact on the company.

New Particulate NAAQS (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. The previous section describes the May 1999 Court of Appeals ruling against EPA's new standards and subsequent appeals and rulings.

The Court of Appeals resolved the outstanding issues in their 2002 ruling by upholding the Supreme Courts opinions. At this time EPA has announced that it intends for states to propose designation of areas as attainment or nonattainment for fine PM by February 15, 2004 and make final designations by December 15, 2004. States will then develop emission reduction plans on how to bring these areas into attainment a few years later. Additional costs to lower sulfur dioxide and particulate emissions will depend on the stringency of the requirement. Cinergy will continue to study the impact of these potential regulations on the company.

Interstate Air Quality Rule

On December 17, 2003, the EPA Administrator signed the proposed Interstate Air Quality Rule (IAQR), that is expected to be published in the Federal Register in early 2004. The basis for the rule is that regional reductions of sulfur dioxide and nitrogen oxides emissions from electric generating units in the eastern half of the United States is a cost effective method of attaining the new ozone and fine particulate matter national ambient air quality standards, along with local controls. The proposed reductions would occur in two phases (2010 & 2015) and result in approximately 70% reduction of both emissions. The proposal calls for a regional cap and trade program for emissions and revisions to the existing emissions trading programs for sulfur dioxide and nitrogen oxides. EPA has not issued any specific regulatory language yet, but expects to issue a supplement notice of proposed rulemaking this spring and complete the promulgation process by the end of the year. Cinergy will continue to study the impact of the proposed rule package on the company.

Regional Haze

On July 1, 1999, the EPA issued final regional haze rules under authority of Section 169A and 169B of the Clean Air Act Amendments of 1990. 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 required states to submit visibility SIPs by 2008 that include emission reduction requirements in the time frame of 2013. 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. In May 2002, the DC Court of Appeals issued its opinion in the appeal and vacated parts of the rule and upheld other parts of the rule. The Court rejected EPA's appeal of the decision, so EPA is now in the process of revisiting the rule and determining its future course of action. Cinergy will continue to monitor these developments and their potential impact on the company.

Hazardous Air Pollutants from Utility Power Plants

The air toxics provisions of the Clean Air Act delayed possible air toxics regulation of fossil-fueled steam utility plants until the EPA completed a study of the impact on human health of power plant emissions of a list of 189 Hazardous Air Pollutants (HAPs). The final report, issued in February 1998, confirmed that utility air toxic emissions pose little risk to public health. However, it also stated that mercury is the pollutant of the greatest concern and requires further study.

A Mercury Study Report, issued in December 1997, stated that mercury is not a risk to the average American and expressed uncertainty about whether reductions in current domestic sources would reduce human mercury exposure. U.S. utilities are a large domestic source, but they are insignificant when compared to global mercury emissions.

On December 14, 2000, the EPA made a determination that additional regulation of mercury emissions from coal-fired power plants was appropriate. During 2002 and 2003 the EPA developed a utility mercury MACT (Maximum Achievable Control Technology) workgroup consisting of a cross section of interested stakeholders to advise EPA on the development of the mercury rule. The workgroup submitted its final report to EPA in October 2002, but members did not reach consensus on any key issues.

On December 15, 2003, the EPA Administrator signed a proposed rule to regulate mercury emission from coal-fired power plants and nickel from oil fired power plants. The proposed regulation is expected to be published in the Federal Register in early 2004. The proposal includes several options for regulating mercury under different sections of the Clear Air Act, requiring different reductions, and at different compliance deadlines. Reductions could be required as early as 2008 under a MACT program or by 2010 and 2015 under a phased in approach with emissions trading. EPA expects to complete the rulemaking process by the end of 2004 along with the IAQR described above. Cinergy will continue to study the impact of these potential regulations on the company.

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. The U.S. Department of Energy (DOE) Climate Challenge Participation Accord (Climate Challenge or Participation Accord) signed by Cinergy in February 1995, expired December 31, 2000. However, the activities implemented to reduce Cinergy's GHG emissions during the Climate Challenge period continue to reduce Cinergy's GHG emissions even though the Participation Accord has expired.

Cinergy continues to submit 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 2003 report listed activities that reduced or offset Cinergy's GHG emissions by approximately 2.3 million tons of CO_2 equivalents in calendar year 2002. 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;
- Coal gasification
- Combined heat and power plant projects; and
- Paper and aluminum recycling.

Cinergy's climate change program efforts have resulted in a cumulative total of nearly 20.8 million tons of CO_2 equivalent reductions and offsets since 1991.

In keeping with its climate challenge commitment, Cinergy continues to participate in the U.S. Initiative on Joint Implementation (USIJI) approved Belize Rio Bravo forest preservation and sustainable management project along 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).

In 1999, Cinergy agreed to participate voluntarily in the USEPA 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 the transmission and distribution of electricity.

Cinergy, through one of its non-regulated subsidiaries, Cinergy Solutions, is developing and implementing a number of higher energy efficiency projects (e.g. combined heat and power, district heating and cooling, etc.).

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. Cinergy has engaged the services of a specialist in the field of monitoring and verification 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. Cinergy is participating in a number of research projects that are investigating the feasibility of capturing CO_2 from waste gas streams and disposing of the CO_2 geologically.

On February 20, 2002 Cinergy joined the EPA's voluntary Climate Leader program. Members will work with EPA to develop and report company-wide inventories of greenhouse gases. Companies will also work on developing corporate-wide GHG reduction goals to be achieved over a 10-year period. In addition, Cinergy will report annually on its progress toward achieving its goal.

On February 12, 2003, the Bush Administration released information on its voluntary approach to reducing greenhouse gas intensity by 18 percent over the next decade. The initiative is called "Climate VISION" (Voluntary Innovative Sector Initiatives: Opportunities Now). The initiative will be administered by the Department of Energy. On that date a number of industry associations, including the Edison Electric Institute, provided the administration with commitments that their member industries were willing to make to reduce and offset their GHG emissions voluntarily. The Edison Electric Institute, of which Cinergy is a member, pledged to reduce the intensity of its members' CO_2 emissions by 3 to 5 percent compared to business as usual.

In September 2003, Cinergy announced a voluntary plan to reduce its greenhouse gas emissions to an average of five percent below their 2000 level during the period 2010 through 2012. Cinergy will spend $21 million between 2004 and 2010 on projects to reduce or offset its emissions. It will work with Environmental Defense, a national environmental group that has been a supporter of the use of market mechanisms to achieve environmental objectives, in the implementation of the program. The expenditure of $21 million will include research and development into new technologies that address greenhouse gas emissions. Cinergy will strive to spend at least two-thirds of the dollars on projects that have the potential to reduce emissions from Cinergy's generation, transmission and distribution systems. To meet its GHG emission reduction goal, Cinergy plans to use a combination of programs that will include new technologies, carbon sequestration, demand-side management, energy conservation, improved efficiency of its existing generating fleet, and emission offsets.

Cinergy will also report annually its emissions of the six greenhouse gases -- carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbon and sulfur hexafluoride. It will also report annually on progress toward the 2010 goal by comparing its reductions and offsets to its 2000 baseline. As part of the voluntary program, the company will evaluate its emissions goal in 2010 and determine an appropriate voluntary goal for 2013 through 2015. Cinergy's core operations account for about one percent of worldwide greenhouse gas emissions, or about 67 million tons of CO_2 equivalents per year.

In December 1997, delegates to the United Nations' climate summit in Japan adopted an agreement, the Kyoto Protocol, to address global warming. The Kyoto Protocol establishes legally binding greenhouse gas emission (man-made pollutants thought to be artificially warming the earth's atmosphere) targets for developed nations. Prospects for consideration of the treaty by the U.S. Senate dimmed when in March 2001, the Bush Administration announced that the United States was not interested in ratifying the Protocol. International talks resumed without active U.S. participation at the Conference of the Parties in Bonn in July 2001, where the parties reached broad political agreement on the major outstanding issues. The Marrakech Accord, in November 2001, and the New Deli Accord in December of 2002, built on the Bonn Agreement by turning its broad principles into a detailed set of rules that more clearly define the operating framework for the instruments and institutions created under Kyoto. The Kyoto protocol has been ratified by the European Union, Japan, Canada, and enough other countries to make up the minimum 55 countries necessary for the Protocol to take effect. However, the Protocol still lacks the country ratification that represent 55 percent of global GHG emissions also necessary for the treaty to go into effect. Russia has not yet ratified the Protocol and if it should ratify the Protocol the necessary 55 percent of global GHG emissions will be met.

Because of a lack of the current U.S. Administration's support for the Kyoto Protocol or other domestic legislation, significant uncertainty exists about how and when greenhouse gas emission reductions may be regulated. Any global climate change policy, however, could have a substantial cost associated with it. Cinergy will continue to be on the forefront in looking for ways to decrease greenhouse gases and continue to provide affordable energy as efficiently as possible. Cinergy's plan for managing the potential risk and uncertainty of regulations relating to climate change includes the following:

- Implementing an internal voluntary goal to reduce Cinergy's greenhouse gas emissions 5 percent below Cinergy's 2000 baseline emission levels by 2010 (discussed earlier):
- Measuring and inventorying company-related sources of greenhouse gas emissions;
- Identifying and pursuing cost-effective greenhouse gas emission reduction and offsetting activities;
- Funding research of more efficient and alternative electric generating technologies;
- Funding research to better understand the causes and consequences of climate change;
- Encouraging a global discussion of the issues and how best to manage them; and
- Advocating comprehensive legislation for fossil-fired power plants.

<u>Clean Water Act Section 316(a) and 316(b)</u>

Protection of single fish species and aquatic communities is a primary focus of water permitting for coal, oil, gas, and nuclear power plants and industrial facilities under the Clean Water Act Section 316(a) - heated cooling water discharges, and 316(b) – entrainment through cooling water intake systems and impingement on intake screens. The financial implications of new 316(a) and 316(b) regulations to electric generation capacity and plants operations are potentially large. Electric utilities have a far greater number of cooling water intake structures and higher flows than other industries.

All of Cinergy's existing stations that have once-through cooling are potentially affected by Section 316(a) regulation on station's heated cooling-water discharge. This regulation could require closed circuit cooling (e.g., cooling towers) at all of Cinergy's open-cycle stations on the Wabash, White, and Ohio rivers to protect downstream fish communities. If adversely interpreted, 316(a) could result in station modifications costing hundreds of millions of dollars in capital expense and tens of millions for annual O&M and generation lost at these stations.

On December 18, 2001, U.S. EPA published the final 316(b) rule for new cooling water intake sources. This rule will impact the design of cooling water intakes at any new power plants built in the future. The rule requires that new intake structures have closed cooling systems equipped with low design flow screens, using only a small percentage of the intake streams flow rate. Detailed biological studies may also be needed to support system design.

EPA proposed the rule for existing facilities on April 9, 2002. It applies to facilities that have a design flow of 50 MGD or more. It requires a facility to meet performance standards which are to reduce impingement mortality by 80-95% (compared to a baseline) and if the intake flow is large enough compared to the water body, reduce entrainment by 60-90%. The proposed rule also allows a facility to do a site-specific approach if the costs of meeting the performance standards are significantly greater than the benefits or the costs EPA has in the rulemaking. A final rule is scheduled for February 2004.

Bevill Determination

On April 25, 2000, EPA issued a regulatory determination for fossil fuel combustion wastes (65 FR 32214, May 22, 2000). The purpose of the determination was to decide whether certain wastes from the combustion of fossil fuels (including coal, oil and natural gas) should remain exempt from subtitle C (management as hazardous waste) of the Resource Conservation and Recovery Act (RCRA). The Agency's decision was to retain the exemption from hazardous waste management for all of the fossil fuel combustion wastes. However, the Agency also determined and announced that waste management regulations under RCRA subtitle D (management as non-hazardous wastes) are appropriate for certain coal combustion wastes that are disposed in landfills and surface impoundments.

The utility industry has made significant improvements in its waste management practices over recent years but there may be sufficient evidence that adequate controls are not in place at some facilities. In the Agency's view, this justifies the development of national regulations. The Agency is initiating this action to develop and issue appropriate waste management regulations under subtitle D of RCRA as outlined in the November 2003 Annual Agenda of Regulatory and Deregulatory

Actions. Draft regulations could be issued in January 2004 and final regulations in 2005.

EPA's regulatory action will impact all coal combustion waste management units. At a minimum, utilities will be required to install ground water monitoring systems for each of the units to determine if there are any impacts to water quality. Any impacts will require further assessments and possibly corrective action to mitigate the impacts. Corrective actions could include retrofitting engineering controls such as liners and leachate collection, slurry walls, or closure with impermeable caps. The cost to retrofit these types of controls can be prohibitive and may force the closure of many of the older management units before they reach maximum capacity. Closure of facilities will require the construction of new units designed and built with the appropriate controls to protect ground water. Regardless of the path taken to comply with the new standards being developed, all solutions will have a significant impact on the costs to manage coal combustion waste and will directly impact the cost to generate electricity.

Arsenic

Arsenic is one of the eight Resource Conservation and Recovery Act (RCRA) metals, and one of thirteen priority pollutant metals. Trace amounts of arsenic exist in coal and oil and are released in very small amounts when those fuels are burned to produce electricity. Most of the arsenic attaches itself to particles of flyash. Cinergy's ash is primarily managed by being hydraulically sluiced to surface impoundments or collected dry and used for scrubber sludge fixation. Additionally, much of Cinergy's ponded and dry ash is beneficially reused in structural fills or concrete applications.

On October 31, 2001, EPA revised the drinking water standard for arsenic from 50 parts per billion (ppb) maximum contaminant level (MCL) standard to 10 ppb. State and federal regulatory agencies typically incorporate current drinking water MCLs into other regulatory areas such as groundwater quality standards, soil assessment thresholds and remediation programs. How quickly the new arsenic MCL permeates through various regulatory systems is difficult to predict. However, when the new standard is adopted it could mean substantial direct and indirect costs for the utility industry. The RCRA subtitle D standards being drafted, as a result of the Bevill Determination, will require groundwater monitoring wells be installed around Cinergy's ash ponds and landfills. The lower arsenic MCL may mean some of our waste management units will be forced into corrective action, whereas with the old standard they would not. Corrective action for surface impoundments and landfills could be extremely expensive, as mentioned previously.

Additionally, the MCL value is also linked to what in RCRA is referred to as the Toxicity Characteristic, or TC, level. This value is ordinarily set at 100 times the MCL and is used to determine when a waste is hazardous. The current TC level for arsenic is 5 ppm. If EPA so chooses, it could initiate revision to this value to reflect the change in the MCL. This would change the arsenic TC level to 1 ppm and could mean having to handle some flyash as hazardous waste. The change in the TC level is not automatic and would have to be proposed through notice and comment rulemaking. Cinergy will continue to monitor the situation.

New Source Review (NSR)

The Clean Air Act's NSR provisions require that a company obtain a pre-construction permit if it plans to build a new stationary source of pollution or make a major change to an existing facility unless the changes are exempt. On December 31, 2002, and March 10, 2003, the EPA finalized revisions to the NSR regulations. However on July 30, 2003, the EPA issued a notice of reconsideration of certain parts of the revisions. In addition, the EPA is still considering comments it received to the July 1998 proposed revisions to the program that would be more applicable to utilities.

On September 15, 1999, on November 3, 1999, and on February 2, 2001, the Attorneys General of the states of New York, Connecticut, and New Jersey, respectively, issued letters notifying Cinergy and CG&E of their intent to sue under the citizens' suit provisions of the CAA. New York and Connecticut allege violations of the CAA by constructing and continuing to operate a major change to CG&E's W.C. Beckjord Station (Beckjord) without obtaining the required NSR pre-construction permits.

On November 3, 1999, the EPA sued a number of holding companies and electric utilities, including Cinergy, CG&E, and PSI, in various U.S. District Courts. The Cinergy, CG&E, and PSI suit alleged violations of the CAA at two of our generating stations relating to NSR and NSPS requirements. The suit sought (1) injunctive relief to require installation of pollution control technology on each of the generating units at Beckjord and PSI's Cayuga Generating Station (Cayuga), and (2) civil penalties in amounts of up to $27,500 per day for each violation.

On March 1, 2000, the EPA filed an amended complaint against Cinergy, CG&E, and PSI. The amended complaint added the alleged violations of the NSR requirements of the CAA at two of our generating stations contained in the Notice of Violation (NOV) filed by the EPA on November 3, 1999. It also added claims for relief of alleged violations of nonattainment NSR, Indiana and Ohio SIPs, and particulate matter emission limits.

The amended complaint sought (1) injunctive relief to require installation of pollution control technology on each of the generating units at Beckjord, Cayuga, and PSI's Wabash River and Gallagher Generating Stations, and such other measures as necessary, and (2) civil penalties in amounts of up to $27,500 per day for each violation.

On June 28, 2000, the EPA issued an NOV to Cinergy, CG&E, and PSI for alleged violations of NSR, Prevention of Significant Deterioration (PSD), and SIP requirements at CG&E's Miami Fort Station and PSI's Gibson Station. In addition, Cinergy and CG&E have been informed by DP&L, the operator of J.M. Stuart Station (Stuart), that on June 30, 2000, the EPA issued a NOV for alleged violations of NSR, PSD, and SIP requirements at this station. CG&E owns 39% of Stuart. The NOVs indicated that the EPA may (1) issue an order requiring compliance with the requirements of the SIP, or (2) bring a civil action seeking injunctive relief and civil penalties of up to $27,500 per day for each violation.

On November 30, 1999, the EPA filed an NOV against Cinergy and CG&E alleging that emissions of particulate matter at the Beckjord Station exceeded the allowable limit. The NOV indicated that the EPA may (1) issue an administrative penalty order, or (2) file a civil action seeking injunctive relief and civil penalties of up to $27,500 per day for each violation. The allegations contained in this NOV were incorporated within the March 1, 2000, amended complaint. On June 22, 2000, the EPA issued an NOV and a Finding of Violation (FOV) alleging additional particulate emission violations at Beckjord Station and offered Cinergy an opportunity to meet and discuss the allegations and corrective measures. The NOV/FOV indicated the EPA may issue an administrative compliance order, issue an administrative penalty order, or bring a civil or criminal action.

Agreement in Principle On December 21, 2000, Cinergy, CG&E, and PSI, reached an agreement in principle with the EPA, the U.S. Department of Justice, three northeast states, and two environmental groups that could serve as the basis for a negotiated resolution of CAA claims and other related matters brought against coal-fired power plants owned and operated by Cinergy's operating subsidiaries. The complete resolution of these issues is contingent upon establishing a final agreement with the EPA and other parties. If a final agreement is reached with these parties, this would resolve the NSR claims as well as the Beckjord Station NOVs/FOV discussed above.

Under the terms of the tentative agreement, EPA and the other plaintiffs have agreed to drop all challenges of past maintenance and repair activities at our coal-fired generation plants. In addition, Cinergy would be allowed to continue on-going activities to maintain reliability and availability without subjecting the plants to future litigation regarding federal permitting requirements.

In return for resolution of past claims, future operational certainty, and protection of system wide demand growth, Cinergy tentatively agreed to:

- shut down or repower with natural gas nine small coal-fired boilers at three power plants beginning in 2004;
- build four additional SO_2 scrubbers, the first of which must be operational by December 31, 2007;
- upgrade existing pollution control systems;
- phase in the operation of NO_x reduction technology year-round starting in 2004;

- retire 50,000 tons of SO_2 allowances between 2001 and 2005 and reduce the company's SO_2 cap by 35 percent in 2013;
- pay a civil penalty of $8.5 million to the U.S. government; and
- implement $21.5 million in environmental mitigation projects.

In reaching the tentative agreement, Cinergy did not admit any wrongdoing and remains free to continue its current maintenance practices, as well as implement future projects for improved reliability. If the settlement is not completed, Cinergy believes the allegations contained in the amended complaint are without merit, and would defend the suit vigorously in court. In such an event, it is not possible at this time to determine the likelihood that the plaintiffs would prevail on their claims or whether resolution of this matter would have a material effect on Cinergy's financial condition.

On October 27, 2003, USEPA finalized its rule on Routine Maintenance, Repair, and Replacement Regulation (RMRR) exclusions and it would have become effective on December 26, 2003. On December 24, 2003, the US Court of Appeals ordered a stay of the RMRR revisions to the New Source Review regulations and their effective date will now wait until the case filed by primarily northeastern states is completed sometime in 2004. The regulation was issued as a draft for comment on December 31, 2002, and was signed by the acting USEPA Administrator on August 27, 2003.

Most states will need to modify state regulations to incorporate the provisions of the RMRR exclusions. In brief, the exclusion clarifies what routine maintenance, repair, and replacement projects may proceed without obtaining permits under the New Source Review program. Those projects would include physical changes on a process unit that: (1) are identical or functionally equivalent replacement, (2) costs do not exceed 20% of replacing the entire process unit, and (3) the basic design parameters and emission limitations are met.

The impact of the RMRR exemption clarification regulation on Cinergy operations is still being reviewed. Cinergy continues to monitor the issue.

Multi-Emission Legislation

Coal-fired power plants will face numerous regulations over the next decade to reduce SO_2, NO_x, and mercury emissions, and various proposals to regulate greenhouse gas emissions are being debated. Alternatively, there is the potential for reaching agreement on a multi-emission legislation approach to air quality issues that could lead to greater certainty and flexibility for the utility industry, and a cleaner environment. Cinergy continues to be very supportive of multi-emission legislation efforts.

On February 14, 2002, President Bush announced his own version of this legislation – the "Clear Skies Initiative." It was reintroduced in early 2003, in the 108th Congress by the Committee Chairmen and Subcommittee Chairmen of the two Clean

Air Subcommittees in the House and Senate. Cinergy believes that a single set of environmental rules will provide greater certainty to utilities with coal-fired plants, and result in more cost-effective emission reductions. The proposal sets the following timetables and targets:

- Cut SO_2 emissions by 73 percent, from current emissions of 11 million tons to a cap of 4.5 million tons in 2010, and 3 million tons in 2018.
- Cut emissions of NO_x by 67 percent, from current emissions of 5 million tons to a cap of 2.1 million tons in 2008, and to 1.7 million tons in 2018.
- Cut mercury emissions by 69 percent, – the first-ever national cap on mercury emissions. Emissions will be cut from current emissions of 48 tons to a cap of 26 tons in 2010, and 15 tons in 2018.

Emission caps will be set to account for different air quality needs in the eastern and western states.

On February 12, 2003, Senator Jeffords introduced his Clean Power Act of 2003, which would impose the following emissions caps on the U.S. electric power sector by the year 2009:

- Reduce NO_x emissions to 1.5 million tons or 75 percent below 1997 levels;
- Reduce SO_2 emissions to 2.25 million tons or 75 percent below full implementation of the existing Acid Rain program under Title IV of the Clean Air Act;
- Reduce mercury emissions to 5 tons or 90 percent below 1999 levels; and

- Reduce CO_2 emissions to 1990 levels.

In addition, the measure also includes a "birthday" provision that requires all fossil generation units to install best available controls within 5 years of passage of the bill or on the plant's 40th birthday, whichever date is later.

Senator Carper reintroduced his Clean Air Planning Act Bill of 2003 (S. 843) on April 28, 2003 , which is expected to impose the following emissions caps on the U.S. electric power sector:

- Reduce NO_x emissions to 1.87 million tons by 2009 and 1.7 million tons by 2013;
- Reduce SO_2 emissions to 4.5 million tons by 2009 and 3.5 million tons by 2013 and 2.25 million tons by 2016;
- Reduce mercury emissions to 24 tons by 2009 and between 10 ton by 2013; and
- Reduce CO_2 emissions to 2006 levels by 2009 and 2001 levels by 2013.

Both bills also contain unique emission allowance schemes that would further disadvantage coal-based generation. There are, or will likely be, other bills introduced into Congress, which could affect Cinergy's environmental requirements, for instance the McCain-Liebermann bill. Congress will debate the various multi-emissions reduction bills during 2004.

Cinergy will continue to study these developments and their potential impact on the company.

F. PLAN SELECTION

1. Economic Considerations

The sensitivity analyses showed that the East Bend/Miami Fort 6/Woodsdale Plan had the lowest PVRR across all sensitivities, ranging from a minimum of $353 million, or about 11%, to a maximum of over $1 billion, or about 36%.

2. Qualitative/Judgment Factors

The qualitative/judgment factors considered in this IRP analysis were risk-related. First, any time new capacity must be constructed (versus purchasing existing capacity), there is always the risk of construction or siting delay. Because the Plants are already built and operating, those risks are not present with the East Bend/Miami Fort 6/Woodsdale Plan.

In addition, there are pricing, non-performance, and deliverability risk considerations associated with purchasing large amounts of power from the wholesale market as in the Full-Requirements PPA Plan. Price volatility, which was quite extreme in the recent past, could well occur again in the Midwest region as proposed power plants are cancelled and existing stations are retired or mothballed. A purchased power contract expiring at a time when prices are high would subject customers to this volatility. In addition, heavy reliance on purchased power to meet utility load requirements puts the utility and its customers at the mercy of the balance sheet and financial health of the counter-parties who are the potential sellers of power. At any given moment in time, a potential seller of power may appear to be quite financially robust, but, as Enron and other market participants have shown, appearances can be very deceiving. Finally, recent Transmission Loading Relief (TLR) events in the Midwest suggest that there is increasing potential for transmission constraints, with the corresponding increasing potential for disruptions of purchased power imports. A relatively large number of TLR procedures have been invoked in ECAR over the last couple of years. The East Bend/Miami Fort 6/Woodsdale Plan minimizes or eliminates exposure to these risks.

Delivery of power from distant generating units, whether owned by the Company or not, can also present delivery risks. These risks are mitigated with a plan that calls for the acquisition of on-system generating capacity by ULH&P, as opposed to a plan that relies heavily on purchased power or ownership of generating units distant from the Cinergy transmission system.

Gas-fired units can also be at risk from high natural gas prices in the winter months due to the higher demand for natural gas during these periods. The propane back-up fuel supply at Woodsdale provides a price hedge for the East Bend/Miami Fort 6/Woodsdale Plan.

3. Description of Selected Plan

Based upon both the quantitative and qualitative results of the analyses, the East Bend/Miami Fort 6/Woodsdale Plan including the Back-up PSA was selected to be the 2003 IRP. It was robust and it had the lowest PVRR in the Base Case and across all sensitivities.

A summary of this plan is shown in Figure 8-12, assuming the transfer of the plants to ULH&P occurs on 7/1/04. The details of the 2003 IRP including yearly capacity, purchases, capacity additions, retirements/derates, cogeneration, load, DSM, interruptible load, firm sales and reserve margins for summer and winter are shown in Figures 8-13 and 8-14, respectively. Additional information concerning the future generating units in the plan is shown on Figure 8-15. The year-by-year Projected Generating Capability Changes to the ULH&P system (including existing unit changes) are shown in Figure 8-16. Figures 8-17 and 8-18 show the net dependable generating capacity for each year of the planning period by unit and for the system for summer and winter, respectively.

This IRP is the plan with the lowest PVRR, over $640 million lower than the next lowest PVRR plan without the Plants. It contains the DSM bundle and DLC/RTP/CallOption programs. The supply-side resources consist of East Bend, Miami Fort 6, and Woodsdale, along with a Back-up PSA for East Bend and Miami Fort 6. In addition, the plan contains small amounts of summer purchases (*i.e.*, 25-50 MW per year) in 2011-2012. Later on in the plan, there are PCFB units in 2013, 2018, and 2023, and Fuel Cell units in 2015 and 2017, which currently act as "placeholders" for whatever capacity resources are the most economical at the time decisions for adding capacity need to be made. Of course, as the time approaches when final commitments have to be made for capacity in the last ten years of the plan, the plan may be adjusted – to levelize the reserve margins a little, or to substitute purchases for some of the new plant construction beginning in 2013 in the plan, if the economics and reliability of purchases improve. This illustrates the inherent flexibility of this plan. As explained earlier, the planning process is a dynamic process; an IRP represents a snapshot in time of this process. However, based on the planning parameters available at this time, this plan meets ULH&P's future demand with an adequate and reliable supply of electricity at the lowest possible cost.

The relative value for the 2003 Present Value Total Cost obtained from the STRATEGIST® output for the 2003 IRP is $3,313,502,200. The effective after-tax discount rate used was 8.737%.

The modeling performed in the IRP process does not include items such as T&D rate base and expenses, corporate A&G, etc. which are not relevant to determine the least cost generation supply plan to serve ULH&P's customers (because these cost items are common to all plans). Therefore, an accurate projection of customer rates cannot be provided. In addition, ULH&P's rates will continue to be frozen at their current levels until 2007.

4. Projected Reliability

The 2003 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.

5. Joint Dispatch

East Bend, Miami Fort 6, and Woodsdale are currently dispatched economically along with CG&E's other units and with PSI's generating units under a Joint Generation Dispatch Agreement (JGDA) between CG&E and PSI. After ULH&P acquires these plants, they will continue to be dispatched economically with the other Cinergy system units under a Purchase, Sales and Operation Agreement between ULH&P and CG&E. This agreement will also allow energy transfers between ULH&P and CG&E at market price.

6. Environmental Effects

As mentioned previously, the plan includes the use of the Woodsdale Station, which consists of existing gas-fired CTs. These CTs and the Fuel Cells in the plan are relatively clean technologies. The emissions of the market purchases are unknown at this time because the exact source(s) of the power are unknown.

However, since these purchases represent peaking capacity, the power may well be generated from gas or oil. Therefore, the majority of air emissions in the plan will be produced by East Bend and Miami Fort 6 and future coal-fired units on ULH&P'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. Cinergy has some experience with selling fly ash as a component of building materials and will continue to explore the potential for this in the future.

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.

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 Incremental O&M costs of environmental controls at existing generating units have been accounted for in their O&M cost estimates.

7. Advantages of East Bend, Miami Fort 6, and Woodsdale in Plan

The plan chosen has a number of distinct advantages due to the inclusion of East Bend, Miami Fort 6, and Woodsdale as outlined below:

- Because these Plants already exist, there is no risk of construction or siting delay as would be the case with building new capacity.
- Excessive reliance on the wholesale market can pose pricing, scarcity, and non-performance (i.e., supplier credit) risks. The acquisition of these Plants

greatly reduces ULH&P's reliance on the wholesale market for its reliability needs.

- Because these Plants are within the Cinergy control area and connected to the Cinergy transmission system, ULH&P can avoid the risks associated with trying to import the large amounts of purchases that would be required without these plants. In addition, ULH&P can avoid the deliverability risks associated with the acquisition of generation distant from the Cinergy transmission system.
- The inclusion of these plants in ULH&P's portfolio will provide stability to Kentucky's electric supply which has been a key factor historically in economic development in the state.

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 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 ULH&P be factored into the decisions concerning the implementation of the 2003 IRP.

1. Environmental Regulatory Climate

The regulatory climate is becoming more burdensome for the public utility industry. As discussed in Section E, 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, New Source Review, and additional new facility siting requirements, to name a few. The outlook, from the regulated utility's perspective, contains a great deal of uncertainty with respect to the regulatory climate.

2. Volatility in the Wholesale Market

The collapse of Enron has caused credit concerns for many of the merchant plant developers, which, coupled with a weaker economy, has caused many of these developers to either cancel or delay the installation of announced plants in the region. This has the potential to set up a classic "boom/bust" cycle (possibly even more extreme than would otherwise occur) which would increase volatility and cause a return to price spikes if supply and demand are out of balance.

3. Transmission Constraints

The level of new transmission infrastructure additions has not kept pace with the increasing use of the transmission system to transport power over larger distances than it was originally designed to handle. The number of TLRs has increased each year. Although the creation of RTOs may enhance coordination and reliability, utilities that need to import a large amount of power to serve their customers needs may have cause for concern in this area.

Although ULH&P will continue to monitor these developments in the future, the chosen plan should help alleviate some of the potential uncertainties since for the first time, ULH&P will own capacity, which will reduce its reliance on the purchased power market. In addition, this capacity is located within Cinergy's control area, so deliverability risk is reduced.

H. PLAN IMPLEMENTATION

1. Supply-Side Resources

On July 21, 2003, ULH&P filed a petition with the Kentucky Public Service Commission to obtain Certificates of Public Convenience and Necessity to acquire the East Bend, Miami Fort 6, and Woodsdale units (Case No. 2003-00252). ULH&P also requested approval of the Back-up PSA for East Bend and Miami Fort 6. On December 5, 2003, the Kentucky Public Service Commission approved ULH&P's acquisition of the Plants and approved the Back-up PSA. Regulatory approvals are also required from the Federal Energy Regulatory Commission (FERC) and the Securities Exchange Commission (SEC).

After 2007, the purchases, fluidized bed units, and Fuel Cells in the plan represent, to a large extent, "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. Environmental Compliance Resources

Cinergy's current strategy, as described in previous IRPs, includes a combination of switching to lower-sulfur coals and using an emission allowance banking strategy. 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 potential fuel switches has not been finalized at this time.

The NO_x compliance strategy was also described in Chapter 6. Cinergy has begun to implement its strategy (specifically by installing and operating an SCR on East Bend, as well as other Cinergy system units) in order to be ready to meet the compliance deadline. However, Cinergy continues to study the compliance alternatives and the viability of allowance purchases from the market to meet the requirements in the most cost-effective manner. 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.

3. Demand-Side Resources

The KY PSC approved ULH&P's current DSM programs through December 31, 2005, in an order dated December 17, 2002. Under this Agreement, ULH&P is implementing several DSM programs and RTP and the PowerShare® load interruption program as discussed in detail in Chapter 4 of this IRP and in the Short-Term Implementation Plan. In addition, on November 20, 2003, ULH&P obtained approval to amend its DSM program to add a Direct Load Control program. The incremental impacts going forward of the Interruptible customer contract and the DSM, DLC, RTP, and CallOption programs are incorporated into the resource plan for ULH&P.

4. Consistency with Planning Objectives and Goals

The 2003 IRP, with its proposed implementation, is consistent with the overall planning objectives and goals discussed in Chapter 2. The plan that was chosen was the least cost (PVRR), provides reliable service to ULH&P's customers, is robust, and minimizes risks to customers. In addition, monitoring of the SO_2 and NO_x emission allowance markets provide flexibility to Cinergy's compliance strategy.

5. Financial Impact

ULH&P 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 2003 IRP on the financial status of ULH&P is dependent on economic conditions, legislative and regulatory actions, and on the frequency and timing of future rate relief.

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Figure 8-1

ULH&P
SUPPLY VS. DEMAND BALANCE
No Uncommitted Supply-Side Additions
(Summer Capacity and Loads)

YEAR	INITIAL CAPACITY	SHORT TERM PURCH.	INCR. CAPACITY ADDITIONS	INCR. CAPACITY RETIRE./ DERATES	COGEN. CAPACITY	TOTAL CAPACITY	PEAK LOAD	INCR. DSM[a]	DLC/RTP/ CALLOPTION	INDUSTRIAL INTER./AS AVAIL LOAD	FIRM SALES	NET LOAD	RES. MAR. (%)	MW TO ADD FOR 15% RM
2003	0	843	0	0	0	843	848	-0.4	-2	-3	0	843	0.0	NA
2004	0	857	0	0	0	857	864	-0.4	-4	-3	0	857	0.0	NA
2005	0	869	0	0	0	869	879	-0.4	-7	-3	0	869	0.0	NA
2006	0	877	0	0	0	877	890	-0.4	-10	-3	0	877	0.0	NA
2007	0	0	0	0	0	0	905	-0.4	-13	-3	0	889	-100.0	1022
2008	0	0	0	0	0	0	917	-0.4	-15	-3	0	899	-100.0	1034
2009	0	0	0	0	0	0	931	-0.4	-15	-3	0	913	-100.0	1050
2010	0	0	0	0	0	0	946	-0.4	-15	-3	0	928	-100.0	1067
2011	0	0	0	0	0	0	960	-0.4	-15	-3	0	942	-100.0	1083
2012	0	0	0	0	0	0	974	-0.4	-15	-3	0	956	-100.0	1100
2013	0	0	0	0	0	0	989	-0.4	-15	-3	0	971	-100.0	1117
2014	0	0	0	0	0	0	1003	-0.4	-15	-3	0	985	-100.0	1133
2015	0	0	0	0	0	0	1016	-0.4	-15	-3	0	998	-100.0	1148
2016	0	0	0	0	0	0	1030	-0.4	-15	-3	0	1012	-100.0	1164
2017	0	0	0	0	0	0	1047	-0.4	-15	-3	0	1029	-100.0	1183
2018	0	0	0	0	0	0	1060	-0.4	-15	-3	0	1042	-100.0	1198
2019	0	0	0	0	0	0	1075	-0.4	-15	-3	0	1057	-100.0	1216
2020	0	0	0	0	0	0	1089	-0.4	-15	-3	0	1071	-100.0	1232
2021	0	0	0	0	0	0	1102	-0.4	-15	-3	0	1084	-100.0	1247
2022	0	0	0	0	0	0	1116	-0.4	-15	-3	0	1098	-100.0	1263
2023	0	0	0	0	0	0	1131	-0.4	-15	-3	0	1113	-100.0	1280

[a] Not included in load forecast

Figure 8-2

Significantly Different Plans- Base Case

Year	All New Generic Units #1 Plan Unit Additions/Purchases	1 Less Coal Unit Plan Unit Additions/Purchases	1 Additional Coal Unit Plan Unit Additions/Purchases	East Bend/MF6/Woodsdale Plan Unit Additions/Purchases	Full Requirements PPA Plan Unit Additions/Purchases
2003					
2004					
2005					
2006					
2007	8-70 MW Coal Units 3-70 MW CC Units 4-70 MW CT Units	7-70 MW Coal Units 5-70 MW CC Units 2-70 MW CT Units 50 MW 5-Year Summer Purchase	9-70 MW Coal Units 1-70 MW CC Units 5-70 MW CT Units	East Bend 2 w/ Back-up PSA (414 MW) Miami Fort 6 w/ Back-up PSA (163 MW) Woodsdale 1-6 (500 MW)	Full Req. Market-Priced PPA (throughout study period)
2008		25 MW Summer Purchase			
2009	25 MW Summer Purchase	25 MW Summer Purchase	25 MW Summer Purchase		
2010	25 MW Summer Purchase	50 MW Summer Purchase	25 MW Summer Purchase		
2011	50 MW Summer Purchase	1-70 MW Coal Unit	50 MW Summer Purchase	25 MW Summer Purchase	
2012	50 MW Summer Purchase	50 MW Summer Purchase	50 MW Summer Purchase	50 MW Summer Purchase	
2013	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit	
2014	25 MW Summer Purchase	25 MW Summer Purchase	25 MW Summer Purchase		
2015	1-70 MW PCFB Unit	50 MW Summer Purchase	1-70 MW PCFB Unit	1-25 MW Fuel Cell	
2016		1-70 MW PCFB Unit			
2017				1-25 MW Fuel Cell	
2018	25 MW Summer Purchase	25 MW Summer Purchase	25 MW Summer Purchase	1-70 MW PCFB Unit	
2019	1-70 MW PCFB Unit	50 MW Summer Purchase	50 MW Summer Purchase		
2020		50 MW Summer Purchase	50 MW Summer Purchase		
2021		1-70 MW PCFB Unit	1-70 MW PCFB Unit		
2022	25 MW Summer Purchase	25 MW Summer Purchase	25 MW Summer Purchase		
2023	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit	

Figure 8-3

Reserve Margin Criterion Calculation for East Bend/Miami Fort 6/Woodsdale Plan

YEAR	PEAK LOAD	INCR. DSM[a]	DLC/RTP/ CALLOPTION	INDUSTRIAL INTERRUPTIBLE LOAD	FIRM SALES	NET LOAD	RESERVE LEVEL BY COMPONENT OPERATING @ 4%	WEATHER @ 3%	OUTAGE @ > 83.4 MW OR 8%	TOTAL	RM CRITERION (%)
2003	848	-0.4	-2	-3	0	843	NA	NA	NA	NA	NA
2004	864	-0.4	-4	-3	0	857	NA	NA	NA	NA	NA
2005	879	-0.4	-7	-3	0	869	NA	NA	NA	NA	NA
2006	890	-0.4	-10	-3	0	877	NA	NA	NA	NA	NA
2007	905	-0.4	-13	-3	0	889	NA	NA	NA	NA	NA
2008	917	-0.4	-15	-3	0	899	36	27	83	146	16.4
2009	931	-0.4	-15	-3	0	913	36	27	83	146	16.3
2010	946	-0.4	-15	-3	0	928	37	27	83	147	16.1
2011	960	-0.4	-15	-3	0	942	37	28	83	148	16.0
2012	974	-0.4	-15	-3	0	956	38	28	83	149	15.9
2013	989	-0.4	-15	-3	0	971	38	29	83	150	15.7
2014	1003	-0.4	-15	-3	0	985	39	29	83	151	15.6
2015	1016	-0.4	-15	-3	0	998	39	30	83	152	15.5
2016	1030	-0.4	-15	-3	0	1012	40	30	83	153	15.4
2017	1047	-0.4	-15	-3	0	1029	40	30	83	154	15.2
2018	1060	-0.4	-15	-3	0	1042	41	31	83	155	15.1
2019	1075	-0.4	-15	-3	0	1057	42	31	83	156	15.0
2020	1089	-0.4	-15	-3	0	1071	42	32	85	159	15.0
2021	1102	-0.4	-15	-3	0	1084	43	32	86	161	15.0
2022	1116	-0.4	-15	-3	0	1098	43	33	87	163	15.0
2023	1131	-0.4	-15	-3	0	1113	44	33	88	165	15.0

[a] Not included in load forecast

Figure 8-4

Significantly Different Plans- Higher Gas Price Sensitivity

	All New Generic Units #1 Plan	1 Less Coal Unit Plan	1 Additional Coal Unit Plan	East Bend/MF6/Woodsdale Plan	Full Requirements PPA Plan
Year	Unit Additions/Purchases	Unit Additions/Purchases	Unit Additions/Purchases	Unit Additions/Purchases	Unit Additions/Purchases
2003					
2004					
2005					
2006					
2007	8-70 MW Coal Units 3-70 MW CC Units 4-70 MW CT Units	7-70 MW Coal Units 5-70 MW CC Units 2-70 MW CT Units 50 MW 5-Year Summer Purchase	9-70 MW Coal Units 1-70 MW CC Units 5-70 MW CT Units	East Bend 2 w/ Back-up PSA (414 MW) Miami Fort 6 w/ Back-up PSA (163 MW) Woodsdale 1-6 (500 MW)	Full Req. Market-Priced PPA (throughout study period)
2008		25 MW Summer Purchase			
2009	25 MW Summer Purchase	25 MW Summer Purchase	25 MW Summer Purchase		
2010	25 MW Summer Purchase	1-70 MW Coal Unit	25 MW Summer Purchase		
2011	50 MW Summer Purchase		50 MW Summer Purchase	25 MW Summer Purchase	
2012	50 MW Summer Purchase	50 MW Summer Purchase	50 MW Summer Purchase	50 MW Summer Purchase	
2013	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit	
2014	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit		
2015				1-25 MW Fuel Cell	
2016					
2017				1-25 MW Fuel Cell	
2018	1-70 MW PCFB Unit	25 MW Summer Purchase	25 MW Summer Purchase	1-70 MW PCFB Unit	
2019		1-70 MW PCFB Unit	1-70 MW PCFB Unit		
2020					
2021					
2022	25 MW Summer Purchase	25 MW Summer Purchase	25 MW Summer Purchase		
2023	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit	

Figure 8-5

Significantly Different Plans- Lower Gas Price Sensitivity

	All New Generic Units #1 Plan	1 Less Coal Unit Plan	1 Additional Coal Unit Plan	East Bend/MF6/Woodsdale Plan	Full Requirements PPA Plan
Year	Unit Additions/Purchases	Unit Additions/Purchases	Unit Additions/Purchases	Unit Additions/Purchases	Unit Additions/Purchases
2003					
2004					
2005					
2006					
2007	8-70 MW Coal Units 3-70 MW CC Units 4-70 MW CT Units	7-70 MW Coal Units 5-70 MW CC Units 2-70 MW CT Units 50 MW 5-Year Summer Purchase	9-70 MW Coal Units 1-70 MW CC Units 5-70 MW CT Units	East Bend 2 w/ Back-up PSA (414 MW) Miami Fort 6 w/ Back-up PSA (163 MW) Woodsdale 1-6 (500 MW)	Full Req. Market-Priced PPA (throughout study period)
2008		25 MW Summer Purchase			
2009	25 MW Summer Purchase	25 MW Summer Purchase	25 MW Summer Purchase		
2010	25 MW Summer Purchase	1-70 MW CT Unit	25 MW Summer Purchase		
2011	1-70 MW CT Unit		1-70 MW CT Unit	1-70 MW CC Unit	
2012		1-70 MW CT Unit			
2013					
2014	1-25 MW Fuel Cell	25 MW Summer Purchase	1-25 MW Fuel Cell		
2015	25 MW Summer Purchase	1-70 MW CT Unit	1-25 MW Fuel Cell	1-25 MW Fuel Cell	
2016	25 MW Summer Purchase				
2017	1-70 MW CT Unit		1-25 MW Fuel Cell	1-25 MW Fuel Cell	
2018		1-25 MW Fuel Cell	1-25 MW Fuel Cell	1-25 MW Fuel Cell	
2019	25 MW Summer Purchase	25 MW Summer Purchase			
2020	25 MW Summer Purchase	25 MW Summer Purchase	25 MW Summer Purchase	1-25 MW Fuel Cell	
2021	1-70 MW CT Unit	1-70 MW CT Unit	50 MW Summer Purchase		
2022			1-70 MW CT Unit	1-25 MW Fuel Cell	
2023				1-25 MW Fuel Cell	

Figure 8-6

Significantly Different Plans- Capacity Oversupply Sensitivity

	All New Generic Units #1 Plan	1 Less Coal Unit Plan	1 Additional Coal Unit Plan	East Bend/MF6/Woodsdale Plan	Full Requirements PPA Plan
Year	Unit Additions/Purchases	Unit Additions/Purchases	Unit Additions/Purchases	Unit Additions/Purchases	Unit Additions/Purchases
2003					
2004					
2005					
2006					
2007	8-70 MW Coal Units 3-70 MW CC Units 4-70 MW CT Units	7-70 MW Coal Units 5-70 MW CC Units 2-70 MW CT Units 50 MW 5-Year Summer Purchase	9-70 MW Coal Units 1-70 MW CC Units 5-70 MW CT Units	East Bend 2 w/ Back-up PSA (414 MW) Miami Fort 6 w/ Back-up PSA (163 MW) Woodsdale 1-6 (500 MW)	Full Req. Market-Priced PPA (throughout study period)
2008		25 MW Summer Purchase			
2009	25 MW Summer Purchase	25 MW Summer Purchase	25 MW Summer Purchase		
2010	25 MW Summer Purchase	50 MW Summer Purchase	25 MW Summer Purchase		
2011	50 MW Summer Purchase	1-70 MW Coal Unit	50 MW Summer Purchase	25 MW Summer Purchase	
2012	50 MW Summer Purchase	50 MW Summer Purchase	50 MW Summer Purchase	50 MW Summer Purchase	
2013	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit	
2014	25 MW Summer Purchase	25 MW Summer Purchase	25 MW Summer Purchase		
2015	1-70 MW PCFB Unit	50 MW Summer Purchase	1-70 MW PCFB Unit	1-25 MW Fuel Cell	
2016		1-70 MW PCFB Unit			
2017				1-25 MW Fuel Cell	
2018	25 MW Summer Purchase	25 MW Summer Purchase	25 MW Summer Purchase	1-70 MW PCFB Unit	
2019	1-70 MW PCFB Unit	50 MW Summer Purchase	50 MW Summer Purchase		
2020		50 MW Summer Purchase	50 MW Summer Purchase		
2021		1-70 MW PCFB Unit	1-70 MW PCFB Unit		
2022	25 MW Summer Purchase	25 MW Summer Purchase	25 MW Summer Purchase		
2023	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit	

Figure 8-7

Significantly Different Plans- Higher Load Forecast Sensitivity

	All New Generic Units #1 Plan	1 Less Coal Unit Plan	1 Additional Coal Unit Plan	East Bend/MF6/Woodsdale Plan	Full Requirements PPA Plan
Year	Unit Additions/Purchases	Unit Additions/Purchases	Unit Additions/Purchases	Unit Additions/Purchases	Unit Additions/Purchases
2003					
2004					
2005					
2006					
2007	9-70 MW Coal Units 3-70 MW CC Units 4-70 MW CT Units	8-70 MW Coal Units 5-70 MW CC Units 2-70 MW CT Units 50 MW 5-Year Summer Purchase	9-70 MW Coal Units 2-70 MW CC Units 5-70 MW CT Units	East Bend 2 w/ Back-up PSA (414 MW) Miami Fort 6 w/ Back-up PSA (163 MW) Woodsdale 1-6 (500 MW) 1-70 MW CC Unit	Full Req. Market-Priced PPA (throughout study period)
2008		25 MW Summer Purchase			
2009		25 MW Summer Purchase			
2010	25 MW Summer Purchase	50 MW Summer Purchase	25 MW Summer Purchase		
2011	50 MW Summer Purchase	1-70 MW Coal Unit	50 MW Summer Purchase	25 MW Summer Purchase	
2012	50 MW Summer Purchase	50 MW Summer Purchase	50 MW Summer Purchase	50 MW Summer Purchase	
2013	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit	
2014	25 MW Summer Purchase	25 MW Summer Purchase	25 MW Summer Purchase		
2015	50 MW Summer Purchase	50 MW Summer Purchase	1-70 MW PCFB Unit	1-70 MW PCFB Unit	
2016	50 MW Summer Purchase	50 MW Summer Purchase			
2017	1-70 MW PCFB Unit	1-70 MW PCFB Unit			
2018	25 MW Summer Purchase	25 MW Summer Purchase	25 MW Summer Purchase		
2019	50 MW Summer Purchase	50 MW Summer Purchase	50 MW Summer Purchase	1-70 MW PCFB Unit	
2020	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit		
2021					
2022	25 MW Summer Purchase	25 MW Summer Purchase	25 MW Summer Purchase		
2023	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit	

Figure 8-8

Significantly Different Plans- Lower Load Forecast Sensitivity

	All New Generic Units #1 Plan	1 Less Coal Unit Plan	1 Additional Coal Unit Plan	East Bend/MF6/Woodsdale Plan	Full Requirements PPA Plan
Year	Unit Additions/Purchases	Unit Additions/Purchases	Unit Additions/Purchases	Unit Additions/Purchases	Unit Additions/Purchases
2003					
2004					
2005					
2006					
2007	8-70 MW Coal Units 3-70 MW CC Units 4-70 MW CT Units	7-70 MW Coal Units 5-70 MW CC Units 2-70 MW CT Units 50 MW 5-Year Summer Purchase	9-70 MW Coal Units 1-70 MW CC Units 5-70 MW CT Units	East Bend 2 w/ Back-up PSA (414 MW) Miami Fort 6 w/ Back-up PSA (163 MW) Woodsdale 1-6 (500 MW)	Full Req. Market-Priced PPA (throughout study period)
2008					
2009					
2010					
2011					
2012		50 MW Summer Purchase			
2013		1-70 MW PCFB Unit			
2014	1-70 MW PCFB Unit	25 MW Summer Purchase	25 MW Summer Purchase		
2015		25 MW Summer Purchase	25 MW Summer Purchase	1-25 MW Fuel Cell	
2016		1-70 MW PCFB Unit	1-70 MW PCFB Unit		
2017				1-25 MW Fuel Cell	
2018	25 MW Summer Purchase	25 MW Summer Purchase	25 MW Summer Purchase		
2019	25 MW Summer Purchase	25 MW Summer Purchase	25 MW Summer Purchase	1-70 MW PCFB Unit	
2020	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit		
2021					
2022					
2023	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit	1-70 MW PCFB Unit	

Figure 8-9

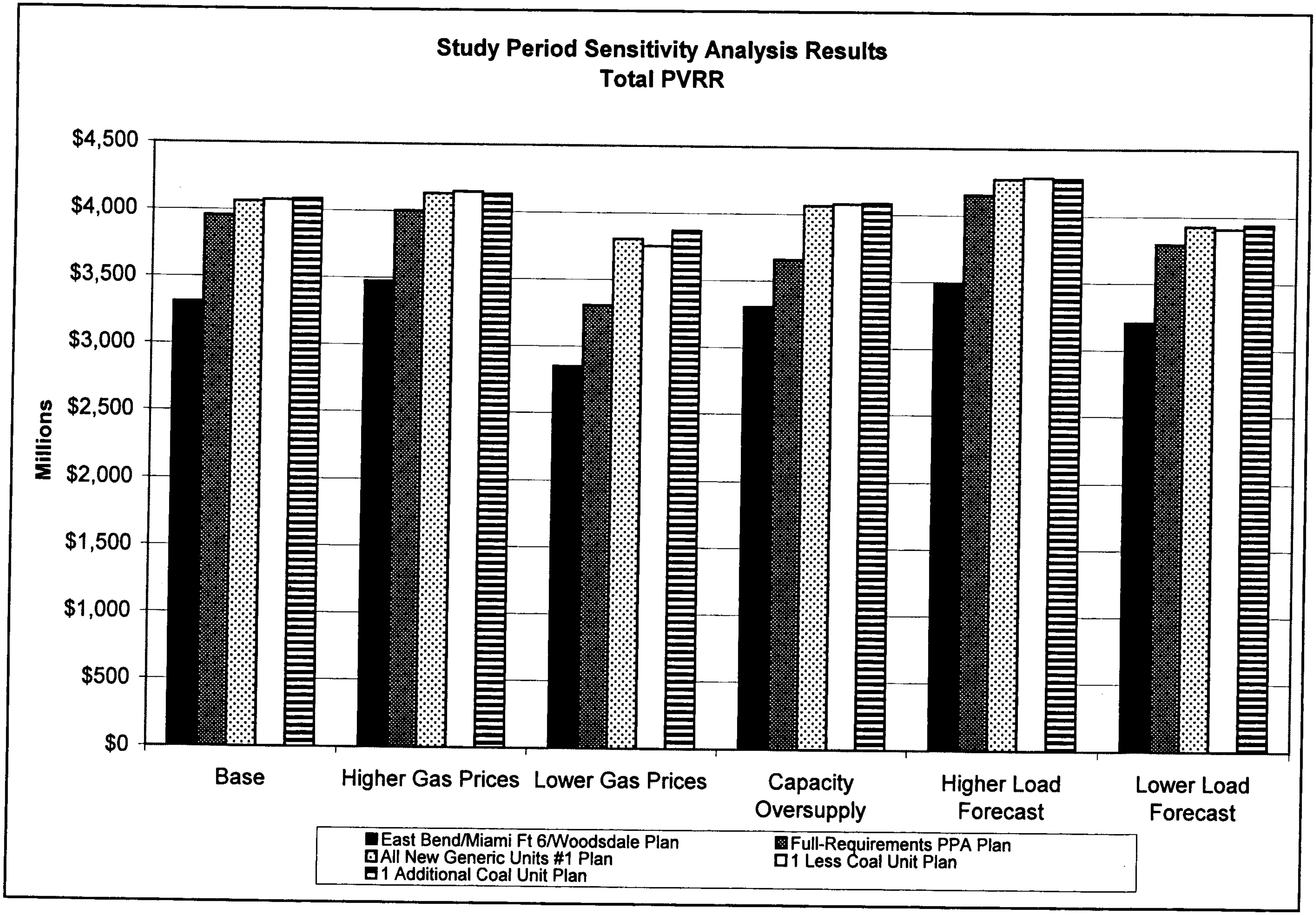
Study Period Sensitivity Analysis Results
Total PVRR
Millions
$4,500
$4,000
$3,500
$3,000
$2,500
$2,000
$1,500
$1,000
$500
$0
Base
Higher Gas Prices
Lower Gas Prices
Capacity Oversupply
Higher Load Forecast
Lower Load Forecast
East Bend/Miami Ft 6/Woodsdale Plan
Full-Requirements PPA Plan
All New Generic Units #1 Plan
1 Less Coal Unit Plan
1 Additional Coal Unit Plan

Figure 8-10

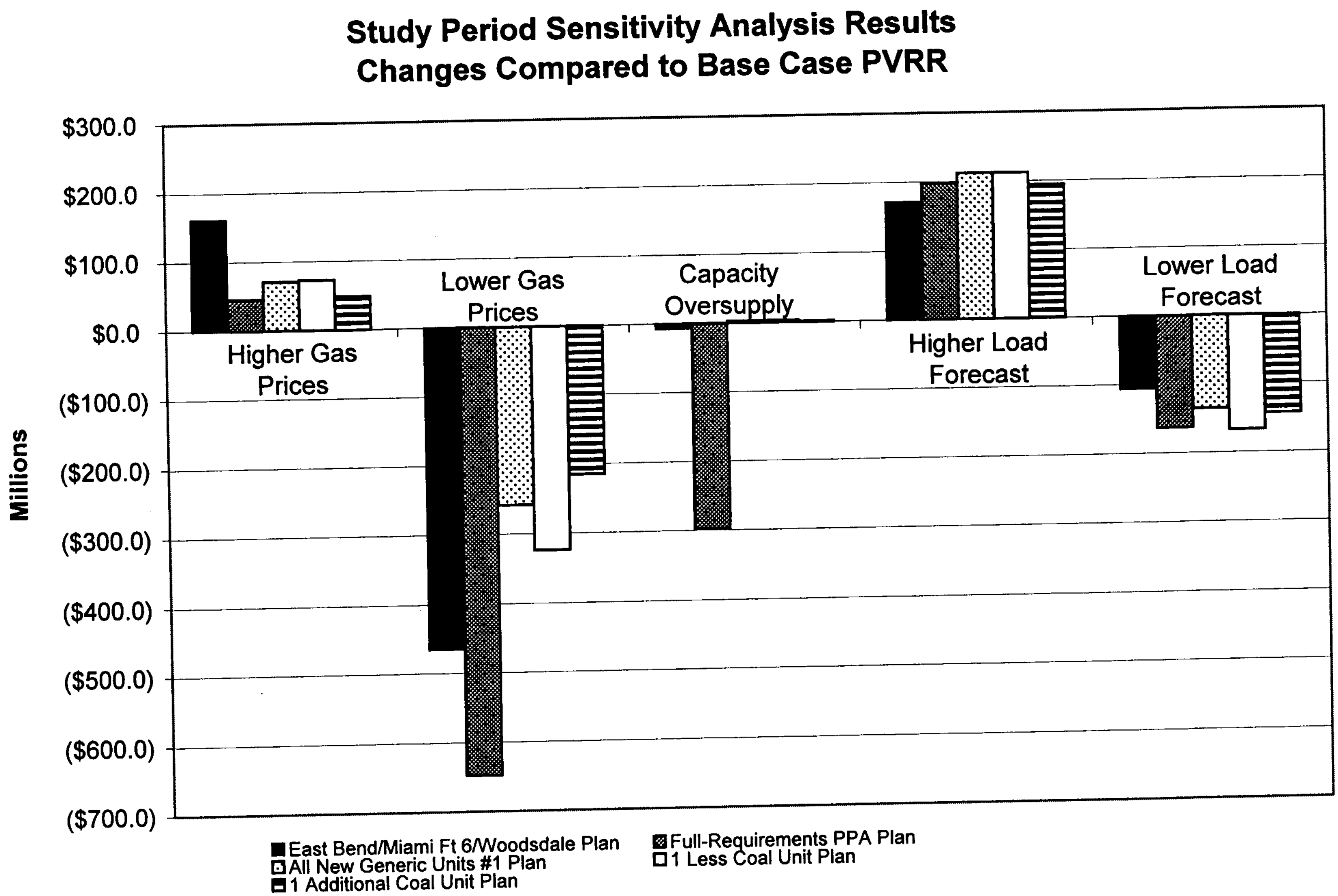
Study Period Sensitivity Analysis Results
Changes Compared to Base Case PVRR
Millions
$300.0
$200.0
$100.0
$0.0
($100.0)
($200.0)
($300.0)
($400.0)
($500.0)
($600.0)
($700.0)
Higher Gas Prices
Lower Gas Prices
Capacity Oversupply
Higher Load Forecast
Lower Load Forecast
East Bend/Miami Ft 6/Woodsdale Plan
All New Generic Units #1 Plan
1 Additional Coal Unit Plan
Full-Requirements PPA Plan
1 Less Coal Unit Plan

Figure 8-11

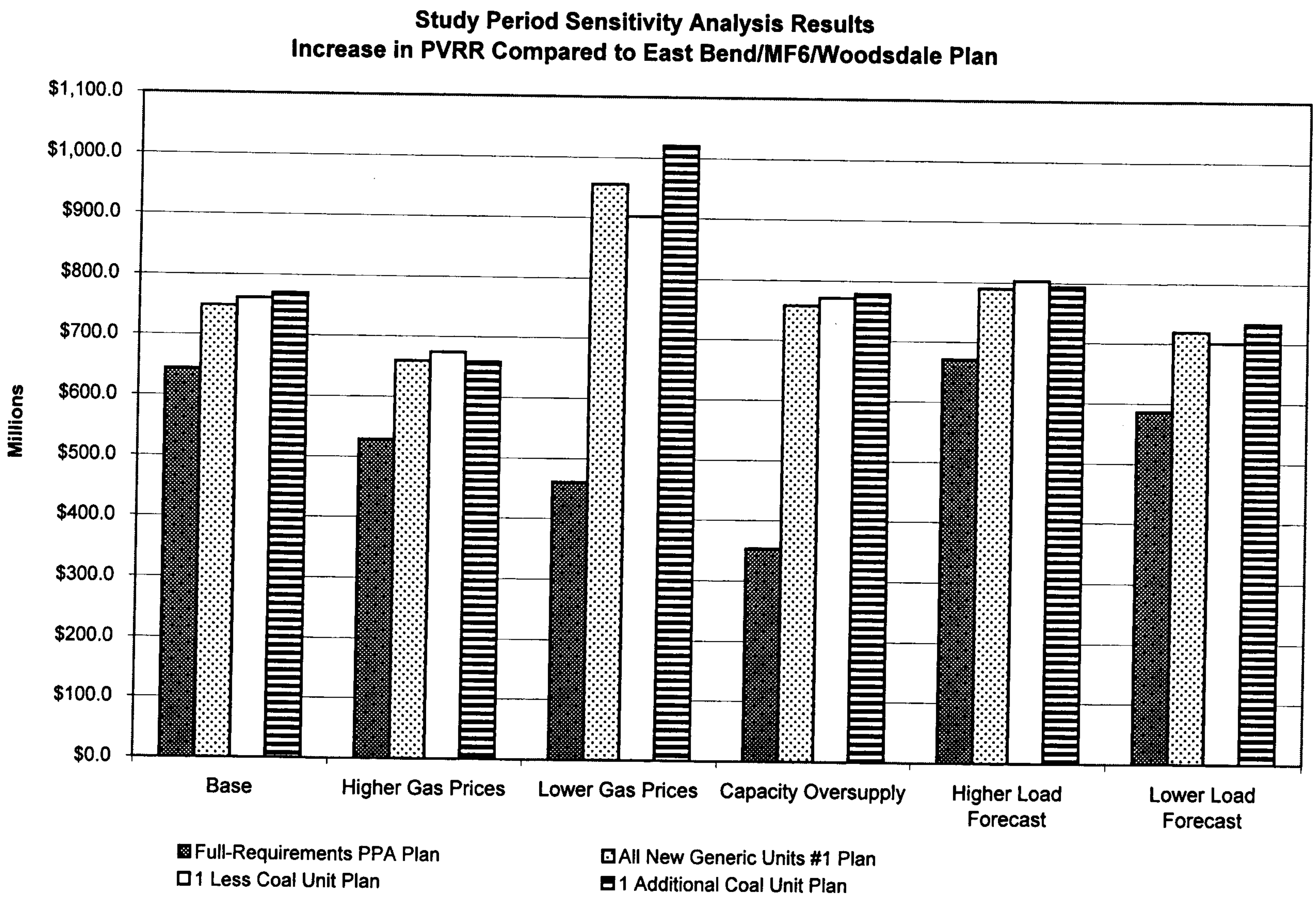
Study Period Sensitivity Analysis Results
Increase in PVRR Compared to East Bend/MF6/Woodsdale Plan
Millions
$1,100.0
$1,000.0
$900.0
$800.0
$700.0
$600.0
$500.0
$400.0
$300.0
$200.0
$100.0
$0.0
Base
Higher Gas Prices
Lower Gas Prices
Capacity Oversupply
Higher Load Forecast
Lower Load Forecast
Full-Requirements PPA Plan
1 Less Coal Unit Plan
All New Generic Units #1 Plan
1 Additional Coal Unit Plan

Figure 8-12

ULH&P INTEGRATED RESOURCE PLAN
2003-2023

Year	Demand-Side[1]	Purchases/Unit Additions[2]
2003	DSM Bundle Interruptible Contracts RTP/DLC/CallOption Programs	
2004		East Bend 2 with Back-up PSA Miami Fort 6 with Back-up PSA Woodsdale 1-6
2005		
2006		
2007		
2008		
2009		
2010		
2011		25 MW Summer Purchase
2012		50 MW Summer Purchase
2013		1-70 MW PCFB Unit
2014		
2015		1-25 MW Fuel Cell
2016		
2017		1-25 MW Fuel Cell
2018		1-70 MW PCFB Unit
2019		
2020		
2021		
2022		
2023		1-70 MW PCFB Unit

[1] The Demand-side resources are assumed to continue throughout the planning period (2003-2023)
[2] Capacity shown denotes summer ratings

Figure 8-13

ULH&P
INTEGRATED RESOURCE PLAN
East Bend/Miami Fort 6/Woodsdale Plan
(Summer Capacity and Loads)

YEAR	INITIAL CAPACITY	SHORT TERM PURCH.	INCR. CAPACITY ADDITIONS	INCR. CAPACITY RETIRE./ DERATES	COGEN. CAPACITY	TOTAL CAPACITY	PEAK LOAD	INCR. DSM[a]	DLC/RTP/ CALLOPTION	INDUSTRIAL INTERRUPTIBLE LOAD	FIRM SALES	NET LOAD	RES. MAR. (%)	RM CRITERION[b] (%)	MW TO ADD TO MEET RM
2003	0	843	0	0	0	843	848	-0.4	-2	-3	0	843	NA	NA	NA
2004	0	0	1077	0	0	1077	864	-0.4	-4	-3	0	857	25.7	16.7	-77
2005	1077	0	0	0	0	1077	879	-0.4	-7	-3	0	869	24.0	16.6	-64
2006	1077	0	0	0	0	1077	890	-0.4	-10	-3	0	877	22.9	16.5	-56
2007	1077	0	0	0	0	1077	905	-0.4	-13	-3	0	889	21.2	16.4	-43
2008	1077	0	0	0	0	1077	917	-0.4	-15	-3	0	899	19.8	16.3	-32
2009	1077	0	0	0	0	1077	931	-0.4	-15	-3	0	913	18.0	16.1	-17
2010	1077	0	0	0	0	1077	946	-0.4	-15	-3	0	928	16.1	16.0	-1
2011	1077	25	0	0	0	1102	960	-0.4	-15	-3	0	942	17.0	15.9	-11
2012	1077	50	0	0	0	1127	974	-0.4	-15	-3	0	956	17.9	15.7	-21
2013	1077	0	70	0	0	1147	989	-0.4	-15	-3	0	971	18.2	15.6	-25
2014	1147	0	0	0	0	1147	1003	-0.4	-15	-3	0	985	16.5	15.5	-10
2015	1147	0	25	0	0	1172	1016	-0.4	-15	-3	0	998	17.5	15.4	-21
2016	1172	0	0	0	0	1172	1030	-0.4	-15	-3	0	1012	15.8	15.2	-6
2017	1172	0	25	0	0	1197	1047	-0.4	-15	-3	0	1029	16.4	15.1	-13
2018	1197	0	70	0	0	1267	1060	-0.4	-15	-3	0	1042	21.6	15.0	-69
2019	1267	0	0	0	0	1267	1075	-0.4	-15	-3	0	1057	19.9	15.0	-52
2020	1267	0	0	0	0	1267	1089	-0.4	-15	-3	0	1071	18.3	15.0	-36
2021	1267	0	0	0	0	1267	1102	-0.4	-15	-3	0	1084	16.9	15.0	-21
2022	1267	0	0	0	0	1267	1116	-0.4	-15	-3	0	1098	15.4	15.0	-5
2023	1267	0	70	0	0	1337	1131	-0.4	-15	-3	0	1113	20.2	15.0	-57

[a] Not included in load forecast

[b] East Bend and Miami Fort 6 have a back-up contract, so Reserve Margin Criterion is the greater of 15% or 7% plus reserving for the loss of the largest unit

Figure 8-14

ULH&P
INTEGRATED RESOURCE PLAN
East Bend/Miami Fort 6/Woodsdale Plan
(Winter Capacity and Loads)

YEAR	INITIAL CAPACITY	SHORT TERM PURCH.	INCR. CAPACITY ADDITIONS	INCR. CAPACITY RETIRE./ DERATES	COGEN. CAPACITY	TOTAL CAPACITY	PEAK LOAD	INCR. DSM[a]	DLC/RTP/ CALLOPTION	INDUSTRIAL INTERRUPTIBLE LOAD	FIRM SALES	NET LOAD	RES. MAR. (%)	RM CRITERION[b] (%)	MW TO ADD TO MEET RM
2003	0	697	0	0	0	697	700	-0.4		-3	0	697	NA	NA	NA
2004	0	0	1141	0	0	1141	712	-0.4		-3	0	709	61.0	20.3	-289
2005	1141	0	0	0	0	1141	724	-0.4		-3	0	721	58.3	20.0	-276
2006	1141	0	0	0	0	1141	737	-0.4		-3	0	734	55.5	19.8	-262
2007	1141	0	0	0	0	1141	750	-0.4		-3	0	747	52.8	19.6	-248
2008	1141	0	0	0	0	1141	762	-0.4		-3	0	759	50.4	19.4	-235
2009	1141	0	0	0	0	1141	773	-0.4		-3	0	770	48.3	19.2	-224
2010	1141	0	0	0	0	1141	784	-0.4		-3	0	781	46.2	19.0	-212
2011	1141	0	0	0	0	1141	796	-0.4		-3	0	793	44.0	18.9	-199
2012	1141	0	0	0	0	1141	809	-0.4		-3	0	806	41.6	18.7	-185
2013	1141	0	70	0	0	1211	819	-0.4		-3	0	816	48.5	18.5	-244
2014	1211	0	0	0	0	1211	830	-0.4		-3	0	827	46.5	18.4	-233
2015	1211	0	25	0	0	1236	841	-0.4		-3	0	838	47.6	18.2	-246
2016	1236	0	0	0	0	1236	851	-0.4		-3	0	848	45.8	18.1	-235
2017	1236	0	25	0	0	1261	864	-0.4		-3	0	861	46.5	17.9	-246
2018	1261	0	70	0	0	1331	874	-0.4		-3	0	871	52.9	17.8	-305
2019	1331	0	0	0	0	1331	886	-0.4		-3	0	883	50.8	17.7	-293
2020	1331	0	0	0	0	1331	897	-0.4		-3	0	894	48.9	17.5	-281
2021	1331	0	0	0	0	1331	908	-0.4		-3	0	905	47.1	17.4	-269
2022	1331	0	0	0	0	1331	919	-0.4		-3	0	916	45.4	17.3	-257
2023	1331	0	70	0	0	1401	930	-0.4		-3	0	927	51.2	17.1	-316

[a] Not included in load forecast
[b] East Bend and Miami Fort 6 have a back-up contract, so Reserve Margin Criterion is the greater of 15% or 7% plus reserving for the loss of the largest unit

Figure 8-15

UNION LIGHT HEAT & POWER

Future Electric Generating Facilities

Plant Name	Unit No.	Location	Status	Operation Date	Facility Type	Net Capability (MW)		Fuel Type	Fuel Storage Capacity	Scheduled Upgrades, Derates, Retirements
						Winter	Summer			
PCFB	1	Unknown	Planned	2013	Steam	70	70	Coal	Unknown	None
	2	Unknown	Planned	2018	Steam	70	70	Coal	Unknown	None
	3	Unknown	Planned	2023	Steam	70	70	Coal	Unknown	None
Fuel Cell	1	Unknown	Planned	2015	NA	25	25	Gas	Unknown	None
	2	Unknown	Planned	2017	NA	25	25	Gas	Unknown	None

Figure 8-16

UNION LIGHT HEAT & POWER

PROJECTED GENERATING CAPABILITY CHANGES [In MegaWatts]

				CAPABILITY CHANGES		SEASONAL TOTAL	
YEAR	UNIT DESIGNATION	NOTES	COMMENT	SUMMER	WINTER	SUMMER	WINTER
2013	PCFB - Unit 1	[1]		70.00	70.00	70.00	70.00
2015	Fuel Cell -Unit 1	[2]		25.00	25.00	25.00	25.00
2017	Fuel Cell -Unit 2	[2]		25.00	25.00	25.00	25.00
2018	PCFB - Unit 2	[1]		70.00	70.00	70.00	70.00
2023	PCFB - Unit 3	[1]		70.00	70.00	70.00	70.00

[1] The PCFB (pressurized circulating fluidized bed) coal units are generic. The parameters modeled are representative values. The exact unit characteristics will depend on the site and equipment vendor selected.

[2] The Fuel Cell units are generic. The parameters modeled are representative values. The exact unit characteristics will depend on the site and equipment vendor selected.

Figure 8-17

CURRENT AND PROJECTED SUMMER GENERATING CAPABILITIES
Rounded to Nearest MW

STATION	UNIT	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
East Bend	2	NA*	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414
Miami Fort	6	NA*	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163
Woodsdale	1	NA*	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
Woodsdale	2	NA*	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
Woodsdale	3	NA*	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
Woodsdale	4	NA*	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
Woodsdale	5	NA*	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
Woodsdale	6	NA*	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
PCFB	1	NA*	0	0	0	0	0	0	0	0	0	70	70	70	70	70	70	70	70	70	70	70
PCFB	2	NA*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	70	70	70	70	70	70
PCFB	3	NA*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	70
Fuel Cell	1	NA*	0	0	0	0	0	0	0	0	0	0	0	25	25	25	25	25	25	25	25	25
Fuel Cell	2	NA*	0	0	0	0	0	0	0	0	0	0	0	0	0	25	25	25	25	25	25	25
Total		0	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,147	1,147	1,172	1,172	1,197	1,267	1,267	1,267	1,267	1,267	1,337

* ULH&P will be served under a PSA until the plants are transferred, currently expected to occur 7/1/04

Figure 8-18

CURRENT AND PROJECTED WINTER GENERATING CAPABILITIES
Rounded to Nearest MW

STATION	UNIT	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
East Bend	2	NA*	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414
Miami Fort	6	NA*	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163	163
Woodsdale	1	NA*	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Woodsdale	2	NA*	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Woodsdale	3	NA*	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Woodsdale	4	NA*	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Woodsdale	5	NA*	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Woodsdale	6	NA*	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
PCFB	1	NA*	0	0	0	0	0	0	0	0	0	70	70	70	70	70	70	70	70	70	70
PCFB	2	NA*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	70	70	70	70	70
PCFB	3	NA*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Cell	1	NA*	0	0	0	0	0	0	0	0	0	0	0	25	25	25	25	25	25	25	25
Fuel Cell	2	NA*	0	0	0	0	0	0	0	0	0	0	0	0	0	25	25	25	25	25	25
Total		0	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,141	1,211	1,211	1,236	1,236	1,261	1,331	1,331	1,331	1,331	1,331

* ULH&P will be served under a PSA until the plants are transferred, currently expected to occur 7/1/04

CINERGY®

The Union Light, Heat & Power Company

2003

INTEGRATED RESOURCE PLAN

VOLUME I

GENERAL APPENDIX

April 1, 2004

By: The Union Light, Heat and Power Company.
Gregory C. Ficke, President
139 East Fourth Street
Cincinnati, OH 45202

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GENERAL APPENDIX
Table of Contents

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ULH&P Long-Term Electric Forecast

The following pages pertain to customer demand for electric energy within the ULH&P service territory. Differences between the figures shown in this document and those contained in Volume I are due to the treatment of DSM.

UNION LIGHT, HEAT AND POWER COMPANY
FORECAST OF ELECTRIC DELIVERIES
MWH - BILLING

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	O.P.A.	INTER-DEPARTMENT	TOTAL RETAIL
1997	1,158,180	918,822	973,852	15,725	343,290	625	3,410,493
1998	1,217,326	974,915	1,047,913	15,713	346,919	702	3,603,489
1999	1,254,643	1,042,927	966,516	16,764	354,417	876	3,636,143
2000	1,259,784	1,161,743	1,030,210	18,029	316,288	1,761	3,787,815
2001	1,297,467	1,297,651	880,519	17,163	291,605	2,779	3,787,185
2002	1,318,690	1,249,043	773,450	20,471	281,994	2,516	3,646,164
2003	1,342,657	1,270,153	815,394	20,708	282,523	2,535	3,733,970
2004	1,365,459	1,299,138	835,764	20,980	282,710	2,555	3,806,606
2005	1,386,764	1,328,709	861,589	21,255	284,570	2,573	3,885,460
2006	1,414,184	1,357,926	892,732	21,533	287,057	2,593	3,976,025
2007	1,434,518	1,378,697	928,134	21,815	289,748	2,611	4,055,523
2008	1,460,309	1,402,816	957,145	22,099	292,766	2,631	4,137,766
2009	1,477,987	1,421,684	991,810	22,389	295,188	2,651	4,211,709
2010	1,498,358	1,440,956	1,027,500	22,677	297,456	2,673	4,289,620
2011	1,520,940	1,460,621	1,066,430	22,976	299,474	2,692	4,373,133
2012	1,542,617	1,480,414	1,105,466	23,275	301,486	2,713	4,455,971
2013	1,565,979	1,501,196	1,141,936	23,581	302,983	2,732	4,538,407
2014	1,587,034	1,522,112	1,179,412	23,892	304,304	2,753	4,619,507
2015	1,605,090	1,541,952	1,216,363	24,200	305,563	2,772	4,695,940
2016	1,625,435	1,561,347	1,255,605	24,516	306,595	2,793	4,776,291
2017	1,641,966	1,579,717	1,299,740	24,835	307,442	2,816	4,856,516
2018	1,663,963	1,599,233	1,339,078	25,162	308,237	2,837	4,938,510
2019	1,684,601	1,618,066	1,382,594	25,490	308,859	2,857	5,022,467
2020	1,704,595	1,636,736	1,425,814	25,822	309,153	2,877	5,104,997
2021	1,715,614	1,651,753	1,464,255	26,160	309,316	2,899	5,169,997
2022	1,737,733	1,669,956	1,510,073	26,501	309,805	2,923	5,256,991
2023	1,752,800	1,685,119	1,558,866	26,848	309,748	2,944	5,336,325
2024	1,778,409	1,702,319	1,608,876	27,198	309,943	2,966	5,429,711
2025	1,790,792	1,715,005	1,653,081	27,554	309,652	2,989	5,499,073
2026	1,809,411	1,729,001	1,702,786	27,914	309,620	3,011	5,581,743
GROWTH RATE							
2002-2007	1.7%	2.0%	3.7%	1.3%	0.5%	0.7%	2.2%
2002-2012	1.6%	1.7%	3.6%	1.3%	0.7%	0.8%	2.0%
2002-2026	1.3%	1.4%	3.3%	1.3%	0.4%	0.8%	1.8%

NOTE: 2002 FIGURES REPRESENT TWELVE MONTHS FORECAST

(Economy.com Forecast Spring 2002)

UNION LIGHT, HEAT AND POWER COMPANY
FORECAST OF ELECTRIC ENERGY AND PEAK DEMAND

	MWH - BILLING						ESAL PEAK DEMAND - MW	
	TOTAL RETAIL	WHOLESALE **	COMPANY USE	TOTAL DELIVERIES	LOSSES	TOTAL ENERGY	WINTER	SUMMER
1997	3,410,493	50,839	593	3,461,925	192,287	3,654,212	572	736
1998	3,603,489	0	771	3,604,260	33,536	3,637,796	586	724
1999	3,636,143	0	1,023	3,637,166	210,364	3,847,529	674	775
2000	3,787,815	0	1,996	3,789,810	222,718	4,012,529	637	758
2001	3,787,185	0	3,387	3,790,572	20,458	3,811,030	584	766
2002	3,646,164	0	3,539	3,649,703	164,444	3,814,147	700	831
2003	3,733,970	0	3,569	3,737,539	170,371	3,907,910	712	848
2004	3,806,606	0	3,597	3,810,203	172,773	3,982,976	724	864
2005	3,885,460	0	3,628	3,889,088	176,624	4,065,712	737	879
2006	3,976,025	0	3,655	3,979,680	181,177	4,160,857	750	890
2007	4,055,523	0	3,688	4,059,211	187,540	4,246,751	762	905
2008	4,137,766	0	3,715	4,141,481	185,635	4,327,116	773	917
2009	4,211,709	0	3,747	4,215,456	191,952	4,407,408	784	931
2010	4,289,620	0	3,776	4,293,396	198,677	4,492,073	796	946
2011	4,373,133	0	3,807	4,376,940	199,777	4,576,717	809	960
2012	4,455,971	0	3,838	4,459,809	203,086	4,662,895	819	974
2013	4,538,407	0	3,867	4,542,274	206,213	4,748,487	830	989
2014	4,619,507	0	3,900	4,623,407	210,005	4,833,412	841	1,003
2015	4,695,940	0	3,930	4,699,870	214,386	4,914,256	851	1,016
2016	4,776,291	0	3,963	4,780,254	218,073	4,998,327	864	1,030
2017	4,856,516	0	3,996	4,860,512	226,940	5,087,452	874	1,047
2018	4,938,510	0	4,026	4,942,536	224,232	5,166,768	886	1,060
2019	5,022,467	0	4,061	5,026,528	227,106	5,253,634	897	1,075
2020	5,104,997	0	4,092	5,109,089	229,034	5,338,123	908	1,089
2021	5,169,997	0	4,125	5,174,122	241,828	5,415,950	919	1,102
2022	5,256,991	0	4,158	5,261,149	240,431	5,501,580	930	1,116
2023	5,336,325	0	4,191	5,340,516	248,250	5,588,766	941	1,131
2024	5,429,711	0	4,224	5,433,935	243,319	5,677,254	955	1,145
2025	5,499,073	0	4,258	5,503,331	251,079	5,754,410	964	1,145
2026	5,581,743	0	4,293	5,586,036	254,583	5,840,619	973	1,161
GROWTH RATE								
2002-2007	2.2%	-NM-	0.8%	2.1%	2.7%	2.2%	1.7%	1.7%
2002-2012	2.0%	-NM-	0.8%	2.0%	2.1%	2.0%	1.6%	1.6%
2002-2026	1.8%	-NM-	0.8%	1.8%	1.8%	1.8%	1.4%	1.4%

** WHOLESALE REFLECTS THE LOSS OF WILLIAMSTOWN IN 1998.
NOTE: 2002 FIGURES REPRESENT TWELVE MONTHS FORECAST

(Economy.com Forecast Spring 2002)

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
1997	104,529	10,926	399	117	889	1	116,861		11,080
1998	106,433	11,201	400	126	886	0	119,046	2,184	11,438
1999	108,453	11,624	395	142	900	0	121,514	2,468	11,568
2000	110,477	11,958	395	192	923	0	123,944	2,430	11,403
2001	112,163	12,251	430	251	946	0	126,042	2,098	11,568
2002	111,518	12,126	400	198	952	0	125,194	(848)	11,825
2003	112,313	12,288	404	195	971	0	126,171	977	11,955
2004	113,358	12,453	407	196	990	0	127,404	1,233	12,046
2005	114,394	12,616	408	198	1,006	0	128,622	1,218	12,123
2006	115,661	12,804	409	202	1,021	0	130,097	1,475	12,227
2007	116,909	12,996	410	208	1,033	0	131,556	1,459	12,270
2008	118,046	13,170	410	214	1,042	0	132,882	1,326	12,371
2009	119,208	13,343	411	220	1,051	0	134,233	1,351	12,398
2010	120,413	13,523	411	228	1,062	0	135,637	1,404	12,443
2011	121,648	13,714	411	236	1,073	0	137,082	1,445	12,503
2012	122,830	13,891	411	243	1,074	0	138,449	1,367	12,559
2013	123,996	14,067	411	252	1,075	0	139,801	1,352	12,629
2014	125,113	14,238	411	260	1,075	0	141,097	1,296	12,685
2015	126,202	14,403	411	268	1,075	0	142,359	1,262	12,718
2016	127,268	14,566	411	276	1,074	0	143,595	1,236	12,772
2017	128,292	14,724	411	284	1,071	0	144,782	1,187	12,799
2018	129,273	14,875	411	293	1,066	0	145,918	1,136	12,872
2019	130,225	15,022	411	300	1,060	0	147,018	1,100	12,936
2020	131,147	15,164	411	309	1,053	0	148,084	1,066	12,998
2021	132,047	15,303	411	316	1,045	0	149,122	1,038	12,992
2022	132,929	15,440	411	324	1,035	0	150,139	1,017	13,073
2023	133,802	15,575	411	332	1,024	0	151,144	1,005	13,100
2024	134,674	15,711	411	340	1,014	0	152,150	1,006	13,205
2025	135,[illegible]44	15,846	411	348	1,005	0	153,154	1,004	13,212
2026	136,[illegible]59	15,987	411	357	996	0	154,210	1,056	13,260
GROWTH RATE									
2002-2007	0.9%	0.9%	-1.0%	-4.3%	1.5%	-NM-	0.6%		1.1%
2002-2012	1.0%	1.1%	-0.5%	-0.6%	1.3%	-NM-	0.8%		0.8%
2002-2026	0.8%	1.1%	-0.2%	1.4%	0.3%	-NM-	0.8%		0.6%

NOTE: 2002 FIGURES REPRESENT TWELVE MONTHS FORECAST

(Economy.com Forecast Spring 2002)

Supply-Side Screening Curves

The following pages contain the screening curves and associated data discussed in Chapter 5 of this filing.

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Figur A-5-12

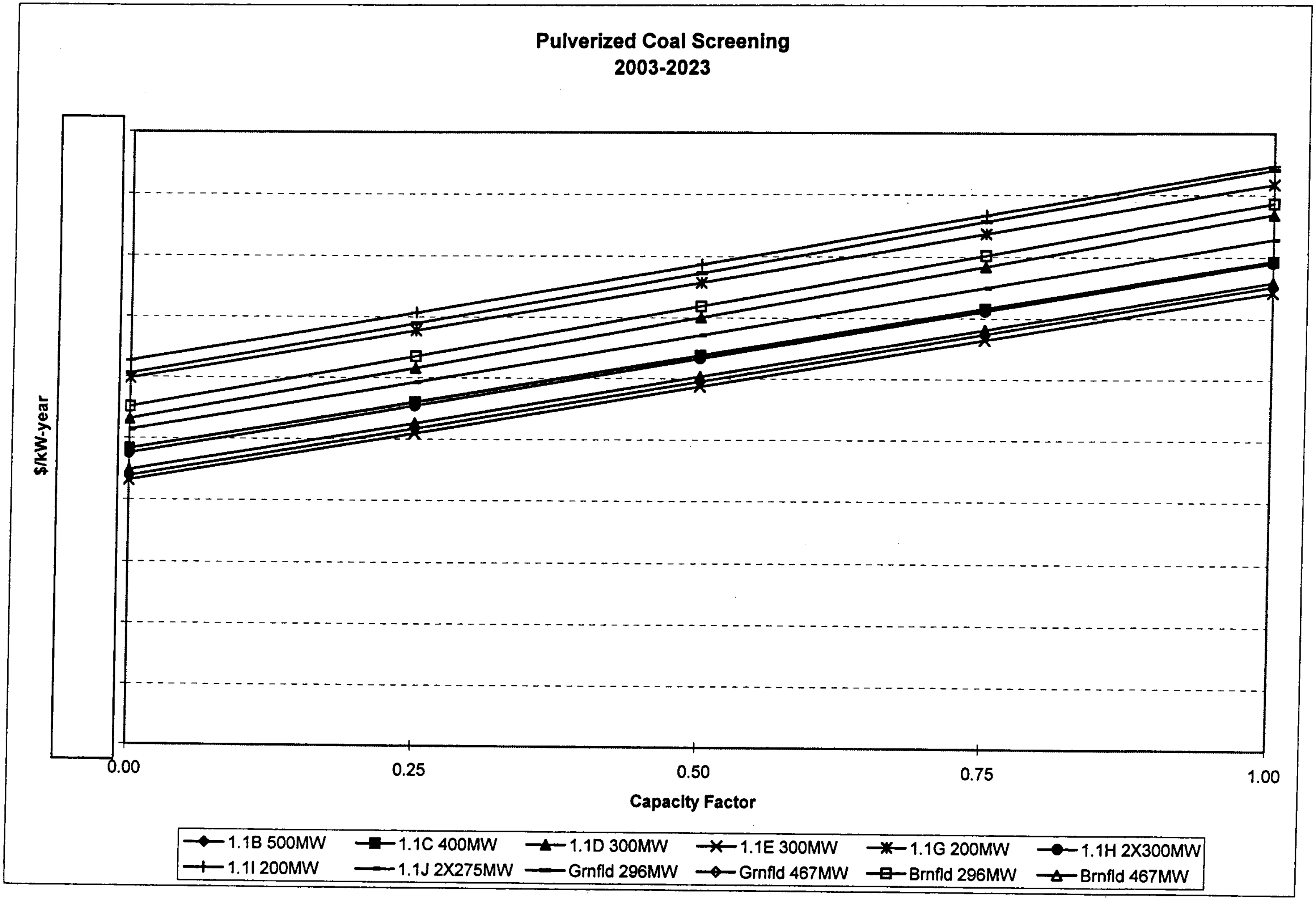

Pulverized Coal Screening
2003-2023
$/kW-year
0.00
0.25
0.50
0.75
1.00
Capacity Factor
1.1B 500MW
1.1C 400MW
1.1D 300MW
1.1E 300MW
1.1G 200MW
1.1H 2X300MW
1.1I 200MW
1.1J 2X275MW
Grnfld 296MW
Grnfld 467MW
Brnfld 296MW
Brnfld 467MW

Figure GA-5-13

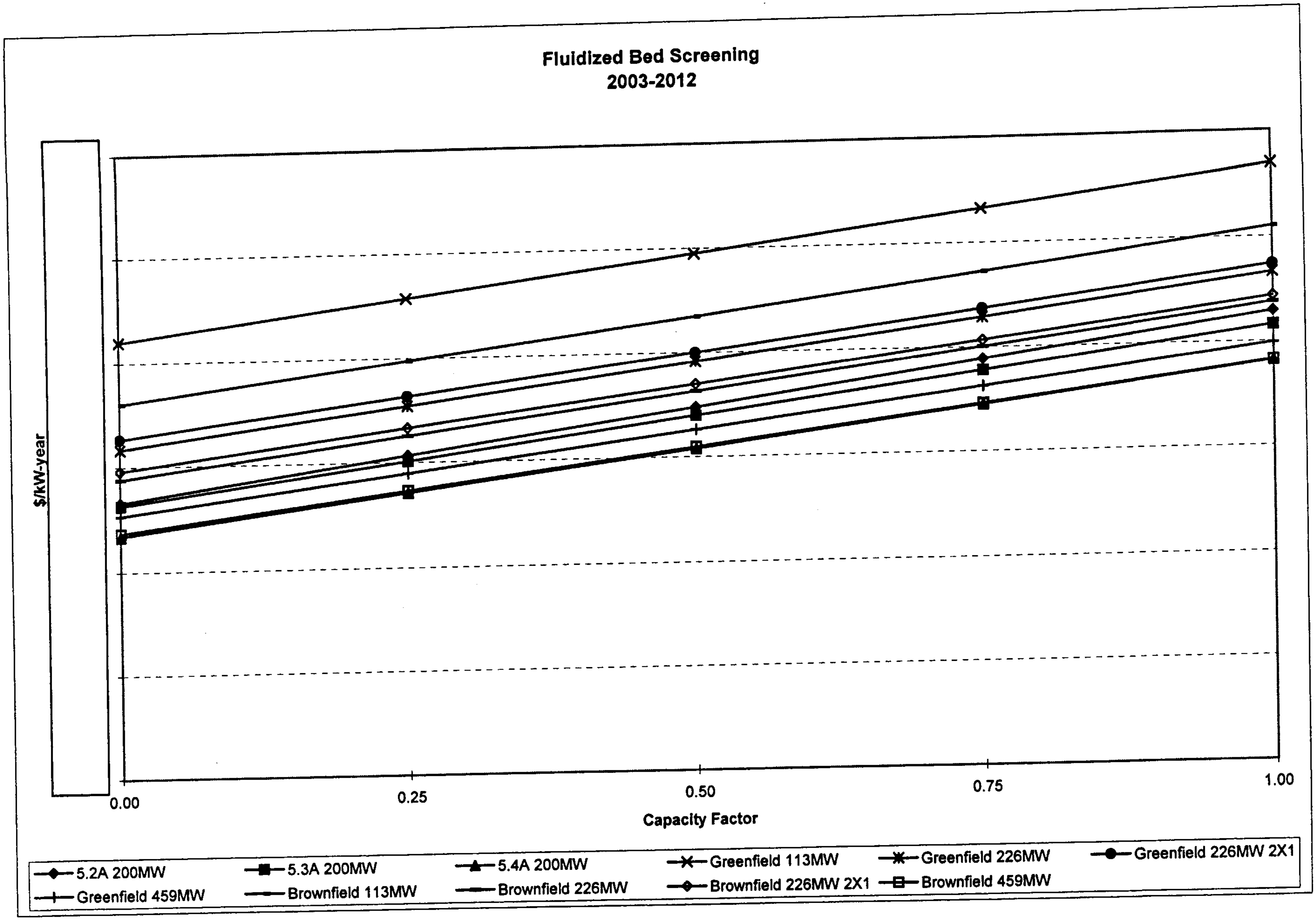


Figure GA-5-14

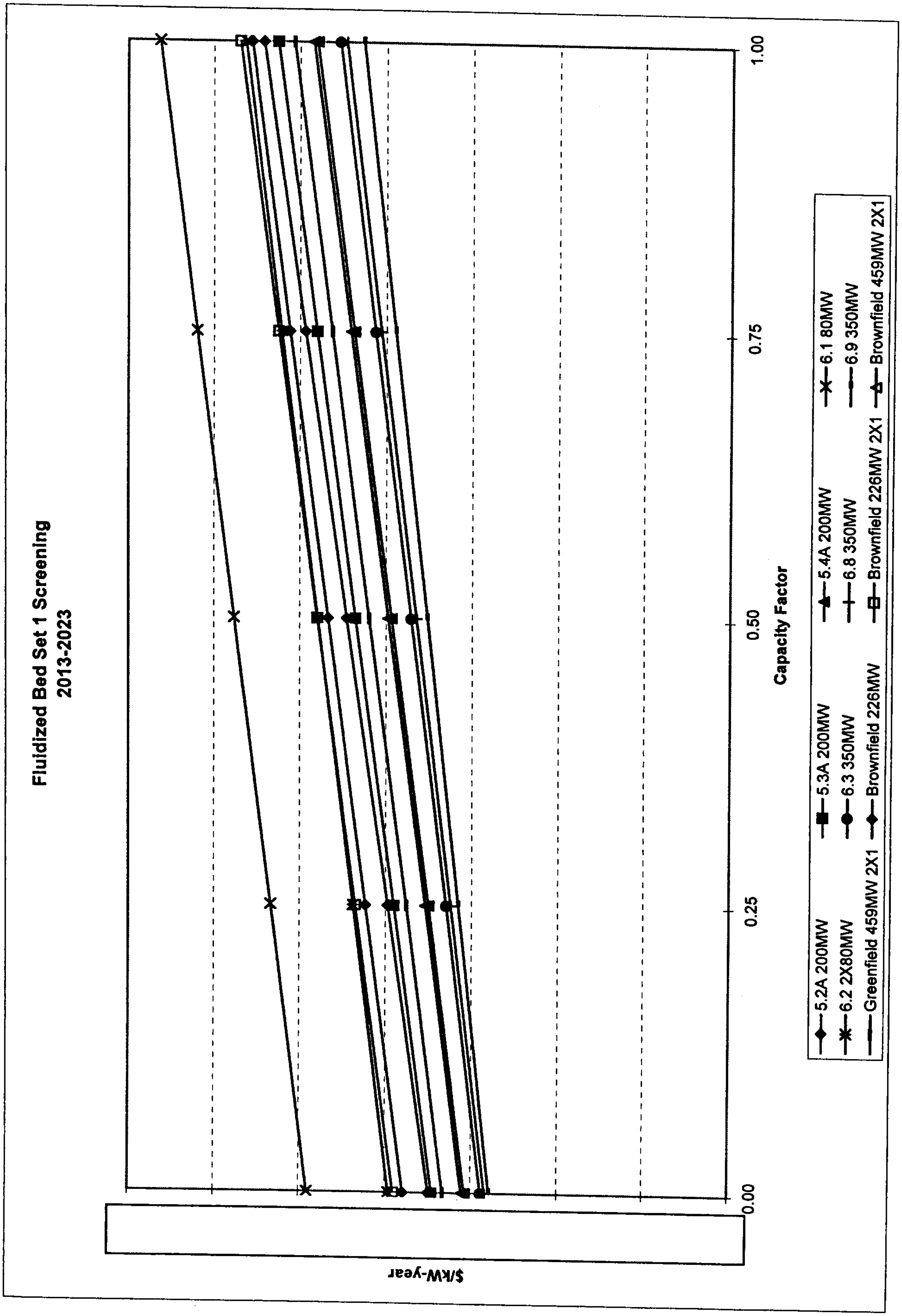


Figure GA-5-15

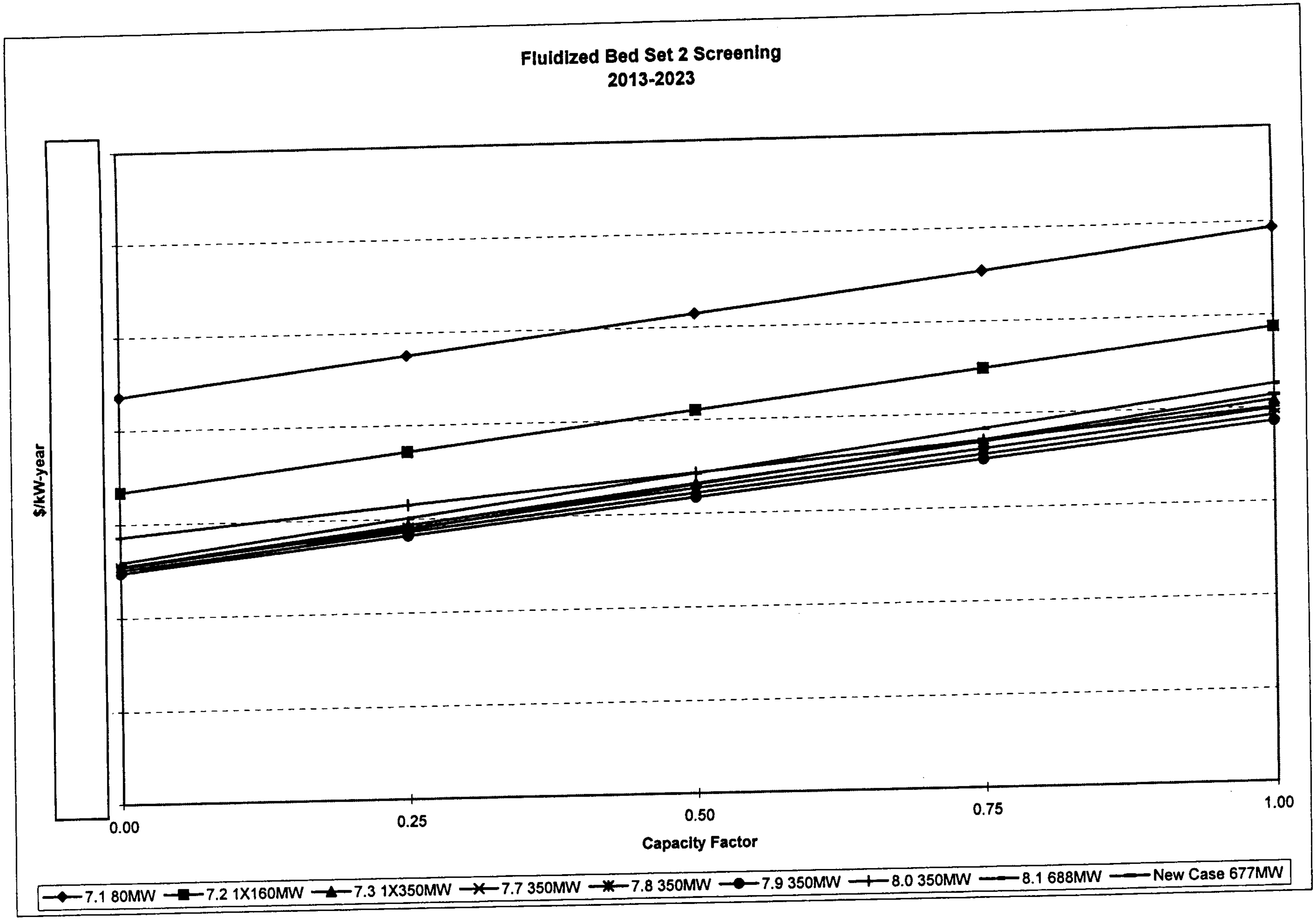


Figure GA-5-16

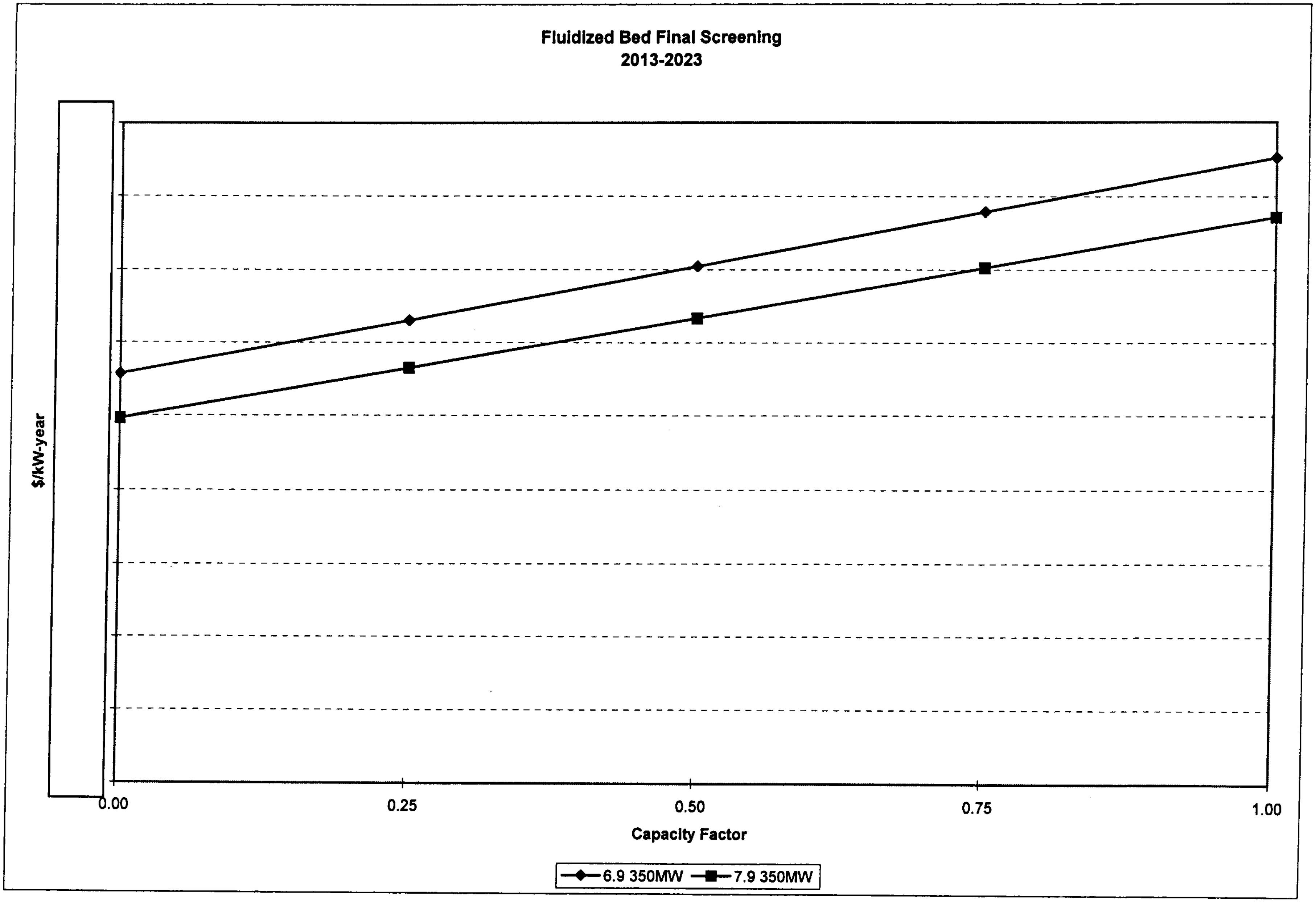


Figure GA-5-17

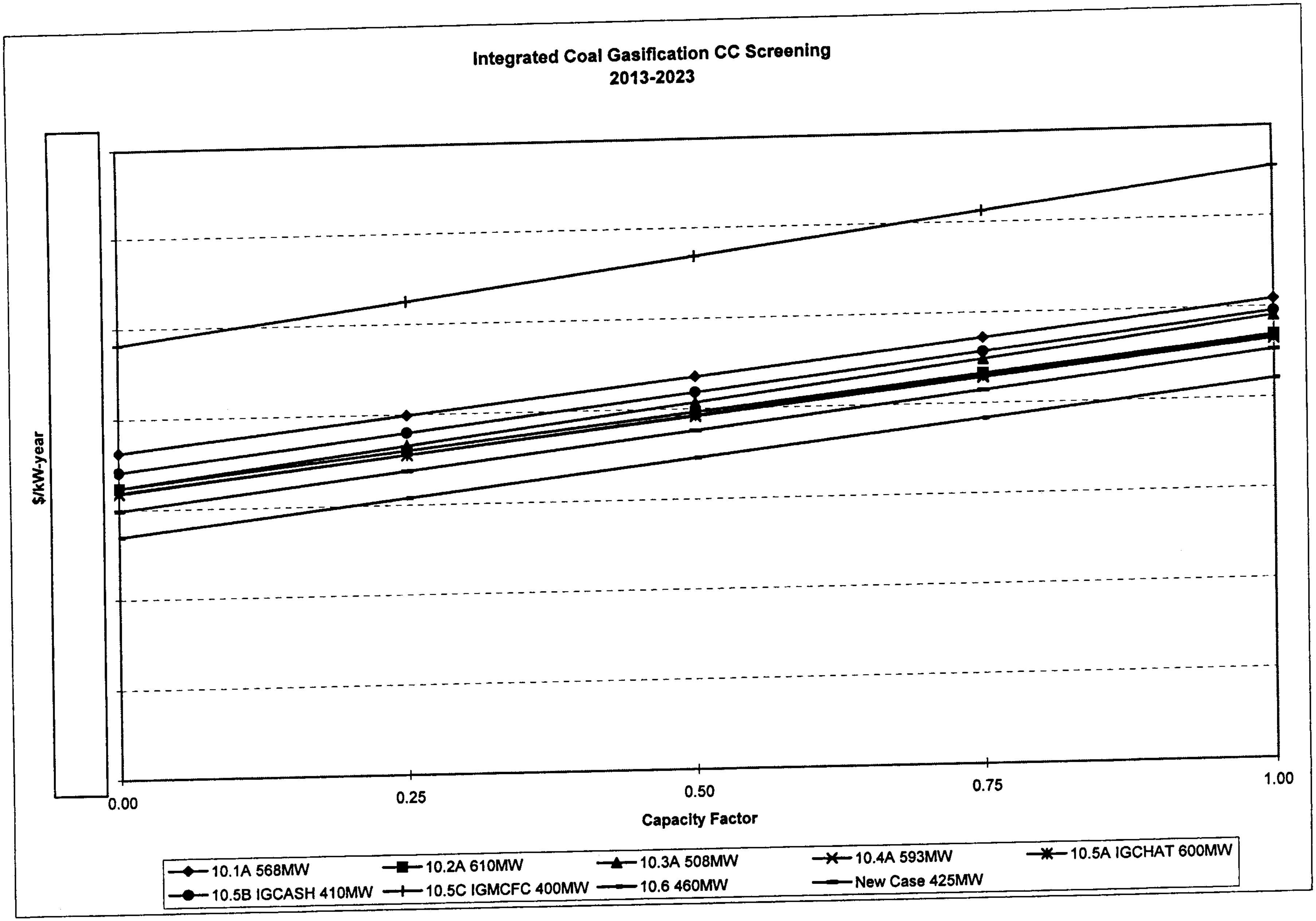


Figure GA-5-18

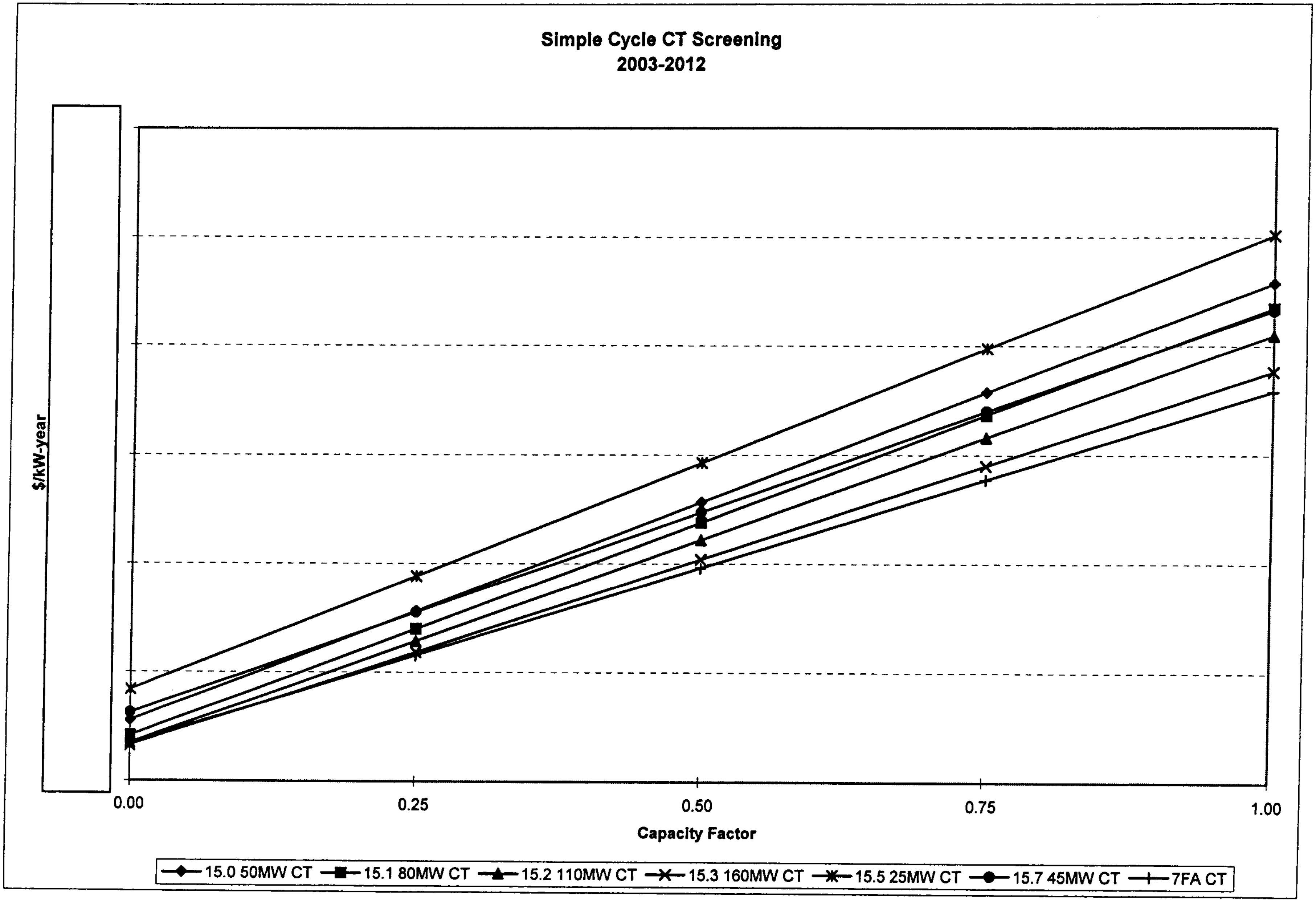


Figure GA-5-19

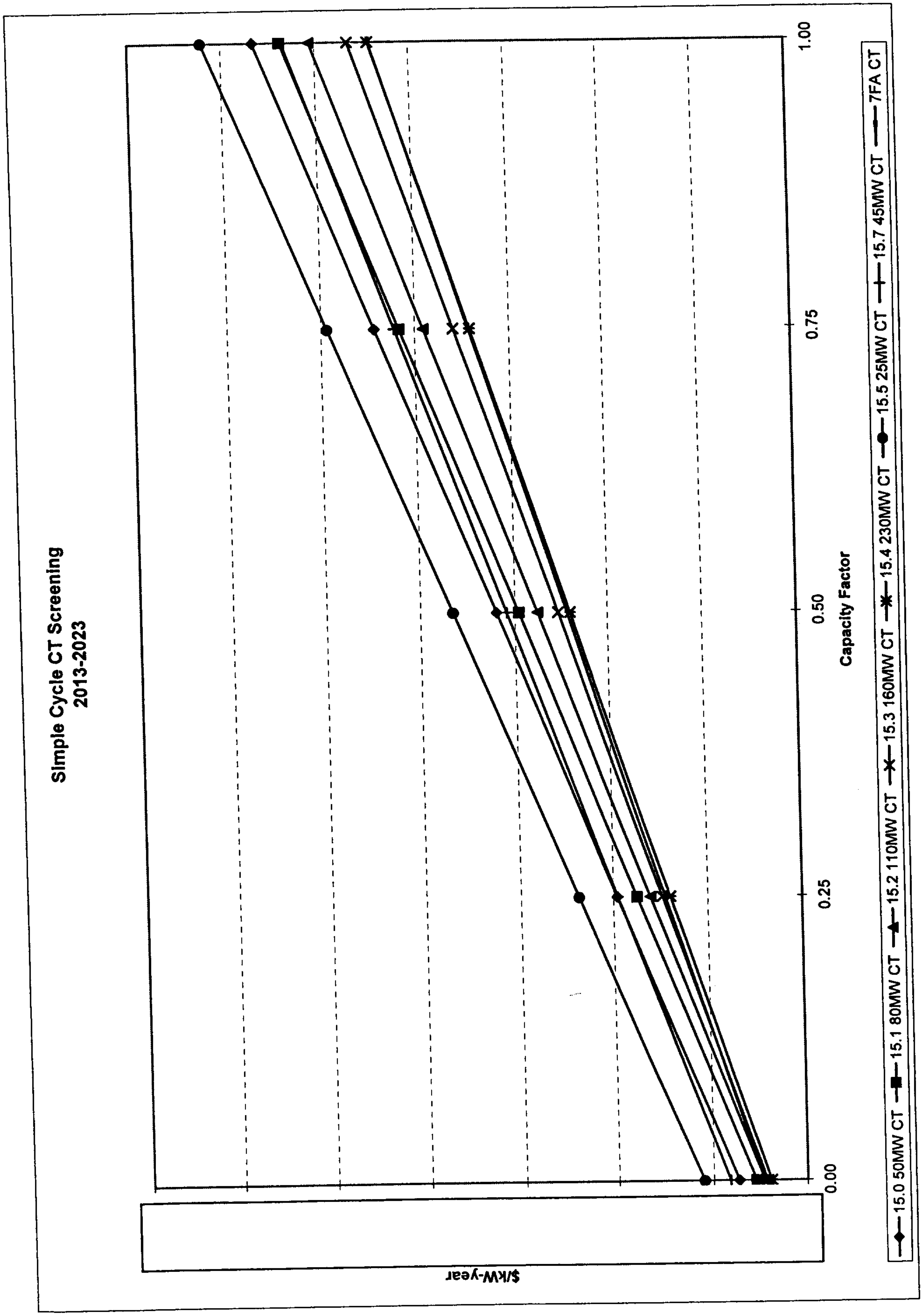


Figure GA-5-20

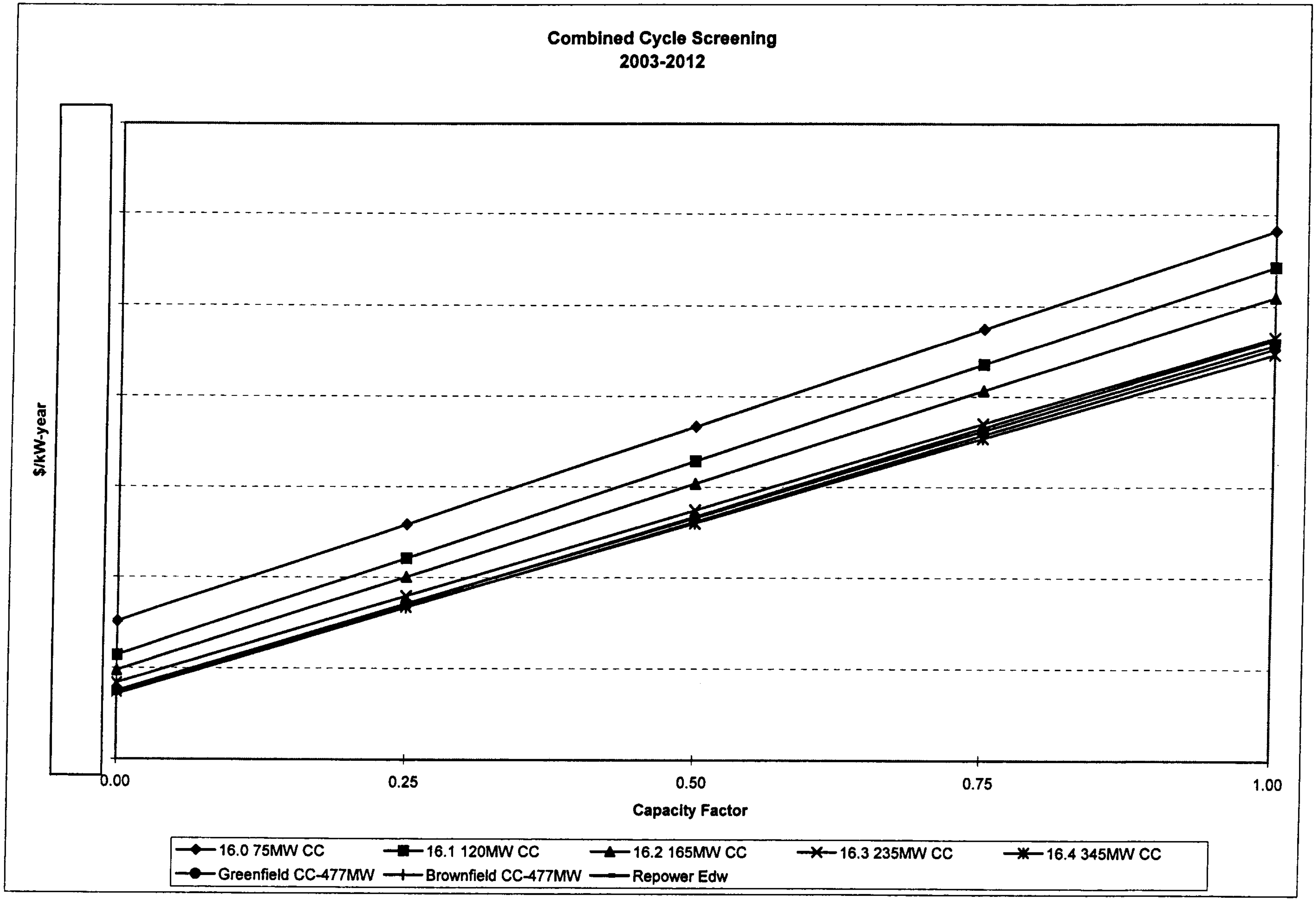


Figure GA-5-21

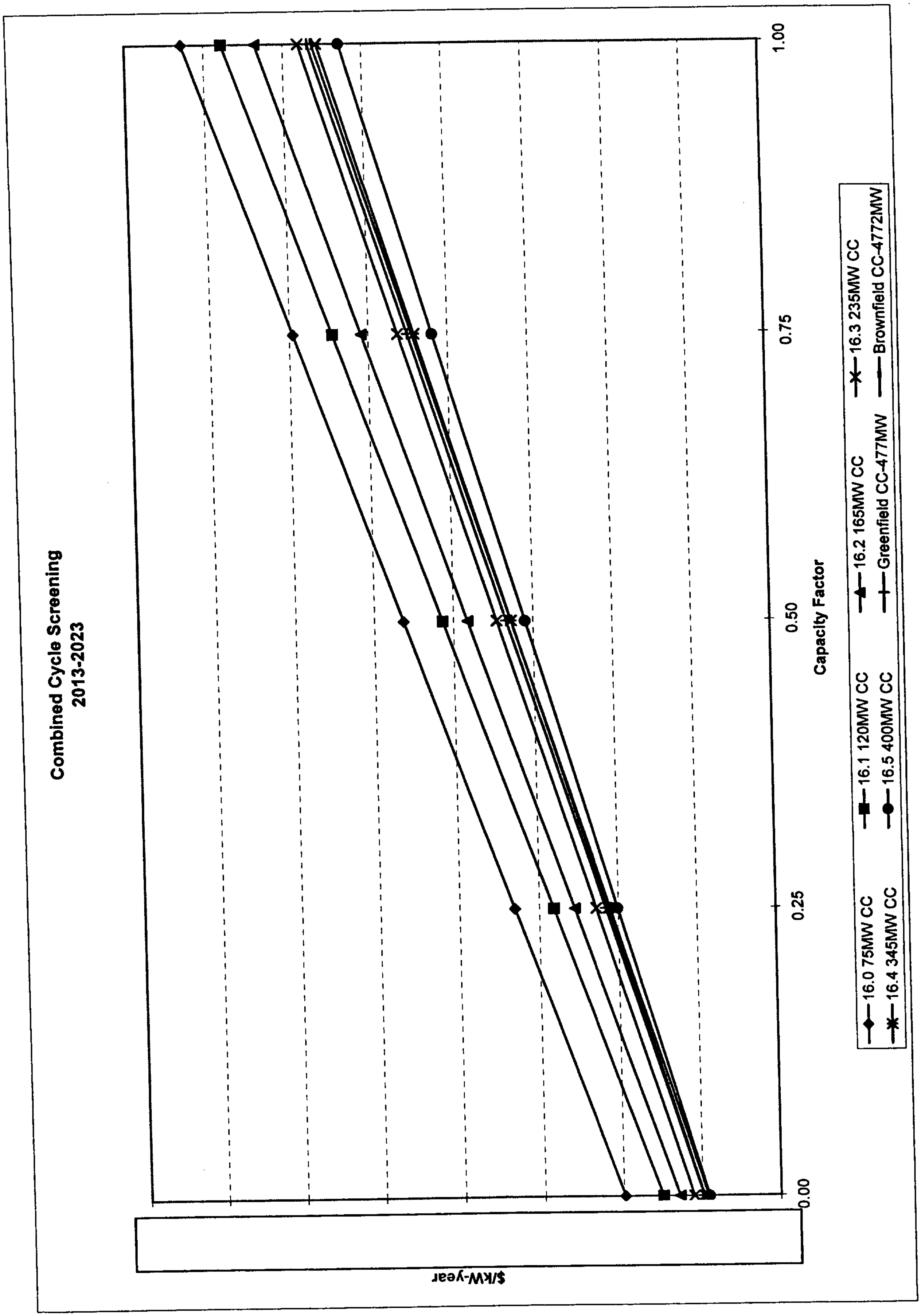


Figure GA-5-22

Fuel Cell Screening
2013-2023

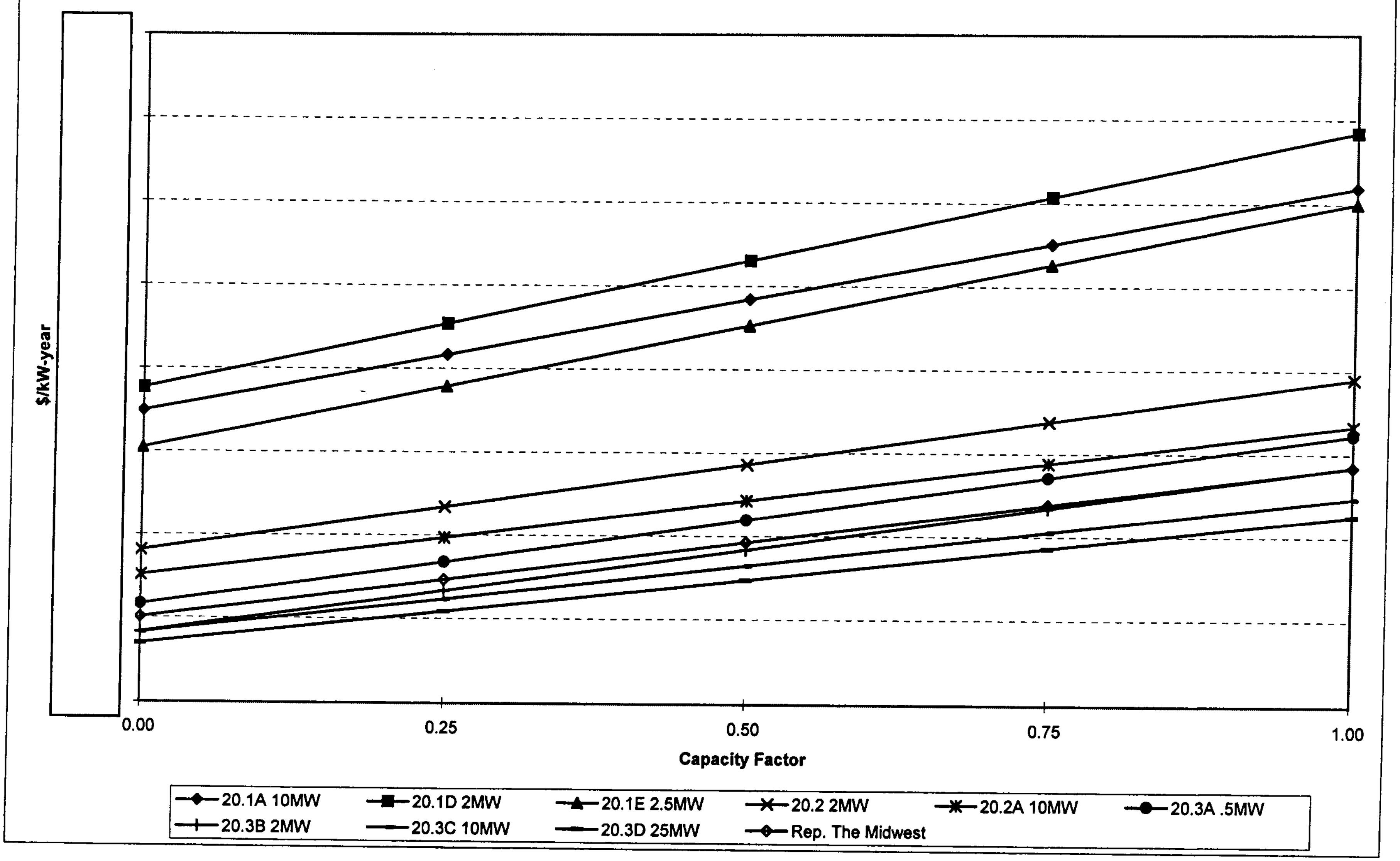


Figure GA-5-23

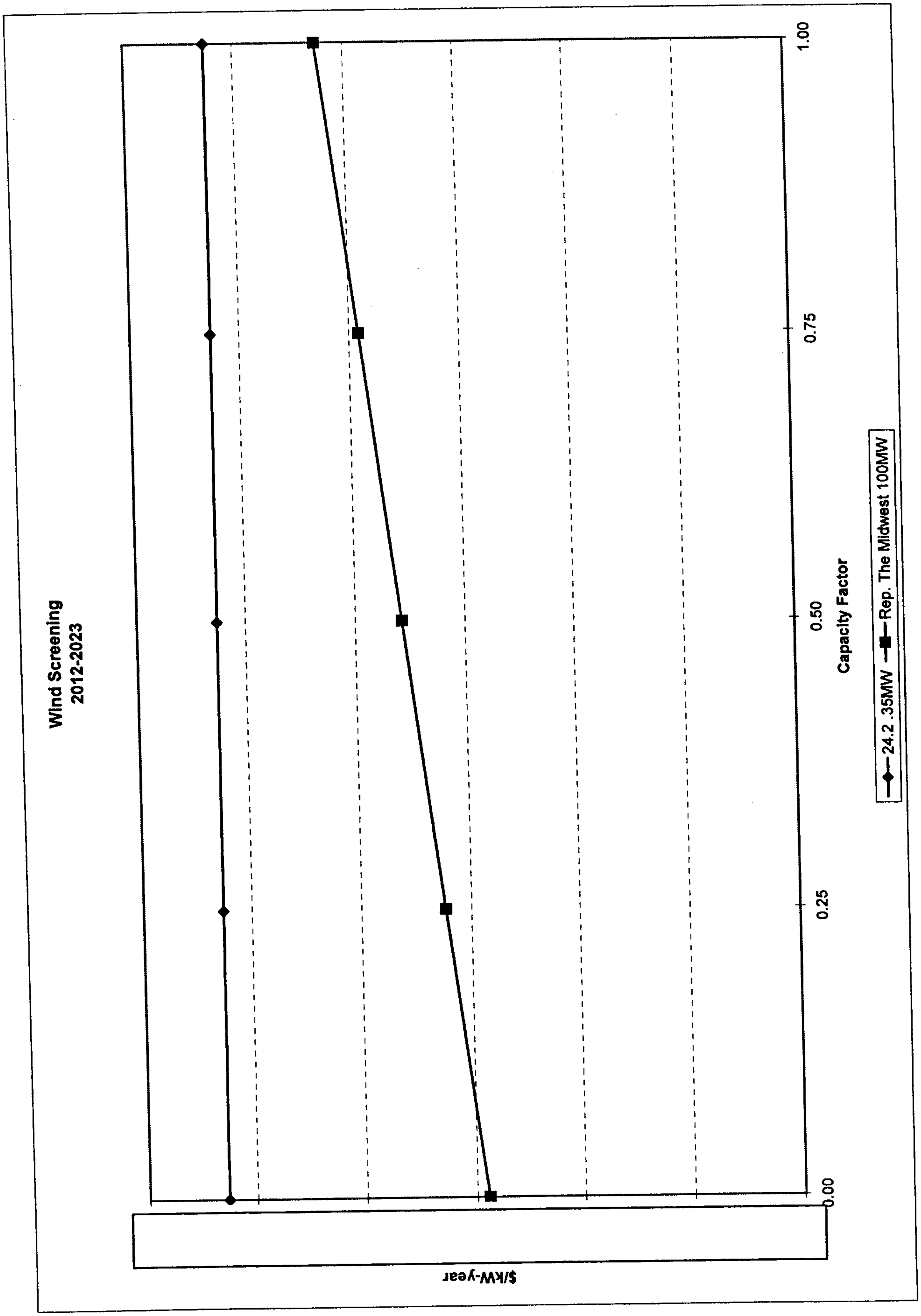


Figure GA-5-24

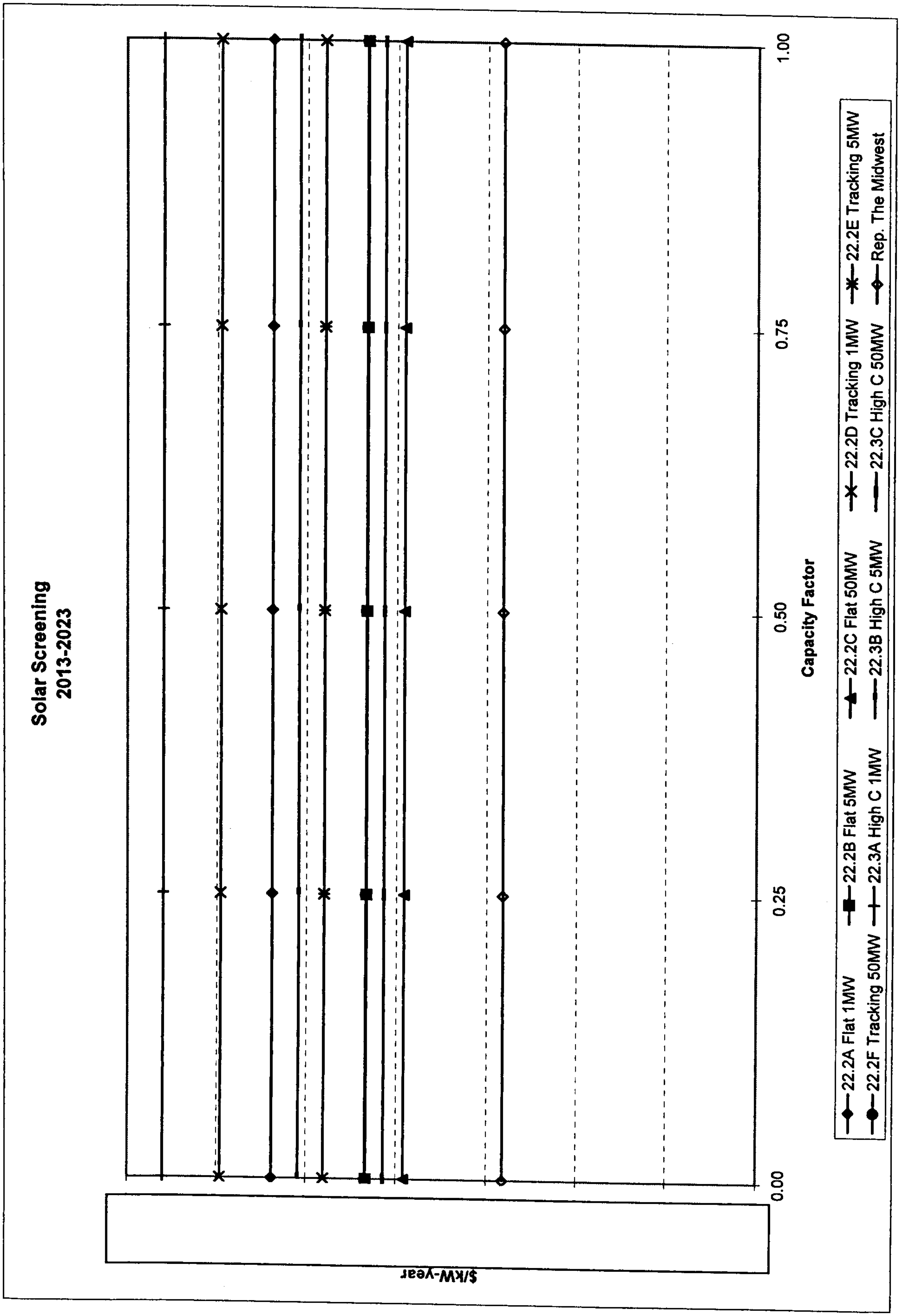


Figure GA-5-25

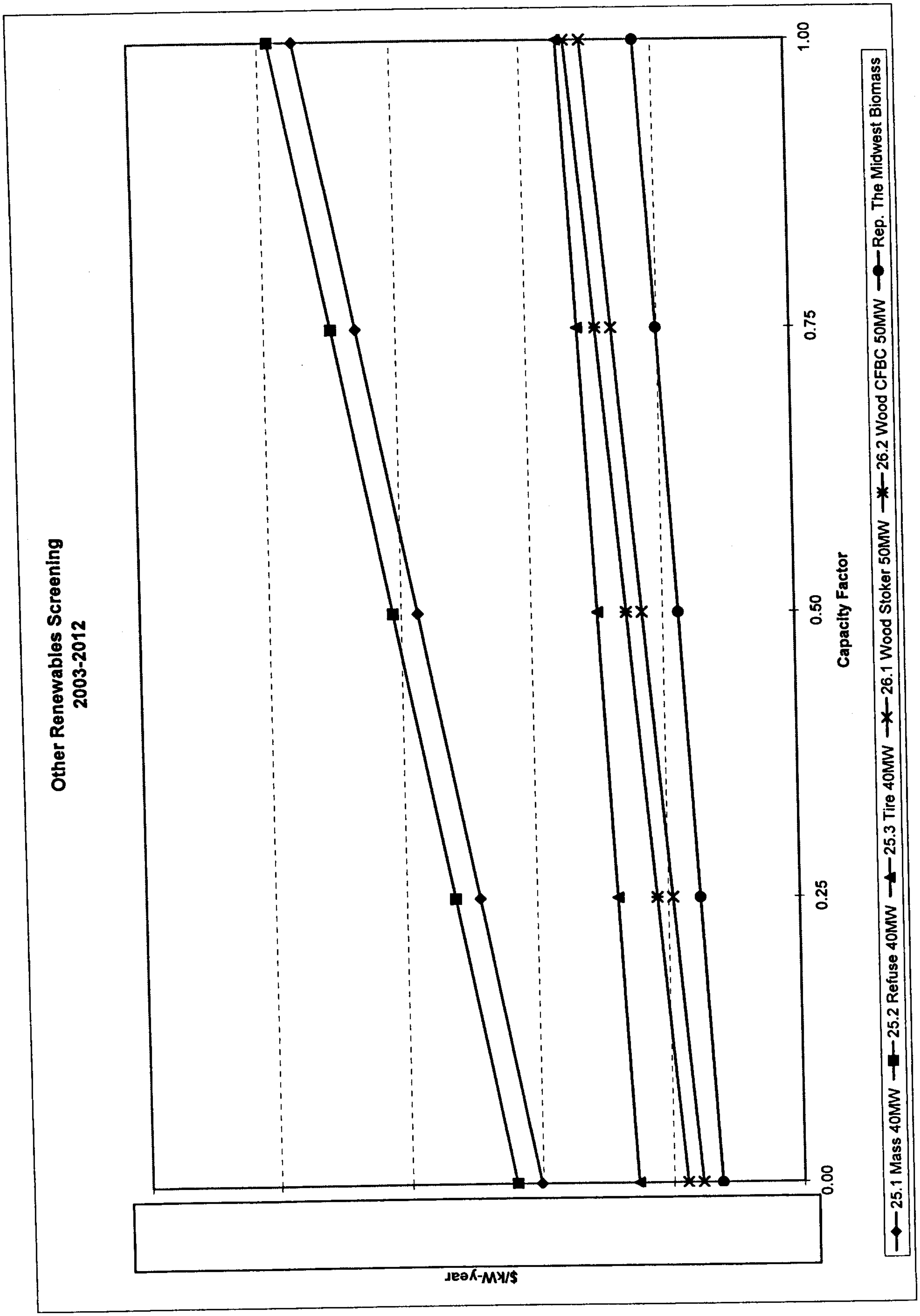


Figure GA-5-26

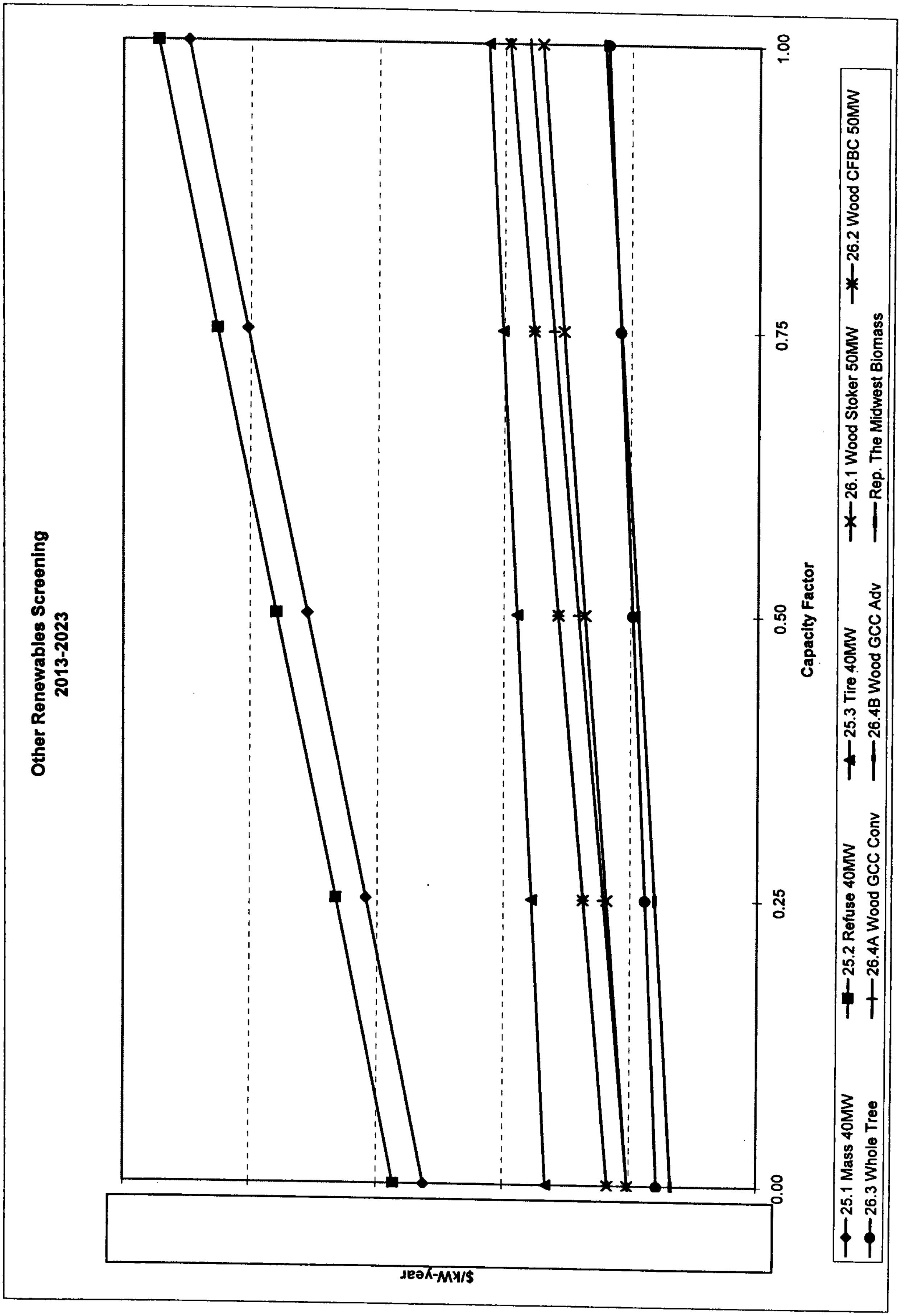
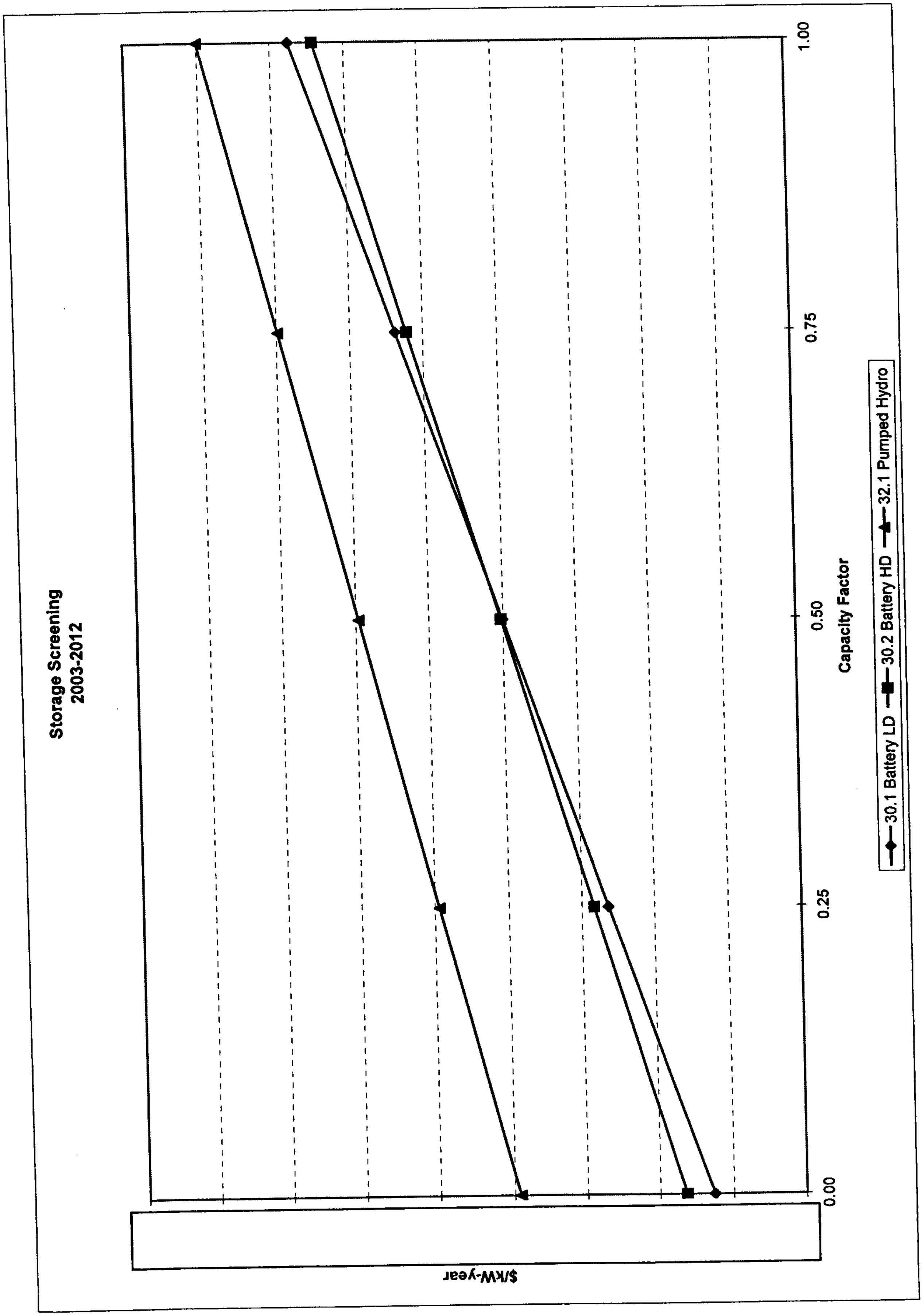


Figure GA-5-27



Figu GA-5-28

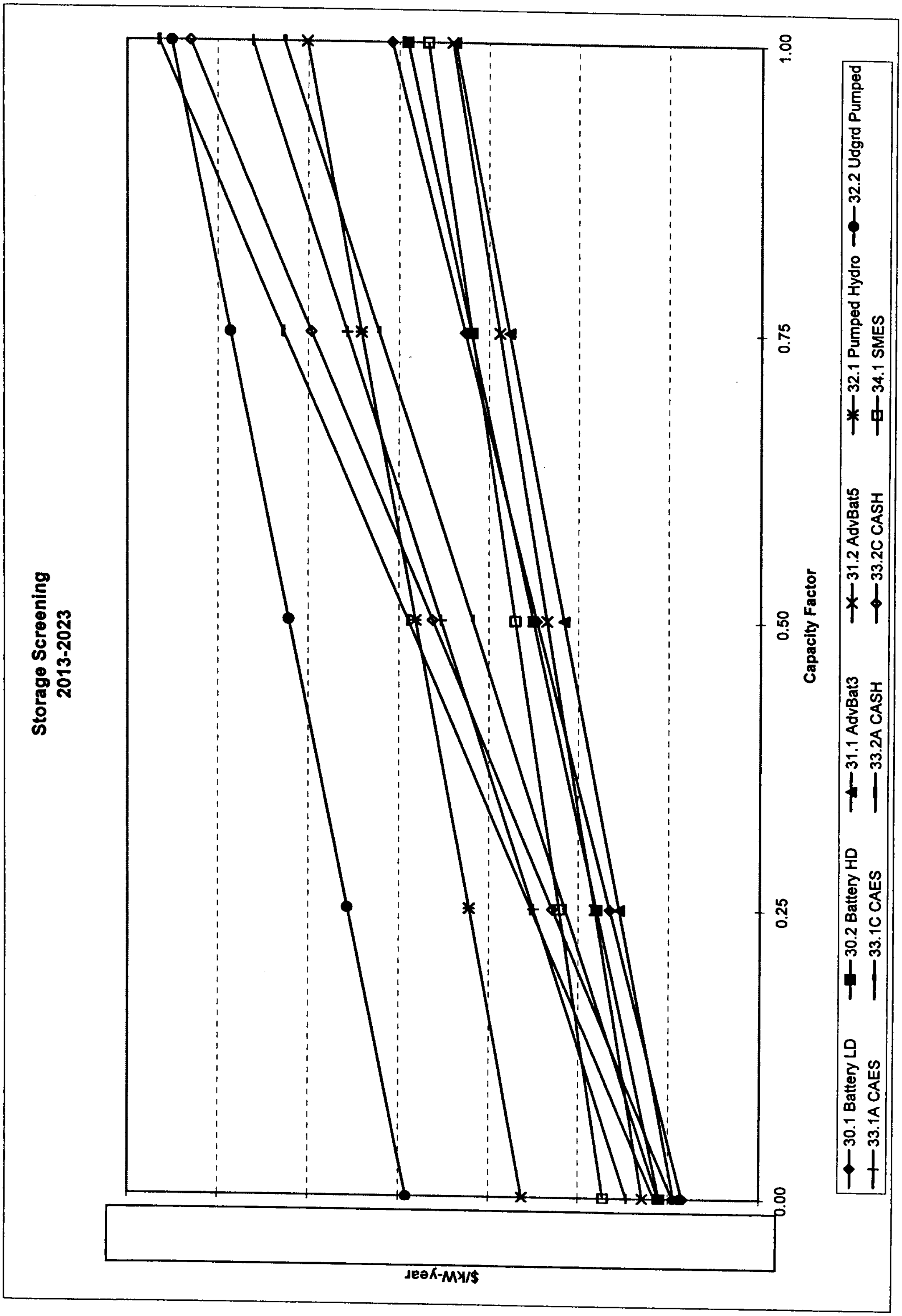

Storage Screening
2013-2023
$/kW-year
Capacity Factor
0.00
0.25
0.50
0.75
1.00
30.1 Battery LD
30.2 Battery HD
31.1 AdvBat3
31.2 AdvBat5
32.1 Pumped Hydro
32.2 Udgrd Pumped
33.1A CAES
33.1C CAES
33.2A CASH
33.2C CASH
34.1 SMES

Figure GA-5-30

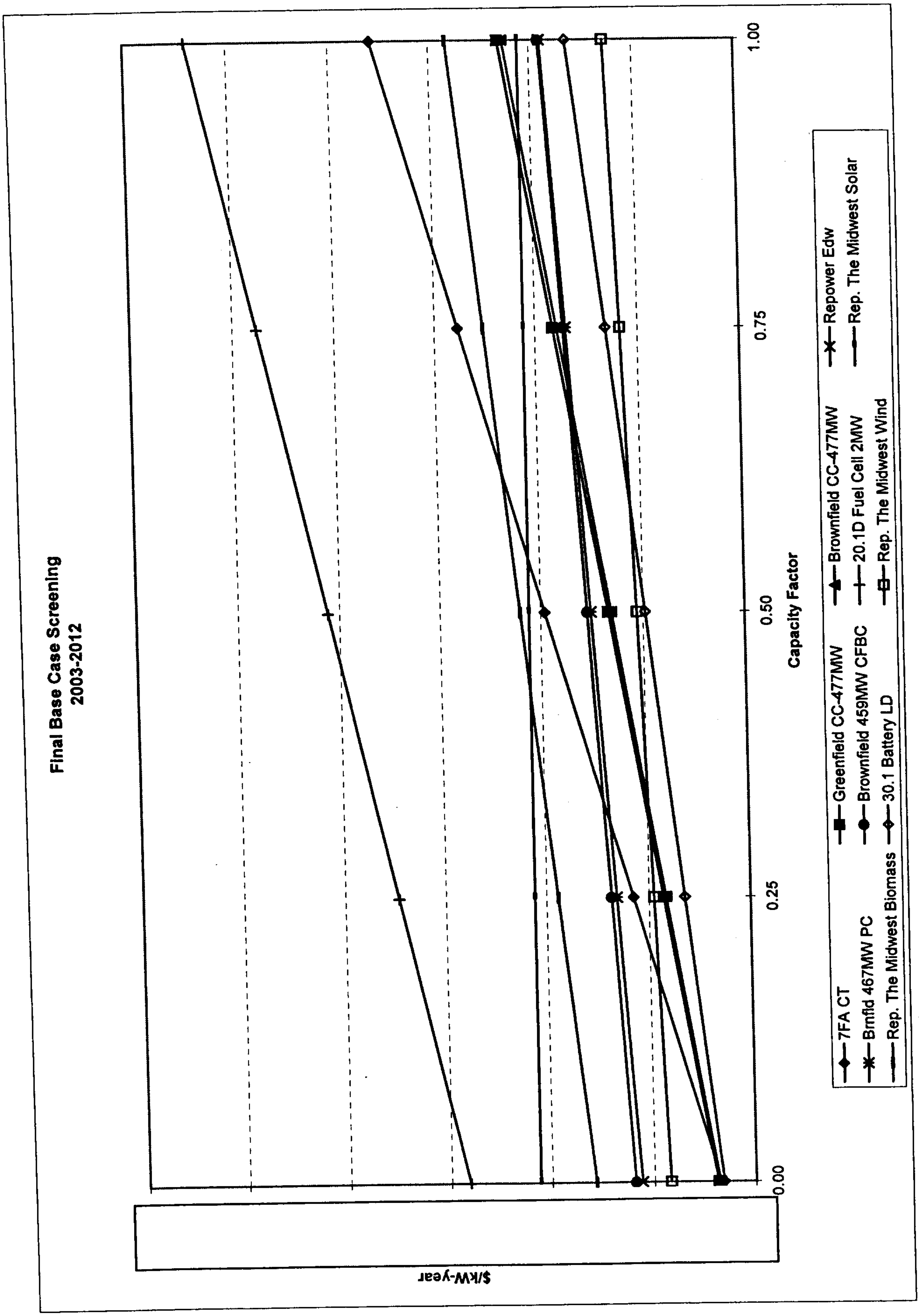


Figure GA-5-31

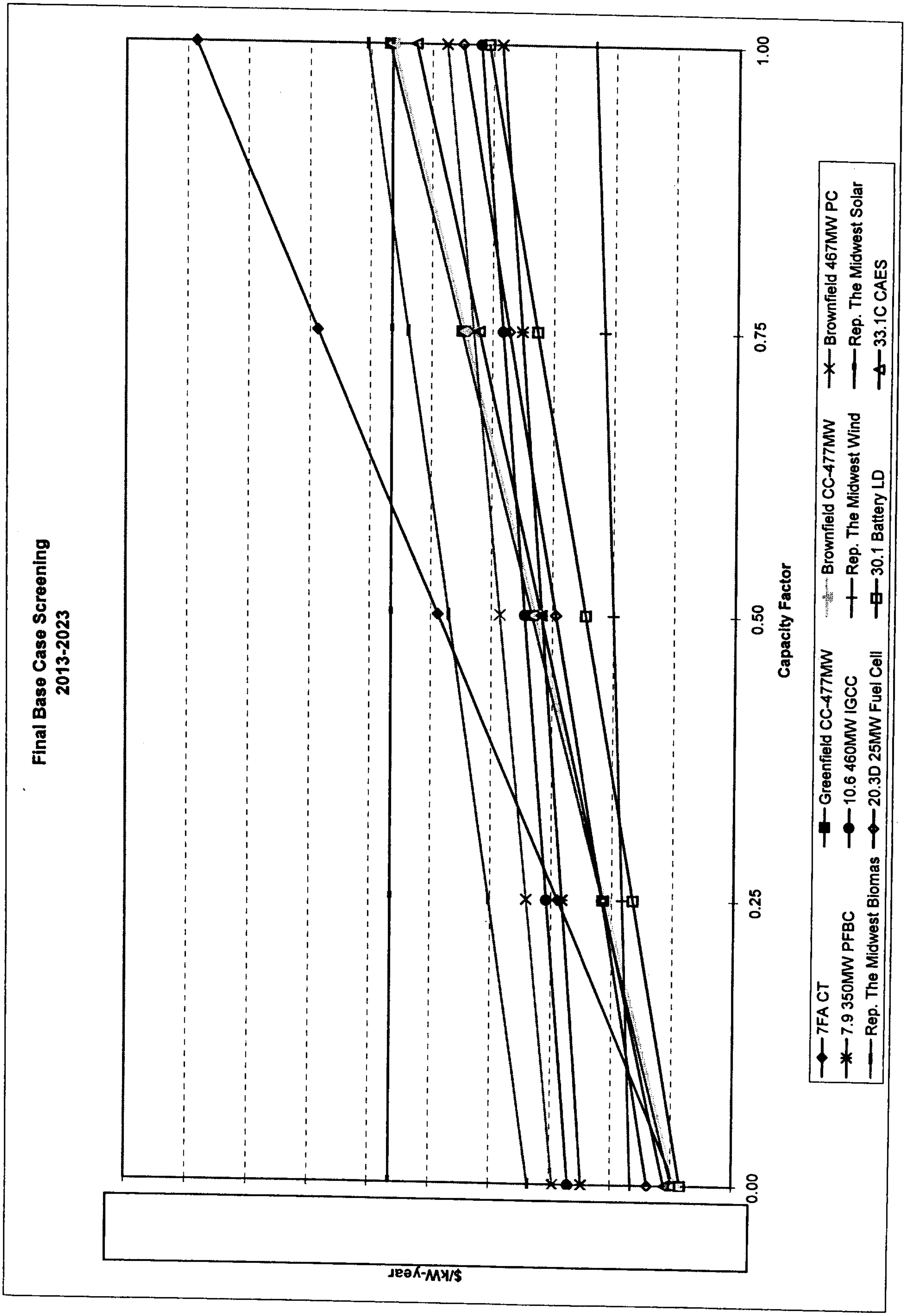


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Figure GA-5-32

Final Base Case Screening 2003-2012

SO2 Allowance ($/ton): 0.00% Annual Allowance Escalation

Discount Rate: 8.075%

2003 Dollars

GRAPH LEGEND:

	Plant A	Plant B	Plant C	Plant D	Plant E	Plant F	Plant G	Plant H	Plant I	Plant J	Plant K
	7FA CT	Greenfield CC-477MW	Brownfield CC-477MW	Repower Edw	Brnfld 467MW PC	Brownfield 459MW CFBC	20.1D Fuel Cell 2MW	Rep. The Midwest Solar	Rep. The Midwest Biomass	30.1 Battery LD	Rep. The Midwest Wind
Size (MWe)	156.0	477.0	477.0	453.0	467.0	459.0	2.0	1.0	75.0	20.0	50.0
Capital Cost ($/kWe)											
Annual Fixed Charge Rate	12.13%	12.13%	12.13%	12.13%	12.13%	12.13%	12.13%	12.13%	12.13%	12.13%	12.13%
Book Life (yrs)	30	30	30	30	30	30	30	30	30	30	30
Heat Rate (Btu/kWh)											
Var. O&M ($/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 estimate of AFUDC is included in the capital costs except for Renewables.

Levelized $/kwyr =

CONFIDENTIAL

Figure GA-5-33

Final Base Case Screening **2013-2023**

SO2 Allowance ($/ton): 0.00% Annual Allowance Escalation

Discount Rate: 8.075%

2013 Dollars

GRAPH LEGEND:	Plant A	Plant B	Plant C	Plant D	Plant E	Plant F	Plant G	Plant H	Plant I	Plant J	Plant K	Plant L
	7FA CT	Greenfield CC-477MW	Brownfield CC-477MW	Brownfield 467MW PC	7.9 350MW PFBC	10.6 460MW IGCC	Rep. The Midwest Wind	Rep. The Midwest Solar	Rep. The Midwest Biomass	20.3D 25MW Fuel Cell	30.1 Battery LD	33.1C CAES
Size (MWe)	156.0	477.0	477.0	467.0	350.0	460.0	100.0	1.0	100.0	25.0	20.0	350.0
Capital Cost ($/kWe)												
Annual Fixed Charge Rate	12.13%	12.13%	12.13%	12.13%	12.13%	12.13%	12.13%	12.13%	12.13%	12.13%	12.13%	12.13%
Book Life (yrs)	30	30	30	30	30	30	30	30	30	30	30	30
Heat Rate (Btu/kWh)												
Var. O&M ($/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 estimate of AFUDC is included in the capital costs except for Renewables.

Levelized $/kwyr =

Figure GA-5-34

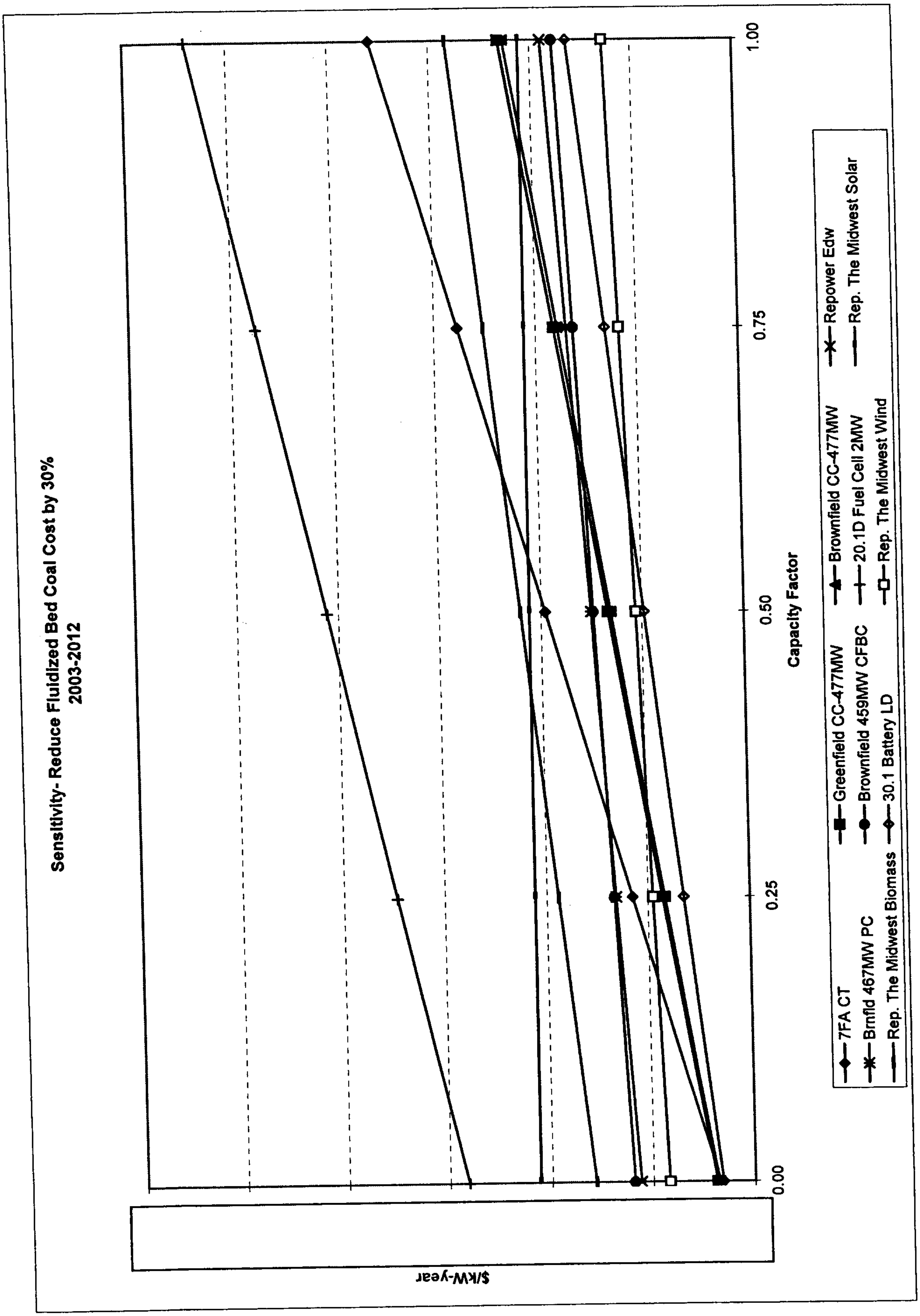


Figure GA-5-35

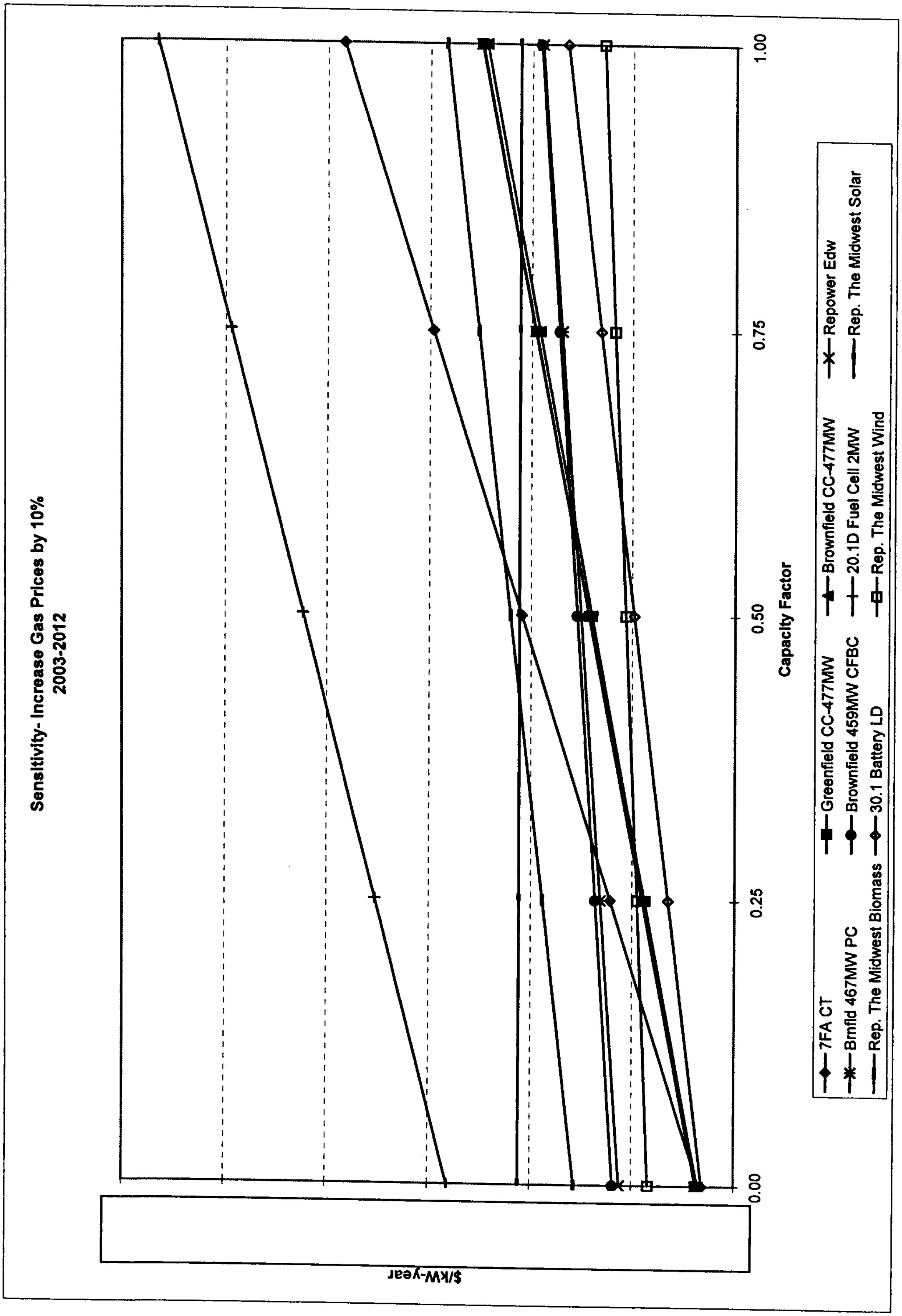


Figure GA-5-36

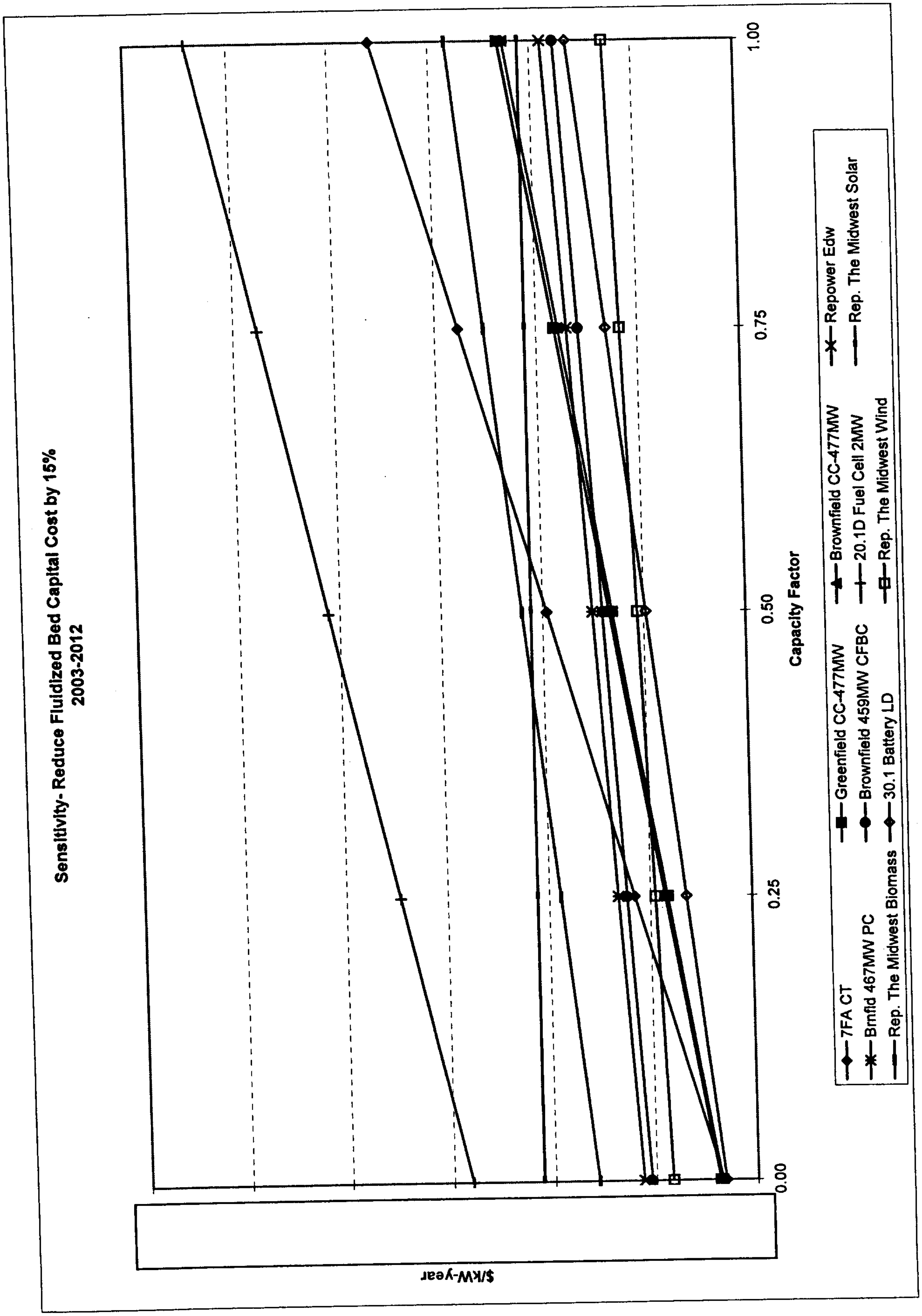


Figure A-5-37

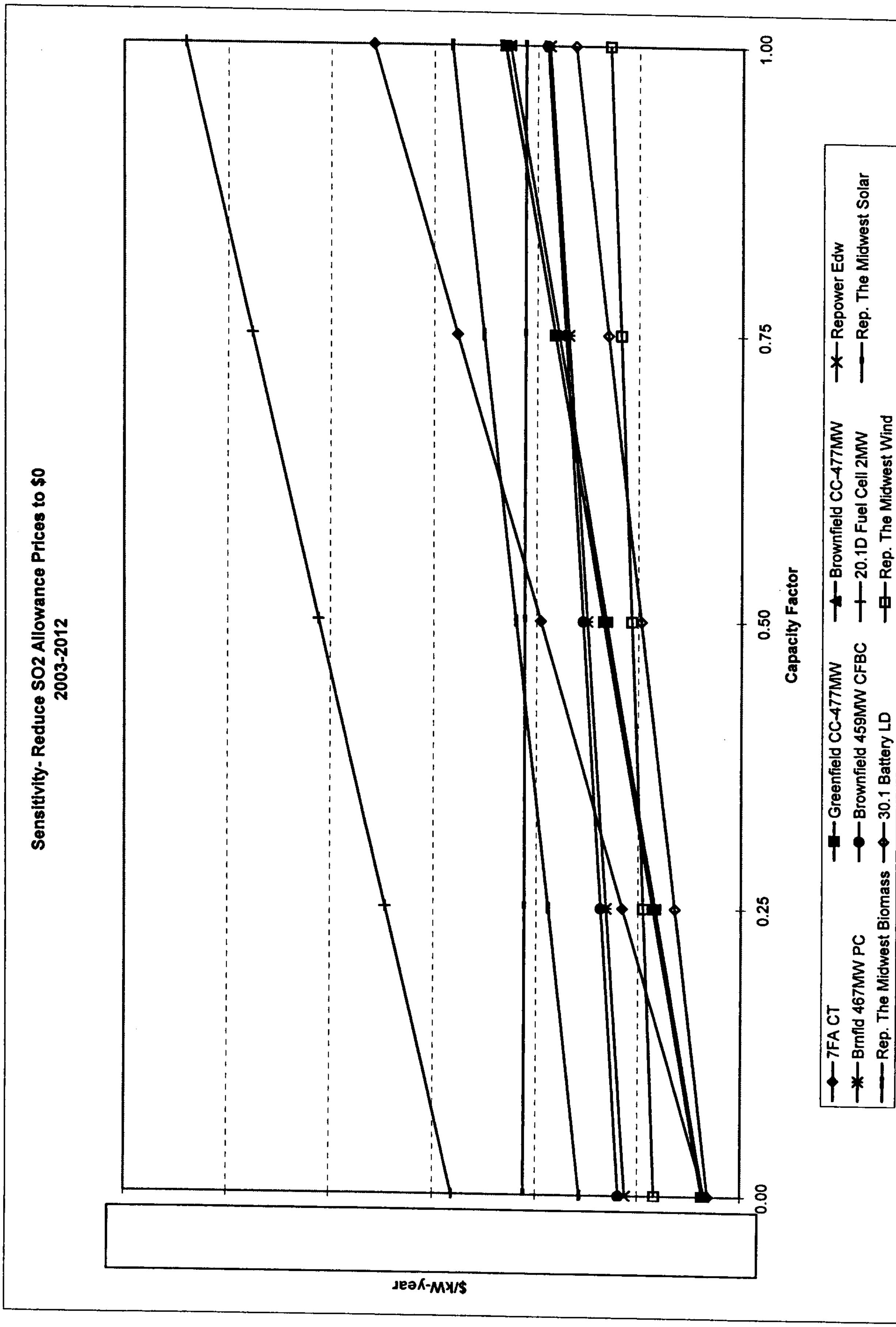

Sensitivity- Reduce SO2 Allowance Prices to $0
2003-2012
$/kW-year
0.00
0.25
0.50
0.75
1.00
Capacity Factor
7FA CT
Greenfield CC-477MW
Brownfield CC-477MW
Repower Edw
Brnfld 467MW PC
Brownfield 459MW CFBC
20.1D Fuel Cell 2MW
Rep. The Midwest Solar
Rep. The Midwest Biomass
30.1 Battery LD
Rep. The Midwest Wind

Figure GA-5-38

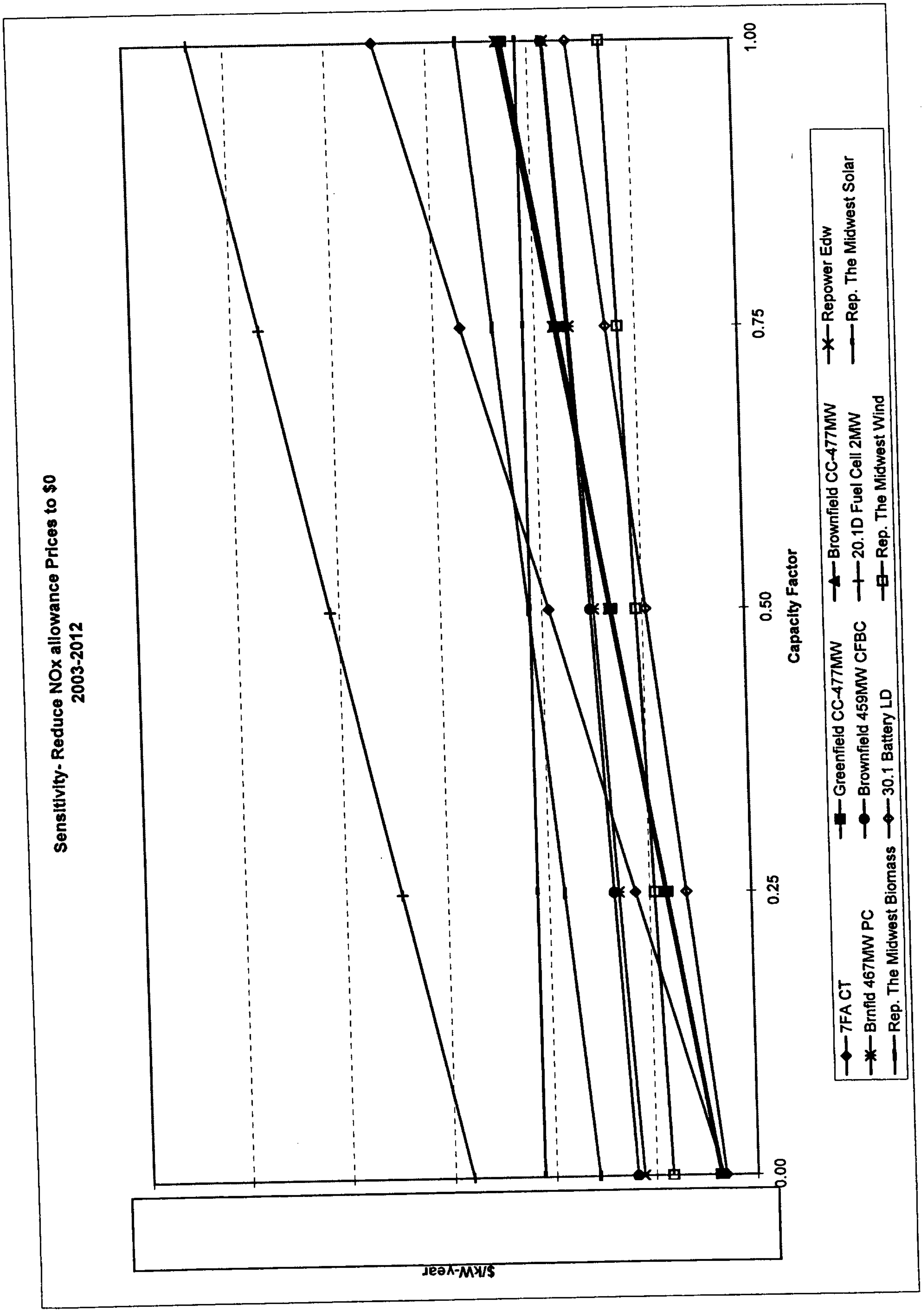


Figure GA-5-39

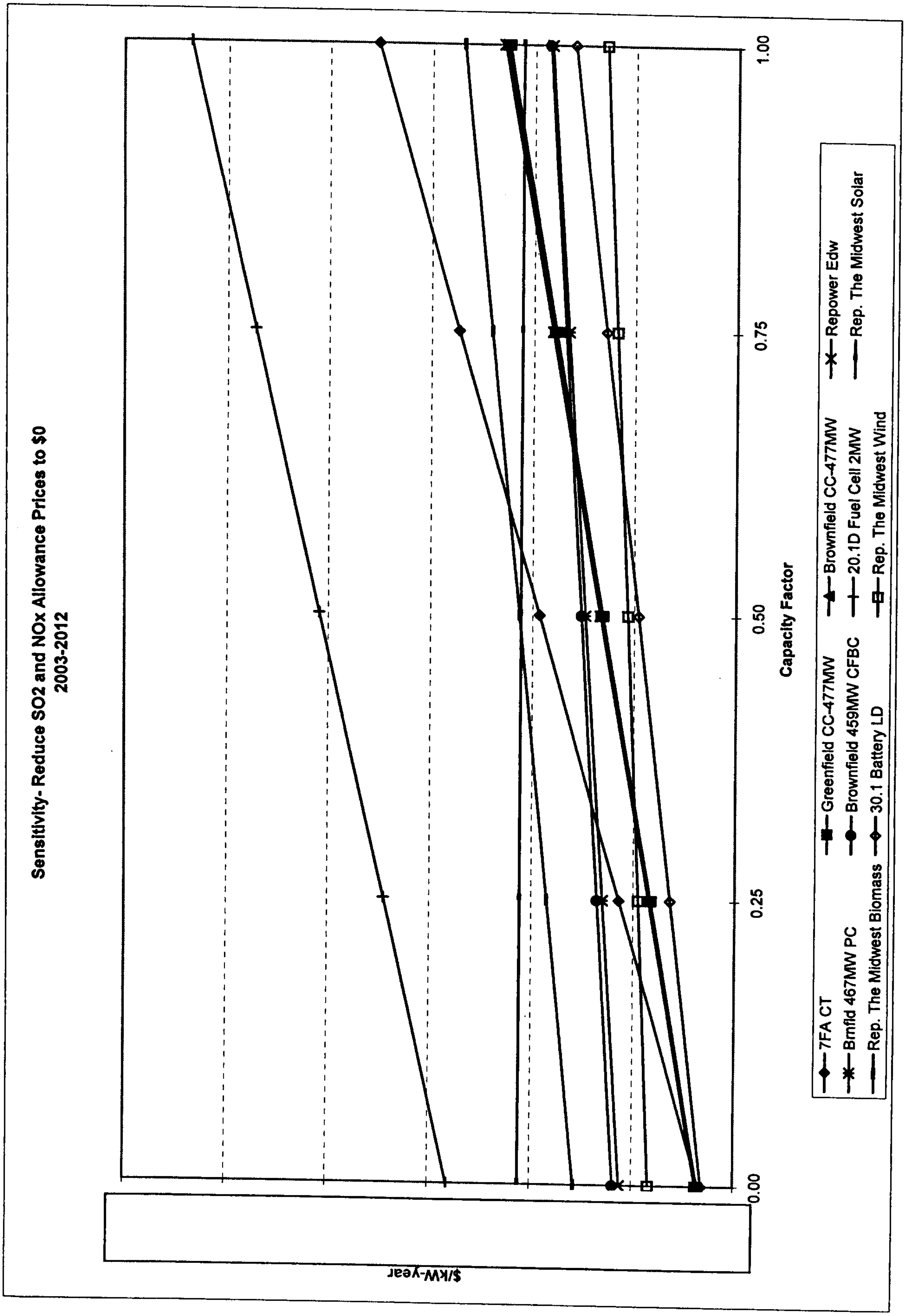


Figure GA-5-40

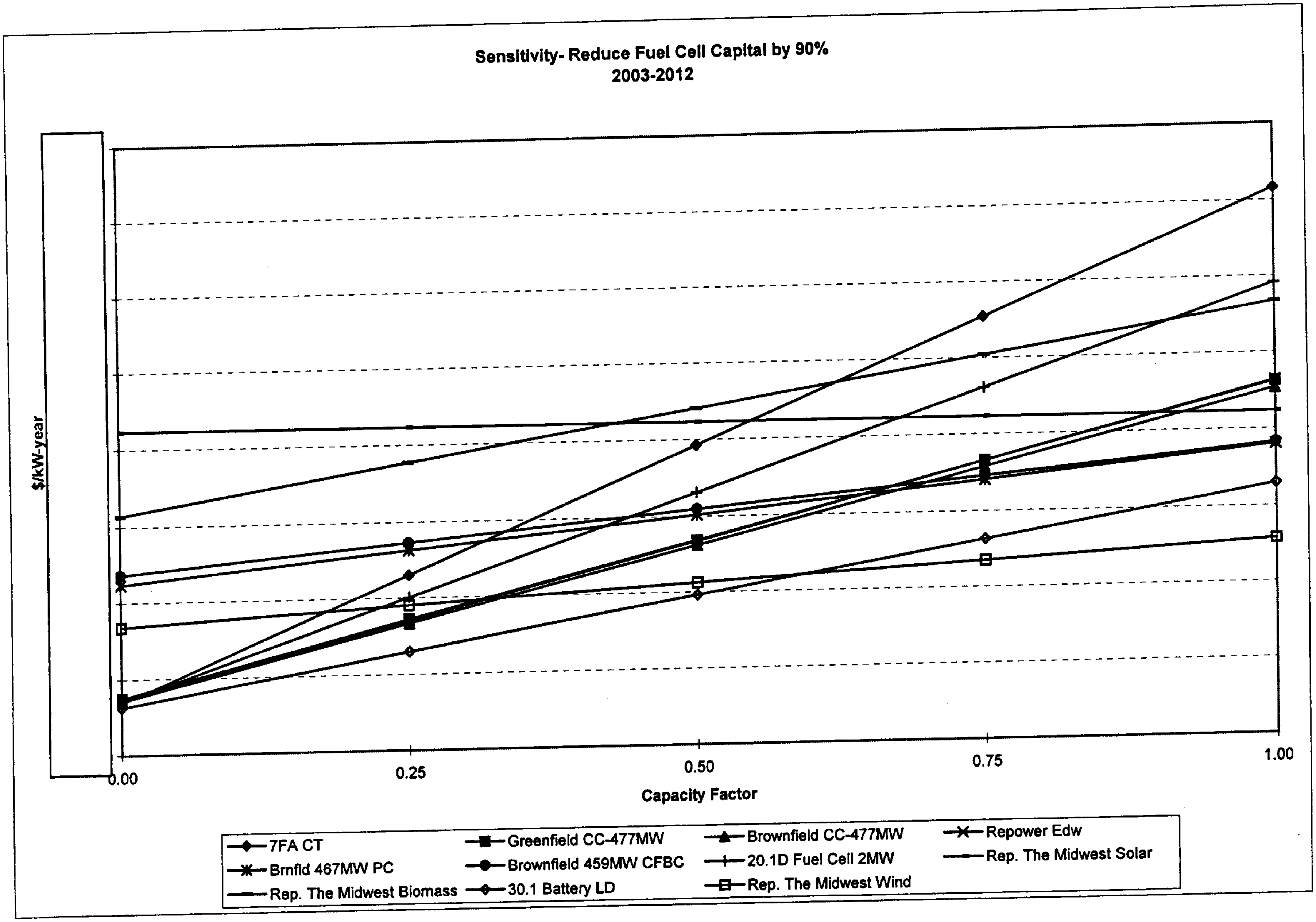


Figure A-5-41

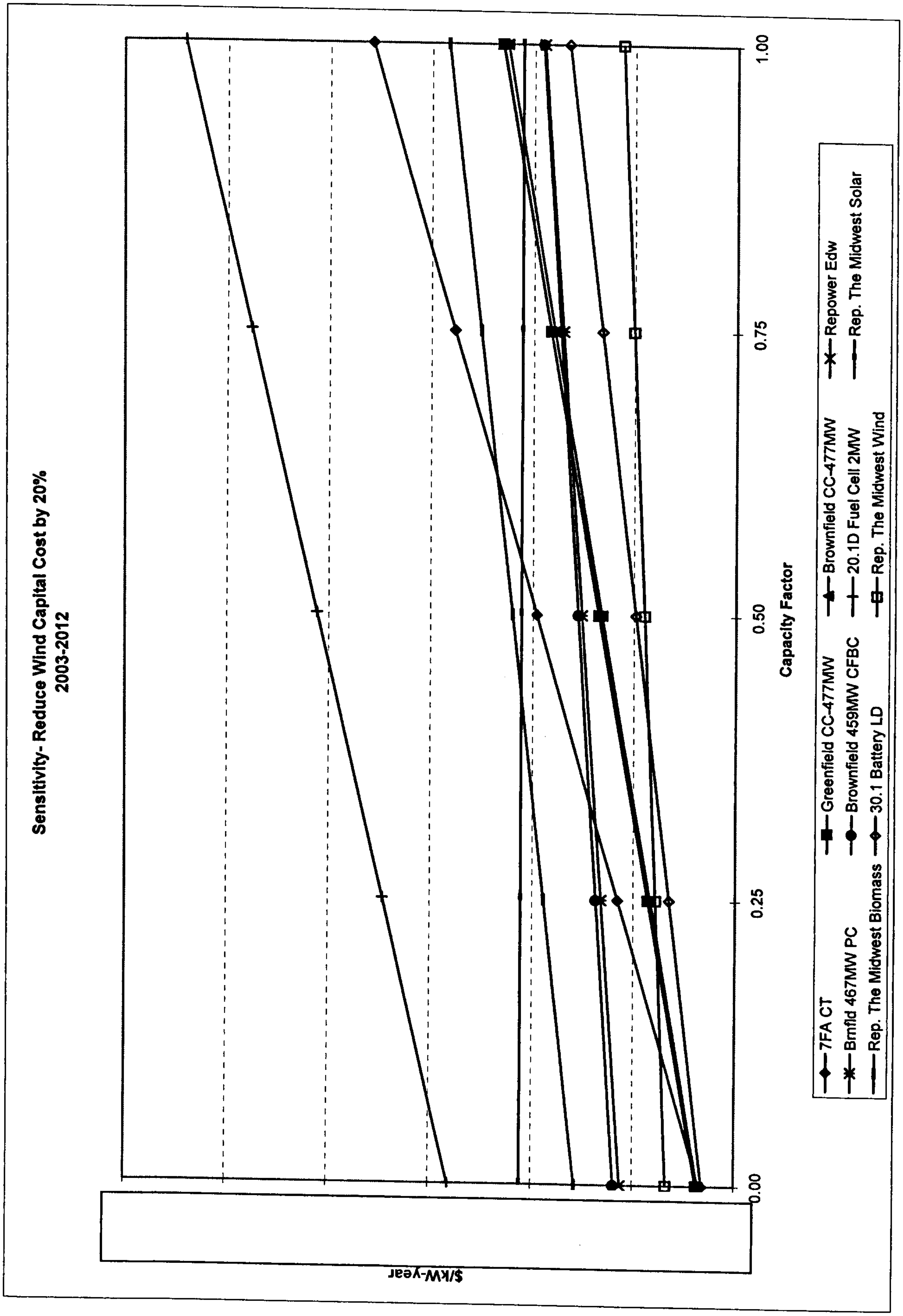

Sensitivity- Reduce Wind Capital Cost by 20%
2003-2012
$/kW-year
0.00
0.25
0.50
0.75
1.00
Capacity Factor
7FA CT
Greenfield CC-477MW
Brownfield CC-477MW
Repower Edw
Brnfld 467MW PC
Brownfield 459MW CFBC
20.1D Fuel Cell 2MW
Rep. The Midwest Solar
Rep. The Midwest Biomass
30.1 Battery LD
Rep. The Midwest Wind

Figure GA-5-42

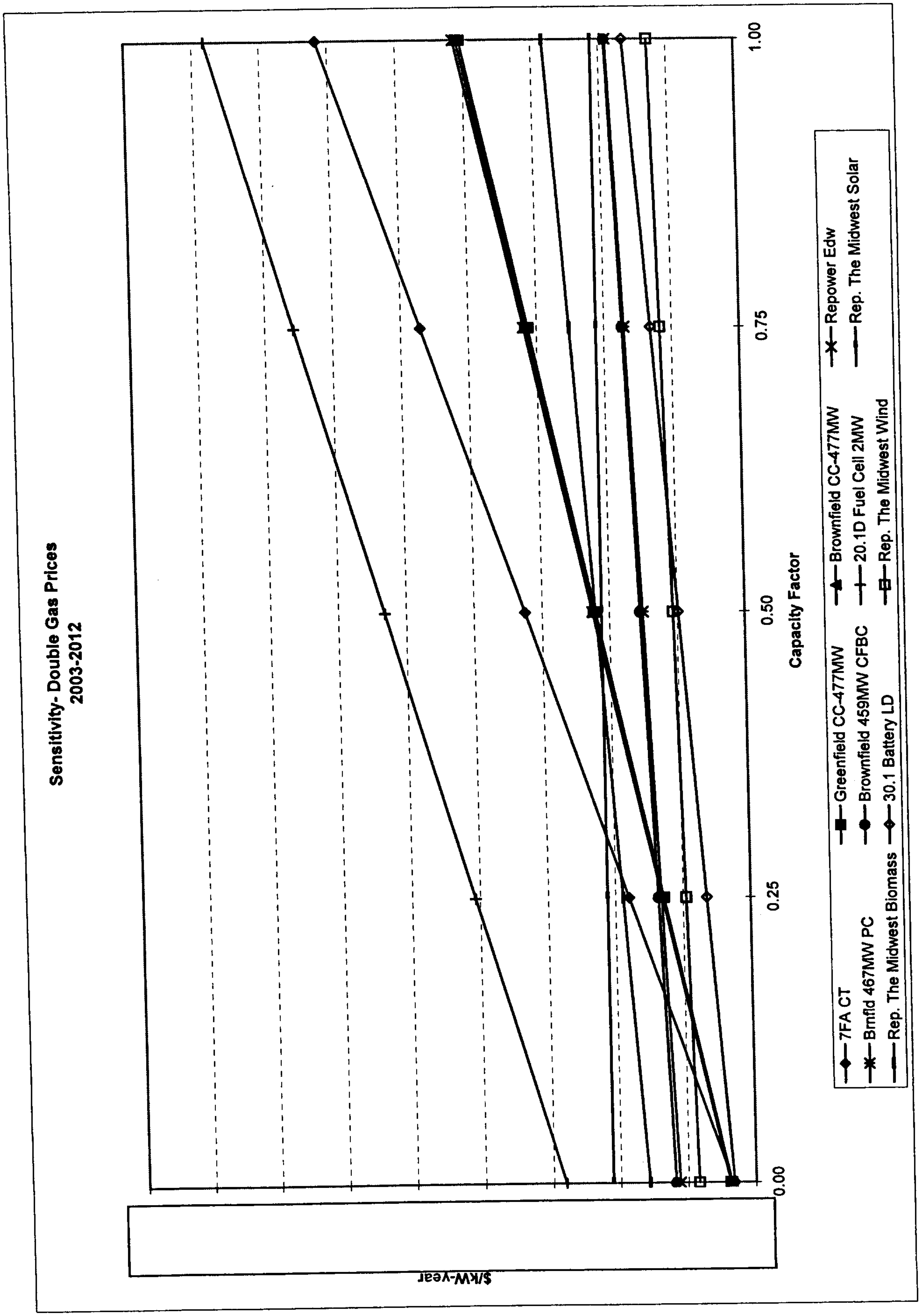


Figure GA-5-43

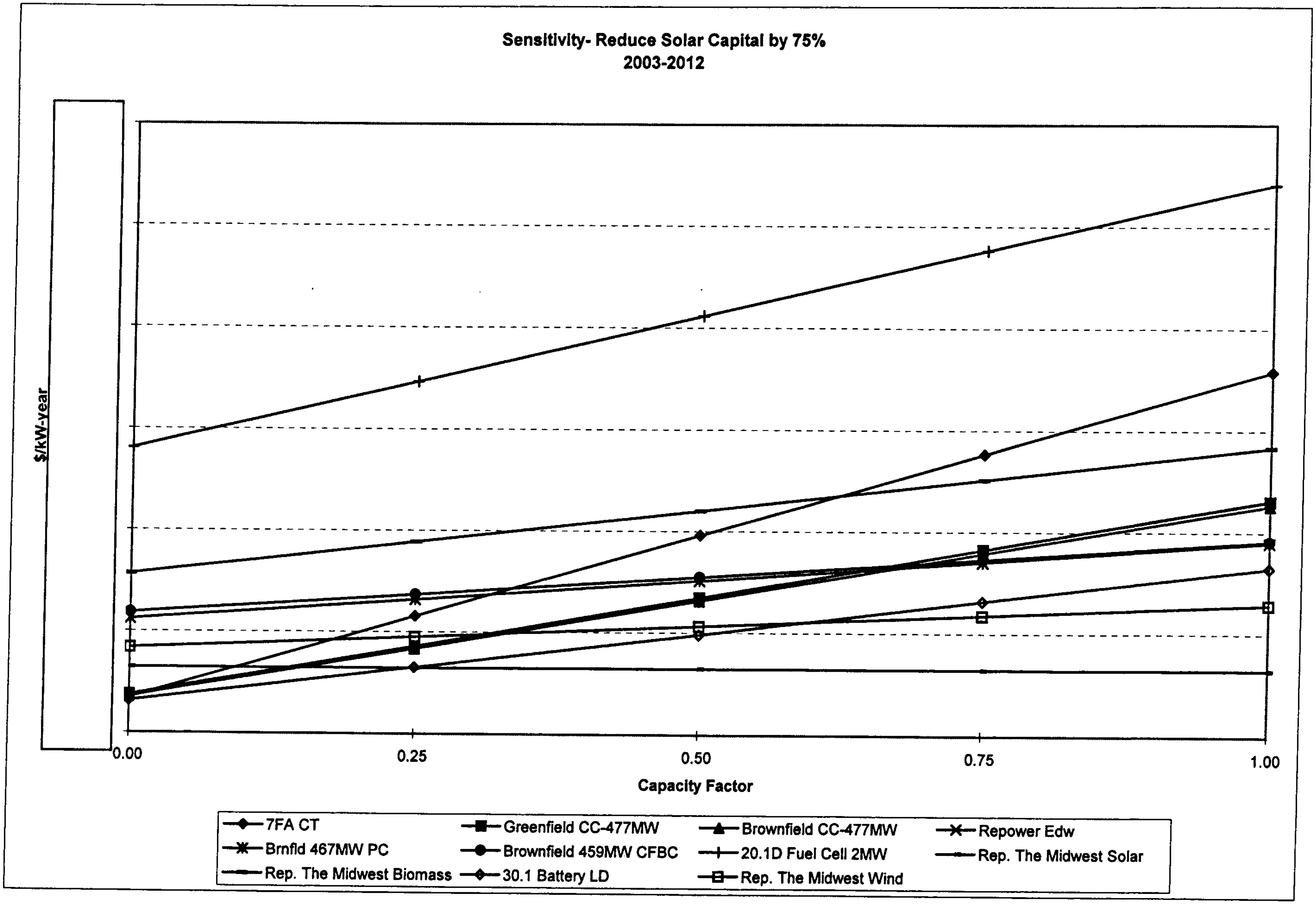


Figure GA-5-44

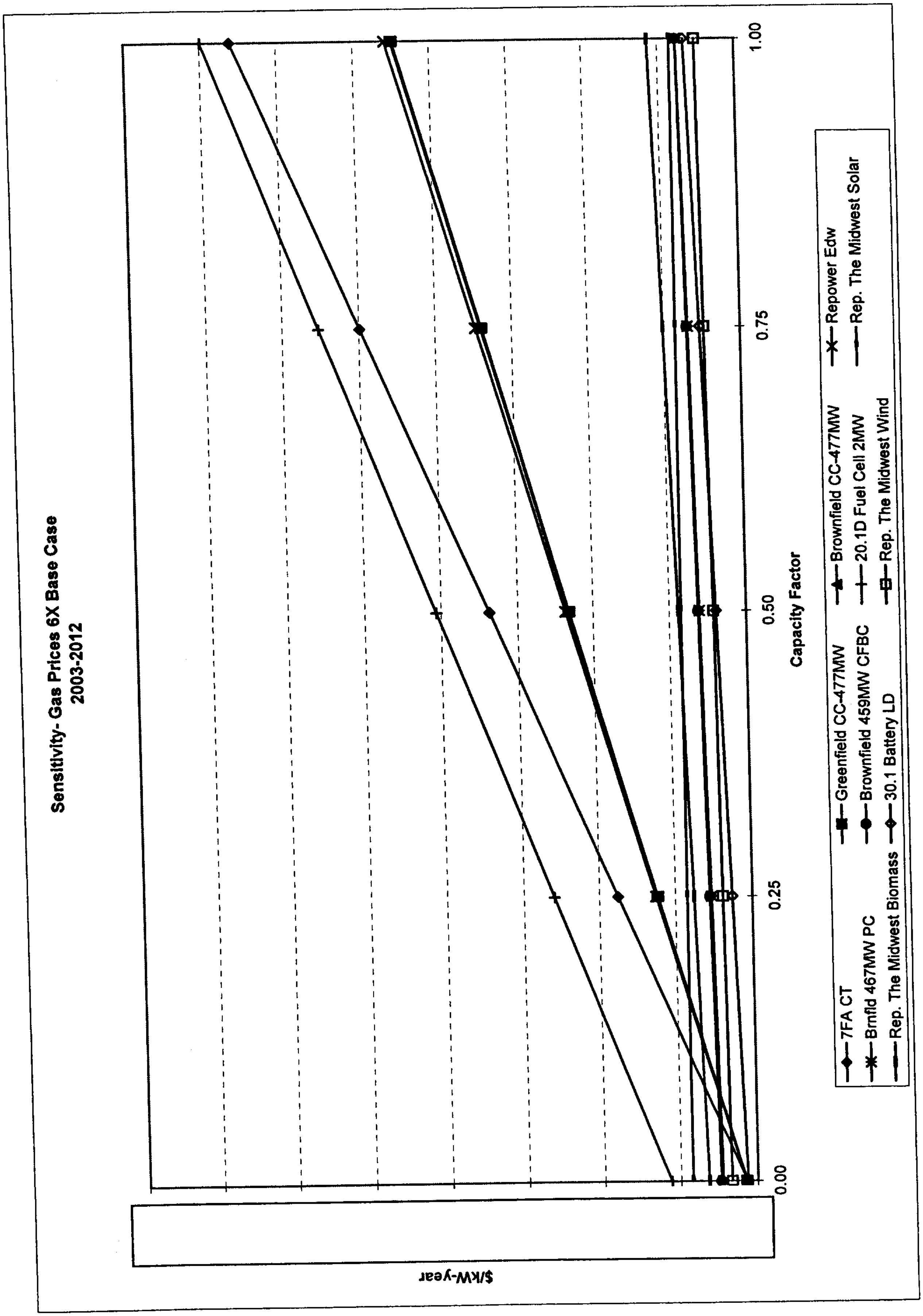


Figure A-5-45

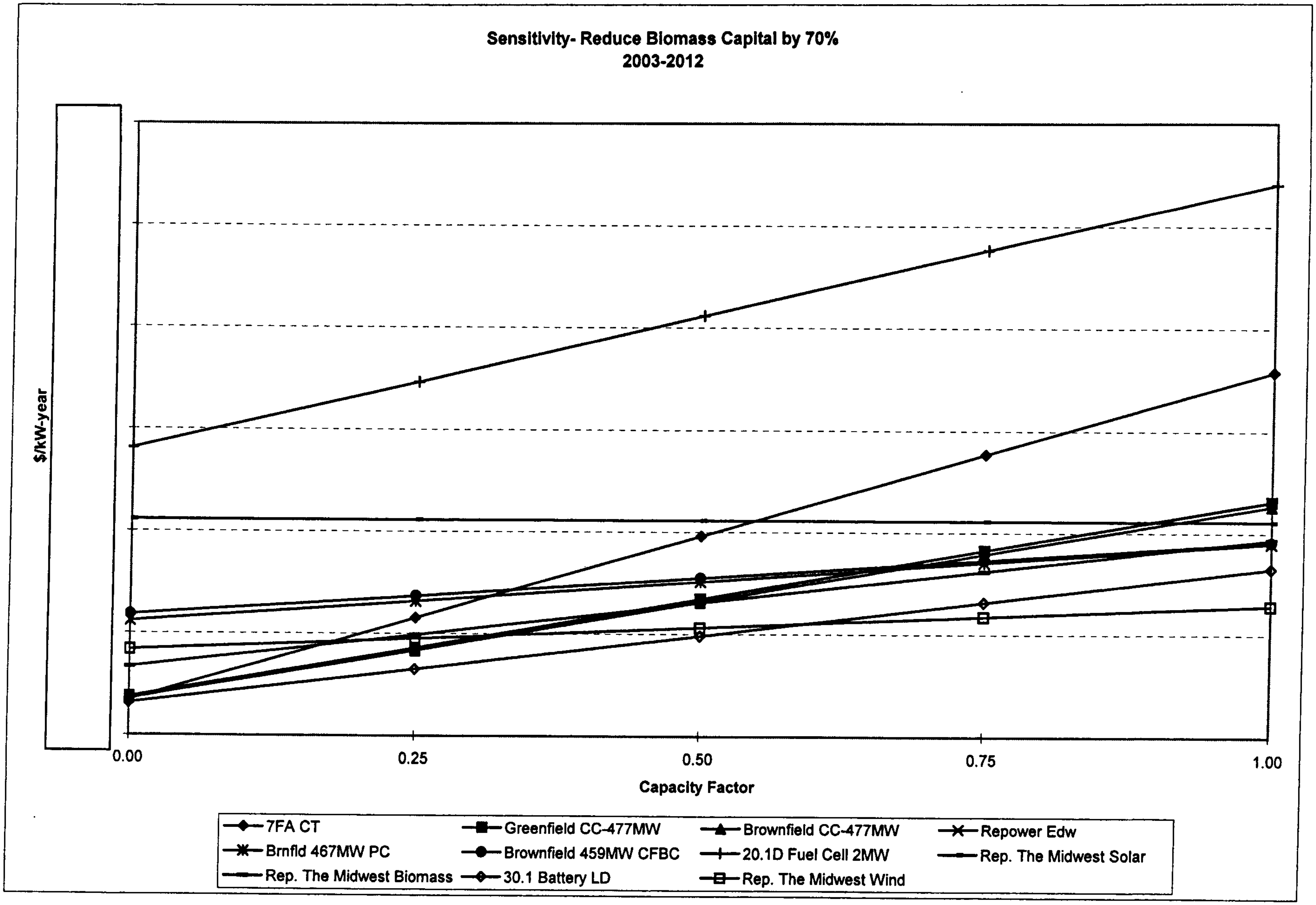

Sensitivity- Reduce Biomass Capital by 70%
2003-2012
$/kW-year
0.00
0.25
0.50
0.75
1.00
Capacity Factor
7FA CT
Greenfield CC-477MW
Brownfield CC-477MW
Repower Edw
Brnfld 467MW PC
Brownfield 459MW CFBC
20.1D Fuel Cell 2MW
Rep. The Midwest Solar
Rep. The Midwest Biomass
30.1 Battery LD
Rep. The Midwest Wind

Figure GA-5-46

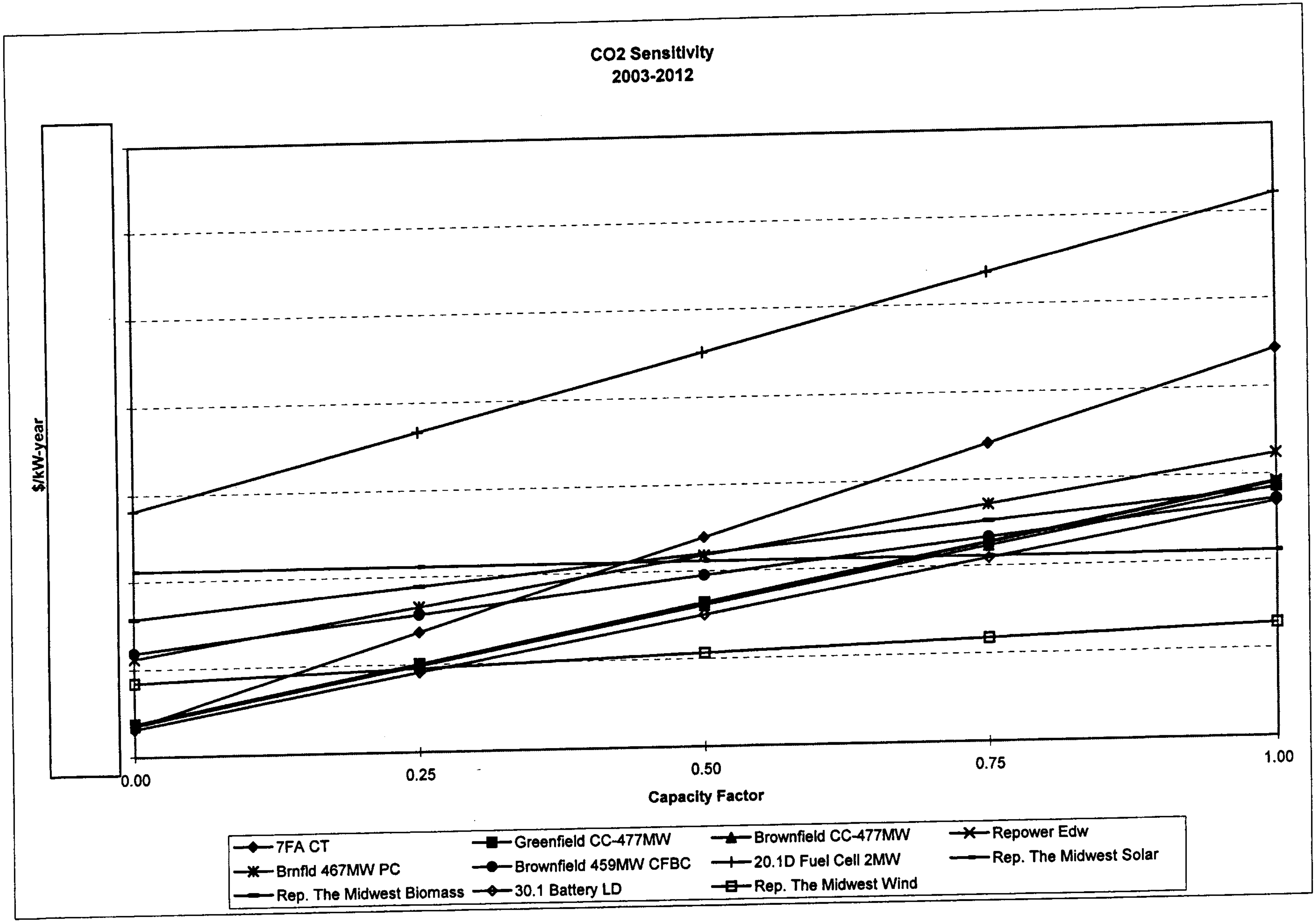
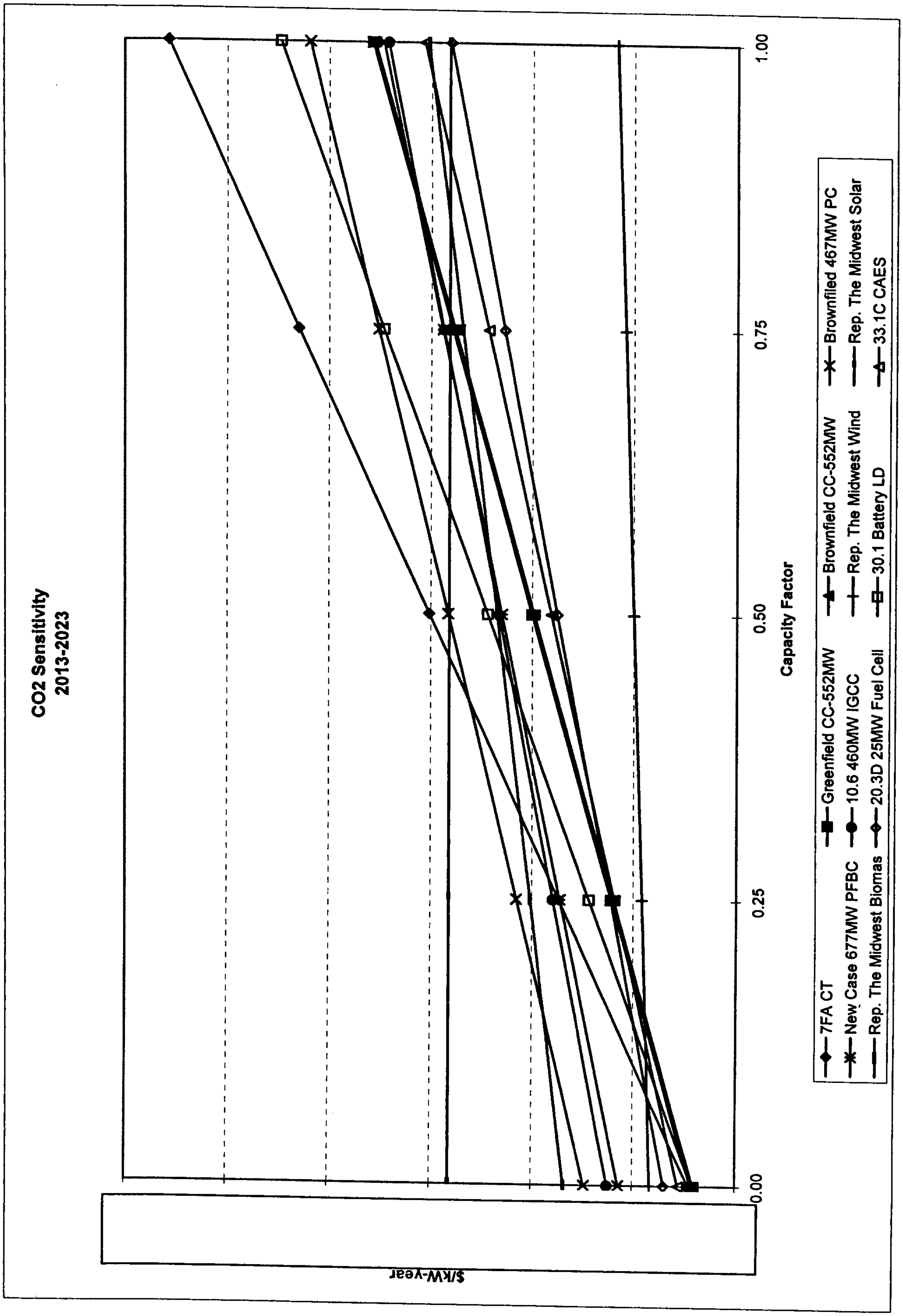


Figure GA-5-47



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SO_2 Allowance Price Forecast

The following table contains the SO_2 allowance price forecast used in the development of this IRP, in redacted form. This forecast is a trade secret and is proprietary to JD Energy. 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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SO2 Allowance Price Forecast

Year	Nominal Price $/Ton
2003	[redacted]
2004	
2005	
2006	
2007	
2008	
2009	
2010	
2011	
2012	
2013	
2014	
2015	
2016	
2017	
2018	
2019	
2020	
2021	
2022	
2023	

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NO_x Allowance Price Forecast

The following table contains the NO_x allowance price forecast used in the development of this IRP, in redacted form. This forecast is a trade secret and is proprietary to ICF Consulting. 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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NOx Allowance Price Forecast

Year	Nominal Price $/Ton
2003	[redacted]
2004	
2005	
2006	
2007	
2008	
2009	
2010	
2011	
2012	
2013	
2014	
2015	
2016	
2017	
2018	
2019	
2020	
2021	
2022	
2023	

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CINERGY®

The Union Light, Heat & Power Company

2003

INTEGRATED RESOURCE PLAN

VOLUME I

SECONDARY APPENDIX

April 1, 2004

By: The Union Light, Heat and Power Company.
Gregory C. Ficke, President
139 East Fourth Street
Cincinnati, OH 45202

SECONDARY APPENDIX
Table of Contents

IN COMPLIANCE WITH THE STANDARDS 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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Section 4(2) Identification of Individuals Responsible for Preparation of the Plan

The following individuals are responsible for the preparation of this filing:

Name	Department
Diane L. Jenner	Asset Planning and Analysis
Richard G. Stevie	Market Analysis
James A. Riddle	Market Analysis
Ronald C. Snead	Bulk Transmission Planning

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Section 6 Significant Changes

Waiver received.

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Section 7(2)(a) Number of customers by Class

The following page contains the data requested.

Section 7. (2) (a)

UNION LIGHT, HEAT AND POWER COMPANY
ELECTRIC CUSTOMERS BY MAJOR CLASSIFICATIONS
ANNUAL AVERAGES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	OTHER PUBLIC AUTHORITY
1997	104,529	10,926	399	117	889
1998	106,433	11,201	400	126	886
1999	108,453	11,624	395	142	900
2000	110,477	11,958	395	192	923
2001	112,163	12,251	430	251	946
2002	111,518	12,126	400	198	952
2003	112,313	12,288	404	195	971
2004	113,358	12,453	407	196	990
2005	114,394	12,616	408	198	1,006
2006	115,661	12,804	409	202	1,021
2007	116,909	12,996	410	208	1,033
2008	118,046	13,170	410	214	1,042
2009	119,208	13,343	411	220	1,051
2010	120,413	13,523	411	228	1,062
2011	121,648	13,714	411	236	1,073
2012	122,830	13,891	411	243	1,074
2013	123,996	14,067	411	252	1,075
2014	125,113	14,238	411	260	1,075
2015	126,202	14,403	411	268	1,075
2016	127,268	14,566	411	276	1,074
2017	128,292	14,724	411	284	1,071
2018	129,273	14,875	411	293	1,066
2019	130,225	15,022	411	300	1,060
2020	131,147	15,164	411	309	1,053
2021	132,047	15,303	411	316	1,045
2022	132,929	15,440	411	324	1,035
2023	133,802	15,575	411	332	1,024
2024	134,674	15,711	411	340	1,014
2025	135,544	15,846	411	348	1,005
2026	136,459	15,987	411	357	996

NOTE: 2002 FIGURES REPRESENT TWELVE MONTHS FORECAST

Section 7(2)(b) and (c) Weather Normalized Data

The following page contains the requested data.

Section 7. (2) (b) and (c)

UNION LIGHT, HEAT AND POWER COMPANY
WEATHER NORMALIZED
ANNUAL ENERGY AND PEAKS

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	OTHER PUBLIC AUTHORITY
1998	1,223,110	979,440	1,046,055	15,713	346,753
1999	1,239,176	1,041,319	965,811	16,764	353,531
2000	1,285,337	1,167,854	1,033,005	18,029	318,129
2001	1,302,665	1,294,151	880,194	17,163	292,368
2002	1,316,806	1,295,939	765,600	19,493	287,160

	INTER DEPARTMENT	COMPANY USE	TOTAL CONSUMPTION	LOSSES AND UNACCOUNTED FOR	NET ENERGY FOR LOAD
1998	702	771	3,612,544	36,359	3,648,903
1999	876	1,023	3,618,499	209,555	3,828,054
2000	1,761	1,996	3,826,110	227,208	4,053,319
2001	2,779	3,387	3,792,708	26,873	3,819,580
2002	2,369	4,742	3,692,108	168,545	3,860,652

	SUMMER PEAK MW	WINTER PEAK MW
1998	771	628
1999	828	700
2000	863	739
2001	799	670
2002	798	710

Section 7(4)(d) DSM Program Data

The DSM Program Data is voluminous in nature. This data will be made available to appropriate parties for viewing at Cinergy offices during normal business hours. Please contact Richard Stevie at (513) 287-2617 for more information.

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Section 7(4)(e) ULH&P Growth Rates

The following page contains the requested data.

Section 7. (4) (e)

UNION LIGHT, HEAT AND POWER COMPANY
ELECTRIC ENERGY AND PEAK LOAD
FORECAST: ANNUAL GROWTH RATES

	<u>2003 - 2023</u>
Residential MWH	1.3%
Commercial MWH	1.4%
Industrial MWH	3.3%
Net Energy MWH	1.9%
Summer Peak MW	1.4%
Winter peak MW	1.5%

Section 7(5)(a) System Weather Normalized Data

Waiver received.

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Section 7(7)(a) Data Set Description

The following pages contain the descriptions of the variables contained in the load forecast model.

VARIABLE	DESCRIPTION
LKWHCUSRESNS@CGE	=LOG(KWHCUSRESNS@CGE)
LRPCYP@CGE@APP	=LOG(APPLSTK@EFF@CGE*(YP@CGE/N@CGE/CPI))
LRMP@RES@CGE@APP	=LOG(APPLSTK@EFF@CGE*(MP@RES@CGE/CPI))
HDDB@24@500	=MINIMUM(HDDB,500)
MJFM	=MJAN+MFEB+MMAR
HDDB@24@500@1000	=MAXIMUM(0,MINIMUM(HDDB-500,500))
HDDB@24@1000	=MAXIMUM(HDDB-1000,0)
CDDB@24@100	=MINIMUM(CDDB,100)
MOCT	QUALITATIVE VARIABLE - OCTOBER
CDDB@24@100@200	=MAXIMUM(0,MINIMUM(HDDB-100,100))
MAUG	QUALITATIVE VARIABLE - AUGUST
CDDB@24@200	=MAXIMUM(HDDB-200,0)
MMAY	QUALITATIVE VARIABLE - MAY
MJJA	=MJUN+MJUL+MAUG
MSEP	QUALITATIVE VARIABLE - SEPTEMBER
SAT@RAC@EFF	=EFF@RAC@CGE*SAT@RAC@CGE
MJAN	QUALITATIVE VARIABLE - JANUARY
MDEC	QUALITAITVE VARIABLE - DECEMBER
EFF@EHP@CGE	EFFICIENCY OF ELECTRIC HEAT PUMP UNITS IN SERVICE AREA
MNOV	QUALITATIVE VARIABLE - NOVEMBER
MFEB	QUALITATIVE VARIABLE - FEBRUARY
M6519612	QUALITATIVE VARIABLE - JANUARY, 1965 TO DECEMBER, 1996
MMAR	QUALITATIVE VARIABLE - MARCH
MAPR	QUALITATIVE VARIABLE - APRIL
HDDB@24	BILLING HEATING DEGREE DAYS
SAT@EH@EFF	=(SAT@ER@CGE+(SAT@EHP@CGE*EFF@EHP@CGE))
MJUN	QUALITATIVE VARIABLE - JUNE
M6519312	QUALITATIVE VARIABLE - JANUARY, 1965 TO DECEMBER, 1993
MJUL	QUALITATIVE VARIABLE - JULY
CDDB@24	BILLING COOLING DEGREE DAYS
SAT@CAC@EFF	=EFF@CAC@CGE*(SAT@EHP@CGE+SAT@CACNHP@CGE)
M8118512	QUALITATIVE VARIABLE - JANUARY, 1981 THRU DECEMBER, 1985
M829	QUALITATIVE VARIABLE - SEPTEMBER, 1982
M855	QUALITATIVE VARIABLE - MAY, 1985
M8512	QUALITATIVE VARIABLE - DECEMBER, 1985
M918	QUALITATIVE VARIABLE - AUGUST, 1991
M919	QUALITATIVE VARIABLE - SEPTEMBER, 1991
M938	QUALITATIVE VARIABLE - AUGUST, 1993
M9511	QUALITATIVE VARIABLE - NOVEMBER, 1995
M996	QUALITATIVE VARIABLE - JUNE, 1999
M005	QUALITATIVE VARIABLE - MAY, 2000
M019	QUALITATIVE VARIABLE - SEPTEMBER, 2001

AND:

KWHCUSRESNS@CGE	SERVICE AREA KWH SALES - USE PER RESIDENTIAL CUSTOMER
YP@CGE	SERVICE AREA PERSONAL INCOME
N@CGE	SERVICE AREA TOTAL POPULATION
APPLSTK@EFF@CGE	EFFICIENT APPLIANCE STOCK
MP@RES@CGE	MARGINAL PRICE OF ELECTRICITY - RESIDENTIAL
CPI	CONSUMER PRICE INDEX (ALL URBAN) - ALL ITEMS

MJAN	QUALITATIVE VARIABLE - JANUARY
MFEB	QUALITATIVE VARIABLE - FEBRUARY
MMAR	QUALITATIVE VARIABLE - MARCH
CDDB	BILLING COOLING DEGREE DAYS
HDDB	BILLING HEATING DEGREE DAYS
MJUN	QUALITATIVE VARIABLE - JUNE
MJUL	QUALITATIVE VARIABLE - JULY
MAUG	QUALITATIVE VARIABLE - AUGUST
EFF@RAC@CGE	EFFICIENCY OF WINDOW AIR CONDITIONING UNITS IN SERVICE AREA
SAT@RAC@CGE	SERVICE AREA SATURATION OF WINDOW AIR CONDITIONING
SAT@ER@CGE	SATURATION RATE OF ELECTRIC RESISTANCE HEATERS IN SERVICE AREA
EFF@EHP@CGE	EFFICIENCY OF ELECTRIC HEAT PUMP UNITS IN SERVICE AREA
EFF@CAC@CGE	EFFICIENCY OF CENTRAL AIR CONDITIONING UNITS IN SERVICE AREA
SAT@EHP@CGE	SERVICE AREA SATURATION OF ELECTRIC HEAT PUMPS - RESIDENTIAL
SAT@CACNHP@CGE	SERVICE AREA SATURATION OF CENTRAL AIR CONDITIONING WITHOUT HEAT PUMP

LKWHCOMNS@CGE	=LOG(KWHCOMNS@CGE)
LECOMNS@CGE	=LOG(ECOMNS@CGE)
LDS@KWH@COM@CPI	=LOG(DS@KWH@COM@CGE/CPI)
LRAPGCOM@CGE	=LOG(APGCOM@CGE/CPI)
HDDB@24@EFF	=HDDB@24*(SAT@ER@CGE+SAT@EHP@CGE*EFF@EHP@CGE)
HDDB@24	BILLING HEATING DEGREE DAYS
CDDB@24@EFF@CAC	=CDDB@24*EFF@CAC@CGE*(SAT@EHP@CGE+SAT@CACHP@CGE)
CDDB@24	BILLING COOLING DEGREE DAYS
MJAN	QUALITATIVE VARIABLE - JANUARY
MFEB	QUALITATIVE VARIABLE - FEBRUARY
MMAR	QUALITATIVE VARIABLE - MARCH
M6519612	QUALITATIVE VARIABLE - JANUARY, 1965 TO DECEMBER, 1996
MAPR	QUALITATIVE VARIABLE - APRIL
MMAY	QUALITATIVE VARIABLE - MAY
MJUN	QUALITATIVE VARIABLE - JUNE
MJUL	QUALITATIVE VARIABLE - JULY
MAUG	QUALITATIVE VARIABLE - AUGUST
MSEP	QUALITATIVE VARIABLE - SEPTEMBER
MOCT	QUALITATIVE VARIABLE - OCTOBER
MNOV	QUALITATIVE VARIABLE - NOVEMBER
MDEC	QUALITAITVE VARIABLE - DECEMBER
M7511	QUALITATIVE VARIABLE - NOVEMBER, 1975
M9512	QUALITATIVE VARIABLE - DECEMBER, 1995
M817	QUALITATIVE VARIABLE - JULY, 1981
M9111	QUALITATIVE VARIABLE - NOVEMBER, 1991
M833	QUALITATIVE VARIABLE - MARCH, 1983
M914	QUALITATIVE VARIABLE - APRIL, 1991
M939	QUALITATIVE VARIABLE - SEPTEMBER, 1993
M988	QUALITATIVE VARIABLE - AUGUST, 1998
M9311	QUALITATIVE VARIABLE - NOVEMBER, 1993
M954	QUALITATIVE VARIABLE - APRIL, 1995
M956	QUALITATIVE VARIABLE - JUNE, 1995
M978	QUALITATIVE VARIABLE - AUGUST, 1997

M993	QUALITATIVE VARIABLE - MARCH, 1999
M998	QUALITATIVE VARIABLE - AUGUST, 1999
M001	QUALITATIVE VARIABLE - JANUARY, 2000
M007	QUALITATIVE VARIABLE - JULY, 2000
M0010	QUALITATIVE VARIABLE - OCTOBER, 2000

AND:

KWHCOMNS@CGE	KWH SALES - COMMERCIAL
ECOMNS@CGE	SERVICE AREA EMPLOYMENT - COMMERCIAL
DS@KWH@COM@CGE	SERVICE AREA DS RATE FOR USAGE FOR COMMERCIAL CUSTOMER
APGCOM@CGE	SERVICE AREA AVERAGE PRICE OF GAS FOR COMMERCIAL CUSTOMER
CPI	CONSUMER PRICE INDEX (ALL URBAN) - ALL ITEMS
HDDB@24	BILLING HEATING DEGREE DAYS
SAT@ER@CGE	SATURATION RATE OF ELECTRIC RESISTANCE HEATERS IN SERVICE AREA
EFF@EHP@CGE	EFFICIENCY OF ELECTRIC HEAT PUMP UNITS IN SERVICE AREA
CDDB@24	BILLING COOLING DEGREE DAYS
EFF@CAC@CGE	EFFICIENCY OF CENTRAL AIR CONDITIONING UNITS IN SERVICE AREA
SAT@EHP@CGE	SERVICE AREA SATURATION OF ELECTRIC HEAT PUMPS - RESIDENTIAL
SAT@CACHP@CGE	SERVICE AREA SATURATION OF CENTRAL AIR CONDITIONING WITHOUT HEAT PUMP

LKWH20NS@CGE	=LOG(KWH20NS@CGE)
LJQIND20@CGE	=LOG(JQIND20@CGE)
LDS@KW@IND@CPI	=LOG(DS@KW@IND@CGE/CPI)
LDS@KWH@IND@CPI	=LOG(DS@KWH@IND@CGE/CPI)
LDS@KWH@IND@OIL	=LOG(DS@KWH@IND@CGE/WPI0561)
CDDB@24	BILLING COOLING DEGREE DAYS
HDDB@24	BILLING HEATING DEGREE DAYS
Q2	QUALITATIVE VARIABLE - SECOND QUARTER
Q003	QUALITATIVE VARIABLE - THIRD QUARTER, 2000

AND:

KWH20NS@CGE	KWH SALES - FOOD AND PRODUCTS
JQIND20@CGE	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - FOOD AND PRODUCTS
DS@KW@IND@CGE	SERVICE AREA DS RATE FOR DEMAND FOR INDUSTRIAL CUSTOMER
CPI	CONSUMER PRICE INDEX (ALL URBAN) - ALL ITEMS
DS@KWH@IND@CGE	SERVICE AREA DS RATE FOR USAGE FOR INDUSTRIAL CUSTOMER
WPI0561	WHOLESALE PRICE INDEX FOR CRUDE PETROLEUM

LKWH26NS@CGE	=LOG(KWH26NS@CGE)
LJQIND26@CGE	=LOG(JQIND26@CGE)
LDS@KW@IND@CPI	=LOG(DS@KW@IND@CGE/CPI)
LDS@KWH@IND@AHEM	=LOG(DS@KWH@IND@CGE/AHEM@1640)
LDS@KWH@IND@APG	=LOG(DS@KWH@IND@CGE/APGIND@CGE)
Q1	QUALITATIVE VARIABLE - FIRST QUARTER
Q2	QUALITATIVE VARIABLE - SECOND QUARTER

Q3	QUALITATIVE VARIABLE - THIRD QUARTER
Q4	QUALITATIVE VARIABLE - FOURTH QUARTER
Q651984	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 THRU FOURTH QUARTER, 1998
Q781	QUALITATIVE VARIABLE - FIRST QUARTER, 1978
Q921	QUALITATIVE VARIABLE - FIRST QUARTER, 1992
Q931	QUALITATIVE VARIABLE - FIRST QUARTER, 1993
Q963	QUALITATIVE VARIABLE - THIRD QUARTER, 1996
Q003	QUALITATIVE VARIABLE - THIRD QUARTER, 2000

AND:

KWH26NS@CGE	SERVICE AREA KWH - INDUSTRIAL - PAPER AND PRODUCTS
JQIND26@CGE	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - PAPER AND PRODUCTS
DS@KW@IND@CGE	SERVICE AREA DS RATE FOR DEMAND FOR INDUSTRIAL CUSTOMER
CPI	CONSUMER PRICE INDEX (ALL URBAN) - ALL ITEMS
AHEM@1640	SERVICE AREA AVERAGE HOURLY EARNINGS FOR MANUFACTURING
DS@KWH@IND@CGE	SERVICE AREA DS RATE FOR USAGE FOR INDUSTRIAL CUSTOMER
APGIND@CGE	SERVICE AREA AVERAGE PRICE OF GAS FOR INDUSTRIAL CUSTOMERS

LKWH28NS@CGE	=LOG(KWH28NS@CGE)
LJQIND28@CGE	=LOG(JQIND28@CGE)
LTS@KWH@IND@AHEM	=LOG(TS@KWH@IND@CGE/AHEM@1640)
Q651854	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 TO FOURTH QUARTER, 1985
LTS@KWH@IND@COAL	=LOG(TS@KWH@IND@CGE/WPI051)
CDDB@24	BILLING COOLING DEGREE DAYS
HDDB@24	BILLING HEATING DEGREE DAYS
Q651824	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 TO
Q1	QUALITATIVE VARIABLE - FIRST QUARTER
Q2	QUALITATIVE VARIABLE - SECOND QUARTER
Q4	QUALITATIVE VARIABLE - FOURTH QUARTER
Q651994	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 TO FOURTH QUARTER, 1999
Q3	QUALITATIVE VARIABLE - THIRD QUARTER
Q833	QUALITATIVE VARIABLE - THIRD QUARTER, 1983
Q923	QUALITATIVE VARIABLE - THIRD QUARTER, 1992
Q973	QUALITATIVE VARIABLE - THIRD QUARTER, 1997
Q994	QUALITATIVE VARIABLE - FOURTH QUARTER, 1999
Q004	QUALITATIVE VARIABLE - FOURTH QUARTER, 2000

AND:

KWH28NS@CGE	SERVICE AREA KWH SALES - INDUSTRIAL - CHEMICALS AND PRODUCTS
JQIND28@CGE	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - CHEMICALS AND PRODUCTS
AHEM@1640	SERVICE AREA AVERAGE HOURLY EARNINGS FOR MANUFACTURING
TS@KWH@IND@CGE	SERVICE AREA TS RATE FOR USAGE FOR INDUSTRIAL CUSTOMER
WPI051	PRODUCER PRICE INDEX - COAL

LKWH33LARMNS@CGE	=LOG(KWH33LARMNS@CGE)
LJQIND33@CMSA	=LOG(JQIND33@CMSA)
LTS@KWH@IND@APG	=LOG(TS@KWH@IND@CGE/APGIND@CGE)
LTS@KWH@IND@OIL	=LOG(TS@KWH@IND@CGE/WPI0561)
Q651934	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 TO FOURTH QUARTER, 1993
LRPCOCP	=LOG(PCOCP/CPI)
Q1	QUALITATIVE VARIABLE - FIRST QUARTER
Q2	QUALITATIVE VARIABLE - SECOND QUARTER
Q3	QUALITATIVE VARIABLE - THIRD QUARTER
Q4	QUALITATIVE VARIABLE - FOURTH QUARTER
Q651982	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 TO SECOND QUARTER, 1998
Q651012	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 TO SECOND QUARTER, 2001
Q852	QUALITATIVE VARIABLE - SECOND QUARTER, 1985
Q004	QUALITATIVE VARIABLE - FOURTH QUARTER, 2000
Q984	QUALITATIVE VARIABLE - FOURTH QUARTER, 1998
Q992	QUALITATIVE VARIABLE - SECOND QUARTER, 1999
Q993	QUALITATIVE VARIABLE - THIRD QUARTER, 1999

AND:

KWH33LARMNS@CGE	SERVICE AREA LESS AK STEEL - INDUSTRIAL - PRIMARY METAL INDUSTRIES
JQIND33@CMSA	CINCINNATI CMSA INDUSTRIAL PRODUCTION INDEX - PRIMARY METAL INDUSTRIES
APGIND@CGE	SERVICE AREA AVERAGE PRICE OF GAS FOR INDUSTRIAL CUSTOMERS
TS@KWH@IND@CGE	SERVICE AREA TS RATE FOR USAGE FOR INDUSTRIAL CUSTOMER
WPI0561	WHOLESALE PRICE INDEX FOR CRUDE PETROLEUM
PCOCP	AVERAGE REFINERS' ACQUISITION PRICE - CRUDE OIL - COMPOSITE
CPI	CONSUMER PRICE INDEX (ALL URBAN) - ALL ITEMS

LKWH35NS@CGE	=LOG(KWH35NS@CGE)
LJQIND35@CGE	=LOG(JQIND35@CGE)
LDS@KW@IND@CPI	=LOG(DS@KW@IND@CGE/CPI)
LDS@KWH@IND@APG	=LOG(DS@KWH@IND@CGE/APGIND@CGE)
CDDB@24	BILLING COOLING DEGREE DAYS
Q651864	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 THRU FOURTH QUARTER, 1986
HDDB@24	BILLING HEATING DEGREE DAYS
Q1	QUALITATIVE VARIABLE - FIRST QUARTER
Q2	QUALITATIVE VARIABLE - SECOND QUARTER
Q3	QUALITATIVE VARIABLE - THIRD QUARTER
Q4	QUALITATIVE VARIABLE - FOURTH QUARTER
Q781	QUALITATIVE VARIABLE - FIRST QUARTER, 1978
Q002	QUALITATIVE VARIABLE - SECOND QUARTER, 2000

AND:

KWH35NS@CGE	SERVICE AREA KWH SALES - INDUSTRIAL - INDUSTRIAL MACHINERY AND EQUIPMENT
JQIND35@CGE	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - INDUSTRIAL MACHINERY AND EQUIPMENT

DS@KW@IND@CGE	SERVICE AREA DS RATE FOR DEMAND FOR INDUSTRIAL CUSTOMER
CPI	CONSUMER PRICE INDEX (ALL URBAN) - ALL ITEMS
DS@KWH@IND@CGE	SERVICE AREA DS RATE FOR USAGE FOR INDUSTRIAL CUSTOMER
APGIND@CGE	SERVICE AREA AVERAGE PRICE OF GAS FOR INDUSTRIAL CUSTOMERS

LKWH36NS@CGE	=LOG(KWH36NS@CGE)
LJQIND36@CGE	=LOG(JQIND36@CGE)
LDS@KWH@IND@OIL	=LOG(DS@KWH@IND@CGE/WPI0561)
LDS@KWH@IND@APGL4	=LOG(DS@KWH@IND@CGE/APGIND@CGE)\4
Q1	QUALITATIVE VARIABLE - FIRST QUARTER
Q2	QUALITATIVE VARIABLE - SECOND QUARTER
Q3	QUALITATIVE VARIABLE - THIRD QUARTER
Q4	QUALITATIVE VARIABLE - FOURTH QUARTER
Q761	QUALITATIVE VARIABLE - FIRST QUARTER, 1976
Q883	QUALITATIVE VARIABLE - THIRD QUARTER, 1988
Q884	QUALITATIVE VARIABLE - FOURTH QUARTER, 1988
Q891	QUALITATIVE VARIABLE - FIRST QUARTER, 1989
Q922	QUALITATIVE VARIABLE - SECOND QUARTER, 1992

AND:

KWH36NS@CGE	SERVICE AREA KWH SALES - INDUSTRIAL - ELECTRONIC AND OTHER ELECTRICAL EQUIPMENT
JQIND36@CGE	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - ELECTRONIC AND OTHER ELECTRICAL EQUIPMENT
WPI0561	WHOLESALE PRICE INDEX FOR CRUDE PETROLEUM
DS@KWH@IND@CGE	SERVICE AREA DS RATE FOR USAGE FOR INDUSTRIAL CUSTOMER
APGIND@CGE	SERVICE AREA AVERAGE PRICE OF GAS FOR INDUSTRIAL CUSTOMERS

LKWH371NS@CGE	=LOG(KWH371NS@CGE)
LJQIND371@CGE	=LOG(JQIND371@CGE)
LTS@KWH@IND@OIL	=LOG(TS@KWH@IND@CGE/WPI0561)
CDDB@24	BILLING COOLING DEGREE DAYS
HDDB@24	BILLING HEATING DEGREE DAYS
Q2	QUALITATIVE VARIABLE - SECOND QUARTER
Q3	QUALITATIVE VARIABLE - THIRD QUARTER
Q4	QUALITATIVE VARIABLE - FOURTH QUARTER
Q1	QUALITATIVE VARIABLE - FIRST QUARTER
Q651854	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 TO FOURTH QUARTER, 1985
Q651802	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 TO SECOND QUARTER, 1980
Q781	QUALITATIVE VARIABLE - FIRST QUARTER, 1978
Q784	QUALITATIVE VARIABLE - FOURTH QUARTER, 1978
Q813	QUALITATIVE VARIABLE - THIRD QUARTER, 1981
Q874	QUALITATIVE VARIABLE - FOURTH QUARTER, 1987
Q881	QUALITATIVE VARIABLE - FIRST QUARTER, 1988
Q911	QUALITATIVE VARIABLE - FIRST QUARTER, 1991
Q001	QUALITATIVE VARIABLE - FIRST QUARTER, 2000
Q013	QUALITATIVE VARIABLE - THIRD QUARTER, 2001

AND:

KWH371NS@CGE	SERVICE AREA KWH SALES - INDUSTRIAL - MOTOR VEHICLES AND PARTS
JQIND371@CGE	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - MOTOR VEHICLES AND PARTS
TS@KWH@IND@CGE	SERVICE AREA TS RATE FOR USAGE FOR INDUSTRIAL CUSTOMER
WPI0561	WHOLESALE PRICE INDEX FOR CRUDE PETROLEUM

LKWH372@9NS@CGE	=LOG(KWH372@9NS@CGE)
LJQIND372@CGE	=LOG(JQIND372@CGE)
LTS@KWH@IND@CPI	=LOG(TS@KWH@IND@CGE/CPI)
LTS@KWH@IND@APG	=LOG(TS@KWH@IND@CGE/APGIND@CGE)
CDDB@24	BILLING COOLING DEGREE DAYS
Q1	QUALITATIVE VARIABLE - FIRST QUARTER
Q2	QUALITATIVE VARIABLE - SECOND QUARTER
Q3	QUALITATIVE VARIABLE - THIRD QUARTER
Q4	QUALITATIVE VARIABLE - FOURTH QUARTER
Q781	QUALITATIVE VARIABLE - FIRST QUARTER, 1978
Q914	QUALITATIVE VARIABLE - FOURTH QUARTER, 1991
Q921	QUALITATIVE VARIABLE - FIRST QUARTER, 1992
Q942	QUALITATIVE VARIABLE - SECOND QUARTER, 1994
Q003	QUALITATIVE VARIABLE - THIRD QUARTER, 2000
Q012	QUALITATIVE VARIABLE - SECOND QUARTER, 2001
Q013	QUALITATIVE VARIABLE - THIRD QUARTER, 2001

AND:

KWH372@9NS@CGE	SERVICE AREA KWH SALES - INDUSTRIAL - TRANSPORTATION EQUIPMENT OTHER THAN MOTOR VEHICLES AND PARTS
JQIND372@CGE	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - AIRCRAFT AND PARTS
CPI	CONSUMER PRICE INDEX (ALL URBAN) - ALL ITEMS
TS@KWH@IND@CGE	SERVICE AREA TS RATE FOR USAGE FOR INDUSTRIAL CUSTOMER
APGIND@CGE	SERVICE AREA AVERAGE PRICE OF GAS FOR INDUSTRIAL CUSTOMERS

LKWHAOINS@CGE	=LOG(KWHAOINS@CGE)
LJQINDAOIDG@CGE	=LOG(JQINDAOIDG@CGE)
LJQINDAOINDG@CGE	=LOG(JQINDAOINDG@CGE)
LDS@KWH@IND@APG	=LOG(DS@KWH@IND@CGE/APGIND@CGE)
LDS@KWH@IND@OIL	=LOG(DS@KWH@IND@CGE/WPI0561)
LDS@KWH@IND@COAL	=LOG(DS@KWH@IND@CGE/WPI051)
CDDB@24	BILLING COOLING DEGREE DAYS
HDDB@24	BILLING HEATING DEGREE DAYS
Q1	QUALITATIVE VARIABLE - FIRST QUARTER
Q2	QUALITATIVE VARIABLE - SECOND QUARTER
Q3	QUALITATIVE VARIABLE - THIRD QUARTER
Q4	QUALITATIVE VARIABLE - FOURTH QUARTER
Q651002	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 THRU SECOND QUARTER, 2000
Q741	QUALITATIVE VARIABLE - FIRST QUARTER, 1974
Q771	QUALITATIVE VARIABLE - FIRST QUARTER, 1977
Q714	QUALITATIVE VARIABLE - FOURTH QUARTER, 1971

Q781	QUALITATIVE VARIABLE - FIRST QUARTER, 1978
Q931	QUALITATIVE VARIABLE - FIRST QUARTER, 1993
Q881	QUALITATIVE VARIABLE - FIRST QUARTER, 1988
Q933	QUALITATIVE VARIABLE - THIRD QUARTER, 1993
Q962	QUALITATIVE VARIABLE - SECOND QUARTER, 1996
Q002	QUALITATIVE VARIABLE - SECOND QUARTER, 2000
Q003	QUALITATIVE VARIABLE - THIRD QUARTER, 2000

AND:

KWHAOINS@CGE	SERVICE AREA KWH SALES - ALL OTHER INDUSTRIES
JQINDAOIDG@CGE	SERVICE AREA INDUSTRIAL PRODUCTION - ALL OTHER INDUSTRIES - DURABLE GOODS
JQINDAOINDG@CGE	SERVICE AREA INDUSTRIAL PRODUCTION - ALL OTHER INDUSTRIES - NON-DURABLE GOODS
APGIND@CGE	SERVICE AREA AVERAGE PRICE OF GAS FOR INDUSTRIAL CUSTOMERS
WPI0561	WHOLESALE PRICE INDEX FOR CRUDE PETROLEUM
DS@KWH@IND@CGE	SERVICE AREA DS RATE FOR USAGE FOR INDUSTRIAL CUSTOMER
WPI051	WHOLESALE PRICE INDEX FOR COAL

LKWHOPAWPNS@CGE	=LOG(KWHOPAWPNS@CGE)
LCUSRESNS@CGE	=LOG(CUSRESNS@CGE)
LDS@KW@OPA@CPI	=LOG(DS@KW@OPA@CGE/CPI)
PRC	PRECIPITATION
CDD@24	COOLING DEGREE DAYS
HDD@24	HEATING DEGREE DAYS
MJAN	QUALITATIVE VARIABLE - JANUARY
MFEB	QUALITATIVE VARIABLE - FEBRUARY
MMAR	QUALITATIVE VARIABLE - MARCH
MAPR	QUALITATIVE VARIABLE - APRIL
MMAY	QUALITATIVE VARIABLE - MAY
MJUN	QUALITATIVE VARIABLE - JUNE
MJUL	QUALITATIVE VARIABLE - JULY
MAUG	QUALITATIVE VARIABLE - AUGUST
MSEP	QUALITATIVE VARIABLE - SEPTEMBER
MOCT	QUALITATIVE VARIABLE - OCTOBER
MNOV	QUALITATIVE VARIABLE - NOVEMBER
MDEC	QUALITAITVE VARIABLE - DECEMBER
SUMMER885888	QUALITATIVE VARIABLE - MAY, 1988 THRU AUG, 1988
M6519910	QUALITATIVE VARIABLE - JANUARY, 1965 THRU OCTOBER, 1999
M9911007	QUALITATIVE VARIABLE - NOVEMBER, 1999 THRU JULY, 2000
M789	QUALITATIVE VARIABLE - SEPTEMBER, 1978
M826	QUALITATIVE VARIABLE - JUNE, 1982
M8011	QUALITATIVE VARIABLE - NOVEMBER, 1980
M9111	QUALITATIVE VARIABLE - NOVEMBER, 1991
M9112	QUALITATIVE VARIABLE - DECEMBER, 1991
M926	QUALITATIVE VARIABLE - JUNE, 1992
M927	QUALITATIVE VARIABLE - JULY, 1992
M923	QUALITATIVE VARIABLE - MARCH, 1992
M937	QUALITATIVE VARIABLE - JULY, 1993
M968	QUALITATIVE VARIABLE - AUGUST, 1996
M9710	QUALITATIVE VARIABLE - OCTOBER, 1997
M985	QUALITATIVE VARIABLE - MAY, 1998

M986	QUALITATIVE VARIABLE - JUNE, 1998
M988	QUALITATIVE VARIABLE - AUGUST, 1998
M9810	QUALITATIVE VARIABLE - OCTOBER, 1998
M993	QUALITATIVE VARIABLE - MARCH, 1999
M9911	QUALITATIVE VARIABLE - NOVEMBER, 1999
M9912	QUALITATIVE VARIABLE - DECEMBER, 1999
M001	QUALITATIVE VARIABLE - JANUARY, 2000
M004	QUALITATIVE VARIABLE - APRIL, 2000
M005	QUALITATIVE VARIABLE - MAY, 2000
M006	QUALITATIVE VARIABLE - JUNE, 2000
M007	QUALITATIVE VARIABLE - JULY, 2000
M008	QUALITATIVE VARIABLE - AUGUST, 2000
M009	QUALITATIVE VARIABLE - SEPTEMBER, 2000
M011	QUALITATIVE VARIABLE - JANUARY, 2001
M017	QUALITATIVE VARIABLE - JULY, 2001
M018	QUALITATIVE VARIABLE - AUGUST, 2001

AND:

KWHOPAWPNS@CGE	KWH SALES - OPA WATER PUMPING
CUSRESNS@CGE	SERVICE AREA ELECTRIC CUSTOMERS - RESIDENTIAL
DS@KW@OPA@CGE	SERVICE AREA DS RATE FOR DEMAND FOR OTHER PUBLIC AUTHORITIES CUSTOMER
CPI	CONSUMER PRICE INDEX (ALL URBAN) - ALL ITEMS

LKWHOPALWPNS@CGE	=LOG(KWHOPALWPNS@CGE)
LE90XNS@CGE	=LOG(E90XNS@CGE)
LDS@KWH@OPA@CPI	=LOG(DS@KWH@OPA@CGE/CPI)
LDS@KWH@OPA@APG	=LOG(DS@KWH@OPA@CGE/APGOPA@CGE)
CDDB@24	BILLING COOLING DEGREE DAYS
HDDB@24	BILLING HEATING DEGREE DAYS
M7618412	QUALITATIVE VARIABLE - JANUARY, 1976 TO DECEMBER, 1984
MJUN	QUALITATIVE VARIABLE - JUNE
MSEP	QUALITATIVE VARIABLE - SEPTEMBER
MDEC	QUALITAITVE VARIABLE - DECEMBER
M928	QUALITATIVE VARIABLE - AUGUST, 1992
M937	QUALITATIVE VARIABLE - JULY, 1993
M9311	QUALITATIVE VARIABLE - NOVEMBER, 1993
M939	QUALITATIVE VARIABLE - SEPTEMBER, 1993
M941	QUALITATIVE VARIABLE - JANUARY, 1994
M943	QUALITATIVE VARIABLE - MARCH, 1994
M9410	QUALITATIVE VARIABLE - OCTOBER, 1994
M958	QUALITATIVE VARIABLE - AUGUST, 1995
M969	QUALITATIVE VARIABLE - SEPTEMBER, 1996
M9711	QUALITATIVE VARIABLE - NOVEMBER, 1997
M986	QUALITATIVE VARIABLE - JUNE, 1998
M9812	QUALITATIVE VARIABLE - DECEMBER, 1998
M993	QUALITATIVE VARIABLE - MARCH, 1999
M996	QUALITATIVE VARIABLE - JUNE, 1999
M997	QUALITATIVE VARIABLE - JUL, 1999
M998	QUALITATIVE VARIABLE - AUGUST, 1999
M9910	QUALITATIVE VARIABLE - OCTOBER, 1999
M9911	QUALITATIVE VARIABLE - NOVEMBER, 1999
M9912	QUALITATIVE VARIABLE - DECEMBER, 1999
M002	QUALITATIVE VARIABLE - FEBRUARY, 2000
M004	QUALITATIVE VARIABLE - APRIL, 2000

M007	QUALITATIVE VARIABLE - JULY, 2000
M0012	QUALITATIVE VARIABLE - DECMEBER, 2000
M011	QUALITATIVE VARIABLE - JANUARY, 2001
M014	QUALITATIVE VARIABLE - APRIL, 2001
M018	QUALITATIVE VARIABLE - AUGUST, 2001

AND:

KWHOPALWPNS@CGE	KWH SALES - OPA LESS WATER PUMPING
E90XNS@CGE	SERVICE AREA EMPLOYMENT - STATE AND LOCAL GOVERNMENT
CPI	CONSUMER PRICE INDEX (ALL URBAN) - ALL ITEMS
DS@KWH@OPA@CGE	SERVICE AREA DS RATE FOR USAGE FOR OTHER PUBLIC AUTHORITIES CUSTOMER
APGOPA@CGE	SERVICE AREA AVERAGE PRICE OF GAS FOR OPA CUSTOMER

LKWHSL@CGE	=LOG(KWHSL@CGE)
LCUSRES@CGE	=LOG(CUSRES@CGE)
SATMERC@CGE	SERVICE AREA SATURATION OF MERCURY VAPOR STREET LIGHTING
SATSODVAP@CGE	SERVICE AREA SATURATION OF SODIUM VAPOR STREET LIGHTING
Q1	QUALITATIVE VARIABLE - FIRST QUARTER
Q2	QUALITATIVE VARIABLE - SECOND QUARTER
Q651904	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 THRU FOURTH QUARTER, 1990
Q3	QUALITATIVE VARIABLE - THIRD QUARTER
Q4	QUALITATIVE VARIABLE - FOURTH QUARTER
Q782	QUALITATIVE VARIABLE - SECOND QUARTER, 1978
Q791	QUALITATIVE VARIABLE - FIRST QUARTER, 1979
Q801	QUALITATIVE VARIABLE - FIRST QUARTER, 1980
Q811	QUALITATIVE VARIABLE - FIRST QUARTER, 1981
Q852	QUALITATIVE VARIABLE - SECOND QUARTER, 1985
Q911	QUALITATIVE VARIABLE - FIRST QUARTER, 1991
Q994	QUALITATIVE VARIABLE - FOURTH QUARTER, 1999
Q913	QUALITATIVE VARIABLE - THIRD QUARTER, 1991
Q992	QUALITATIVE VARIABLE - SECOND QUARTER, 1999
Q004	QUALITATIVE VARIABLE - FOURTH QUARTER, 2000
Q013	QUALITATIVE VARIABLE - THIRD QUARTER, 2001
Q012	QUALITATIVE VARIABLE - SECOND QUARTER, 2001

AND:

KWHSL@CGE	SERVICE AREA KWH SALES - STREET LIGHTING
CUSRES@CGE	SERVICE AREA ELECTRIC CUSTOMERS - RESIDENTIAL

LMWSPEAK	=LOG(MWSPEAK)
LSENDDAYS	=LOG(MWHSENDNORMNS@CGE/DAYS)
TPMHL1	TPMH\1
TAM	MINIMUM HOURLY TEMPERATURE - MORNING
M741902	QUALITATIVE VARIABLE - JANUARY, 1974 THRU FEBRUARY, 1990
MJUN	QUALITATIVE VARIABLE - JUNE
MJUL	QUALITATIVE VARIABLE - JULY
MAUG	QUALITATIVE VARIABLE - AUGUST
MSEP	QUALITATIVE VARIABLE - SEPTEMBER
HUM	HUMIDITY - AFTERNOON
JULY4WKALT	QUALITATIVE VARIABLE FOR THE WEEK OF JULY 4TH

TPMH	MAXIMUM HOURLY TEMPERATURE - AFTERNOON
M785	QUALITATIVE VARIABLE - MAY, 1978
M788	QUALITATIVE VARIABLE - AUGUST, 1978
M8411	QUALITATIVE VARIABLE - NOVEMBER, 1984
M7910	QUALITATIVE VARIABLE - OCTOBER, 1979
M801	QUALITATIVE VARIABLE - JANUARY, 1980
M8210	QUALITATIVE VARIABLE - OCTOBER, 1982
M871	QUALITATIVE VARIABLE - JANUARY, 1987
M876	QUALITATIVE VARIABLE - JUNE, 1987
M8812	QUALITATIVE VARIABLE - DECEMBER, 1988
M8911	QUALITATIVE VARIABLE - NOVEMBER, 1989
M902	QUALITATIVE VARIABLE - FEBRUARY,1990
M906	QUALITATIVE VARIABLE - JUNE,1990
M918	QUALITATIVE VARIABLE - AUGUST, 1991
M9110	QUALITATIVE VARIABLE - OCTOBER, 1991

AND:

MWSPEAK	SERVICE AREA MW PEAK - SUMMER
MWHSENDNORMNS@CGE	MWH SENDOUT - WEATHER NORMALIZED
DAYS	NUMBER OF DAYS IN THE MONTH

MWWPEAK	SERVICE AREA MW PEAK - WINTER
WINDAM	WIND SPEED MPH - MORNING
TEMPPML1	TEMPPM\1
LSENDDAYS	=LOG(MWHSENDNORMNS@CGE/DAYS)
MDEC	QUALITAITVE VARIABLE - DECEMBER
MFEB	QUALITATIVE VARIABLE - FEBRUARY
MMAR	QUALITATIVE VARIABLE - MARCH
MJAN	QUALITATIVE VARIABLE - JANUARY
AMPEAK	QUALITATIVE VARIABLE - MORNING PEAK
TEMPAM	MINIMUM HOURLY TEMPERATURE - MORNING
M6518611	QUALITATIVE VARIABLE - JANUARY, 1965 THRU NOVEMBER, 1986
XMAS	QUALITATIVE VARIABLE - CHRISTMAS WEEK
PMPEAK	QUALITATIVE VARIABLE - EVENING PEAK
TEMPPM	MINIMUM HOURLY TEMPERATURE - EVENING
M777	QUALITATIVE VARIABLE - JULY, 1977
M781	QUALITATIVE VARIABLE - JANUARY, 1978
M858	QUALITATIVE VARIABLE - AUGUST, 1985
M863	QUALITATIVE VARIABLE - MARCH, 1986
M865	QUALITATIVE VARIABLE - MAY, 1986
M867	QUALITATIVE VARIABLE - JULY, 1986
M869	QUALITATIVE VARIABLE - SEPTEMBER, 1986
M8612	QUALITATIVE VARIABLE - DECEMBER, 1986
M871	QUALITATIVE VARIABLE - JANUARY, 1987
M873	QUALITATIVE VARIABLE - MARCH, 1987
M874	QUALITATIVE VARIABLE - APRIL, 1987

AND:

MWHSENDNORMNS@CGE	MWH SENDOUT - WEATHER NORMALIZED
DAYS	NUMBER OF DAYS IN THE MONTH

Section 8(4)(b) and (c) Energy by Primary Fuel Type, Energy from Utility Purchases, and Energy from Nonutility Purchases

The following pages contain the information required.

Table 8.(4)(b)

UNION LIGHT HEAT & POWER

Forecast Annual Energy (GWh)

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Energy Requirements	3,908	3,983	4,066	4,161	4,247	4,328	4,407	4,492	4,577	4,663	4,748	4,833	4,914	4,998	5,088	5,166	5,252	5,338	5,415	5,501	5,588

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
2	Energy By Fuel Type																					
	Coal	0	1,860	3,656	3,720	3,448	3,521	3,509	3,593	3,643	3,729	4,100	4,131	4,244	4,231	4,342	4,617	4,675	4,719	4,770	4,786	5,084
	Gas	0	222	408	436	282	302	329	320	380	375	338	363	402	412	466	373	385	419	434	465	357

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
3	Firm Purchases From Other Utilities																					
	CG&E	3,906	1,899	0.3	0.5	0.4	0.4	0.4	0.5	18.1	36.6	0.5	0.5	0.4	0.5	0.4	0.3	0.4	0.4	0.4	0.5	0.3

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
4	Purchases From Non Utility	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
5	Reductions or Increases In Energy																					
	DSM	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)
	Interruptible	0.00	(0.05)	(0.06)	(0.07)	(0.05)	(0.05)	(0.05)	(0.05)	(0.06)	(0.06)	(0.05)	(0.05)	(0.05)	(0.06)	(0.05)	(0.04)	(0.05)	(0.05)	(0.05)	(0.06)	(0.04)
	PowerShare	0.00	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
	RTP	0.00	(0.04)	(0.06)	(0.07)	(0.04)	(0.04)	(0.04)	(0.05)	(0.05)	(0.05)	(0.04)	(0.05)	(0.04)	(0.05)	(0.04)	(0.03)	(0.04)	(0.04)	(0.04)	(0.05)	(0.03)
	DLC	0.00	(0.04)	(0.18)	(0.36)	(0.27)	(0.33)	(0.34)	(0.38)	(0.39)	(0.44)	(0.35)	(0.38)	(0.35)	(0.38)	(0.35)	(0.27)	(0.30)	(0.32)	(0.34)	(0.39)	(0.26)
	Total	(1.50)	(1.63)	(1.80)	(2.00)	(1.85)	(1.92)	(1.94)	(1.98)	(2.00)	(2.05)	(1.95)	(1.98)	(1.95)	(1.99)	(1.95)	(1.85)	(1.89)	(1.91)	(1.94)	(2.00)	(1.84)

Table 8.(4)(c)

UNION LIGHT HEAT & POWER

Total Energy Input and Total Generation by Primary Fuel Type

Coal	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Energy (GWh)	0	1,860	3,656	3,720	3,448	3,521	3,509	3,593	3,643	3,729	4,100	4,131	4,244	4,231	4,342	4,617	4,675	4,719	4,770	4,786	5,084
Total (Tons)	0	753	1,530	1,565	1,462	1,490	1,485	1,517	1,536	1,569	1,708	1,720	1,763	1,759	1,801	1,903	1,926	1,943	1,962	1,968	2,079
(000 MBTUs) Consumed	0	18,403	36,211	36,785	34,342	35,009	34,871	35,642	36,081	36,870	39,850	40,123	41,149	41,037	42,032	44,140	44,667	45,068	45,520	45,661	47,985

Gas	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Energy (GWh)	0	222	408	436	282	302	329	320	380	375	338	363	402	412	466	373	385	419	434	465	357
Total (MCF)	0	2,838	5,202	5,559	3,608	3,863	4,201	4,086	4,845	4,788	4,322	4,625	4,638	4,757	4,911	3,901	4,040	4,403	4,568	4,918	3,745
(000 MBTUs) Consumed	0	2,912	5,338	5,703	3,701	3,963	4,310	4,192	4,971	4,913	4,434	4,745	4,759	4,881	5,039	4,002	4,145	4,517	4,687	5,046	3,842

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Section 9(4) Yearly Average System Rates

The modeling performed in the IRP process does not include items such as T&D rate base and expenses, corporate A&G, etc. which are not relevant to determine the least cost generation supply plan to serve ULH&P's customers (because these cost items are common to all plans). Therefore, an accurate projection of customer rates cannot be provided. In addition, ULH&P's rates will continue to be frozen at their current levels until 2007.

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Section 11(4) Response to Staff's Comments and Recommendations

ULH&P last filed an IRP in October 1999. The Kentucky Public Service Commission Staff issued its report on the ULH&P 1999 IRP on July 17, 2000. Since that time, DSM has been implemented pursuant to statute and orders of this Commission and the IRP rules were revised. ULH&P and its parent, Cinergy Corp., have attempted to keep the Commission abreast of on-going planning activities and progress by submitting courtesy copies of IRP filings made in other jurisdictions since the last IRP filing in Kentucky. Copies of significant orders have been provided also.

Load Forecasting

ULH&P should prepare an analysis comparing actual demand and energy levels with its forecasted levels for the years included in this forecast for which actual results will be available at the time of its next IRP.

Comparison of Actual and Forecasted Peak and Energy
ULH&P

Year	Actual Energy	Forecast Energy	Actual Peak	Forecast Peak Native Load
1999	3,848	3,803	775	743
2000	4,013	3,911	757	765
2001	3,811	4,035	763	782
2002	4,095	4,181	786	803

ULH&P should identify and discuss any changes in its load forecasting process resulting from the introduction of customer choice in Ohio for CG&E.

No changes were made to the load forecasting process as the result of customer choice in Ohio.

<u>Demand-Side Management</u>

The Commission's concerns as expressed in its most recent Order approving the continuation of ULH&P's DSM programs should be reflected in that filing.

ULH&P responded to the Commission's concerns in its September 30, 2002, filing on the progress of its DSM programs. As noted in Chapter 4, ULH&P provided results on the cost-effectiveness of each DSM program as well as made recommendations on the continuation or termination of each program. The Commission, in its Order in Case No. 2002-00358 dated December 17, 2002, ruled in agreement with ULH&P's recommendations. This completed the issues concerning the first recommendation of the Staff.

ULH&P should provide greater discussion in its next filing regarding its consideration of LIRP-related concepts in its service territory.

ULH&P has reviewed the level of load impacts achieved through its DSM efforts. In this IRP, the level of load impacts is reflected in the after-DSM forms provided in Chapter 3. Currently, the incremental impacts of the programs are less than 1 MW per year. To obtain this level of DSM impact, the DSM programs have been marketed across the compact service area of ULH&P. As a result, the load impacts from the DSM programs are distributed geographically across the service area. Achieving more concentrated impacts that could defer distribution expansion costs is not likely given the size of the programs. However, in the current DSM status report, ULH&P, with the DSM Collaborative, applied to the Commission to approve implementation of a direct load control (DLC) program in ULH&P's service area. The direct load control program provides potential for larger MW impacts. Given the Commission's approval of the DLC program, ULH&P will re-evaluate the potential for benefits from LIRP.

<u>Supply-Side Resource Assessment</u>

In conjunction with CG&E's next IRP update to the Ohio PUC, provide an update of ULH&P's 1999 IRP to the Kentucky Commission Staff.

Due to restructuring in Ohio, there were no additional full IRP filings made at the PUCO after the 1999 IRP.

In ULH&P's next IRP, provide the Company's current plan for meeting the May 2003 requirements contained in EPA's NO_x SIP Call.

See Chapter 6 Section D.

Integration and Plan Optimization

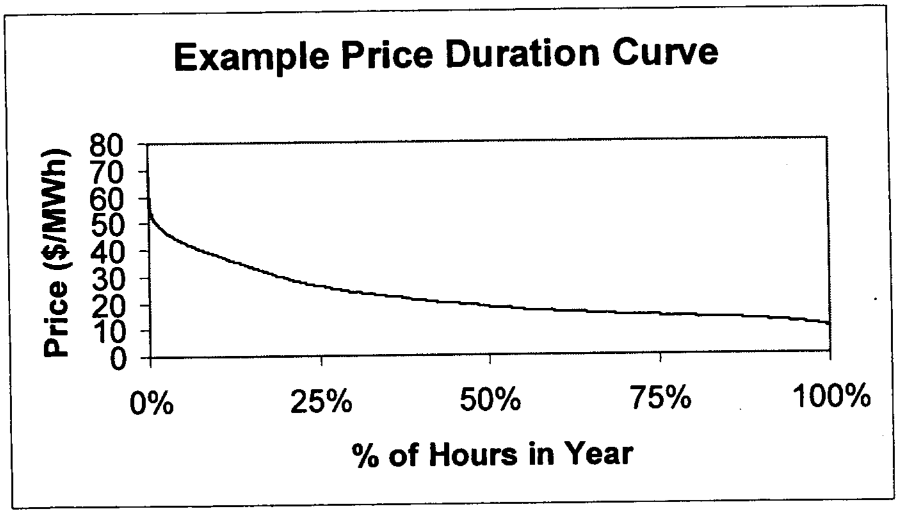
In its next IRP filing, ULH&P should discuss in significant detail its efforts to obtain OVEC capacity related to the planned closing of the Portsmouth Gaseous Diffusion Plant.

On December 5, 2003, the Kentucky PSC issued its order in Case No. 2003-00252 which conditionally approved the transfer of the package of the East Bend 2, Miami Fort 6, and Woodsdale 1-6 units from CG&E to ULH&P. If ULH&P were to obtain OVEC capacity in addition to these plants, ULH&P's reserve levels would be higher than necessary, which would only increase costs to ULH&P's customers. Therefore, obtaining OVEC capacity for ULH&P was not considered any further. However, OVEC capacity remains a part of CG&E's portfolio and will be dispatched in conjunction with ULH&P's units under the terms of the PSOA.

ULH&P should report on the feasibility of implementing the concept of crediting all resources with the value of the energy used, using market prices as a proxy, in the context of resource screening.

The current methodology for screening supply-side resources compares the levelized \$/kW-year costs of the various resources at different capacity factors, as discussed in Chapter 5, Section F. The most rigorous approach to crediting these resource costs with the value of the energy at market prices would be to perform a chronological analysis that would correlate when each resource produces energy with the market price at that time. However, this level of analysis would be extremely time-consuming and would not yield significantly more useful information than an approach that utilizes a price duration curve.

A price duration curve is similar to a load duration curve, with prices ranked from highest to lowest and graphed on the y-axis with the number of hours in the year on the x-axis, as shown in the diagram below.



The traditional technology resources will all be dispatched economically such that the resource will be running at the highest priced hours and run less or not at all at the lowest priced hours, depending on the dispatch cost of each resource. Therefore, we can map the revenues from the price duration curve to the screening curve as a credit for each resource. For example, for the pulverized coal unit, if the total revenues per kW from the price duration curve up to the 25% hours point are credited against the 25% capacity factor point on the screening curve, this would provide an approximation of the revenues that would be expected for the coal unit if it ran 25% of the time. This methodology could be repeated at the 50%, 75%, and 100% points for the coal unit and the same methodology could be applied to the other traditional technology units. The result would be that each resource would be credited with the same revenues per kW at each capacity factor, which would not change the relative economic relationship of the resources to each other.

This methodology could also be used for most of the renewable resources. For example, solar and biomass would also tend to operate the most during the highest priced hours. The only resource for which this methodology would not be technically correct would be the wind resource because this methodology would greatly overstate its revenues. The nature of the wind resource is such that during the highest priced hours (which are usually during the summer peak), there is typically little or no wind. Conversely, the hours when the wind resource is greatest may be during the late evening or early morning hours when the market prices are at the lowest. Nevertheless, we can utilize the price duration curve methodology discussed above, as long as we recognize that we are significantly overstating the revenues for wind. In the screening analysis in this IRP, wind resources were not economic in comparison with the other resources, so applying the same credit as applied to the other resources will not improve the economics of wind resources. Rather, if we had performed a chronological analysis to credit the correct revenue amount, wind resources would have become even less economical in relation to the other resources.

The conclusion of this discussion is that crediting the resources in the screening analysis with the value of the energy revenues at market price will move all resources equally in relation to each other while moving wind resources too much. Therefore, no further analysis was necessary since the same resources would have been passed to the integration stage of the analysis.

Within 90 days from the date of this report, ULH&P shall provide Commission Staff an update on the status of the renewal/extension of ULH&P's full requirements contract with CG&E.

On December 5, 2003, the Kentucky PSC issued its order in Case No. 2003-00252 which conditionally approved the transfer of the package of the East Bend 2, Miami Fort 6, and Woodsdale 1-6 units from CG&E to ULH&P. As part of this order, the termination of ULH&P's current PSA with CG&E, effective on the closing date of the transfer of facilities, was also approved.

Kentucky's major jurisdictional electric utilities shall conduct a renewed analysis of appropriate reserve margins to be used for planning purposes and shall include that analysis in their next IRPs filed pursuant to 807 KAR:058.

See reserve margin discussions in Chapters 2 and 8.

Kentucky's major jurisdictional electric utilities shall thoroughly evaluate DSM as a component of the IRPs filed pursuant to 807 KAR 5:058.

See Chapter 4.

Section 8(3)(b)(12)a-c, e, and g Capacity Factors, Availability Factors, Average Heat Rates, Average Variable, and Total Production Costs

The required information is contained in the tables that follow, in redacted form. Cinergy considers this information to be trade secrets and confidential and competitive information. It 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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UNION LIGHT HEAT & POWER

Projected Cost and Operating Information For

East Bend 2

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor %	[redacted]																			
Availability Factor %	[redacted]																			
Average Heat Rate (BTU/kWh)	[redacted]																			
Cost of Fuel ($/MBTU)	[redacted]																			
Fixed O&M ($000)	[redacted]																			
Variable O&M ($000)	[redacted]																			
Avg. Variable Prod. Costs (cents/kWh)	[redacted]																			
Total Prod. Costs (cents/kWh)	[redacted]																			

Note: Total Production Costs not provided for 2004-2006 due to rate impacts of East Bend asset transfer not expected to take effect until 2007.

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UNION LIGHT HEAT & POWER

Projected Cost and Operating Information For

Miami Fort 6

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor %	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor %	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (BTU/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cost of Fuel ($/MBTU)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($000)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($000)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Avg. Variable Prod. Costs (cents/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Prod. Costs (cents/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Note: Total Production Costs not provided for 2004-2006 due to rate impacts of Miami Fort 6 asset transfer not expected to take effect until 2007.

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UNION LIGHT HEAT & POWER

Projected Cost and Operating Information For

Woodsdale 1

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor %	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor %	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (BTU/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cost of Fuel ($/MBTU)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($000)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($000)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Avg. Variable Prod. Costs (cents/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Prod. Costs (cents/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Note: Total Production Costs not provided for 2004-2006 due to rate impacts of Woodsdale asset transfer not expected to take effect until 2007.

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UNION LIGHT HEAT & POWER

Projected Cost and Operating Information For

Woodsdale 2

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor %	[redacted]																			
Availability Factor %																				
Average Heat Rate (BTU/kWh)																				
Cost of Fuel ($/MBTU)																				
Fixed O&M ($000)																				
Variable O&M ($000)																				
Avg. Variable Prod. Costs (cents/kWh)																				
Total Prod. Costs (cents/kWh)																				

Note: Total Production Costs not provided for 2004-2006 due to rate impacts of Woodsdale asset transfer not expected to take effect until 2007.

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UNION LIGHT HEAT & POWER

Projected Cost and Operating Information For

Woodsdale 3

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor %	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor %	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (BTU/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cost of Fuel ($/MBTU)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($000)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($000)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Avg. Variable Prod. Costs (cents/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Prod. Costs (cents/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Note: Total Production Costs not provided for 2004-2006 due to rate impacts of Woodsdale asset transfer not expected to take effect until 2007.

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UNION LIGHT HEAT & POWER

Projected Cost and Operating Information For

Woodsdale 4

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor %	[redacted]																			
Availability Factor %																				
Average Heat Rate (BTU/kWh)																				
Cost of Fuel ($/MBTU)																				
Fixed O&M ($000)																				
Variable O&M ($000)																				
Avg. Variable Prod. Costs (cents/kWh)																				
Total Prod. Costs (cents/kWh)																				

Note: Total Production Costs not provided for 2004-2006 due to rate impacts of Woodsdale asset transfer not expected to take effect until 2007.

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Projected Cost and Operating Information For

Woodsdale 5

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor %	[redacted]																			
Availability Factor %																				
Average Heat Rate (BTU/kWh)																				
Cost of Fuel ($/MBTU)																				
Fixed O&M ($000)																				
Variable O&M ($000)																				
Avg. Variable Prod. Costs (cents/kWh)																				
Total Prod. Costs (cents/kWh)																				

Note: Total Production Costs not provided for 2004-2006 due to rate impacts of Woodsdale asset transfer not expected to take effect until 2007.

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UNION LIGHT HEAT & POWER

Projected Cost and Operating Information For

Woodsdale 6

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor %	[redacted]																			
Availability Factor %																				
Average Heat Rate (BTU/kWh)																				
Cost of Fuel ($/MBTU)																				
Fixed O&M ($000)																				
Variable O&M ($000)																				
Avg. Variable Prod. Costs (cents/kWh)																				
Total Prod. Costs (cents/kWh)																				

Note: Total Production Costs not provided for 2004-2006 due to rate impacts of Woodsdale asset transfer not expected to take effect until 2007.

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UNION LIGHT HEAT & POWER

Projected Cost and Operating Information For

PCFB Unit 1

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor %	NA	NA	NA	NA	NA	NA	NA	NA	NA	[redacted]										
Availability Factor %	NA	NA	NA	NA	NA	NA	NA	NA	NA											
Average Heat Rate (BTU/kWh)	NA	NA	NA	NA	NA	NA	NA	NA	NA											
Cost of Fuel ($/MBTU)	NA	NA	NA	NA	NA	NA	NA	NA	NA											
Fixed O&M ($000)	NA	NA	NA	NA	NA	NA	NA	NA	NA											
Variable O&M ($000)	NA	NA	NA	NA	NA	NA	NA	NA	NA											
Avg. Variable Prod. Costs (cents/kWh)	NA	NA	NA	NA	NA	NA	NA	NA	NA											
Total Prod. Costs (cents/kWh)	NA	NA	NA	NA	NA	NA	NA	NA	NA											

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UNION LIGHT HEAT & POWER

Projected Cost and Operating Information For

PCFB Unit 2

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor %	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	[redacted]					
Availability Factor %	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA						
Average Heat Rate (BTU/kWh)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA						
Cost of Fuel ($/MBTU)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA						
Fixed O&M ($000)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA						
Variable O&M ($000)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA						
Avg. Variable Prod. Costs (cents/kWh)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA						
Total Prod. Costs (cents/kWh)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA						

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UNION LIGHT HEAT & POWER

Projected Cost and Operating Information For

PCFB Unit 3

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor %	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	[redacted]
Availability Factor %	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	[redacted]
Average Heat Rate (BTU/kWh)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	[redacted]
Cost of Fuel ($/MBTU)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	[redacted]
Fixed O&M ($000)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	[redacted]
Variable O&M ($000)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	[redacted]
Avg. Variable Prod. Costs (cents/kWh)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	[redacted]
Total Prod. Costs (cents/kWh)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	[redacted]

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UNION LIGHT HEAT & POWER

Projected Cost and Operating Information For

Fuel Cell Unit 1

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor %	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	[redacted]								
Availability Factor %	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA									
Average Heat Rate (BTU/kWh)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA									
Cost of Fuel ($/MBTU)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA									
Fixed O&M ($000)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA									
Variable O&M ($000)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA									
Avg. Variable Prod. Costs (cents/kWh)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA									
Total Prod. Costs (cents/kWh)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA									

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UNION LIGHT HEAT & POWER

Projected Cost and Operating Information For

Fuel Cell Unit 2

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor %	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	[redacted]						
Availability Factor %	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	[redacted]						
Average Heat Rate (BTU/kWh)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	[redacted]						
Cost of Fuel ($/MBTU)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	[redacted]						
Fixed O&M ($000)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	[redacted]						
Variable O&M ($000)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	[redacted]						
Avg. Variable Prod. Costs (cents/kWh)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	[redacted]						
Total Prod. Costs (cents/kWh)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	[redacted]						

Section 8(3)(b)(12)d, f Estimated Capital Costs of Planned Units, Escalation Rates

As discussed in Volume I, Chapter 5, most of the specific technology parameters used in the screening process were based on information taken from the Technical Assessment Guide® (TAG®) -Central Stations report dated December 2000 and the Technical Assessment Guide Supply-Side Technologies program (TAG-Supply™), Version 3.11, produced by the Electric Power Research Institute (EPRI) of Palo Alto, California, supplemented by estimates from S&L and from Cinergy's engineering department. EPRI considers its information to be trade secrets and proprietary and confidential. Cinergy considers the S&L study to be confidential and competitive information. Cinergy also considers its internal estimates to be confidential and competitive information. The information will be made available to appropriate parties for viewing at Cinergy offices during normal business hours upon execution of appropriate confidentiality agreements or protective orders. Please contact Diane Jenner at (317) 838-2183 for more information.

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UNION LIGHT HEAT & POWER

Capital Costs and Escalation Factors
Existing Units
(In 2003 Dollars)

	East Bend Unit 2	Miami Fort Unit 6	Woodsdale Unit 1	Woodsdale Unit 2	Woodsdale Unit 3	Woodsdale Unit 4	Woodsdale Unit 5	Woodsdale Unit 6
Capital Costs ($/kW)	473	81	275	275	275	275	275	275
Total Capital Costs ($000)	195,642	13,280	25,863	25,863	25,863	25,863	25,863	25,863
Capital Escalation Rate (%)	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Variable O&M Escalation Rate (%)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Fixed O&M Escalation Rate (%)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5

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UNION LIGHT HEAT & POWER

Capital Costs and Escalation Factors
New Units
(In 2003 Dollars)

	PCFB Unit 1 (70 MW)	PCFB Unit 2 (70 MW)	PCFB Unit 3 (70 MW)	Fuel Cell Unit 1 (25 MW)	Fuel Cell Unit 2 (25 MW)
Capital Costs ($/kW)	[redacted]				
Total Capital Costs ($000)					
Capital Escalation Rate (%)	3.0	3.0	3.0	3.0	3.0
Variable O&M Escalation Rate (%)	2.5	2.5	2.5	2.5	2.5
Fixed O&M Escalation Rate (%)	2.5	2.5	2.5	2.5	2.5

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Section 9(3) Yearly Revenue Requirements

The projections of yearly revenue requirements from STRATEGIST® are shown on the following page in redacted form. Cinergy considers these projections 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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Table 9(3)

UNION LIGHT HEAT & POWER

Annual Revenue Requirement - Real and Nominal

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Annual Revenue Requirement - Nominal (000's $)	[redacted]																				
Annual Revenue Requirement - Real (000's $)	[redacted]																				

Notes: Nominal values were discounted to 2003 using a rate of 8.74%.
Data assumes that the rate impact of the East Bend 2/Miami Fort 6/Woodsdale 1-6 asset transfer will begin on Jan. 1, 2007.