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Anita M. Schafer
Sr. Paralegal

RECEIVED
JUL 01 2008
PUBLIC SERVICE COMMISSION

VIA OVERNIGHT DELIVERY

June 30, 2008

Ms. Stephanie Stumbo
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602-0615

Re: Case No. 2008-~~00127~~ 00248

Dear Ms. Stumbo:

Enclosed please find an original and ten copies of the Duke Energy Kentucky 2008 Integrated Resource Plan Volume I and Volume II. Please note that Volume II is within the inside pocket of the Volume I binder.

Also enclosed is an original and twelve copies of the Petition for Confidential Treatment of Information Contained in its IRP.

Please date-stamp the extra cover sheet copies and the extra two copies of the Petition and return to me in the enclosed envelope.

Sincerely,

Anita M. Schafer

Anita M. Schafer
Senior Paralegal

233233

COMMONWEALTH OF KENTUCKY

BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of Duke Energy Kentucky, Inc.'s Integrated Resource Plan	)))	Case No. 2008-~~127~~ 248

PETITION OF DUKE ENERGY KENTUCKY, INC.
FOR CONFIDENTIAL TREATMENT OF INFORMATION
CONTAINED IN ITS INTEGRATED RESOURCE PLAN

Duke Energy Kentucky, Inc. ("DE-Kentucky" or "Company"), pursuant to 807 KAR 5:001, Section 7, respectfully requests the Commission to classify and protect certain information that is contained in DE-Kentucky's 2008 Integrated Resource Plan ("IRP") contemporaneously filed with this Petition. The information that DE-Kentucky seeks confidential treatment generally includes: (1) information related to operations and management ("O&M") costs, projected fuel and environmental compliance costs, power market prices, projected capacity, and resource alternative capital costs; (2) information regarding projected sales and revenue requirements; (3) supply side screening curves and resource evaluations; (4) third party owned and licensed modeling tools; and (5) critical transmission system maps. The public disclosure of the information described would place DE-Kentucky at a commercial disadvantage as it negotiates contracts with various suppliers and vendors and potentially harm DE-Kentucky's competitive position in the marketplace, to the detriment of DE-Kentucky and its customers. Moreover, DE-Kentucky's transmission system maps show the location of critical infrastructure necessary to deliver safe and reliable electric service to its consumers. The public release of this information would create a security risk for both the Company and its customers.

In support of this Petition, DE-Kentucky states:

1. The Kentucky Open Records Act exempts from disclosure certain commercial information. KRS 61.878 (1)(c). To qualify for this exemption and, therefore, maintain the confidentiality of the information, a party must establish that disclosure of the commercial information would permit an unfair advantage to competitors of that party. Public disclosure of the information identified herein would, in fact, prompt such a result for the reasons set forth below.

2. The information regarding power production costs that DE-Kentucky wishes to protect from public disclosure -- including supply side screening curves, projected costs of fuel and O&M expenses, capital costs, power market prices, projected capacity and present value revenue requirements ("PVRR") -- is identified in the filing submitted concurrently herewith. This information was developed internally by DE-Kentucky personnel, is not on file with any public agency, and is not available from any commercial or other source outside DE-Kentucky. The aforementioned information is distributed within DE-Kentucky only to those employees who must have access for business reasons. If publicly disclosed, this information setting forth DE-Kentucky's costs of operation, expected need for fuel and allowances and projected capacity could give competitors an advantage in bidding for and securing new resources. Similarly, disclosure would afford an undue advantage to DE-Kentucky's vendors and suppliers as they would enjoy an obvious advantage in any contractual negotiations to the extent they could calculate DE-Kentucky's requirements and what DE-Kentucky anticipates those requirements to cost. Finally, public disclosure of this

information, particularly as it relates to supply-side alternatives, would reveal the business model DE-Kentucky uses -- the procedure it follows and the factors and inputs it considers -- in evaluating the economic viability of various generation related projects. Public disclosure would give DE-Kentucky's contractors, vendors and competitors access to DE-Kentucky's cost and operational parameters, as well as insight into its contracting practices. Such access would impair DE-Kentucky's ability to negotiate with prospective contractors and vendors, and could harm the DE-Kentucky's competitive position in the power market, ultimately affecting the costs to serve customers.

3. DE-Kentucky requests confidential protections for certain third-party data contained in the IRP. In developing the 2008 IRP, DE-Kentucky used certain confidential and proprietary data modeling consisting of confidential information belonging to third parties who take reasonable steps to protect their confidential information, such as only releasing such information subject to confidentiality agreements. DE-Kentucky used forecasts of various commodities and inputs such as SO_2 emission allowances prices, NO_x emission allowance prices, mercury emission allowance prices, power market prices, coal prices, gas prices, and oil prices developed by an independent third party, Ventyx Energy, LLC, subject to confidentiality restrictions. DE-Kentucky is contractually bound to maintain such information confidential. Moreover, this information is deserving of protection to protect DE-Kentucky's customers. If allowance brokers or equipment vendors knew DE-Kentucky's forecasted emissions and fuel prices, by station or otherwise, such brokers or vendors would have an unfair advantage in negotiating future emission allowance or emission control equipment sales, to the detriment of DE-Kentucky and its customers.

Furthermore, if competitors of DE-Kentucky knew such forecasts, they could have an advantage in competing for new business against DE-Kentucky.

4. DE-Kentucky requests confidential treatment for the transmission system maps included in the IRP. These maps show the location of Critical Energy Infrastructure Information ("CEII"), which has been granted confidential treatment in the past. DE-Kentucky takes all reasonable steps in order to protect the CEII, including, but not limited to, only sharing such information internally on a need to know basis. The reliability entities with access to such data, such as Midwest Independent System Operator ("MISO") also take appropriate precautions to protect such data. This information needs to be kept confidential in order to continue to provide delivery of safe and reliable electric service to DE-Kentucky customers. The release of this information would provide a security risk for the Company and its customers.

5. The information for which DE-Kentucky is seeking confidential treatment is not known outside of DE-Kentucky.

6. The information that DE-Kentucky seeks confidential treatment herein demonstrates on its face that it merits confidential protection. If the Commission disagrees, however, it must hold an evidentiary hearing to protect the due process rights of the Company and supply the Commission with a complete record to enable it to reach a decision with regard to this matter. *Utility Regulatory Commission v. Kentucky Water Service Company. Inc.,* Ky. App., 642 S.W.2d 591, 592-94 (1982).

7. DE-Kentucky does not object to limited disclosure of the confidential information described herein, pursuant to an acceptable protective agreement, to the Attorney General or

other intervenors with a legitimate interest in reviewing the same for the purpose of commenting on DE-Kentucky's 2008 IRP.

8. In accordance with the provisions of 807 KAR 5:001 Section 7, the Company is filing with the Commission one copy of the 2008 IRP under seal and ten (10) copies without the confidential information.

WHEREFORE, Duke Energy Kentucky, Inc. respectfully requests that the Commission classify and protect as confidential the specific information described herein.

Respectfully submitted,

DUKE ENERGY KENTUCKY, INC.

Amy B. Spiller (85309)
Associate General Counsel
Rocco O. D'Ascenzo
Senior Counsel
139 East Fourth Street, Room 25 AT II
Cincinnati, OH 45202
Phone: (513) 419-1810
Fax: (513) 419-1846
e-mail: amy.spiller@duke-energy.com

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of Duke Energy Kentucky, Inc.'s Petition for Confidential Treatment of Information Contained in Duke Energy Kentucky, Inc.'s 2008 Integrated Resource Plan was served on the following by overnight mail, this 30th day of June 2008.

Amy B. Spiller

Amy B. Spiller

Honorable Dennis G. Howard, II
Honorable David E. Spenard
Assistant Attorneys General
1024 Capital Center Drive, Suite 200
Frankfort, Kentucky 40601

SANDRA P MEYER
President
Duke Energy Ohio
Duke Energy Kentucky

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RECEIVED
JUL 01 2008
PUBLIC SERVICE COMMISSION

July 1, 2008

Ms. Stephanie Stumbo
Executive Director
Public Service Commission of Kentucky
P.O. Box 615
Frankfort, KY 40602

RE: Case No., 2008- ~~127~~ 248 Duke Energy Kentucky 2008 Integrated Resource Plan

Dear Director Stumbo:

Pursuant to 807 KAR 5:058, Duke Energy Kentucky, Inc. submits ten (10) bound and one (1) unbound copies of the Duke Energy Kentucky 2008 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 Duke Energy Kentucky 2008 IRP, the Company has filed a petition with the Commission requesting confidential treatment of such information.

The Duke Energy Kentucky 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. Items related to transmission and distribution 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 2008 IRP consists of two volumes.

Please note that Rocco D'Ascenzo, Legal Department, Room 25ATII, 139 East Fourth Street, Cincinnati, OH 45202, (513) 419-1852, is the Attorney of Record for this forecast.

Specific questions regarding the contents of this report should be directed to Janice D. Hager, Integrated Resource Planning, at the offices of Duke Energy located at 526 South Church Street, Charlotte, NC 28202.

Yours truly,

Sandra Meyer

Sandra Meyer, President
Duke Energy Kentucky, Inc.

Attachments

ATTACHMENT "A"

Duke Energy Kentucky

2008 INTEGRATED RESOURCE PLAN

CERTIFICATE OF SERVICE

The undersigned states that she is the President of Duke Energy Kentucky, Inc; that she is duly authorized in such capacity to execute and file this Integrated Resource Plan on behalf of Duke Energy Kentucky, Inc.

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 Duke Energy Kentucky's last integrated resource plan review proceeding:

Hon.. Larry Cook
Assistant Attorney General
Kentucky Office of the
Attorney General
1024 Capital Center Drive, Suite 200
Frankfort, KY 40601-8204

Florence Tandy
Northern Kentucky Community
Action Commission
717 Madison Ave.
Covington, KY 41011

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 Duke Energy Kentucky, Inc, 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.

Sandra Meyer, President

July 1, 2008
Date

ATTACHMENT "B"

NOTICE OF FILING

Please take notice that, pursuant to 807 KAR 5:058, Section 2, Part(2), Duke Energy Kentucky, Inc., has, this 1st day of July, 2008, filed a copy of the Duke Energy Kentucky 2008 Integrated Resource Plan ("IRP") with the Public Service Commission of Kentucky ("Commission").

This IRP contains Duke Energy Kentucky, Inc.'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 Duke Energy Kentucky, Inc. during normal business hours. A copy of this IRP will be provided, at cost, to cover expenses incurred, upon request.

KENTUCKY INDEX TO 2008 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
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(2) Chapter 1, Sections C, D, E, F, G, H, I, J
(3) Chapter 1, Section E
(4) Chapter 1, Sections F, G, H, J
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Section 7. Load Forecasts
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(c) Secondary Appendix
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(f) Chapter 3, Section F
(g) Chapter 3, Section F
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(h) No response required
(3) Chapter 3, Section F
(4)(a) Chapter 3, Section F
Secondary Appendix
(b) Chapter 3, Section F

(c)	Chapter 3, Section F
(d)	Chapter 3, Section F Chapter 4
(e)	No response required
(5)(a)(1)	Waiver received
(2)	Waiver received
(b)(1)	Waiver received
(2)	Waiver received
(6)	No response required
(7)(a)	Chapter 3, Section D Secondary Appendix
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(2)	Chapter 3, Section B
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(2) Chapter 8, Sections C, D
(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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SECONDARY APPENDIX

Annual Report

Volume II

TRANSMISSION INFORMATION

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

Duke Energy Kentucky, Inc. ("DE-Kentucky" or "Company") is a wholly owned subsidiary of Duke Energy Ohio, Inc. ("DE-Ohio") that provides electric and gas service in the Northern Kentucky area contiguous to the Southwestern Ohio area served by DE-Ohio. DE-Kentucky serves approximately 134,000 customers in its 500 square mile service territory. DE-Kentucky's service territory includes the cities of Covington and Newport, Kentucky.

The total installed net summer generation capability owned by DE-Kentucky is 1,077 Megawatts ("MW"). This capacity consists of 577 MW of coal-fired steam capacity, and 500 MW of natural gas-fired peaking capacity. The steam capacity, located at two stations, is comprised of two coal-fired units. The peaking capacity consists of six natural gas-fired combustion turbines ("CTs") located at one station. These natural gas-fired units have propane as a back-up fuel. One of the coal-fired steam units, East Bend Unit 2, is jointly owned with Dayton Power & Light. DE-Kentucky owns 69% of the unit and is the operator.

DE-Kentucky owns an electric transmission system and an electric distribution system in portions of Kenton, Campbell, Boone, Grant, and Pendleton counties of Northern Kentucky. The Company also owns a gas distribution system, which serves either all or parts of Kenton, Campbell, Boone, Grant, Gallatin, and Pendleton counties in

Northern Kentucky. DE-Kentucky contracts with the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") for bulk transmission service to transport electric power from DE-Kentucky's plants and from outside the Duke Energy Midwest system through the Duke Energy Midwest transmission system to DE-Kentucky's transmission and distribution system for ultimate delivery to DE-Kentucky's distribution system and end-use retail customers. The numerous interconnections Duke Energy Midwest has with neighboring balancing authorities increase electric system reliability and decrease costs to the customer by permitting the exchange of power and energy with other balancing authorities. DE-Kentucky is a member of the Midwest ISO.

DE-Kentucky, DE-Ohio, and Duke Energy Indiana, Inc. ("DE-Indiana") comprise the Duke Energy Midwest balancing authority. The Duke Energy Midwest balancing authority 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. SIGNIFICANT CHANGES SINCE THE PREVIOUS IRP

DE-Kentucky last filed an Integrated Resource Plan ("IRP") on April 1, 2004. This section and the individual topic sections later in this chapter discuss the significant changes since that filing.

Duke Energy Merger

On May 9, 2005, Cinergy and Duke Energy announced an agreement to merge. The merger was conditioned upon approval by the shareholders of both companies, as well as a number of regulatory approvals or reviews by federal and state energy authorities. The merger closed on April 3, 2006, after all the approvals were received.

DE-Kentucky's utility operations have not been impacted by the merger because Duke Energy's operating company serving portions of North and South Carolina is not contiguous to DE-Kentucky's electric service territory. The planning is performed separately from that of DE-Indiana or Duke Energy Carolinas, LLC ("DE-Carolinas"). However, the planning is performed by a shared staff, which results in savings. In addition, the merged company has standardized many of its processes, resulting in the use of different software planning models than those previously used by DE-Kentucky, but this has not changed the fundamental planning process.

Generating Resources

As approved by the Kentucky Public Service Commission ("PSC" or "Commission"), East Bend Unit 2, Miami Fort Unit 6, and Woodsdale Units 1-6 were transferred from

DE-Ohio to DE-Kentucky and, as a result, the wholesale Power Sales Agreement is no longer in effect. These resources are discussed in more detail in Chapter 5.

Energy Independence and Security Act

In late 2007, President Bush signed the Energy Independence and Security Act, part of which sets new efficiency standards for lighting staring in 2012. According to a white paper from the Lighting Controls Association, "New Energy Law to Phase Out Today's Common Incandescent Lamps, Probe-Start Metal Halide Magnetic Ballasted Fixtures" by Craig DiLouie, the new legislation "...virtually eliminates the manufacture of most common general-service incandescent lamps..." and "Lamps that do not comply on or after the effective dates cannot be manufactured or imported." According to the Association they believe that compact fluorescent light bulbs ("CFLs") will capture the entire general incandescent market. Therefore, the Company estimated the impact of this legislation on lighting load and reduced the forecast accordingly, starting in 2012.

Tighter Environmental Regulations

In March 2005, the United States Environmental Protection Agency ("USEPA" or "EPA") issued the Clean Air Interstate Rule ("CAIR") that requires states to revise their State Implementation Plan ("SIP") by September 2006 to address alleged contributions to downwind non-attainment with the revised National Ambient Air Quality Standards for ozone and fine particulate matter. The rule establishes a two-phased, regional cap and trade program for sulfur dioxide ("SO_2") and nitrogen oxides ("NO_x"), affecting 28 states, including Kentucky. CAIR requires NO_x and SO_2

emissions to be cut by 65 percent and 70 percent, respectively, by 2015, with the first phase of reductions by 2009 and 2010, respectively. In March 2005, the EPA issued the Clean Air Mercury Rule ("CAMR") that requires the reduction of mercury emissions from coal-fired power plants for the first time. The CAMR adopted a two-phased cap and trade program that would cut mercury emissions by 70 percent by 2018 with the first phase in 2010. However, the Circuit Court of Appeals for the District of Columbia vacated the CAMR on February 8, 2008, and it could take two or more years before EPA proposes new mercury regulations to replace CAMR. These tighter environmental regulations are expected to result in much higher emission allowance ("EA") prices, which generally will make installing environmental compliance measures more economic than in previous IRPs. These more stringent regulations will also affect the resource choices going forward. Chapters 6 and 8 contain detailed discussions of the impact of these regulations on this IRP.

Energy Policy Act of 2005

The Energy Policy Act of 2005 was signed into law on August 8, 2005, and includes a wide range of provisions addressing many aspects of the energy industry. The legislation will be implemented through the development of more than 270 rulemakings and studies that will be prepared across the federal government. DE-Kentucky will be impacted by some of the provisions and is assessing the impact of new standards, obligations, incentives, and opportunities.

Increased Potential for Renewable Portfolio Standard ("RPS") Legislation

In 2007, the Energy Bill passed by the U.S. House of Representatives contained a 15% RPS that allowed energy efficiency to provide up to 25% of the requirement, but the Senate version did not include such a standard. While the final version that was signed into law did not include the RPS provision, there continue to be bills introduced in Congress that would mandate an RPS.

Based on these events, the eventual imposition of some kind of RPS on DE-Kentucky appears to be more likely than in past years, which will impact the Company's resource mix and costs to serve its customers. Therefore, this IRP includes analysis of a sensitivity concerning the impact of these potential requirements. The results of this analysis are discussed in detail in Chapter 8.

Increased Potential for CO_2 Legislation

There are a number of proposed bills in Congress that could impose restrictions on future CO_2 emissions either through a Carbon Tax or through a cap-and-trade system. The passage of legislation within the next four years which will impact CO_2 emissions appears to be much more likely after the 2008 presidential election. Therefore, sensitivity analyses concerning the impacts such restrictions would have on the DE-Kentucky resource plan and the costs to customers were performed as a part of this IRP. The results of these analyses are discussed in detail in Chapter 8.

C. PLANNING OBJECTIVES AND CRITERIA

An IRP process generally encompasses an assessment of a variety of supply-side, demand-side management[1], 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 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 major objectives of the IRP presented in this filing are:

- Provide adequate, reliable, and economic 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.*)

In this IRP, the long-term reliability criterion was a 15% minimum reserve margin. 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 increase risks and potentially result in additional costs to customers.

[1] Kentucky Revised Statutes (KRS) § 278.010 define Demand Side Management as "any conservation, load management, or other utility activity intended to influence the level or pattern of customer usage or demand including home energy assistance programs." KY. REV. STAT. ANN. § 278.010 (Michie 2007).

Since the filing of the last IRP, Reliability*First* has enacted a Resource Planning Reserve Requirement Standard that the Loss of Load Expectation ("LOLE") due to resource inadequacy cannot exceed one occurrence in ten years (0.1 occurrence per year). The Midwest ISO also has an approved Resource Adequacy requirement.

DE-Kentucky is a member of the Midwest Planning Reserve Sharing Group ("PRSG"). On February 5, 2008, this group issued its preliminary report showing the required reserve margin targets for the June 2008-May 2009 planning year. The target is 14.3% for the zone where DE-Kentucky is located. This is the first year that the Midwest PRSG has performed this type of study, so there are many refinements to assumptions and methodologies that undoubtedly will be incorporated in future studies. DE-Kentucky believes that some of the assumptions in the study tended to bias the results toward producing a lower reserve margin. Other RTOs that have routinely performed these types of studies for years produce results in the 14-16% range.

On December 28, 2007, the Midwest ISO filed a proposal for long-term resource adequacy at FERC. The proposal would require load-serving entity ("LSE") market participants in the Midwest ISO region to have and maintain access to sufficient planning resources. The Midwest ISO would establish a Planning Reserve Margin based on an LOLE study using the 1 day in 10 year standard to align with Regional Entity requirements such as those of Reliability*First*. The initial Planning Year would be from June 1, 2009, through May 31, 2010, with LSEs required to submit their specific plans for meeting the requirement by March 1, 2009. FERC issued its order generally approving this proposal on March 26, 2008.

DE-Kentucky anticipates that the Midwest ISO LOLE study process will essentially replace the Midwest PRSG study process. Since the Midwest ISO was the contractor that performed the Midwest PRSG's LOLE study, the processes should be similar. However, the capacity toward reserves will be adjusted by the unit-specific Equivalent Forced Outage Rates exclusive of outside management control ("$XEFOR_d$") as part of the Midwest ISO tariff, which may change the amount of reserves each LSE is required to carry. Units with better availability will be credited with higher capacity value compared to units with poorer availability.

For the reasons described above, DE-Kentucky believes that continuing to use a reserve margin target of 15% in its IRPs is prudent until the LOLE study process matures. DE-Kentucky will keep this Commission informed once the result of these efforts becomes clearer.

D. PLANNING PROCESS

The analysis performed to prepare this IRP covers the period 2008-2028, although the primary focus is 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. The planning period was extended compared to the fifteen-year period required by the IRP rules in order to incorporate a longer period of time with regard to CO_2 restriction impacts.

For this IRP analysis, the Base Case assumed a CO_2 allowance price/tax[2]. The other major environmental assumptions for the first ten years were as follows:

- All current environmental requirements will be met.
- The requirements of CAIR to reduce NO_x and SO_2 emissions further beginning in 2009 and 2010, respectively, will be met.
- A mercury Maximum Achievable Control Technology ("MACT") standard will be enacted with a 2.0 lb per trillion Btu emission limit.[3]
- No Hazardous Air Pollutant controls other than mercury will be mandated and implemented during the period.
- No Renewable Energy Portfolio Standard will be mandated or implemented during the period.

Risks associated with potential changes to environmental regulations are discussed further later in this report (See Chapter 8, Section E). Some of these risks are quantified through sensitivity analysis (see Chapter 8, Section D). Risks related to other changes

[2] Despite significant uncertainty surrounding potential future climate change policy, DE-Kentucky has incorporated the potential for CO_2 climate change regulations in its resource planning process. Inclusion of this assumption is not intended to reflect DE-Kentucky's or Duke Energy's preferences regarding future climate change policy.

[3] The exact nature of the standard that will replace CAMR is unknown at this time. Therefore, for this IRP, a MACT standard similar to that proposed by the EPA in 2004 was assumed. Inclusion of this assumption is not intended to reflect DE-Kentucky's or Duke Energy's preferences regarding future mercury policy.

to assumptions are addressed through sensitivity analysis and qualitative reasoning later in this report (see 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 IRP Team which consists of experts from key functional areas of Duke Energy. The Team approach facilitated the high level of communication necessary across the functional areas required to develop an IRP. The IRP Team 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 areas.

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 demand-side management 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 management, supply-side, and environmental compliance options.
7. Perform final sensitivity analyses on the integrated resource alternatives and recommend a plan.
8. Determine the best way to implement the recommended plan.

The resource plan presented herein represents the results of this extensive business planning process.

E. LOAD FORECAST

The electric energy and peak demand forecasts of the DE-Kentucky 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 national economic and demographic concepts such as population, employment, industrial production, inflation, wage rates, and income. The national economic forecast is obtained from Moody's 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 Moody's 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 along with electric system losses are aggregated to produce a forecast of net energy.

Table 1-1 provides information on the forecasted DE-Kentucky System annual growth rates (without the implementation of any new, or incremental, conservation energy efficiency programs but with demand response impacts included) in energy for the major customer classes as well as net energy and peak demand.

TABLE 1-1

DE-Kentucky System
ELECTRIC ENERGY AND PEAK LOAD FORECAST: ANNUAL GROWTH RATES

	2008-2028
Residential MWh	0.2%
Commercial MWh	1.3%
Industrial MWh	1.1%
Net Energy MWh	0.8%
Summer Peak MW	0.8%
Winter Peak MW	0.7%

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 IRP.

Actual vs. Forecast

Table 1-2 provides information comparing the actual and forecast energy and peak demands (after demand response program impacts) for the DE-Kentucky System. The table compares the actual levels for the years 2003 through 2007 to the forecast provided in the 2003 IRP.

TABLE 1-2

DE-Kentucky System
ELECTRIC ENERGY AND PEAK LOAD
COMPARISON: ACTUAL VS. FORECAST

	Energy – MWh		Native Peak - Mw	
Year	**Actual**	**Forecast**	**Actual**	**Forecast**
2003	**4,092,800**	**3,907,910**	**811**	**848**
2004	**4,218,533**	**3,982,976**	**817**	**864**
2005	**4,274,518**	**4,065,712**	**905**	**879**
2006	**4,074,050**	**4,160,857**	**881**	**890**
2007	**4,287,280**	**4,246,751**	**930**	**905**

Changes In Methodology

There were no significant changes to the forecast methodology. Because the Company uses the latest historical data available and relies on recent economic data and forecasts from Moody's Economy.com, the new forecast will be different from the one filed in 2003. Figures 1-3, 1-4, and 1-5 show the difference in the energy and summer and winter peak forecasts, respectively. The new forecast is lower mainly due to higher energy prices, higher efficiency levels, and changing expectations about economic growth. The growth in energy over the forecast period is expected to be 0.8 percent as compared to 1.8 percent in 2003. Similarly, the summer peak demand is expected to grow 0.8 percent as compared to 1.5 percent.

In addition, the Company made changes to the calculation of heating and cooling degree days. See Chapter 3, Section E for further details.

F. DEMAND-SIDE MANAGEMENT RESOURCES

DE-Kentucky's demand-side management ("DSM") programs include traditional conservation energy efficiency ("EE") programs and demand response ("DR") programs and are expected to help reduce demand on the DE-Kentucky system during times of peak load.

In the previous IRP, DE-Kentucky included 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

These programs plus the demand response programs Power Manager and PowerShare® were expected to provide approximately 15 MW of peak reduction.

Since that time, the Company has terminated the Residential New Construction program. Through applications by the Company and in conjunction with the Company's DSM Collaborative, the Commission approved expansions of the Company's DSM efforts. The expansion of the programs has led to the implemention of the following set of programs:

Program 1: Residential Conservation and Energy Education

Program 2: Residential Home Energy House Call

Program 3: Residential Comprehensive Energy Education Program ("NEED")

Program 4: Program Administration, Development & Evaluation Funds

Program 5: Payment Plus (*formerly* Home Energy Assistance Plus)

Program 6: Power Manager

Program 7: Energy Star® Products

Program 8: Energy Efficiency Website

Program 9: Personal Energy Report ("PER")

Program 10: C&I High Efficiency Incentive (for Businesses and Schools)

Program 11: PowerShare®

These programs are expected to provide approximately 22 MW of peak load reduction compared to the 2003 IRP. The increase is coming primarily from the conservation programs. Details on each program are provided in Chapter 4. In the Commission Order in Case No. 2004-00389, dated February 14, 2005, 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 5-year period, through December 31, 2009.

Under the current DSM Agreement and prior Commission Orders, all of the programs, except Power Manager and PER, will end December 2009 unless an application is made to continue them. It is the Company's intention to submit a filing subsequent to this report, requesting the approval of a set of energy efficiency and demand response products and services. The first ten programs are involved with conservation objectives as well as the measurement and verification of program impacts.

DE-Kentucky's PowerShare® pricing program entails an innovative approach to demand response. 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 DE-Kentucky 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).

The expected impacts of all the programs are incorporated into the IRP analysis and provided in Chapter 4.

G. SUPPLY-SIDE RESOURCES

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

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

Customers make cogeneration decisions based on their particular economic situations, so DE-Kentucky 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.

In the 2003 IRP, a list of over one hundred supply-side resources was developed as potential alternatives for the IRP process. Experience from the 2003 analyses and from the many technology screening analyses performed for Duke Energy's other jurisdictions allowed a more focused approach to resource screening for this IRP. For the IRP screening analyses this year, technology types were screened within the categories of baseload, peaking/intermediate, and renewable using a set of relative dollar per kilowatt-year versus capacity factor screening curves. The ultimate goal of the screening was to pass the best alternatives from each of these three categories to the optimization computer model that integrates the supply-side, DSM, and environmental compliance alternatives to produce a least cost plan that meets the prescribed reliability criteria. Sensitivity analyses were performed to determine the necessary data input and/or assumption changes which make a technology that is not economical under base case conditions become economical.

The options passed as candidates to the final base case integration process were simple-cycle gas-fired CT units, gas-fired Combined Cycle ("CC") units, Supercritical Pulverized Coal ("PC") units, Integrated Gasification Combined Cycle ("IGCC") units, Nuclear units, Turnkey Wind projects, Poultry Waste projects, Hog Waste Digesters, fluidized bed biomass, and solar alternatives. These units could represent potential non-utility generating units, purchases, repowering of existing DE-Kentucky units, or utility-constructed units.

H. ENVIRONMENTAL COMPLIANCE

CAAA Phase I & Phase II Compliance

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

NO_x Compliance Planning

A detailed description of DE-Kentucky's NO_x SIP Call compliance planning process can be found in the former Cinergy 1999, 2001, and 2003 IRPs.

Clean Air Interstate Rule/Clean Air Mercury Rule Compliance Planning- Phase I

DE-Kentucky's CAIR/CAMR Phase I compliance plan includes the upgrade of the existing flue gas desulphurization equipment ("FGD") at East Bend Unit 2, and the installation of advanced low NO_x burners with over-fire air on Miami Fort Unit 6. Both of these projects are complete and in service. In addition, the existing East Bend Unit 2 selective catalytic reduction equipment ("SCR") will be required to operate annually beginning in 2009. DE-Kentucky also plans to operate the SCR additional time in 2008 in order to earn CAIR Annual NO_x Compliance Supplement Pool Allowances.

CAIR/CAMR Analysis- Phase II

Further analysis was performed for this IRP regarding Phase II compliance projects. For this analysis, DE-Kentucky used a three-stage analytical modeling process, involving the Ventyx Energy, LLC ("Ventyx") MARKETSYM™ model, DE-Kentucky's internal Engineering Screening Model, and the Ventyx System Optimizer and Planning and Risk models. This most recent Phase II analysis assumed the Phase I compliance actions would be executed, and thus concentrated on additional compliance at Miami Fort Unit 6. Consideration was also given to the potential for a future mercury MACT regulation.

Ventyx used MARKETSYM™ to model the final CAIR and CAMR, including known state-specific mercury rules (prior to the CAMR being vacated by the court), and an assumption for future CO_2 regulations. They provided forecasted emission allowance prices (for SO_2, Seasonal NO_x, Annual NO_x, mercury, and CO_2), power prices, and fuel prices (coal, oil, natural gas).

The Engineering Screening Model was used to screen down to the most economic emission reduction options for further analysis in the System Optimizer model. Technology options that were screened included wet and dry FGDs for SO_2 reduction; SCR and SNCR for NO_x reduction; and ACI with baghouses for mercury control, in addition to FGD and FGD/SCR mercury reduction co-benefits. Fuel switch options to lower sulfur coals with appropriate particulate control upgrades as needed were also modeled. Cost and performance estimates for all of the modeled technologies were reviewed and updated as appropriate prior to screening. In addition, a new technology, in-duct trona injection (or "in-duct dry FGD") was included in this round of screening.

With its existing SCR and FGD, East Bend Unit 2 is well placed to comply with the CAIR regulations. There were no additional economic compliance options identified for this unit. For Miami Fort Unit 6, however, there is a strong emphasis on reducing the SO_2 emissions due the reductions brought on by CAIR. Switching to lower sulfur content fuels appeared to be economic in the Engineering Screening Model analysis. This would include projects for particulate controls upgrades; either precipitator upgrades with SO_3 injection, or the installation of a baghouse. The installation of a baghouse with activated carbon injection would likely be required under a future mercury MACT regulation and was thus also selected as an option[4].

These Phase II compliance alternatives passed to the System Optimizer from the Engineering Screening Model were analyzed in the integration step of this IRP in conjunction with the DSM and supply-side alternatives. This is discussed in detail in Chapter 8.

I. ELECTRIC TRANSMISSION FORECAST

The transmission information is located in the Transmission Volume of this report.

[4] This option results in a derate of approximately 1 MW due to increased auxiliary load.

J. 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. System Optimizer and Planning and Risk were the models utilized in this final integration process. From the optimized plans, three portfolios 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 gas and coal price forecasts, higher capital costs for unit alternatives, changes in the level of service area load, changes in regulatory requirements, and increased environmental regulation or rules, including a sensitivity with a higher CO_2 tax/allowance price and a Renewable Portfolio Standard.

Based upon both the quantitative and qualitative results of the screening analyses and sensitivity analyses, the plan selected to be the 2008 IRP is shown in Figure 1-6. The details of the plan including yearly capacity, purchases, capacity additions, retirements/derates, cogeneration, load, EE, DR, firm sales, and reserve margins are shown in Figure 1-7.

This IRP is the plan with the lowest relative PVRR. It contains the conservation EE and DR programs. The supply-side resources selected consist of a two CT units (35 MW each) added in 2019 and 2023, and a nuclear unit (35 MW) added in 2027.

Each of the supply-side resources selected should be viewed as "placeholders" for the types of capacity resources that are the most economical at the time decisions for adding capacity need to be made. In addition, the sizes of the resources selected generally represent "shares" of larger, more economical unit sizes.

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. In addition, if the new mercury standard is MACT rather than cap-and-trade, switching to low sulfur fuel and installing a baghouse with activated carbon injection at Miami Fort 6 will be required. The Company will continue to monitor the coming mercury rulemaking and will perform additional analysis prior to making any final decisions concerning these expenditures. Any shortfalls between the yearly allowance allocation from the EPA and the actual emissions will be supplied by DE-Kentucky's allowance bank or by allowance purchases from the market.

Plan Changes Compared to 2003 IRP

The major changes include a lower level of additional resources required compared to the 2003 IRP due to a lower level of forecasted load. The 2003 IRP added 260 MW of new resources over the period 2013 to 2023, consisting of fuel cells and coal units. The 2008 IRP includes 105 MW of new resources consisting of new gas-fired CTs and a nuclear unit. The plan also includes additional environmental compliance resources that resulted from new regulations (*e.g.* CAIR) that have been enacted after the 2003 IRP was filed. The changes in the mix of resources chosen also tend to be lower emitting resources due to the tightened environmental regulations and the increased potential for carbon regulations. The 2008 IRP is described in more detail in Chapter 8.

Implementation

In making decisions concerning what steps to take to begin the implementation of the 2008 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
- Volatility in the natural gas market
- Transmission constraints

Because they do not appear until late in the planning horizon, the new supply-side resources in the plan represent, to a large extent, "placeholders" for capacity and energy needs on the system. No decisions concerning additional supply-side resources are necessary over the next three years, so DE-Kentucky can continue to evaluate its resource requirements. 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 participation in the Midwest ISO market.

However, the existing DE-Kentucky portfolio lacks some diversity in that it contains two relatively large coal-fired units (compared to the overall size of the DE-Kentucky system). These units can pose additional risks when they are out of service for either planned or forced outages. The ability to offer these units into the Midwest ISO market and to purchase from a more diverse pool of resources from that market helps to mitigate some of these risks. Nevertheless, in the future, DE-Kentucky will continue to assess these risks and may look for opportunities to diversify the portfolio. Potential alternatives may include shared ownership or capacity swaps with other utilities. DE-Kentucky will keep this Commission informed of any developments in this area.

The only environmental compliance resource identified in the chosen plan is the installation of a baghouse with ACI on Miami Fort 6, along with switching to lower sulfur coal. However, until the mercury rules that will replace CAMR are known, no final decisions will be made. The Company will continue to monitor and study the need for these changes. DE-Kentucky also will be closely monitoring the SO_2 and NO_x emission allowance markets.

In the Commission Order in Case No. 2004-00389, dated February 14, 2005, 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 5-year period, through December 31, 2009.

Under the current DSM Agreement and prior Commission Orders, all of these programs except Power Manager and PER, will end December 2009 unless an application is made to continue them. As stated earlier, it is the Company's intention to submit a filing subsequent to this report, requesting the approval of a set of energy efficiency and demand response products and services.

The incremental impacts going forward of the current set of EE and DR programs are incorporated into the resource plan for DE-Kentucky. An analysis was also performed comparing the economics of the 2008 IRP plan to a plan that did not contain any EE or DR programs. This analysis showed that the inclusion of these programs in the chosen plan reduces the PVRR of that plan by approximately $2.5 million.

The 2008 IRP, with its proposed implementation, is consistent with the overall planning objectives and goals outlined earlier. The plan selected was the least cost, provides reliable service to DE-Kentucky's customers, is robust, and minimizes risks to customers.

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DUKE ENERGY KENTUCKY SYSTEM
ENERGY 2003 - 2028

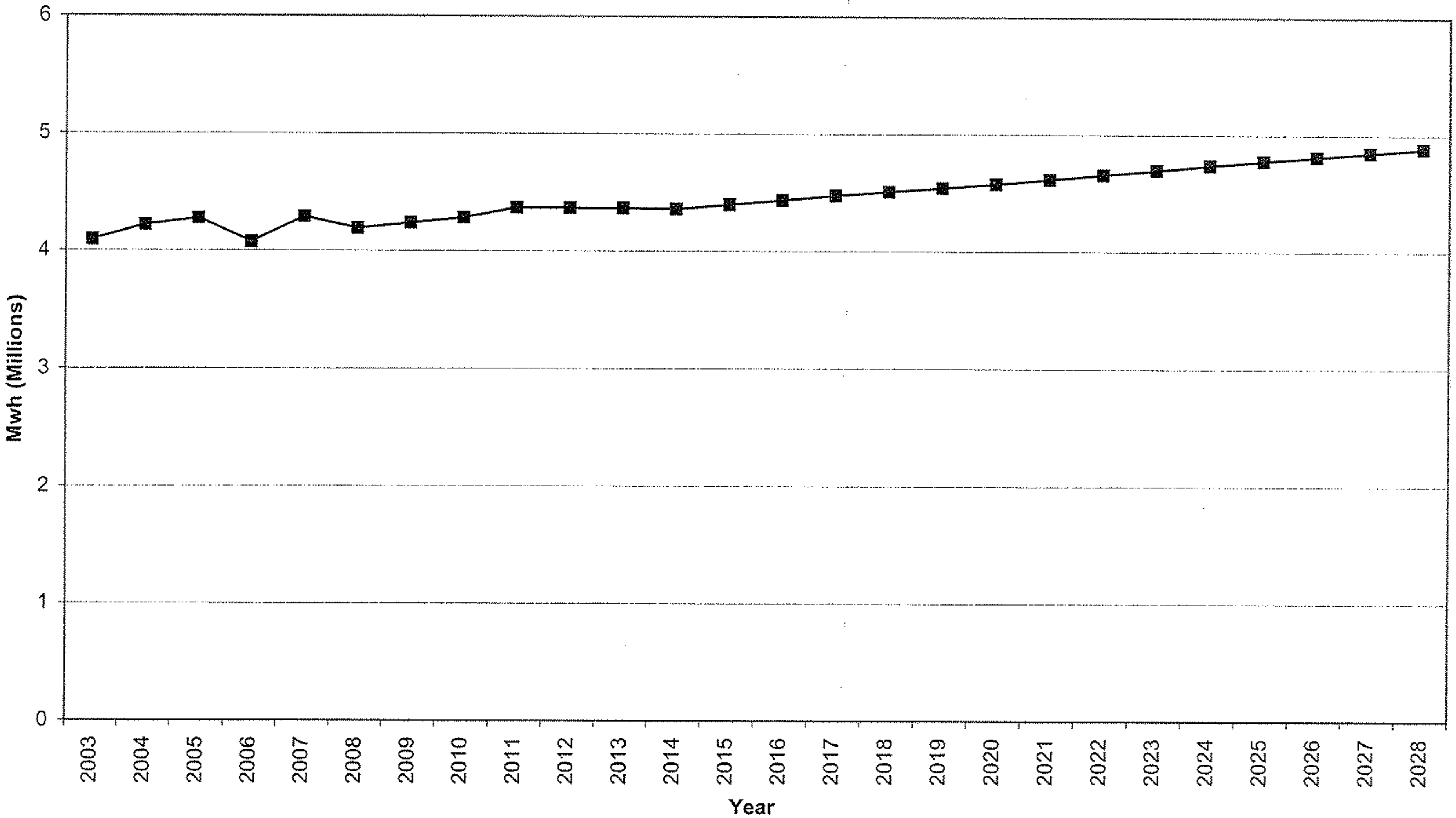
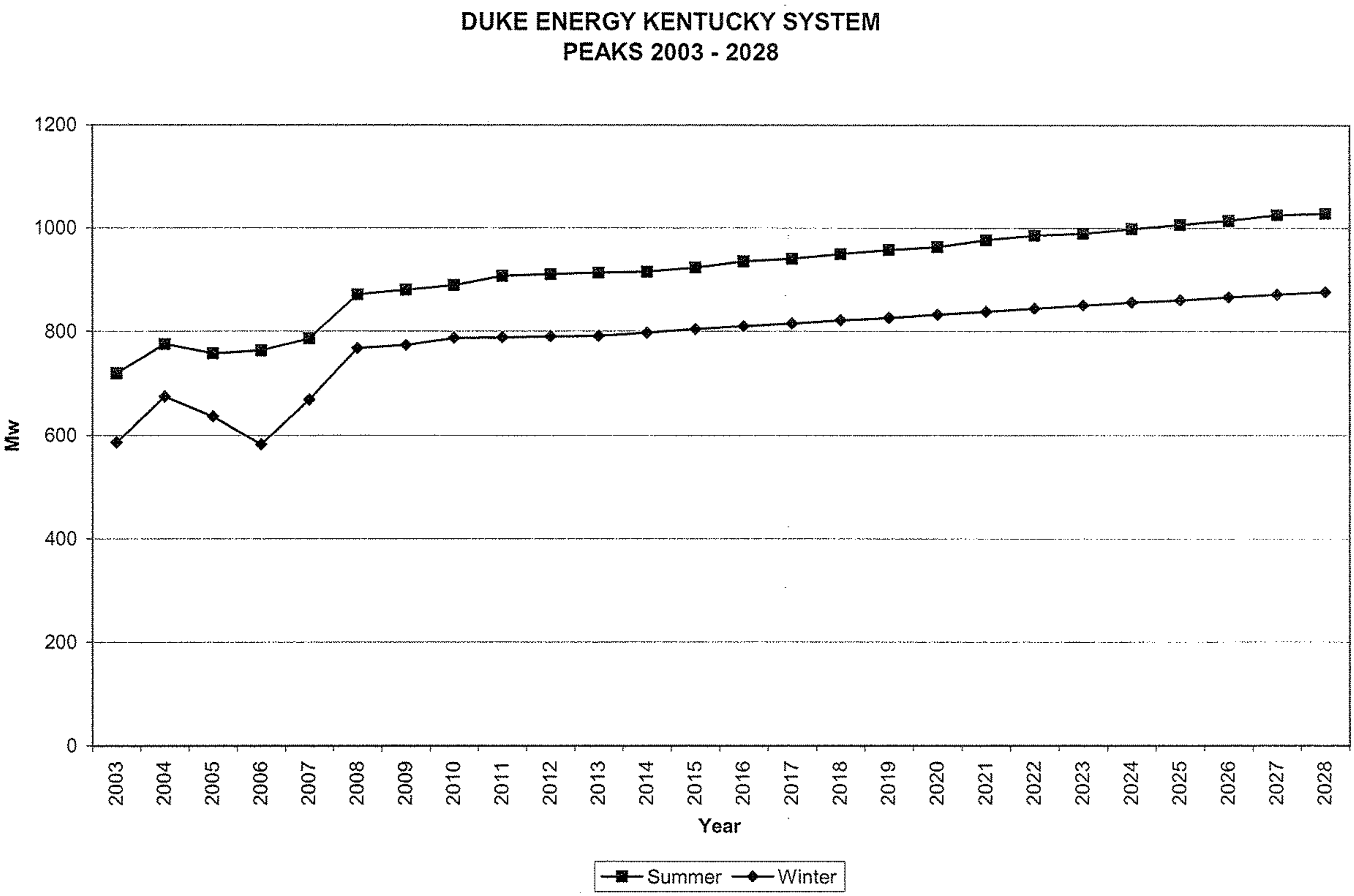


Figure 1-2



DUKE ENERGY KENTUCKY SYSTEM
PEAKS 2003 - 2028
Mw
1200
1000
800
600
400
200
0
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
Year
Summer
Winter

Fi 1-3

DUKE ENERGY KENTUCKY SYSTEM
COMPARISON OF ENERGY 2003 - 2028
2003 IRP vs. 2008 IRP

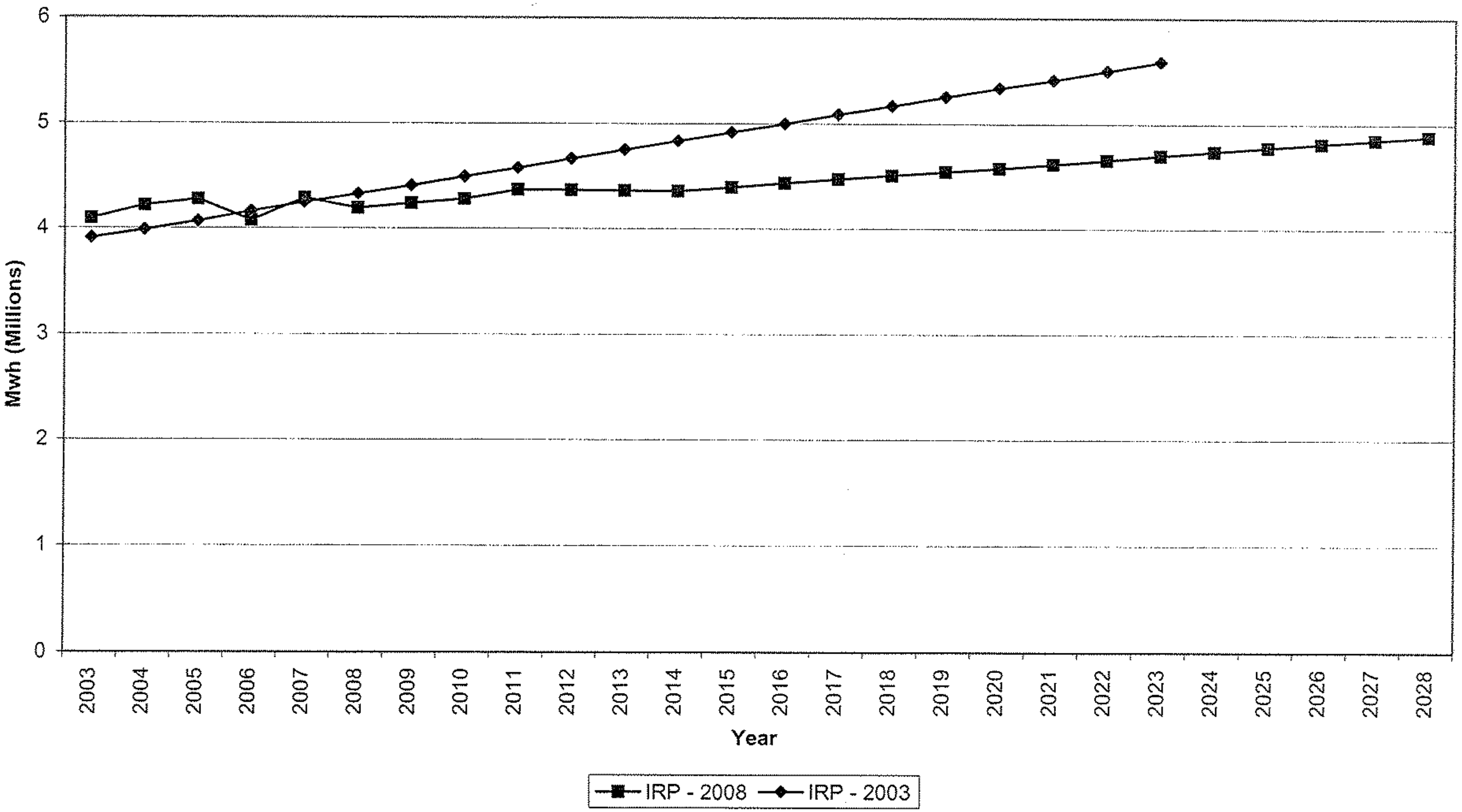
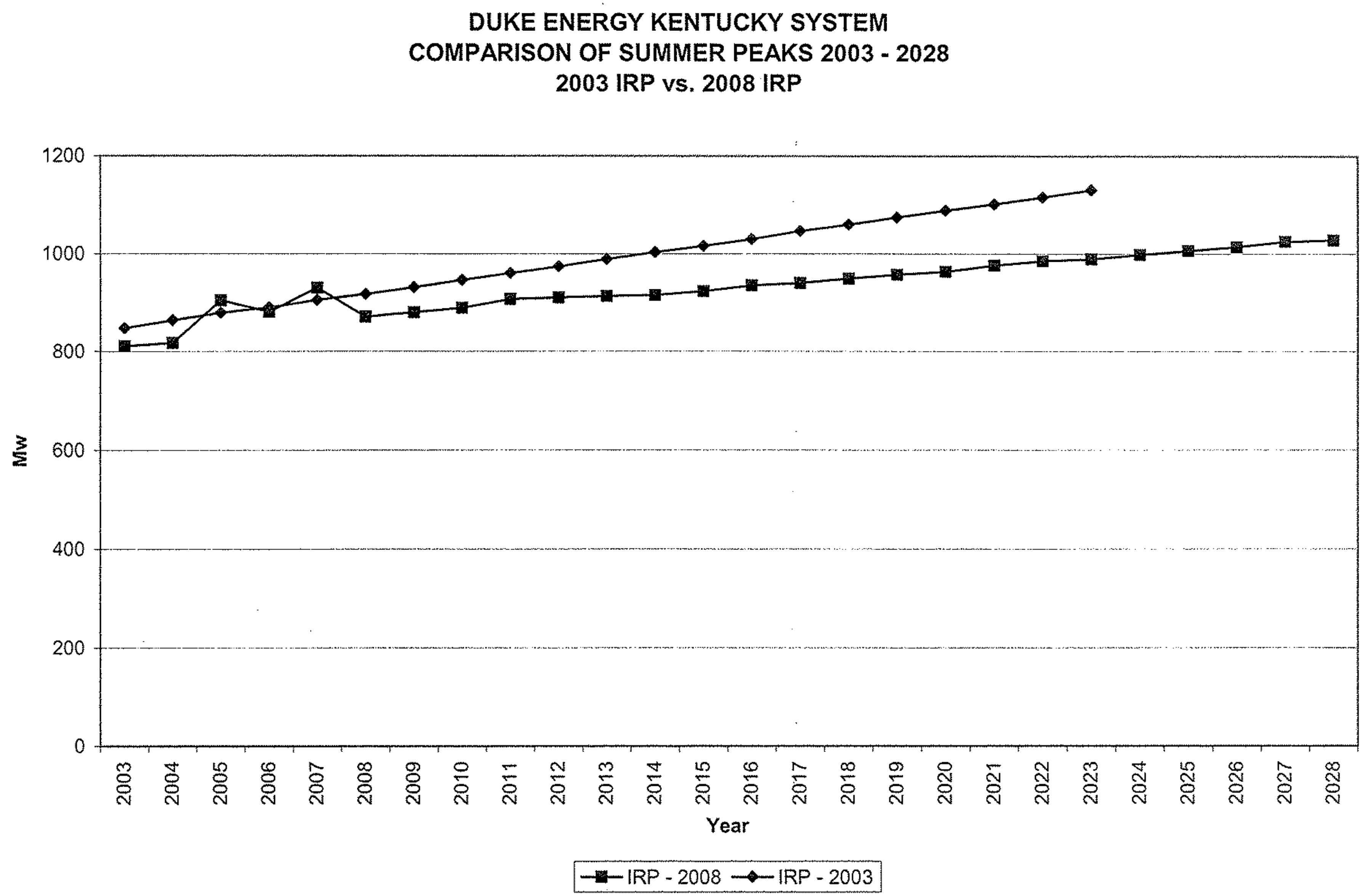


Figure 1-4



DUKE ENERGY KENTUCKY SYSTEM
COMPARISON OF SUMMER PEAKS 2003 - 2028
2003 IRP vs. 2008 IRP
Mw
1200
1000
800
600
400
200
0
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
Year
IRP - 2008
IRP - 2003

Fi 1-5

**DUKE ENERGY KENTUCKY SYSTEM
COMPARISON OF WINTER PEAKS 2003 - 2028
2003 IRP vs. 2008 IRP**

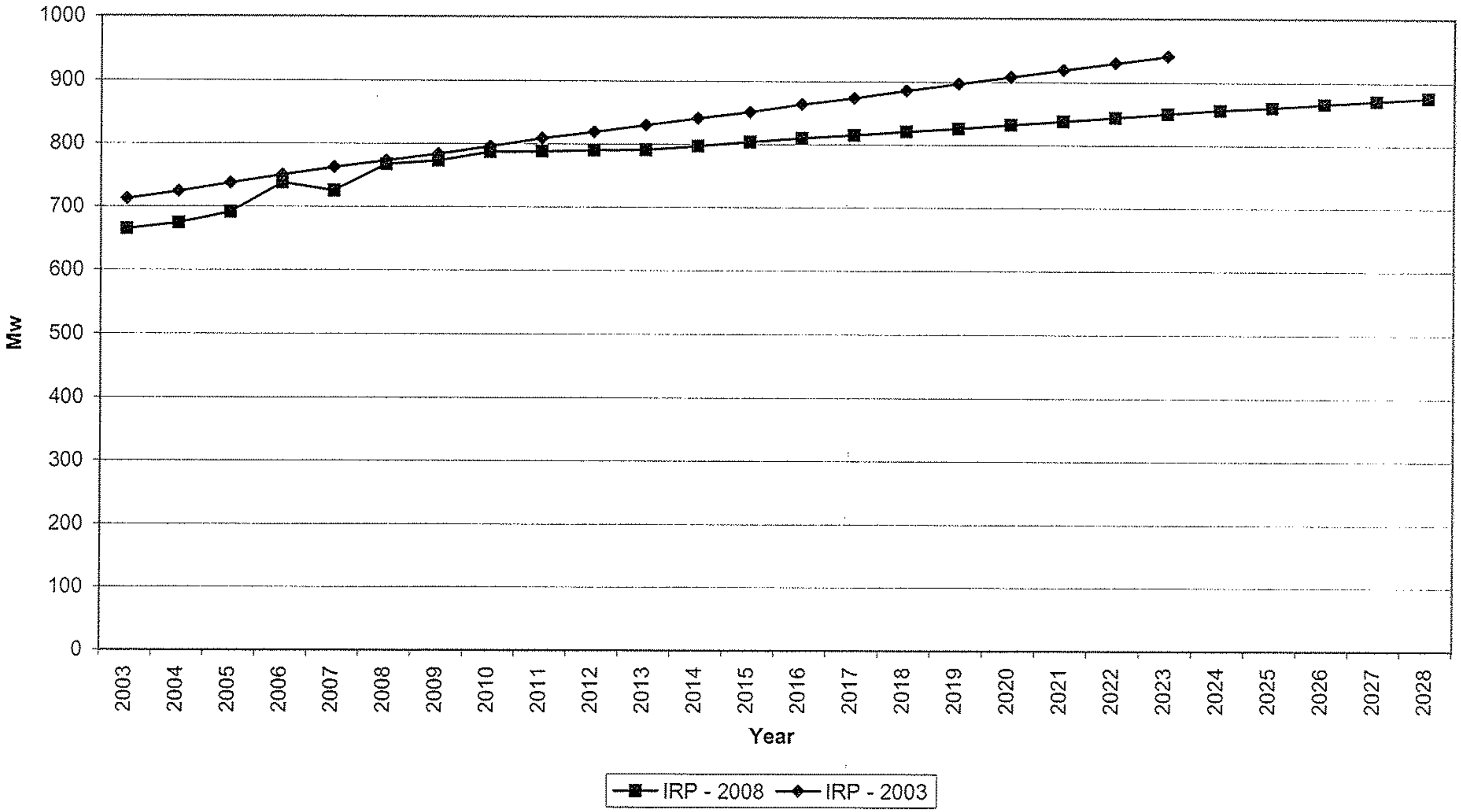


Figure 1-6

DUKE ENERGY KENTUCKY INTEGRATED RESOURCE PLAN
2008-2028

Year	Demand-Side[1]	Purchases/Unit Additions[2]	Compliance
2008	Conservation EE Bundle DR Bundle - Residential DR Bundle - Non-Residential		
2009			
2010			
2011			
2012			Low SO_2 Fuel, BH, ACI on Miami Fort 6
2013			
2014			
2015			
2016			
2017			
2018			
2019		Install New CT (35 MW)	
2020			
2021			
2022			
2023		Install New CT (35 MW)	
2024			
2025			
2026			
2027		Install New Nuclear (35 MW)	
2028			

[1] The Demand-side resources are assumed to continue throughout the planning period (2008-2028)
[2] Capacity shown denotes summer ratings

DUKE ENERGY KENTUCKY
SUPPLY VS. DEMAND BALANCE
(Summer Capacity and Loads)

YEAR	INITIAL CAPACITY	SHORT TERM PURCH.	INCR. CAPACITY ADDITIONS	INCR. CAPACITY RETIRE./ DERATES	COGEN. CAPACITY	TOTAL CAPACITY	PEAK LOAD	ENERGY SECURITY ACT LIGHTING IMPACTS	INCR. CONSERV.[a]	DEMAND RESPONSE	FIRM SALES	NET LOAD	RES. MAR. (%)	CAPACITY MINUS NET LOAD	PURCHASES NEEDED TO MEET 15% RM
2008	1077	0	0	0	0	1077	871	0	0	-11	0	859	25.3	218	(89)
2009	1077	0	0	0	0	1077	880	0	-1	-13	0	866	24.3	211	(81)
2010	1077	0	0	0	0	1077	889	0	-1	-14	0	874	23.3	203	(72)
2011	1077	0	0	0	0	1077	907	0	-2	-14	0	891	20.9	186	(53)
2012	1077	0	0	-1	0	1076	918	-8	-2	-14	0	893	20.5	183	(49)
2013	1076	0	0	0	0	1076	928	-15	-3	-14	0	896	20.1	180	(46)
2014	1076	0	0	0	0	1076	938	-23	-3	-14	0	898	19.9	178	(44)
2015	1076	0	0	0	0	1076	948	-25	-3	-14	0	905	18.8	171	(35)
2016	1076	0	0	0	0	1076	958	-23	-4	-14	0	917	17.3	159	(21)
2017	1076	0	0	0	0	1076	968	-28	-4	-14	0	922	16.7	154	(16)
2018	1076	0	0	0	0	1076	978	-29	-4	-14	0	931	15.6	145	(5)
2019	1076	0	35	0	0	1111	987	-30	-4	-14	0	939	18.3	172	(31)
2020	1111	0	0	0	0	1111	995	-32	-4	-14	0	945	17.6	166	(24)
2021	1111	0	0	0	0	1111	1004	-28	-4	-14	0	958	16.0	153	(9)
2022	1111	0	0	0	0	1111	1013	-28	-4	-14	0	967	14.9	144	1
2023	1111	0	35	0	0	1146	1021	-32	-4	-14	0	971	18.0	175	(29)
2024	1146	0	0	0	0	1146	1030	-32	-4	-14	0	980	16.9	166	(19)
2025	1146	0	0	0	0	1146	1038	-32	-4	-14	0	988	16.0	158	(10)
2026	1146	0	0	0	0	1146	1046	-32	-4	-14	0	996	15.1	150	(1)
2027	1146	0	35	0	0	1181	1053	-28	-4	-14	0	1007	17.3	174	(23)
2028	1181	0	0	0	0	1181	1061	-33	-4	-14	0	1010	16.9	171	(19)

[a] Not included in load forecast
The values shown are the impacts coincident with the summer peak, not the maximum impacts.

DUKE ENERGY KENTUCKY
SUPPLY VS. DEMAND BALANCE
(Winter Capacity and Loads)

YEAR	INITIAL CAPACITY	SHORT TERM PURCH.	INCR. CAPACITY ADDITIONS	INCR. CAPACITY RETIRE./ DERATES	COGEN. CAPACITY	TOTAL CAPACITY	PEAK LOAD	ENERGY SECURITY ACT LIGHTING IMPACTS	INCR. CONSERV.[a]	DEMAND RESPONSE	FIRM SALES	NET LOAD	RES. MAR. (%)	CAPACITY MINUS NET LOAD	PURCHASES NEEDED TO MEET 15% RM
2008-2009	1141	0	0	0	0	1141	767	0	-1	0	0	766	49.0	375	(260)
2009-2010	1141	0	0	0	0	1141	773	0	-2	0	0	771	48.0	370	(254)
2010-2011	1141	0	0	0	0	1141	787	0	-3	0	0	784	45.5	357	(239)
2011-2012	1141	0	0	0	0	1141	794	-6	-4	0	0	784	45.5	357	(239)
2012-2013	1141	0	0	-1	0	1140	802	-12	-5	0	0	785	45.1	355	(237)
2013-2014	1140	0	0	0	0	1140	809	-18	-5	0	0	786	45.1	354	(236)
2014-2015	1140	0	0	0	0	1140	816	-19	-6	0	0	791	44.1	349	(230)
2015-2016	1140	0	0	0	0	1140	824	-20	-6	0	0	798	42.9	342	(223)
2016-2017	1140	0	0	0	0	1140	831	-21	-7	0	0	803	42.0	337	(216)
2017-2018	1140	0	0	0	0	1140	838	-23	-7	0	0	808	41.1	332	(211)
2018-2019	1140	0	0	0	0	1140	845	-24	-7	0	0	814	40.0	326	(204)
2019-2020	1140	0	38	0	0	1178	851	-25	-7	0	0	819	43.8	358	(236)
2020-2021	1178	0	0	0	0	1178	857	-25	-7	0	0	825	42.7	352	(229)
2021-2022	1178	0	0	0	0	1178	863	-25	-7	0	0	831	41.7	346	(222)
2022-2023	1178	0	0	0	0	1178	869	-25	-7	0	0	837	40.7	340	(215)
2023-2024	1178	0	38	0	0	1215	875	-25	-7	0	0	843	44.1	372	(245)
2024-2025	1215	0	0	0	0	1215	881	-25	-7	0	0	849	43.1	366	(239)
2025-2026	1215	0	0	0	0	1215	886	-26	-7	0	0	853	42.4	362	(234)
2026-2027	1215	0	0	0	0	1215	892	-26	-7	0	0	859	41.4	356	(227)
2027-2028	1215	0	35	0	0	1250	897	-26	-7	0	0	864	44.7	386	(256)

[a] Not included in load forecast
The values shown are the impacts coincident with the wiinter peak, not the maximum impacts.

2. OBJECTIVES AND PROCESS

A. INTRODUCTION

This chapter will explain the objectives of, and the process used to develop, the 2008 Duke Energy Kentucky Integrated Resource Plan. In this IRP process, the modeling of DE-Kentucky includes the firm electric loads, supply-side and demand-side resources, and environmental compliance measures associated with the DE-Kentucky service territory.

B. OBJECTIVES

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 satisfy reliably the electricity demands of customers located within a service territory. The purpose of this IRP is to outline a strategy to furnish electric energy services over the planning horizon 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 DE-Kentucky 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.

DE-Kentucky's long-term planning objective is to employ a dynamic planning process and pursue a resource strategy that considers the costs and benefits to 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 economic 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.*)

C. <u>ASSUMPTIONS</u>

The analysis performed to prepare this IRP covers the period 2008-2028, although the primary focus is 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. The planning period was extended compared to the fifteen-year period required by the IRP rules in order to incorporate a longer period of time with regard to CO_2 restriction impacts.

For this IRP analysis, the Base Case assumed a CO_2 allowance price/tax[1].

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

- All current environmental requirements will be met.
- The requirements of CAIR, which reduces NO_x and SO_2 emissions further beginning in 2009 and 2010, respectively, will be met.
- A mercury MACT standard will be enacted with a 2.0 lb. per trillion Btu emission limit[2].
- No Hazardous Air Pollutant controls other than mercury will be mandated and implemented during the period.
- No Renewable Energy Portfolio Standard will be mandated or implemented during the period.

Risks associated with potential changes to environmental regulations are discussed further later in this report (See Chapter 8, Section E). Some of these risks are quantified through scenario analysis (see Chapter 8, Section D). Risks related to other changes to assumptions are addressed through sensitivity analysis and qualitative reasoning later in this report (see Chapters 5, 6, and 8).

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[1] Despite significant uncertainty surrounding potential future climate change policy, DE-Kentucky has incorporated the potential for CO_2 climate change regulations in its resource planning process. Inclusion of this assumption is not intended to reflect DE-Kentucky's or Duke Energy's preferences regarding future climate change policy.

[2] The CAMR was vacated by the Circuit Court of Appeals for the District of Columbia on February 8, 2008. However, it could take two or more years before EPA proposes new mercury regulations to replace CAMR, so the exact nature of the new standards is unknown at this time. Therefore, for this IRP, a MACT standard similar to that proposed by the EPA in 2004 was assumed. Inclusion of this assumption is not intended to reflect DE-Kentucky's or Duke Energy's preferences regarding future mercury policy.

The source of the general escalation assumption of 2.3% per year utilized in the Load Forecast and in the IRP in general was Moody's Economy.com. In addition, an annual escalation rate of 3.88% was utilized as the capital cost escalation rate for new supply-side alternatives for the years 2008-2013 to better reflect the recent increases in commodity and construction pricing. In 2014, the escalation rate reverted to 2.3% per year to reflect that the recent increases are not expected to represent a permanent trend. DE-Kentucky's rate and financial departments provided the after-tax effective discount rate of 7.33% and the AFUDC rate of 5.45% to use for the development of the IRP. Plans were evaluated based on Present Value of Revenue Requirements ("PVRR").

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 Reliability*First* Corporation ("RFC") and the Midwest ISO.

While lower reserves may help restrain base rates, there are clearly limits to and trade-offs for any gains from lower reserves, as some past summers have demonstrated. 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 could incur additional costs. These costs can be substantial if the spot market price is experiencing a spike at the time purchases must be made to maintain service. If shortages in the wholesale market occur such that load must be involuntarily curtailed, customers incur additional costs such as loss of production and inconvenience.

Current IRP

As explained in previous IRP filings since 1995, DE-Kentucky had 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 under certain risk environments. In the 2003 IRP and in this IRP, the long-term reliability criterion was a 15% minimum reserve margin.

Planning Reserve Margins are an obligation for a number of reasons. First, the reserve margin must cover Operating Reserves which includes both Contingency and Regulating Reserves. The Operating Reserve is a daily requirement to ensure that the real-time balancing needs of the electric system are met in accordance with NERC and RFC Standards. DE-Kentucky is a signatory of the Midwest Contingency Reserve Sharing Group ("CRSG") Agreement as the means for DE-Kentucky to comply with RFC and NERC standards related to Contingency Reserves. As such, the resulting Contingency Reserve requirement is 11 MW, of which at least 45% must be Spinning Reserve that is on-line. The remainder can be Non-Spinning Reserve that is capable of being supplied within ten minutes. In addition, on a day-ahead basis, Duke Energy Kentucky plans to maintain regulating reserves typically based upon 1% of the projected peak load for the next operating day to provide on-line generation for load and frequency regulation.

The portion of the total CRSG Contingency Reserve Requirement allocated to DE-Kentucky will change over time as load and generating resources change. The Contingency Reserve as a percentage of the peak load forecast for 2008 is approximately 1.3%, while the percentage of the minimum peak for 2008 is approximately 4.6%. For simplicity of modeling, these were averaged and then the 1% Regulating Reserve was added, for a total Operating Reserve requirement of approximately 4%.

Upon the start of the Midwest ISO Ancillary Service Market ("ASM") scheduled for September 9, 2008, the provision of regulating reserves and contingency reserves to transmission customers of the Midwest ISO will no longer be the responsibility of the individual Balancing Authorities, such as Duke Energy's Midwest Control Area Operation; rather, it will be the responsibility of the Midwest ISO to procure such resources through its ASM. However, the modeling in this IRP has conservatively assumed that reserves will be self-provided until DE-Kentucky has more experience with this market.

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 outages or derates will occur when the units are most needed. DE-Kentucky believes that 8% is a reasonable expected margin for a normal level of outages and derates, based on historical outage rates. However, the average age of DE-Kentucky's coal-fired generating unit fleet is approximately 37 years, which means that units may be more likely to experience a higher frequency of outages or longer duration outages as they continue to age.

Third, there is always the possibility 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, DE-Kentucky's load forecasting personnel estimate that a 1 degree F increase in temperature can result in approximately a 1.1% increase in DE-Kentucky's load to be served. The load forecast is based on the expected weather at the time of the peak. There is a 50% chance that the weather conditions could be harsher and a 50% chance they could be milder. Since extreme temperatures are not used as a basis for the load forecast (approximately 93 degrees F is used), DE-Kentucky considers an additional 3% reserve component a bare minimum to cover weather-induced load. DE-Kentucky's load forecasting personnel have also estimated that there is approximately a 23% chance that the peak load in a year could exceed the forecasted peak plus a 3% reserve margin.

Taking these reserve considerations in the aggregate, DE-Kentucky considers 15% to be a minimum reserve margin.

Resource Adequacy Requirements

On April 1, 2005, the Midwest ISO began its security-constrained economic dispatch of wholesale electricity (MISO Day 2). In conjunction with MISO Day 2, the administration of Midwest ISO Module E required the Midwest ISO members formerly within ECAR to meet a day-ahead offer requirement consistent with the member's forecasted load and a 4% operating reserve requirement (after outages and derates) from physical capacity since ECAR did not have a standard for planning reserve requirements. This was a much higher standard than an installed reserve margin requirement since compliance with the standard is affected by outages and derates.

Beginning in June 2008, DE-Kentucky's reserve requirements are impacted by Reliability*First*, which has adopted a Resource Planning Reserve Requirement Standard that the LOLE due to resource inadequacy cannot exceed one occurrence in ten years (0.1 occurrence per year). DE-Kentucky is a member of the Midwest PRSG. On February 5, 2008, this group issued its preliminary report showing the required reserve margin targets for the June 2008-May 2009 planning year. The target is 14.3% for the zone where DE-Kentucky is located. This is the first year that the Midwest PRSG has performed this type of study, so there are many refinements to assumptions and methodologies that undoubtedly will be incorporated in future studies. DE-Kentucky believes that some of the assumptions in the study tended to bias the results toward producing a lower reserve margin. Other RTOs that have routinely performed these types of studies for years produce results in the 14-16% range.

On December 28, 2007, the Midwest ISO filed a proposal for long-term resource adequacy at FERC. The proposal would require LSE market participants in the Midwest ISO region to have and maintain access to sufficient planning resources. The Midwest ISO would establish a Planning Reserve Margin based on an LOLE study using the 1 day in 10 year standard to align with Regional Entity requirements such as those of Reliability*First*. The initial Planning Year would be from June 1, 2009, through May 31, 2010, with LSEs required to submit their specific plans for meeting the requirement by March 1, 2009. FERC issued its order conditionally approving this proposal on March 26, 2008.

With FERC's conditional approval of the Midwest ISO's Module E filing, DE-Kentucky anticipates that the functions currently performed by the Midwest PRSG will be transitioned to Midwest ISO starting with the June 2009-May 2010 planning year as part of the Midwest ISO tariff. Since the Midwest PRSG LOLE study was performed by the Midwest ISO as Group Administrator, the study process in the future should be similar. However, the capacity toward reserves will be adjusted by the unit-specific $XEFOR_d$ as part of the Midwest ISO tariff, which may change the amount of reserves each LSE is required to carry. Units with better availability will be credited with higher capacity value compared to units with poorer availability.

For the reasons described above, DE-Kentucky believes that continuing to use a reserve margin target of 15% in its IRPs is prudent until the LOLE study process matures. DE-Kentucky will keep this Commission informed once the result of these efforts becomes clearer.

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. DE-Kentucky's IRP Team, which manages this process, consists of experts in the following key functional areas: electric load forecasting, resource (supply) planning, retail marketing (DSM program development and evaluation), environmental compliance planning, environmental policy, financial, fuel planning and procurement, engineering and construction, and transmission and distribution planning. It is the IRP 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 is the integration of the electric load forecast, supply-side options, environmental compliance options, and DSM options. In addition, it is important to select the best way to conduct the integration while incorporating interrelationships with other areas.

2. Analytical Process

The development of an IRP is a multi-step process involving the key functional planning areas mentioned above. The steps involved are listed below. To facilitate timely completion of this project, a number of these steps are 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 cost-effective DSM 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 DSM, 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 recommend a plan. More details concerning this step of the process can be found in Chapter 8.

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

Many of the screening steps and the integration step mentioned above involve a comparison to a projected market price for electricity. The analytical methodology also includes 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 reasonable, 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.

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

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3. ELECTRIC LOAD FORECAST

A. GENERAL

DE-Kentucky provides electric and gas service in the Northern Kentucky area. DE-Kentucky serves approximately 134,000 customers in its 500 square mile service territory. DE-Kentucky's service territory includes the cities of Covington and Newport, Kentucky.

DE-Kentucky owns an electric transmission system and an electric distribution system in Kenton, Campbell, Boone, Grant, and Pendleton counties of Northern Kentucky. DE-Kentucky also owns a gas distribution system, which serves either all or parts of Kenton, Campbell, Boone, Grant, Gallatin, and Pendleton counties in Northern Kentucky.

The electric energy and peak demand forecasts of the DE-Kentucky service territory are prepared each year as part of the planning process by a staff that is shared with the other Duke Energy affiliated utilities, using the same methodology. DE-Kentucky does not perform joint load forecasts with non-affiliated utility companies, and the forecast is prepared independently of the forecasting efforts of non-affiliated utilities.

B. FORECAST METHODOLOGY

The forecast methodology is essentially the same as that presented in past Integrated Resource Plans filed with the Commission.

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 national economic and demographic concepts such as population, employment, industrial production, inflation, wage rates, and income. The national economic forecast is obtained from Moody's 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 Moody's Economy.com. The DE-Kentucky service area is located in Northern Kentucky adjacent to the service area of DE-Ohio. The economy of Northern Kentucky is contained within the Cincinnati Primary Metropolitan Statistical Area ("PMSA") and is an integral part of the regional economy.

The service area economic forecast is used along with the energy and peak models to produce the electric load forecast.

1. Service Area Economy

There are sectors to the service area economy: employment, income, inflation, production, and population. Forecasts of employment are provided by North American Industry Classification System ("NAICS") and aggregated to major sectors such as commercial and industrial. Income for the local economy is forecasted in several categories including wages, rents, proprietors' income, personal contributions for social insurance, and transfer payments. The forecasts of these items are summed to produce the forecast of income less personal contributions for social insurance. Inflation is measured by changes in the Consumer Price Index ("CPI"). Production is projected for each key NAICS group by multiplying the forecast of productivity (production per employee) by the forecast of employment. Population projections are aggregated from forecasts by age-cohort. This information serves as input into the energy and peak load forecast models.

2. Electric Energy Forecast

The forecast methodology follows economic theory in that the use of energy is dependent upon key economic factors such as income, production, energy prices, and the weather. The projected energy requirements for DE-Kentucky'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 DE-Kentucky forecast of energy requirements is included within the overall forecast of energy requirements of the Greater Cincinnati and Northern Kentucky region. The DE-Kentucky sales forecast is developed by allocating percentages of the total regional forecast for each customer group. These groups include residential, commercial, industrial, governmental or other public authority, 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 DE-Kentucky 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 DE-Kentucky's 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:

(1) 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 real per capita income. This is represented as follows:

(2) Residential Customers =

f (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.

Residential Use per Customer - The key ingredients that impact energy use per customer are per capita income, real electricity prices and the combined impact of numerous other determinants. These include the saturation of air conditioners, electric space heating, other appliances, the efficiency of those appliances, and weather.

(3) Energy usage per Customer =

f (Real Income per Capita * Efficient Appliance Stock,

Real Electricity Price * Efficient Appliance Stock, Saturation of Electric Heating Customers,

Saturation of Customers with Central Air Conditioning,

Saturation of Window Air Conditioning Units,

Efficiency of Space Conditioning Appliances,

Billed Cooling and Heating Degree Days).

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 the level of local commercial employment, real electricity price, and the impact of weather. The model is formulated as follows:

(4) Commercial Sales =

f (Commercial Employment,

Marginal Electric Price/Consumer Price Index,

Billed Cooling and Heating Degree Days).

Industrial Sector - DE-Kentucky produces industrial sales forecasts by NAICS classifications. Electricity use by industrial customers is primarily dependent upon the level of industrial production and the impacts of real electricity prices, electric price relative to alternate fuels, and weather. The general model of industrial sales is formulated as follows:

(5) Industrial Sales =

f (Industrial Production,

Real Electricity Price,

Electricity Price/Alternate Fuel Price,

Billed Cooling and Heating Degree Days).

<u>Governmental Sector</u> - The Company uses the term Other Public Authorities ("OPA") to indicate those customers involved and/or affiliated with federal, state or local government. Two categories comprise the electricity sales in the 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:

(6) Water Pumping Sales =

f (Residential Electricity Customers,

Real Electricity Demand Price,

Precipitation,

Cooling Degree Days).

Electricity sales to the non-water pumping component of OPA 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:

(7) Non-Water Pumping Sales =

f (Governmental Employment,

Marginal Electric Energy Price/Natural Gas Price,

Billed Cooling and Heating 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 population of the service area. The efficiency of the street lights is related to the saturation of mercury and sodium vapor lights. That is:

(8) Street Lighting Sales =

f (Population,

Saturation of Mercury Vapor Lights,

Saturation of Sodium Vapor Lights).

Total Electric Sales - Once these separate components have been projected - Residential sales, Commercial sales, Industrial sales, OPA sales, and Street

Lighting sales - they can be summed along with Interdepartmental sales to produce the projection of total electric sales.

Total System Sendout - Upon completion of the total electric sales forecast, the forecast of total system sendout (net energy) can be prepared. This requires that the total electric sales forecast be combined with the 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. Only days when the temperature equaled or exceeded 90 degrees are included in the summer peak model. For the winter, only those days with a temperature at or below 10 degrees are included in the winter peak model.

Summer Peak - Summer peak loads are influenced by the current level of economic activity and the weather conditions. The primary weather factors are temperature and humidity; however, 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 to capture effect of thermal buildup.

The summer equation can be specified as follows:

(9) Peak =

f (Weather Normalized Sendout,

Weather Factors).

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

(10) Peak =

f (Weather Normalized Sendout,

Weather Factors).

The summer and winter 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 activity. 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 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 deviation 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. 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 in 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. Macro

It is generally assumed that the DE-Kentucky service territory economy will tend to react much like the national economy over the forecast period. DE-Kentucky uses a long-term forecast of the national and service area economy prepared by Moody's Economy.com.

No major wars or energy embargoes are assumed to occur during the forecast period. Even if minor conflicts and/or energy supply disruptions, such as those caused by hurricanes, occur during the forecast period, the long-range path of the overall forecast would not be dramatically altered.

A major risk to the regional economic forecasts and hence the electric load forecast is the level of continued economic growth in the U.S. economy. The national economy has been experiencing slow growth since the fourth quarter of 2007. The ultimate outcome in the near term is dependent upon the success of the economy moving forward out of this slow period.

With extensive economic diversity, the Cincinnati area economy, including Northern Kentucky, is well structured to withstand an economic slowdown and 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.

In late 2007, President Bush signed the Energy Independence and Security Act, part of which sets new efficiency standards for lighting staring in 2012. According to a white paper from the Lighting Controls Association, "New Energy Law to Phase Out Today's Common Incandescent Lamps, Probe-Start Metal Halide Magnetic Ballasted Fixtures" by Craig DiLouie, the new legislation "...virtually eliminates the manufacture of most common general-service incandescent lamps..." and "Lamps that do not comply on or after the effective dates cannot be manufactured or imported." According to the Association they believe that compact CFLs will capture the entire general incandescent market. Therefore, the Company estimated the impact of this legislation on lighting load and reduced the forecast accordingly, starting in 2012.

2. Local

Forecasts of employment, local population, industrial production, and inflation are key indicators of economic and demographic trends for the DE-Kentucky service area. The majority of the employment growth over the forecast period occurs in the non-manufacturing sector. This reflects a continuation of the trend toward the service industries and the fundamental change that is occurring in manufacturing and other basic industries. The rate of growth in local employment expected over the forecast will be slightly above that of the nation: 1.6 percent locally versus 1.2 percent nationally.

DE-Kentucky is also affected by national population trends. The average age of the U.S. population is rising. The primary reasons for this phenomenon are stagnant birth rates and lengthening life expectancies. As a result, the portion of the population of the DE-Kentucky service area that is "age 65 and older" increases over the forecast period. Over the period 2008 to 2028, DE-Kentucky's population is expected to increase at an annual average rate of 0.5 percent. Nationally, population is expected to grow at an annual rate of 0.8 percent over the same period.

For the forecast period, local industrial production is expected to increase at a 1.5 percent annual rate, while 1.1 percent is the expected growth rate for the nation.

The residential sector is the largest in terms of total existing customers and total new customers per year. Within the DE-Kentucky service area, many commercial customers serve local markets. Therefore, there is a close relationship between the growth in local residential customers and the growth in commercial customers. The number of new industrial customers added per year is relatively small.

3. Specific

<u>Commercial Fuels</u> - 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 severe limitations in their supply, although world reserves of natural gas and oil are believed to be dwindling. There are unknown potential impacts from future changes in legislation or a change in the pricing or supply policy of oil-producing countries that might affect fuel supply. However, these cannot be quantified within the forecast. The only non-utility information source relied upon is Moody's Economy.com.

Pricing Policy – DE-Kentucky's electric tariffs for residential customers have a seasonal pattern. In Kentucky, an inverted rate (a block rate structure in which price increases as usage increases) 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.

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

2003	114,199
2004	116,524
2005	117,270
2006	118,642
2007	119,245
2008	120,293
2009	121,514
2010	122,722
2011	123,800
2012	124,868
2013	125,923
2014	126,953
2015	127,976
2016	129,008
2017	130,024
2018	131,019
2019	131,993
2020	132,958
2021	133,903
2022	134,829
2023	135,737
2024	136,631
2025	137,511
2026	138,377
2027	139,229
2028	140,071

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 by the federal government.

D. DATA BASE DOCUMENTATION

In the following sections, information on databases is provided for DE-Kentucky.

The first step in the forecasting process is the collection of relevant information and data. The database discussion is broken into three parts:

1) Economic Data,
2) Energy and Peak Data, and
3) Forecast Data.

1. Economic Data

The major groups of data in the economic forecast are employment, demographics, income, production, inflation and prices. National and local values for these concepts are available from Moody's Economy.com and company data.

Employment - Employment numbers are required on both a national and service area basis. Quarterly national and local employment series by industry are obtained from Moody's Economy.com. Employment series are available for manufacturing and non-manufacturing sectors.

Population - National and local values for total population and population by age-cohort groups are obtained from Moody's Economy.com.

Income - Local income data series are obtained from Moody's Economy.com. The data is available 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; personal contributions for social insurance; and non-farm proprietors' income.

Consumer Price Index - The CPI is obtained from Moody's Economy.com.

Electricity and Natural Gas Prices - The average price of electricity and natural gas is available from DE-Kentucky financial reports. Data on marginal electricity price (including fuel cost) is collected for each customer class. This information is obtained from DE-Kentucky records and rate schedules.

2. Energy and Peak Models

The majority of data required to develop the electricity sales and peak forecasts is obtained from the DE-Kentucky service area economic data provided by Moody's Economy.com, from DE-Kentucky financial reports and research groups, and from national sources. With regard to the national sources of information, generally all national information is obtained from Moody's Economy.com. However, local weather data are obtained from the National Oceanic and Atmospheric Administration ("NOAA").

The major groups of data that are used in developing the energy forecasts are: kilowatt-hour sales by customer class, number of customers, use-per-customer, electricity prices, natural gas prices, appliance saturations, and local weather data. The following are descriptions of the adjustments performed on various groups of data to develop the final data series actually used in regression analysis.

Kilowatt-hour Sales and Revenue - DE-Kentucky collects sales and revenue data monthly by rate class. For forecast purposes this information is aggregated into the following categories: residential, commercial, industrial, OPA, and the other sales categories. In the industrial sector, sales and revenue for each manufacturing NAICS are collected. From the sales and revenue information, average electricity prices by sector can be calculated.

The OPA sales category is analyzed in two parts: water pumping and OPA less water-pumping sales.

Number of Customers - The number of customers by class is obtained on a monthly basis from Company records.

Use Per Customer – Average use per customer is computed on a monthly basis by dividing residential sales by total customers.

Local Weather Data - Local climatologic data are provided by NOAA for the Cincinnati/Covington airport reporting station. Cooling degree days and heating degree days are calculated on a monthly basis using temperature data. The degree day series are required on a billing cycle basis for use in regression analysis.

Appliance Stock - To account for the impact of appliance saturations and federal efficiency standards, an appliance stock variable is created. This variable is composed of three parts: appliance efficiencies, appliance saturations, and appliance energy consumption values.

The appliance stock variable is calculated as follows:

(11) Appliance Stock_t=

$$\text{SUM}\ (K_i * SAT_{i,t} * EFF_{i,t})\ \text{for all}\ i$$

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.

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

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 data provided by ITRON Inc., a forecast consulting firm. They have developed Regional Statistically Adjusted End-use ("SAE") Models, an end-use approach to electric forecasting that provides forward-looking levels of appliance saturations and efficiencies.

Peak Weather Data - The weather conditions associated with the monthly peak load are collected from the hourly and daily data recorded by NOAA. 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 winter 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. An average extreme weather condition can be computed using historical data for the single worst summer weather occurrence and the single worst winter weather occurrence in each year.

3. Forecast Data

Projections of exogenous variables in DE-Kentucky's models are required in the following areas: national and local employment, income, industrial production, and population, as well as natural gas and electricity prices.

Employment -The forecast of employment by industry is provided by Moody's Economy.com.

Income -The forecast of income is provided by Moody's Economy.com.

Industrial Production - The forecast of industrial production is also provided by Moody's Economy.com.

Population - DE-Kentucky's population forecast, which is prepared by collecting county-level population forecasts for the counties in DE-Kentucky's service area and then summing, is provided by Moody's Economy.com.

Prices - The projected change in electricity and natural gas prices over the forecast interval is provided by the Company's Financial Planning and Analysis department and Moody's Economy.com.

4. Load Research and Market Research Efforts

DE-Kentucky is committed to the continued development and maintenance of a substantive class load database of typical customer electricity consumption patterns and the collection of primary market research data on customers.

Load Research – 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, DE-Kentucky 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.

Periodically, DE-Kentucky monitors selected end-uses or systems associated with energy efficiency evaluations performed in conjunction with energy efficiency 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 DE-Kentucky'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

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

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

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

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. This is known as serial correlation. By correcting for this serial correlation of the estimated residuals, forecast error is reduced and the estimated coefficients are more efficient. The Gauss-Newton technique is employed to correct for the existence of autocorrelation.

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

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

DE-Kentucky continues to use the current forecasting methodology as it has for the past several years. DE-Kentucky considers the forecasting methods currently utilized to be adequate.

4. Changes In Methodology

There were no significant changes to the forecast methodology. DE-Kentucky uses the latest historical data available and relies on recent economic data and forecasts from Moody's Economy.com. However, DE-Kentucky did make changes in regards to the calculation of heating degree days ("HDD") and cooling degree days ("CDD").

When DE-Kentucky filed its last IRP, heating and cooling degree days were calculated using a base temperature of 65°F. DE-Kentucky looked at the base temperature used to calculate HDD because evidence indicated that customers in the DE-Kentucky service area started using energy for heating at a temperature other than 65°F. Because DE-Kentucky is a combination utility, it is important that the degree day calculations be consistent across both commodities. Since HDD and heating loads primarily impact the gas commodity, DE-Kentucky concentrated on gas loads in particular.

DE-Kentucky analyzed historical load and temperature data by plotting gas loads vs. average temperature. The analyses provide visual evidence that heating loads begin around 59°F as opposed to 65°F. Similar evidence was found in plots of residential electric load and temperature. Since it was the most weather sensitive, DE-Kentucky further examined the residential class gas data, evaluating the r-square values after regressing natural gas usage against HDD which were calculated using different base temperatures ranging from 65°F through 55°F.

Results showed that the r-square value at 59°F was the largest which indicates the best fit. Since the visual evidence in the plots and the r-square analysis evidence indicates that heating loads begin at 59°F, DE-Kentucky selected 59°F as the base temperature for HDD. DE-Kentucky did not make a change to the base temperature used to calculate CDD.

Also, in 2003 DE-Kentucky used 30 year normal degree day data as provided by NOAA. The "normal" weather must be representative of current weather trends since it is used to predict the level of weather expected to occur in the future. Actual weather data for the years 1971 through 2006 indicates that HDD have experienced a downward trend while CDD have experienced a slight upward trend. However, the 30 year NOAA normal HDD was not capturing this downward trend. In fact, for 1997 through 2006, there were nine out of ten years where actual annual HDD were below the NOAA normal.

DE-Kentucky decided to analyze alternatives to the NOAA normals, deciding to use degree day normals based on a recent ten year historical period. With the DE-Kentucky ten-year normal HDD, there were five out of the ten years where actual annual HDD were below the ten-year normal and five out of ten years where actual annual HDD were above the ten-year normal, an even distribution around the normal as one would expect. Similarly, there were five out of the ten years where actual annual CDD were below the ten-year normal and five out of ten years where actual annual CDD were above the ten-year normal. Since the objective in forecasting is to use a level of normal degree days that provides an unbiased estimate of the expected weather conditions, DE-Kentucky concluded that it would be reasonable to use normal degree days derived from the actual weather experienced over a recent ten-year period.

5. Computer Software

The computer software package employed in the preparation of the forecast is called Eviews. It is a licensed software product utilized on microcomputers.

F. FORECASTED DEMAND AND ENERGY

On the following pages, the loads for DE-Kentucky are provided. Forecast data is provided before and after the incremental impacts of EE programs. The term "Internal" refers to a forecast without the impacts of either EE or DR removed. The term "Native" refers to the Internal forecast with the DR removed.

1. Service Area Energy Forecasts

Figure 3-1 contains the energy forecast for DE-Kentucky's service area.

Before implementation of any new EE programs or incremental EE impacts, Residential use for the twenty-year period of the forecast is expected to increase an average of 0.2 percent per year; Commercial use, 1.3 percent per year; and Industrial use, 1.1 percent per year. The summation of the forecast across each sector and including losses results in a growth rate forecast of 0.8 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 EE programs and any incremental EE impacts (Figure 3-2) Residential use is expected to increase an average of 0.2 percent per year; Commercial use, 1.3 percent per year; and Industrial use, 1.1 percent per year. The summation of the forecast across each sector and including losses results in an after EE growth rate forecast of 0.7 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 DE-Kentucky service area. As state earlier, the difference between native and internal load before EE reflects the impact of controllable loads (see Section F-3).

Figure 3-4, labeled "Internal Load", summarizes historical and projected growth of the internal peak before implementation of EE 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 0.8 percent. Projected growth in the winter peak demand is 0.7 percent.

Peak load forecasts after implementation of EE programs (Figure 3-5 and Figure 3-6) are shown for native and internal loads after EE. Based on Figure 3-6, the projected growth in the summer peak is 0.8 percent. Projected growth in winter peak demand is 0.6 percent.

3. Controllable Loads

The native peak load forecast reflects the MW impacts from the PowerShare® demand response program and controllable loads from the Power Manager program. The amount of load controlled depends upon the level of operation of the particular customers participating in the programs. The difference between the internal and native peak loads consists of the impact from these controllable loads. See Chapter 4 for a complete discussion of the impacts of DR programs.

4. Load Factor

The numbers on the following page represent the annual percentage load factor for the DE-Kentucky System before any new or incremental EE. It shows the relationship between Net Energy for Load, Figure 3-1, and the annual peak, Figure 3-4, before EE.

YEAR	LOAD FACTOR
2003	65.03%
2004	62.14%
2005	64.46%
2006	60.95%
2007	62.27%
2008	54.91%
2009	54.97%
2010	54.97%
2011	55.00%
2012	54.78%
2013	54.56%
2014	54.37%
2015	54.36%
2016	54.14%
2017	54.32%
2018	54.24%
2019	54.18%
2020	54.23%
2021	53.98%
2022	53.97%
2023	54.22%
2024	54.19%
2025	54.19%
2026	54.17%
2027	53.99%
2028	54.22%

5. Range of Forecasts

Under the assumption of normal weather, the most likely forecast of electrical energy demand and peak loads is generated using forecasts of economic variables. Moody's Economy.com provides the base economic forecast used to prepare the most likely energy demand and peak load forecasts.

In generating the high and low forecasts, DE-Kentucky used the standard errors of the regression from the econometric models used to produce the base energy forecast. The bands are based on an 80% confidence interval (from 10% to 90%) around the forecast which equates to 1.28 standard deviations. These calculations were used to adjust the base forecast up or down, thus providing high and low bands around the most likely forecast.

In general, the upper band reflects relatively optimistic assumptions about the future growth of DE-Kentucky sales while the lower band depicts the impact of a pessimistic scenario.

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

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 DE-Kentucky system before EE. Likewise, Figure 3-11 and 3-12 present the net monthly energy and internal peak load forecasts for the total DE-Kentucky system after EE.

FIGURE 3-1 PART 1

DUKE ENERGY KENTUCKY SYSTEM

SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)

BEFORE EE

	YEAR	(1) RURAL AND RESIDENTIAL	(2) COMMERCIAL	(3) INDUSTRIAL	(4) STREET-HWY LIGHTING	(5) SALES FOR RESALE a	(6) OTHER
-5	2003	1,342,581	1,296,517	765,922	19,020	0	302,556
-4	2004	1,371,604	1,329,565	768,023	18,742	0	304,798
-3	2005	1,481,111	1,373,341	785,636	18,776	0	316,329
-2	2006	1,404,458	1,371,330	781,003	17,338	0	308,383
-1	2007	1,534,340	1,460,428	806,736	15,988	0	321,236
0	2008	1,430,223	1,432,927	794,726	16,417	0	310,542
1	2009	1,467,175	1,440,459	793,362	16,625	0	312,522
2	2010	1,477,865	1,468,751	794,791	16,758	0	313,808
3	2011	1,516,385	1,497,135	808,532	16,890	0	317,108
4	2012	1,491,708	1,508,521	821,141	17,010	0	315,594
5	2013	1,466,475	1,521,562	831,153	17,137	0	314,184
6	2014	1,440,670	1,535,109	841,126	17,268	0	311,774
7	2015	1,444,632	1,556,844	850,021	17,401	0	312,472
8	2016	1,449,948	1,579,345	859,275	17,534	0	312,565
9	2017	1,454,727	1,601,988	868,766	17,601	0	312,161
10	2018	1,457,404	1,624,265	878,637	17,617	0	311,335
11	2019	1,458,003	1,646,929	888,449	17,637	0	309,880
12	2020	1,458,171	1,670,107	898,029	17,660	0	307,889
13	2021	1,464,678	1,693,988	908,012	17,685	0	306,290
14	2022	1,470,729	1,717,756	918,519	17,719	0	304,893
15	2023	1,476,182	1,741,244	929,474	17,757	0	303,625
16	2024	1,481,597	1,764,097	940,493	17,805	0	302,396
17	2025	1,486,486	1,785,757	951,397	17,853	0	301,161
18	2026	1,491,434	1,806,619	961,630	17,909	0	299,644
19	2027	1,496,244	1,826,642	972,226	17,969	0	298,044
20	2028	1,500,544	1,846,246	983,045	18,043	0	296,682

(a) Sales for resale to municipals.

FIGURE 3-1 PART 2

DUKE ENERGY KENTUCKY SYSTEM

SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR)

BEFORE EE

	YEAR	(7) (1+2+3 +4+5+6) TOTAL CONSUMPTION	(8) LOSSES AND UNACCOUNTED FOR b	(9) (7+8) NET ENERGY FOR LOAD
-5	2003	3,726,596	366,204	4,092,800
-4	2004	3,792,732	425,801	4,218,533
-3	2005	3,975,193	299,325	4,274,518
-2	2006	3,882,512	191,538	4,074,050
-1	2007	4,138,728	148,552	4,287,280
0	2008	3,984,835	204,746	4,189,581
1	2009	4,030,143	207,047	4,237,190
2	2010	4,071,973	209,204	4,281,177
3	2011	4,156,050	213,495	4,369,545
4	2012	4,153,974	213,216	4,367,190
5	2013	4,150,511	212,828	4,363,339
6	2014	4,145,947	212,390	4,358,337
7	2015	4,181,370	214,179	4,395,549
8	2016	4,218,667	216,063	4,434,730
9	2017	4,255,243	217,916	4,473,159
10	2018	4,289,258	219,635	4,508,893
11	2019	4,320,898	221,233	4,542,131
12	2020	4,351,856	222,811	4,574,667
13	2021	4,390,653	224,809	4,615,462
14	2022	4,429,616	226,827	4,656,443
15	2023	4,468,282	228,833	4,697,115
16	2024	4,506,388	230,819	4,737,207
17	2025	4,542,654	232,687	4,775,341
18	2026	4,577,236	234,481	4,811,717
19	2027	4,611,125	236,238	4,847,363
20	2028	4,644,560	237,986	4,882,546

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

FIGURE 3-2 PART 1

DUKE ENERGY KENTUCKY SYSTEM

SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR) a

AFTER EE

		(1)	(2)	(3)	(4)	(5)	(6)
	YEAR	RURAL AND RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET-HWY LIGHTING	SALES FOR RESALE b	OTHER
-5	2003	1,342,581	1,296,517	765,922	19,020	0	302,556
-4	2004	1,371,604	1,329,565	768,023	18,742	0	304,798
-3	2005	1,481,111	1,373,341	785,636	18,776	0	316,329
-2	2006	1,404,458	1,371,330	781,003	17,338	0	308,383
-1	2007	1,534,340	1,460,428	806,736	15,988	0	321,236
0	2008	1,427,795	1,432,636	794,567	16,354	0	310,479
1	2009	1,460,230	1,439,637	792,907	16,446	0	312,343
2	2010	1,466,403	1,467,385	794,050	16,468	0	313,518
3	2011	1,500,395	1,495,231	807,501	16,487	0	316,705
4	2012	1,472,654	1,506,074	819,812	16,496	0	315,080
5	2013	1,445,755	1,518,576	829,536	16,513	0	313,560
6	2014	1,418,230	1,531,570	839,218	16,538	0	311,044
7	2015	1,420,476	1,552,752	847,820	16,568	0	311,639
8	2016	1,423,977	1,574,682	856,780	16,595	0	311,626
9	2017	1,428,009	1,597,073	866,149	16,625	0	311,185
10	2018	1,430,687	1,619,340	876,019	16,653	0	310,371
11	2019	1,431,290	1,641,989	885,831	16,687	0	308,930
12	2020	1,431,383	1,665,134	895,407	16,724	0	306,953
13	2021	1,437,985	1,689,015	905,397	16,765	0	305,370
14	2022	1,444,023	1,712,769	915,902	16,813	0	303,987
15	2023	1,449,464	1,736,245	926,855	16,867	0	302,735
16	2024	1,454,798	1,759,075	937,863	16,926	0	301,517
17	2025	1,459,778	1,780,739	948,771	16,989	0	300,297
18	2026	1,464,732	1,801,592	959,001	17,057	0	298,792
19	2027	1,469,551	1,821,607	969,590	17,132	0	297,207
20	2028	1,473,745	1,841,193	980,398	17,212	0	295,851

(a) Includes EE Impacts.

(b) Sales for resale to municipals.

FIGURE 3-2 PART 2

DUKE ENERGY KENTUCKY SYSTEM

SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS/YEAR) c

AFTER EE

	YEAR	(7) (1+2+3 +4+5+6) TOTAL CONSUMPTION	(8) LOSSES AND UNACCOUNTED FOR d	(9) (7+8) NET ENERGY FOR LOAD
	----	-----------	-----------	-----------
-5	2003	3,726,596	366,204	4,092,800
-4	2004	3,792,732	425,801	4,218,533
-3	2005	3,975,193	299,325	4,274,518
-2	2006	3,882,512	191,538	4,074,050
-1	2007	4,138,728	148,552	4,287,280
0	2008	3,981,831	204,592	4,186,423
1	2009	4,021,563	206,606	4,228,169
2	2010	4,057,824	208,477	4,266,301
3	2011	4,136,319	212,481	4,348,800
4	2012	4,130,116	211,991	4,342,107
5	2013	4,123,940	211,466	4,335,406
6	2014	4,116,600	210,887	4,327,487
7	2015	4,149,255	212,534	4,361,789
8	2016	4,183,660	214,270	4,397,930
9	2017	4,219,041	216,062	4,435,103
10	2018	4,253,070	217,782	4,470,852
11	2019	4,284,727	219,381	4,504,108
12	2020	4,315,601	220,955	4,536,556
13	2021	4,354,532	222,960	4,577,492
14	2022	4,393,494	224,977	4,618,471
15	2023	4,432,166	226,983	4,659,149
16	2024	4,470,179	228,964	4,699,143
17	2025	4,506,574	230,839	4,737,413
18	2026	4,541,174	232,634	4,773,808
19	2027	4,575,087	234,392	4,809,479
20	2028	4,608,399	236,133	4,844,532

(c) Includes EE Impacts

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

FIGURE 3-3

DUKE ENERGY KENTUCKY SYSTEM

SEASONAL PEAK LOAD FORECAST (MEGAWATTS)

BEFORE EE

NATIVE LOAD a

		SUMMER			WINTER d		
	YEAR	LOAD	CHANGE b	PERCENT CHANGE c	LOAD	CHANGE b	PERCENT CHANGE c
-5	2003	811			665		
-4	2004	814	3	0.4	674	10	1.5
-3	2005	892	77	9.5	692	17	2.6
-2	2006	881	-11	-1.2	738	46	6.6
-1	2007	911	30	3.4	725	-13	-1.7
0	2008	860	-51	-5.6	767	42	5.8
1	2009	868	8	0.9	773	6	0.8
2	2010	875	7	0.8	787	14	1.8
3	2011	893	18	2.1	788	1	0.1
4	2012	896	3	0.3	790	2	0.3
5	2013	899	3	0.3	791	1	0.1
6	2014	901	2	0.2	797	6	0.8
7	2015	909	8	0.9	804	7	0.9
8	2016	921	12	1.3	810	6	0.7
9	2017	926	5	0.5	815	5	0.6
10	2018	935	9	1.0	821	6	0.7
11	2019	943	8	0.9	826	5	0.6
12	2020	949	6	0.6	832	6	0.7
13	2021	962	13	1.4	838	6	0.7
14	2022	971	9	0.9	844	6	0.7
15	2023	975	4	0.4	850	6	0.7
16	2024	984	9	0.9	856	6	0.7
17	2025	992	8	0.8	860	4	0.5
18	2026	1,000	8	0.8	866	6	0.7
19	2027	1,011	11	1.1	871	5	0.6
20	2028	1,014	3	0.3	876	5	0.6

(a) Excludes controllable 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

DUKE ENERGY KENTUCKY 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	2003	811			665		
-4	2004	817	6	0.8	674	10	1.5
-3	2005	905	87	10.7	692	17	2.6
-2	2006	881	-24	-2.6	738	46	6.6
-1	2007	930	49	5.6	725	-13	-1.7
0	2008	871	-59	-6.3	767	42	5.8
1	2009	880	9	1.0	773	6	0.8
2	2010	889	9	1.0	787	14	1.8
3	2011	907	18	2.0	788	1	0.1
4	2012	910	3	0.3	790	2	0.3
5	2013	913	3	0.3	791	1	0.1
6	2014	915	2	0.2	797	6	0.8
7	2015	923	8	0.9	804	7	0.9
8	2016	935	12	1.3	810	6	0.7
9	2017	940	5	0.5	815	5	0.6
10	2018	949	9	1.0	821	6	0.7
11	2019	957	8	0.8	826	5	0.6
12	2020	963	6	0.6	832	6	0.7
13	2021	976	13	1.3	838	6	0.7
14	2022	985	9	0.9	844	6	0.7
15	2023	989	4	0.4	850	6	0.7
16	2024	998	9	0.9	856	6	0.7
17	2025	1,006	8	0.8	860	4	0.5
18	2026	1,014	8	0.8	866	6	0.7
19	2027	1,025	11	1.1	871	5	0.6
20	2028	1,028	3	0.3	876	5	0.6

(a) Excludes controllable 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

DUKE ENERGY KENTUCKY SYSTEM

SEASONAL PEAK LOAD FORECAST (MEGAWATTS) a

AFTER EE

NATIVE LOAD b

		SUMMER			WINTER e		
	YEAR	LOAD	CHANGE c	PERCENT CHANGE d	LOAD	CHANGE c	PERCENT CHANGE d
-5	2003	811			665		
-4	2004	814	3	0.4	674	10	1.5
-3	2005	892	77	9.5	692	17	2.6
-2	2006	881	-11	-1.2	738	46	6.6
-1	2007	911	30	3.4	725	-13	-1.7
0	2008	859	-52	-5.7	766	41	5.7
1	2009	866	7	0.8	770	4	0.5
2	2010	872	6	0.7	783	13	1.7
3	2011	889	17	1.9	783	0	0.0
4	2012	891	2	0.2	785	2	0.3
5	2013	894	3	0.3	785	0	0.0
6	2014	895	1	0.1	790	5	0.6
7	2015	902	7	0.8	797	7	0.9
8	2016	914	12	1.3	802	5	0.6
9	2017	919	5	0.5	807	5	0.6
10	2018	928	9	1.0	813	6	0.7
11	2019	936	8	0.9	818	5	0.6
12	2020	942	6	0.6	824	6	0.7
13	2021	955	13	1.4	830	6	0.7
14	2022	964	9	0.9	836	6	0.7
15	2023	968	4	0.4	842	6	0.7
16	2024	977	9	0.9	848	6	0.7
17	2025	985	8	0.8	852	4	0.5
18	2026	993	8	0.8	858	6	0.7
19	2027	1,004	11	1.1	863	5	0.6
20	2028	1,007	3	0.3	868	5	0.6

(a) Includes EE Impacts.
(b) Includes controllable 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

DUKE ENERGY KENTUCKY SYSTEM

SEASONAL PEAK LOAD FORECAST (MEGAWATTS) a

AFTER EE

INTERNAL LOAD b

		SUMMER			WINTER e		
	YEAR	LOAD	CHANGE c	PERCENT CHANGE d	LOAD	CHANGE c	PERCENT CHANGE d
-5	2003	811			665		
-4	2004	817	6.3756372	0.8	674	9.71	1.5
-3	2005	905	87.203	10.7	692	17.232	2.6
-2	2006	881	-24	-2.6	738	45.962	6.6
-1	2007	930	49	5.6	725	-12.534	-1.7
0	2008	870	-60	-6.4	766	41	5.7
1	2009	878	8	0.9	770	4	0.5
2	2010	886	8	0.9	783	13	1.7
3	2011	903	17	1.9	783	0	0.0
4	2012	905	2	0.2	785	2	0.3
5	2013	908	3	0.3	785	0	0.0
6	2014	909	1	0.1	790	5	0.6
7	2015	916	7	0.8	797	7	0.9
8	2016	928	12	1.3	802	5	0.6
9	2017	933	5	0.5	807	5	0.6
10	2018	942	9	1.0	813	6	0.7
11	2019	950	8	0.8	818	5	0.6
12	2020	956	6	0.6	824	6	0.7
13	2021	969	13	1.4	830	6	0.7
14	2022	978	9	0.9	836	6	0.7
15	2023	982	4	0.4	842	6	0.7
16	2024	991	9	0.9	848	6	0.7
17	2025	999	8	0.8	852	4	0.5
18	2026	1,007	8	0.8	858	6	0.7
19	2027	1,018	11	1.1	863	5	0.6
20	2028	1,021	3	0.3	868	5	0.6

(a) Includes EE Impacts.
(b) Excludes controllable 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

DUKE ENERGY KENTUCKY SYSTEM

RANGE OF FORECASTS
ECONOMIC BANDS

BEFORE EE

	ENERGY FORECAST (GWH/YR) (NET ENERGY FOR LOAD)			PEAK LOAD FORECAST (MW) INTERNAL a		
YEAR	LOW	MOST LIKELY	HIGH	LOW	MOST LIKELY	HIGH
2008	3,967	4,190	4,412	822	871	920
2009	3,984	4,237	4,492	830	880	930
2010	4,018	4,281	4,545	839	889	939
2011	4,097	4,370	4,644	856	907	958
2012	4,061	4,367	4,675	859	910	961
2013	4,024	4,363	4,704	862	913	964
2014	4,013	4,358	4,732	864	915	966
2015	4,053	4,396	4,780	871	923	975
2016	4,096	4,435	4,829	882	935	988
2017	4,139	4,473	4,878	887	940	993
2018	4,179	4,509	4,924	896	949	1,002
2019	4,217	4,542	4,967	903	957	1,011
2020	4,254	4,575	5,009	909	963	1,017
2021	4,291	4,615	5,045	921	976	1,031
2022	4,327	4,656	5,082	930	985	1,040
2023	4,364	4,697	5,118	933	989	1,045
2024	4,400	4,737	5,153	942	998	1,054
2025	4,434	4,775	5,186	949	1,006	1,063
2026	4,467	4,812	5,217	957	1,014	1,071
2027	4,499	4,847	5,246	967	1,025	1,083
2028	4,531	4,883	5,276	970	1,028	1,086

(a) Excludes controllable load.

FIGURE 3-8

DUKE ENERGY KENTUCKY SYSTEM

RANGE OF FORECASTS a
ECONOMIC BANDS

AFTER EE

	ENERGY FORECAST (GWH/YR) (NET ENERGY FOR LOAD)			PEAK LOAD FORECAST (MW) NATIVE b		
YEAR	LOW	MOST LIKELY	HIGH	LOW	MOST LIKELY	HIGH
2008	3,964	4,186	4,409	810	859	907
2009	3,975	4,228	4,482	817	866	914
2010	4,004	4,266	4,530	823	872	921
2011	4,077	4,349	4,622	839	889	939
2012	4,038	4,342	4,648	841	891	941
2013	3,998	4,335	4,674	843	894	944
2014	3,984	4,327	4,699	844	895	945
2015	4,022	4,362	4,743	851	902	952
2016	4,062	4,398	4,789	862	914	965
2017	4,104	4,435	4,837	867	919	970
2018	4,144	4,471	4,882	876	928	980
2019	4,181	4,504	4,925	883	936	988
2020	4,219	4,537	4,967	889	942	995
2021	4,256	4,577	5,004	901	955	1,008
2022	4,292	4,618	5,040	909	964	1,018
2023	4,329	4,659	5,076	913	968	1,022
2024	4,364	4,699	5,111	922	977	1,032
2025	4,399	4,737	5,145	929	985	1,040
2026	4,432	4,774	5,175	937	993	1,049
2027	4,464	4,809	5,205	947	1,004	1,060
2028	4,495	4,845	5,235	950	1,007	1,063

(a) Includes EE Impacts.

(b) Includes controllable load.

FIGURE 3-9

DUKE ENERGY KENTUCKY SYSTEM

NET MONTHLY ENERGY FORECAST (MEGAWATT HOURS)

BEFORE EE

YEAR 0	2008	KENTUCKY
January		373,130
February		326,392
March		334,909
April		300,515
May		321,144
June		365,468
July		411,374
August		414,540
September		337,279
October		314,255
November		318,354
December		372,004

YEAR 1	2009	
January		377,535
February		330,647
March		339,080
April		303,595
May		324,351
June		369,430
July		416,340
August		419,919
September		341,014
October		317,125
November		321,310
December		376,224

FIGURE 3-10

DUKE ENERGY KENTUCKY SYSTEM

NET MONTHLY INTERNAL PEAK LOAD FORECAST (MEGAWATTS)

BEFORE EE

YEAR 0	2008	KENTUCKY
January		759
February		709
March		668
April		606
May		677
June		831
July		871
August		871
September		782
October		598
November		673
December		731
YEAR 1	2009	
January		767
February		716
March		675
April		613
May		684
June		840
July		880
August		880
September		790
October		604
November		680
December		739

FIGURE 3-11

DUKE ENERGY KENTUCKY SYSTEM

NET MONTHLY ENERGY FORECAST (MEGAWATT HOURS) a

AFTER EE

YEAR 0	2008	KENTUCKY
January		373,085
February		326,313
March		334,792
April		300,377
May		320,967
June		365,250
July		411,102
August		414,236
September		336,965
October		313,906
November		317,946
December		371,484

YEAR 1	2009	
January		376,954
February		330,109
March		338,495
April		303,043
May		323,749
June		368,777
July		415,602
August		419,158
September		340,283
October		316,357
November		320,458
December		375,184

(a) Includes EE impacts.

FIGURE 3-12

DUKE ENERGY KENTUCKY SYSTEM

NET MONTHLY INTERNAL PEAK LOAD FORECAST (MEGAWATTS) a

AFTER EE

YEAR 0	2008	KENTUCKY
January		759
February		709
March		668
April		606
May		677
June		830
July		870
August		870
September		781
October		597
November		672
December		730
YEAR 1	2009	
January		766
February		715
March		674
April		612
May		682
June		838
July		878
August		878
September		788
October		602
November		678
December		737

(a) Includes EE impacts.

4. DEMAND-SIDE MANAGEMENT RESOURCES

A. INTRODUCTION

Since the previous IRP filed in 2004, DE-Kentucky has devoted its DSM[1] efforts to the implementation of the following eleven programs that have been developed in conjunction with the DSM Collaborative:

Program 1: Residential Conservation and Energy Education

Program 2: Residential Home Energy House Call

Program 3: Residential Comprehensive Energy Education Program (NEED)

Program 4: Program Administration, Development & Evaluation Funds

Program 5: Payment Plus (*formerly* Home Energy Assistance Plus)

Program 6: Power Manager

Program 7: Energy Star® Products

Program 8: Energy Efficiency Website

Program 9: Personal Energy Report (PER)

Program 10: C&I High Efficiency Incentive (for Businesses and Schools)

Program 11: PowerShare®

There are two collaborative groups: a Residential DSM Collaborative and a Commercial and Industrial DSM Collaborative. Both contain local stakeholders as well as other parties interested in the development and implementation of DSM or conservation EE and DR programs.

[1] Kentucky Revised Statutes (KRS) § 278.010 define Demand Side Management as "any conservation, load management, or other utility activity intended to influence the level or pattern of customer usage or demand

The Commission has been kept appraised of the activities and progress made on these programs with the DSM collaborative process through annual status reports filed with the Commission in the Fall of each year.

As a result of the Commission's review of the 2004 status report, the Commission approved an expansion of the Company's DSM efforts. In the Commission's order on the Company's 2006 status report, the Commission approved the movement of the Payment Plus program from pilot status to a full program. In the 2007 status report, DE-Kentucky provided detailed results on the cost effectiveness of all programs and evaluation reports.

In the Commission Order in Case No. 2004-00389, dated February 14, 2005, 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 5-year period, through December 31, 2009.

Under the current DSM Agreement and prior Commission Orders, all of these programs except Power Manager and PER, will end December 2009 unless an application is made to continue them. It is the Company's intention to submit a

including home energy assistance programs." KY. REV. STAT. ANN. § 278.010 (Michie 2007).

filing subsequent to this report, requesting the approval of a set of energy efficiency and demand response products and services.

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 is designed to help the Company's income-qualified customers reduce their energy consumption and lower their energy costs. This program specifically focuses on Low Income Home Energy Assistance Program ("LIHEAP") customers that meet the income qualification level (*i.e.*, income below 130% of the federal poverty level). This program uses the LIHEAP intake process as well as other community outreach to improve participation. The program provides direct installation of weatherization and energy-efficiency measures and educates DE-Kentucky's income-qualified customers about their energy usage and other opportunities to reduce energy consumption and lower their costs.

The Company estimates that at least 6,000 customers (number of single family owner occupied households with income below $25,000) within DE-Kentucky's service area may qualify for services under this program. The program has provided weatherization services to 251 homes in 2000; 283 in 2001; 203 in 2002; 252 in 2003; 252 in 2004; 130 in 2005; 232 in 2006; and 252 homes in 2007.

The program is structured so that the homes needing the most work and having the highest energy use per square foot receive the most funding. The program does this by placing each home into one of two "tiers." This allows the implementing agencies to spend the limited budgets where there is the most significant potential for savings.

The tier structure is defined as follows:

	Therm / square foot	**kWh use/ square foot**	**Investment Allowed**
Tier 1	$0 < 1$ therm / ft^2	$0 < 7$ kWh / ft^2	Up to $600
Tier 2	1 + therms / ft^2	7 + kWh / ft^2	All SIR $\geq$ 1.5 up to $4K

(where SIR = Savings - Investment Ratio)

For each home in Tier 2, the field auditor uses the National Energy Audit Tool ("NEAT") to determine which specific measures are cost effective for that home. The specific services provided within each tier are described below.

<u>Tier 1 Services</u>

Tier 1 services are provided to customers by DE-Kentucky, through its subcontractors. Customers are considered Tier 1 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 1 services is

$600.00 per home.

Tier 1 services are as follows:

- Furnace tune-up and cleaning
- Furnace replacement if investment in repair over $500 (through Gas WX program)
- Venting check & repair
- Water heater wrap
- Pipe wrap
- Waterbed mattress covers
- Cleaning of refrigerator coils
- Cleaning of dryer vents
- Compact Fluorescent Lightbulbs
- 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 2 Services

DE-Kentucky will provide Tier 2 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 DE-Kentucky-supplied fuels.

Tier 2 services are as follows:

- All Tier 1 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 cost of gas and electric as provided by DE-Kentucky. 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, DE-Kentucky provides energy education to all customers in the program. To increase the cost-effectiveness of this program and to provide more savings and bill control for the customer, the Collaborative and DE-Kentucky proposed in the September 27, 2002 filing in Case No. 2002-00358 and subsequently received approval 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. Based on an evaluation of the refrigerators replaced in 2006, customers can save an average of 1,033 kWh 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. The program replaces 43% of the units tested. Replacement with a new Energy Star® qualified refrigerator, which uses approximately 400 kWh, results in an overall savings to the average customer of 1,033 kWh per year. Refrigerators tested and replaced:

- 2003 = 116 tested and 47 replaced
- 2004 = 163 tested and 73 replaced
- 2005 = 115 tested and 39 replaced
- 2006 = 116 tested and 52 replaced
- 2007 = 181 tested and 101 replaced

When the existing refrigerator is replaced, it is removed from the home and destroyed in an environmentally-appropriate manner. These actions are taken to insure the units are not used as a second refrigerator (thereby increasing, rather than reducing, energy consumption) or do not end up being resold in the secondary appliance market.

Evaluation Findings:

With respect to the weatherization and auditing portions of this program, there were no additional evaluations in this reporting year as these impacts and findings were reported in the last DSM filing. However, the refrigerator program impacts have been updated this year, with an overall average energy savings of 1,033 kWh saved per year.

Program 2: Residential Home Energy House Call

The Home Energy House Call (HEHC) program, implemented by DE-Kentucky subcontractor Enertouch Inc. (d/b/a GoodCents Solutions), provides a comprehensive walk through in-home analysis by a qualified home energy specialist to identify energy savings opportunities in homes. The energy specialist analyzes the total home energy usage, checks the home for air infiltration, examines insulation levels in different areas of the home, and checks appliances and heating/cooling systems. A comprehensive energy usage report specific to the customer's home is then completed and mailed back to the customer within ten business days. The report focuses on building envelope improvements as well as low-cost and no-cost improvements to save energy. At the time of the home audit, the customer receives, at no cost, a kit containing several energy-saving measures. The measures include a low-flow showerhead, two aerators, outlet gaskets, two CFLs, and a motion sensor night-light. The auditors can install the measures so customers begin realizing an immediate savings on their electric bill, but customers may also opt to install the measures at a later date themselves.

For the period of July 1, 2006, through June 30, 2007, a total of 697 audits were completed in Kentucky. This surpasses the annual goal of 500 by 197 audits. From January 2007 through December 2007, Duke Energy distributed 23,161 direct mail brochures and received 790 responses (3.4%). More than one-third of the responses were through the web enrollment process. Of those who responded, 599 received audits through December of 2007. The dollars saved in marketing have allowed Duke Energy to exceed goal during the calendar year by 99 audits. Customer satisfaction ratings for the program to-date remain high: 4.8 on a five-point scale (5 being most satisfied). This score is the result of survey cards completed and returned to DE-Kentucky from customers who have received an audit. The survey asks them to rate five components of the program with comments. The survey card rate of return is approximately 30%. Since program year 2000, over 4,380 customers have participated with 485 in 2000; 500 in 2001; 513 in 2002; 507 in 2003; 569 in 2004; 506 in 2005; 701 in 2006; and 599 in 2007.

Evaluation Findings:

No new evaluation studies were conducted for this program over the past 12 months. The most recent evaluation study results from the previous year were, therefore, used for this analysis. The program is scheduled to have an updated impact evaluation conducted during the next fiscal year period.

Program 3: Residential Comprehensive Energy Education

The Residential Comprehensive Energy Education program is operated under subcontract by Kentucky NEED.

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 K through 12.

The Kentucky NEED program not only follows national guidelines for materials used in teaching, but also offers additional services. These services include: 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.

Overall, the program has reached teachers and students in 57 schools in the six counties served by DE-Kentucky. There are currently over 200 teachers enrolled in the program. At a minimum, these teachers have impacted over 5,000 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 middle school and 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 also share this information with their families and reduce consumption in their homes.

The program addresses: (1) building energy efficiency improvements through retrofits financed by use of energy saving performance contracts ("ESPC") and improved new construction; (2) school transportation practices; (3) educational programs; (4) procurement practices; and (5) linkages between school facilities and activities within the surrounding community

To improve and better document the energy savings associated with the program, a change was made in 2004, adding a new survey instrument for use in the classroom and an energy savings "kit" as a teaching tool. A new curriculum was developed around this kit and survey to allow teachers to have actual in-home measures assessed and implemented. The result of this change has allowed the program to demonstrate that the kit contents provided through this program are being installed in the home. These kits include CFLs, low-flow shower heads, faucet aerators, a water temperature gauge, outlet insulation pads and a flow meter bag.

The kits were tested in the spring of 2003 and began full application in the new school year beginning September 2003 when the science curriculum dealt with these issues. The number of kits distributed from 2003-2005 totaled 985. During the 2006-07 school year, 235 kits were distributed to students. In the first half of the 2007-08 school year, 215 kits were distributed to students in five schools in DE-Kentucky's Northern service territory.

Activities in the 2006-07 school year included: six teachers from six schools in the service territory attended a five-day training conference for the NEED summer teacher training workshop; 182 teachers received NEED materials; and two teacher/student training workshops with 22 teachers and 110 students. Kentucky NEED works with the Kentucky Office of Renewable Energy and Energy Efficiency to develop and facilitate the Kentucky Energy Smart Schools programs.

NEED hosted the fifth annual High Performance Schools Workshop. Participants in the 2006-07 Youth Awards Program included: M. Yealey Elementary-Florence, KY; Glenn O. Swing Elementary-Covington, KY; Phillip A. Sharp Middle School-Butler, KY; and Twenhofel Middle School - Independence, KY. Students from Glenn O. Swing attended the summer 2007 national conference in Washington, D.C.

During the summer of 2007, Kentucky NEED staff worked with Kenton County Schools to develop their Energy WISE Manual. Due to the success of the Twenhofel NEED Team, Kenton County implemented a voluntary program, encouraging all schools in the district to form student energy teams. Training for the teams was held in September. All 18 schools in the district have energy teams this year. These teams promote energy efficiency and conservation measures in the schools and monitor energy consumption.

In partnership with the Governor's Office of Energy Policy ("GOEP"), Kentucky NEED is promoting student participation in the "Change a Light, Change the World" campaign. Using NEED's Change a Light ("CAL") Teacher's Guide, students are encouraged to facilitate CAL activities in their schools and communities. GOEP and Kentucky NEED are offering $350 mini-grants to student groups facilitating Change a Light. Kentucky students ranked 23rd in overall pledges during the 2006-07 campaign, in which hundreds of organizations participated. Kentucky NEED is also actively promoting the energy efficiency incentive program for schools, coordinating a presentation at the Northern KY Superintendents monthly meeting.

Evaluation Findings:

The results from the 2005 NEED impact evaluation are used for this analysis. However, even though the 2005 impact estimates are used, the cost effectiveness results have decreased, due to increasing costs for the program related to fewer kits being distributed and installed within customer homes. As such, future efforts will focus more attention on ensuring that teachers and administrators follow through on the energy training and program material recommendations, such that program completion through kit distribution, installation and customer follow-up are possible. This program is scheduled for an update of impact evaluation findings and reporting during the 2008 fiscal year cycle.

Program 4: Program Administration, Development, & Evaluation Funds

This program is responsible for designing, implementing and capturing costs related to the administration, evaluation and support of the Collaborative and DE-Kentucky's overall DSM effort. Program development funds are utilized for the redesign of programs and for the development of new programs, or program enhancements, such as the refrigerator replacement portion of the Residential Conservation and Energy Education program. Evaluation funds are used for cost-effectiveness analysis and evaluation, impact evaluation and process evaluation of program activities.

Funds going forward will be used again to monitor, evaluate and analyze these programs to improve cost effectiveness and program design. While more than half of the total funds were spent for the twelve-month period ending June 30, 2007, several of the implemented impact evaluation studies were not completed until September and October 2007. Therefore, DE-Kentucky expects, and has planned for, the continuation of funding for this program to cover evaluation study costs for the current year's activities as well as future evaluations. DE-Kentucky strives to optimize and balance the use of these program funds, such that program development and redesign continues, that all programs are analyzed every year for cost effectiveness, and that programs are generally afforded the opportunity for a full-scale impact evaluation and energy savings assessment once every two years. DE-Kentucky believes that it is unnecessary to spend significant funds on impact evaluations every year for all programs, but also understands that all programs must undergo impact evaluation scrutiny and review at least once every two years.

Program 5: Payment Plus *(formerly* Home Energy Assistance Plus)

From January 2002 through June 2006, the Residential Collaborative and DE-Kentucky tested a home energy assistance program called Payment Plus. The 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. That program was extended with the Commission's Order in

Case No. 2004-00389 to include both the early participants and new participants each year.

The program has three parts:

1. Energy and Budget Counseling – To help customers understand how to control their energy usage and how to manage their household bills, a combined education/counseling approach is 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 allows for approximately 125 homes to participate per year as some customers do not complete all three steps or have already had the weatherization completed prior to the program.

This program is offered over six winter months per year starting in October. Customers are tracked and the program evaluated after two years to see if customer energy consumption dropped and changes in bill paying habits occurred. Over the last five years, participants have been monitored and compared to a control group of customers with similar arrearages and incomes. This evaluation has looked at not only energy savings, but arrearage and payment practices. It is the only long-term impact and process evaluation in the country looking at both energy savings and arrearages from a single program. As a result, there is some evidence the program is effective at both saving energy and having a positive impact on arrearages. The evaluation firm recommended that the program continue. Copies of the evaluation report were included in the 2006 filing.

Given the evaluation results, the Collaborative proposed, and the Commission approved, in May 2007, continuation of the program at a cost of $150,000 per year, through 2009. By expanding the program DE-Kentucky is adding an additional 80 participants beginning Fall of 2007. Follow-up educational reinforcement for all participants began in Fall 2007. There were 168 participants who received energy education, 140 participants who received financial management sessions and 108 homes that were weatherized (71 homes received weatherization prior to or during 2007 and 37 homes received weatherization from the original 168 participants in 2008).

<u>Evaluation Findings</u>:

The last evaluation was done for the 2006 DSM filing, and these findings are used for energy savings for the current year cost-effectiveness results, given current year program implementation costs.

Program 6: Power Manager

The purpose of the Power Manager program is to reduce demand by controlling residential air conditioning usage during peak demand conditions in the summer months. The program is offered to residential customers with central air conditioning. DE-Kentucky attaches a load control device to the customer's compressor to enable DE-Kentucky to cycle the air conditioner off and on when the load on DE-Kentucky's system reaches peak levels. Customers receive financial incentives for participating in this program based upon the cycling option selected. If a customer selects Option A, the air conditioner is cycled to achieve a 1 kW reduction in load. If a customer selects Option B, the air conditioner is cycled to achieve a 1.5 kW load reduction. Incentives are provided at the time of installation: $25 for Option A and $35 for Option B. In addition, when a cycling event occurs, a Variable Daily Event Incentive based upon marginal costs is also provided.

Cycling a customer's air-conditioning system has shown minimal impacts on the customer's comfort level. The load control device has built-in safeguards to prevent the "short cycling" of the air-conditioning system which results in no impact on the systems long-term operations. Research from other programs, including previous DE-Ohio and DE-Kentucky programs, has shown that the indoor temperature should rise approximately one to two degrees for control Option A and approximately two to three degrees for control Option B. Additionally, the indoor fan will continue to run and circulate air during the cycling event.

The initial design of Power Manager has been structured on the same basic principles as DE-Kentucky's innovative PowerShare® program. Power Manager combines direct load control with a flavor of "real-time pricing" through the Variable Daily Event Incentive structure as described above. By implementing the Variable Daily Event Incentive structure, DE-Kentucky customers become better informed regarding the real-time cost of electricity. DE-Kentucky continues to explore opportunities to cross-market the Power Manager program with DE-Kentucky's other DSM programs, thus tying both conservation and peak load management together as one package.

In 2006, DE-Kentucky mailed 270,015 Power Manager marketing pieces and had 2,587 customers enrolled in the program with 1,958 switch installations completed from the enrollments. The cumulative installations as of the end of 2006 total 6,888 switches. The installation rate during 2007 was intentionally less than projected originally, due to a desire to ensure that existing switches, operations and systems were operating as efficiently and effectively as possible. Previous quality control assessments, measurements and verifications suggested that paging, installation, operations and signaling were not being effectively received within some areas. As such, significant effort during 2007 resulted in the successful increase in load reductions realized per household to an average of 1.04 kW per home. This quality management effort has provided increased assurance that the program operates as intended, and at a load reduction level that is clearly cost effective and worthy of further pursuit and customer promotion. Termed the "Duke A Quality Control" ("QC") program, the effort was implemented in January of 2007 to visit 3,400 switches in the field. The program consisted of a general inspection of the health of the air conditioner, the switch installation, and retrieval of the event performance data stored inside the switch.

The switch interrogation equipment was enhanced during the first quarter of 2007, which enabled DE-Kentucky to receive information stored in the switch in an electronic format that enables faster data review versus transfer of data from a hard copy report onto a spreadsheet. For 2007, DE-Kentucky completed 2,898 quality control inspections of the 3,400 switches planned for review. Since resources were focused on the QC efforts, DE-Kentucky completed 1,510 of projected switch installations in 2007, with 1,403 customer enrollments in 2007. Some of the 2006 customer enrollments were installed in 2007. The cost-effectiveness modeling results for Power Manager reflect this successful effort.

Evaluation Findings:

The 2007 DE-Kentucky Power Manager Impact Evaluation study reports that the program successfully achieves an average load reduction per home of 1.04 kW, with favorable cost-effectiveness results, given the program costs. To conduct the study as economically and efficiently as possible, existing DE-Kentucky meters, staff and logger equipment were used to save costs. To insure objectivity, DE-Kentucky contracted with Integral Analytics (Dr. Michael Ozog) to review the study design, processes, results and statistics to insure that the study findings are reasonable, accurate and can be projected for the IRP. DE-Kentucky will continue to monitor and evaluate the load reductions attributable for the program, given its projected significance to the IRP.

Program 7: Energy Star® Products

As approved in Order 2004-00389, the Energy Star® Products program provides market incentives and market support through retailers to build market share and usage of Energy Star® products. Special incentives to buyers and in-store support stimulate demand for the products and make it easier for store participation. The programs targets Residential customers' purchase of specified technologies through retail stores and special sales events. The first year of the program focused on CFLs and torchiere lamps. Technologies may change over the future years of program operation based on new technologies and market responses.

There are several market barriers addressed through the program. The first is price. Purchase rewards are provided for customers to lower first cost of the item and stimulate interest. The second barrier is retailer participation. Through retail education, in-field sales support (signs, ads, *etc.*), and stimulated market demand, retailers stock more product, provide special promotions and plan sales strategies around these Energy Star® products. Additional support is provided through manufacturer relationships that often can reduce prices through special large-scale purchases. Coordination occurs with the national Energy Star® initiatives such as "Change a Light, Change the World" promotion.

To stimulate the market and get customers to buy and install the efficient lighting, the program provides incentives or "customer rewards" through special in-store "Instant Reward" events that occur in stores at the time of purchase or at special promotional events in the community. Technology incentives start at $2 per bulb and $20 per torchiere. The program also provides training to sales staff of the retailers on the sales aids provided. DE-Kentucky has contracted with the Wisconsin Energy Conservation Corporation ("WECC") to provide this service. WECC has been recognized as the national leader in this program and is located in the region, so DE-Kentucky is taking advantage of WECC's current activity to control costs and leverage other activity.

To reduce administrative costs and maintain cost-effectiveness of the program, a revised approach to the market was implemented. Instead of year-round activities for the program, special campaigns are held at different times of the year and at different locations to promote these Energy Star® Products. Two sales events took place in the 2005-06 filing period. The first event took place at Covington's City Hall with the support of Covington's Mayor Callery. Eight Do-It-Best retail stores participated in the sales promotion that lasted through February of 2006 and resulted in the sale of 24,616 CFLs. A second event took place during April 2006 as part of DE-Kentucky's promotion of Earth Day. This sales promotion targeted Alexandria and Ludlow. Four True Value Hardware retailers in these areas participated in this sales promotion. The final results of these events totaled sales of 3,886 CFLs through August of 2006.

During the most current DSM filing period, a total of five promotional events took place. Three events in the fall were planned in coordination with the

October national "Change the Light, Change the World" campaign. They were held in Covington, hosted by Mayor Callery's office, in Florence, hosted by Mayor Diane Whalen's office, and in Newport, hosted by Mayor Thomas Guidugli's office. Thirteen local retailers participated in the program. In the spring, in coordination with Earth Day, two events took place. One was held in Alexandria, hosted by Mayor Dan McGinley's office, and the other in Ludlow, hosted by Mayor Ed Schroeder's office. Four local retailers supported the sales events in Alexandria and Ludlow. Sales in this filing period totaled 48,823 CFLs and 737 torchieres, exceeding the goals by 8,823 CFLs and 237 torchieres. With such a successful response, marketing costs were reduced which enabled these additional bulb incentives to be paid within the existing budget.

During calendar year 2007, along with the two events hosted by the Mayors in Alexandria and Ludlow as part of their Earth Day celebrations mentioned above, three events were hosted in the fall in Bellevue, Ft. Mitchell, and Newport in coordination with the 2007 "Change a Light, Change the World" campaign. Total sales in 2007 consisted of 36,607 CFLs and 502 Torchieres.

<u>Evaluation Findings</u>:

The latest Impact Evaluation for this program demonstrates cost-effective energy savings impacts for this program. Slightly more customer-reported hours of use were found, indicating that more energy savings will be realized for this program than originally expected. Continued and expanded promotions for this type of program are likely to deliver additional savings. Some concern has arisen relative to the maximum number of coupons or bulbs that should be permitted per home to guard against the possible customer behavior of "stockpiling" bulbs (*i.e.*, more than 12) or inventorying bulbs for future use. The intent of the program is to promote and initiate use among large segments of customers and not to subsidize customers that are already using these types of energy savings devices within their homes.

Program 8: Energy Efficiency Website, On-line Energy Assessment and Free Energy Efficiency Starter Kit

As approved in Order 2004-00389, DE-Kentucky's residential website offers opportunities for customers to assess their energy usage and obtain recommendations for more efficient use of energy in their homes. This Kentucky program fits suitably into the Company's new multi-state program design now referred to as the Residential Energy Assessment Program. As an expansion to the previous energy efficiency website model, new website pages, new content and new on-line tools have been added. These on-line services help accomplish several things by providing energy efficiency information, tips, and bill analysis. However, DE-Kentucky also intends to use these tools to help identify those customers who could benefit most by investing in new energy efficiency measures or practices. Those customers can then be targeted for participation in other DE-Kentucky programs.

In November 2006, the Quick-e-Audit tool was upgraded to the Home Energy Calculator provided by Apogee. In this new, easy-to-use energy analysis tool, a customer provides information about their home, number of occupants, and other energy-related home and family characteristics. This tool allows an unlimited number of potentially energy-saving scenarios to be run and charts and tables compare the scenarios to show energy savings. As an incentive to encourage customers to use the website, a free Energy Efficiency Starter Kit is offered. The kit is mailed directly to the customer's service address and provides the customer with the following measures:

- Showerhead, 1.5 GPM .
- Kitchen Swivel Aerator, 1.5 GPM
- Bathroom Aerator, 1.0 GPM
- 15 Watt CFL
- 20 Watt CFL
- Shrink Fit Window Kit
- Closed Cell Foam Weatherstrip, 17' Roll
- Switch and outlet draft stopper gaskets

The free kit offer was added to the DE-Kentucky website in June 2006. For 2007, 299 kits were mailed.

Evaluation Findings:

The Website Audit Impact Evaluation indicates that the program savings, given the costs, are cost effective and successful. Future efforts for the program should focus on increasing the number of customers that use the website and take advantage of the program.

Program 9: Personal Energy Report ("PER")

The PER program was a pilot program that ended in December 2006. It provided DE-Kentucky customers with a customized energy report aimed at helping them better manage their energy costs. With rising energy costs in all aspects of daily life, the customer was searching for information they could use and ideas they could implement which would impact their monthly energy bill. The PER program also included the Energy Efficiency Starter Kit containing nine easily-installed measures which demonstrated how easy it is to move towards improved home energy efficiency. For purposes of this pilot program, DE-Kentucky agreed to test the efficacy of the kit by sending it to 25% of the survey respondents. The program targeted single family residential customers in the DE-Kentucky market that had not received measures through the Home Energy House Call energy efficiency audit or Residential Conservation & Energy Education programs within the prior three years.

The program gave information on the entire home from an energy usage standpoint, providing energy tips and information regarding how they use energy and what simple, low cost/no cost measures could be undertaken to lower their energy bill. This program provided value because customers lack education on how they individually consume energy in their home and the steps which can be taken to lower their energy bills. This program was meant to educate the customer and put at their disposal information, customized tips and simple-to-install measures which could all lower their energy costs.

To get this information, a customer completed an energy survey which generated the PER. Both are excellent educational tools. The survey stimulated the customer to think about how they use energy and then the PER provided them with tools and information to lower their energy costs. Additionally, the PER provided instructions on how to install the energy measures, demonstrating how easy it is to improve their efficiency.

To gain customer participation, the PER program commenced with a letter to the customer, offering the PER if they would return a short, 14 question survey about their home. The survey asked very simple questions such as age of home, number of occupants, types of fuel used to cool, heat, and cook. Once the survey was returned, the information was used to generate a customized energy report. The report contained the following information:

- Month-to Month Comparisons of electric and/or gas usage including the amount of the bill
- Predictions of customer's usage based on 95th percentile weather conditions (extremely hot summer/extremely cold winter) and 5th percentile weather conditions (extremely mild summer/extremely mild winter). Also included bill amounts based on 2006 tariffs.
- Trend chart showing usage of electric and/or gas by kWh/cf by month and amount of monthly bill
- Bill comparison of DE-Kentucky vs. the average national electric and/or gas rate
- A disaggregation of how the customer uses electricity and/or gas
- Description of Budget Bill
- Customized energy tips. Customized tips were based upon the customer's specific answers to questions in the survey. As an example:
    - If the age of the home was over 30 years, plastic window kits would be a recommended measure

- If over 50% of the ducts were in the attic, adding duct insulation would also be a measure.

As part of quality control and evaluation, DE-Kentucky completed a follow-up survey with a sub-segment of the customers who received the offer and those who also responded to determine what drove their responses. An additional sub-segment of customers who received the Energy Efficiency Starter Kit also received the survey and include questions regarding installation of the measures found in the kit. For the 25% of customers who received The Energy Efficiency Starter Kit, the kit contained the following items:

- 2-1.5 GPM showerheads
- 1 Kitchen Swivel Aerator 2.2 GPM
- 1 Bathroom Aerator 1.0 GPM
- 1 Bath Aerator 1.5GPM
- 1 Small Roll Teflon Tape
- 1-15 Watt CFL Mini Spiral
- 1-20 Watt CFL Mini Spiral
- 2-17' Roll Door Weatherstrip
- 1 Combination Pack Switch/Outlet Gasket Insulators
- Installation instructions for all measures

DE-Kentucky is using a similar kit in the Home Energy House Call and NEED programs with significant success. For the pilot, mailings went out in three (3) waves:

- Wave 1 - May 22, 2006, to 6,250 customers; 1,417 responses = 22.7% (with kits)
- Wave 2 – July 5, 2006, to 5,489 customers; 1,393 responded = 25.4% (with kits)
- Wave 3 – August 18, 2006, to 35,336 customer; 6,249 responded = 17.7% (w/o kits)

Total mailed = 47,075; Response = 9,059; Kits shipped = 2,810; Overall response rate = 19%.

For the pilot, the budget totaled was $109,246; however, total expenditures were $67,749. The primary reason for the difference of $41,497 was that the number of customers fitting the criteria within the target was only 47,000 versus the 72,000 originally expected.

Evaluation Findings:

DE-Kentucky conducted a process and impact evaluation for the program as well as a billing analysis of the pre- and post-usage by customers. The program was shown to be cost-effective, given these findings. The kit measures were estimated to achieve 212 kWh of savings from engineering estimates, and the pre- and post-usage analysis confirmed this estimate with 204 kWh of savings observed. In addition, the audit recommendations sparked additional savings recommendations that the customers could take to further achieve energy savings. Follow-up surveys of intended customer actions revealed approximately 658 kWh of additional intended savings. However, given that these savings were intended and not actual, DE-Kentucky projects that only 20% of these intentions are likely to be realized within a year. As such, the 2008 impact evaluation will target post-participation on-site measurements and verifications of these intentions, and true-up whatever additional or decremental savings occurred, relative to this 20% realization assumption.

Program 10: C&I High Efficiency Incentive (Including Schools Initiative)

The Commission's Order in Case No. 2004-00389 approved a new program for DE-Kentucky to provide incentives to small commercial and industrial customers to install high efficiency equipment in applications involving new construction, retrofit, and replacement of failed equipment. In the original filing, this program was to be jointly implemented with the DE-Indiana territory to reduce administrative costs and leverage promotion. This joint program included expanded technologies beyond what was provided in Indiana. That expanded program in Indiana has not yet been approved. However, a new C&I expanded program is approved in the DE-Ohio's territory for implementation in that state. Given that approval, the program can now economically expand technologies in Kentucky to those initially proposed in the Kentucky filing and include the following:

High-Efficiency Incentive Lighting

- T-8 with Electric Ballasts replacing T-12
- LED Exit Signs New/Electronic
- CFL Fixture
- CFL Screw in
- T-5 with Elec. Ballast replacing T-12
- T-5 High Output with Elec. Ballast replacing T-12
- T-5 High Output High Bay
- Tubular Skylight
- Hi Bay Fluorescent
- 320 Metal Halide Pulse Start
- LED Traffic Signals
- Controls/Occupancy Sensors

High Efficiency Incentive HVAC

- Packaged Terminal AC
- Unitary AC & Heat Pump
- Rooftop HP & AC
- Ground Source HP – Closed Loop

- Air Cooled Chillers
- Water Cooled Chillers
- Window AC
- HP Water Heater
- Thermostats/Controls

High Efficiency Incentive Pumps, Motors & Drives

- NEMA Premium Motors 1 to 250 HP with greater than 1500 hours per year
- High Efficiency Pumps 1-20 HP
- Variable Frequency Drives 1-50 HP

Refrigeration

- Energy Star® Refrigerators and Freezers
- Energy efficiency Ice Machines
- Head Pressure Controls
- Night Covers for displays
- Efficient Refrigeration Condensers
- Anti-sweat Heater Controls
- Vending Machine Controls

Other Misc. Technologies

- Injection Molder Barrel Wraps
- Engineered Air Compressor Nozzles
- Pellet Dryer Duct Insulation
- Energy Star® Clothes Washers for Commercial Applications

Timing of the expansion will be dependent on the budget availability and market response to the existing technologies within the program. Incentives are provided through the market providers (contractors and retail stores) based on DE-Kentucky's cost-effectiveness modeling but with a high-end limit of 50% of measure cost. Using the DE-Kentucky cost-effectiveness model assures cost-effectiveness over the life of the measure. Primary delivery of the program is through the existing market channels, equipment providers and contractors. DE-Kentucky is using its current DSM team to manage and support the program. Additional outside technical assistance is being provided by Good Cents Solutions to analyze technical applications and provide customer/market provider assistance as necessary. DE-Kentucky also will provide education and training to its market providers to understand the program and the appropriate applications for the technologies.

Full program operations began in the last quarter of 2005. Results to date were beyond expectation. In the first nine months of the program, 36 applications were processed totaling $313,350 in incentives. DE-Kentucky attributes this to high installation rates of T-8, T-5 High Output, and High Bay Lighting technologies as well as to a pent-up demand in the marketplace. To respond to the market, the following adjustments were made to the program in order to serve more customers and remain cost effective:

- Incentives for T-8, T-5 and High Bay fixtures are no longer eligible in a "new construction" application, only retrofit applications. The new construction market is utilizing these technologies as a normal practice so incentives are not needed now.
- The incentive levels for T-8 High Bay and T-5 High Output High Bay fixtures were adjusted to align with price changes in the market.
- A cap of $50,000 per facility per calendar year was implemented in an effort to serve more customers.
- A reservation system was instituted during the proposal stage, to ensure that customers will receive their incentives once the project is complete.

Even given these changes, the program still ran out of funds in April of 2007. There were seven applications waiting to get paid in the amount totaling $81,248 and DE-Kentucky received four reservation applications totaling $83,279 for projects scheduled to be completed in July-September. In the Fall of 2006, DE-Kentucky filed with the Commission a request for a 100% increase in funding along with an additional $451,885 for a Kentucky Schools program to respond to market demand and customer opportunities – providing schools funding for facility assessments, custom and prescriptive measures rebates and energy efficiency education from the NEED organization. On May 15, 2007, the Commission approved DE-Kentucky's application to expand the program. During the current DSM filing period, 12,742 light fixtures have been installed of which 30% were T8 High Bay six-lamp and T5 High Output High Bay four-lamp fixtures. Twenty HVAC units were installed, four motors and no pumps. Activity for the 2007 12 month calendar year included the following total installations by measure type:

- Lighting – 10,713 fixtures
- Motors – 4
- Pumps – 0
- HVAC (cooling) – 28

To date, Kenton County Schools are the only schools who have taken advantage of the Schools Program in Northern Kentucky to date. They will begin more extensive school renovations beginning this summer and are building a NET ZERO school in DE-Kentucky's service territory. Given that the Commission's Order was issued May 15th and the filing period ended June 30th, it was unlikely to see significant impact for the first year to 18 months.

In May of 2008, letters went out to all eligible Kentucky customers and participating vendors announcing the current program has been expanded in each of the existing technologies (Lighting, HVAC and Motors/Pumps) to include more measures eligible for incentives, as well as adding three new technology categories (explained above) – Energy Star® Commercial Clothes Washers, Process Equipment and Food Services Equipment. The DE-Kentucky website has been updated with the new applications.

Evaluation Findings:

Energy and demand savings from the most recent evaluation exceeded the tracking system estimates and the program planning estimates used by DE-Kentucky. The differences are due to a combination of original data entry set up errors within the tracking system and differences in the methods used to estimate savings between the original program design period and the time of the more robust and rigorous impact evaluation study. The impact evaluation analysis was affected by several factors that could be improved in the future, as well:

1. **Uncertainty in lighting measure baseline**. The tracking system contained information on lighting fixtures installed, but no data were available on the type of lighting fixtures removed. AEC and TechMarket Works made assumptions on the type of fixture removed based on a review of the program engineering documentation. Recording the number and type of fixtures removed within the tracking system removes this uncertainty. This information is not always readily available or reliable, but applying some effort in this regard should improve the overall impact estimates in the future.

2. **Ambiguity in measure descriptions**. The lighting measure descriptions in the tracking system for T-8 fluorescent lamps were somewhat ambiguous. Although the lamp type, length and number of lamps per fixture were recorded, the lamp watts were not. Several styles of T-8 lamps with varying input watts are available, and adding a lamp wattage description will better define the specific type of the installed measure.

3. **Lack of building type information.** Lighting and HVAC measure savings calculations rely on an understanding of the building type. It was possible to identify the building type from the customer name in most cases, but an additional field indicating the building type or customer SIC

or NAICS code would be helpful in making this determination in the future.

Program 11: PowerShare®

PowerShare® is the brand name given to DE-Kentucky's Peak Load Management Program (Rider PLM, Peak Load Management Program KY.P.S.C. Electric No. 4, Sheet No. 77). The PLM Program is voluntary and offers customers the opportunity to reduce their electric costs by managing their electric usage during the Company's peak load periods. Customers and the Company will enter into a service agreement under this Rider, specifying the terms and conditions under which the customer agrees to reduce usage. There are two product options offered for PowerShare® called CallOption and QuoteOption:

- CallOption – A customer served under a CallOption product agrees, upon notification by the Company, to reduce its demand or provide generation for purchase by the Company. Each time the Company exercises its option under the agreement, the Company will provide the customer a credit for the energy reduced or generation provided. If available, the customer may elect to buy through the reduction at a market-based price. In addition to the energy credit, customers on the CallOption will receive an option premium credit. Only customers able to provide a minimum of 100 kW load response qualify for CallOption.

- QuoteOption– Under the QuoteOption products, the customer and the Company agree that when the average wholesale market price for energy during the notification period is greater than a pre-determined strike price, the Company may notify the customer of a QuoteOption event and provide a Price Quote to the customer for each event hour. The customer will decide whether to reduce demand or provide generation during the event period. If they decide to do so, the customer will notify the Company and provide the Company an estimate of the customer's projected load reduction or generation. Each time the Company exercises the option, the Company will provide the customer an energy credit. There is no option premium for the QuoteOption product since customer load reductions are voluntary. Only customers able to provide a minimum of 100 kW load response qualify for QuoteOption.

The customer participation goal for 2007 was to retain all QuoteOption customers that currently participate and to get as many of these customers as possible to migrate to the CallOption program. This would provide additional demand response that may delay the need for new generation.

During the summer of 2007, CallOption and QuoteOption events occurred on August 8 and August 9. The average hourly potential load curtailed during these two events was 1,722 kW. Even though the temperatures on these two event days were extreme, a special note should be made regarding the Midwest ISO market prices for energy. The wholesale market prices were relatively low and therefore did not encourage a large QuoteOption participation. This situation occurred due to the mild temperatures in the northern areas of the Midwest ISO which allowed wholesale market prices for energy to remain relatively low even though the southern areas of the Midwest ISO experienced extreme heat.

Integral Analytics time series regression based impact evaluation analysis confirmed 1,144 KW of peak load impact, consistent with a peak normal 93.5 degree summer weekday. In addition, given the buy-through option observed from one of the customers, averaging 578 kW, the sum total peak load capability for the PowerShare® program overall is 1,722 kW.

C. DSM SCREENING AND COST-EFFECTIVENESS

DE-Kentucky evaluates the cost-effectiveness of DSM measures when making decisions about inclusion in DSM programs. The net present value of the financial stream of costs vs. benefits is assessed, *i.e.*, the costs to implement the measures are valued against the savings or avoided costs using the DSMore model. The resultant benefit/cost ratios, or tests, provide a summary of the measure's cost-effectiveness relative to the benefits of its projected load impacts.

The main criteria DE-Kentucky uses for screening DSM measures are the Utility Cost Test ("UCT"), the Total Resource Cost Test ("TRC"), and the Ratepayer Impact Test ("RIM"). A Participant Test is also reviewed to make sure the program makes sense for the individual consumer. The UCT compares utility benefits to utility costs and does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected market price of power including the projected cost of environmental compliance. With the expected increase in the cost of compliance for controlling SO_2, NO_x, and Hg emissions, the benefits of conservation have increased. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs, load (line) losses, and avoided ancillary services.

The TRC test compares the total benefits to the utility and to participants relative to the costs to the utility to implement the program and the costs to the participant. The benefits to the utility are the same as those computed under the UCT test. The RIM test, or non-participants test, indicates if market prices and rates increase or decrease over the long-run as a result of implementing the program.

The costs associated with implementing measures in DSM programs include incentives offered to consumers to encourage participation and vendor delivery and installation costs (if applicable). The costs to market the program (including direct mail and/or channel fees) and the expenses for program administration are not directly included in the calculation of the UCT due to the difficulty of allocating them to the individual measures. Rather, measures are considered cost-effective as long as the UCT is more than 30% above 1.0 in order to allow for the additional program costs.

The cost-effectiveness test results for the Company's current programs are provided in the table below.

Program	Cost Effectiveness Test Results			
	UCT	TRC	RIM	Participant
Residential Conservation and Energy Education	0.93	0.93	0.45	NA
Refrigerator Replacement	1.03	1.03	0.46	NA
Residential Home Energy House Call	3.38	3.38	1.02	NA
Residential Comprehensive Energy Education Program (NEED)	1.57	1.57	0.64	NA
Power Manager	3.32	3.98	3.32	NA
Energy Star Products	9.75	7.92	0.66	18.13
Energy Efficiency Website	1.95	2.49	0.57	NA
Personal Energy Report (PER)	5.78	10.76	0.71	NA
C&I High Efficiency Incentive (for Businesses and Schools)				
Lighting	4.73	2.69	0.84	3.6
HVAC	2.17	1.32	0.79	1.67
Motors	1.39	1.23	0.61	2.03
PowerShare	2.16	261.94	1.86	NA

D. DSM PROGRAMS AND THE IRP

The projected impacts of the DSM programs discussed above have been included in the least-cost supply plan for DE-Kentucky. The conservation DSM programs are projected to reduce energy consumption by approximately 35,000 MWh and 7 MW by 2017. At the same time, the direct load control program is projected to reduce peak demand by 13 MW and the PowerShare® program another 2 MW. This brings the total peak reduction across all programs to approximately 22 MW by 2017. The following table summarizes the projected load management impacts included in this IRP analysis.

Duke Energy Kentucky

Projected Energy Efficiency Load Impacts

	Conservation Program Impacts MWH			Conservation Program Impacts MW			Demand Response Program Impacts MW			Total MW
Year	Residential	Non-Residential	Total	Residential	Non-Residential	Total	PowerShare	Power Manager	Total	Impacts
2008	2,428	513	2,941	0.6	0.2	0.8	1.8	9.6	11.4	12.2
2009	6,945	1,455	8,400	1.4	0.5	1.9	1.8	10.9	12.7	14.6
2010	11,462	2,396	13,859	2.3	0.8	3.1	1.8	12.2	14.0	17.1
2011	15,989	3,338	19,327	3.2	1.0	4.2	1.8	12.6	14.4	18.6
2012	19,054	4,290	23,344	3.6	1.3	5.0	1.8	12.6	14.4	19.4
2013	20,718	5,226	25,944	3.9	1.6	5.5	1.8	12.6	14.4	19.9
2014	22,439	6,176	28,615	4.1	1.9	6.0	1.8	12.6	14.4	20.4
2015	24,157	7,126	31,283	4.4	2.2	6.6	1.8	12.6	14.4	21.0
2016	25,970	8,096	34,067	4.6	2.5	7.1	1.8	12.6	14.4	21.5
2017	26,718	8,508	35,226	4.7	2.6	7.3	1.8	12.6	14.4	21.7
2018	26,716	8,508	35,224	4.7	2.6	7.3	1.8	12.6	14.4	21.7
2019	26,713	8,508	35,221	4.7	2.6	7.3	1.8	12.6	14.4	21.7
2020	26,786	8,531	35,318	4.7	2.6	7.3	1.8	12.6	14.4	21.7
2021	26,693	8,508	35,201	4.7	2.6	7.3	1.8	12.6	14.4	21.7
2022	26,705	8,508	35,213	4.7	2.6	7.3	1.8	12.6	14.4	21.7
2023	26,718	8,508	35,226	4.7	2.6	7.3	1.8	12.6	14.4	21.7
2024	26,799	8,530	35,329	4.7	2.6	7.3	1.8	12.6	14.4	21.7
2025	26,708	8,508	35,216	4.7	2.6	7.3	1.8	12.6	14.4	21.7
2026	26,701	8,508	35,209	4.7	2.6	7.3	1.8	12.6	14.4	21.7
2027	26,693	8,508	35,201	4.7	2.6	7.3	1.8	12.6	14.4	21.7
2028	26,798	8,531	35,329	4.7	2.6	7.3	1.8	12.6	14.4	21.7
2029	26,716	8,508	35,224	4.7	2.6	7.3	1.8	12.6	14.4	21.7
2030	26,713	8,508	35,221	4.7	2.6	7.3	1.8	12.6	14.4	21.7
2031	26,708	8,508	35,216	4.7	2.6	7.3	1.8	12.6	14.4	21.7
2032	26,783	8,531	35,314	4.7	2.6	7.3	1.8	12.6	14.4	21.7

Note: the conservation MW program impacts represent the monthly seasonal maximum.

5. SUPPLY-SIDE RESOURCES

A. INTRODUCTION

The phrase "supply-side resources" encompasses a wide variety of options that DE-Kentucky uses to meet the energy needs of its customers, both reliably and economically. These options can include existing generating units, repowering options for these units, existing or potential power purchases from other utilities, IPPs and cogenerators, and new utility-built generating units (conventional, advanced technologies, and renewables). The IRP process assesses the possible supply-side resource options that would be appropriate to meet the system needs by considering their technical feasibility, fuel availability and price, length of the contract or life of the resource, construction or implementation lead time, capital cost, O&M cost, reliability, and environmental effects. This chapter will discuss in detail the specific options considered, the screening processes utilized, and the results of the screening processes.

B. EXISTING UNITS

1. Description

The total installed net summer generation capability owned by DE-Kentucky is 1,077 Megawatts (MW). This capacity consists of 577 MW of coal-fired steam capacity, and 500 MW of natural gas-fired peaking capacity.

Information concerning the existing generating units as of the date of this filing is contained in Figure 5-1. This table lists the name and location of each station, unit number, type of unit, installation date, tentative retirement year, net dependable summer and winter capability (DE-Kentucky share), and current environmental protection measures. The steam capacity, located at two stations, is comprised of two coal-fired units. The peaking capacity consists of six natural gas-fired CTs located at one station. These natural gas-fired units have propane as a back-up fuel. East Bend Unit 2, one of the coal-fired steam units, is jointly owned with Dayton Power & Light (see Figure 5-2). DE-Kentucky owns 69% of the unit and is the operator. The approximate fuel storage capacity at each of the generating stations is shown in Figure 5-3.

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 owned by DE-Kentucky. It is anticipated that future units will be governed by similar guidelines.

Scheduling Guidelines for DE-Kentucky 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 reliability. At appropriate times, when it is economic to do so, units may be taken out of service for short periods of time (*i.e.*, less than nine days) to perform maintenance activities. This enhancement in maintenance philosophy reflects DE-Kentucky's focus on having 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 have been performed annually to further focus actions during maintenance and availability outages. Finally, system-wide and plant-specific contingency planning were 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 models (described in Chapter 8) which were used to develop the IRP.

4. Fuel Supply

<u>**Coal**</u>

The goal of DE-Kentucky'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 station, the cost of emissions based on the sulfur content, and the effects of the coal quality on boiler operation and station operation.

DE-Kentucky has set broad fuel procurement policies such as contract/spot ratios and inventory levels that aid in contract negotiations. 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, DE-Kentucky 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. DE-Kentucky also maintains stockpiles of coal at each station to guard against short-term supply disruptions. 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.

Coal supplied to DE-Kentucky currently comes primarily from the states of Ohio, Kentucky, and Illinois. These states are rich in coal reserves with decades of remaining economically recoverable reserves.

East Bend customarily receives approximately 70% to 80% of its annual coal requirements under long-term coal supply agreements. Contract commitments offer 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 DE-Kentucky against primarily upward price fluctuations in the market. This is accomplished using a combination of low fixed-escalation, market price re-openers, and contract extension options and volume flexibilities.

The remainder of the fuel need at East Bend 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.

For Miami Fort Unit 6, coal is procured via long-term contracts and spot market purchases. Approximately 75% of its annual coal requirements are under long-term coal supply agreements. Utilizing both the long-term contract purchase and the spot market purchase allows the Company to secure the benefits of long-term contracts and maintain the flexibility provided by spot purchases to absorb the changes in its coal requirements. The fuels group focuses on coal qualities that are acceptable to the generating plant. Once those coals are identified, suppliers are evaluated based on credit worthiness, SO_2 and Btu adjusted delivered price, coal production basin/ transportation diversity, and supplier diversity. The inventory target for coal inventory at Miami Fort is to provide between 20 to 30 days of coal inventory (running at full load).

Natural Gas

DE-Kentucky's use of natural gas for electric generating purposes has been limited to peaking applications. This natural gas is currently purchased in 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 Fuel Supply and Management Agreement with a third party supplier, Eagle Energy Partners I, L.P. ("Eagle"). Eagle supplies the full requirements of natural gas needed by Woodsdale either by purchasing gas from third parties as an agent or by selling the gas from supplies owned or controlled by Eagle. Eagle nominates the appropriate quantity of gas for transportation on pipelines, either under transportation contracts owned by DE-Kentucky and released to Eagle or on transportation contracts owned by Eagle. The price paid for the gas by DE-Kentucky is equal to the price paid by Eagle, plus a small administrative fee paid to Eagle for these services. The Fuel Supply and Management Agreement allows Woodsdale to obtain natural gas more economically by using Eagle for these services.

Propane

At Woodsdale, propane is used as the back-up fuel in case natural gas is unavailable or as a hedge against high natural gas prices. A Propane Services Agreement with TEPPCO LLC ("TEPPCO") provides DE-Kentucky the ability to purchase propane at market prices. Woodsdale can pull propane from storage owned by DE-Kentucky, where 48,000 barrels of propane storage space is available or use up to 40,000 barrels of propane from TEPPCO on loan for replacement within 45 days.

Oil

At East Bend and Miami Fort 6, DE-Kentucky 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 relatively low volume needs for the foreseeable future.

Opportunity Fuels

Duke Energy 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. Duke Energy 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.

Renewable/Alternate Fuels

Duke Energy continues to research the economics of co-firing biomass in its existing generating units. Historically, Duke Energy has supported the Electric Power Research Institute ("EPRI") and various other research organizations in developing new economically-competitive, environmentally-conscious sources of energy.

DE-Kentucky will continue to explore fuels that can compete with coal for the lowest cost production of electricity. Technologies being considered are Refuse-Derived Fuel ("RDF"), Tire-Derived Fuel ("TDF"), and advanced coal slurry.

DE-Kentucky'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 DE-Kentucky'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 fuel utilization and managing environmental risk.

5. Fuel Prices

The coal and gas prices for both existing and new units utilized in this IRP were developed using a combination of consultants and in-house expertise and judgment. Long-term coal and gas prices were provided by Ventyx. DE-Kentucky's and Ventyx's projected fuel prices are considered by both DE-Kentucky and Ventyx to be trade secrets and proprietary competitive information.

6. Condition Assessment

DE-Kentucky continues to implement its engineering condition assessment programs. The intent is to maintain the generating units, where economically feasible, at their current levels of efficiency and reliability. East Bend has made improvements to the Flue Gas Desulfurization system that increased its SO_2 removal ability along with enhancing controllability and maintainability.

7. Efficiency

DE-Kentucky evaluates the cost-effectiveness of maintenance options on various individual components of the existing generating units. If the potential maintenance options 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.

DE-Kentucky routinely monitors the efficiency and availability of its generating units. Based on those observations, projects that are intended to maintain the long-term performance of the units are planned, evaluated, selected, budgeted, and executed. Such routine periodic projects include combustion and steam turbine-generator overhauls; condenser cleanings and condenser system repairs, such as cooling tower rebuilds and vacuum and circulating water pump rebuilds; burner replacements, coal pulverizer overhauls, and combustion system tuning; secondary air heater basket material replacements; boiler tube section replacements; and pollution control equipment maintenance, such as SCR catalyst replacement and FGD slurry pump rebuilds. In addition, DE-Kentucky looks for opportunities to improve the overall performance of the units, including targeted projects for generating unit efficiency improvements.

Duke Energy has also initiated an internal, voluntary greenhouse gas reduction initiative. This involves additional targeted efficiency improvement projects at the various generating units across the Duke Energy system, including those in Kentucky and Ohio. Examples include circulating water pump and condenser system improvements, improvements in steam cycle isolation, reductions in boiler system air in-leakage, and combustion system advanced controls tuning.

However, any plans to increase fossil fuel generation efficiency must be viewed in light of regulatory requirements, specifically the EPA's new source review ("NSR") rules. These regulatory requirements are subject to interpretation and change over the years. Within the context of such requirements, DE-Kentucky plans routine maintenance projects, which may maintain or increase the efficiency of its generating units. All of these plans are subject to change depending on the changing regulatory environment and rules related to NSR.

8. Environmental Regulations

The technology available to meet environmental regulations adds constraints to the power plant fuel cycle and also requires energy to operate. The net result is a reduction in the 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 for new resources to replace the reduction in capacity.

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 non-catalytic reduction ("SNCR") technology, 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 trona) and baghouses for mercury control and SO_2 control; and 5) cooling towers or other closed-cycle cooling systems for reducing the potential impact of thermal discharges and fish entrainment/impingement from water intake systems. In addition to these emission/environmental-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 can be an effective combination in reducing mercury emissions as well for many units. Similarly, baghouses for particulate control are also effective in reducing mercury emissions when carbon injection is added.

East Bend Unit 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 the unit by about 1.2% to 1.6%. An SCR was also added in 2002 for compliance with the NO_x SIP Call. An approximate 0.6% capacity and efficiency impact is caused by this equipment currently during the ozone season. This effect will be annualized due to the new

CAIR Annual NO_x program which will require annual operation of the SCR beginning in 2009.

The environmental standards limiting the stack discharge of particulates have necessitated retrofitting and/or upgrading precipitators on both existing generating units. The upgraded precipitators will generally require more auxiliary power. 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 retrofitted control technologies on generating unit output and the efficiency of the fuel cycle, Table 5-1 shows the approximate impacts.

Table 5-1

ESTIMATED IMPACTS OF NEW CONTROL TECHNOLOGIES

TECHNOLOGY	Abbreviation	Impact on Output	Impact on Efficiency*
Selective Catalytic Reduction System	SCR	-0.6%	-0.6%
Selective Non- Catalytic Reduction System	SNCR	-0.1%	-0.1%
Flue Gas Desulfurization System	FGD	-4.0%	-4.0%
Activated Carbon Injection plus Baghouse	ACI plus BH	-0.5%	-0.5%
Baghouse Filtration Product no ACI	BH	-0.5%	-0.5%

Negative values indicate a reduction in the output or efficiency.
*A decrease in efficiency translates to an increase in heat rate.

The Woodsdale simple-cycle combustion turbines require water injection to control NO_x emissions. Additional capital expenditures were required for wells or other water sources, water treatment, storage, injection systems, and controls. The addition of these systems also reduces unit efficiency and reliability. Any future simple-cycle combustion turbine additions may require similar water injection systems, or additional special dry low NO_x combustors, SCR technology, or a combination of these technologies. Specific changes to DE-Kentucky's existing coal-fired units as a result of recent SO_2, NO_x, and mercury regulations are discussed in Chapter 6.

The capital cost required for the construction of closed-cycle 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). East Bend Unit 2 was constructed with such a closed-cycle cooling-tower system. The closed-cycle 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 has increased, and will continue to increase, the cost of producing electricity.

Implementation of CAIR Phase 1 projects, and other future regulations or legislation to reduce air emissions (such as a potential mercury MACT regulation) will also increase the cost of electricity production (see Chapters 6 and 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.

DE-Kentucky generally 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, capture, and sequestration; 7) combustion by-product use; and 8) mercury reduction.

For DE-Kentucky, the solid waste streams of significance are the coal combustion by-products. These include the fly ash, bottom ash, and the fixated sludge from the scrubbers. Historically, DE-Kentucky has disposed of the fly and bottom ash in mono-purpose solid waste disposal 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 DE-Kentucky's continued commitment to pollution prevention. This effort will lead to a continued search for alternative reuses of these materials. Duke Energy

Midwest has experience with selling fly ash as a component of building materials and will continue to explore the potential for this in the future. In addition, Duke Energy Midwest has experience selling gypsum, a by-product of the wet forced-oxidation FGD process, to the wallboard industry and will continue to explore this potential.

As is common with most industrial operations, some DE-Kentucky facilities generate small quantities of hazardous wastes. These wastes are generally related to basic equipment maintenance activities, rather than being specifically related to the process of energy generation or delivery. Examples of such wastes include spent solvents from parts cleaning, paint-related wastes, *etc*. DE-Kentucky facilities normally operate as either Conditionally Exempt Small Quantity Generators (<100 kg in a month), or as Small Quantity Generators (<1000 kg in a month). Only on rare occasions will any DE-Kentucky facility generate enough hazardous waste to be classified as a Large Quantity Generator (>1000 kg in a month). All hazardous wastes generated by DE-Kentucky are properly characterized prior to disposal at appropriately permitted disposal facilities. The specific disposal facility chosen for a given waste will depend on the nature of that particular waste. DE-Kentucky's largest volume waste streams are byproducts from the combustion of coal (fly ash, bottom ash, scrubber sludge, *etc*.). These wastes have been extensively studied by the EPA and their reports to Congress have concluded that coal combustion byproducts do not present threats to the environment adequate to merit management as hazardous waste.

9. Age of Units

As part of Administrative Case No. 2005-00090, the Commission required that each of the jurisdictional generating utilities address issues relating to their older generating units in their next scheduled IRP filing. The oldest units on DE-Kentucky's system are Miami Fort Unit 6, which is 48 years old, and East Bend Unit 2, which is 27 years old. DE-Kentucky does not have any current plans to retire either of these units within the 20 year timeframe of this IRP.

Generating unit age alone is not the sole identifier for the likelihood of equipment failure. It is generally true that older generating units have increased probability of failure of any given component due to wear-and-tear over its lifetime. It is also generally true, however, that newer units, while having less equipment wear-and-tear, are more complex (such units are generally larger and thus have more components, and are more commonly equipped with modern environmental controls such as cooling towers, and FGD and SCR systems). How generating units are operated (*i.e.*, operation within manufacturers recommended specifications; cycling duty; ramp rate, *etc.*) and maintained throughout their economic lifetime also helps to determine the likelihood of a failure event. Thus, how a generating unit is initially designed, constructed, as well as operated, and maintained during its lifetime, all play a role in the probability of failure.

As discussed earlier, DE-Kentucky routinely monitors the efficiency and availability of its generating units. Based on those observations, projects that are intended to maintain the long-term performance of the units are planned, evaluated, selected, budgeted, and executed. DE-Kentucky performs routine maintenance activities on its generating units to maintain the efficiency and reliability of those units at current levels. Using standard industry practices, generating unit support and auxiliary equipment and/or sub-systems that are nearing their normal useful lives are identified and repaired, prior to failure and the resultant loss of overall unit availability. Examples of such practices might include: vibration monitoring, lube oil analyses, visual inspections, including boroscopic inspection of difficult-to-access areas; non-destructive examination ("NDE") such as boiler tube thickness measurement surveys, dye-penetrate crack testing, eddy-current thickness testing, and nuclear material analysis; and sometimes even destructive examinations such as taking boiler tube samples or high-energy piping "boat" samples. All of these methods of monitoring are intended to identify equipment condition so that equipment failure can be predicted and avoided.

Using such monitoring and testing methods, along with manufacturer-recommended operating practices, and diligent maintenance practices, a given generating unit may continue operating reliably and efficiently for many years. Even under such conditions, however, instances of unanticipated equipment failure still occur. Normally, though, such events do not result in a significant loss of unit availability (more than two weeks of unit outage). Rarely in the industry does a catastrophic failure result in the permanent complete loss of a generating asset.

Finally, few technological breakthroughs have occurred relating to coal-fired steam units since the early-1950s, before which times the efficiency of the generally much smaller units (less than 100 MW) without re-heat steam cycles may have forced generating units into technological obsolescence. Supercritical steam cycles offered some incremental improvements to unit efficiencies since the 1950s, but because coal costs are lower and historically less volatile than more premium fuel types, these changes were not enough to force technological obsolescence.

C. EXISTING NON-UTILITY GENERATION

DE-Kentucky does not currently have any contracts with non-utility generators.

Some of DE-Kentucky'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 DE-Kentucky which, like DSM programs, also reduces the need for new capacity. Some of these customers are participants in DE-Kentucky's PowerShare® program which was discussed in Chapter 4.

D. EXISTING POOLING AND BULK POWER AGREEMENTS

At present, DE-Kentucky does not participate in any formal type of power pooling. However, DE-Kentucky participates in the Midwest ISO Energy Markets as discussed in Chapter 2. DE-Kentucky co-owns East Bend Unit 2 with Dayton Power & Light. Miami Fort Unit 6 is located at the Miami Fort Station, at which Duke Energy Ohio owns additional coal-fired units and several CTs.

Duke Energy Midwest 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, DE-Kentucky contacts neighboring utilities, utilities beyond them, power marketers, and power brokers on a daily basis in the interest of promoting opportunistic purchases and sales. DE-Kentucky 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.

E. NON-UTILITY GENERATION AS FUTURE RESOURCE OPTIONS

It is DE-Kentucky'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. DE-Kentucky typically receives several requests a year for independent/small power production and cogeneration buyback rates. DE-Kentucky does not currently have any contracts for cogeneration. However, DE-Kentucky has two cogeneration tariffs available to customers. DE-Kentucky will supply any customer interested in cogeneration with a copy of these tariffs and will discuss options with that 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 DE-Kentucky's comparatively low electricity rates and avoided cost buyback rates, cogeneration and small power production are generally uneconomical for most customers.

For these reasons, DE-Kentucky does not attempt to forecast specific megawatt levels of this activity. 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 represents 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. If 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.

Duke Energy has direct involvement in the cogeneration area. Duke Energy Generation Services, an unregulated affiliate of DE-Kentucky, 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 CTs, CC units, 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 DE-Kentucky initiates the acquisition of new capacity, a decision will be made as to the best source.

F. SUPPLY-SIDE RESOURCE SCREENING

Experience from the many technology screening analyses performed for all of Duke Energy's jurisdictions allowed a more focused approach to resource screening for this IRP. A diverse range of technology choices utilizing a variety of different fuels was considered including pulverized coal units, IGCC, CTs, CC units, and nuclear units. In addition, relative to previous filings, renewable technologies such as wind, biomass, hydro, animal waste, and solar received a greater focus in this year's screening analysis.

For the 2008 IRP screening analyses, technology types were screened within their own general category of baseload, peaking/intermediate, and renewable, with the ultimate goal of screening being to pass the best alternatives from each of these three categories to the integration process, as opposed to, for instance, having all renewable technologies screened out because they didn't fare well against the more conventional technologies on the final screening curve. As in past years, the reason for performing these initial screening analyses is to determine the most viable and cost-effective resources for further evaluation. This is necessary because of the size of the problem to be solved and computer execution time limitations of the System Optimizer integration model (described in detail in Chapter 8).

1. Process Description

Information Sources

The cost and performance data for each technology being screened are based on research and information from several sources. These sources include, but may not be limited to the following: Duke Energy's New Generation Team, Duke Energy Analytical and Investment Engineering group, the EPRI Technology Assessment Guide (TAG®), studies performed by and/or information gathered from entities such as the DOE, LaCapra, Navigant, Fibrowatt, and others. In addition, fuel and operating cost estimates are developed internally by Company personnel, or from other sources such as those mentioned above, or a combination of the two. The EPRI information along with any information or estimates from external studies are not site-specific, but generally reflect the costs and operating parameters for installation in the Midwest.

Finally, every effort is made to ensure, as much as possible, that the cost and other parameters are current, on a common basis, and include similar scope across the technology types being screened. While this has always been important, keeping cost estimates across a variety of technology types consistent in today's construction material, manufactured equipment, and commodity markets, is getting very difficult. The rapidly escalating prices in these markets often make cost estimates and other price/cost information out-of-date in as little as six months. In addition, vendor quotes and/or other estimates once relied upon as being a good indicator of, or basis for, the cost of a generating project, may have lives as short as 30 days.

Technical Screening

The first step in the supply-side screening process was a technical screening of the technologies to eliminate those that have technical limitations, commercial availability issues, or are not feasible in the DE-Kentucky service territory. A brief explanation of the technologies excluded at this point and the logic for their exclusion follows:

- Geothermal was eliminated because there are no suitable geothermal resources in the region to develop into a power generation project.
- Advanced Battery storage technologies remain relatively expensive and are generally suitable for small-scale emergency back-up and/or power quality applications with short-term duty cycles of three hours or less. In addition, the current energy storage capability is generally 100 MWh or less. Research, development, and demonstration continue, but this technology is generally not commercially available on a larger utility scale.
- Compressed Air Energy Storage ("CAES"), although demonstrated on a utility scale and generally commercially available, is not a widely applied

technology. This is due to the fact that suitable sites that possess the proper geological formations and conditions necessary for the compressed air storage reservoir are relatively scarce.

- Coal-fired Circulating Fluidized Bed combustion is a conventional commercially-proven technology in utility use. However, boiler size remains generally limited to 300-350 MW, typically reducing any advantages in lowering the installed capital cost per kilowatt for large scale baseload unit sizes. In addition, the new source performance standards ("NSPS") generally dictate that post-boiler flue gas clean-up equipment must be installed to meet the standards when burning coal, which effectively eliminates one of the advantages of this technology. Both of these issues cause it to be one of the higher-cost baseload alternatives available on a utility scale. Nevertheless, it is still a viable technology on a utility scale to burn low-grade or "waste" coals and may be economic if long-term supplies of relatively low cost fuels of this type can be secured.
- Fuel Cells, although originally envisioned as being a competitor for combustion turbines and central power plants, are now targeted to mostly distributed power generation systems. The size of the distributed generation applications ranges from a few kilowatts to tens of megawatts in the long-term. Cost and performance issues have generally limited their application to niche markets and/or subsidized installations. While a medium level of research and development continues, this technology is not commercially available for utility-scale application.

The recent interest in adopting RPS in several states has led to a deeper investigation into renewable technologies. This included an initial compilation of information from over a dozen sources on eight broad categories of renewable technologies and six subcategories within these eight. In addition to this, information from five specific wind projects was included within this compilation. Based on this information, the renewable technologies that were added to the screening analyses for this IRP include:

- Poultry Waste
- Fluidized Bed Biomass
- Solar Photovoltaic
- Solar Thermal Gas Hybrid
- Hog Waste Digester
- Wind

Economic Screening

In the supply-side screening analysis, the fuel prices for coal and gas, and emission allowance prices were the same as those utilized downstream in the System Optimizer analysis (discussed in Chapter 8). The biomass fuel price was derived from various vendor fuel and delivery prices. The biomass fuel price may vary in the future as more utilities begin to use biomass fuel to co-fire.

The technologies were 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 Duke Energy. This model is considered confidential and competitive information by Duke Energy.

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. Some of the renewable resources that have known limited energy output, such as wind and solar, have screening curves limited to their expected operating range on the individual graphs. In addition, although the Solar Thermal Gas Hybrid can operate at very high capacity factors on natural gas fuel, the screening curves include only the solar-fueled portion, with the remainder of the curve being similar to a simple-cycle CT curve's slope.

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 ranges, have a very low probability of being part of the least cost solution, and generally can be eliminated from further analysis.

2. Screening Results

The results of the screening within each category are discussed in more detail below[1]. The technologies were screened with consideration of CO_2 emissions.

<u>Baseload Technologies</u>

Figure GA-5-4 in the General Appendix shows the screening curves for the baseload category of screening. Nuclear becomes economic compared to Pulverized Coal at about 70% capacity factor. The two coal technologies are

[1] While these estimated levelized screening curves provide a reasonable basis for initial screening of technologies, simple levelized screening has limitations. In isolation, levelized cost information has limited applicability in decision-making because it is highly dependent on the circumstances being considered. A complete analysis of feasible technologies must include consideration of the interdependence of the technologies and DE-Kentucky's existing generation portfolio, as is performed within the System Optimizer and Planning and Risk analyses.

shown without any CO_2 capture technologies installed. The capital and operating costs for carbon capture technology are still the subjects of ongoing industry studies and research, along with the feasibility and costs of geological sequestration of CO_2 once it is captured.

Peak / Intermediate Technologies

Figure GA-5-5 shows the screening curves for the peak / intermediate category. The simple-cycle CT unit makes up the lower envelope of the curves up to about 15% capacity factor, where the Unfired (duct firing Off) is the most economic over the rest of the capacity factor range.

Duct firing in a CC unit is a process to introduce more fuel (heat) directly into the combustion turbine exhaust (waste heat) stream, by way of a duct burner, to increase the temperature of the exhaust gases entering the Heat Recovery Steam Generator ("HRSG"). This additional heat allows the production of additional steam to produce more electricity in the steam (bottoming) cycle of a CC unit. It is a low cost ($/kW installed cost) way to increase power (MW) output during times of very high electrical demands and/or system emergencies. However, it adversely impacts the efficiency (raises the heat rate) and thereby dramatically increases the operating cost of a CC unit (notice the much steeper slope of the duct firing "On" cases in the screening curve figures). Duct firing also increases emissions, generally resulting in a very limited number of hours per year that duct firing is allowed within operating permits.

Within the screening curves, the estimated capital cost for a combined cycle unit always includes the duct burner and related equipment. The two curves, one "On," and one "Off," are intended to show the efficiency loss (steeper slope) when the duct burner is "On", but also show that even with the duct burner "On" the efficiency (slope) is still better than a simple-cycle CT unit (much steeper slope). The duct burner "Off" curve is where the combined cycle unit will operate most of the time, and this is the one best compared with all other candidate technologies.

Renewable Technologies

Figure GA-5-6 shows the screening curves for the renewable category of screening. One must remember that busbar charts comparisons involving some renewable resources, particularly wind and solar resources, can be somewhat misleading because these resources do not contribute their full installed capacity at the time of the system peak[2]. Since busbar charts attempt to levelize and compare costs on an installed kW basis, wind and solar resources appear to be more economic than they would be if the comparison was performed on a peak kW basis.

[2] For purposes of this IRP, wind resources are assumed to contribute 15% of installed capacity at the time of peak and solar resources are assumed to contribute 70% of installed capacity at the time of peak.

Since these renewable technologies either have no CO_2 emissions or are deemed to be carbon neutral, the cost of CO_2 emissions does not impact their operating cost. Wind appears to be the least cost renewable alternative through its maximum practical capacity factor range. Next, Poultry Waste and Solar Thermal Gas Hybrid are relatively close with Poultry Waste more economic than Solar Thermal Gas Hybrid in all cases but a very small band of capacity factors from about 25% to about 30%, where the Solar Thermal Gas Hybrid appears to be lower cost by a very small margin (recall that at capacity factors above 30% the slope of the Solar Gas Hybrid curve would follow the relatively steep path of a simple-cycle CT). The Fluidized Bed Biomass is generally the next least costly alternative up to the 85% capacity factor range where the Hog Waste Digester appears to be the more economic of the two.

<u>Renewable Technologies – Further Discussion and Considerations</u>

There is a gradual emergence of renewable and alternative resource technologies in the Duke Energy Midwest service territory. Commercial wind developers are currently investigating the more promising wind resource regions in Northwestern Indiana. Typically, wind resources are greater at higher heights above ground level, usually in the 80 to 100 meter heights. At these heights, the Midwest Low Level Jet stream enhances a phenomenon known as "wind shear". This phenomenon provides for a better wind resource the higher wind turbine rotors are placed, which leads to improved capacity-utilization factors for the wind turbines. The higher location of wind resources requires the center of the wind turbine rotor (*i.e.* the nacelle and hub) to be located on 80 meter towers. These higher towers require additional capital costs for tower material and larger tower foundations.

In addition, the actual capacity that would be available from wind resources generally does not coincide well with DE-Kentucky's power supply system requirements. At the time of summer peak (when the capacity is needed the most), the available wind resource is significantly less or not available at all. 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 dispatchable capacity of a conventional technology resource. Even then, there is no guarantee that the wind power resources will be available when needed.

Solar energy continues to grow in popularity throughout the world in areas with either government mandates, such as RPS, or good solar power density (insolation). Duke Energy Midwest is continuing its work with solar energy to study the supply curve shape of solar power and to use demonstration projects to promote and raise awareness of solar technology. The two types of solar included in the renewable category, the Solar Photovoltaic and the Solar Thermal Gas Hybrid, can be considered as placeholders for solar technology in general. However, when considering current costs, solar power is still not cost-competitive for bulk power production in the Midwest as is generally indicated on the renewable screening curves even when only compared to other renewable resources.

Landfill gas is another source of alternative energy that generally has 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 preferred to collect and transport this low-Btu gas short distances where it can be used in various manufacturing processes. This "landfill to boiler" activity is generally best suited to private enterprise ventures, not utility-scale projects. To Duke Energy Midwest's knowledge, only a small number of private companies currently utilize landfill gas within Duke Energy Midwest's service territory. Generally, landfill gas is consumed as boiler fuel, or to generate power on a small scale which is introduced into the grid at the distribution voltage level.

Biogas generally represents a fuel that is associated with waste water treatment plants or anaerobic digesters at very large livestock operations (*e.g.* large dairy or hog operations). This type of power generation is complementary to the primary operation of waste treatment. The environmental benefits resulting from a reduction in the land application of manure also include an ancillary benefit of power generation. A dairy farm operation in Northwest Indiana is a prime example of this application. The Hog Waste Digester considered in the renewables screening analysis is generally a placeholder for this type of resource, with Poultry Waste as a related technology.

Combustion of Municipal solid waste ("MSW") is rarely done solely to produce energy. Generally, when communities resort to MSW combustion it is to offset landfilling, not to generate low-cost energy. In most instances, however, the energy sales do help to offset some of the costs associated with MSW combustion. Siting a MSW combustion facility is usually a challenge as local opposition can be great. In addition, most states and national green energy certifying organizations do not consider combustion of MSW a renewable source of energy eligible to meet RPS.

Dedicated biomass energy production facilities are generally limited by the availability of fuel, which, due to low heat content, can be cost-prohibitive if transported greater than about 50 miles. The Fluidized Bed Biomass technology in the renewable category is a placeholder for this. Also, the use of this fuel in an existing pulverized coal power plant can result in material handling and storage problems and additional expense can be incurred at high blend ratios due to upgrading fuel handling and feed systems designed for pulverized coal, and unit derates due to low heat content. These limitations negatively impact both the size and economics of biomass energy production in existing power plants. However, in areas where biomass is available and is close to existing power plants, co-firing biomass in existing coal-fired boilers in relatively low blend ratios of about 10% or less (exact blend ratios that can be tolerated by existing equipment depend on the specific unit) may be one of the most economical ways for utilities to meet RPS requirements for very high levels of renewable energy compared to other renewable alternatives, or where other renewable sources are not available.

Despite the fact that Alternative Technologies are generally not economic in comparison to more traditional technologies, with the heightened interest in renewables as they relate to global climate change, and with many states adopting requirements or goals related to renewable energy production and use, they were included 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. In addition, since the exact levels (MW capacity, and MWh energy potential) of each of the renewable resources considered in the screening is not known, all of the technologies in the renewable category included in the screening curves were passed on to the System Optimizer portion of the IRP analyses.

3. Other Technologies Considered

Other Hydro Resources

New hydro resources tend to be very site-specific; therefore, DE-Kentucky normally evaluates both pumped storage capacity and run-of-river energy resources on a project-specific basis. In addition, even though hydro is a renewable resource that does not emit CO_2, some states and other organizations do not consider it as such within the context of meeting RPS.

Repowering Resources

In general, the cost estimate for combined cycle repowering is similar to the cost of a new CC 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 any feasible existing sites will be investigated prior to initiating construction of a CC facility at a new site.

4. Final Supply-Side Alternatives

Figure GA-5-7 in the General Appendix shows the final screening curves containing the curves from all three of the general categories on a single graph. It is within this graph that all technologies reveal their relative costs against the competing technologies.

The simple-cycle CT is least cost in the low capacity factor region below 10%. The next least cost alternative is the CC Unit with the duct firing off, followed by Wind (assuming wind can achieve capacity factors above about 20%). After Wind, the Combined Cycle Unit is economic up to about 70% capacity factor. Above 70% capacity factor, the Nuclear unit appears to be economic.

As a result of the learning and experience from past screening analyses, together with the increased focus on renewable resources within this IRP screening process, the following supply technologies were selected to be candidate supply-side resources in the System Optimizer dynamic integration computer runs[3]:

1) 100 MW Wind (renewable)

2) 80 MW Solar Thermal Gas Hybrid (renewable)

3) 2x1,117 MW Nuclear

4) 4x160 MW Simple-Cycle CT

5) 800 MW Supercritical Coal

6) 10 x 5 MW Solar Photovoltaic - Fixed Flat Plate (renewable)

7) 75 MW Fluidized Bed Biomass (renewable)

8) Hog Waste Digester (renewable)

9) Poultry Waste (renewable)

10) 460 MW Unfired + 120 MW Duct Fired + 40 MW Inlet Chilling CC (620MW total)

11) 460 MW Unfired + 40 MW Inlet Chilling CC (500 MW total)

12) 630 MW Class IGCC Coal

More detailed information on the final supply side technologies screened can be found in Figure GA-5-8. Since the emissions of each of these potential resources will be modeled in the integration process, their effects on compliance with air emission rules and/or regulations will be factored into the analysis.

[3] Due to the relatively small size of the DE-Kentucky system and the small amount of additional capacity needed over the study period, some of the generic supply-side options were modeled in blocks smaller than the normal sizes of these units. See Chapter 8 for additional discussion.

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, or part of a least cost solution, under base assumptions, become part of that solution.

This methodology using the screening model (rather than performing all sensitivities within System Optimizer at the end of the analysis) is more efficient and provides a better understanding of the magnitude of changes in input variables such as: fuel prices, capital costs, *etc.*, that will affect resource decisions.

Gas-Fired vs. Coal-Fired Capacity

A sensitivity study showed a reduction in gas prices of 45% is necessary before the coal-fired units and nuclear are no longer competitive at baseload capacity factors (see Figure GA-5-9). Similarly, an increase of 45% in coal prices is necessary before the combined cycle unit dominates the coal-fired units at both baseload and peak/intermediate capacity factors (see Figure GA-5-10).

Wind

As discussed earlier, the screening curve analysis greatly overstates the value of Wind due to the reduced level of capacity actually available on peak. Therefore, performing sensitivity analysis on wind alternatives during the screening stage would not yield any useful information. Instead, the Wind alternative was included in the System Optimizer integration stage of the IRP, where additional sensitivity analysis was performed (see Chapter 8 for more details).

Solar

For solar to be economical in a relevant capacity factor range, the estimated capital cost must be reduced by 70% to compete with Wind and Combined Cycle units (see Figure GA-5-11), and, even then, the insolation is limited in the Midwest. Because of the high capital cost of solar units, even if gas prices were four times their base case levels, the technology would not be competitive (see Figure GA-5-12).

Biomass

For the Biomass unit to become competitive with a CC unit, an 80% decrease in biomass fuel would be necessary (see Figure GA-5-13). Alternatively, gas prices would have to be double their base case levels for the Biomass unit to be competitive (see Figure GA-5-14).

Summary of Screening Sensitivities

All technologies contained in the final screening curves were ultimately passed to the System Optimizer integration portion of the analysis. However, the sensitivity exercises indicate the magnitude of changes in input parameters necessary to make some of the less economic, or non-economic, resource alternatives part of an economic solution.

6. Unit Size

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. In the case of very large unit sizes such as those utilized for the Nuclear and/or Supercritical Coal technology types, if these are routinely selected as part of a least cost plan, joint ownership can and may be pursued.

7. Cost, Availability, and Performance Uncertainty

Supply-side alternative project scope and estimated costs used for planning purposes for conventional technology types such as simple-cycle CT units and CC units are relatively well known and are estimated in the TAG® and can be obtained from architect and engineering ("A&E") firms and/or equipment vendors. Duke Energy's experience is also used to confirm their reasonability. The cost estimates include step-up transformers and a 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, typical values for additional transmission costs were added to the alternatives. A listing of the projected generating facility estimated costs (in 2008 dollars, including AFUDC) from the screening curves can be found in Figure GA-5-8. The unit availability and performance of conventional supply-side options is also relatively well known and the TAG®, A&E firms and/or equipment vendors are sources of estimates of these parameters. However, as noted earlier, keeping cost estimates consistent across a variety of technology types in today's construction cost market environment is becoming very difficult.

8. Lead Time for Construction

The estimated construction lead time and the lead time used for modeling purposes for the proposed simple-cycle CT units is about two years. For the CC 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.

9. RD&D Efforts and Technology Advances

New energy and technology alternatives are needed to ensure a long-term sustainable electric future. Duke Energy Midwest's research, development, and delivery ("RD&D") activities enable Duke Energy Midwest to track new options including modular and potentially dispersed generation systems, CTs, and advanced fossil technologies. 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. Duke Energy is also a member of EPRI.

Within the horizon of this forecast, it is expected that significant advances will continue to be made in CT technology. Advances in stationary industrial CT technology should result from ongoing research and development efforts to improve both commercial and military aircraft engine efficiency and power density, as well as expanding research efforts to burn more hydrogen-rich fuels. The ability to burn hydrogen-rich fuels will enable very high levels of CO_2 removal and shifting in the syngas utilized in IGCC technology, thereby enabling a major portion of the advancement necessary for a significant reduction in the carbon footprint of this coal-based technology.

10. 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 units that are larger than needed for DE-Kentucky's requirements 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.

Figure 5-1

DUKE ENERGY KENTUCKY

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, SO_2 Scrubber, SCR, & TRO
Miami Fort North Bend, Ohio		6	CF-S	11-1960	Unknown	163,000	163,000	EP, LNB, & OFA
Woodsdale Trenton, Ohio	B	1	GF/PF-GT	5-1993	Unknown	83,433	94,000	WI
	B	2	GF/PF-GT	7-1992	Unknown	83,433	94,000	WI
	B	3	GF/PF-GT	5-1992	Unknown	83,433	94,000	WI
	B	4	GF/PF-GT	7-1992	Unknown	83,433	94,000	WI
	B	5	GF/PF-GT	5-1992	Unknown	83,433	94,000	WI
	B	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
GF = Natural Gas Fired
PF = Propane Fired

S = Steam
GT = Simple-Cycle Combustion Turbine

EP = Electrostatic Precipitator
CT = Cooling Towers
WI = Water Injection, NOx
LNB = Low NOx Burners
OFA = Overfire Air
SCR = Selective Catalytic Reduction
TRO = Trona Injection System

FOOTNOTES:

(A) Unit 2 is commonly owned by Duke Energy Kentucky (69% - Operator) and The Dayton Power and Light Company (31%). Earlier vintage LNB installed.

(B) Unit Ratings are at Ambient Temperature Conditions of: Summer - 90 degF; Winter - 20 degF and include inlet misting capability

Figure 5-2

Maximum Net Demonstrated Capaility of Jointly Owned Generating Units

Station Name and Location	Unit Number	Installation Date	Total MW Summer	Total MW Winter	DEK Share Summer	DEK 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 5-3

APPROXIMATE FUEL STORAGE CAPACITY

Generating Station	Coal Capacity (Tons)	Oil Capacity (Gallons)	Propane Capacity (Barrels)
East Bend	500,000	500,000	--
Miami Fort	350,000	4,300,000	--
Woodsdale	--	--	48,000

6. ENVIRONMENTAL COMPLIANCE

A. INTRODUCTION

The purpose of the environmental compliance planning process is to develop an integrated resource/compliance plan that meets the future resource needs of DE-Kentucky 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.

B. CLEAN AIR ACT AMMENDMENTS ("CAAA") PHASE I COMPLIANCE

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

C. CAAA PHASE II COMPLIANCE

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

D. NO_x SIP CALL COMPLIANCE PLANNING

A detailed description of Duke Energy's NO_x SIP Call compliance planning process can be found in the former Cinergy 1999, 2001, and 2003 IRPs.

E. CLEAN AIR INTERSTATE RULE AND CLEAN AIR MERCURY RULE

1. Final CAIR Regulations

In March 2005, the EPA issued CAIR which required states to revise their SIPs by September 2006 to address alleged contributions to downwind non-attainment with the revised National Ambient Air Quality Standards for ozone and fine particulate matter. The rule, which was first proposed in 2004, establishes a two-phased, regional cap-and-trade program for sulfur dioxide and nitrogen oxides, affecting 28 states, including Kentucky and Ohio. CAIR requires NO_x and SO_2 emissions to be cut by 65 percent and 70 percent, respectively, by 2015, with the first phase of reductions by 2009 and 2010, respectively. CAIR contains a model cap-and-trade rule that states may include in their SIPs, but, regardless, states must comply with the prescribed reduction levels under CAIR. Under CAIR, companies have flexible compliance options including installation of pollution controls on large plants where such controls are particularly efficient and utilization of emission allowances for smaller plants where controls are not cost effective. States also have flexibility in development of their SIPs within the model cap-and-trade rule, such as allowance allocation processes.

In the final rule, EPA set the NO_x compliance deadline for the annual program to 2009, versus 2010 which was in the 2004 proposed rule. The 2009 deadline more closely matches the dates by which many ozone non-attainment areas have to be in compliance. In addition, in EPA's opinion, due to the large existing base of

SCRs resulting from the NO_x SIP Call, there would not be any reliability problems caused by moving the deadline forward one year.

Although the CAIR rule adds an annual NO_x emission cap, EPA also retained the requirement for a separate ozone season cap. The new CAIR ozone season program will replace the NO_x SIP Call ozone season program starting 2009. The Phase I provisions of the programs are very similar, however.

EPA assigns NO_x emission budgets for the annual and ozone season programs to each state. EPA has developed a model rule which is suggested for use by the states when allocating NO_x allowances in the states' final implementation rules. EPA calculated each state's share of the total CAIR caps in 2009 and 2015. When EPA calculated each state's cap in the final rule, it included adjustment factors based on whether a unit burns coal, oil or gas, since those fuels give off differing amounts of NO_x. However, it did not change the size of the total NO_x cap, but only the amounts each state received. Thus, economic theory would suggest that there should be no change in the price of allowances in competitive markets. Kentucky's share of the annual NO_x cap is 83,205 tons and 69,337 tons for 2009-2014 and 2015 and beyond, respectively. Ohio's share (Miami Fort Unit 6 is physically located in Ohio) of the annual NO_x cap is 108,667 tons and 90,556 tons for 2009-2014 and 2015 and beyond, respectively.

EPA recommends to the states that NO_x emission allowance allocations should be based on each unit's prorated share of the state cap reflecting the average of the highest three years of heat input of the period 2000 through 2004. However, states are free to develop alternative methodologies. In the case of Kentucky, the state SIP baseline period is 2001-2005, and in Ohio the baseline period is 1998-2005.

Also, similar to the NO_x SIP Call, a pool of annual NO_x allowances (totaling 200,000 tons) was created and apportioned to each of the affected CAIR states. This Compliance Supplement Pool (also known as early reduction credits) is earmarked for companies that choose to operate NO_x control equipment outside of the ozone season prior to 2009, and thus generate early NO_x reductions. This pool of 200,000 allowances essentially raises the Phase I annual NO_x cap by the same number of tons, which makes it slightly easier to comply with the Phase I requirements. In the case of Kentucky and Ohio, this works out to 14,935 and 25,037 allowances, respectively, that the States can distribute to companies that reduce annual NO_x emissions during 2007 or 2008.

For SO_2, there were not any changes made in the Acid Rain SO_2 requirements in the final CAIR. EPA cannot change the statutory elements of that program. DE-Kentucky's SO_2 allowance allocations did not change under the new CAIR, since the Federal Acid Rain program established by Congress is still in effect. EPA has imposed, instead, that holders of vintage 2010 to 2014 SO_2 Acid Rain EAs will be required to surrender two EAs for every ton of SO_2 emitted. Holders of vintage 2015 and beyond EAs would need to surrender 2.86 EAs to emit one ton of SO_2.

Upon signature of the final rule, the states had 18 months to implement the new requirements. Kentucky's and Ohio's SIPs were both approved in October 2007.

2. Final CAMR Regulations

In March 2005, the EPA issued CAMR which required the reduction of mercury emissions from coal-fired power plants for the first time. The CAMR adopted a two-phase cap-and-trade program that would have cut mercury emissions by 70 percent by 2018 with the first phase in 2010. Under the cap-and-trade program, companies had flexible compliance options including installation of pollution controls on large plants where such controls are particularly efficient and utilization of emission allowances for smaller plants where controls are not cost effective. States also had flexibility in development of their SIPs within the model cap-and-trade rule, such as allowance allocation processes. The states could also choose to not participate in the cap-and-trade program and instead prescribe more stringent rules. Both Kentucky and Ohio have developed state SIP rules that mirror the federal model cap-and-trade rule.

In EPA's proposed regulations, it offered two alternate approaches to reduce mercury emissions: (1) a traditional MACT command-and-control emissions standard; or (2) a cap-and-trade program for mercury similar to the SO_2 and NO_x

programs for coal-fired power plants. In the final rule, EPA established a mercury cap-and-trade program under Section 111 of the Clean Air Act versus requiring MACT reductions at each power plant under Section 112. The cap-and-trade reductions would be accomplished through a two step reduction. Phase I capped emissions at 38 tons of mercury emissions in 2010, while the Phase II cap was 15 tons starting in 2018. The Phase I cap was set based on the expected mercury co-benefits achieved by the CAIR program.

Similar to the CAIR rule, EPA provided a mercury emission budget to each state and recommended methods for allocating the state budgets to the CAMR-affected units. However, states were free to develop alternative methodologies of allocating allowances, and, as was experienced with the NO_x SIP Call rulemaking, most states developed alternative approaches that ultimately gave existing sources fewer allowances. Several states, including the neighboring state of Illinois, opted out of the cap-and-trade program and instead required MACT-standard compliance.

3. The Vacatur of CAMR

On February 8, 2008, a 3-judge panel of the Circuit Court of Appeals for the District of Columbia ruled that EPA incorrectly "de-listed" coal-fired generating units from requiring mercury regulation under Section 112 of the Clean Air Act. Following this ruling, the entire Clean Air Mercury Rule, which was based on a cap-and-trade compliance mechanism under Section 111 of the CAA, was completely vacated by the court. These actions have left a huge veil of uncertainty regarding future mercury emission compliance requirements. It is now reasonably likely that any new EPA regulation regarding mercury emissions will be a MACT standard. This could require compliance on a unit-specific or facility-wide basis, and result in additional emission control installations beyond that expected under the original CAMR. It could be several more years before the final requirements of the CAMR are known.

4. CAIR/CAMR Compliance Plan – Phase I

As part of the transfer of assets into Kentucky, two environmental compliance projects, upgrade of the original FGD system at East Bend Unit 2, and installation of advanced low NO_x burners with over-fire air at Miami Fort Unit 6, were included in the costs transferred to DE-Kentucky. These projects were previously analyzed and found to be economic and necessary under the new CAIR rules, which require significant reductions in both SO_2 and NO_x emissions. Both of these Phase I projects are complete and in-service.

In addition, the East Bend Unit 2 SCR equipment, originally installed to comply with the NO_x SIP Call, will be required to operate annually beginning on January 1, 2009. DE-Kentucky also plans to operate the SCR additional time in 2008 in order to earn CAIR Annual NO_x Compliance Supplement Pool Allowances.

F. CLEAN AIR INTERSTATE RULE AND MERCURY COMPLIANCE – PHASE II

For the current planning cycle, analysis was performed to determine if there are additional economic environmental compliance projects available on the DE-Kentucky units. In addition, some consideration was given to the potential impacts of the CAMR should EPA issue mercury MACT regulations.

1. Compliance Planning Process

For this analysis, DE-Kentucky used a three-stage analytical modeling process, involving the Ventyx MARKETSYM™ model, DE-Kentucky's internal Engineering Screening Model, and the Ventyx System Optimizer and Planning and Risk models (see Chapter 8 for a detailed description of these models). Ventyx used MARKETSYM™ to model the final CAIR and CAMR, including known state-specific mercury rules (prior to CAMR being vacated by the court), and an assumption for future CO_2 regulations. They provided to DE-Kentucky forecasted EA prices (for SO_2, Seasonal NO_x, Annual NO_x, mercury, and CO_2), power prices, and fuel prices (coal, oil, natural gas).

2. Engineering Screening Model Results

The Engineering Screening Model was used to screen down to the most economic emission reduction options for further analysis in the System Optimizer model. Technology options that were screened included wet and dry FGDs and in-duct trona injection for SO_2 reduction; SCR and SNCR for NO_x reduction; and activated carbon injection ("ACI") with baghouses for mercury control, in addition to FGD and FGD/SCR mercury reduction co-benefits. Also modeled were fuel switch options to lower sulfur coals with appropriate particulate control upgrades as needed.

New Technologies

DE-Kentucky continuously evaluates new technologies for potential application to its generating units. This includes involvement with EPRI and the US Department of Energy ("DOE"), meeting with vendors and reviewing developing technologies, performing data searches, and maintaining a database of developed and developing technologies that have future potential for application to Duke Energy units. For example, Duke Energy is a partner in three of DOE's Regional Carbon Sequestration Partnerships and is hosting a Phase II demonstration project at the East Bend Station as part of the Midwest Regional Carbon Sequestration Partnership. During this demonstration project approximately 2,000 tons of CO_2 will be purchased, transported to and sequestered in a Class V injection well at East Bend Station.

In this round of investigation, a new technology, duct sorbent injection, or "in-duct dry FGD" was modeled. Research of this technology has revealed its applicability and its limitations. This involves the injection of the mineral trona (or other similar reagents) in powdered form into the flue gas ductwork upstream of the particulate control device. Trona injection acts to capture acid gases, including SO_3, SO_2, and NO_x. With a baghouse, SO_2 removals of up to 60% may be possible. This technology has potential applicability to Miami Fort Unit 6.

However, the technology only works well in conjunction with lower sulfur content coals, as the SO_2 removal capability is limited by the capacity of the particulate control device to remove the additional solids created from the flue gas stream. Overall, this technology has low initial capital costs (similar to activated carbon injection equipment), but high ongoing variable O&M costs for reagent (trona) and solid waste disposal. In addition, there is a supply risk for the trona material itself, as it is a naturally occurring mineral that is mined in Wyoming. It shares the same long-distance transportation logistical risks as Powder River Basin ("PRB") coal.

Capital Cost Estimates

Prior to screening out technologies for Phase II, the capital cost estimates used in the Engineering Screening Model for the various emission control technologies were reviewed based on the experience to date across the Duke Energy system. Generally, the capital costs for all of the technologies are increasing with time, as the cost of construction commodities, such as steel, concrete, and copper, are escalating at a rate faster than inflation. Also, the remaining units in the country without environmental controls also tend to be the smaller, older units that have a higher construction retrofit difficulty, again driving up the costs relative to past installations.

Considerations for a Mercury MACT Future

With the court vacating CAMR (with due consideration given to ongoing appeals), it is now possible that EPA will promulgate a new mercury compliance regulation based on a MACT standard. It is therefore reasonably prudent to at least consider the impact of such a regulation on the DE-Kentucky units. However, the exact requirements and timing of compliance are unpredictable at this time.

For units equipped with both SCR and FGD technology, DE-Kentucky has assumed that, on average over an operating year, 85% of the mercury in the in-coming coal will be removed prior to final emission in the flue gas stack. This would have been sufficient to comply with the original MACT standard proposed by EPA prior to the finalization of the cap-and-trade CAMR. For East Bend, which is equipped with both an SCR and an FGD, it is assumed that the unit will likely comply with the new regulation and no additional actions are assumed to be necessary at this time. This will have to be re-evaluated once the provisions of the revised CAMR are known.

For Miami Fort Unit 6, however, it is much more likely that additional emission controls will be required to comply with a new mercury rule. This depends highly on the level of compliance required, and the way in which compliance is measured (unit-by-unit, or generating facility/station-wide). If compliance is determined on a facility-wide basis, then it is possible that the unit could be averaged in with the other units at Miami Fort Station, two of which have an SCR and an FGD, and achieve the compliance standard. If the average emission is still too high, or if unit-specific compliance is required, then it is very likely that Miami Fort Unit 6 will require additional emission controls.

Additional mercury control at Miami Fort Unit 6 would most likely come in the form of a baghouse with ACI. A baghouse (or fabric filter) uses a filter media to physically capture particulates from the flue gas stream. This is a similar concept to a vacuum cleaner with a HEPA filter. As solid material builds up on the surface of the filters (also called bags), it can also become effective at absorbing vapor compounds. This is due to the increased surface contact of the flue gas having to pass through the built-up filter cake. Then, when an absorbing agent, such as powdered activated carbon, is injected into the flue gas upstream of the baghouse and collects on the bag surface, it becomes a highly effective means of removing the mercury.

Technology Options Passed to System Optimizer

With its existing SCR and FGD, East Bend Unit 2 is well placed to comply with the CAIR regulations. There were no additional economic compliance options identified for this unit. For Miami Fort Unit 6, however, there is a strong emphasis on reducing the SO_2 emissions due the reductions brought on by CAIR.

Switching to lower sulfur content fuels appeared to be economic in the Engineering Screening Model analysis.

To make this fuel switch, however, the particulate controls on the unit require enhancement. This could be accomplished through a precipitator upgrade project with the addition of a flue gas conditioning system (SO_3 injection), or through the installation of a baghouse. Since the baghouse installation is linked to the potential for mercury MACT regulations, both particulate upgrade options were passed to the System Optimizer with the low sulfur fuel switch option. Thus, the two distinct options passed on to the System Optimizer for Miami Fort Unit 6 were:

- Switch to Low Sulfur Fuel, Precipitator Upgrades, SO_3 Injection
- Switch to Low Sulfur Fuel, Baghouse, Activated Carbon Injection[1]

Lastly, given the installation of a baghouse and a switch to lower sulfur content fuel, the addition of trona injection on Miami Fort Unit 6 also appears economic. However, this is still a developing technology, and its economics depend on the existence of the baghouse. Duke Energy is considering testing this technology at another unit in the Duke Energy system that already has a baghouse installed. If that testing is performed and is successful, then this technology will be given due consideration for DE-Kentucky in future analyses.

[1] This option results in a derate of approximately 1 MW due to increased auxiliary load.

3. System Optimizer Results

The Phase 2 alternatives passed to the System Optimizer from the Engineering Screening Model were analyzed in the integration step of this IRP in conjunction with the DSM and supply-side alternatives. This is discussed in detail in Chapter 8.

G. EMISSION ALLOWANCE MANAGEMENT

Figure 6-1 shows the number of SO_2 allowances allotted by the EPA for East Bend, Miami Fort 6, and Woodsdale. Figures 6-2 and 6-3 show the projected number of Seasonal and Annual NO_x allowances respectively that will be allotted to these units.

The emission allowance markets impact the compliance strategies. 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).

Duke Energy has maintained an interdepartmental group to perform SO_2 and NO_x emission allowance management. DE-Kentucky 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

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	12,642	12,664
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			19,314	19,351

Note: Number of allowances shown are DE-Kentucky's portion for jointly owned units.

Figure 6-2

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

Plant Name	Unit/ Boiler No.	Percent Ownership	ALLOWANCES ALLOCATED 2008	2009 to 2014	2015 & After
Miami Fort	6	100.00	365	396	354
East Bend	2	69.00	945	976	828
Woodsdale	1	100.00	25	12	11
Woodsdale	2	100.00	25	12	11
Woodsdale	3	100.00	25	14	13
Woodsdale	4	100.00	28	14	13
Woodsdale	5	100.00	31	15	13
Woodsdale	6	100.00	29	14	13
Total			1,473	1,453	1,256

Note:

Number of allowances shown are DE-Kentucky's portion for jointly owned units. Year 2009 transitions from the NOx SIP Call to the CAIR NOx Ozone Season Program. Year 2015 allocations are an estimate; they will be determined through a future reallocation.

Figure 6-3

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

Plant Name	Unit/ Boiler No.	Percent Ownership	ALLOWANCES ALLOCATED 2009 to 2014	2015 & After
Miami Fort	6	100.00	966	822
East Bend	2	69.00	2,414	2,011
Woodsdale	1	100.00	20	17
Woodsdale	2	100.00	20	17
Woodsdale	3	100.00	22	18
Woodsdale	4	100.00	23	19
Woodsdale	5	100.00	24	20
Woodsdale	6	100.00	23	19
Total			3,512	2,943

Note:

Number of allowances shown are DE-Kentucky's portion for jointly owned units. Year 2015 allocations are an estimate; they will be determined through a future reallocation.

7. ELECTRIC TRANSMISSION FORECAST

The transmission information is located in the Transmission Volume of this report.

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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 the 2008 Integrated Resource Plan ("IRP"), and its general implementation.

Figure 8-1 shows DE-Kentucky's supply versus demand balance with existing DSM programs but without any additional supply-side or compliance resources. DE-Kentucky's reserve margin from 2019 forward is consistently below 15%.

B. RESOURCE INTEGRATION PROCESS

The goal of the integration process was to take all of the pre-screened DSM, supply-side, and the environmental compliance options, and develop an integrated resource plan using a consistent method of evaluation. The tools used in this portion of the process were the Ventyx System Optimizer model and the Ventyx Planning and Risk model. The models utilized to develop the power market price forecast and to screen the environmental compliance alternatives are also described below.

1. Model Descriptions

System Optimizer

System Optimizer is a state-of-the-art computer model licensed from Ventyx. System Optimizer is commercially licensed to many utilities and CEM (its predecessor program) has been used by DE-Carolinas (an affiliate of DE-Kentucky) for several years.

System Optimizer is an economic optimization model that can be used to develop integrated resource plans while satisfying reliability criteria. The model assesses the economics of various resource investments including conventional units (*e.g.*, CTs, CCs, coal units, IGCCs, *etc.*), renewable resources (*e.g.*, wind, biomass), DSM resources, and environmental compliance alternatives (*e.g.*, scrubbers, SCRs, baghouses, *etc.*).

System Optimizer uses a linear programming optimization procedure to select the most economic expansion plan based on Present Value Revenue Requirements ("PVRR"). The model 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, NO_x, or CO_2 emission rates incur larger dispatch penalty cost adders than units with low or no SO_2, NO_x, or CO_2 emissions. The dispatch adders are calculated by the model using the projected prices of emission allowances and the emission rates of the generating units.

Planning and Risk

Planning and Risk is a commercially licensed product developed by Ventyx. Prosym, the computational engine of Planning and Risk, has also been used by DE-Carolinas for several years and is widely accepted throughout the industry. However, unlike System Optimizer, Planning and Risk 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.

Some of the key inputs include generating unit data, fuel data, load data, transaction data, DSM data, emission and allowance cost data, and utility-specific system operating data. These inputs, along with its complex algorithms, make Planning and Risk a powerful tool for projecting utility electric production facility operating costs.

MARKETSYM™

The power market price forecast utilized in this IRP was developed by Ventyx using their proprietary MARKETSYM™ system. The operation of individual generators, utilities, and control areas are simulated by the model in hourly detail to meet the loads within the region. Smaller zones within the region are modeled so that critical transmission constraints are taken into account. The objective of the model is to minimize the cost of serving load within the region. Individual unit forced outages are taken into account using Monte Carlo analysis. The outputs from the model include emission allowance prices, fuel prices, and a long-term price forecast sufficient for existing and new generators to recover their costs from the market.

Engineering Screening Model

Duke Energy's in-house Engineering Environmental Compliance Planning and Screening Model ("Engineering Screening Model") is a Microsoft Excel-based spreadsheet program that is used to screen environmental compliance technology options down to those that are most economic for further consideration in the System Optimizer model. The model incorporates the operating characteristics of the DE-Kentucky units (net MW, heat rates, emission rates, emission control equipment removal rates, availabilities, variable O&M expenses, *etc.*), and market information (energy prices in the form of a price duration curve, emission allowance prices, fuel prices), calculates the dispatch costs of the units, and dispatches them independently against the energy price curve. The model calculates generation, emissions, operating margin, and, ultimately, free cash flow with the inclusion of capital costs.

The Engineering Screening Model also contains costs and operating characteristics of emission control equipment. This includes wet and dry flue gas desulfurization equipment ("FGD" or "scrubber") and in-duct trona injection for

SO_2 removal; selective and non-selective catalytic reduction ("SCR" and "SNCR") and low NO_x burners ("LNB") for NO_x removal; baghouses with ACI for mercury removal; and various fuel switching options with related capital costs (such as a switch to lower sulfur content coal with required electrostatic precipitator upgrades). The model also appropriately treats emission reduction co-benefits, such as increased mercury removal with the combination of SCR and FGD.

The screening operation of the Engineering Screening Model involves testing the economics of the many various combinations of emission control equipment on each unit individually by calculating the present value of the change in free cash flow ("NPV") due to adding an emission control technology or fuel switch. The model ranks the alternatives by NPV. This model is considered proprietary confidential and competitive information by Duke Energy.

2. Process

The first step in the integration process was to update the database with the most current forecasts and assumptions. Once this was completed, output reports were examined to determine the reasonableness of the model results by examining selected variables such as unit capacity factors and emission rates. Throughout the IRP process the modeling was reviewed for accuracy. Also, system load reports were reviewed to make sure forecasted peak and energy values, as well as DSM impacts, were modeled correctly. The projected market prices for electricity from Ventyx for the Duke Energy Midwest modeling region were included in the database to simulate the interactions between DE-Kentucky'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 System Optimizer:

Demand-Side Management

Option	Year(s) Available
Conservation EE Bundle	2008
Demand Response Bundle - Residential	2008
Demand Response Bundle - Non-Residential	2008

Notes: 1) The impacts of these programs continued or increased throughout the study period

Supply-Side

Option	Year(s) Available
50 MW Block Market-Based Purchases	2008-2011
Brownfield 35 MW 7FA CT (22% of a 158 MW unit)	2012-2028
Brownfield 35MW CC (6% of a 620 MW unit)	2012-2028
Greenfield 35 MW Supercritical Pulverized Coal (4% of an 800 MW unit)	2014-2028

Greenfield 35 MW Generic IGCC (6% of a 619 MW unit)	2014-2028
Greenfield 35 MW Nuclear (1.5% of a 2234 MW station)	2025-2028
Generic 50 MW Turnkey Wind (15% Capacity Credit toward Reserve Margin Requirements)	2010-2028
35 MW Poultry Waste Firing	2010-2028

Notes:
1) The ratings shown are summer capacity
2) No Carbon Capture and Sequestration ("CC&S") equipment was assumed on the supply-side alternatives

Environmental Compliance

Option	Year(s) Available
Low SO_2 Fuel, Precipitator Upgrade, SO_3 Injection on Miami Fort 6	2010
Low SO_2 Fuel, Baghouse, ACI on Miami Fort 6	2012

Due to the relatively small size of the DE-Kentucky system and the small amount of additional capacity needed over the study period, some of the generic supply-side options were modeled in blocks smaller than either the optimal economic or the commercially available sizes of these units. For example, the CT, CC, pulverized coal, IGCC, and nuclear units were limited to blocks of 35 MW in size to match the size of the renewable Poultry Waste alternative, even though actual units utilizing these technologies are normally much larger. Using comparably sized units also creates a more level playing field for these alternatives in the model so that choices will be made based on economics rather than being unduly influenced by the sizes of units in comparison to the reserve margin requirement. This is a conservative assumption because supply-side screening in past IRPs generally showed that the largest unit sizes available for any given technology type were the most cost-effective, due to economies of scale. If smaller units were required for DE-Kentucky, the capital costs on a $/kW basis would be much higher than the cost estimates used in this analysis. DE-Kentucky could take advantage of the economies of scale from a larger unit by jointly owning such a unit with another utility or by signing a Purchased Power Agreement from such a facility.

Nuclear units were considered as resource alternatives in the development of this IRP even though Kentucky currently has a moratorium on nuclear power plants until a long-term federal disposal site becomes operational. The reason for this modeling assumption is that allowing such alternatives can provide insights into what kinds of resources may be needed in the future, especially given the potential for future constraints on carbon emissions. The Kentucky legislature considered lifting the moratorium in its 2008 legislative session, although it did not come to a vote.

The DR programs were modeled as two separate "bundles" (one bundle of Non-Residential programs and one bundle of Residential programs) that could be selected based on economics. The conservation EE programs were modeled as one bundle that could be selected based on economics[1]. The assumption was made that these costs and impacts would continue throughout the planning period.

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, IGCC, or nuclear units selected by the model can be viewed as placeholders for base load purchases.

The number of Renewable technology types included in the modeling had to be limited in order to allow the model to reach solution more easily. Based on the results of the screening curve analysis (discussed in Chapter 5), the renewables that were made available to the model were the Wind and the Poultry Waste ("Animal Waste") since these were the most economic of all of the renewables. These technologies act as placeholders for the renewables that are the most economic, taking into account availability and reliability considerations, at the time renewable resources are procured. The availability of these kinds of resources for DE-Kentucky was not considered in this analysis.

Although market purchases were not available after 2011 in System Optimizer, any CTs and CCs selected by the model can be viewed as placeholders for further peaking and intermediate market purchases.

[1] The DR and conservation EE bundles were eventually "fixed" in the System Optimizer model due to the bundles not being selected economically because no additional resources were required for many years.

Both the Wind and Animal Waste alternatives were credited with an assumed revenue stream from selling the Renewable Energy Certificates ("RECs") generated in the cases without an RPS. However, for the case with an RPS, no revenue stream from the sale of RECs was incorporated because they would be surrendered to comply with the RPS.

The integration analysis in system Optimizer was performed over a twenty-one year period (2008-2028). The final detailed production costing modeling in Planning and Risk was performed over the same time period, but with an additional 15 years of fixed costs and escalated production costs incorporated to better incorporate end effects.

C. IDENTIFICATION OF SIGNIFICANTLY DIFFERENT PLANS

1. Develop Theoretical Portfolio Configurations

A screening analysis using the System Optimizer model was conducted to identify the most attractive capacity options under the expected load profile as well as under a range of risk cases. This step began with a nominal set of varied inputs to test the system under different future conditions such as changes in fuel prices, load levels, and environmental requirements. These analyses yielded many different theoretical configurations of resources required to meet an annual 15 percent target planning reserve margin while minimizing the long-run revenue requirements to customers, with differing operating (production) and capital costs. A discount rate of 7.33% was utilized.

The nominal set of inputs included:

- Fuel costs and availability for coal, gas, and nuclear generation;
- Development, operation, and maintenance costs of both new and existing generation;
- Compliance with current and potential environmental regulations;
- Cost of capital;
- System operational needs for load ramping, voltage/VAR support, spinning reserve (10 to 15-minute start-up) and other requirements as a result of Reliabilty*First* / NERC standards;
- The projected load and generation resource need; and
- A menu of new resource options with corresponding costs and timing parameters.
- An assumed level of CO_2 prices[2] as discussed below.

The level of CO_2 prices assumed was based on the safety valve prices contained in legislation introduced by Senator Bingaman. Although the safety valve price in Senator Bingaman's bill is $12/metric ton in 2012 dollars, it is unlikely that legislation will be passed in time to implement this in 2012. Therefore, the assumption was made that 2013 would be the starting year for the $12 safety valve price. When this is converted from metric tons to short tons, the starting price in 2013 is $10.88, which is then escalated at 5% plus inflation of 2.3%. The CO_2 prices assumed were as follows:

	Nominal $/Short Ton
2013	$10.88
2014	$11.67
2015	$12.53
2016	$13.44
2017	$14.42
2018	$15.47
2019	$16.60
2020	$17.82
2021	$19.12
2022	$20.51
2023	$22.01
2024	$23.62
2025	$25.34
2026	$27.19
2027	$29.18
2028	$31.31

These prices were used for each ton of CO_2 emissions, with no allowance allocations from the government assumed. To the extent that there are less expensive methods to comply, such as potentially utilizing carbon capture and sequestration, they will be analyzed as reasonable assumptions for these costs and impacts become available.

[2] Despite significant uncertainty surrounding potential future climate change policy, DE-Kentucky has incorporated the potential for CO_2 climate change regulations in its resource planning process. Inclusion of this assumption is not intended to reflect DE-Kentucky's or Duke Energy's preferences regarding future climate change policy.

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 (*e.g.*, coal vs. natural gas)
- Changes in the level of service area load
- Changes in regulatory requirements
- Increased environmental regulation or rules
- Changes in the level of EE and DR

Differences in the relative economics of different technologies, as well as changes in relative fuel prices were addressed in the supply-side screening discussed in Chapter 5. Changes in gas and coal prices, service area load, and regulatory requirements are addressed as sensitivities at the integration stage described below. Changes in environmental regulations are addressed quantitatively through sensitivity analysis described below and through qualitative discussions in Section E.

The sensitivities studied were:

- High Load Forecast - A sensitivity with a higher load level based on optimistic growth assumptions was chosen. As described in Chapter 3, the Company used the standard errors of the regression from the econometric models used to produce the base energy forecast. The bands are based on an 80% confidence interval around the forecast which equates to 1.28 standard deviations. The growth rates in this sensitivity are 0.8% and 0.9% for peak demand and energy, respectively (versus 0.8% and 0.8%, respectively, in the Base Forecast). All other assumptions remained at Base Case levels for this sensitivity.

- Low Load Forecast/Higher Level of Renewables - A sensitivity with a lower load level based on pessimistic growth assumptions was chosen. As described in Chapter 3, the Company used the standard errors of the regression from the econometric models used to produce the base energy forecast. The bands are based on an 80% confidence interval around the forecast which equates to 1.28 standard deviations. The growth rates in this sensitivity are 0.8% and 0.7% for peak demand and energy, respectively (versus 0.8% and 0.8%, respectively, in the Base Forecast). This sensitivity can also serve as a proxy for the effects of a higher level of renewables since the reduction in the load level could be caused by a lower net load to be served after renewables rather than a lower rate of growth. By 2028, the difference in peak load was about 58 MW in the summer, while the difference in energy was 352,000 MWh per year. This is the equivalent of seven to eight 50 MW wind farms based on the peak differential or two to three wind farms based on the energy differential. All other assumptions remained at Base Case levels for this sensitivity.

- Higher Gas Prices - Changes in gas prices can affect the relative economics of the plan chosen. Therefore, a sensitivity using approximately 23% Higher Gas Prices was performed. All other assumptions remained at Base Case levels for this sensitivity.

- Higher Coal Prices - Changes in coal prices can also affect the relative economics of the plan chosen. Therefore, a sensitivity using a 10% Higher Coal Price Forecast was performed. All other assumptions remained at Base Case levels for this sensitivity.

- Higher Carbon Tax/Allowance Prices - The Company continues to believe that there will be a cost control mechanism incorporated into climate change legislation that is ultimately enacted to prevent high emission allowance prices and reduce price volatility. Given the uncertainty around the price levels that will result from the price control mechanism, however, this IRP analysis considered a range of potential prices. The following table shows the CO_2 prices that were modeled for the Higher Carbon sensitivity:

	Nominal \$/Short Ton
2013	$31.38
2014	$34.67
2015	$40.59
2016	$43.54
2017	$46.61
2018	$49.79
2019	$53.09
2020	$56.51
2021	$59.21
2022	$62.01
2023	$64.90
2024	$67.89
2025	$70.99
2026	$76.60
2027	$82.43
2028	$88.48

Because these changes in environmental policy would affect not only CO_2 prices, but also fuel prices, market prices, and load level, adjustments to these other parameters were made based on work performed for the Company by outside consultants. These assumptions were then used to perform the analysis for this sensitivity.

- No Carbon Tax/Allowance Prices – A sensitivity was also performed without any carbon tax assumed. Because that change would affect not only CO_2 prices, but also fuel prices, market prices, and load level, adjustments to these other parameters were made based on work performed for the Company by outside consultants. These assumptions were then used to perform the analysis for this sensitivity.

- 15% Federal Renewable Portfolio Standard - The version of the Energy Bill passed by the U.S. House of Representatives in 2007 contained a 15% RPS, while the Senate version did not include such a standard. The final bill did not contain this standard. However, given the likelihood that some sort of RPS may be imposed at the Federal level in the future, a sensitivity was performed utilizing the 15% House version of the standard. The key requirements assumed for modeling purposes were as follows:

Annual % Requirements	
2010	2.75%
2011	2.75%
2012	3.75%
2013	4.50%
2014	5.50%
2015	6.50%
2016	7.50%
2017	8.25%
2018	10.25%
2019	12.25%
2020–2039	15.00%

  Eligible Resources

  - Facilities placed in service on or after January 1, 2001
  - Biomass including animal waste and agricultural crops
  - Incremental hydro at existing facilities
  - Solar
  - Wind
  - Landfill gas
  - Biomass co-firing in existing units
  - Energy Efficiency up to 25% of the requirements

- CAMR (cap-and-trade) reinstated for mercury regulations instead of MACT – Due to the uncertainties surrounding future mercury regulations, a sensitivity was performed to determine the impacts of regulations similar to the CAMR cap-and-trade system instead of a MACT regime.

- No Energy Efficiency/Demand Response programs – A sensitivity was also performed to determine what additional resources would be required if DE-Kentucky did not have any EE or DR programs.

The sensitivities chosen for this IRP analysis were those that represented the highest risks going forward. Therefore, it was determined that a lower gas price sensitivity and a lower coal price sensitivity would not lead to any insightful results.

Figure 8-2 summarizes the optimal plans produced by the System Optimizer model for each of the sensitivities studied.

Base Load Forecast

The Base Load Forecast was reduced using energy efficiency and demand response. With the EE/DR bundles added in 2008 there is no significant need for additional capacity until 2019. The optimum plan for the Base Load Forecast case consisted of adding the Low SO_2 fuel, BH, ACI environmental compliance option on Miami Fort 6 in 2012 in order to comply with MACT. The remainder of the plan called for adding 105 MW supply side resources. Two simple-cycle CT units (70 MW) were added, one each in 2019 and 2023. There was also one

35 MW nuclear unit added in 2027. The addition of CTs and the nuclear unit indicates a need for a combination of peaking and baseload generation. However, 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. The selection of these resources is highly dependent on the projected capital costs and heat rates of the units. Renewable resources were not selected by the model due to their higher cost in comparison to traditional supply-side options.

Higher Load Forecast Sensitivity

The need for new capacity was advanced to 2011 due to the higher load level. The plan contains two additional CTs and a Wind unit in comparison to the Base Load Forecast plan.

Lower Load Forecast/Higher Level of Renewables Sensitivity

There is no need for any new capacity due to the lower load level.

Higher Gas Prices Sensitivity

The main impact on the plan was to substitute an Animal Waste unit for the second natural gas-fired CT in 2023 in comparison to the Base Load plan.

Higher Coal Prices Sensitivity

The optimum plan was unchanged from the Base Load Forecast plan.

Higher Carbon Tax Sensitivity

The reserve margin criterion was limited to a maximum 20%. Since other parameters would be affected by an increase in carbon prices, additional price-induced load destruction was modeled. No new capacity was needed after the EE and DR were added in 2008 due to the lower load level.

No Carbon Tax Sensitivity

The No Carbon Tax plan was significantly different from the Base Load Forecast plan. In the absence of a carbon tax it is expected that the load level would be higher, this creating a need for additional resources. The key difference between this plan and the Base Load plan is the coal-fired base load resources added. Four 35 MW Supercritical PC units are added, one each in 2017, 2020, 2023 and 2026. The majority of the resources are added late in the study with the exception of the first coal unit. The rest of the coal units were added at relatively the same time period as the resources in the Base Load Forecast plan. No other types of resources were added during the study. A 35 MW increase in capacity (for a total of 140 MW) was needed over the Base Load plan (105 MW).

15% RPS Sensitivity

Only renewable resources were selected by the model in this sensitivity. These supply-side resources, along with the DSM resources, satisfied the annual RPS constraints modeled as well as the reserve margin constraints. The plan consisted of two 35 MW Animal Waste Firing units added, one each in 2013 and 2019. The remainder of the plan was made up of two Wind units (100 MW total) introduced in 2010 and 2027. Although the resources shown are Animal Waste and Wind farms, they are placeholders for the most economic and reliable resources available at the time they are procured.

CAMR Sensitivity

If the new mercury regulations contain a cap-and-trade system rather than MACT, the optimum plan would include the precipitator upgrade on Miami Fort Unit 6 rather than the baghouse with ACI, based on economics. The plan also replaced one CT with 100 MW of Wind resources.

No EE/DR Sensitivity

The results without any EE or DR are slightly different from the Base Load Forecast plan in that all of the resources additions occur two years earlier. There was also additional capacity required in 2028, and the Wind resource was selected to meet this need.

Other Observations

With the exception of the No Carbon Tax sensitivity, no coal-fired resources were added. Instead, the supply-side resources added generally consisted of gas-fired CTs, renewables, and nuclear units.

2. Develop Various Portfolio Options

Using the insights gleaned from developing theoretical portfolios, DE-Kentucky created a representative range of generation plans reflecting different mixes of resources. Recognizing that different generation plans expose customers to different sources and levels of risk, a variety of portfolios were developed to assess the impact of various risk factors on the costs to serve customers. The portfolios analyzed for the development of this IRP were chosen in order to focus on the near-term (i.e., within the next ten years) decisions that must be made while placing less emphasis on differences in portfolios ten to twenty years in the future that DE-Kentucky will have the opportunity to re-visit in subsequent IRPs.

Figure 8-3 shows the three portfolios of interest that were considered in the portfolio analysis phase: 1) the Gas/Nuclear/EE portfolio, 2) the Coal/Nuclear/EE portfolio, and 3) the High Renewables/EE portfolio. Each portfolio contains the maximum amount of both demand response and conservation that was available. The Gas/Nuclear/EE portfolio was based on the System Optimizer model results for the Base Case Load Forecast. The Coal/Nuclear/EE portfolio is identical to the Gas/Nuclear/EE portfolio with the exception that the CT unit in 2019 was replaced with a coal unit since the No Carbon Case model run contained all coal units rather than gas unit additions. The High Renewables/EE portfolio was based on the System Optimizer model results for the 15% Federal RPS sensitivity.

The Gas/Nuclear/EE portfolio contains the EE and DR bundles. The supply-side resources consist of a two CT units (35 MW each) added in 2019 and 2023, and a nuclear unit (35 MW) added in 2027. In addition, the plan contains the Fabric Filter/ACI environmental compliance alternative for Miami Fort Unit 6 in order to be in compliance with the mercury MACT standard. Each of the supply-side units should be viewed as placeholders for the types of capacity resources that are the most economical at the time decisions for adding capacity need to be made.

The Coal/Nuclear/EE portfolio also contains the EE and DR bundles. The supply-side resources consist of a coal unit (35 MW) added in 2019, a CT unit (35 MW) added in 2023, and a nuclear unit (35 MW) added in 2027. In addition, the plan contains the Fabric Filter/ACI environmental compliance alternative for Miami Fort Unit 6 in order to be in compliance with the mercury MACT standard. As discussed above, the units added should be viewed as placeholders.

The High Renewables/EE portfolio also contains the EE and DR bundles. The supply-side resources consist of two Wind plants (50 MW each) added in 2010 and 2013, and two Animal Waste units (35 MW each) added in 2017 and 2020. In addition, the plan contains the Fabric Filter/ACI environmental compliance alternative for Miami Fort Unit 6 in order to be in compliance with the mercury MACT standard. As discussed earlier, the units added should be viewed as placeholders.

Overall, these plans are representative of the kinds of choices that DE-Kentucky will be considering in the future.

D. SENSITIVITY ANALYSES

In the next stage of the analysis, the three portfolios were tested under the Base Case set of inputs as well as a variety of risk sensitivities in order to understand the strengths and weaknesses of various resource configurations and evaluate the long-term costs to customers under various potential outcomes. The Planning and Risk model (discussed earlier) was used to perform more detailed production cost analysis. The sensitivities chosen to be performed were those representing the highest risks going forward. For this IRP analysis, the sensitivities studied were as follows:

- High Load Forecast (described earlier)
- Low Load Forecast/Higher Level of Renewables (described earlier)
- Higher Gas Prices (described earlier)
- Higher Coal Prices (described earlier)
- High Carbon Tax/Allowance Prices (described earlier)
- No Carbon Tax/Allowance Prices (described earlier)
- Higher Construction cost sensitivities[3]
  - 20% Higher Capital Cost for CT and CC units compared to Base Case

[3] These sensitivities test the risks from increases in construction costs of one type of supply-side resource at a time. In reality, cost increases of many construction component inputs such as labor, concrete and steel would affect all supply-side resources to varying degrees rather than affecting one technology in isolation.

- 20% Higher Capital Cost for Coal Units compared to Base Case
- 20% Higher Capital Cost for Nuclear Units compared to Base Case
- 20% Higher Capital Cost for Renewable Units compared to Base Case

Figure 8-4 shows a comparison of the difference in PVRR for the Study Period (*i.e.*, twenty-one year Planning Period plus 15 year end effects) of each of the three portfolios versus the average PVRR of the three portfolios under Base Load Forecast conditions. The effective after-tax discount rate used was 7.33%. The Gas/Nuclear/EE portfolio is the least cost portfolio, with the Coal/Nuclear/EE portfolio close in cost. The High Renewables/EE portfolio is much higher in cost.

Higher Load Forecast Sensitivity

Figure 8-5 shows a comparison of the difference in PVRR of each of the portfolios versus the average PVRR of the portfolios for this sensitivity. The Gas/Nuclear/EE portfolio is the least cost portfolio, with the Coal/Nuclear/EE portfolio close in cost.

Lower Load Forecast/Higher Level of Renewables Sensitivity

Figure 8-6 shows a comparison of the difference in PVRR of each of the portfolios versus the average PVRR of the portfolios for this sensitivity. The

Gas/Nuclear/EE portfolio is the least cost portfolio, with the Coal/Nuclear/EE portfolio close in cost.

Higher Gas Price Forecast Sensitivity

Figure 8-7 shows a comparison of the difference in PVRR of each of the portfolios versus the average PVRR of the portfolios for this sensitivity. The Gas/Nuclear/EE portfolio is the least cost portfolio, with the Coal/Nuclear/EE portfolio close in cost.

Higher Coal Price Forecast Sensitivity

Figure 8-8 shows a comparison of the difference in PVRR of each of the portfolios versus the average PVRR of the portfolios for this sensitivity. The Gas/Nuclear/EE portfolio is the least cost portfolio.

Higher Carbon Tax Forecast Sensitivity

Figure 8-9 shows a comparison of the difference in PVRR of each of the portfolios versus the average PVRR of the portfolios for this sensitivity. The Gas/Nuclear/EE portfolio is the least cost portfolio. Although the High Renewables/EE portfolio became relatively more economic than in previous sensitivities, it was still much higher cost.

No Carbon Tax Forecast Sensitivity

Figure 8-10 shows a comparison of the difference in PVRR of each of the portfolios versus the average PVRR of the portfolios for this sensitivity. The Coal/Nuclear/EE portfolio was the least cost portfolio, with the Gas/Nuclear/EE portfolio close in cost.

Higher CT/CC Unit Capital Cost Sensitivity

Figure 8-11 shows a comparison of the difference in PVRR of each of the portfolios versus the average PVRR of the portfolios for this sensitivity. The Gas/Nuclear/EE portfolio is the least cost portfolio, with the Coal/Nuclear/EE portfolio close in cost.

Higher Coal Unit Capital Cost Sensitivity

Figure 8-12 shows a comparison of the difference in PVRR of each of the portfolios versus the average PVRR of the portfolios for this sensitivity. The Gas/Nuclear/EE portfolio is the least cost portfolio.

Higher Nuclear Unit Capital Cost Sensitivity

Figure 8-13 shows a comparison of the difference in PVRR of each of the portfolios versus the average PVRR of the portfolios for this sensitivity. The Gas/Nuclear/EE portfolio was the least cost portfolio.

Higher Renewable Capital Cost Sensitivity

Figure 8-14 shows a comparison of the difference in PVRR of each of the portfolios versus the average PVRR of the portfolios for this sensitivity. The Gas/Nuclear/EE portfolio was the least cost portfolio.

E. ENVIRONMENTAL RISK/REGULATORY IMPACTS

There are a number of environmental risks/regulatory changes that can affect DE-Kentucky in the future. As a result, Duke Energy closely monitors these changes and develops responses to the changes. The most significant risks are discussed in more detail below.

Ozone National Ambient Air Quality Standard ("NAAQS")

In 1997, the EPA announced a new and tighter ozone standard to protect human health. The standard established new limits for the permissible levels of ground level ozone in the atmosphere. However, the effect of the standard and its implementation were delayed for years in court proceedings, as the standard was challenged, but ultimately upheld. Still, the Circuit Court for the District of Columbia invalidated the EPA's implementation procedure for dealing with the 8-hour ozone standard. The EPA has yet to finalize implementation rules for the 8-hour ozone standard in accordance with the Court's opinion. Compliance with the new standard could require significant reductions in volatile organic compounds

("VOC") and NO_x emissions from utility, automotive and industrial sources including DE-Kentucky facilities.

In 2004, ozone non-attainment counties for Kentucky, Ohio, and other states were finalized by the EPA. The Commonwealth of Kentucky and State of Ohio have been working with the EPA to re-designate all Kentucky and Ohio counties as attaining the 8-hour standard based on three years of acceptable ozone monitoring results. In 2005, EPA issued phase 1 of its implementation requirements and additional requirements are pending.

Depending on the outcome of the 8-hour implementation rule and each county's non-attainment status, states may require affected sources to implement pollution controls in the future to reduce emissions which lead to the creation of ozone. DE-Kentucky will continue to monitor these developments and their potential impact on the Company.

In March 2008, the EPA again revised the ozone standard and increased the stringency from 0.08 ppm to 0.075 ppm. States will be required to propose designations as attainment or non-attainment for monitor locations by March 2009. The EPA will finalize the designations and states will be required to submit a new state implementation plan by 2013 to attain the new standards, if necessary. If additional emission reductions are required, sources would have to be in compliance between 2015 and 2030, depending on the severity of the ozone problem. DE-

Kentucky will continue to monitor these developments and their potential impact on the Company.

New Particulate NAAQS ("PM 2.5")

In 1997, EPA announced new annual and daily particulate matter ("PM") standards intended to protect human health. The standards establish limits for very small particulate, those considered respirable, less than 2.5 microns in diameter. The control of these very small particles could require significant reductions in gaseous sulfur dioxide and nitrogen oxides emissions. As with the ozone standard discussed above, EPA's new PM standard and subsequent implementation, were delayed for years because of legal challenges.

In 2005, EPA finalized state non-attainment area designations to implement the new PM standard, which where subsequently challenged in court. The Commonwealth of Kentucky and State of Ohio have been working with the EPA to redesignate appropriate Kentucky and Ohio counties as attaining the annual PM 2.5 standard based on three years of acceptable monitoring results.

On April 27, 2007, EPA finalized requirements for states to meet the implementation of the PM 2.5 standard which were subsequently challenged in court. Depending on the outcome of the implementation rule litigation, and each county's non-attainment status, states may require some sources to install pollution controls in the 2010 to 2015 timeframe to reduce emissions which lead to the formation of PM 2.5.

Kentucky and Ohio both developed attainment demonstrations in 2008, based upon emission reduction requirements already required by state and federal rules.

On October 17, 2006, the EPA finalized its rule strengthening the 24-hour fine particle standard from the 1997 level of 65 micrograms per cubic meter, to 35 micrograms per cubic meter and retained the current annual fine particle limit. Kentucky and Ohio filed proposed county designations under the new standard and USEPA will finalize the designations by the end of 2009. States will follow a schedule to implement the new 24-hour standard with attainment of the standard in the 2015 to 2020 timeframe through an implementation plan developed by 2013. Additional costs to lower sulfur dioxide and other precursor particulate emissions will depend on the stringency of the requirements. DE-Kentucky will continue to study the impact of these regulations on the Company.

Clean Air Interstate Rule

In December 2005, numerous states, environmental organizations, industry groups and individual companies challenged various portions of the CAIR as published. Those challenges are pending in the Federal Circuit Court for the District of Columbia. It is impossible to predict the outcome of the court deliberations. Historically, the courts have given great deference to EPA when deciding on the merits of technical issues.

However, even if the courts remand parts of the rule or vacate the rule entirely, Kentucky, Ohio, and the other affected states are still required by the Clean Air Act to develop the necessary emissions reductions of SO_2 and NO_x to bring the many non-attainment counties for ozone and fine particles into attainment in the 2009-2015 timeframe. The emissions reductions contained in CAIR were not designed to solve all the non-attainment problems in the country or even in the Midwest. Therefore, the same level of emissions reductions contained in CAIR, or possibly even more, could be required.

In August 2005, EPA proposed a Federal Implementation Plan ("FIP") to reduce interstate transport of fine particulate matter and ozone. This proposed rule would only be applicable to facilities in states without approved SIPs under the CAIR. The EPA finalized the FIP in 2006. Kentucky's and Ohio's SIPs were both approved in October 2007.

North Carolina Section 126 Petition

Section 126 of the CAA authorizes downwind states to petition EPA to control upwind source emissions that are significantly contributing to non-attainment in the state. In March 2004, the state of North Carolina filed a petition under Section 126 of the CAA in which it alleges that sources in 13 upwind states, including Kentucky and Ohio, significantly contribute to North Carolina's non-attainment with ozone and fine particulate matter ambient air quality standards. In August 2005, EPA proposed to deny the North Carolina petition based upon the final CAIR and proposed CAIR FIP. EPA finalized their Section 126 Petition decision in April 2006, by denying the North Carolina petition.

North Carolina has challenged EPA's decision denying the petition and that litigation is ongoing. Depending on the outcome, it is possible that greater or faster emissions reductions than those required under CAIR may be required in the future. Duke Energy will actively participate in the rulemaking process as necessary.

Clean Air Mercury Rule

The Commonwealth of Kentucky adopted the EPA version of the CAMR almost entirely by reference in 2007. The State of Ohio also adopted their EPA version of the model CAMR in 2007. Their programs maintain the emissions caps and regulatory timelines contained in the final EPA mercury rule.

Numerous states, environmental organizations, industry groups and individual companies challenged various portions of the CAMR and the determination that it is not appropriate or necessary to regulate mercury emissions under Section 112 of the Clean Air Act. In February 2008, a federal court vacated both the Clean Air Mercury Rule and EPA delisting of coal fired power plants from being regulated by MACT under Section 112 of the Clean Air Act. In March 2008, the same court issued the mandate to act on the order to vacate the rule. EPA has yet to issue guidance to the states on the impact of the court ruling, but has appealed the ruling along with industry. In May 2008, the request for rehearing was denied. While appeal to the

Supreme Court is possible, if the court ruling stands, EPA would have to propose a new mercury emission reduction program. Under this scenario, it is quite possible that a future mercury rule could be a facility-specific, command-and-control type of regulation which may be more stringent and much more difficult with which to comply. Duke Energy will continue to monitor these developments and their potential impact on the Company.

Regional Haze

In June 2005, the EPA issued final regional haze rules, also known as the Clean Air Visibility Rules ("CAVR"). These rules establish 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. These new emission reduction rules could require newer and cleaner generation technologies and additional SO_2 and NO_x emission controls on utility sources. However, EPA concluded in the final rule, that for utilities, a SIP compliant with CAIR would require more reductions than CAVR, and therefore no additional reductions would be required. However, states may choose to implement more stringent emission reductions than promulgated by the EPA. Both Kentucky and Ohio developed regional haze plans that show compliance with the program goals without additional emission reductions on DE-Kentucky facilities.

Clean Water Act Section 316(a) and 316(b)

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 plant operations are potentially large. Electric utilities generally have a far greater number of cooling water intake structures and higher flows than other industries.

Miami Fort Unit 6 is potentially affected by Section 316(a) regulation of a station's heated cooling-water discharge. This regulation could require closed circuit cooling (*e.g.*, cooling towers) at Miami Fort Unit 6 to protect fish communities.

The U.S. Environmental Protection Agency (EPA) finalized its cooling water intake structures 316b rule in July 2004. The rule established aquatic protection requirements for existing facilities that withdraw 50 million gallons or more of water per day from rivers, streams, lakes, reservoirs, estuaries, oceans, or other U.S. waters for cooling purposes. On January 25, 2007, the U.S. Court of Appeals for the Second Circuit issued its opinion in *Riverkeeper, Inc. v. EPA*, Nos. 04-6692-ag(L) et. al. (2d Cir. 2007) remanding most aspects of EPA's rule back to the agency. The court effectively disallowed those portions of the rule most favorable to industry, and the decision creates a great deal of uncertainty regarding future requirements and their timing.

Duke Energy is still unable to estimate costs to comply with the EPA's rule, although it is expected that costs will increase as a result of the court's decision. The magnitude of any such increase cannot be estimated at this time. On April 14, 2008, the U.S. Supreme Court issued an order granting review of the case. A decision is not likely until 2009 after briefs are submitted and oral argument occurs. Duke Energy will monitor the outcome of the Supreme Court decision.

Bevill Determination

In April 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. The Agency published in the Federal Register on August 29, 2007, a notice requesting comments on the management of coal combustion wastes in landfills and ash ponds. Based on comments received the Agency has the discretion to initiate the development of national standards and issue appropriate waste management regulations under subtitle D of RCRA as outlined in the November 2003 Annual Agenda of Regulatory and Deregulatory Actions. Duke Energy will continue to monitor these developments and their potential impact on the Company.

Global Climate Change

Duke Energy's focus on the issues surrounding global climate change began in 1994, shortly after the merger of PSI Energy and The Cincinnati Gas & Electric Company created the Cinergy Corp. Cinergy, which in 2006 merged with Duke Energy Corporation, first worked internally to evaluate its greenhouse gas emissions profile and determine an appropriate reduction strategy. Duke Energy's first efforts to address these emissions, which most scientists believe are contributing to global climate change, were made in conjunction with membership in the U.S. Department of Energy ("DOE") Climate Challenge Participation Accord ("Climate Challenge" or "Participation Accord") signed by Cinergy in February 1995. This accord, which encouraged companies to take voluntary steps to reduce their greenhouse gas emissions, expired December 31, 2000, but the actions Duke Energy took to reduce its Midwest emissions continue.

In keeping with its climate challenge commitment, Duke Energy continues to participate in the Rio Bravo forest preservation and sustainable management project as part of the U.S. Initiative on Joint Implementation ("USIJI"). The project, based in Belize, is a partnership 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).

Duke Energy continues to lead the industry in promoting public policy positions in Washington that would regulate greenhouse gas emissions through a cap-and-trade market-based system. Cinergy first noted the emerging climate science in testimony presented in 2000 before the U.S. Senate Committee on Environment and Public Works. In 2003, Cinergy began calling for national greenhouse gas regulation. In December 2004, Cinergy published its Air Emissions Report to Stakeholders, which discussed the risks, challenges and opportunities of operating in a carbon-constrained environment. In the spring of 2005, Cinergy published its first annual report (for year 2004) which focused on the global climate change issue. In 2007, Duke Energy testified in both Senate and House committees on the specific design of an economically fair greenhouse gas regulatory program.

Duke Energy reports its greenhouse gas emissions and offsets annually to the Department of Energy through the Section 1605(b) process. Its first report, in 1995, identified activities implemented between 1991 and 1994 that reduced or offset the Company's greenhouse gas emissions. Additionally, Duke Energy has participated in the Carbon Disclosure Project since 2003.

Duke Energy's Section 1605(b) reports list activities that reduced or offset Duke Energy Midwest's GHG emissions by million tons of CO_2 equivalents in a calendar year. Activities historically implemented or supported by Cinergy, and now Duke Energy, that have reduced or offset its GHG emissions include:

- Electric generation from recovered landfill (methane) gas;
- Conservation energy efficiency and demand response programs;
- Landfill gas recovery for use as a natural gas supply;
- Rio Bravo carbon sequestration project;
- Trees planted at Duke Energy's Midwest 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.;
- PowerTree Carbon Company, LLC;
- Beneficial reuse of coal ash;
- Efficiencies created through merged dispatching after the Cinergy merger;
- Power plant efficiency programs;
- Coal gasification;

- Combined heat and power plant projects; and
- Paper and aluminum recycling.

In 1999, Cinergy agreed to participate in the USEPA voluntary sulfur hexafluoride ("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 SF_6 during operation and maintenance of equipment used in the transmission and distribution of electricity.

One of Duke Energy's non-regulated subsidiaries, Duke Energy Generation Services, is developing and implementing a number of higher energy efficiency projects (*e.g.* combined heat and power, district heating and cooling, wind, biomass, *etc.*).

Research and development will be very important in any effort to reduce CO_2 emissions by the electric industry. Duke Energy is participating in a number of research projects that are investigating the feasibility of capturing CO_2 from waste gas streams and sequestering the CO_2 geologically.

In 2002, Cinergy joined the EPA's voluntary Climate Leaders program. Under this program, members were asked to work with EPA to develop and report company-wide inventories of greenhouse gases. Companies were also encouraged to develop corporate-wide GHG reduction goals to be achieved over a 10-year period and provide annual progress reports.

In 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 is administered by the Department of Energy. 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 Duke Energy is a member, pledged to reduce the intensity of its members' carbon dioxide emissions by 3 to 5 percent compared to business as usual.

In response to the Climate Leaders commitment, Cinergy announced in September 2003 a voluntary plan to reduce its greenhouse gas emissions to an average of five percent below 2000 levels during the period 2010 through 2012. Additionally, Cinergy committed to spend $21 million between 2004 and 2010 on projects to reduce or offset its emissions. Cinergy also worked with Environmental Defense, a national environmental organization, to determine the goals and implementation of the program.

While Cinergy's program expired upon the completion of the Duke Energy merger in April 2006, the new Duke Energy has announced voluntary greenhouse gas commitments to implement projects to avoid, offset, or reduce 10 million tons of greenhouse gas emissions over the next seven years. As in the predecessor program,

$21 million will be allocated over the period in support of this pledge. Similarly, Duke Energy will strive to spend at least two-thirds of the dollars on projects that have the potential to reduce emissions from Duke Energy's generation, transmission and distribution systems. To meet its GHG emission reduction goal, Duke Energy plans to use a combination of programs that will include new technologies, terrestrial carbon sequestration (forest and soil), energy efficiency programs, improved efficiency of its existing generating fleet, and emission offsets. Duke Energy will report its emissions annually.

Duke Energy voluntarily joined The Climate Registry in January 2008. The Climate Registry is made up of 39 states and other North American governmental entities. The Climate Registry goal is to develop and maintain a greenhouse gas emission reporting system and a verified emissions inventory for participants. Duke Energy will be recognized as a "founding reporter." As such, Duke Energy will be required to report its 2008 system wide emissions in 2009, pay a filing fee, and have its emissions verified by a third party.

While several bills have been proposed, there remains uncertainty as to if or when Congress will choose to regulate greenhouse gas emissions. There is also uncertainty regarding the response anticipated from the U.S. Environmental Protection Agency in the wake of a U.S. Supreme Court decision in *Massachusetts v EPA* that the Agency has the authority to regulate greenhouse gases under the Clean Air Act Amendments of 1990. Despite this uncertainty, Duke Energy believes greenhouse gases will eventually be regulated. Depending on the policy design, the regulatory program could be very costly. Duke Energy will continue to be on the forefront in policy analysis and recommendations and in looking for ways to decrease greenhouse gases while continuing to provide affordable energy as efficiently as possible. Duke Energy's plan for managing the potential risk and uncertainty of regulations relating to climate change includes the following:

- Implementing the voluntary greenhouse gas commitment;
- Measuring and reporting company-related sources of greenhouse gas emissions;
- Identifying and pursuing cost-effective greenhouse gas emission reductions and offsets;
- Funding research of more efficient and alternative electric generating technologies;
- Funding research to better understand the causes and consequences of climate change;
- Investing in renewable energy;
- Promoting energy efficiency;
- Encouraging a global discussion of the issues and how best to manage them – for example, Duke Energy is a founding member of the United States Climate Action Partnership, the Resources For the Future climate change forum, and participates actively in several other policy foray focused on climate change; and
- Advocating an economy-wide greenhouse gas reduction program.

Renewable Portfolio Standard

On August 4, 2007, the U.S. House of Representatives passed an amendment to its energy bill to establish a 15-percent mandatory federal RPS requirement by 2020 for shareholder-owned retail electric suppliers, up to 25 percent of which can be met through energy efficiency. The percentage phase-in of the RPS requirements was as follows:

2010-2011	2.75%
2012	3.75%
2013	4.5%
2014	5.5%
2015	6.5%
2016	7.5%
2017	8.25%
2018	10.25%
2019	12.25%
2020-2039	15%

The types of renewable sources allowed were solar (including solar water heating), wind, ocean, tidal, geothermal, biomass, landfill gas and incremental hydropower. The Governor of a state may request that a retail electric supplier in the state meet up to 25% of its RPS obligation through energy efficiency. However, the Senate version of the energy bill did not include language for a renewable portfolio standard, and the ultimate bill passed by Congress did not contain an RPS. Duke Energy will continue to monitor future bills.

New Source Review ("NSR") Rulemaking Revisions

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. In December 2002 and March 2003, the EPA finalized revisions to the NSR regulations, which represented the first substantial change to the NSR Program since the 1992 NSR Rule. Following EPA's Reconsideration of the NSR in 2003, multiple petitions for review of the Rule were filed in the D.C. Circuit Court of Appeals. In June 2005, the D.C. Circuit Court issued a decision substantially upholding EPA's NSR Rule. Two of the key provisions upheld by the Court included a "Demand Growth Exclusion" and the use of a historical baseline emissions period representative of higher historic capacity levels. However, the Court vacated two key provisions of the NSR Program: the "Clean Unit" applicability test of the 2002 NSR Rule and the "Pollution Control Exemption" of the 1992 NSR Rule.

In October 2003, the EPA published its final rule on Routine Maintenance, Repair, and Replacement Regulation ("RMRR") exclusion, referred to as the "Equipment Replacement Provision" ("ERP"). The ERP was challenged by the State of New York and other citizens groups, and a stay was issued of the ERP Rule in December 2003, while New York's petition challenging the ERP Rule was briefed on appeal. In March 2006, the D.C. Circuit Court issued a decision that vacated the ERP Rule.

In October 2005, EPA proposed to replace the annual emissions increase test with an hourly emissions test. The proposed hourly emissions test was similar to the hourly emissions test in the New Source Performance Standards ("NSPS") program. On April 25, 2007, EPA proposed further options to change the emissions increase test that would only apply to existing electric generating units at power plants. Duke Energy continues to monitor the developments regarding this rulemaking, but it is unknown when a final rule will be issued.

NSR Lawsuits

In November 1999, and through subsequent amendments, the United States brought a lawsuit in the United States Federal District Court for the Southern District of Indiana against Cinergy, CG&E, and PSI alleging various violations of the CAA.
Specifically, the lawsuit alleges that the companies violated the CAA by not obtaining Prevention of Significant Deterioration ("PSD"), Non-Attainment NSR, and Ohio and Indiana State Implementation Plan ("SIP") permits for various maintenance projects at their owned and co-owned generating stations. Additionally, the suit claims that Cinergy violated an Administrative Consent Order entered into in 1998 between the EPA and Cinergy relating to alleged violations of Ohio's SIP provisions governing particulate matter at Unit 1 at the W.C. Beckjord Station. The suit seeks (1) injunctive relief to require installation of pollution control technology on various generating units at the W.C. Beckjord and Miami Fort Stations, and the Cayuga, Gallagher, Wabash River, and Gibson Stations, and (2) civil penalties in amounts of up to $27,500 per day for each violation. In addition, three northeast states and two environmental groups have intervened in the case.

A jury trial on liability issues commenced on May 5, 2008, in Indianapolis, Indiana. The trial concluded on May 22, 2008, with a jury verdict in favor of Cinergy/Duke Energy on all projects except for projects at three Wabash River units. A remedy phase trial is scheduled to commence on December 8, 2008, to determine what remedies will be imposed by the trial court for the three Wabash River projects, which may include ordering the installation of pollution control equipment or other remedies.

In March 2000, the United States also filed in the United States District Court for the Southern District of Ohio an amended complaint in a separate lawsuit alleging violations of the CAA relating to PSD, NSR, and Ohio SIP requirements regarding various generating stations, including a generating station operated by Columbus Southern Power Company ("CSP") and jointly-owned by CSP, The Dayton Power and Light Company ("DP&L"), and CG&E. A bench trial occurred in mid 2006. CSP is a subsidiary of American Electric Power. On October 9, 2007, AEP announced a settlement agreement with the United States, eight states and thirteen citizen groups, resolving litigation regarding alleged violations of the NSR provisions of the CAA. AEP admitted no violations of law, and all claims against AEP were released, including the claim involving the generating station jointly owned by CSP, DP&L and CG&E.

CO_2 Lawsuits

In July 2004, the states of Connecticut, New York, California, Iowa, New Jersey, Rhode Island, Vermont, Wisconsin, and the City of New York brought a lawsuit in the United States District Court for the Southern District of New York against Cinergy, American Electric Power Company, Inc., American Electric Power Service Corporation, The Southern Company, Tennessee Valley Authority, and Xcel Energy Inc. That same day, a similar lawsuit was filed in the United States District Court for the Southern District of New York against the same companies by Open Space Institute, Inc., Open Space Conservancy, Inc., and The Audubon Society of New Hampshire. These lawsuits allege that the defendants' emissions of CO_2 from the combustion of fossil fuels at electric generating facilities contribute to global warming and amount to a public nuisance. The complaints also allege that the defendants could generate the same amount of electricity while emitting significantly less CO_2. The plaintiffs are seeking an injunction requiring each defendant to cap its CO_2 emissions and then reduce them by a specified percentage each year for at least a decade. In September 2005, the district court granted the defendants' motion to dismiss the lawsuit. The plaintiffs have appealed this ruling to the Second Circuit Court of Appeals. Oral argument was held before the Second Circuit Court of Appeals on June 7, 2006.

In a separate action, on April 27, 2006, several states and environmental groups filed a petition asking the DC Circuit Court of Appeals to review EPA's ability to establish CO_2 emissions standards for boilers under the New Source Performance Standard regulations. Duke Energy will continue to monitor this litigation and its potential impact on the Company.

Native Village of Kivalina v. ExxonMobil et al

On February 26, 2008, plaintiffs filed suit against various oil and power company defendants, including Duke Energy Corporation and Peabody Coal. Plaintiffs, the governing bodies of an Inupiat village in Alaska, brought the action on their own behalf and on behalf of the village's approximately 400 residents. The lawsuit alleges that defendants' emissions of carbon dioxide contributed to global warming and constituted a private and public nuisance. Plaintiffs also allege that certain defendants, including Duke Energy, conspired to mislead the public with respect to the global warming. Plaintiffs seek unspecified monetary damages, attorneys' fees and expenses.

F. PLAN SELECTION

1. Economic Considerations

As stated earlier, the relative economics of the different plans are dependent on the sensitivity assumptions. In addition, as discussed in Section E above, there are many uncertainties regarding future environmental regulations, particularly the scope and timing of potential CO_2 regulations. However, final decisions concerning new supply-side and environmental compliance resources are not required at this time; the Company will continue to monitor the relevant issues.

2. Qualitative/Judgment Factors

The qualitative/judgment factors considered in this IRP analysis were risk-related. First, any time new capacity must be constructed, there is always the risk of construction or siting delay.

In addition, there are pricing, non-performance, and deliverability risk considerations associated with purchasing large amounts of power from the wholesale market. Price volatility, which was quite extreme in the recent past, could well occur again in the Midwest region if proposed new power plants are not constructed and/or if increasing environmental regulations cause retirements of some existing units. Finally, there is increasing potential for transmission constraints, with the corresponding increasing potential for disruptions of purchased power imports. Delivery of power from distant generating units, whether owned by the Company or not, can also present delivery risks.

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, as well as high volatility throughout the year.

3. Description of Selected Plan

Based upon both the quantitative and qualitative results of the analyses, the Gas/Nuclear/EE portfolio was selected to be the 2008 IRP. It was robust and it had the lowest PVRR in the Base Case and across all sensitivities, except for the No Carbon case. The Coal/Nuclear/EE portfolio was only approximately 0.2% higher in PVRR than the chosen portfolio, so it could have been chosen instead. DE-Kentucky will continue to monitor the economics of various resource alternatives in the future.

A summary of the plan is shown in Figure 8-15. The details of the 2008 IRP including yearly capacity, purchases, capacity additions, retirements/derates, cogeneration, load, EE, DR, and reserve margins are shown in Figure 8-16. The year-by-year Projected Generating Capability Changes to the DE-Kentucky system (including existing unit changes and long-term purchases) are shown in Figure 8-17. Figures 8-18 and 8-19 show the net dependable generating capacity for each year of the planning period by unit and for the system for summer and winter, respectively. Additional information concerning the future generating units in the plan is shown on Figure 8-20.

This IRP is the most robust plan, as discussed earlier. It contains the conservation EE and Demand Response programs. The supply-side resources consist of a two CT units (35 MW each) added in 2019 and 2023, and a nuclear unit (35 MW) added in 2027. Each of the supply-side units should be viewed as placeholders for the types of capacity resources that are the most economical at the time decisions for adding capacity need to be made.

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. In addition, if the new mercury standard is MACT rather than cap-and-trade, switching to low sulfur fuel and installing a baghouse with ACI at Miami Fort 6 will be required. The Company will continue to monitor the coming mercury rulemaking and will perform additional analysis prior to making any final decisions concerning these expenditures. Any shortfalls between the yearly allowance allocation from the EPA and the actual emissions will be supplied by DE-Kentucky's allowance bank or by allowance purchases from the market.

The units shown in the plan can represent power purchase agreements, cogeneration, repowering, self-built generation, or joint ownership of generating facilities. The decision as to the actual types of resources that DE-Kentucky will make depends on the relative prices of the alternatives available at that time.

This IRP is the plan with the lowest PVRR. Of course, as the time approaches when final commitments have to be made for capacity, the plan may be adjusted based on the most current assumptions of capital and fuel costs at that time. 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 DE-Kentucky's future demand with an adequate and reliable supply of electricity at the lowest possible cost.

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 DE-Kentucky's customers (because these cost items are common to all plans). Therefore, an accurate projection of customer rates cannot be provided.

4. Projected Reliability

The 2008 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. Environmental Effects

The recommended plan consists of adding new gas-fired and nuclear capacity and switching to lower sulfur coal with adding baghouses and ACI on Miami Fort Unit 6. The gas-fired CTs will have no SO_2 or mercury emissions (although there will be NO_x and CO_2 emissions). The nuclear addition will be a clean resource. The majority of electricity as well as the associated emissions and wastes in the plan will be produced by the existing coal-fired units on DE-Kentucky's system.

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.

DE-Kentucky currently complies with existing environmental requirements and is committed to continue to do so. Duke Energy's Environmental, Health & Safety Policy establishes principles to fulfill its commitment to people and the environment. Protecting and responsibly managing natural resources are critical to the quality of life in the areas Duke Energy serves, the environment, and Duke Energy's long-term business success.

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.

6. Fuel and Technology Diversity

As discussed previously, this IRP analysis considered a wide diversity of fuels and technologies, including renewables. The recommended plan further diversifies DE-Kentucky's resource mix through the addition of more CTs which utilize natural gas. In addition, the plan contains DSM programs, *i.e.*, the "fifth fuel", covering a wide range of measures. Finally, a nuclear alternative was shown to be an economic addition near the end of the 20 year Planning Period and will be studied further in future analyses.

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. Since three of the IRP Objectives discussed in Chapter 2 were to maintain flexibility, provide economic service, and minimize risk, it is imperative that the uncertainties facing DE-Kentucky be factored into the decisions concerning the implementation of the 2008 IRP.

1. Environmental Regulatory Climate

The environmental regulatory climate is becoming more burdensome for the electric utility industry. As discussed in Sections C and E, the potential exists for additional regulation to be imposed on utilities in the form of CO_2 emission limits; carbon taxes and energy taxes; renewable portfolio standards; additional regulations to address regional haze, ozone, fine particulates, and mercury; 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/legislative climate.

2. Volatility in the Wholesale Power Market

While many potential new generating unit construction projects have been announced, there have also been a significant number of project cancellations recently due to increasing capital costs caused by global competition and uncertainty concerning potential greenhouse gas legislation. The number of projects that will actually be constructed is highly uncertain, potentially causing increases in supply to lag behind increases in demand. This can increase volatility and cause a return to price spikes if supply and demand are out of balance.

3. Volatility in the Natural Gas Market

Between 2003 and 2005, natural gas prices at Henry Hub increased by over 50%, partially due to higher demand. The supply disruptions caused by Hurricanes Katrina and Rita exacerbated the situation. Several additional aspects of the current natural gas price situation are concerning. In May 2008 there were unprecedented prices for natural gas on the NYMEX. For example, on May 14, the highest NYMEX gas future of $12.74/MMBtu was reported for January 2009 delivery. In addition, the spot Henry Hub natural gas price was $11.49/MMBtu; the natural gas futures for the rest of 2008 were $11.94/MMBtu; for 2009 they were $11.12/MMBtu; and for 2010 they were $10.21/MMBtu. This was occurring *in the absence of* CO_2 emission regulations. Further, year-to-date Henry Hub spot gas prices through May 14, 2008, averaged $9.17/MMBtu, which exceeds the prices for the entire year of 2005 ($8.50/MMBtu) -- the year with the highest spot Henry Hub gas prices in history, even though there have been no supply disruptions as there were in 2005 when hurricanes Katrina and Rita occurred. It is expected that the natural gas market will continue to exhibit high volatility.

4. 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. Although the creation of RTOs may enhance coordination and reliability, without new investments in the transmission infrastructure, constraints will continue to exist. This can adversely impact utilities needing to import large amounts of power to their systems.

Although DE-Kentucky will continue to monitor these developments in the future, no immediate commitments to new resources are necessary at this time.

H. PLAN IMPLEMENTATION

1. Supply-Side Resources

Because they do not appear until late in the planning horizon, the new supply-side resources in the plan represent, to a large extent, placeholders for capacity and energy needs on the system. No decisions concerning additional supply-side resources are necessary over the next three years, so DE-Kentucky can continue to evaluate its resource requirements. 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 participation in the Midwest ISO market.

However, the relatively small size of the system can cause challenges. The existing DE-Kentucky portfolio lacks some diversity in that it contains two relatively large coal-fired units (compared to the overall size of the DE-Kentucky system). These units can pose additional risks when they are out of service for either planned or forced outages. The ability to offer these units into the Midwest ISO market and to purchase from a more diverse pool of resources from that market helps to mitigate some of these risks. Nevertheless, in the future, DE-Kentucky will continue to assess these risks and may look for opportunities to diversify the portfolio. Potential alternatives may include shared ownership or capacity swaps with other utilities. DE-Kentucky will keep this Commission informed of any developments in this area.

2. Environmental Compliance Resources

The only environmental compliance resource identified in the chosen plan is installation of a baghouse with ACI on Miami Fort 6, along with switching to lower sulfur coal. However, until the mercury rules that will replace CAMR are known, the Company will continue to monitor and study the need for these changes. DE-Kentucky also will be closely monitoring the SO_2 and NO_x emission allowance markets.

3. Demand-Side Resources

In the Commission Order in Case No. 2004-00389, dated February 14, 2005, 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 5-year period, through December 31, 2009.

Under the current DSM Agreement and prior Commission Orders, all of these programs except Power Manager and PER will end December 2009 unless an application is made to continue them. It is the Company's intention to submit a filing subsequent to this report, requesting the approval of a set of energy efficiency and demand response products and services.

The incremental impacts going forward of the current set of EE and DR programs are incorporated into the resource plan for DE-Kentucky. An analysis was also performed comparing the economics of the 2008 IRP plan to a plan that did not contain any EE or DR programs. This analysis showed that the inclusion of these programs in the chosen plan reduces the PVRR of that plan by approximately $2.5 million.

4. Consistency with Planning Objectives and Goals

The 2008 IRP, with its proposed implementation, is consistent with the overall planning objectives and goals discussed in Chapter 2. The plan selected was the least cost, provides reliable service to DE-Kentucky'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 DE-Kentucky's compliance strategy.

5. Consideration of Market Forces and Competition

As discussed throughout this document, DE-Kentucky has considered market forces and competition in the development of its IRP. Examples include the modeling of an hourly market price forecast to simulate interactions with the wholesale power market, use of market-based emission allowances in the dispatch, and the use of long-term fuel prices developed using a fundamental forecast that considers supply and demand of fuels. Furthermore, in the No Carbon and High Carbon alternative sensitivities, these market variables were adjusted in recognition that different environmental requirements would impact the price levels.

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Figure 8-1

DUKE ENERGY KENTUCKY
SUPPLY VS. DEMAND BALANCE
Existing DSM and No Uncommitted Supply-Side or Compliance Resources
(Summer Capacity and Loads)

YEAR	INITIAL CAPACITY	SHORT TERM PURCH.	INCR. CAPACITY ADDITIONS	INCR. CAPACITY RETIRE./ DERATES	COGEN. CAPACITY	TOTAL CAPACITY	PEAK LOAD	ENERGY SECURITY ACT LIGHTING IMPACTS	INCR. CONSERV.[a]	DEMAND RESPONSE	FIRM SALES	NET LOAD	RES. MAR. (%)	CAPACITY MINUS NET LOAD	PURCHASES NEEDED TO MEET 15% RM
2008	1077	0	0	0	0	1077	871	0	0	-11	0	859	25.3	218	(89)
2009	1077	0	0	0	0	1077	880	0	-1	-13	0	866	24.3	211	(81)
2010	1077	0	0	0	0	1077	889	0	-1	-14	0	874	23.3	203	(72)
2011	1077	0	0	0	0	1077	907	0	-2	-14	0	891	20.9	186	(53)
2012	1077	0	0	0	0	1077	918	-8	-2	-14	0	893	20.6	184	(50)
2013	1077	0	0	0	0	1077	928	-15	-3	-14	0	896	20.2	181	(47)
2014	1077	0	0	0	0	1077	938	-23	-3	-14	0	898	20.0	179	(45)
2015	1077	0	0	0	0	1077	948	-25	-3	-14	0	905	19.0	172	(36)
2016	1077	0	0	0	0	1077	958	-23	-4	-14	0	917	17.4	160	(22)
2017	1077	0	0	0	0	1077	968	-28	-4	-14	0	922	16.8	155	(17)
2018	1077	0	0	0	0	1077	978	-29	-4	-14	0	931	15.7	146	(6)
2019	1077	0	0	0	0	1077	987	-30	-4	-14	0	939	14.7	138	3
2020	1077	0	0	0	0	1077	995	-32	-4	-14	0	945	14.0	132	10
2021	1077	0	0	0	0	1077	1004	-28	-4	-14	0	958	12.4	119	25
2022	1077	0	0	0	0	1077	1013	-28	-4	-14	0	967	11.4	110	35
2023	1077	0	0	0	0	1077	1021	-32	-4	-14	0	971	10.9	106	40
2024	1077	0	0	0	0	1077	1030	-32	-4	-14	0	980	9.9	97	50
2025	1077	0	0	0	0	1077	1038	-32	-4	-14	0	988	9.0	89	59
2026	1077	0	0	0	0	1077	1046	-32	-4	-14	0	996	8.1	81	68
2027	1077	0	0	0	0	1077	1053	-28	-4	-14	0	1007	7.0	70	81
2028	1077	0	0	0	0	1077	1061	-33	-4	-14	0	1010	6.6	67	85
2029	1077	0	0	0	0	1077	1068	-33	-4	-14	0	1017	5.9	60	93
2030	1077	0	0	0	0	1077	1074	-33	-4	-14	0	1023	5.3	54	100

[a] Not included in load forecast
The values shown are the impacts coincident with the summer peak, not the maximum impacts.

Optimal Plans Produced by System Optimizer Model

Capacity (MW) Built

	Base Load Forecast		Higher Load Forecast		Lower Load Forecast/Higher Renew.		Higher Gas Prices		Higher Coal Prices	
	MW Built	Online Year	MW Built	Online Year	MW Built	Online Year	MW Built	Online Year	MW Built	Online Year
Coal Unit										
DR-Power Manager	12.6	2008	12.6	2008	12.6	2008	12.6	2008	12.6	2008
DR-PowerShare®	1.8	2008	1.8	2008	1.8	2008	1.8	2008	1.8	2008
EE	6.94	2008	6.94	2008	6.94	2008	6.94	2008	6.94	2008
IGCC										
Miami Fort 6 Precip. Upgrade										
Miami Fort 6 Baghouse/ACI	163	2012	163	2012	163	2012	163	2012	163	2012
CC Unit										
CC Unit Duct Firing										
CT Unit	70	2019, 2023	140	2012, 2015 2019, 2022			35	2019	70	2019, 2023
Nuclear Unit	35	2027	35	2026			35	2027	35	2027
Animal Waste Unit							35	2023		
1 Year Block Market Purchase			35	2011						
Wind			50	2025						

Capacity (MW) Built

	Higher Carbon Tax		No Carbon Tax		15% RPS		CAMR		No EE/DR	
	MW Built	Online Year	MW Built	Online Year	MW Built	Online Year	MW Built	Online Year	MW Built	Online Year
Coal Unit			140	2017, 2020, 2023, 2026						
DR-Power Manager	12.6	2008	12.6	2008	12.6	2008	12.6	2008		
DR-PowerShare®	1.8	2008	1.8	2008	1.8	2008	1.8	2008		
EE	6.94	2008	6.94	2008	6.94	2008	6.94	2008		
IGCC										
Miami Fort 6 Precip. Upgrade							163	2012		
Miami Fort 6 Baghouse/ACI	163	2012	163	2012	163	2012			163	2012
CC Unit										
CC Unit Duct Firing										
CT Unit							35	2020	70	2017, 2021
Nuclear Unit							35	2025	35	2025
Animal Waste Unit					70	2017, 2020				
1 Year Block Market Purchase										
Wind					100	2010, 2013	100	2023, 2024	50	2028

Figure 8-3

Summary of Portfolios Analyzed

	Gas/Nuclear/EE	*Coal/Nuclear/EE*	*High Renewables/EE*
2008	EE, DR Bundles	EE, DR Bundles	EE, DR Bundles
2009			
2010			50 MW New Wind
2011			
2012	MF6 FF/ACI	MF6 FF/ACI	MF6 FF/ACI
2013			50 MW New Wind
2014			
2015			
2016			
2017			35 MW New Animal Waste
2018			
2019	35 MW New CT	35 MW New Coal	
2020			35 MW New Animal Waste
2021			
2022			
2023	35 MW New CT	35 MW New CT	
2024			
2025			
2026			
2027	35 MW New Nuclear	35 MW New Nuclear	
2028			
Coal	0	35	0
CC	0	0	0
CT	70	35	0
Nuclear	35	35	0
Renew*	0	0	85

* Peak Capacity Value

Figure 8-4

Base Case

PVRR by Portfolio Versus Average PVRR

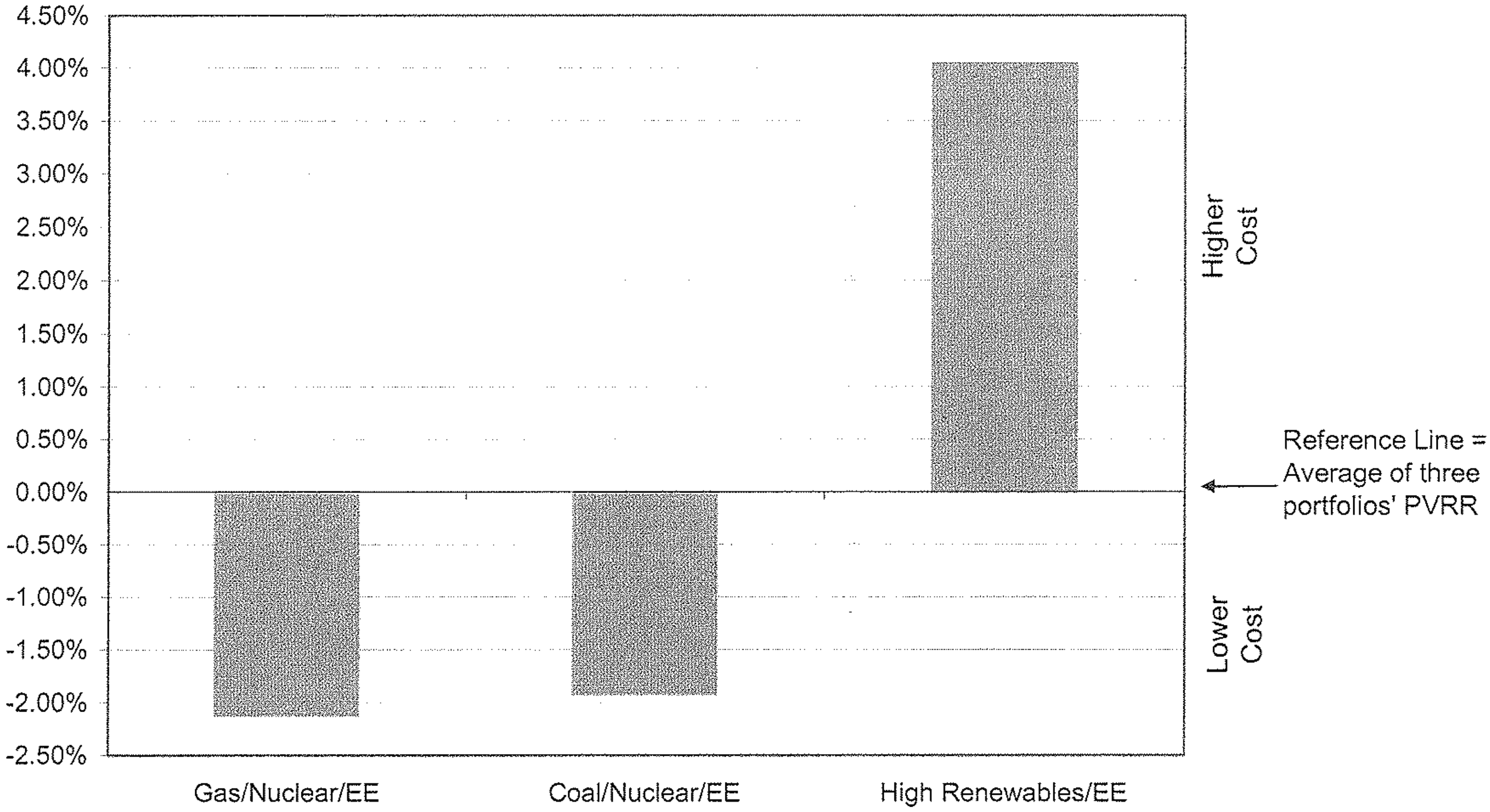

Figure 8-5

High Load

PVRR by Portfolio Versus Average PVRR

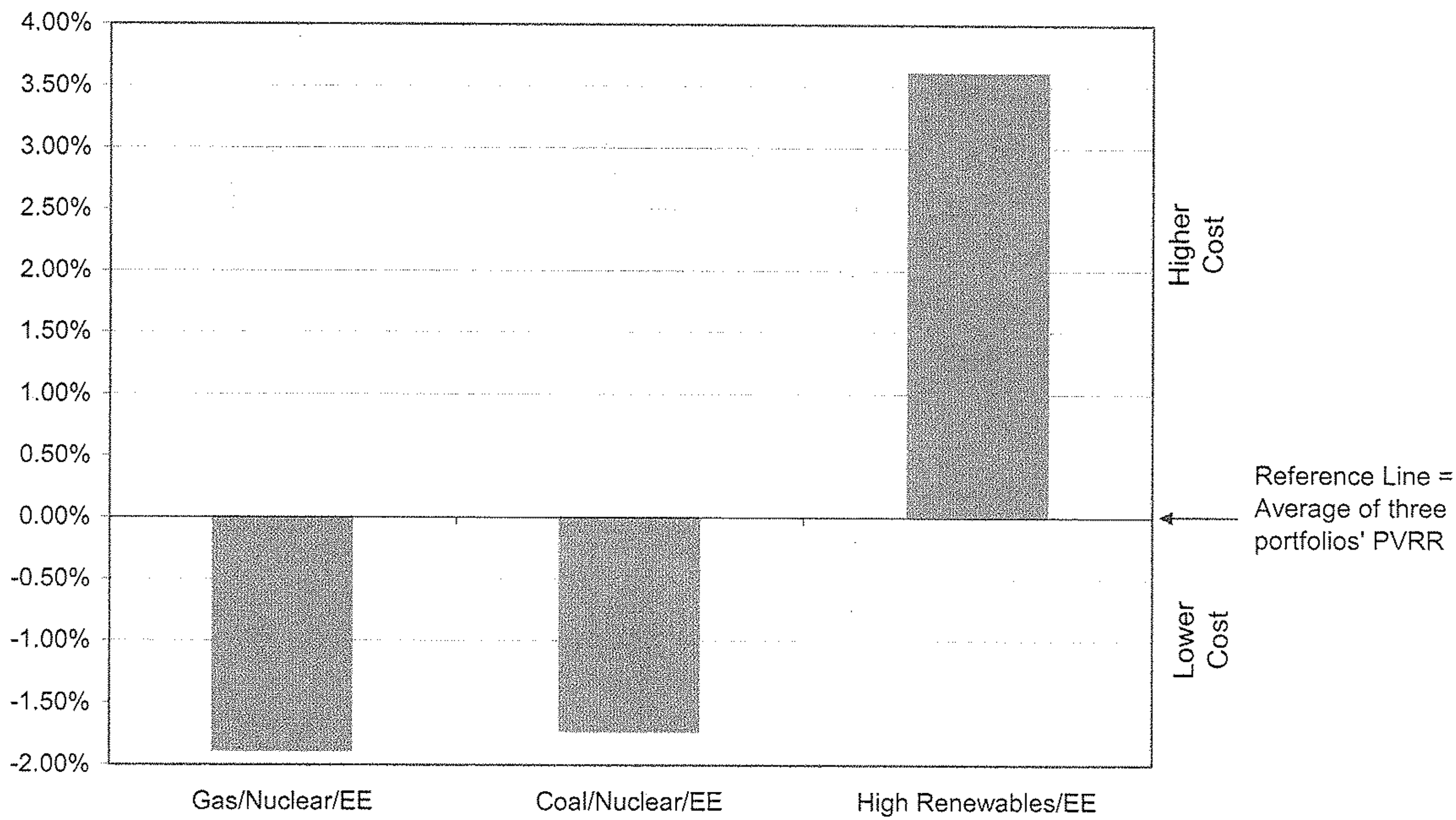

Figure 8-6

Low Load/Higher Renewables

PVRR by Portfolio Versus Average PVRR

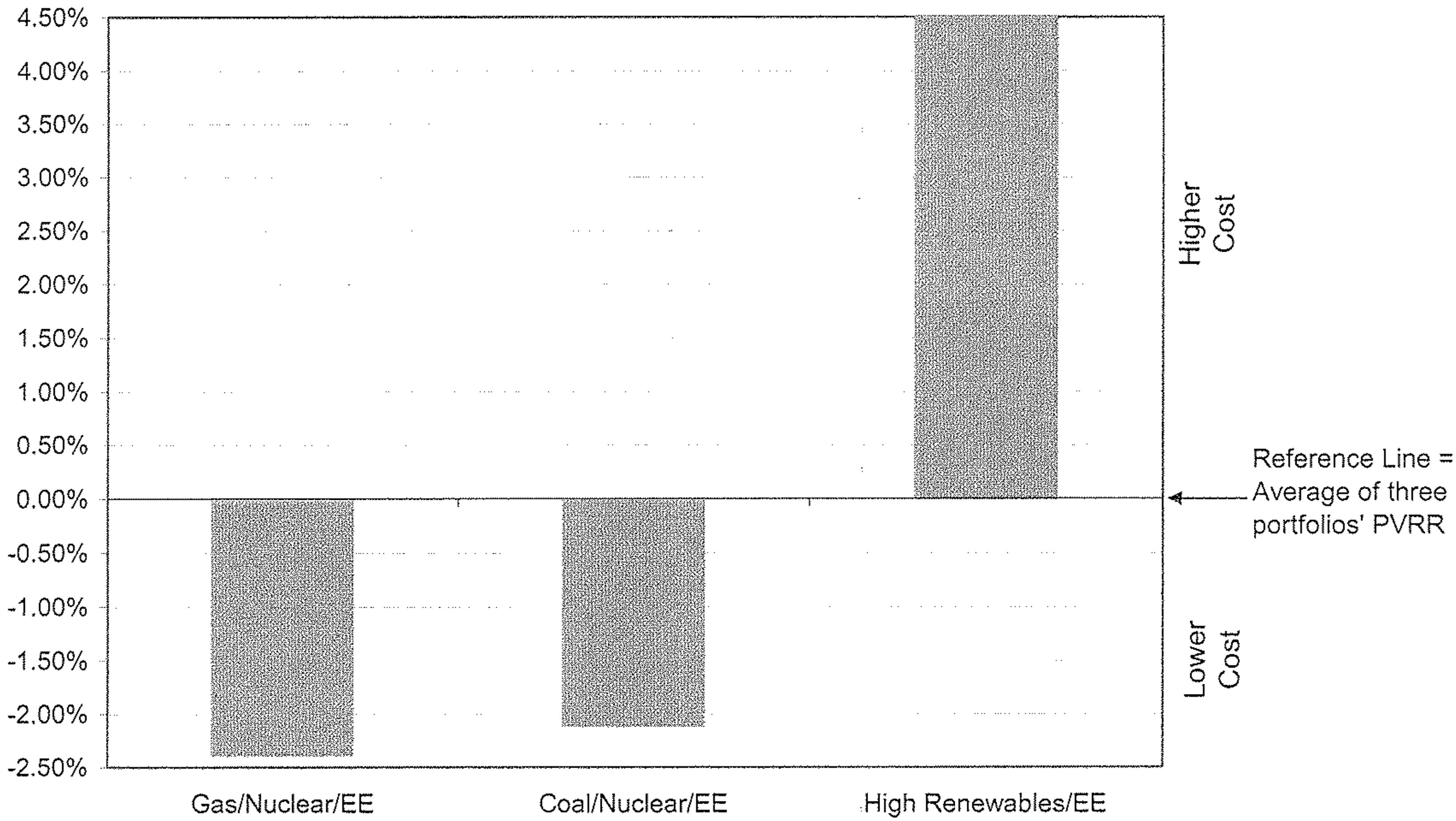

Figure 8-7

Higher Gas Prices

PVRR by Portfolio Versus Average PVRR

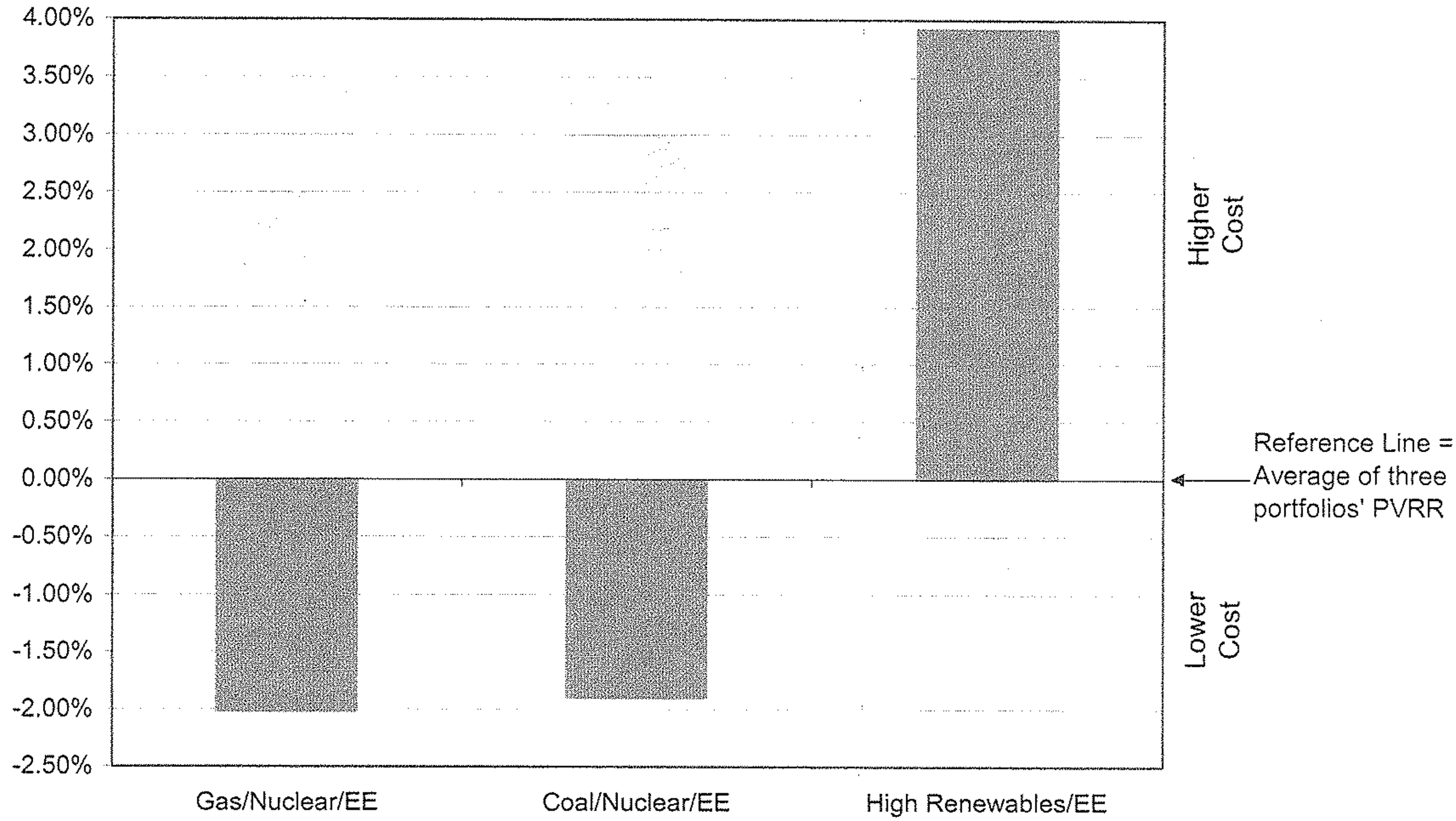

Figure 8-8

Higher Coal Prices

PVRR by Portfolio Versus Average PVRR

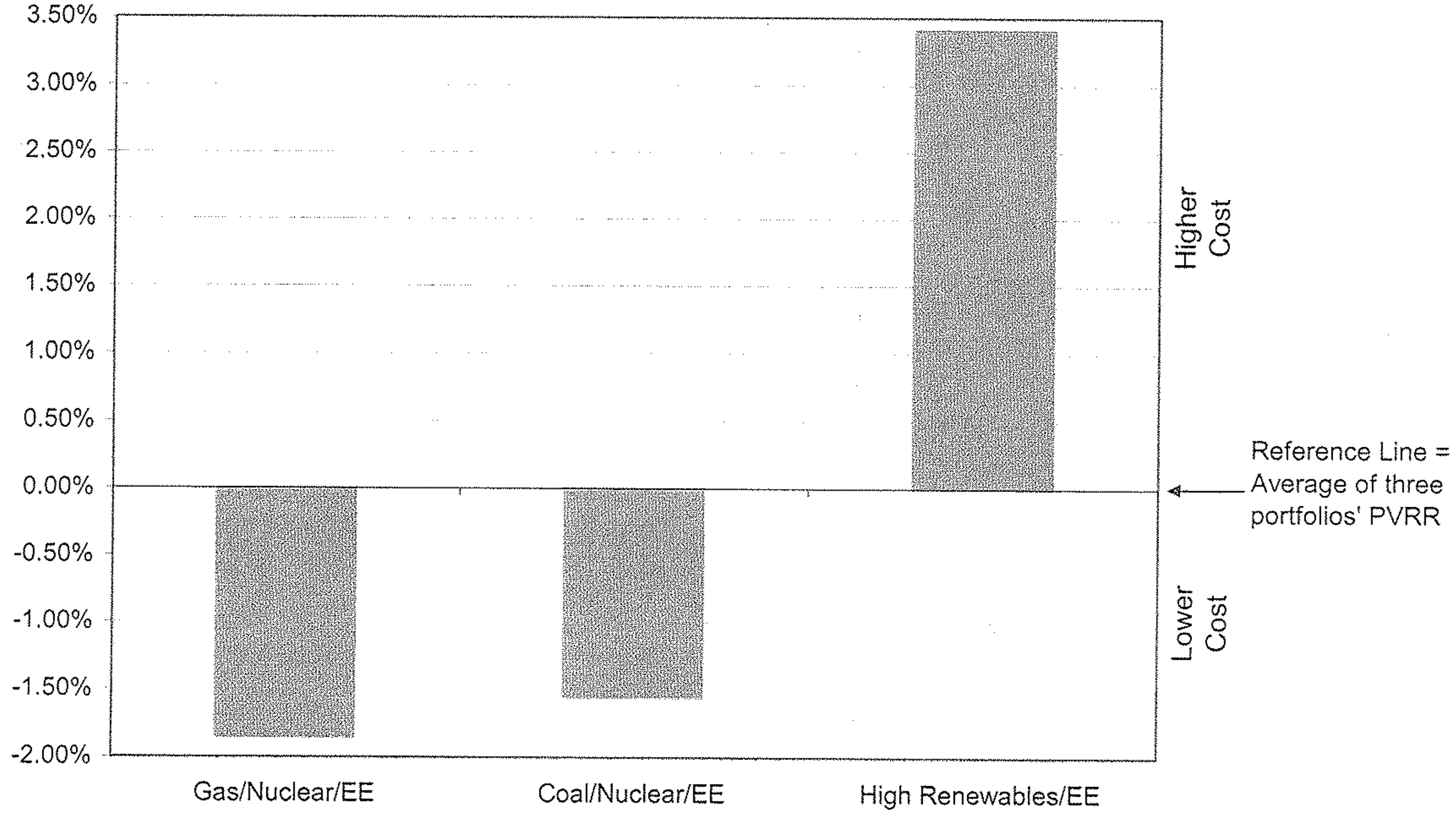

Figure 8-9

Higher Carbon Tax Forecast Case

PVRR by Portfolio Versus Average PVRR

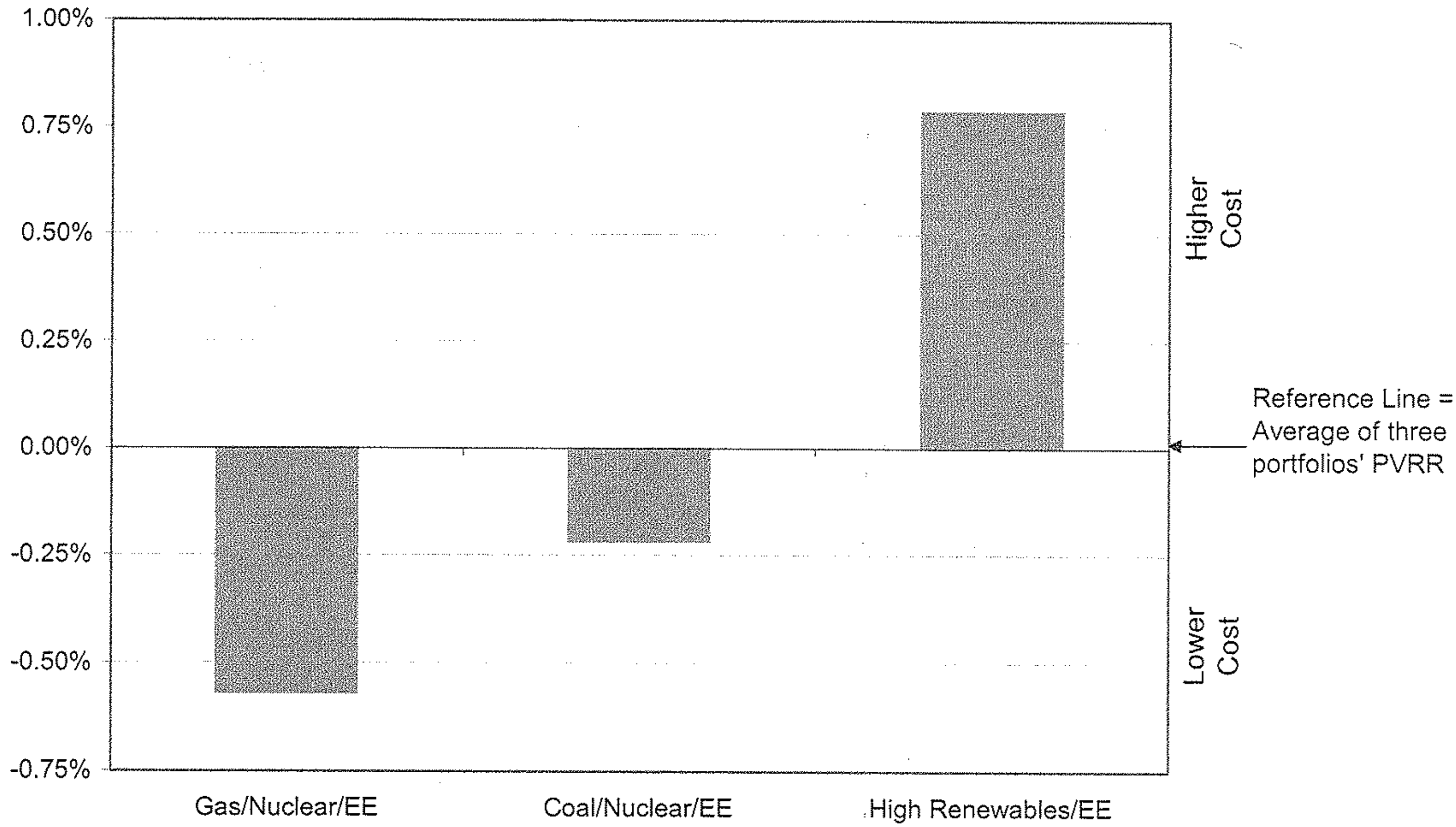

Figure 8-10

No Carbon Case

PVRR by Portfolio Versus Average PVRR

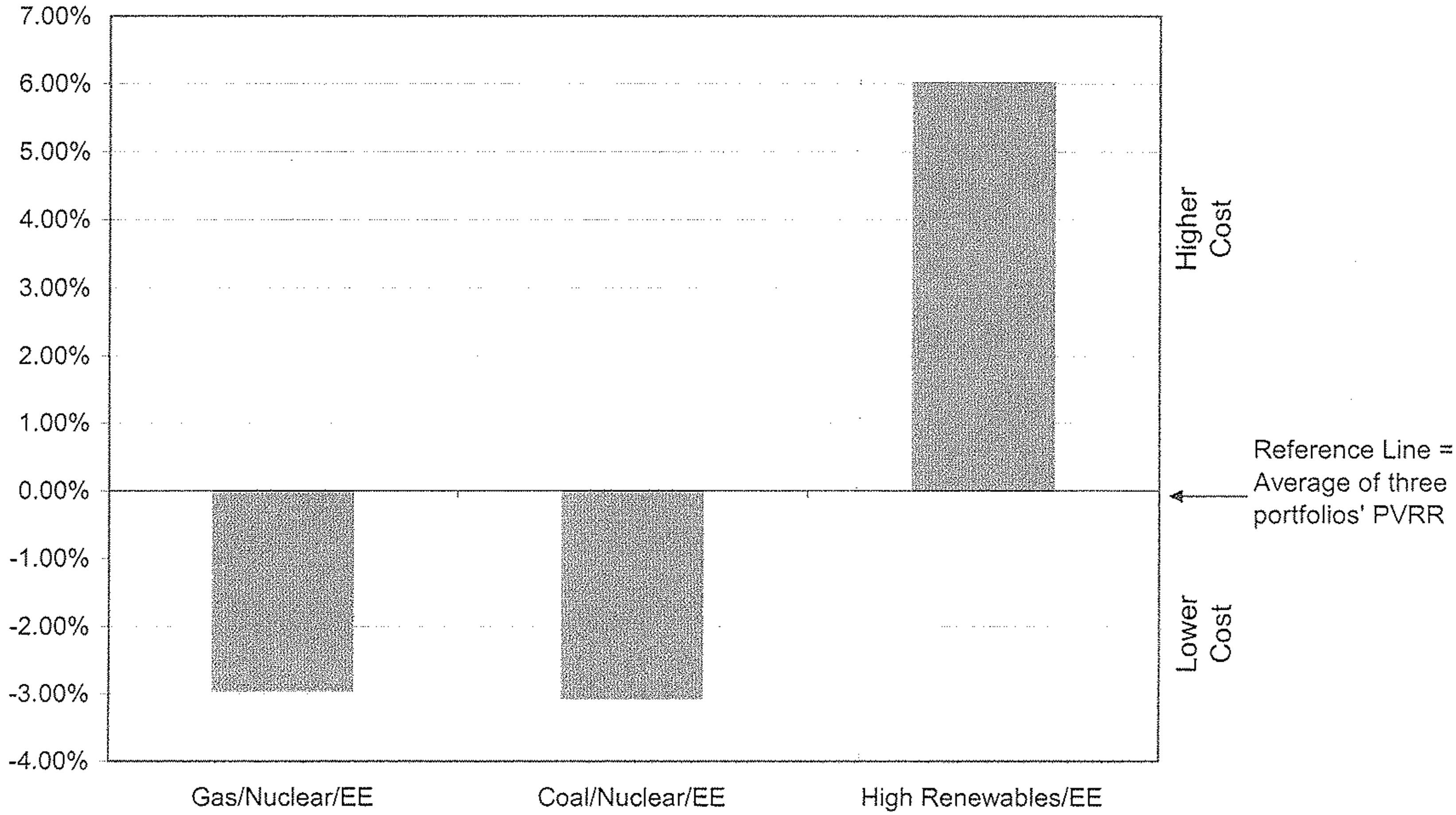

Figure 8-11

20% Higher Capital Cost on CT/CC Units

PVRR by Portfolio Versus Average PVRR

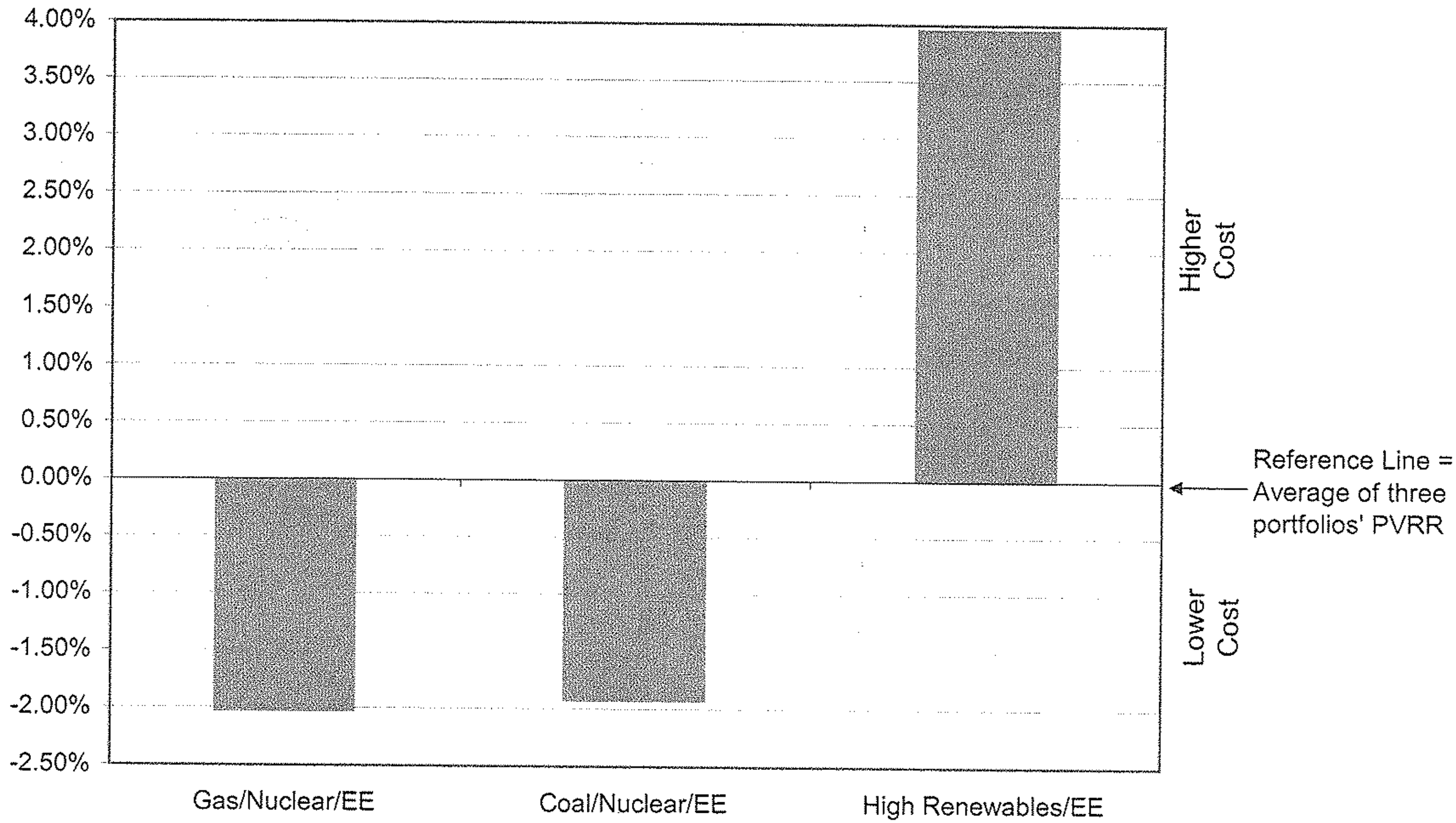

Figure 8-12

20% Higher Capital Cost on Coal Units

PVRR by Portfolio Versus Average PVRR

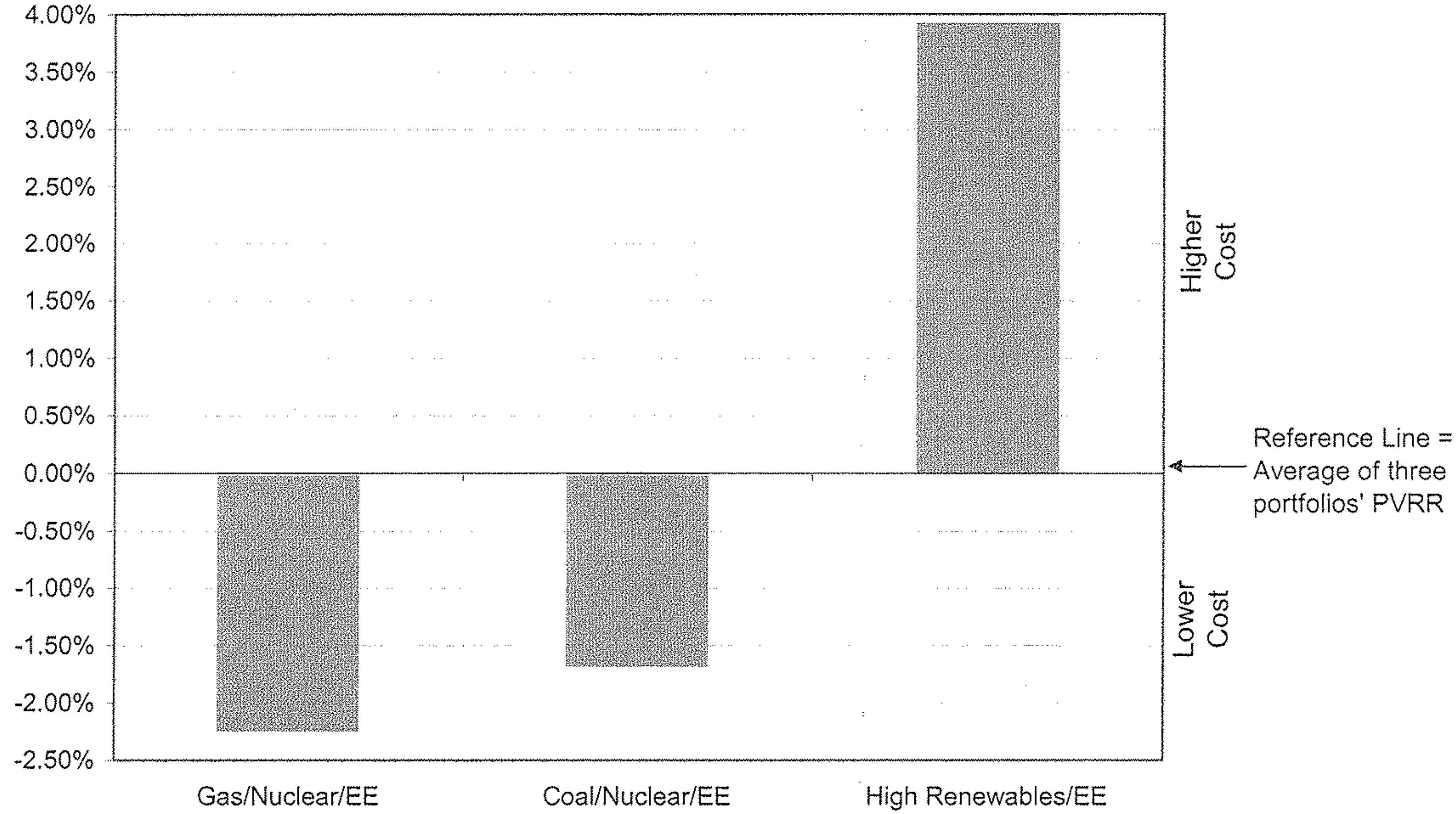

Figure 8-13

20% Higher Capital Cost on Nuclear Units

PVRR by Portfolio Versus Average PVRR

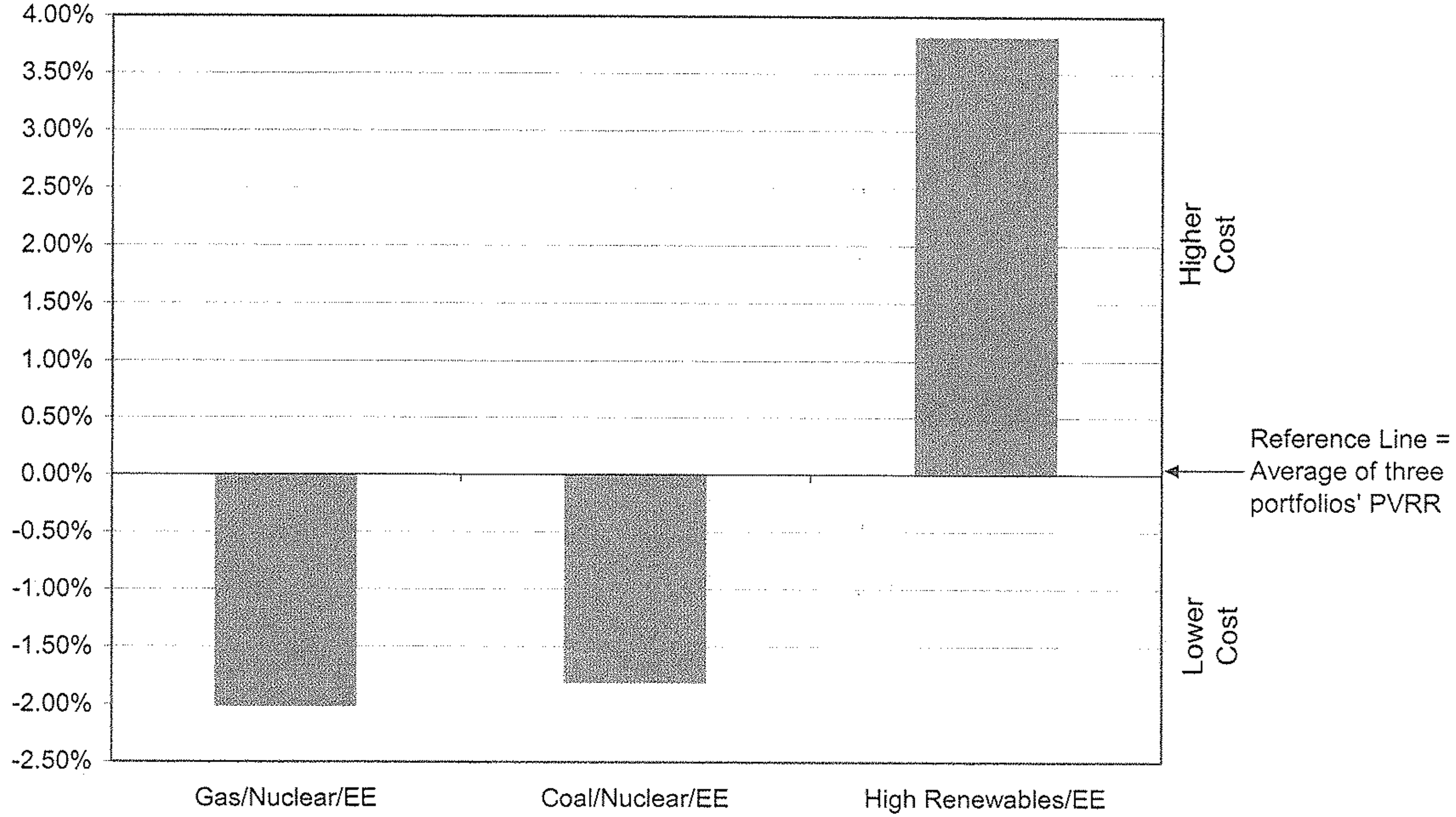

Figure 8-14

20% Higher Capital Cost on Renewables

PVRR by Portfolio Versus Average PVRR

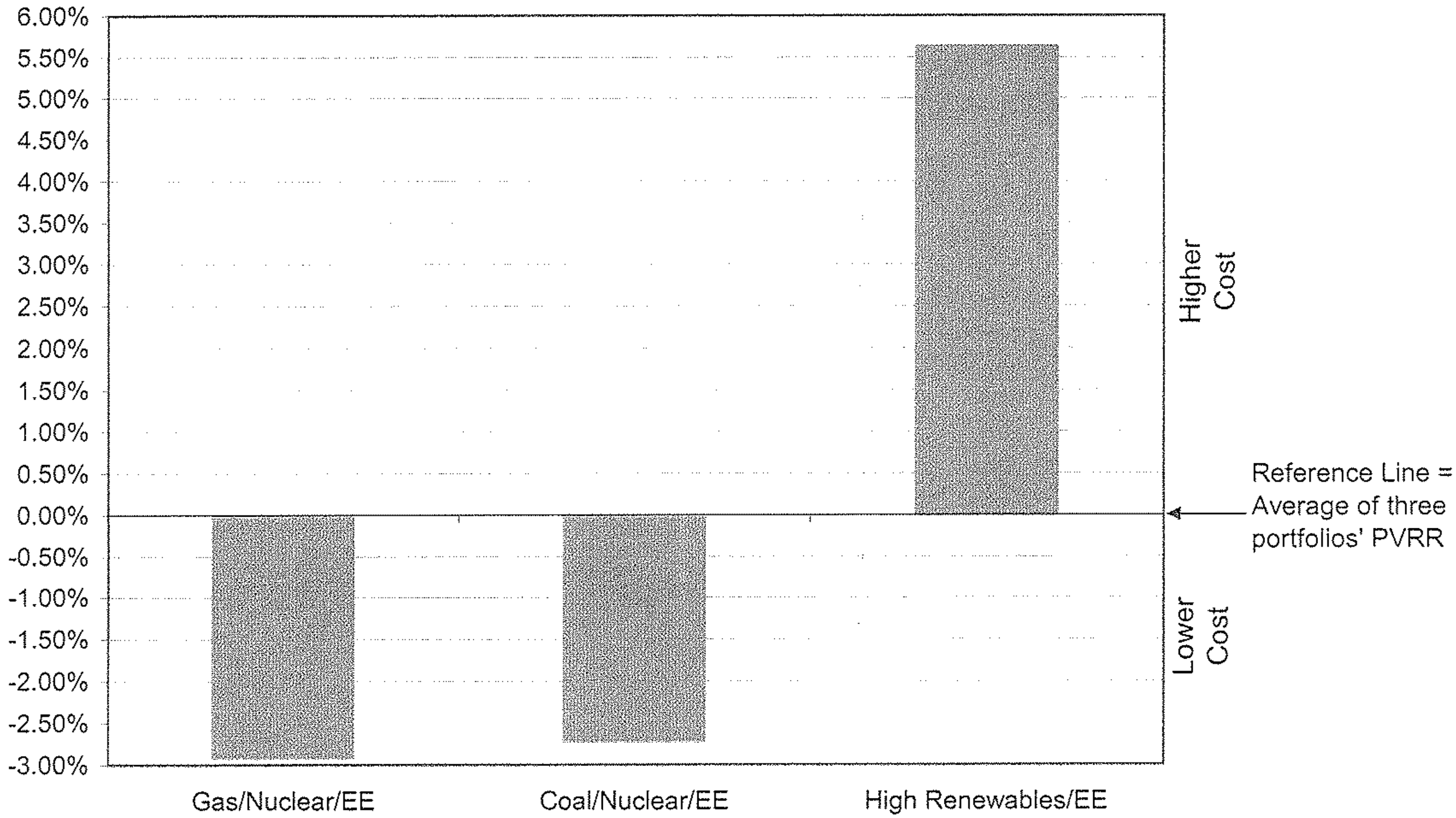

Figure 8-15

DUKE ENERGY KENTUCKY INTEGRATED RESOURCE PLAN 2008-2028

Year	Demand-Side[1]	Purchases/Unit Additions[2]	Compliance
2008	Conservation EE Bundle DR Bundle - Residential DR Bundle - Non-Residential		
2009			
2010			
2011			
2012			Low SO_2 Fuel, BH, ACI on Miami Fort 6
2013			
2014			
2015			
2016			
2017			
2018			
2019		Install New CT (35 MW)	
2020			
2021			
2022			
2023		Install New CT (35 MW)	
2024			
2025			
2026			
2027		Install New Nuclear (35 MW)	
2028			

[1] The Demand-side resources are assumed to continue throughout the planning period (2008-2028)
[2] Capacity shown denotes summer ratings

Figure 8-16

DUKE ENERGY KENTUCKY
SUPPLY VS. DEMAND BALANCE
(Summer Capacity and Loads)

YEAR	INITIAL CAPACITY	SHORT TERM PURCH.	INCR. CAPACITY ADDITIONS	INCR. CAPACITY RETIRE./ DERATES	COGEN. CAPACITY	TOTAL CAPACITY	PEAK LOAD	ENERGY SECURITY ACT LIGHTING IMPACTS	INCR. CONSERV.[a]	DEMAND RESPONSE	FIRM SALES	NET LOAD	RES. MAR. (%)	CAPACITY MINUS NET LOAD	PURCHASES NEEDED TO MEET 15% RM
2008	1077	0	0	0	0	1077	871	0	0	-11	0	859	25.3	218	(89)
2009	1077	0	0	0	0	1077	880	0	-1	-13	0	866	24.3	211	(81)
2010	1077	0	0	0	0	1077	889	0	-1	-14	0	874	23.3	203	(72)
2011	1077	0	0	0	0	1077	907	0	-2	-14	0	891	20.9	186	(53)
2012	1077	0	0	-1	0	1076	918	-8	-2	-14	0	893	20.5	183	(49)
2013	1076	0	0	0	0	1076	928	-15	-3	-14	0	896	20.1	180	(46)
2014	1076	0	0	0	0	1076	938	-23	-3	-14	0	898	19.9	178	(44)
2015	1076	0	0	0	0	1076	948	-25	-3	-14	0	905	18.8	171	(35)
2016	1076	0	0	0	0	1076	958	-23	-4	-14	0	917	17.3	159	(21)
2017	1076	0	0	0	0	1076	968	-28	-4	-14	0	922	16.7	154	(16)
2018	1076	0	0	0	0	1076	978	-29	-4	-14	0	931	15.6	145	(5)
2019	1076	0	35	0	0	1111	987	-30	-4	-14	0	939	18.3	172	(31)
2020	1111	0	0	0	0	1111	995	-32	-4	-14	0	945	17.6	166	(24)
2021	1111	0	0	0	0	1111	1004	-28	-4	-14	0	958	16.0	153	(9)
2022	1111	0	0	0	0	1111	1013	-28	-4	-14	0	967	14.9	144	1
2023	1111	0	35	0	0	1146	1021	-32	-4	-14	0	971	18.0	175	(29)
2024	1146	0	0	0	0	1146	1030	-32	-4	-14	0	980	16.9	166	(19)
2025	1146	0	0	0	0	1146	1038	-32	-4	-14	0	988	16.0	158	(10)
2026	1146	0	0	0	0	1146	1046	-32	-4	-14	0	996	15.1	150	(1)
2027	1146	0	35	0	0	1181	1053	-28	-4	-14	0	1007	17.3	174	(23)
2028	1181	0	0	0	0	1181	1061	-33	-4	-14	0	1010	16.9	171	(19)

[a] Not included in load forecast
The values shown are the impacts coincident with the summer peak, not the maximum impacts.

Figure 8-16

DUKE ENERGY KENTUCKY
SUPPLY VS. DEMAND BALANCE
(Winter Capacity and Loads)

YEAR	INITIAL CAPACITY	SHORT TERM PURCH.	INCR. CAPACITY ADDITIONS	INCR. CAPACITY RETIRE./ DERATES	COGEN. CAPACITY	TOTAL CAPACITY	PEAK LOAD	ENERGY SECURITY ACT LIGHTING IMPACTS	INCR. CONSERV.[a]	DEMAND RESPONSE	FIRM SALES	NET LOAD	RES. MAR. (%)	CAPACITY MINUS NET LOAD	PURCHASES NEEDED TO MEET 15% RM
2008-2009	1141	0	0	0	0	1141	767	0	-1	0	0	766	49.0	375	(260)
2009-2010	1141	0	0	0	0	1141	773	0	-2	0	0	771	48.0	370	(254)
2010-2011	1141	0	0	0	0	1141	787	0	-3	0	0	784	45.5	357	(239)
2011-2012	1141	0	0	0	0	1141	794	-6	-4	0	0	784	45.5	357	(239)
2012-2013	1141	0	0	-1	0	1140	802	-12	-5	0	0	785	45.1	355	(237)
2013-2014	1140	0	0	0	0	1140	809	-18	-5	0	0	786	45.1	354	(236)
2014-2015	1140	0	0	0	0	1140	816	-19	-6	0	0	791	44.1	349	(230)
2015-2016	1140	0	0	0	0	1140	824	-20	-6	0	0	798	42.9	342	(223)
2016-2017	1140	0	0	0	0	1140	831	-21	-7	0	0	803	42.0	337	(216)
2017-2018	1140	0	0	0	0	1140	838	-23	-7	0	0	808	41.1	332	(211)
2018-2019	1140	0	0	0	0	1140	845	-24	-7	0	0	814	40.0	326	(204)
2019-2020	1140	0	38	0	0	1178	851	-25	-7	0	0	819	43.8	358	(236)
2020-2021	1178	0	0	0	0	1178	857	-25	-7	0	0	825	42.7	352	(229)
2021-2022	1178	0	0	0	0	1178	863	-25	-7	0	0	831	41.7	346	(222)
2022-2023	1178	0	0	0	0	1178	869	-25	-7	0	0	837	40.7	340	(215)
2023-2024	1178	0	38	0	0	1215	875	-25	-7	0	0	843	44.1	372	(245)
2024-2025	1215	0	0	0	0	1215	881	-25	-7	0	0	849	43.1	366	(239)
2025-2026	1215	0	0	0	0	1215	886	-26	-7	0	0	853	42.4	362	(234)
2026-2027	1215	0	0	0	0	1215	892	-26	-7	0	0	859	41.4	356	(227)
2027-2028	1215	0	35	0	0	1250	897	-26	-7	0	0	864	44.7	386	(256)

[a] Not included in load forecast
The values shown are the impacts coincident with the wiinter peak, not the maximum impacts.

Figure 8-17

DUKE ENERGY KENTUCKY

PROJECTED GENERATING CAPABILITY CHANGES [In MegaWatts]

				CAPABILITY CHANGES		SEASONAL TOTAL	
YEAR	UNIT DESIGNATION	NOTES	COMMENT	SUMMER	WINTER	SUMMER	WINTER
2012	Miami Fort 6 BH/ACI	[1]		-1.00	-1.00	-1.00	-1.00
2019	New CT - Unit 1	[2]		35.00	37.50	35.00	37.50
2023	New CT - Unit 2	[2]		35.00	37.50	35.00	37.50
2027	New Nuclear - Unit 1	[3]		35.00	35.00	35.00	35.00

[1] Derate due to additional auxiliary load for Baghouse/ACI

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

[3] The Nuclear unit is generic. The parameters modeled are representative values. The exact unit characteristics will depend on the site and equipment vendor selected.

Figure 8-18

CURRENT AND PROJECTED SUMMER GENERATING CAPABILITIES
Rounded to Nearest MW

STATION	UNIT	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
East Bend	2	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414
Miami Fort	6	163	163	163	163	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162
Woodsdale	1	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
Woodsdale	2	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
Woodsdale	3	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
Woodsdale	4	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
Woodsdale	5	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
Woodsdale	6	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
New CT	1	0	0	0	0	0	0	0	0	0	0	0	35	35	35	35	35	35	35	35	35	35
New CT	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	35	35	35	35	35	35
New Nuclear	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	35	35
Total		1,077	1,077	1,077	1,077	1,076	1,076	1,076	1,076	1,076	1,076	1,076	1,111	1,111	1,111	1,111	1,146	1,146	1,146	1,146	1,181	1,181

Figure 8-19

CURRENT AND PROJECTED WINTER GENERATING CAPABILITIES
Rounded to Nearest MW

STATION	UNIT	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	2023-24	2024-25	2025-26	2026-27	2027-28
East Bend	2	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414
Miami Fort	6	163	163	163	163	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162
Woodsdale	1	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Woodsdale	2	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Woodsdale	3	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Woodsdale	4	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Woodsdale	5	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Woodsdale	6	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
New CT	1	0	0	0	0	0	0	0	0	0	0	0	38	38	38	38	38	38	38	38	38
New CT	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	38	38	38	38	38
New Nuclear	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	35
Total		1,141	1,141	1,141	1,141	1,140	1,140	1,140	1,140	1,140	1,140	1,140	1,178	1,178	1,178	1,178	1,215	1,215	1,215	1,215	1,250

Figure 8-20

DUKE ENERGY KENTUCKY

Future Electric Generating Facilities

Plant Name	Unit No.	Location	Status	Operation Date	Facility Type	Net Capability (MW) Winter	Net Capability (MW) Summer	Fuel Type	Fuel Storage Capacity	Scheduled Upgrades, Derates, Retirements
New CT	1	Unknown	Planned	2019	CT	37.5	35	Gas	Unknown	None
	2	Unknown	Planned	2023	CT	37.5	35	Gas	Unknown	None
New Nuclear	1	Unknown	Planned	2027	Steam	35	35	Nuclear	Unknown	None

Kentucky

The Duke Energy Kentucky 2008 Integrated Resource Plan

July 1, 2008

General Appendix

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GENERAL APPENDIX
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Proprietary and Confidential Information:	
Supply-Side Screening Curves	GA-1
Allowance Price Forecasts	GA-13

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Supply-Side Screening Curves

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

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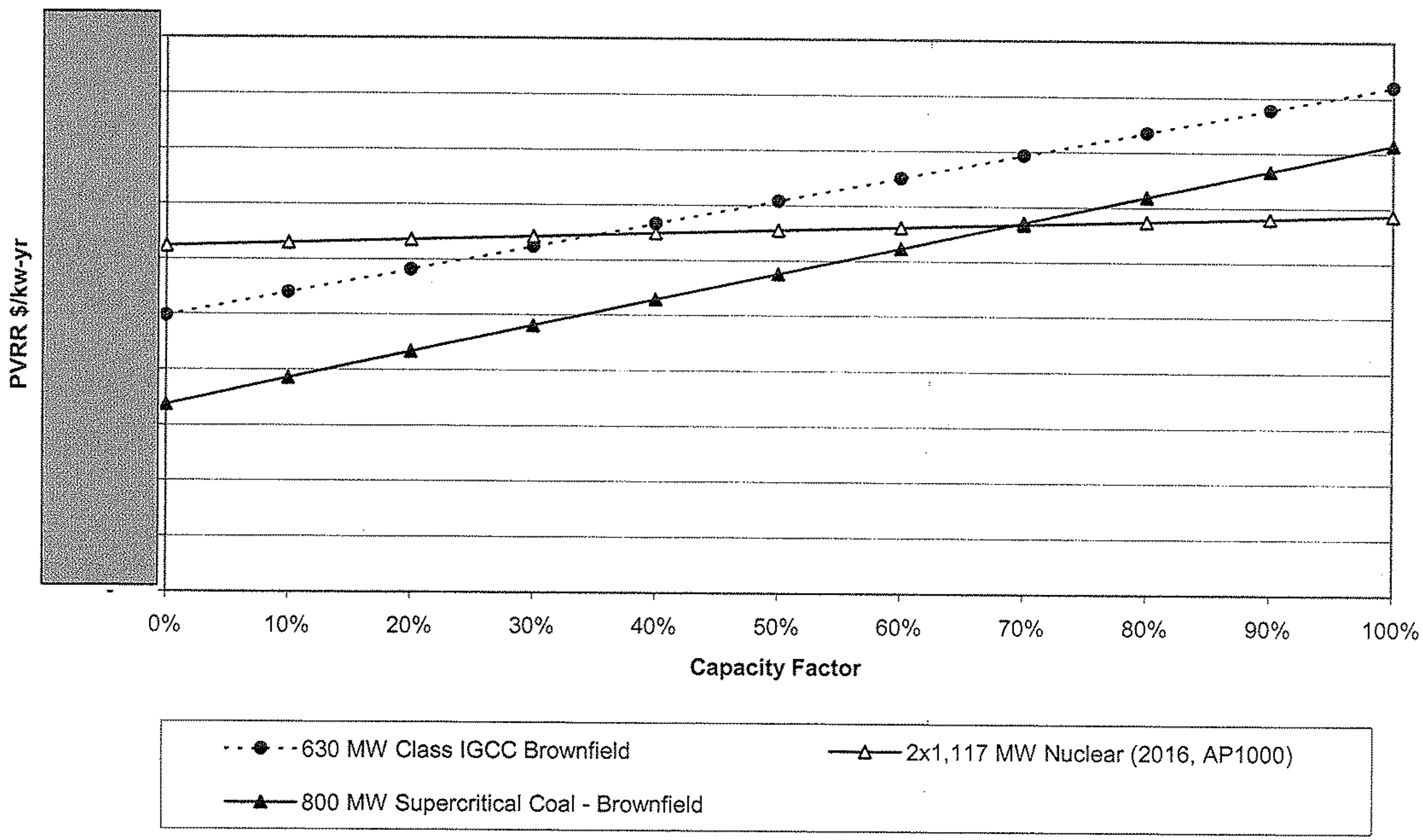
Figure GA-5-4

Baseload Technologies Screening 2008-2028



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Figu. A-5-5

Peak / Intermediate Technologies Screening 2008-2028

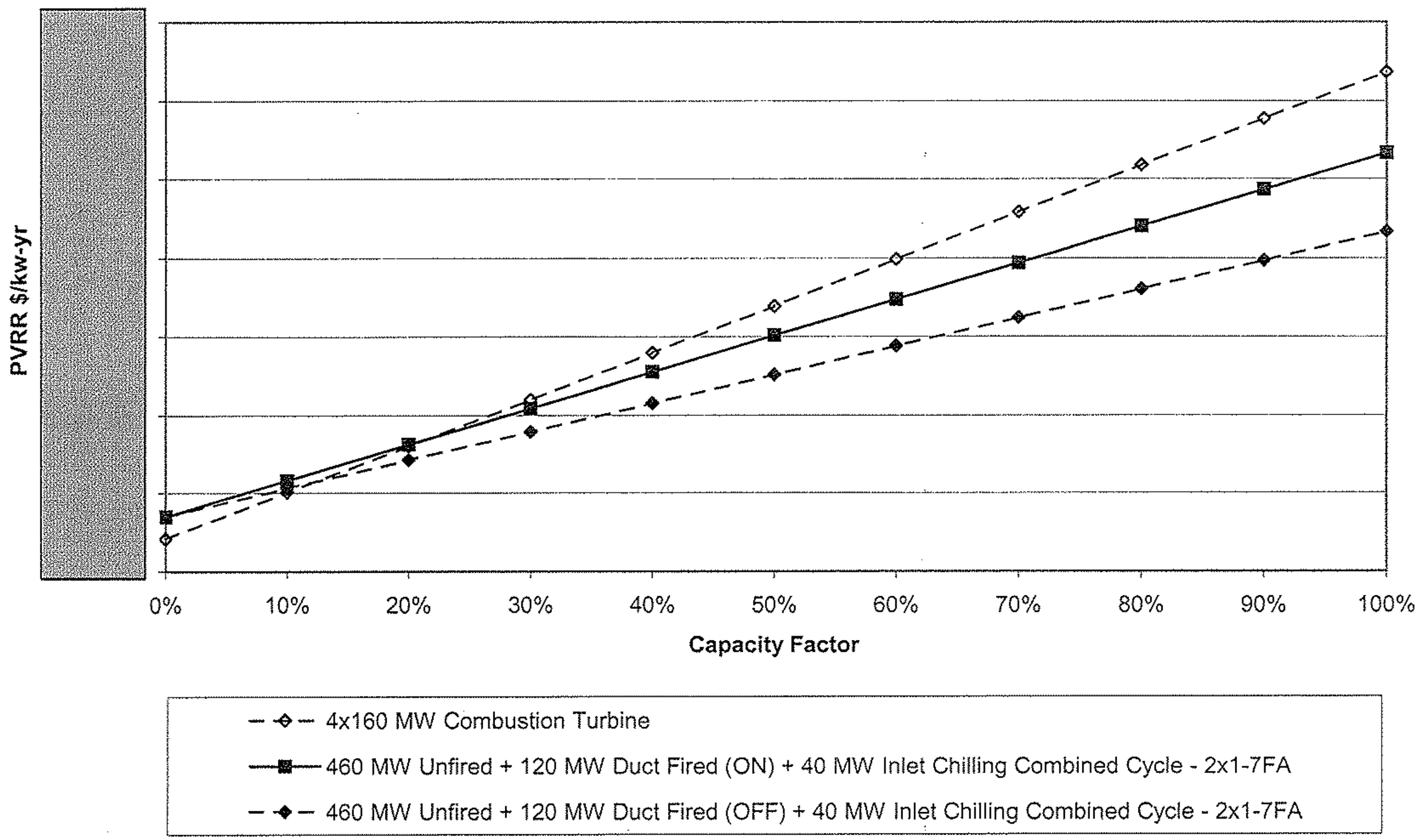

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Figure GA-5-6

Renewable Technologies Screening 2008-2028

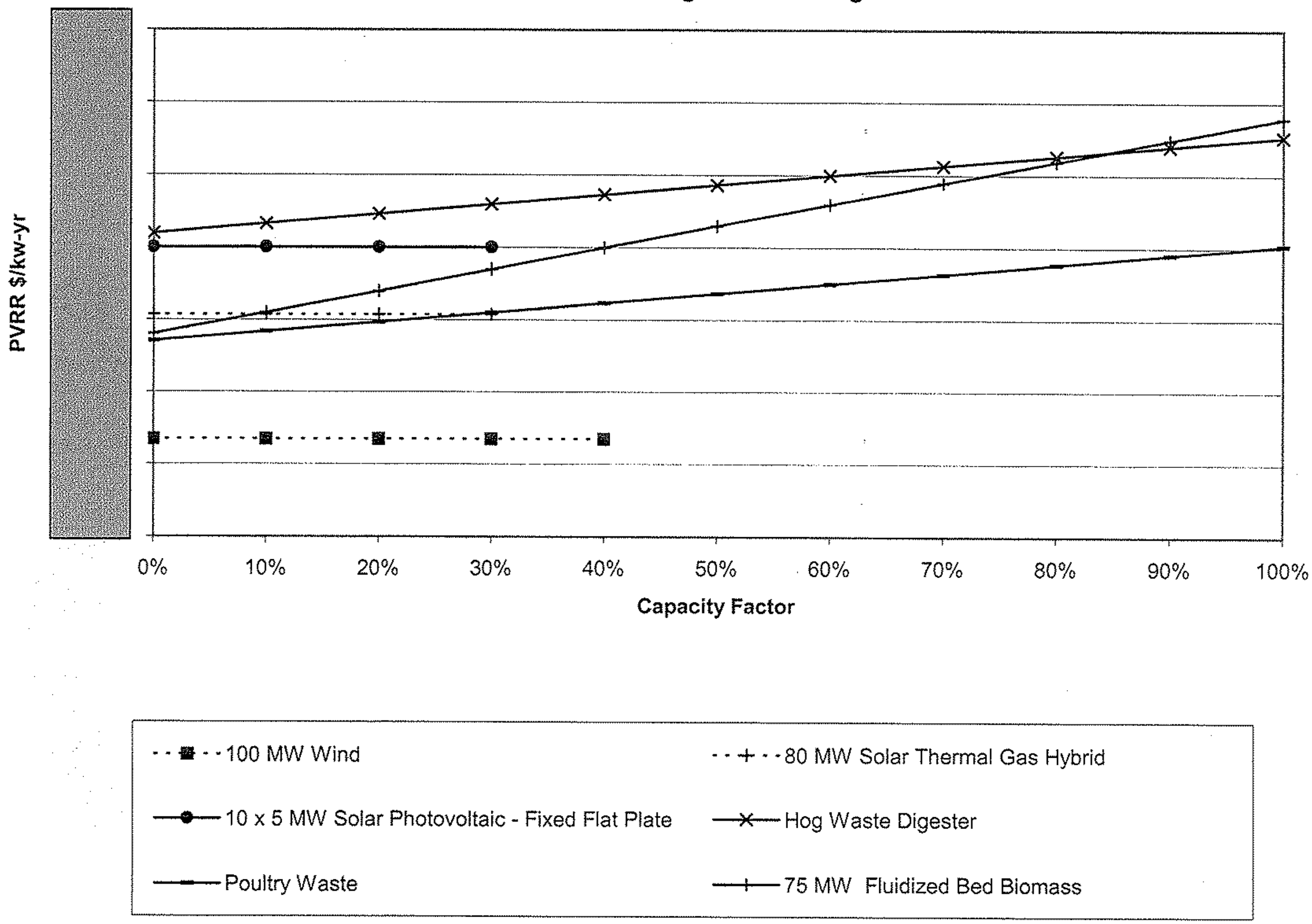

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Fig GA-5-7

Candidate Supply-Side Composite Resources for System Optimizer 2008-2028

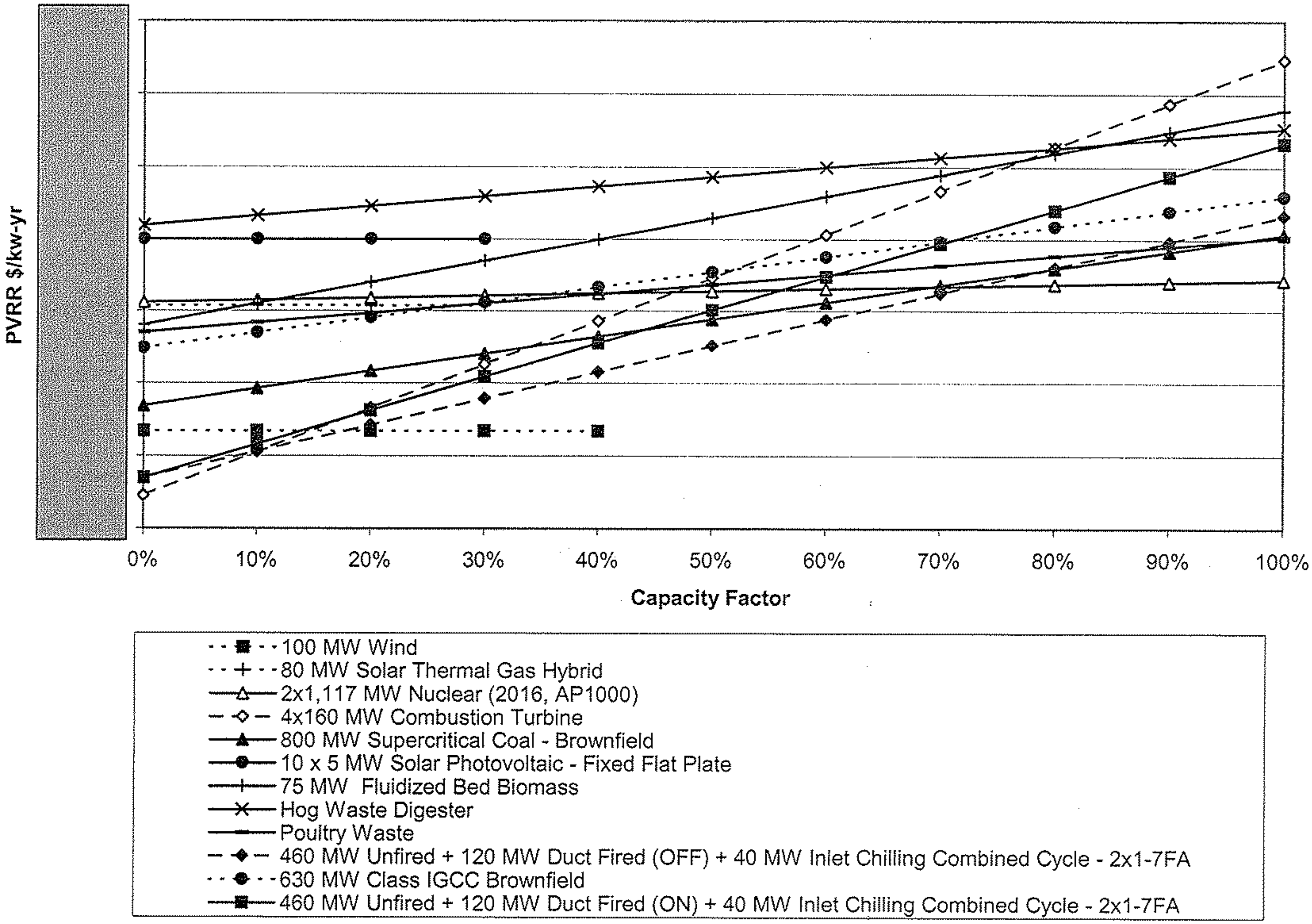

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Figure GA-5-8

Supply Side Technology Information 2008-2028

Final Screening (2008$)

Discount Rate (%):	7.33%
Coal Price Escalation Rate (%):	2.30%
Gas Price Escalation Rate (%):	2.30%
EA Price Escalation Rate (%):	2.30%
FOM and VOM Escalation Rate (%):	2.30%

	Plant A	Plant B	Plant C	Plant D	Plant E	Plant F	Plant G	Plant H	Plant I	Plant J	Plant K	Plant L
Resource Description	800 MW Supercritical Coal - Greenfield	2x1117 MW Nuclear (2016, AP1000)	630 MW Class IGCC Brownfield	4x160 MW Combustion Turbine	460 MW Duct Fired (ON) + 40 MW Inlet Chilling Combined Cycle 2x107FA	460 MW Duct Fired (OFF) + 40 MW Inlet Chilling Combined Cycle 2x107FA	100 MW Wind	80 MW Solar Thermal Gas Hybrid	10x5 MW Solar Photovoltaic - Fixed Flat Plate	75 MW Fluidized Bed Biomass	Hog Waste Digester	Poultry Waste
Book Life / Tax Life (years)	33 / 20	40 / 20	30 / 20	30 / 20	30 / 20	20 / 5	20 / 5	30 / 20	30 / 20	30 / 20	20 / 5	20/ 5
Net Unit Output (Mwe)	800.00	2,233.70	629.91	640.00	620.00	500.00	100.00	80.00	50.00	75.00	15.00	35.00
Capital Cost ($/kwe, with AFUDC)	[redacted]											
Total Plant Cost w/ AFUDC(2008$)												
Average Annual Heat Rate (Btu/kWh)												
FOM Rate ($/kw-yr, 2008$)												
VOM Rate ($/mwh, 2008$)												
Ongoing Capex Rate ($/kw-yr, 2008$)												
Equiv. Planned Outage rate (%)												
Equiv. Unplanned Outage rate (%)												
Equivalent Availability (%)												
SO2 Emission Rate (Lb/mmBtu)												
NOx Emission Rate (Lb/mmBtu)												
Hg Emission Rate (Lb/TBtu)												
CO2 Emission Rate (Lb/mmBtu)												

NOTE:

The values shown above are relative values 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 competition.

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Figu. ˏA-5-9

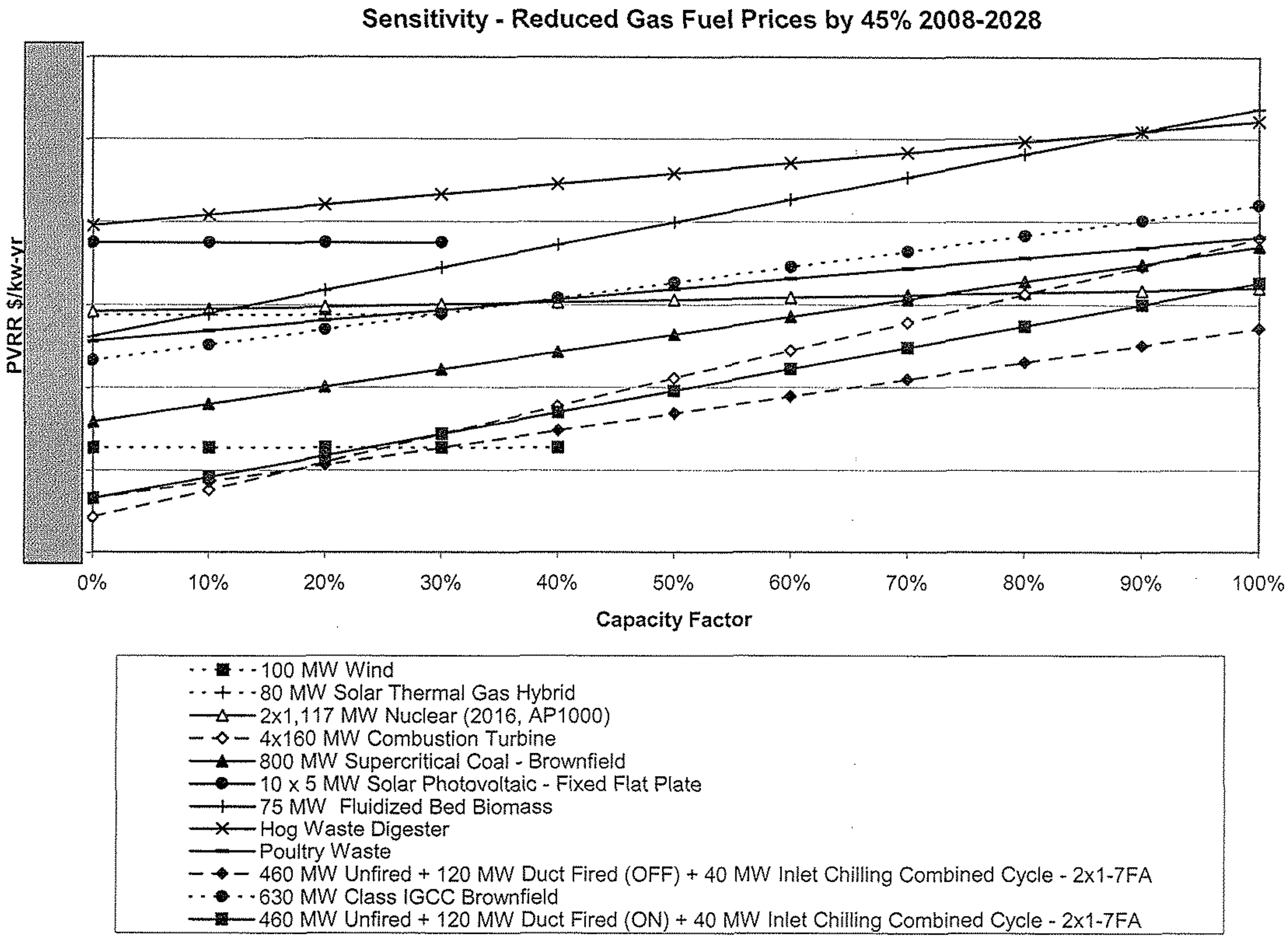

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Figure GA-5-10

Sensitivity - Increased Coal Fuel Prices by 45% 2008-2028

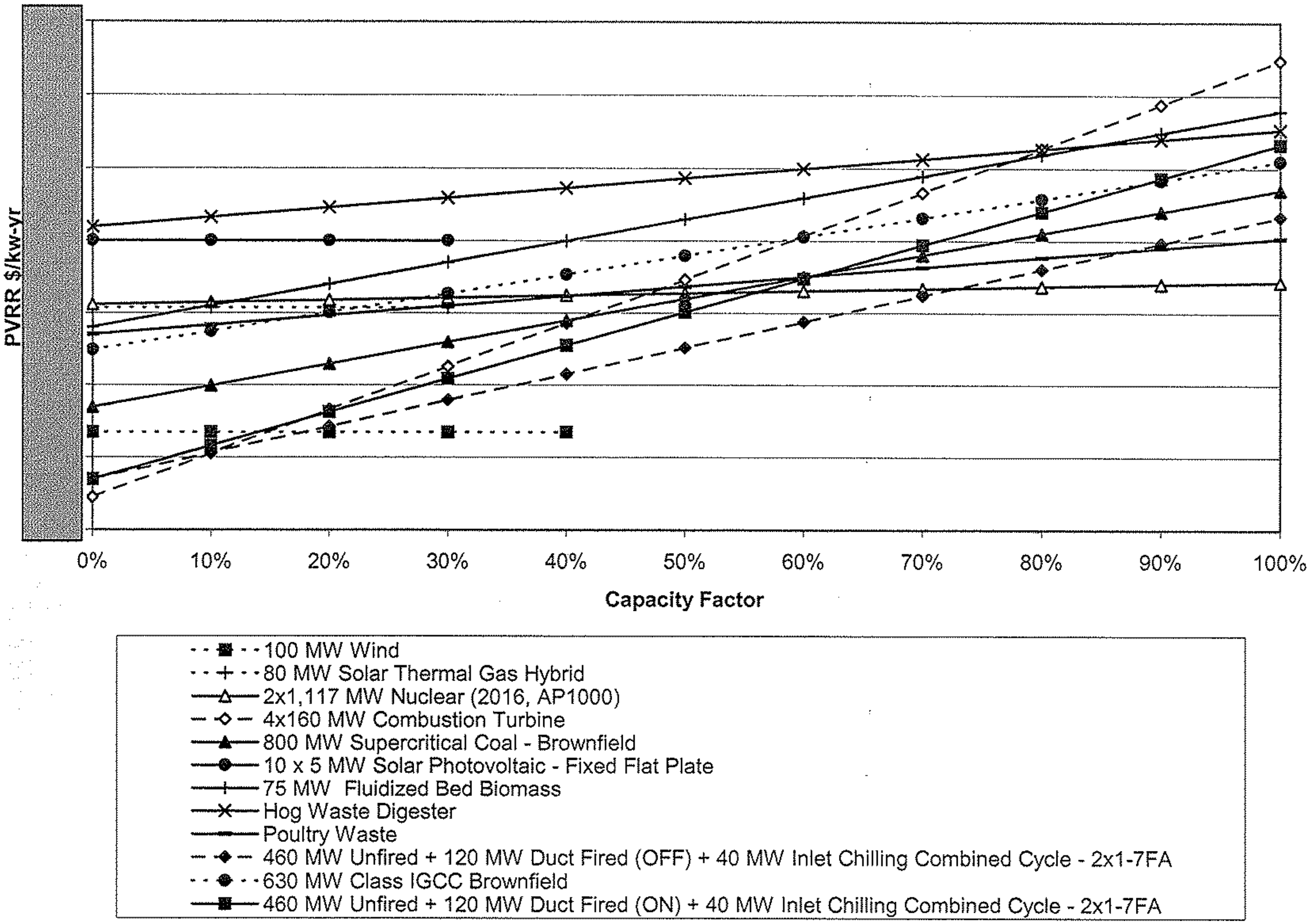

Figure GA-5-11

Sensitivity - Reduced Solar Capital Cost by 70% 2008-2028

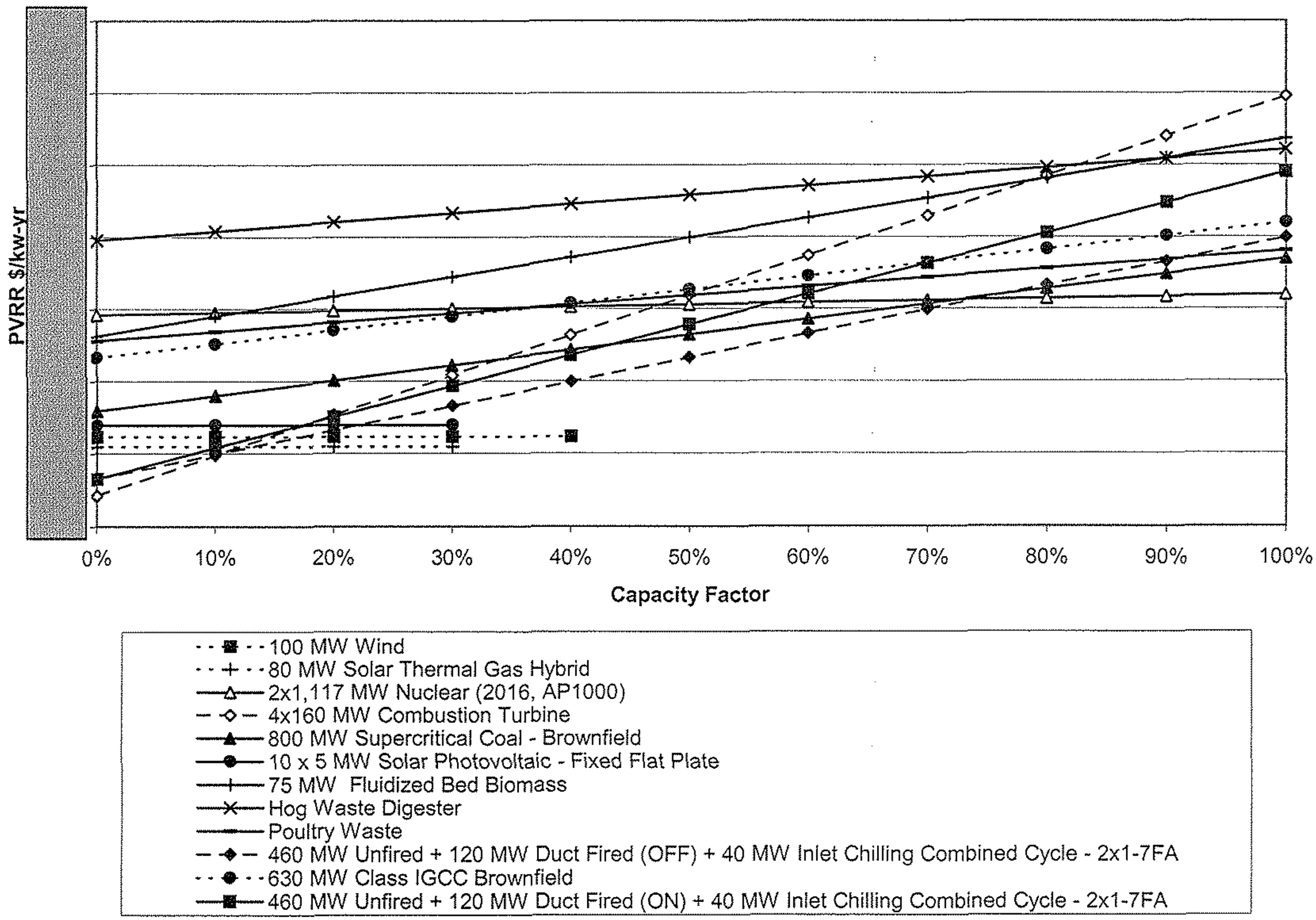

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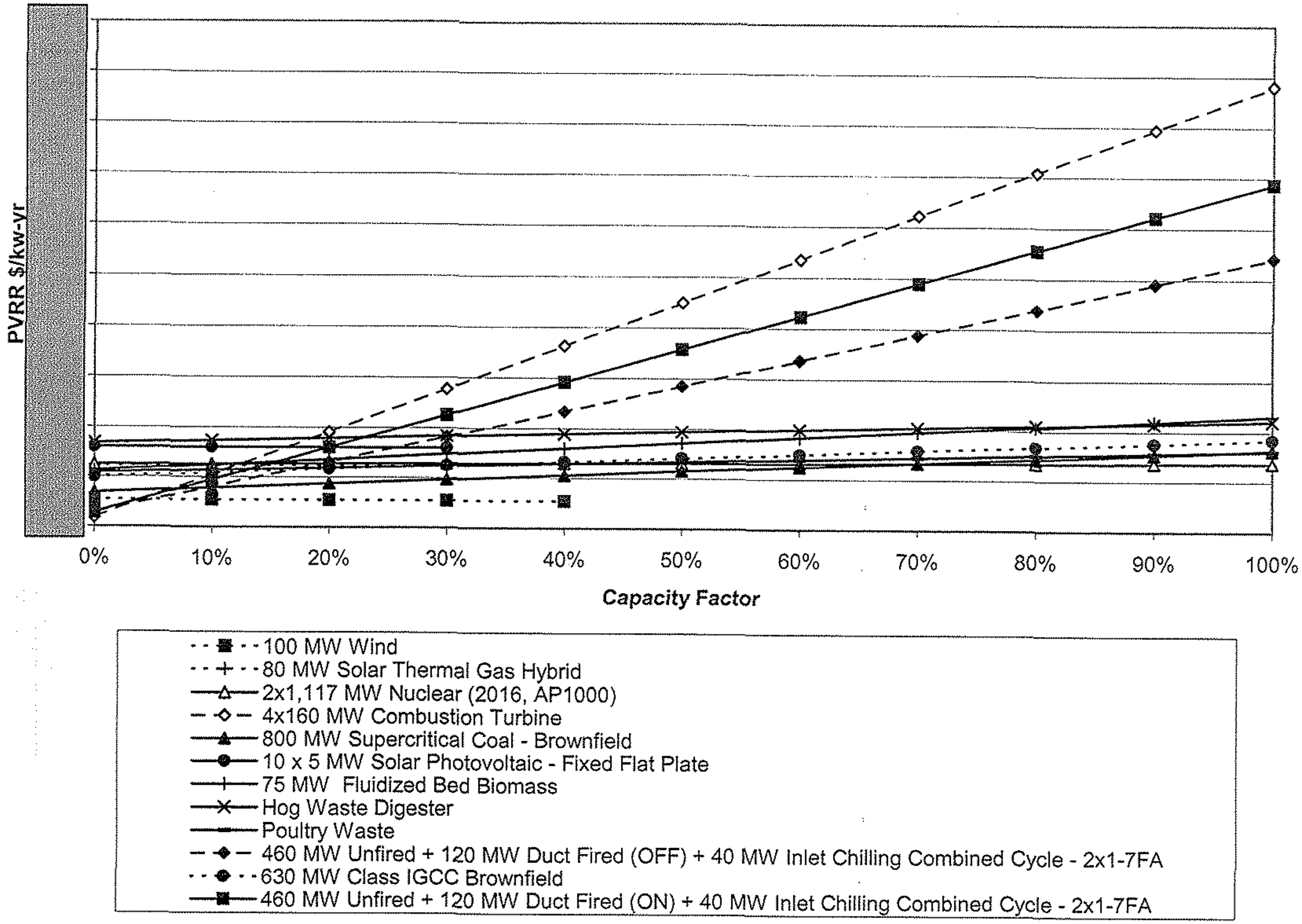
Figure GA-5-12

Sensitivity - Increased Gas Fuel Prices to 4X Base 2008-2028



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Figu. .A-5-13

Sensitivity - Reduced Biomass Fuel Prices by 80% 2008-2028

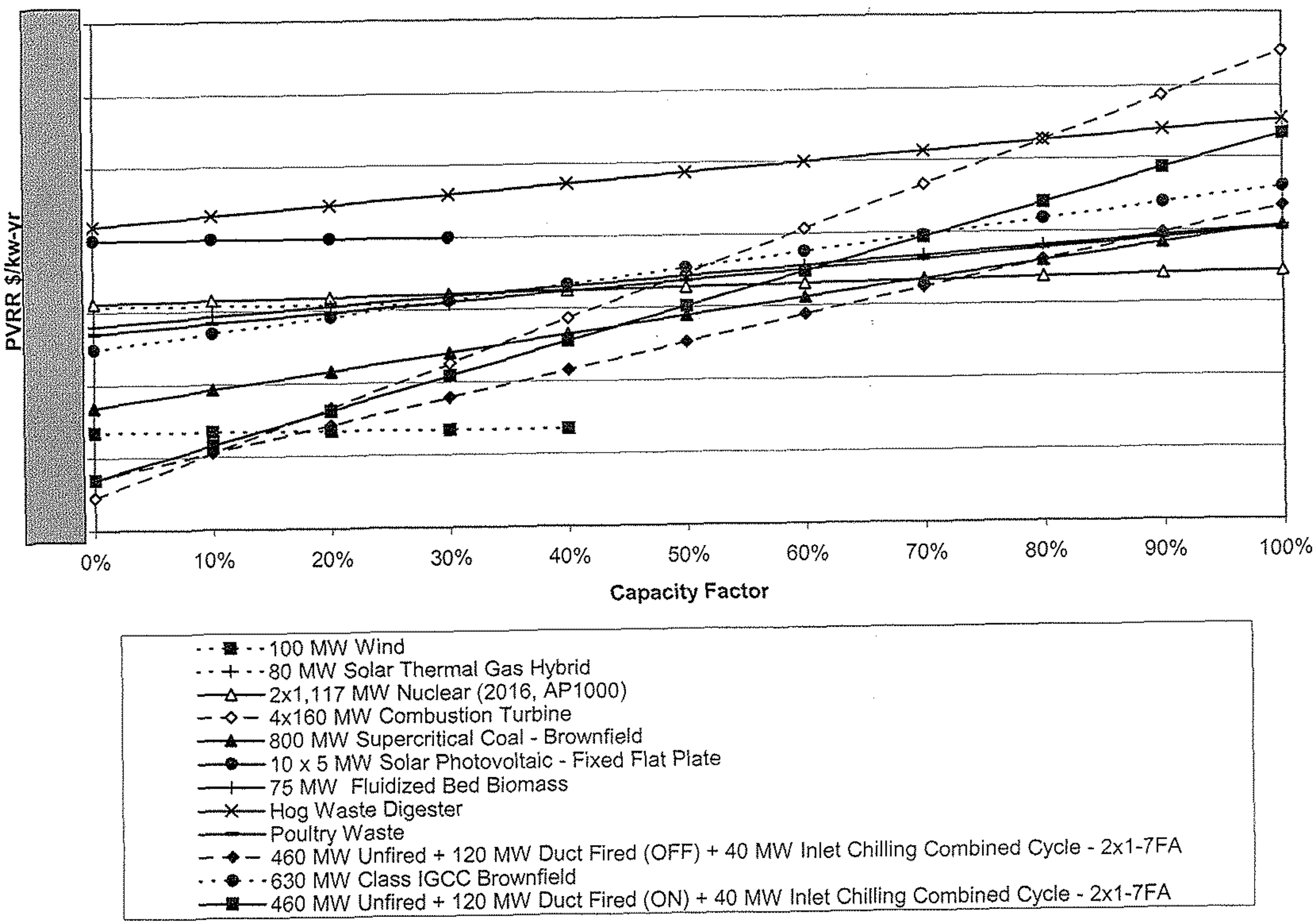

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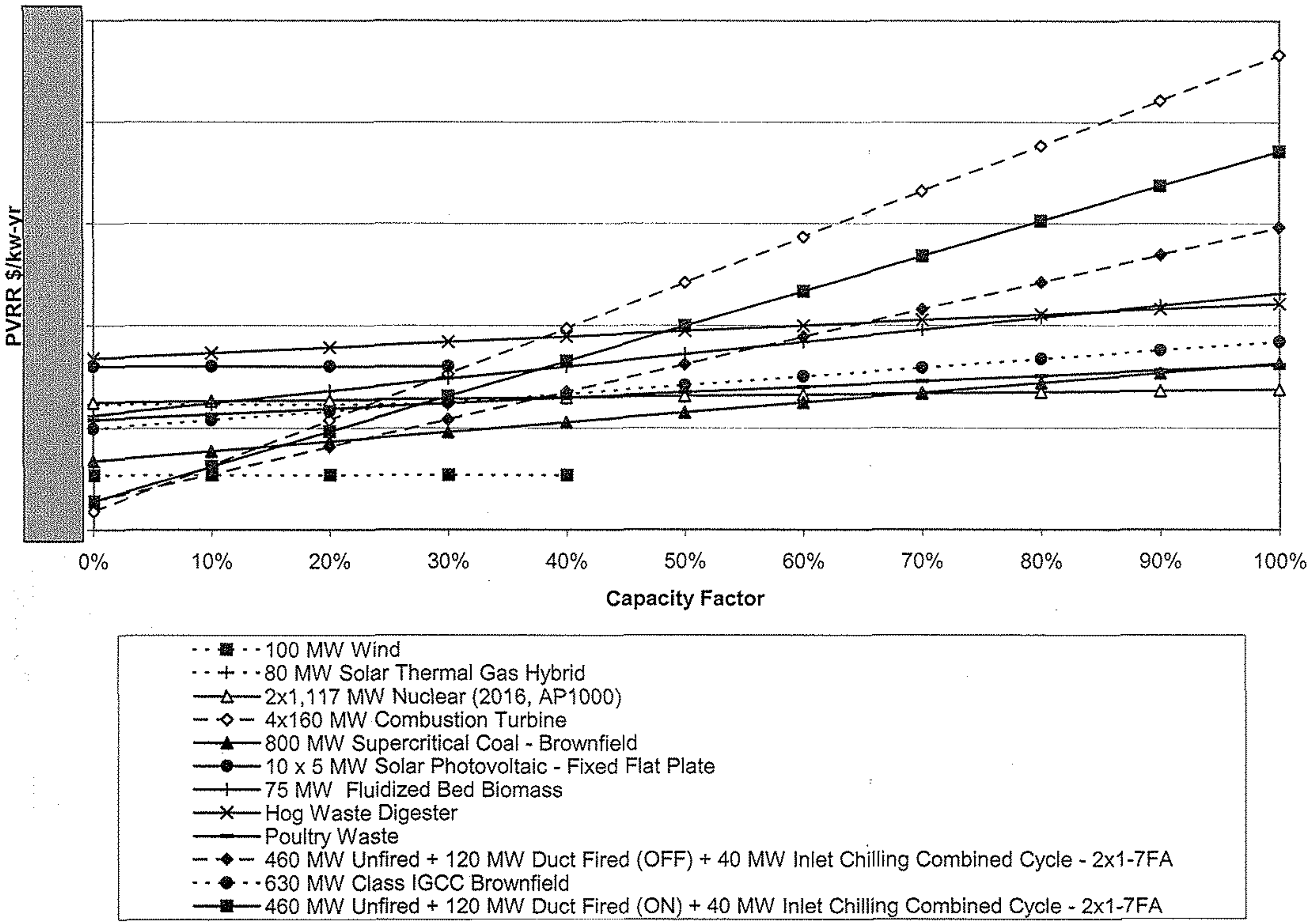
Figure GA-5-14

Sensitivity - Increased Gas Fuel Prices to 2X Base 2008-2028



Allowance Price Forecasts

The following tables contain the allowance price forecasts used in the development of this IRP. These forecasts are trade secrets and are proprietary to Ventyx and DE-Kentucky. The redacted information will be made available to appropriate parties upon execution of appropriate confidentiality agreements or protective orders. Please contact Janice Hager at (704) 382-6963 for more information.

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SO_2 Allowance Price Forecast
(Nominal $/Ton)

Year	No Carbon Case	Carbon Case	High Carbon Case
2008	[redacted]	[redacted]	[redacted]
2009			
2010			
2011			
2012			
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			
2028			

Note: SO_2 Prices are expressed as pre-2010 prices (*i.e.*, the price to emit 1 ton)

Seasonal NO_x Allowance Price Forecast
(Nominal $/Ton)

Year	No Carbon Case	Carbon Case	High Carbon Case
2008	[redacted]	[redacted]	[redacted]
2009	[redacted]	[redacted]	[redacted]
2010	[redacted]	[redacted]	[redacted]
2011	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]

Annual NO_x Allowance Price Forecast
(Nominal $/Ton)

Year	No Carbon Case	Carbon Case	High Carbon Case
2008	0	0	0
2009	[redacted]	[redacted]	[redacted]
2010	[redacted]	[redacted]	[redacted]
2011	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]

Hg Allowance Price Forecast
(Nominal $/lb)

Year	CAMR Sensitivity
2008	0
2009	0
2010	[redacted]
2011	[redacted]
2012	[redacted]
2013	[redacted]
2014	[redacted]
2015	[redacted]
2016	[redacted]
2017	[redacted]
2018	[redacted]
2019	[redacted]
2020	[redacted]
2021	[redacted]
2022	[redacted]
2023	[redacted]
2024	[redacted]
2025	[redacted]
2026	[redacted]
2027	[redacted]
2028	[redacted]

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Kentucky

The Duke Energy Kentucky 2008 Integrated Resource Plan

July 1, 2008

Secondary Appendix

SECONDARY APPENDIX
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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
Janice D. Hager	Integrated Resource Planning
Richard G. Stevie	Market Analytics
James A. Riddle	Load Forecasting
Ed F. Kirschner	Asset Management
John G. Bloemer	Analytical Engineering

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

The following page contains the data requested.

Section 7. (2) (a)

DUKE ENERGY KENTUCKY SYSTEM
ELECTRIC CUSTOMERS BY MAJOR CLASSIFICATIONS
ANNUAL AVERAGES

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	OTHER PUBLIC AUTHORITY
2003	113,989	12,583	394	315	969
2004	115,217	12,755	395	274	961
2005	116,500	12,878	396	281	973
2006	117,722	13,139	389	326	966
2007	118,843	13,302	392	355	976
2008	119,573	13,390	392	367	982
2009	120,732	13,485	395	381	986
2010	121,948	13,587	398	404	989
2011	123,078	13,687	400	429	991
2012	124,147	13,782	402	453	993
2013	125,206	13,878	404	480	994
2014	126,246	13,974	406	509	996
2015	127,270	14,070	408	540	999
2016	128,295	14,165	409	573	1,002
2017	129,317	14,256	411	609	1,004
2018	130,320	14,346	412	646	1,007
2019	131,302	14,436	413	685	1,010
2020	132,269	14,525	414	726	1,013
2021	133,222	14,615	415	769	1,017
2022	134,155	14,704	416	814	1,021
2023	135,069	14,794	416	860	1,026
2024	135,968	14,884	417	907	1,032
2025	136,853	14,974	417	957	1,037
2026	137,724	15,063	418	1,008	1,043
2027	138,580	15,154	418	1,061	1,050
2028	139,425	15,245	419	1,115	1,057

NOTE: 2008 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)

DUKE ENERGY KENTUCKY SYSTEM
WEATHER NORMALIZED
ANNUAL ENERGY (MWh) AND PEAKS (MW)

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	OTHER PUBLIC AUTHORITY
2003	1,395,913	1,317,969	770,244	19,020	302,761
2004	1,423,055	1,344,291	771,538	18,742	306,176
2005	1,432,233	1,357,635	782,390	18,776	318,785
2006	1,435,724	1,381,571	782,090	17,338	312,529
2007	1,439,800	1,422,726	798,348	15,988	316,729

	INTER DEPARTMENT	COMPANY USE	TOTAL CONSUMPTION	LOSSES AND UNACCOUNTED FOR	NET ENERGY FOR LOAD
2003	2,318	2,090	3,810,315	374,199	4,184,514
2004	1,644	1,677	3,867,123	429,663	4,296,786
2005	2,551	2,963	3,915,333	287,008	4,202,341
2006	2,237	2,566	3,934,055	181,976	4,116,031
2007	703	662	3,994,956	146,267	4,141,223

	SUMMER PEAK (MW)	WINTER PEAK (MW)
2003	853	673
2004	900	718
2005	882	802
2006	897	756
2007	862	749

Section 7(7)(a) Data Set Description

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

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

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VARIABLE	DESCRIPTION
@MONTH=1	QUALITATIVE VARIABLE - JANUARY
@MONTH=10	QUALITATIVE VARIABLE - OCTOBER
@MONTH=11	QUALITATIVE VARIABLE - NOVEMBER
@MONTH=12	QUALITATIVE VARIABLE - DECEMBER
@MONTH=2	QUALITATIVE VARIABLE - FEBRUARY
@MONTH=3	QUALITATIVE VARIABLE - MARCH
@MONTH=4	QUALITATIVE VARIABLE - APRIL
@MONTH=5	QUALITATIVE VARIABLE - MAY
@MONTH=6	QUALITATIVE VARIABLE - JUNE
@MONTH=7	QUALITATIVE VARIABLE - JULY
@MONTH=8	QUALITATIVE VARIABLE - AUGUST
@MONTH=9	QUALITATIVE VARIABLE - SEPTEMBER
@QUARTER=1	QUALITATIVE VARIABLE - FIRST QUARTER
@QUARTER=2	QUALITATIVE VARIABLE - SECOND QUARTER
@QUARTER=3	QUALITATIVE VARIABLE - THIRD QUARTER
@QUARTER=4	QUALITATIVE VARIABLE - FOURTH QUARTER
AHEM_1640	SERVICE AREA AVERAGE HOURLY EARNINGS FOR MANUFACTURING
AMPEAK	QUALITATIVE VARIABLE - MORNING PEAK
APGIND_OH_KY	SERVICE AREA AVERAGE PRICE OF GAS FOR INDUSTRIAL CUSTOMERS
APGOPA_OH_KY	SERVICE AREA AVERAGE PRICE OF GAS FOR OPA CUSTOMERS
APPLSTK_EFF_OH_KY	EFFICIENT APPLIANCE STOCK
CDD_OH_KY_65	COOLING DEGREE DAYS
CDDB_OH_KY_65	BILLING COOLING DEGREE DAYS
CDDB_OH_KY_65_0_100	=MINIMUM(CDDB_OH_KY,100)
CDDB_OH_KY_65_100	=MAXIMUM(CDDB_OH_KY-100,0)
CPI	CONSUMER PRICE INDEX (ALL URBAN) - ALL ITEMS
CUSRES_OH_KY	SERVICE AREA ELECTRIC CUSTOMERS - RESIDENTIAL
D_1965M01_2001M12	QUALITATIVE VARIABLE - JANUARY, 1965 THRU DECEMBER, 2001
D_1965M01_2002M12	QUALITATIVE VARIABLE - JANUARY, 1965 THRU DECEMBER, 2002
D_1965M01_2005M12	QUALITATIVE VARIABLE - JANUARY, 1965 THRU DECEMBER, 2005
D_1965Q1_1980Q2	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 TO SECOND QUARTER, 1980
D_1965Q1_1985Q4	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 TO FOURTH QUARTER, 1985
D_1965Q1_1986Q4	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 THRU FOURTH QUARTER, 1986
D_1965Q1_1988Q3	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 THRU THIRD QUARTER, 1988
D_1965Q1_1990Q4	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 THRU FOURTH QUARTER, 1990
D_1965Q1_1998Q2	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 TO SECOND QUARTER, 1998
D_1965Q1_2000Q2	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 THRU SECOND QUARTER, 2000
D_1965Q1_2001Q2	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 TO SECOND QUARTER, 2001
D_1965Q1_2001Q3	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 THRU THIRD QUARTER, 2001
D_1965Q1_2005Q1	QUALITATIVE VARIABLE - FIRST QUARTER, 1965 THRU FIRST QUARTER, 2005
D_1976M01_1984M12	QUALITATIVE VARIABLE - JANUARY, 1976 THRU DECEMBER, 1984
D_1976Q1	QUALITATIVE VARIABLE - FIRST QUARTER, 1976
D_1976Q1_1989Q2	QUALITATIVE VARIABLE - FIRST QUARTER, 1976 TO SECOND QUARTER, 1989
D_1976Q3	QUALITATIVE VARIABLE - THIRD QUARTER, 1976
D_1976Q4	QUALITATIVE VARIABLE - FOURTH QUARTER, 1976
D_1977Q1	QUALITATIVE VARIABLE - FIRST QUARTER, 1977
D_1977Q2	QUALITATIVE VARIABLE - SECOND QUARTER, 1977
D_1978Q1	QUALITATIVE VARIABLE - FIRST QUARTER, 1978
D_1978Q2	QUALITATIVE VARIABLE - SECOND QUARTER, 1978
D_1979Q3	QUALITATIVE VARIABLE - THIRD QUARTER, 1979

D_1980M02	QUALITATIVE VARIABLE - FEBRUARY, 1980
D_1980Q2	QUALITATIVE VARIABLE - SECOND QUARTER, 1980
D_1982M06	QUALITATIVE VARIABLE - JUNE, 1982
D_1982Q4	QUALITATIVE VARIABLE - FOURTH QUARTER, 1982
D_1983Q3	QUALITATIVE VARIABLE - THIRD QUARTER, 1983
D_1986Q3	QUALITATIVE VARIABLE - THIRD QUARTER, 1986
D_1988M05_1988M08	QUALITATIVE VARIABLE - MAY, 1988 THRU AUGUST, 1988
D_1988Q3	QUALITATIVE VARIABLE - THIRD QUARTER, 1988
D_1988Q4	QUALITATIVE VARIABLE - FOURTH QUARTER, 1988
D_1989Q3	QUALITATIVE VARIABLE - THIRD QUARTER, 1989
D_1991M03	QUALITATIVE VARIABLE - MARCH, 1991
D_1991M04	QUALITATIVE VARIABLE - APRIL, 1991
D_1991M06	QUALITATIVE VARIABLE - JUNE, 1991
D_1991M12	QUALITATIVE VARIABLE - DECEMBER, 1991
D_1991Q1	QUALITATIVE VARIABLE - FIRST QUARTER, 1991
D_1991Q4	QUALITATIVE VARIABLE - FOURTH QUARTER, 1991
D_1992M03	QUALITATIVE VARIABLE - MARCH, 1992
D_1992M06	QUALITATIVE VARIABLE - JUNE, 1992
D_1992M07	QUALITATIVE VARIABLE - JULY, 1992
D_1992Q1	QUALITATIVE VARIABLE - FIRST QUARTER, 1992
D_1992Q3	QUALITATIVE VARIABLE - THIRD QUARTER, 1992
D_1993M07	QUALITATIVE VARIABLE - JULY, 1993
D_1993M09	QUALITATIVE VARIABLE - SEPTEMBER, 1993
D_1993M10	QUALITATIVE VARIABLE - OCTOBER, 1993
D_1993M11	QUALITATIVE VARIABLE - NOVEMBER, 1993
D_1993Q1	QUALITATIVE VARIABLE - FIRST QUARTER, 1993
D_1994M01	QUALITATIVE VARIABLE - JANUARY, 1994
D_1994M02	QUALITATIVE VARIABLE - FEBRUARY, 1994
D_1994M05	QUALITATIVE VARIABLE - MAY, 1994
D_1995M04	QUALITATIVE VARIABLE - APRIL, 1995
D_1995M05	QUALITATIVE VARIABLE - MAY, 1995
D_1995M08	QUALITATIVE VARIABLE - AUGUST, 1995
D_1996M09	QUALITATIVE VARIABLE - SEPTEMBER, 1996
D_1996Q3	QUALITATIVE VARIABLE - THIRD QUARTER, 1996
D_1997M10	QUALITATIVE VARIABLE - OCTOBER, 1997
D_1997M12	QUALITATIVE VARIABLE - DECEMBER, 1997
D_1997Q3	QUALITATIVE VARIABLE - THIRD QUARTER, 1997
D_1998M06	QUALITATIVE VARIABLE - JUNE, 1998
D_1998M08	QUALITATIVE VARIABLE - AUGUST, 1998
D_1998M10	QUALITATIVE VARIABLE - OCTOBER, 1998
D_1998Q3_2001Q2	QUALITATIVE VARIABLE - THIRD QUARTER, 1998 THRU SECOND QUARTER, 2001
D_1999M06	QUALITATIVE VARIABLE - JUNE, 1999
D_1999M08	QUALITATIVE VARIABLE - AUGUST, 1999
D_1999M10	QUALITATIVE VARIABLE - OCTOBER, 1999
D_1999M11	QUALITATIVE VARIABLE - NOVEMBER, 1999
D_1999M12	QUALITATIVE VARIABLE - DECEMBER, 1999
D_1999Q1	QUALITATIVE VARIABLE - FIRST QUARTER, 1999
D_1999Q1_2001Q2	QUALITATIVE VARIABLE - FIRST QUARTER, 1999 THRU SECOND QUARTER, 2001
D_1999Q4	QUALITATIVE VARIABLE - FOURTH QUARTER, 1999
D_2000M01	QUALITATIVE VARIABLE - JANUARY, 2000
D_2000M04	QUALITATIVE VARIABLE - APRIL, 2000
D_2000M05	QUALITATIVE VARIABLE - MAY, 2000

D_2000M06	QUALITATIVE VARIABLE - JUNE, 2000
D_2000M07	QUALITATIVE VARIABLE - JULY, 2000
D_2000M08_2001M12	QUALITATIVE VARIABLE - AUGUST, 2000 THRU DECEMBER, 2001
D_2000M10	QUALITATIVE VARIABLE - OCTOBER, 2000
D_2000M11	QUALITATIVE VARIABLE - NOVEMBER, 2000
D_2000M12	QUALITATIVE VARIABLE - DECEMBER, 2000
D_2000Q1	QUALITATIVE VARIABLE - FIRST QUARTER, 2000
D_2000Q2	QUALITATIVE VARIABLE - SECOND QUARTER, 2000
D_2000Q3	QUALITATIVE VARIABLE - THIRD QUARTER, 2000
D_2000Q3_2001Q2	QUALITATIVE VARIABLE - THIRD QUARTER, 2000 THRU SECOND QUARTER, 2001
D_2000Q4	QUALITATIVE VARIABLE - FOURTH QUARTER, 2000
D_2001M01	QUALITATIVE VARIABLE - JANUARY, 2001
D_2001M02	QUALITATIVE VARIABLE - FEBRUARY, 2001
D_2001M03	QUALITATIVE VARIABLE - MARCH, 2001
D_2001M04	QUALITATIVE VARIABLE - APRIL, 2001
D_2001M05	QUALITATIVE VARIABLE - MAY, 2001
D_2001M06	QUALITATIVE VARIABLE - JUNE, 2001
D_2001M07	QUALITATIVE VARIABLE - JULY, 2001
D_2001M08	QUALITATIVE VARIABLE - AUGUST, 2001
D_2001M09_2002M06	QUALITATIVE VARIABLE - SEPTEMBER, 2001 THRU JUNE, 2002
D_2001Q2	QUALITATIVE VARIABLE - SECOND QUARTER, 2001
D_2002M02	QUALITATIVE VARIABLE - FEBRUARY, 2002
D_2002M04	QUALITATIVE VARIABLE - APRIL, 2002
D_2002M05	QUALITATIVE VARIABLE - MAY, 2002
D_2002M06	QUALITATIVE VARIABLE - JUNE, 2002
D_2002M07	QUALITATIVE VARIABLE - JULY, 2002
D_2002M07_2003M01	QUALITATIVE VARIABLE - JULY, 2002 THRU JANUARY, 2003
D_2002M08	QUALITATIVE VARIABLE - AUGUST, 2002
D_2002M10	QUALITATIVE VARIABLE - OCTOBER, 2002
D_2002M12	QUALITATIVE VARIABLE - DECEMBER, 2002
D_2002Q1	QUALITATIVE VARIABLE - FIRST QUARTER, 2002
D_2002Q4	QUALITATIVE VARIABLE - FOURTH QUARTER, 2002
D_2003M01	QUALITATIVE VARIABLE - JANUARY, 2003
D_2003M02	QUALITATIVE VARIABLE - FEBRUARY, 2003
D_2003M05	QUALITATIVE VARIABLE - MAY, 2003
D_2003M06	QUALITATIVE VARIABLE - JUNE, 2003
D_2003M12	QUALITATIVE VARIABLE - DECEMBER, 2003
D_2003Q1	QUALITATIVE VARIABLE - FIRST QUARTER, 2003
D_2003Q4	QUALITATIVE VARIABLE - FOURTH QUARTER, 2003
D_2004M01	QUALITATIVE VARIABLE - JANUARY, 2004
D_2004M03	QUALITATIVE VARIABLE - MARCH, 2004
D_2004M05	QUALITATIVE VARIABLE - MAY, 2004
D_2004M07	QUALITATIVE VARIABLE - JULY, 2004
D_2004M09	QUALITATIVE VARIABLE - SEPTEMBER, 2004
D_2004M10	QUALITATIVE VARIABLE - OCTOBER, 2004
D_2004M11	QUALITATIVE VARIABLE - NOVEMBER, 2004
D_2004M12	QUALITATIVE VARIABLE - DECEMBER, 2004
D_2004Q1	QUALITATIVE VARIABLE - FIRST QUARTER, 2004
D_2004Q2	QUALITATIVE VARIABLE - SECOND QUARTER, 2004
D_2004Q4	QUALITATIVE VARIABLE - FOURTH QUARTER, 2004
D_2005M01	QUALITATIVE VARIABLE - JANUARY, 2005
D_2005M02	QUALITATIVE VARIABLE - FEBRUARY, 2005

D_2005Q1	QUALITATIVE VARIABLE - FIRST QUARTER, 2005
D_2005Q2	QUALITATIVE VARIABLE - SECOND QUARTER, 2005
D_2005Q4	QUALITATIVE VARIABLE - FOURTH QUARTER, 2005
D_2006M02	QUALITATIVE VARIABLE - FEBRUARY, 2006
D_2006M09	QUALITATIVE VARIABLE - SEPTEMBER, 2006
D_2006M10	QUALITATIVE VARIABLE - OCTOBER, 2006
D_2006Q4	QUALITATIVE VARIABLE - FOURTH QUARTER, 2006
D_2007M02	QUALITATIVE VARIABLE - FEBRUARY, 2007
D_2007M04	QUALITATIVE VARIABLE - APRIL, 2007
D_2007M05	QUALITATIVE VARIABLE - MAY, 2007
D_2007M06	QUALITATIVE VARIABLE - JUNE, 2007
D_2007M10	QUALITATIVE VARIABLE - OCTOBER, 2007
D_2007Q1	QUALITATIVE VARIABLE - FIRST QUARTER, 2005
D_2007Q2	QUALITATIVE VARIABLE - SECOND QUARTER, 2007
D_DJF	=(@MONTH=12+@MONTH=1+@MONTH=2)
D_JJA	=(@MONTH=6+@MONTH=7+@MONTH=8)
DAYS	NUMBER OF DAYS IN THE MONTH
DS_KW_IND_OH_KY	SERVICE AREA DS RATE FOR DEMAND FOR INDUSTRIAL CUSTOMERS
DS_KW_OPA_OH_KY	SERVICE AREA DS RATE FOR DEMAND FOR OTHER PUBLIC AUTHORITIES CUSTOMERS
DS_KWH_COM_OH_KY	SERVICE AREA DS RATE FOR USAGE FOR COMMERCIAL CUSTOMERS
DS_KWH_IND_OH_KY	SERVICE AREA DS RATE FOR USAGE FOR INDUSTRIAL CUSTOMERS
DS_KWH_OPA_OH_KY	SERVICE AREA DS RATE FOR USAGE FOR OTHER PUBLIC AUTHORITIES CUSTOMERS
E90X_OH_KY	SERVICE AREA EMPLOYMENT - STATE AND LOCAL GOVERNMENT
ECOM_OH_KY	SERVICE AREA EMPLOYMENT - COMMERCIAL
EFF_CAC_OH_KY	EFFICIENCY OF CENTRAL AIR CONDITIONING UNITS IN SERVICE AREA
EFF_EHP_OH_KY	EFFICIENCY OF ELECTRIC HEAT PUMP UNITS IN SERVICE AREA
EFF_RAC_OH_KY	EFFICIENCY OF WINDOW AIR CONDITIONING UNITS IN SERVICE AREA
HDDB_OH_KY_59	BILLING HEATING DEGREE DAYS
HDDB_OH_KY_59_0_500	=MINIMUM(HDDB_OH_KY,500)
HDDB_OH_KY_59_500	=MAXIMUM(HDDB_OH_KY-500,0)
PMHUMIDATHIGH	HUMIDITY - AFTERNOON
JQINDN322_326_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - PAPER AND PRODUCTS
JQINDN325_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - CHEMICALS AND PRODUCTS
JQINDN311_312_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - FOOD AND PRODUCTS
JQINDN331_CMSA	CINCINNATI CMSA INDUSTRIAL PRODUCTION INDEX - PRIMARY METAL INDUSTRIES
JQINDN332_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - FABRICATED METALS
JQINDN333_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - INDUSTRIAL MACHINERY & EQUIPMEN
JQINDN334_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - COMPUTER AND ELECTRONICS
JQINDN335_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - ELECTRICAL EQUIPMENT
JQINDN361_62_63_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - MOTOR VEHICLES AND PARTS
JQINDN3364_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION INDEX - AIRCRAFT AND PARTS
JQINDNAOI_OH_KY	SERVICE AREA INDUSTRIAL PRODUCTION - ALL OTHER INDUSTRIES
JULY4WEEK	QUALITATIVE VARIABLE FOR THE WEEK OF JULY 4TH
KWHCOM_OH_KY	SERVICEA KWH SALES - COMMERCIAL
KWHCUSRES_OH_KY	SERVICE AREA KWH SALES - USE PER RESIDENTIAL CUSTOMER
KWHOPALWP_OH_KY	SERVICE AREA KWH SALES - OPA LESS WATER PUMPING
KWHOPAWP_OH_KY	SERVICE AREA KWH SALES - OPA WATER PUMPING
KWHSL_OH_KY	SERVICE AREA KWH SALES - STREET LIGHTING
M741902	QUALITATIVE VARIABLE - PEAK MODEL
M715	QUALITATIVE VARIABLE - PEAK MODEL
M717	QUALITATIVE VARIABLE - PEAK MODEL
M838	QUALITATIVE VARIABLE - PEAK MODEL

M849	QUALITATIVE VARIABLE - PEAK MODEL
M954	QUALITATIVE VARIABLE - PEAK MODEL
M8411	QUALITATIVE VARIABLE - PEAK MODEL
M906	QUALITATIVE VARIABLE - PEAK MODEL
M916	QUALITATIVE VARIABLE - PEAK MODEL
M917	QUALITATIVE VARIABLE - PEAK MODEL
M918	QUALITATIVE VARIABLE - PEAK MODEL
M922	QUALITATIVE VARIABLE - PEAK MODEL
M926	QUALITATIVE VARIABLE - PEAK MODEL
M971	QUALITATIVE VARIABLE - PEAK MODEL
M917	QUALITATIVE VARIABLE - PEAK MODEL
M9710	QUALITATIVE VARIABLE - PEAK MODEL
M777	QUALITATIVE VARIABLE - PEAK MODEL
M858	QUALITATIVE VARIABLE - PEAK MODEL
M863	QUALITATIVE VARIABLE - PEAK MODEL
M8610	QUALITATIVE VARIABLE - PEAK MODEL
M8611	QUALITATIVE VARIABLE - PEAK MODEL
M874	QUALITATIVE VARIABLE - PEAK MODEL
M876	QUALITATIVE VARIABLE - PEAK MODEL
M877	QUALITATIVE VARIABLE - PEAK MODEL
M882	QUALITATIVE VARIABLE - PEAK MODEL
M886	QUALITATIVE VARIABLE - PEAK MODEL
M888	QUALITATIVE VARIABLE - PEAK MODEL
M889	QUALITATIVE VARIABLE - PEAK MODEL
M8811	QUALITATIVE VARIABLE - PEAK MODEL
M8812	QUALITATIVE VARIABLE - PEAK MODEL
M891	QUALITATIVE VARIABLE - PEAK MODEL
MDEC	QUALITATIVE VARIABLE - DECEMBER
MFEB	QUALITATIVE VARIABLE - FEBRUARY
MMAR	QUALITATIVE VARIABLE - MARCH
MJAN	QUALITATIVE VARIABLE - JANUARY
MJUN	QUALITATIVE VARIABLE - JUNE
MJUL	QUALITATIVE VARIABLE - JULY
MAUG	QUALITATIVE VARIABLE - AUGUST
MP_RES_OH_KY	MARGINAL PRICE OF ELECTRICITY - RESIDENTIAL
MWHN322_326_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - PAPER AND PRODUCTS
MWHN325_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - CHEMICALS AND PRODUCTS
MWHN311_312_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - FOOD AND PRODUCTS
MWHN331LARM_OH_KY	SERVICE AREA MWH SALES LESS AK STEEL - INDUSTRIAL - PRIMARY METAL INDUSTRIES
MWHN332_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - FABRICATED METALS
MWHN333_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - INDUSTRIAL MACHINERY AND EQUIPMENT
MWHN334_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - COMPUTER AND ELECTRONICS
MWHN335_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - ELECTRICAL EQUIPMENT
MWHN3361_3362_3363_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - MOTOR VEHICLES AND PARTS
MWHN3364_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - TRANSPORTATION EQUIPMENT OTHER THAN MOTOR VEHICLES AND PARTS
MWHNAOI_OH_KY	SERVICE AREA MWH SALES - INDUSTRIAL - ALL OTHER INDUSTRIES
KWHSENDNORM_OH_KY	SERVICE AREA KWH SENDOUT - WEATHER NORMALIZED
MWSPEAK_OH_KY	SERVICE AREA MW PEAK - SUMMER
MWWPEAK_OH_KY	SERVICE AREA MW PEAK - WINTER
N_OH_KY	SERVICE AREA TOTAL POPULATION
PMPEAK	QUALITATIVE VARIABLE - EVENING PEAK

PRECIP_OH_KY	SERVICE AREA PRECIPITATION
SAT_CAC_EFF	=EFF_CAC_OH_KY*(SAT_EHP_OH_KY+SAT_CACNHP_OH_KY)
SAT_CACNHP_OH_KY	SERVICE AREA SATURATION OF CENTRAL AIR CONDITIONING WITHOUT HEAT PUMP
SAT_EH_EFF	=(SAT_ER_OH_KY+(SAT_EHP_OH_KY*EFF_EHP_OH_KY))
SAT_EHP_OH_KY	SERVICE AREA SATURATION OF ELECTRIC HEAT PUMPS - RESIDENTIAL
SAT_ER_OH_KY	SATURATION RATE OF ELECTRIC RESISTANCE HEATERS IN SERVICE AREA
SAT_RAC_EFF	=EFF_RAC_OH_KY*SAT_RAC_OH_KY
SAT_RAC_OH_KY	SERVICE AREA SATURATION OF WINDOW AIR CONDITIONING SERVICE AREA
SAT_SL_OH_KY	=(0.5*SATMERC_OH_KY)+(0.5*SATSODVAP_OH_KY)
SATMERC_OH_KY	SERVICE AREA SATURATION OF MERCURY VAPOR STREET LIGHTING
SATSODVAP_OH_KY	SERVICE AREA SATURATION OF SODIUM VAPOR STREET LIGHTING
AMLOW	MINIMUM HOURLY TEMPERATURE - MORNING
PMLOW	MINIMUM HOURLY TEMPERATURE - EVENING
PMHIGH	MAXIMUM HOURLY TEMPERATURE - AFTERNOON
PREVPMHIGH	MAXIMUM HOURLY TEMPERATURE - PREVIOUS AFTERNOON
PREVPMLOW	MINIMUM HOURLY TEMPERATURE - PREVIOUS AFTERNOON
TS_KWH_IND_OH_KY	SERVICE AREA TS RATE FOR USAGE FOR INDUSTRIAL CUSTOMERS
WINDAM	WIND SPEED - MORNING
WPI0561	WHOLESALE PRICE INDEX FOR CRUDE PETROLEUM
XMAS	QUALITATIVE VARIABLE - CHRISTMAS WEEK
YP_OH_KY	SERVICE AREA PERSONAL INCOME

Section 8(3)(e)4 Energy Efficiency Program Costs

The following page contains the information requested.

Section 8(3)(e)4
Energy Efficiency Program Costs

Energy Efficiency Program	Year 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Residential																
Res. Conservation & Energy Education	$ 512,826	$ 512,826	$ 512,826	$ 512,826	$ 512,826	$ 512,826	$ 512,826	$ 512,826	$ 512,826	$ 512,826						
Refrigerator Replacement	$ 106,445	$ 106,445	$ 106,445	$ 106,445	$ 106,445	$ 106,445	$ 106,445	$ 106,445	$ 106,445	$ 106,445						
Residential Home Energy House Call	$ 235,510	$ 235,510	$ 235,510	$ 235,510	$ 235,510	$ 235,510	$ 235,510	$ 235,510	$ 235,510	$ 235,510						
Res. Comprehensive Energy Education	$ 81,500	$ 81,500	$ 81,500	$ 81,500	$ 81,500	$ 81,500	$ 81,500	$ 81,500	$ 81,500	$ 81,500						
Energy Star Products	$ 996,675	$ 996,675	$ 996,675	$ 996,675	$ 996,675	$ 996,675	$ 996,675	$ 996,675	$ 996,675	$ 996,675						
Energy Efficiency Website	$ 60,846	$ 60,846	$ 60,846	$ 60,846	$ 60,846	$ 60,846	$ 60,846	$ 60,846	$ 60,846	$ 60,846						
Personalized Energy Report Pilot Program	$ 347,681	$ 347,681	$ 347,681	$ 347,681	$ 347,681	$ 347,681	$ 347,681	$ 347,681	$ 347,681	$ 347,681						
Power Manager	$1,049,000	$1,049,000	$1,049,000	$1,049,000	$1,049,000	$1,049,000	$1,049,000	$1,049,000	$1,049,000	$1,049,000	$1,049,000	$1,049,000	$1,049,000	$1,049,000	$1,049,000	$1,049,000
Non-Residential																
High Efficiency Program																
Lighting	$ 528,569	$ 528,569	$ 528,569	$ 528,569	$ 528,569	$ 528,569	$ 528,569	$ 528,569	$ 528,569	$ 528,569						
HVAC	$ 186,595	$ 186,595	$ 186,595	$ 186,595	$ 186,595	$ 186,595	$ 186,595	$ 186,595	$ 186,595	$ 186,595						
Motors	$ 147,426	$ 147,426	$ 147,426	$ 147,426	$ 147,426	$ 147,426	$ 147,426	$ 147,426	$ 147,426	$ 147,426						
PowerShare®	$ 372,641	$ 372,641	$ 372,641	$ 372,641	$ 372,641	$ 372,641	$ 372,641	$ 372,641	$ 372,641	$ 372,641	$ 372,641	$ 372,641	$ 372,641	$ 372,641	$ 372,641	$ 372,641

Note: Assumes program spending remains constant in real dollars and that the programs ramp up over ten years. Values include incentive payments to customers and program administrative costs.

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)

DUKE ENERGY KENTUCKY

Forecast Annual Energy (GWh)

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	Energy Requirements	4,190	4,237	4,281	4,369	4,369	4,368	4,366	4,404	4,443	4,482	4,518	4,552	4,585	4,626	4,667	4,708	4,748	4,786	4,823	4,859	4,894

2	Energy By Fuel Type	2008	2009	2010	2011	2012	2013	2014	1015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
	Coal	4,115	4,150	3,960	3,522	4,080	3,870	4,013	3,905	4,027	3,929	4,114	3,632	4,028	3,867	3,973	3,707	4,055	3,832	3,570	4,086	4,154
	Gas	70	71	91	95	90	104	95	106	111	130	125	134	125	129	138	155	143	151	147	132	130
	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	286	286

3	Firm Purchases From Other Utilities	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
	None	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

4	Firm Purchases From Non-Utility	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
	None	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
5	Reductions or Increases In Energy																					
	DR	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
	EE	(3)	(8)	(14)	(19)	(23)	(26)	(29)	(31)	(34)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
	Total	(4)	(10)	(15)	(21)	(25)	(27)	(30)	(33)	(36)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)

Net (Sales)/Purchaes	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Market	1	7	215	732	175	367	228	360	270	387	243	750	396	594	520	809	514	766	1070	319	287

Table 8.(4)(c)

DUKE ENERGY KENTUCKY

Total Energy Input and Total Generation by Primary Fuel Type

Coal	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Energy (GWh)	4,115	4,150	3,960	3,522	4,080	3,870	4,013	3,905	4,027	3,929	4,114	3,632	4,028	3,867	3,973	3,707	4,055	3,832	3,570	4,086	4,154
Total (000 Tons)	1,829	1,834	1,751	1,563	1,793	1,701	1,764	1,716	1,771	1,726	1,809	1,595	1,773	1,700	1,748	1,632	1,784	1,686	1,569	1,798	1,827
(000 MBTUs) Consumed	42,862	43,062	41,312	36,876	42,232	40,067	41,553	40,424	41,734	40,654	42,621	37,567	41,765	40,040	41,177	38,445	42,008	39,704	36,945	42,342	43,035

Gas	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Energy (GWh)	70	71	91	95	90	104	95	106	111	130	125	134	125	129	138	155	143	151	147	132	130
Total (MCF)	897	907	1,166	1,215	1,147	1,319	1,207	1,343	1,414	1,650	1,578	1,664	1,546	1,602	1,711	1,905	1,752	1,851	1,803	1,619	1,593
(000 MBTUs) Consumed	920	931	1,196	1,247	1,177	1,353	1,238	1,378	1,451	1,693	1,619	1,707	1,586	1,643	1,755	1,955	1,797	1,899	1,850	1,661	1,635

Nuclear	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Energy (GWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	286	286
(000 MBTUs) Consumed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,980	2,988

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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 DE-Kentucky's customers (because these cost items are common to all plans). Therefore, an accurate projection of customer rates cannot be provided.

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

No Staff Report was issued concerning DE-Kentucky's 2003 IRP.

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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. DE-Kentucky considers this information to be trade secrets and confidential and competitive information. It will be made available to appropriate parties for viewing at Duke Energy offices during normal business hours upon execution of an appropriate confidentiality agreement or protective order. Please contact Janice Hager at (704) 382-6963 for more information.

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DUKE ENERGY KENTUCKY

Projected Cost and Operating Information For

East Bend 2

Nominal Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
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)																					

Real 2008 Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Cost of Fuel ($/MBTU)	[redacted]																				
Fixed O&M ($000)																					
Variable O&M ($000)																					
Avg. Variable Prod. Costs (cents/kWh)																					
Total Prod. Costs (cents/kWh)																					

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DUKE ENERGY KENTUCKY

Projected Cost and Operating Information For

Miami Fort 6

Nominal Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
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]																				

Real 2008 Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
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]																				

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DUKE ENERGY KENTUCKY

Projected Cost and Operating Information For

Woodsdale 1

Nominal Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
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]																				

Real 2008 Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
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]																				

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DUKE ENERGY KENTUCKY

Projected Cost and Operating Information For

Woodsdale 2

Nominal Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
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]																				

Real 2008 Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
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]																				

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DUKE ENERGY KENTUCKY

Projected Cost and Operating Information For

Woodsdale 3

Nominal Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
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)																					

Real 2008 Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Cost of Fuel ($/MBTU)	[redacted]																				
Fixed O&M ($000)																					
Variable O&M ($000)																					
Avg. Variable Prod. Costs (cents/kWh)																					
Total Prod. Costs (cents/kWh)																					

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DUKE ENERGY KENTUCKY

Projected Cost and Operating Information For

Woodsdale 4

Nominal Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
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]																				

Real 2008 Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
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]																				

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DUKE ENERGY KENTUCKY

Projected Cost and Operating Information For

Woodsdale 5

Nominal Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capacity Factor %	[redacted]	[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]	[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]	[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]	[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]	[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]	[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]	[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]	[redacted]

Real 2008 Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Cost of Fuel ($/MBTU)	[redacted]	[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]	[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]	[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]	[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]	[redacted]

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DUKE ENERGY KENTUCKY

Projected Cost and Operating Information For

Woodsdale 6

Nominal Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
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]																				

Real 2008 Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
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]																				

8(3)(b)(12) a-c, e, g

DUKE ENERGY KENTUCKY

Projected Cost and Operating Information For

New CT 1

Nominal Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
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]																				

Real 2008 Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
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]																				

DUKE ENERGY KENTUCKY

Projected Cost and Operating Information For

New CT 2

Nominal Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
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)																					

Real 2008 Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Cost of Fuel ($/MBTU)	[redacted]																				
Fixed O&M ($000)																					
Variable O&M ($000)																					
Avg. Variable Prod. Costs (cents/kWh)																					
Total Prod. Costs (cents/kWh)																					

8(3)(b)(12) a-c, e, g

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DUKE ENERGY KENTUCKY

Projected Cost and Operating Information For

NUCLEAR 1

Nominal Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
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)																					

Real 2008 Dollars

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Cost of Fuel ($/MBTU)	[redacted]																				
Fixed O&M ($000)																					
Variable O&M ($000)																					
Avg. Variable Prod. Costs (cents/kWh)																					
Total Prod. Costs (cents/kWh)																					

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

The required information is contained in the following table, in redacted form. As discussed in Volume I, Chapter 5, most of the specific technology parameters used in the screening process were based on information taken from several sources. EPRI considers its information to be trade secrets and proprietary and confidential. DE-Kentucky and its consultants consider cost estimates provided by consultants to be confidential and competitive information. Duke Energy also considers its internal estimates to be confidential and competitive information. The information will be made available to appropriate parties for viewing at Duke Energy offices during normal business hours upon execution of appropriate confidentiality agreements or protective orders. Please contact John Bloemer at (513) 287-3212 for more information.

DUKE ENERGY KENTUCKY

Capital Costs and Escalation Factors
New Units

	MF6 Baghouse/ACI Unit 6 (Environ. Compliance Upgrade) -	New CT Unit 1 (35 MW)	New CT Unit 2 (35 MW)	Nuclear Unit 1 (35 MW)
Capital Costs (Real 2008 $/kW)	[redacted]	[redacted]	[redacted]	[redacted]
Capital Costs (Nominal $/kW)	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Costs (Real 2008 $000)	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Costs (Nominal $000)	[redacted]	[redacted]	[redacted]	[redacted]
Capital Escalation Rate 2009-2013 (%)	3.88	3.88	3.88	3.88
Capital Escalation Rate 2014-2028 (%)	2.3	2.3	2.3	2.3
Variable O&M Escalation Rate (%)	2.3	2.3	2.3	2.3
Fixed O&M Escalation Rate (%)	2.3	2.3	2.3	2.3

Section 8(3)(e)5 Energy Efficiency Cost Savings

The following page contains the information requested.

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Section 8(3)(e)5

Energy Efficiency Avoided Costs

Energy Efficiency Program	Year 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Residential																
Res. Conservation & Energy Education	[redacted]															
Refrigerator Replacement																
Residential Home Energy House Call																
Res. Comprehensive Energy Education																
Energy Star Products																
Energy Efficiency Website																
Personalized Energy Report Pilot Program																
Power Manager																
Non-Residential																
High Efficiency Program																
Lighting	[redacted]															
HVAC																
Motors																
PowerShare®																

Note: Values include avoided generation, transmission, and distribution cost estimates. Assumes replacement with equivalent measures.

Section 9(1) Present Value Revenue Requirements

The 2008 Present Value Revenue Requirement (PVRR) for the 2008 IRP is [redacted] million. The effective after-tax discount rate used was 7.33%.

The modeling does not include the existing rate base (generation, transmission, or distribution.

Duke Energy Kentucky considers the PVRR to be confidential and competitive information. It will be made available to appropriate parties for viewing at Duke Energy offices during normal business hours upon execution of an appropriate confidentiality agreement or protective order. Please contact Janice Hager at (704) 382-6963 for more information.

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Section 9(3) Yearly Revenue Requirements

The projections of yearly revenue requirements are shown on the following page, in redacted form. DE-Kentucky considers these projections to be trade secrets and confidential and competitive information. They will be made available to appropriate parties for viewing at Duke Energy offices during normal business hours upon execution of an appropriate confidentiality agreement or protective order. Please contact Janice Hager at (704) 382-6963 for more information.

Table 9(3)

DUKE ENERGY KENTUCKY

Annual Revenue Requirement - Real and Nominal

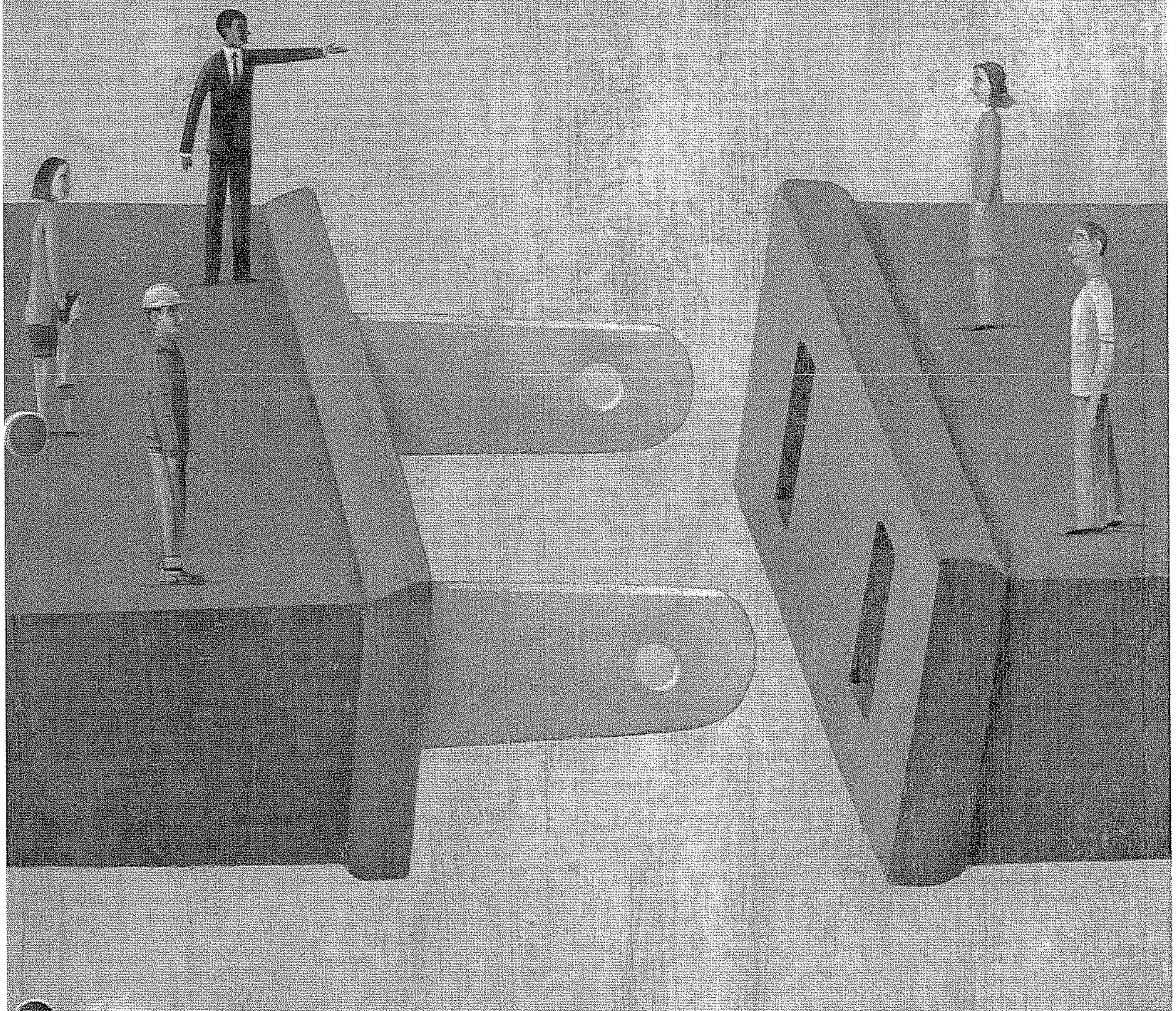
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Annual Revenue Requirement - Nominal (000's $)	[redacted]																				
Annual Revenue Requirement - Real (000's $)	[redacted]																				

Notes: Nominal values were discounted to 2008 using a rate of 7.33%.

Duke Energy

2007 SUMMARY ANNUAL REPORT

Building bridges to a low-carbon future



In 2007, we provided energy when our customers needed it, made plans to build new plants to meet growing demand, developed a new way to promote energy efficiency and continued to confront our industry's biggest challenge — global climate change. As one of the largest emitters of carbon dioxide in the world, we believe we have the responsibility to lead in bridging the gap between today's high-carbon economy and a low-carbon future. This report examines the bridges we are building to reduce our carbon footprint to benefit our current and future stakeholders.

CONTENTS:

2007 Financial Highlights	2
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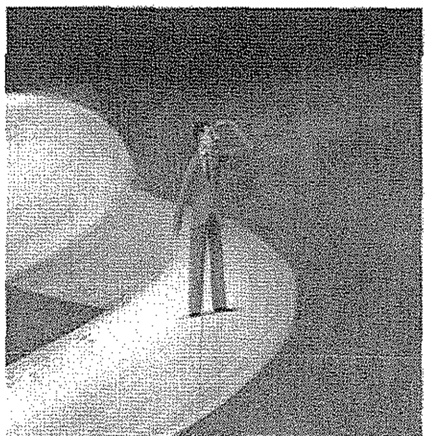
Executive Management	28
Duke Energy at a Glance	30
Non-GAAP Financial Measures	31
Investor Information	32
Forward-Looking Statement	33

BUILDING BRIDGES TO A LOW-CARBON FUTURE:

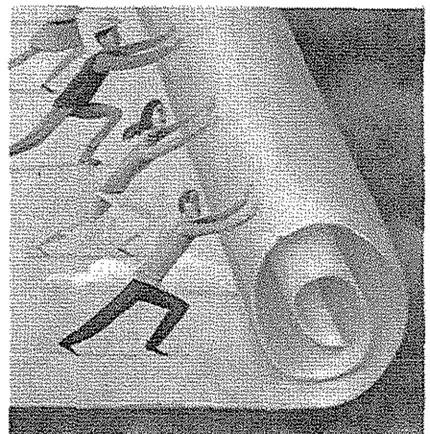
Where we are now 10

We are the third largest emitter of carbon dioxide (CO_2) in the United States — emitting more than 100 million tons last year. We've significantly reduced our non-carbon emissions over the last 20 years and with the right technologies, we believe we can do the same with CO_2. We are working to find solutions to *this challenge that will protect* and benefit our stakeholders.



Where we are going 12

We are assessing what it would take to cut our CO_2 emissions in half — to approximately 50 million tons — by 2030 and the implications of such an effort. By then, we will likely have replaced our oldest coal-fired power plants with advanced cleaner-coal and other technologies, including nuclear power, *natural gas, renewable* energy and greater use of energy efficiency.



How we will get there 14

We are taking five major steps to build bridges to a low-carbon future. We're shaping public policy, pursuing new technology, building projects and talent, balancing diverse interests and taking a long view so we can continue to create value for our stakeholders in the future.

STEP 1: Shaping public policy	16
STEP 2: Pursuing new technology	18
STEP 3: Building projects and talent	20
STEP 4: *Balancing diverse interests*	22
STEP 5: Taking the long view	24

For more information about our sustainability activities and environmental progress, please see the Duke Energy 2007|2008 *Sustainability Report* on the company Web site: www.duke-energy.com.

2007 Financial Highlights[a]

(In millions, except per-share amounts)	2007	2006	2005	2004	2003[c]
Statement of Operations					
Total operating revenues	**$12,720**	$10,607	$ 6,906	$ 6,357	$ 6,006
Total operating expenses	**10,222**	9,210	5,586	5,074	6,550
Gains on sales of investments in commercial and multi-family real estate	—	201	191	192	84
(Losses) gains on sales of other assets and other, net	**(5)**	223	(55)	(435)	(202)
Operating income (loss)	**2,493**	1,821	1,456	1,040	(662)
Total other income and expenses	**428**	354	217	180	326
Interest expense	**685**	632	381	425	431
Minority interest expense (benefit)	**2**	13	24	(15)	(79)
Income (loss) from continuing operations before income taxes	**2,234**	1,530	1,268	810	(688)
Income tax expense (benefit) from continuing operations	**712**	450	375	192	(288)
Income (loss) from continuing operations	**1,522**	1,080	893	618	(400)
(Loss) income from discontinued operations, net of tax	**(22)**	783	935	872	(761)
Income (loss) before cumulative effect of change in accounting principle	**1,500**	1,863	1,828	1,490	(1,161)
Cumulative effect of change in accounting principle, net of tax and minority interest	—	—	(4)	—	(162)
Net income (loss)	**1,500**	1,863	1,824	1,490	(1,323)
Dividends and premiums on redemption of preferred and preference stock	—	—	12	9	15
Earnings (loss) available for common stockholders	**$ 1,500**	$ 1,863	$ 1,812	$ 1,481	$ (1,338)
Ratio of Earnings to Fixed Charges	**3.7**	2.6	2.4	1.6	—[b]
Common Stock Data					
Shares of common stock outstanding[d]					
Year-end	**1,262**	1,257	928	957	911
Weighted average — basic	**1,260**	1,170	934	931	903
Weighted average — diluted	**1,266**	1,188	970	966	904
Earnings (loss) per share (from continuing operations)					
Basic	**$ 1.21**	$ 0.92	$ 0.94	$ 0.65	$ (0.44)
Diluted	**1.20**	0.91	0.92	0.64	(0.44)
(Loss) earnings per share (from discontinued operations)					
Basic	**$ (0.02)**	$ 0.67	$ 1.00	$ 0.94	$ (0.86)
Diluted	**(0.02)**	0.66	0.96	0.90	(0.86)
Earnings (loss) per share (before cumulative effect of change in accounting principle)					
Basic	**$ 1.19**	$ 1.59	$ 1.94	$ 1.59	$ (1.30)
Diluted	**1.18**	1.57	1.88	1.54	(1.30)
Earnings (loss) per share					
Basic	**$ 1.19**	$ 1.59	$ 1.94	$ 1.59	$ (1.48)
Diluted	**1.18**	1.57	1.88	1.54	(1.48)
Dividends per share[e]	**0.86**	1.26	1.17	1.10	1.10
Balance Sheet					
Total assets	**$49,704**	$68,700	$54,723	$55,770	$57,485
Long-term debt including capital leases, less current maturities	**$ 9,498**	$18,118	$14,547	$16,932	$20,622

a Significant transactions reflected in the results above include: 2007 spinoff of the natural gas businesses (see Note 1 to the Consolidated Financial Statements in Duke Energy's 2007 Form 10-K, "Summary of Significant Accounting Policies"), 2006 merger with Cinergy (see Note 2 to the Consolidated Financial Statements in Duke Energy's 2007 Form 10-K, "Acquisitions and Dispositions"), 2006 Crescent joint venture transaction and subsequent deconsolidation effective September 7, 2006 (see Note 2 to the Consolidated Financial Statements in Duke Energy's 2007 Form 10-K, "Acquisitions and Dispositions"), 2005 DENA disposition (see Note 13 to the Consolidated Financial Statements in Duke Energy's 2007 Form 10-K, "Discontinued Operations and Assets Held for Sale"), 2005 deconsolidation of DCP Midstream effective July 1, 2005 (see Note 13 to the Consolidated Financial Statements in Duke Energy's 2007 Form 10-K, "Discontinued Operations and Assets Held for Sale"), 2005 DCP Midstream sale of TEPPCO (see Note 13 to the Consolidated Financial Statements in Duke Energy's 2007 Form 10-K, "Discontinued Operations and Assets Held for Sale") and 2004 sale of the former DENA Southeast plants.

b Earnings were inadequate to cover fixed charges by $746 million for the year ended December 31, 2003.

c As of January 1, 2003, Duke Energy adopted the remaining provisions of Emerging Issues Task Force (EITF) 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-03) and SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). In accordance with the transition guidance for these standards, Duke Energy recorded a net-of-tax and minority interest cumulative effect adjustment for change in accounting principles.

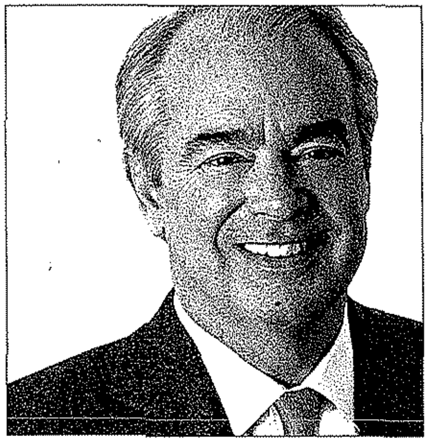
d 2006 increase primarily attributable to issuance of approximately 313 million shares in connection with Duke Energy's merger with Cinergy (see Note 2 to the Consolidated Financial Statements in Duke Energy's 2007 Form 10-K, "Acquisitions and Dispositions").

e 2007 decrease due to the spinoff of the natural gas businesses to shareholders on January 2, 2007 as dividends subsequent to the spinoff were split proportionately between Duke Energy and Spectra Energy such that the sum of the dividends of the two stand-alone companies approximates the former total dividend of Duke Energy prior to the spinoff.

See Notes to Consolidated Financial Statements in Duke Energy's 2007 Form 10-K.

Chairman's Letter to Stakeholders

Dear fellow investors, customers, employees and all who have an interest in our success — our partners, suppliers, policymakers, regulators and communities:



JAMES E. ROGERS
Chairman, President and Chief Executive Officer

We believe that all companies should have great aspirations. At Duke Energy, we have two aspirations that guide our planning and serve as a bridge to the future: (1) Modernize and decarbonize our generation fleet, and (2) Help make the communities we serve the most energy efficient in the world.

These aspirations are grounded in our commitments to provide our customers with clean, affordable and reliable electric and gas services, and to allocate capital over the long term to grow earnings for investors.

Our aspirations are also shaped by the ongoing debate over how to address global climate change. They are action-based. They recognize our intent to ensure that rules limiting greenhouse gas (GHG) emissions will fairly balance the needs of all of our stakeholders.

In this letter I will describe how we are building bridges to a low-carbon future. My confidence in our ability to succeed is based on the dedication of our people. Their hard work and perseverance was evident in our 2007 results.

"Most of the electricity generated in this country is fueled by four natural resources: coal, uranium, natural gas and water. We include a fifth fuel — energy efficiency. By helping our customers use power more efficiently, we can help them save money and reduce the need for new power plants."

2007 — A STRONG, PRODUCTIVE YEAR

Last year, we faced weather-related challenges of record-setting summer heat throughout our service territory and a persistent drought in the Carolinas. We continued to make progress in integrating our 2006 merger with Cinergy, and we completed the spinoff of our natural gas businesses. The people of Duke Energy met these challenges while achieving solid results in customer service and operations.

- ***We increased earnings per share and total return:*** Ongoing diluted earnings per share of $1.24 in 2007 exceeded 2006 ongoing diluted earnings per share of $0.99. Duke Energy's total shareholder return (TSR) — a combination of the change in stock price plus dividends paid out — was more than 9 percent in 2007. This beat the S&P 500 index TSR of 5.5 percent.
- ***We achieved constructive legislative and regulatory outcomes:*** We received approvals to build two new advanced coal plants in Indiana and North Carolina. Thanks to the diligent work of our teams, we received final air permits for both in January 2008. We helped pass comprehensive energy legislation in North Carolina and South Carolina. The legislation enables the more timely recovery of certain operating costs, such as the reagents and chemicals we use in our environmental equipment on our coal plants. And it allows more timely recovery of the financing costs associated with the construction of new baseload generation. In North Carolina, we settled our rate case, which reduced industrial, commercial and residential rates without a material impact on 2008 earnings. In Ohio, we continue to support legislation that will ensure future rate certainty for our customers in that state.
- ***We grew our renewable energy portfolio:*** Our Commercial Businesses acquired 1,000 megawatts of wind power assets planned or under development in the western and southwestern United States. We also began construction of two small hydroelectric power plants in Brazil.
- ***We dedicated ourselves to customer service and economic development:*** We achieved improvements in our key internal satisfaction measures for all customer classes. Economic development efforts helped stimulate new capital investments and new jobs in our five-state service territory.
- ***We met productivity targets:*** Our nuclear and coal plants performed superbly when we needed them the most. Our nuclear fleet had its third-best year ever for capacity. Despite the drought, careful management of our coal and hydro units enabled us to successfully meet our customers' record demand for both peak and baseload power.

BUILDING BRIDGES TO A LOW-CARBON FUTURE

In 2008, we'll continue to focus on delivering results for both customers and investors in our basic business. At the same time, we will continue to chip away at the most difficult challenge in the history of our industry: global climate change.

Demand for electricity is growing locally and globally. Each year, Duke Energy alone is adding approximately 40,000 to 60,000 new customers in the Carolinas, and 11,000 to 16,000 new customers in the Midwest. This means we will need more than 6,000 megawatts of new generating capacity by 2012. According to the U.S. Department of Energy, nationwide power demand will grow approximately 35 percent by 2030.

At the same time, evidence is growing that carbon dioxide (CO_2) released into the atmosphere from burning fossil fuels is creating conditions that could change our way of life. Scientists know climate change is a problem, yet they aren't able to accurately predict its full scope. I leave the science to the scientists, but as an energy company CEO, I have a responsibility to protect our assets against such risks — to meet the need for power, without risking our children's futures.

We must plan ahead. It takes five or more years to build a new baseload coal plant, and 10 to 15 years to build a new nuclear plant. To ensure we can deliver reliable and affordable power to our customers, we have to start now. But today, we lack advanced technologies that can achieve this seemingly impossible dual mission: high growth and low carbon. Consequently, we have developed a multi-pronged strategy to bridge the gap between our current high-carbon economy and a low-carbon future.

Let me explain in this letter how the people of Duke Energy are building four bridges: (1) from "production" (making watts) to "efficiency" (saving watts); (2) from conventional to unconventional generating technologies; (3) spanning investor expectations and new regulatory rules; and (4) from following the status quo to leading with forward-looking policies.

THE FIRST BRIDGE: FROM PRODUCTION (MAKING WATTS) TO EFFICIENCY (SAVING WATTS)

Most of the electricity generated in this country is fueled by four natural resources: coal, uranium, natural gas and water. We include a fifth fuel — energy efficiency. By helping our customers use power more efficiently, we can help them save money and reduce the need for new power plants. In aggregate, energy efficiency investments are the least expensive and most environmentally benign source of energy for our customers.

Why isn't more being done to promote energy efficiency? As co-chair of the National Action Plan on Energy Efficiency and the Alliance to Save Energy, I reviewed state regulatory plans for energy efficiency. We found that many utilities don't invest in such programs, because the current regulatory framework is biased against investments in energy efficiency in favor of putting steel in the ground. Our goal is to change that regulatory paradigm so that earnings from energy efficiency are *on a par with earnings from investments* in new power plants.

In 2007, we introduced Duke Energy's energy efficiency plan, which is designed to set investment returns for the costs and savings of energy efficiency programs. Customers would benefit because they would pay 10 to 15 percent less for energy efficiency than for a new power plant. We filed for regulatory approval of this plan in Indiana, North Carolina and South Carolina. As I was writing this letter, we reached

2007 MAJOR ACHIEVEMENTS

FIRST QUARTER

- Completed the spinoff of Spectra Energy.
- Received approval to build an 800-megawatt advanced coal-fired unit at our Cliffside station in western North Carolina (final air permit received in January 2008).

SECOND QUARTER

- Issued first Sustainability Report.
- Filed energy efficiency plan in North Carolina.
- Helped pass comprehensive energy legislation in South Carolina that provides for the recovery of new nuclear plant financing costs during the construction phase and allows recovery of costs of certain reagents used in emission removal.
- Acquired 1,000 megawatts of wind energy assets under development in the western and southwestern United States.

THIRD QUARTER

- Met customers' demand for electricity during record-setting summer heat throughout the service territory and record-setting drought in the Carolinas.
- Helped pass comprehensive energy legislation in North Carolina that enables the recovery of new plant financing costs during the construction phase and allows recovery of costs of certain reagents used in emission removal. The legislation includes a workable renewable energy and energy efficiency portfolio standard.
- Filed energy efficiency plan in South Carolina.

FOURTH QUARTER

- Filed energy efficiency plan in Indiana.
- Received remand order affirming the Ohio rate stabilization plan. The ruling maintains the current price and provides for the continuation of existing rate components.
- Received approval to build a 630-megawatt cleaner-coal integrated gasification combined cycle (IGCC) power plant in southwestern Indiana (final air permit received in January 2008).
- Settled rate case in North Carolina, which reduced industrial, commercial and residential rates with no material impact on 2008 earnings.
- Filed applications with state regulators for certificates of public convenience and necessity to add two 620-megawatt combined cycle, natural gas-fired units at two existing power plants in North Carolina.
- Submitted a combined construction and operating license application to the U.S. Nuclear Regulatory Commission for the proposed 2,234-megawatt Lee Nuclear Station in Cherokee County, S.C.
- 2007 ongoing diluted earnings per share of \$1.24 exceeded 2006 ongoing diluted earnings per share of \$0.99.

FULL YEAR

- Continued push for federal cap-and-trade legislation limiting greenhouse gas emissions.

"In aggregate, energy efficiency investments are the least expensive and most environmentally benign source of energy for our customers."

a partial settlement in South Carolina for our plan. We expect to file similar plans in Ohio and Kentucky in 2008.

We were pleased that in February 2008, the Alliance to Save Energy, the American Council for an Energy-Efficient Economy and the Energy Future Coalition endorsed our energy efficiency model as "an innovative and promising new direction for the company and its customers."

Building the smart grid — the backbone of reliability

In 2007, we began installing smart meters in Charlotte, N.C., Cincinnati, Ohio, and northwestern South Carolina. Turning analog meters into digital or smart meters enables real-time communication between our power grids and our customers' homes. This will help our customers monitor and manage their power consumption. We have about 7,500 smart meters in place today. With appropriate regulatory recovery, we expect to install an additional 60,000 by the end of 2009.

Over the next five years, we plan to spend about $1 billion to digitize our distribution system. These improvements will help us better balance supply and demand, pinpoint trouble sooner, and restore outages faster or avoid them altogether.

THE SECOND BRIDGE: FROM CONVENTIONAL TO UNCONVENTIONAL GENERATING TECHNOLOGIES

Our energy efficiency focus is vital to providing reliable and cost-effective electricity in the future. But efficiency alone cannot satisfy growing demand and at the same time reduce our CO_2 emissions. We must do more. Instead of looking for a "silver bullet" strategy, we are taking a "silver buckshot" approach. Using new technologies, we plan to build an efficient generation portfolio powered by coal, nuclear, natural gas and renewables. Over the next five years, we plan to invest approximately $23 billion (almost equal to our current market cap) to make our entire system more efficient, retire inefficient plants and increase renewable generation.

Advanced coal technologies

When people ask, "How can a company committed to a low-carbon future continue to build new coal plants?" I remind them of these key facts: Today, coal accounts for about 50 percent of our nation's total electric generation. In the United States, Duke Energy's system is about 70 percent coal. We burn coal today because it is the most abundant and economical fuel available for large-scale reliable power generation. We are finding ways to use coal more efficiently and cleanly.

Indiana regulators approved our four-year plan to build a cleaner-coal integrated gasification combined cycle (IGCC) plant. The 630-megawatt Edwardsport plant is currently expected to cost approximately $2 billion. To encourage this new technology, the project will receive $460 million in local, state and federal tax incentives and credits.

The new plant will be one of the cleanest and most efficient coal-fired power plants in the world. It will emit less sulfur dioxide (SO_2), nitrogen oxides (NO_X) and particulates than the plant it replaces — while providing more than 10 times the power of the existing plant. The current 160-megawatt plant emits about 13,000 tons of SO_2, NO_X and particulates annually and runs about 30 percent of the time. By comparison, a new 630-megawatt IGCC plant running 100 percent of the time will emit about 2,900 tons of the same pollutants. It will also use about 11 million gallons of water a day, compared to the current plant, which uses almost 190 million gallons daily.

Eventually we hope to be able to capture and permanently store the CO_2 emitted from this plant in nearby underground formations, keeping it out of the atmosphere.

North Carolina regulators approved our plan to build a new 800-megawatt unit at our Cliffside Steam Station. At a cost of approximately $2.4 billion, this plant will use supercritical coal-combustion technology, which is 30 percent more efficient than the units it will replace. As a result, it will generate twice the amount of electricity of the existing plant with only one-seventh of the SO_2, one-third of the NO_X and one-half the mercury emissions. The new unit's air permit includes limits on SO_2 and NO_X emissions that are stricter than current state and federal rules. The state's mercury limits are already more stringent than federal rules. The project will receive $125 million in federal clean-coal tax credits.

We also agreed to implement a unique CO_2 mitigation plan for Cliffside. As part of that plan, we will retire the plant's four older coal units by 2012 and shut down 800 megawatts of other older coal units by 2018. In addition, we agreed to invest 1 percent or approximately $50 million of our North Carolina revenues from our regulated operations each year in energy efficiency, pending appropriate regulatory approval.

Natural gas

Natural gas emits less CO_2 than coal, but it is more expensive — so we use it judiciously in our portfolio. We filed with our regulators to build two 620-megawatt gas-fired units, one each at our Buck and Dan River steam stations in North Carolina. Last year, we purchased nearly 1,300 megawatts of gas-fired generation in the Midwest and North Carolina, adding to our existing gas assets.

Non-fossil fuel: nuclear and renewable energy

Today, approximately 28 percent of the power we generate in the United States comes from zero CO_2-emitting nuclear and renewable energy — about 5,000 megawatts of nuclear capacity and about 3,200 megawatts of hydroelectric capacity. We also have more than 3,100 megawatts of hydroelectric capacity in South America.

To reduce CO_2 emissions and meet demand growth, nuclear power must play an even larger role in our portfolio. In December, we filed an application with the Nuclear Regulatory Commission for a combined construction and operating license for our proposed two-unit, 2,234-megawatt Lee Nuclear Station in South Carolina. We also filed with South Carolina regulators to invest and recover up to $230 million in the plant's upfront development costs. We saw similar cost recovery assurance legislation pass in North Carolina. Assuming timely regulatory approvals, we would anticipate unit 1 coming on line in 2018.

We will also increase our use of renewable energy, by adding wind, solar and biomass to our hydroelectric capacity. We will add up to 200 megawatts from renewable sources to serve our Indiana customers, and we are purchasing renewable energy capacity to supply our North Carolina customers starting in 2012. As noted earlier, our nonregulated business is also building a renewable energy portfolio. When completed, these projects will sell wholesale power to other utilities. We expect the first 240 megawatts of these nonregulated assets to come on line in 2008 and 2009.

THE THIRD BRIDGE: SPANNING INVESTOR EXPECTATIONS AND NEW REGULATORY RULES

During the 1970s and 1980s, the industry invested trillions of dollars to build new baseload generation. The result was a sobering demonstration of the limitations of traditional rate-of-return regulation — for both customers and investors. This construction binge resulted in rate shocks for customers, cost overruns, the cancellation of half-finished plants and ultimately red ink for shareholders.

In the 1990s, we turned to the deregulation of power markets, relying on market signals to build new generation cost-effectively. But these experiments produced other undesirable outcomes: overbuilding in premium fuels such as natural gas and the under-recovery of true investment costs.

The lessons are clear to customers, investors, regulators and policymakers. We need new rules based on what we learned from both building eras. Customers and investors can both benefit when regulators reduce the time between when we invest and when we start recovering our investments.

OUR MISSION, OUR VALUES

Our Mission

At Duke Energy, we make people's lives better by providing gas and electric services in a sustainable way. This requires us to constantly look for ways to improve, to grow and to reduce our impact on the environment.

Our Values

- ***Caring*** — We look out for each other. We strive to make the environment and communities around us better places to live.
- ***Integrity*** — We do the right thing. We honor our commitments. We admit when we're wrong.
- ***Openness*** — We're open to change and to new ideas from our co-workers, customers and other stakeholders. We explore ways to grow our business and make it better.
- ***Passion*** — We're passionate about what we do. We strive for excellence. We take personal accountability for our actions.
- ***Respect*** — We value diverse talents, perspectives and experiences. We treat others the way we want to be treated.
- ***Safety*** — We put safety first in all we do.

"As the third largest emitter of CO_2 in the United States, I believe we have a responsibility to provide policy leadership. We must imagine a low-carbon future for our grandchildren and act to lower CO_2 emissions now. Achieving a low-carbon future will require rigorous engineering solutions, continuing technological discoveries, the political will to bridge local interests and global needs, and leaps of imagination."

In 2007, South Carolina passed comprehensive energy legislation that includes provisions allowing recovery of new nuclear plant financing costs during the construction phase. Similarly, North Carolina lawmakers passed legislation that allows us to seek plant financing costs through a rate case. This legislation enables us to synchronize capital spending and rate cases associated with our major investments. The North Carolina law also provided a workable renewable energy and energy efficiency portfolio standard requiring investor-owned utilities to supply 12.5 percent of their power from renewable energy sources by 2021.

This far-thinking leadership will allow us to build new plants so we can deliver reliable and affordable service to our customers while reducing the risk of regulatory lag.

Our strong balance sheet allows us to fund our ambitious five-year building program without issuing public equity. Beginning in 2010, we expect to raise equity of about $200 million per year through our dividend reinvestment and internal benefit programs.

THE FOURTH BRIDGE: FROM FOLLOWING THE STATUS QUO TO LEADING WITH FORWARD-LOOKING POLICIES

I've described actions we are taking in our service territory to meet our growing demand for power and reduce our carbon footprint. With these steps, we will achieve our aspirations of modernizing and decarbonizing our fleet and making our communities more energy efficient.

But we must do more. As the third largest emitter of CO_2 in the United States, I believe we have a responsibility to provide policy leadership. We must imagine a low-carbon future for our grandchildren and act to lower CO_2 emissions now. Achieving a low-carbon future will require rigorous engineering solutions, continuing technological discoveries, the political will to bridge local interests and global needs, and leaps of imagination.

In 2007, we worked to win Congressional support of cap-and-trade rules to control GHG emissions, so that all businesses can calculate the investment needed to reduce their carbon footprints. We advocated for legislation that treats all industries and regions of the nation fairly and ensures that utility customers in high coal-using states aren't penalized. We believe a cap-and-trade approach is the fairest and most equitable and practical way to achieve a 60 to 80 percent reduction in our nation's GHG emissions by 2050.

We also need new ways to fund research, development and deployment of CO_2-reducing technologies. Without such funding, we won't make it across the bridge to a low-carbon future.

More business, political and community leaders are stepping forward to cross that bridge. They're not waiting for others to act. Such leaders are also emerging in our company. They and their colleagues know it's easier not to rock the boat. Yet they've chosen to act and to take personal responsibility for their results. They've chosen to lead with integrity, discipline, vision and compassion — and help prepare and develop our workforce for the future.

During the next five years, we expect almost a third of that workforce to retire. This presents both a recruitment challenge and a great opportunity to grow talent within the company. One of my team's top priorities is development of a highly talented workforce that has the skill and the will to position us for a low-carbon future.

FOCUSED ON GROWTH

Based on current assumptions, we expect to grow ongoing diluted earnings at 5 to 7 percent compounded annually through 2012. We've set our 2008 employee incentive target at $1.27, based on ongoing diluted earnings per share. Our growth objectives are supported by our commitment to balance the needs of our stakeholders, including future generations.

Our many accomplishments this past year were possible because of the diligence, hard work and imagination of the people of Duke Energy. I thank them on your behalf, and mine.

The catalysts to increase future earnings will be continuing cost management, execution on our investment-recovery strategy and steady organic growth. This represents a strong value proposition for our investors, and one that allows us to honor commitments to all of our stakeholders.

We will focus on these priorities as we continue to build bridges to a low-carbon future. I look forward to working together with you to achieve that goal.

James E. Rogers

JAMES E. ROGERS
Chairman, President and Chief Executive Officer

March 7, 2008

Leadership on Climate Disclosure

Investors, customers and other stakeholders need to know the risks and opportunities the company will face in a world of tightening greenhouse gas constraints. They also want to know what the company is doing to position itself for success in a low-carbon future.

As part of its commitment to transparency, Duke Energy has been reporting its carbon dioxide (CO_2) emissions to the U.S. Department of Energy and to the U.S. Environmental Protection Agency since 1995. For the past five years, the company has also participated in the Carbon Disclosure Project (CDP). The CDP is an independent organization that works with shareholders and participating companies who voluntarily share their assessment of the business risks and opportunities they face due to climate change and the associated regulatory requirements. Duke Energy's current CDP report can be found at www.cdproject.net and on the company Web site at www.duke-energy.com/environment/reports/carbon-disclosure-project.asp.

Duke Energy's SEC Form 10-K for 2007 included a detailed assessment of the climate policy debate in Washington and potential costs customers could see under specific legislative proposals. (This form can also be accessed on the company Web site.) The company pointed out that compliance costs will be highly dependent on allowance prices, and will be tied closely to Congress' decision with respect to the allocation of allowances.

In January 2008, Duke Energy agreed to participate in The Climate Registry (TCR) as a Founding Reporter. TCR represents a collaboration of 39 U.S. states, seven Canadian provinces and two Mexican states. Participants in the registry agree to report their greenhouse gas emissions using a common platform. A more detailed description can be found by visiting www.theclimateregistry.org.

In 2007, Duke Energy joined the Advisory Committee of the Climate Disclosure Standards Board (CDSB) — an international partnership of seven organizations formed to establish a generally accepted framework for corporate climate change risk-related reporting. The board's long-term goal is to ensure that companies file these reports with regulatory authorities as part of their annual financial reporting. More information is available at www.weforum.org.

Duke Energy has agreed to participate this year in the CDSB's pilot program to "road test" the template, which includes emissions disclosure, physical risks, regulatory risks and risk management strategy. Once the program is up and running in 2009, completed reports will be posted on the Web sites of participating companies.

These are some of the ways Duke Energy is working to keep its stakeholders informed about its strategy for addressing climate change and the associated regulatory risk, now and in the future. For more information on the company's climate disclosure and overall transparency efforts, please also see Duke Energy's 2007|2008 Sustainability Report on the company Web site.

Where we are now

Duke Energy is one of the largest electricity suppliers in North and South America. We serve our retail and wholesale customers reliably and affordably with approximately 40,000 megawatts of electric generating capacity fueled from coal, nuclear, natural gas, hydroelectric and a growing portfolio of renewable energy. In the United States, about 70 percent of the power we generate today comes from coal, which releases carbon dioxide (CO_2) into the atmosphere and is linked to climate change.

CO_2 and most other greenhouse gases (GHG) have always been present, keeping the earth hospitable for life by trapping heat that would otherwise escape into space. We know this as the greenhouse effect. Since the industrial revolution, however, the concentration of GHG in the atmosphere from the burning of fossil fuels and other human activities has increased, trapping more heat and amplifying the natural greenhouse effect.

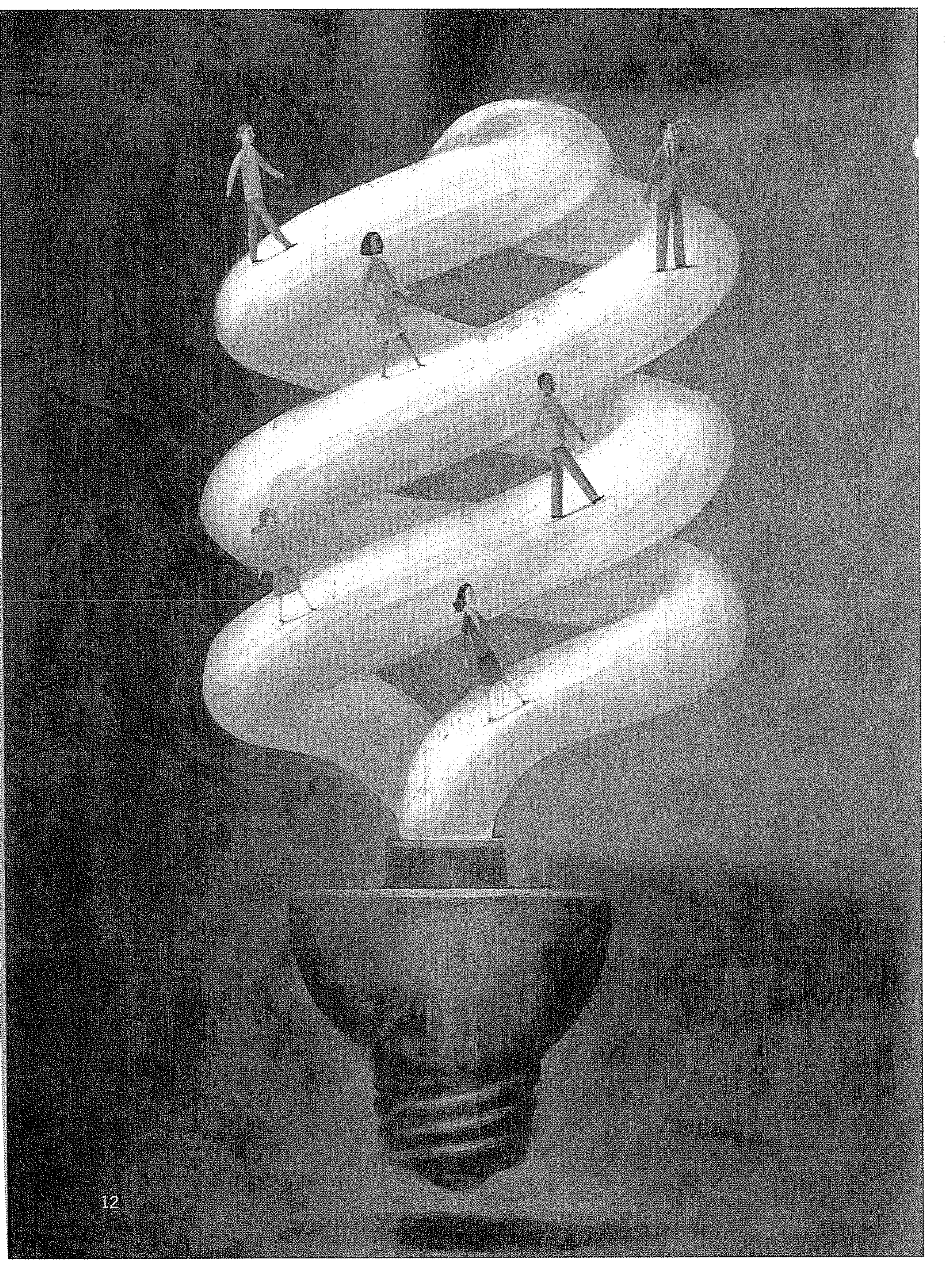
A majority of the public and policymakers now believe that the earth's climate is changing, caused in part by GHG emitted into the atmosphere from human activity.

As the third largest emitter of CO_2 in the United States — more than 100 million tons annually, the equivalent of about 10 million cars on the highway — we realize we have a special responsibility to address this issue.

Our focus is on finding practical solutions that will benefit our stakeholders, our nation, our world and future generations.

"I monitor and analyze emerging environmental issues for the company. Over the last few years, the debate over global climate change has intensified. We believe it is no longer a question of if Congress will enact carbon limits, but when — and what will be required. We have to be ready to comply in a way that keeps customer prices competitive."

MIKE STROBEN
Director, Environmental Policy Analysis & Strategy
Duke Energy
Charlotte, N.C.



Where we are going

We are taking actions today to build a sustainable business that allows our stakeholders and our company to prosper while balancing environmental, social and economic needs.

We don't know when federal restrictions on GHG emissions will be enacted, but we must assume they are coming. Some believe it is premature to set specific emission-reduction targets. But without a stake in the ground, we can't expect to make meaningful progress. We believe that preparing for a carbon-constrained world now carries substantially less risk for our customers and our shareholders than if we wait.

To be ready, we are assessing what it would take to cut our CO_2 emissions in half — approximately 50 million tons — by 2030. By then, we will likely have replaced our oldest coal-fired power plants with advanced cleaner-coal and other technologies including nuclear power, natural gas, renewable energy and energy efficiency.

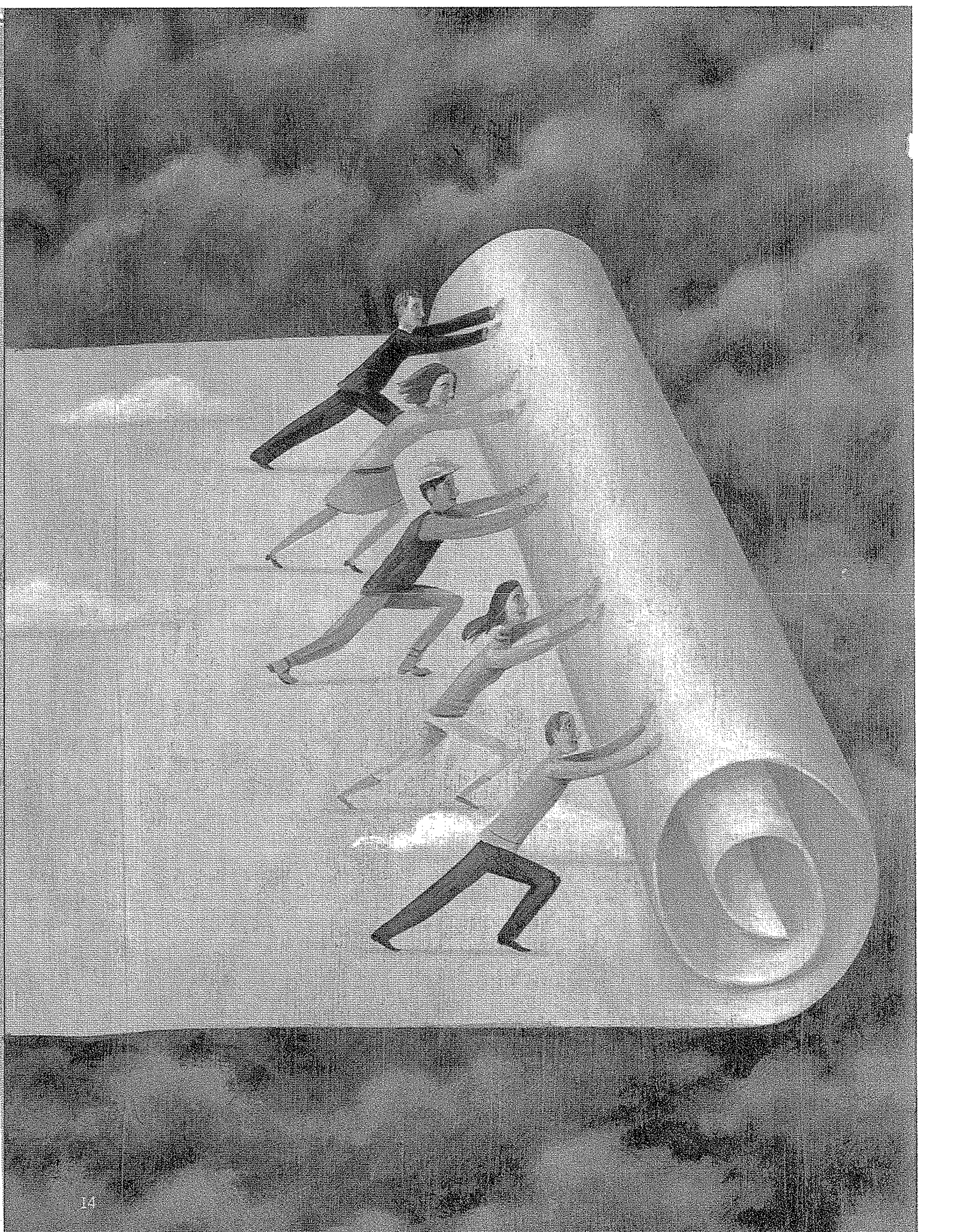
To achieve that reduction and meet our projected electricity demand while keeping our prices competitive, a number of things must happen. These include new technology developments and workable legislative and regulatory solutions.

We will need new, lower-emitting coal-based generating technologies so we can continue using coal, our nation's most abundant and economical fuel. We will need advanced zero-emitting nuclear generation. We will need approval of a new business model to significantly expand energy efficiency.

As we realize our vision, we will be ready to adopt new technologies and address unexpected challenges that will surely come along.

"If we are serious about addressing climate change, we have to be serious about nuclear power. Nuclear power plants safely generate more than 70 percent of all carbon-free electricity in the United States. Along with advanced coal, natural gas, renewable energy and energy efficiency, nuclear power must be part of the mix to meet our need for clean, affordable and reliable electricity."

DAVID JONES
Director, Nuclear Policy & Strategy
Duke Energy
Charlotte, N.C.



How we will get there

We are taking five steps to build our bridges to a low-carbon future:

First, we are working to shape public policy. We are pursuing passage of federal carbon legislation that will give the electric utility industry the time it needs to make the transition to low-carbon generation, without severe damage to our economy and our customers.

Second, we are pursuing new technology for generation and distribution of electricity and for energy efficiency to reduce our carbon footprint.

Third, we are building new generation plants. We are also developing our talent base so we have the workforce we need to successfully transition to a low-carbon future.

Fourth, we are balancing diverse interests. We are engaging with stakeholders to understand all viewpoints and find the best path to sustainable carbon reduction.

Fifth, we are taking a long view. Halving our CO_2 emissions won't happen overnight. This is a marathon, not a sprint — but the sooner we start, the greater the benefits.

The following pages describe these five steps in greater detail.

"I've been a meter reader and worked in Customer Service, Accounting and Human Resources. In my current role, I bring the customer perspective to lawmakers and their staffs on Capitol Hill. This helps them better understand how we are trying to minimize the impact on our customers as we work to reduce our greenhouse gas emissions."

JOHN HAYSBERT
Manager, Federal Governmental Affairs
Duke Energy
Washington, D.C.

STEP 1

MARITZA BEGAN HER CAREER WITH DUKE ENERGY IN 1999 AS ONE OF THE COMPANY'S FIRST BILINGUAL CUSTOMER SPECIALISTS. SHE LEADS A TEAM RESPONSIBLE FOR FULFILLING CUSTOMER SERVICE REQUESTS, INCLUDING THROUGH THE INTERNET.

HOW WE WILL GET THERE:

Shaping public policy

"Customers are concerned about energy costs. They want to know what they and their families can do to reduce their power bills. In that sense, I think Duke Energy's focus on energy efficiency is coming at the right time."

MARITZA RIVERA
Call Center Team Lead
Duke Energy
Charlotte, N.C.

Congress could pass legislation enacting a greenhouse gas (GHG) cap-and-trade program as early as 2009. As we strive to shape that legislation, we are working to:

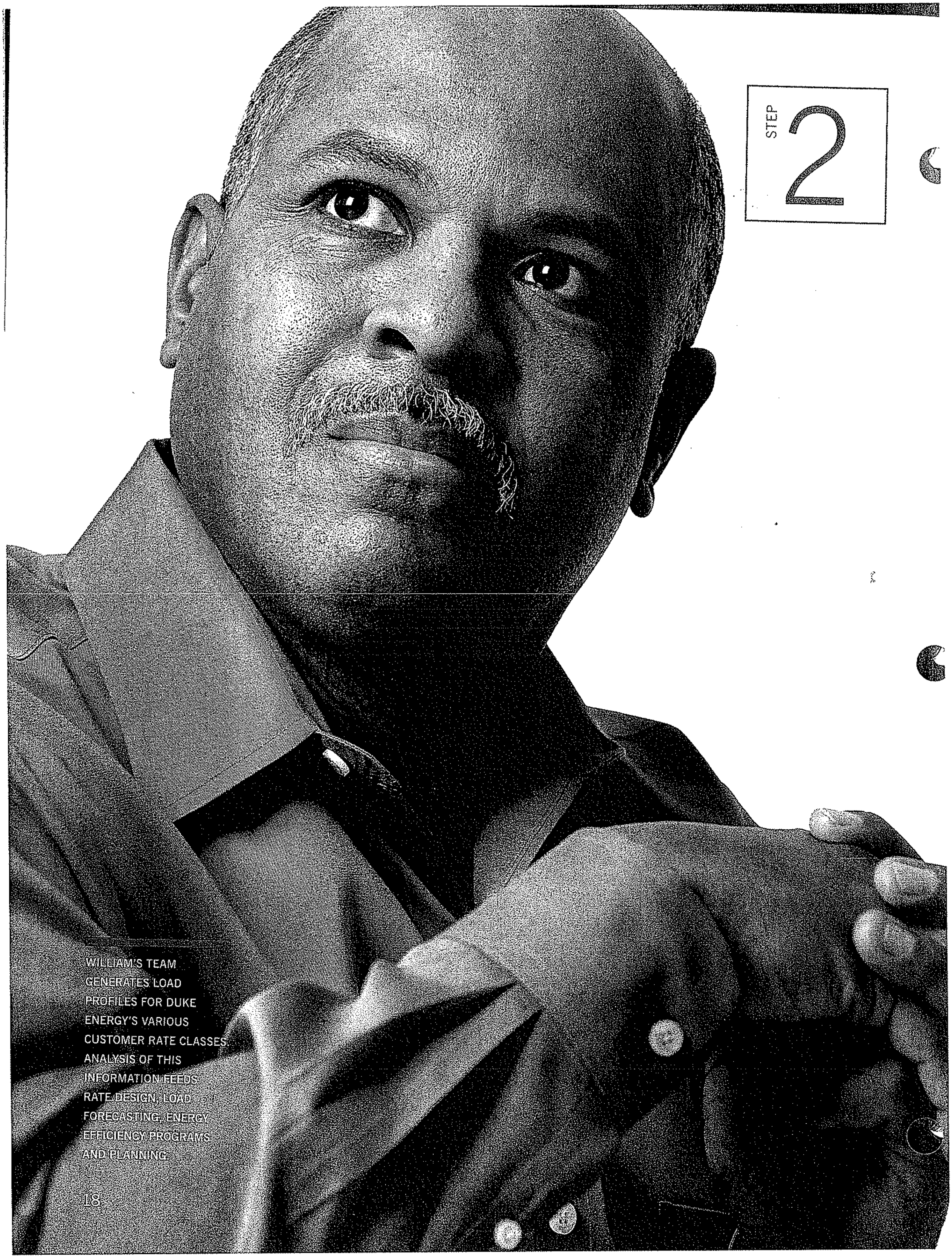
- Better understand the impact alternative policy approaches could have on our industry, our operations and our customers.
- Better understand the technology gap for low- and zero-emitting power generation and promote the funding mechanisms needed to close that gap.
- Communicate with policymakers and other stakeholders, who can help mold and shape federal policy while new technologies develop. This report and our 2007|2008 Sustainability Report are part of that communication process.

Most pending federal legislation calls for reducing our nation's GHG emissions by 60 to 80 percent by 2050. Scientists say the United States and other carbon-intensive nations need to achieve this reduction level by the middle of this century to slow, stop and reverse the effects of climate change. For Duke Energy, we expect that all of our currently operating baseload nuclear and coal-fired generating units will be retired by 2050, with the possible exception of one of our "newest" coal plants in Ohio, which will then be 59 years old.

Given the unknowns — the timing of new low-carbon generation technologies and future carbon dioxide (CO_2) emission constraints — we decided to look instead at what it might take to cut our CO_2 emissions in half — by approximately 50 million tons — by 2030. Due to their relicensing, our three nuclear plants will still be operating, and our planned fourth nuclear plant, Lee Nuclear Station, will have been on line for about 12 years, based on the current schedule. 2030 gives us a more realistic horizon over which to evaluate potential emission-reduction strategies.

With passage of the right cap-and-trade legislation and new technologies, we believe we could successfully reduce our CO_2 emissions like we have our nitrogen oxide (NO_x) and sulfur dioxide (SO_2) emissions. Through 2010, we will have invested approximately $5 billion to further reduce our SO_2 and NO_x emissions. We project that by 2010, those emissions will be about 70 percent lower than they were in 1997. The SO_2 and NO_x controls we have been installing have the added benefit of capturing a significant amount of mercury.

The point is, we acted proactively before to achieve workable regulations and made the necessary investments in new technology to comply. We can do that again with carbon legislation and forge a solution that protects our customers, our business and our nation's economy.



STEP 2

WILLIAM'S TEAM GENERATES LOAD PROFILES FOR DUKE ENERGY'S VARIOUS CUSTOMER RATE CLASSES. ANALYSIS OF THIS INFORMATION FEEDS RATE DESIGN, LOAD FORECASTING, ENERGY EFFICIENCY PROGRAMS AND PLANNING.

HOW WE WILL GET THERE:

Pursuing new technology

"The Load Research team studies how and when our customers are using energy. This information helps to plan for our customers' future needs and to identify the role that emerging technologies and energy efficiency will play in meeting those needs."

WILLIAM BAKER
Manager, Load Research
Duke Energy
Charlotte, N.C.

We are using new technologies to reduce our GHG emissions on both the supply and demand sides. On the supply side, we're building a cleaner-coal integrated gasification combined cycle (IGCC) plant that will replace a half-century-old coal plant. We're building this 630-megawatt plant in southwestern Indiana, where the geology is conducive to underground capture and permanent storage of CO_2 emissions. As that technology develops, we will evaluate its eventual use at the site.

In the Carolinas, we're building an advanced 800-megawatt coal plant that will eventually replace 1,000 megawatts of old higher-emitting coal units in North Carolina. We're not building an IGCC plant as the geology there is not suitable for CO_2 storage, but this will likely be the last new coal plant we build in North Carolina for at least 20 years. By then, we would expect CO_2 capture technology to advance so it can be used on virtually any coal plant, regardless of the geology. Also in North Carolina, we have applied to build more than 1,200 megawatts of natural gas-fired generation capacity to meet increasing demand. This lower-emitting gas generation will also replace older coal units.

We are using our more than three decades of experience in building and operating nuclear plants to plan a new 2,234-megawatt nuclear power plant in South Carolina — a plant that will have zero CO_2 emissions.

We are increasing our use of renewable energy by purchasing renewable capacity to help meet our domestic energy demand with wind, biomass and solar power. Our Commercial Businesses are planning and developing more than 1,000 megawatts of wind power.

On the demand side, we are transforming our passive analog distribution grids into digital information networks to further improve reliability and expand energy efficiency. We are installing "smart" meters, remotely controlled appliance sensors and other energy-saving technologies in customers' homes.

We intend to make energy efficiency part of our standard service offering. This includes providing customers with tools to reduce their energy use without sacrificing comfort, convenience or productivity.

Technology and energy efficiency breakthroughs won't happen without the right regulatory treatment. We seek state regulations that treat energy efficiency as the "fifth fuel" — just like coal, nuclear, natural gas and renewable energy in meeting growing demand. We seek to earn a return on the avoided cost of building new power plants through our energy efficiency gains.

STEP 3

NEETA STUDIES AND SELECTS EMERGING TECHNOLOGIES FOR USE AT DUKE ENERGY. SHE ALSO DEVELOPS ADAPTATION STRATEGIES FOR NEW TECHNOLOGIES THAT HAVE THE POTENTIAL TO CONTRIBUTE TO FUTURE EARNINGS.

Building projects and talent

"I seek out and evaluate emerging technologies that can help bring Duke Energy's vision of the future to life. Technology forces us to examine how we do things. In doing so, we discover ways to work more effectively, enhance the customer experience, achieve operational breakthroughs and reduce our environmental impact — all critical to preparing for a low-carbon future."

NEETA PATEL
Director, Technology Development & Application
Duke Energy
Cincinnati, Ohio

Building new baseload power plants requires sophisticated coordination of planning, labor and materials. We have a long tradition of hands-on involvement in large-scale construction projects. In fact, our existing generation fleet was almost entirely engineered and built and is now operated by our own workforce.

Before the merger of Cinergy and Duke Energy in April 2006, both companies were in the process of completing large environmental retrofits — installing scrubbers and SCR (selective catalytic reduction) systems on some of their largest coal-fired units. Experience gained on those projects by our project management teams and through partnerships with design, engineering and construction firms is being transferred to the new power plant projects.

For example, in the Carolinas, project and construction management team leaders from the Marshall Steam Station scrubber project are moving to work on the new Cliffside unit and the scrubber installation on an existing unit of that plant. Project and construction management team leaders working on the scrubber at Belews Creek Steam Station will transition to the new gas-fired units being planned on the sites of the Buck and Dan River steam stations. These project management teams will also work on the new Lee Nuclear Station in South Carolina. In the Midwest, Duke's project management teams completing environmental retrofits at the Gibson and Gallagher coal-fired plants in Indiana are transitioning to the new Edwardsport IGCC plant.

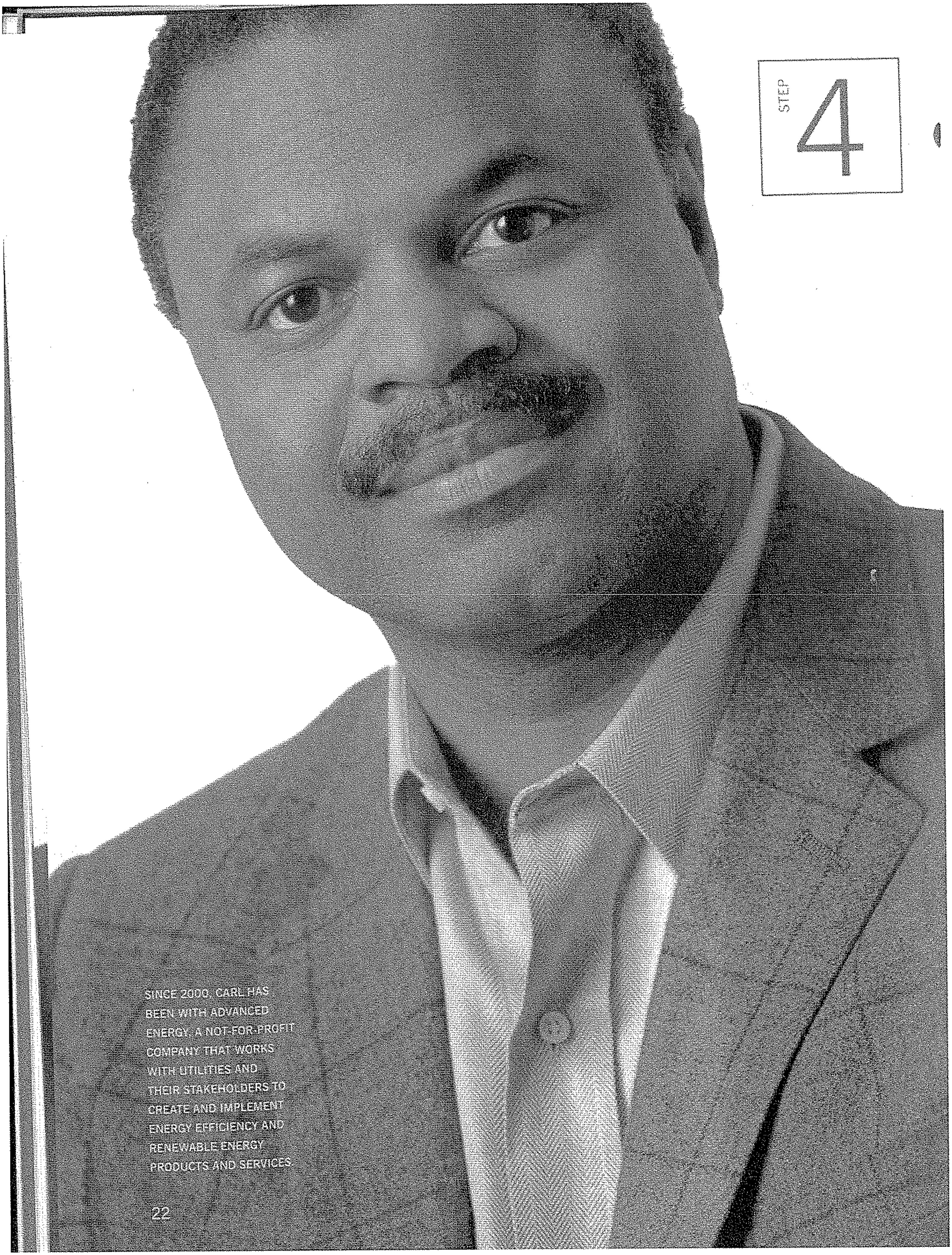
Global demand for engineering, equipment, materials and labor has increased. But with our existing relationships with contractors and suppliers and our use of fixed-price purchase orders, we have already locked in much of the costs for the new coal and gas plants.

We also completed a workforce planning effort to better understand the effects of an aging workforce on our future plans. We found that, due to expected retirements and attrition, we will need to replace almost a third of our workforce over the next five years. Many of our contractors face similar challenges.

Our response strategies include supporting state and local workforce development efforts, providing an employment proposition attractive to a diverse population, broadening existing and initiating new programs to ensure access to top talent, and significantly expanding our employee development, engagement and retention programs.

We have already taken a number of actions, including expanding our staffing functions, ramping up our co-op and summer student hiring programs, developing knowledge transfer strategies, increasing the frequency of internal talent reviews from annually to quarterly, and enhancing our professional development and supervisory/management training programs.

We have also become more active in industry, state and local efforts to develop the workforce of the future. For example, we are supporting K-12 science, technology and math education, and we have partnered with community colleges and technical schools to train technicians to work for us or our contractors. We also advise universities on how to keep curriculum current.



STEP 4

SINCE 2000, CARL HAS BEEN WITH ADVANCED ENERGY, A NOT-FOR-PROFIT COMPANY THAT WORKS WITH UTILITIES AND THEIR STAKEHOLDERS TO CREATE AND IMPLEMENT ENERGY EFFICIENCY AND RENEWABLE ENERGY PRODUCTS AND SERVICES

HOW WE WILL GET THERE:

Balancing diverse interests

"My job is building relationships. Last year, I coordinated and hosted Duke Energy's 15 'collaboratives' on its proposed energy efficiency plans for North Carolina and South Carolina. These sessions brought together a broad array of stakeholders to find ways to put energy efficiency on a more equal footing with new power plants — a position ultimately endorsed by the North Carolina legislature in a bill passed last summer."

CARL WILKINS
Director, Utility Services
Advanced Energy Corp.
Raleigh, N.C.

The new rules of engagement in our world, our nation and our industry are conversation and collaboration. To effectively address the climate change problem, we are working to engage all of our stakeholders in the debate and in our plans. Climate change doesn't respect borders, so to build support for our strategy we are defining our community broadly.

As a sustainable business, our connections with and among stakeholders are increasingly important to achieving our goals. As we work to build bridges between stakeholder groups, we must also balance their frequently competing needs.

As noted earlier, we will have a greater reliance on energy efficiency to meet our customers' future energy needs. How we develop and implement this new regulatory paradigm will largely be decided by state utility regulators. But the momentum to get the job done is coming from many sectors, including utilities, customer groups and the environmental community.

Last year, we conducted a series of energy efficiency summits in collaboration with a broad range of stakeholders and nationally known energy efficiency experts. These gatherings focused on the benefits an effective energy efficiency program can offer customers and utilities. A dialogue began on the best way to move energy efficiency forward in each state. These efforts also provided a framework for building grassroots support for research and development funding for new clean energy technologies, and most importantly, for federal cap-and-trade legislation to reduce GHG emissions.

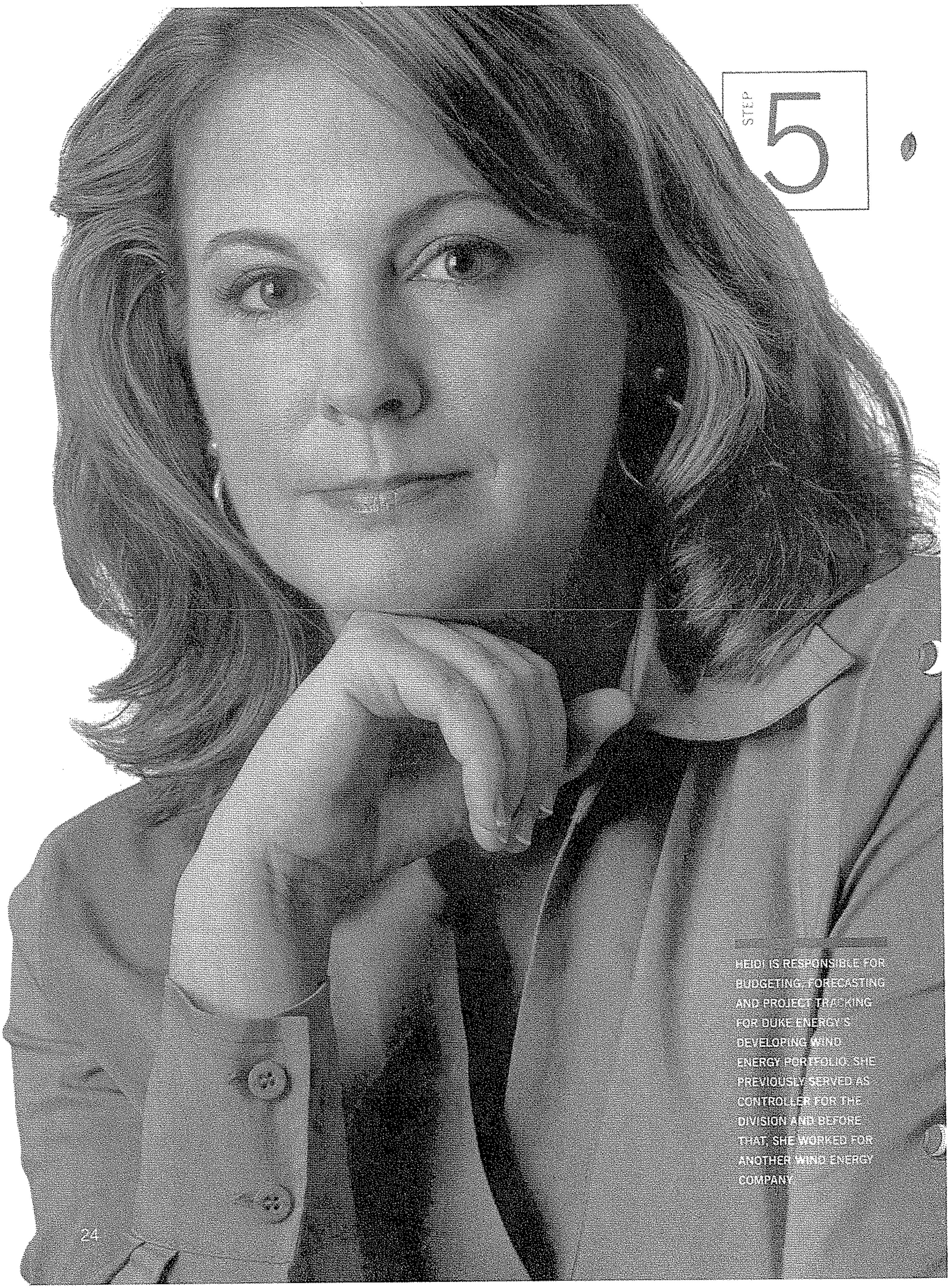
On the national level, we joined with seven other utilities — representing nearly 20 million customers in 22 states — who committed to a combined investment in energy efficiency of about $1.5 billion annually. When fully implemented in 10 years, this increased level of investment in energy efficiency will reduce CO_2 emissions by about 30 million tons — avoiding the need for 50 500-megawatt peaking power plants.

We also helped form the U.S. Climate Action Partnership (USCAP), a group of businesses and leading environmental organizations united in calling on the federal government to move quickly to enact strong national legislation to reduce GHG emissions.

Recognizing that this isn't just a national problem, we're also working very closely with Combat Climate Change (3C), a group of 46 leading companies located around the world. The 3C coalition is committed to finding a common framework for addressing global climate change by 2013.

We believe that engaging diverse stakeholders in our service areas, the nation and around the world will lead to carbon reduction policies that are fair and sustainable for the long term and for all the world's people.

STEP 5



HEIDI IS RESPONSIBLE FOR BUDGETING, FORECASTING AND PROJECT TRACKING FOR DUKE ENERGY'S DEVELOPING WIND ENERGY PORTFOLIO. SHE PREVIOUSLY SERVED AS CONTROLLER FOR THE DIVISION AND BEFORE THAT, SHE WORKED FOR ANOTHER WIND ENERGY COMPANY.

Taking the long view

"I feel that being in wind energy is the best place to be right now. As the technology has advanced and our nation's demand for electricity continues to grow, renewable energy is a growth opportunity for our company and supports our strategy to significantly reduce our carbon emissions."

HEIDI HENTSCHEL
Director, Finance — Wind Energy
Duke Energy Generation Services
Austin, Texas

People today aren't used to looking far into the future or contemplating issues of the scale and complexity of global climate change. We focus on the quick fix. We deal with problems now — then we move on to the next one. Climate change is different. The future can only be changed if we begin today and keep going. Hitting a big target in 2030 or 2050 may be helpful, but to hit longer-term objectives, we need to change the technologies that are vital to a modern society — including those used to generate and distribute electricity.

Today's concentration of CO_2 in the atmosphere is about 380 parts per million (ppm) — only about 100 ppm more than in pre-industrial times. If we continue to use the same technologies, projections of CO_2 concentrations by the end of this century will top 900 ppm. The earth hasn't seen that level of CO_2 for about 35 million years, when things were a lot hotter and wetter than they are today. Scientists say we need to take the first steps to lower our emissions so that future concentrations don't exceed 450 to 550 ppm.

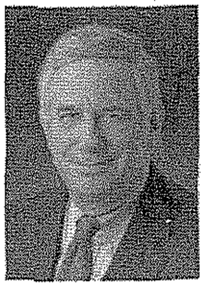
Emissions from less-developed countries will continue to grow as those societies simply improve their lives. This increases the urgency to get to work to develop new non-emitting technologies and lower their cost so they can also be built in the developing world.

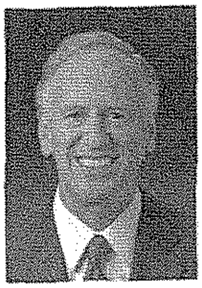
The task for our generation is to get *the policy right, get started and stick to it.* We need to develop the least costly way to address climate change and do it right. That means policies need to be market based and cover most, if not all, of the economy. The early years of a cap should encourage more energy efficiency and lower-cost actions that can slow, stop and begin to reverse the growth in CO_2 emissions. Policies should encourage the development and commercialization of technologies we will need to make the necessary deep reductions. Policymakers need to avoid the temptation to demand immediate deep emissions cuts, which would result in a greater reliance on natural gas. We must give clean coal technologies the time to develop so that we may deploy them as we retire current technologies.

Future generations will continue this work. The technologies we develop today around CO_2 capture and storage will serve as a bridge for the next generation of technologies. Our grandchildren will need new energy sources, whether advanced solar, space-based solar or even nuclear fusion. We may also find new technologies to remove CO_2 from the atmosphere, perhaps using a combination of biomass and carbon capture and storage. There will be plenty of opportunity for innovation and adaptation to a warmer world.

We think of this as "cathedral thinking" — remembering that the architects and builders of the great cathedrals of Europe never saw them completed. Frequently these inspired creations were not finished until the builders' grandchildren were themselves old. Yet that didn't cause them to lose faith, nor did it dull their vision of what might be if they merely began — despite the work, despite the cost and despite the fact they'd never see the end result. Such a commitment is needed for achieving a low-carbon future.

Board of Directors


WILLIAM BARNET III


G. ALEX BERNHARDT SR.


MICHAEL G. BROWNING


PHILLIP R. COX


DANIEL R. DIMICCO


ANN MAYNARD GRAY

WILLIAM BARNET III
Chairman, President and CEO,
The Barnet Co. Inc. and
Barnet Development Corp.;
Chair, Finance and Risk Management Committee; Member, Nuclear Oversight Committee

Director of Duke Energy and its predecessor companies since 2005. Barnet is the mayor of Spartanburg, S.C. He serves on the board of Bank of America and is a trustee of the Duke Endowment.

G. ALEX BERNHARDT SR.
Chairman and CEO,
Bernhardt Furniture Co.;
Member, Audit and Nuclear Oversight Committees

Director of Duke Energy and its predecessor companies since 1991. Besides leading the family business in Lenoir, N.C., Bernhardt serves on the board of Communities In Schools. He is past president of the American Furniture Manufacturers Association and of the International Home Furnishings Marketing Association.

MICHAEL G. BROWNING
President and Chairman of the Board,
Browning Investments Inc.;
Member, Compensation, Corporate Governance, and Finance and Risk Management Committees

Director of Duke Energy and its predecessor companies since 1990. Browning serves on the boards of the Indianapolis Convention & Visitors Association and the Indianapolis Museum of Art. He is a member of the Indiana Public Officer Compensation Committee.

PHILLIP R. COX
President and CEO,
Cox Financial Corp.;
Chair, Audit Committee

Director of Duke Energy and its predecessor companies since 1994. Cox is chairman of the board of Cincinnati Bell and serves on the boards of The Timken Company, Diebold Inc., the Cincinnati Business Committee, Touchstone Mutual Funds and the University of Cincinnati.

DANIEL R. DIMICCO
Chairman, President and Chief Executive Officer,
Nucor Corporation;
Member, Compensation and Corporate Governance Committees

Director of Duke Energy since 2007. DiMicco began his career with Nucor Corporation in 1982 and held a number of senior positions before being named chairman in 2006. He is a former chair of the American Iron and Steel Institute.

ANN MAYNARD GRAY
Former President,
Diversified Publishing Group of ABC Inc.;
Lead Director, Chair, Corporate Governance Committee; Member, Compensation and Finance and Risk Management Committees

Director of Duke Energy and its predecessor companies since 1994. Gray has held a number of senior positions with American Broadcasting Companies and serves on the boards of the Phoenix Companies and Elan Corp. plc.

JAMES H. HANCE JR.

JAMES T. RHODES

JAMES E. ROGERS

MARY L. SCHAPIRO

PHILIP R. SHARP

DUDLEY S. TAFT

JAMES H. HANCE JR.
Retired Vice Chairman, Chief Financial Officer and Board Member, Bank of America Corp.; Chair, Compensation Committee; Member, Finance and Risk Management Committee

Director of Duke Energy and its predecessor companies since 2005. A certified public accountant, Hance spent 17 years with Price Waterhouse. He serves on the boards of Sprint Nextel Corp., Cousins Properties Inc. and Rayonier Corp.

JAMES T. RHODES
Retired Chairman, President and CEO, Institute of Nuclear Power Operations (INPO); Chair, Nuclear Oversight Committee; Member, Audit Committee

Director of Duke Energy and its predecessor companies since 2001. Rhodes is a member of the Electric Power Research Institute's advisory council and a former board member of INPO, the Nuclear Energy Institute, Edison Electric Institute and the Southeastern Electric Exchange.

JAMES E. ROGERS
Chairman, President and CEO, Duke Energy

Rogers became president and CEO of Duke Energy in 2006, having served as chairman and CEO of Cinergy Corp. since 1994 and PSI Energy since 1988. He is chairman of the Institute for Electric Efficiency and the Edison Foundation, and serves as co-chair of the National Action Plan for Energy Efficiency and the Alliance to Save Energy. He is a director of Fifth Third Bancorp and Cigna Corp. and serves on the boards and Executive Committees of the World Business Council for Sustainable Development and the Edison Electric Institute. He is also a board member of the Nuclear Energy Institute, the Institute of Nuclear Power Operations and the Nicholas Institute for Environmental Policy Solutions.

MARY L. SCHAPIRO
Chief Executive Officer, Financial Industry Regulatory Authority; Member, Audit and Corporate Governance Committees

Director of Duke Energy and its predecessor companies since 1999. Schapiro previously served as chairman and CEO of the National Association of Securities Dealers, as chairman of the Commodity Futures Trading Commission and on the Securities and Exchange Commission. She currently serves on the board of Kraft Foods Inc.

PHILIP R. SHARP
President, Resources for the Future; Member, Audit and Nuclear Oversight Committees

Director of Duke Energy since 2007, having served on one of its predecessor companies from 1995 to 2006. A former member of the Indiana delegation to the U.S. House of Representatives, Sharp served as Congressional chair of the National Commission on Energy Policy and was a member of the House Energy and Commerce Committee.

DUDLEY S. TAFT
President and CEO, Taft Broadcasting Co.; Member, Compensation and Finance and Risk Management Committees

Director of Duke Energy and its predecessor companies since 1985. Taft serves on the boards of the Unifi Mutual Holding Co. and Fifth Third Bancorp. He is chairman of the Cincinnati Association for the Arts and a trustee of the Cincinnati Convention & Visitors Bureau.

Executive Management


HENRY B. BARRON JR.


STEPHEN G. DE MAY


LYNN J. GOOD


DAVID L. HAUSER


JULIA S. JANSON


MARC E. MANLY


BEVERLY K. MARSHALL


SANDRA P. MEYER


DAVID W. MOHLER

HENRY B. BARRON JR.
Group Executive and Chief Nuclear Officer

Barron became Duke Energy's chief nuclear officer in 2004. He has been responsible for the safe operation of the company's nuclear generating stations. He joined the company in 1972 as a nuclear power plant engineer. Barron plans to retire March 31, 2008.

STEPHEN G. DE MAY
Vice President and Treasurer

De May leads the treasury function for Duke Energy, as well as risk management, insurance, and administration of pension and retirement plan assets. He previously served as general manager, corporate finance and assistant treasurer.

LYNN J. GOOD
Group Executive and President, Commercial Businesses

Good is responsible for Duke Energy's Midwest nonregulated generation, Duke Energy International, Duke Energy Generation Services, the telecommunications businesses, and all corporate development and merger and acquisition activities. She previously served as senior vice president and treasurer.

DAVID L. HAUSER
Group Executive and Chief Financial Officer

Hauser became Duke Energy's chief financial officer in 2004. He leads the financial function, which includes the controller's office, treasury, tax, risk management and insurance. Hauser joined the company in 1973.

JULIA S. JANSON
Senior Vice President, Ethics and Compliance and Corporate Secretary

Janson directs Duke Energy's ethics and compliance program and serves as corporate secretary. She served as Cinergy's chief compliance officer since 2004 and corporate secretary since 2000.

MARC E. MANLY
Group Executive and Chief Legal Officer

Manly leads Duke Energy's office of general counsel, which includes legal, internal audit, ethics and compliance, human resources and the corporate secretary. He served as Cinergy's executive vice president and chief legal officer since 2002.

BEVERLY K. MARSHALL
Vice President, Federal Policy and Government Affairs

Marshall manages Duke Energy's Washington, D.C., office and serves as the company's primary liaison with the U.S. Congress. She joined the company in 1999 and has 20 years of experience in government affairs.

SANDRA P. MEYER
President, Duke Energy Ohio and Duke Energy Kentucky

Meyer leads Duke Energy's Ohio and Kentucky operations, which serve more than 820,000 customers. She previously served as group vice president of customer service, sales and marketing for Duke Power.

DAVID W. MOHLER
Vice President and Chief Technology Officer

Mohler is responsible for the development and application of technologies in support of Duke Energy's strategic objectives. He previously served as vice president of strategic planning.


CATHY S. ROCHE


CHRISTOPHER C. ROLFE


ELLEN T. RUFF


JIM L. STANLEY


R. SEAN TRAUSCHKE


B. KEITH TRENT


JAMES L. TURNER


STEVEN K. YOUNG

CATHY S. ROCHE
Senior Vice President and
Chief Communications Officer

Roche is responsible for directing and managing Duke Energy's communications with internal and external audiences, as well as executive communications, corporate publications, advertising, and brand management and strategy.

CHRISTOPHER C. ROLFE
Group Executive and
Chief Administrative Officer

Rolfe leads several of Duke Energy's corporate functions, including supply chain, information technology, operations services and other administrative activities. He previously served as group executive and chief human resources officer.

ELLEN T. RUFF
President,
Duke Energy Carolinas

Ruff leads Duke Energy's utility business in North Carolina and South Carolina, which serves more than 2.3 million customers. She was formerly group vice president of planning and external relations for Duke Power.

JIM L. STANLEY
President,
Duke Energy Indiana

Stanley leads Duke Energy's Indiana utility business, which serves more than 770,000 customers. He previously served as vice president of field operations for Duke Energy's Midwest service area.

R. SEAN TRAUSCHKE
Senior Vice President,
Investor Relations and Financial Planning

Trauschke is responsible for monitoring trends in investment markets and for maintaining key relationships with investors, financial analysts and financial institutions. He also has oversight of corporate financial planning and analysis.

B. KEITH TRENT
Group Executive and Chief Strategy,
Policy and Regulatory Officer

Trent is responsible for strategy, federal policy and government affairs, energy efficiency and technology initiatives, environmental health and safety policy, corporate communications, and sustainability and community affairs. He also has oversight of the regulated utility companies in five states.

JAMES L. TURNER
Group Executive; President and
Chief Operating Officer,
U.S. Franchised Electric and Gas

Turner has overall profit and loss responsibility for Duke Energy's U.S. Franchised Electric and Gas business, which serves approximately 3.9 million customers in five states. He leads the company's fossil/hydro generation, power delivery, gas distribution, customer service, wholesale business and new generation projects organizations.

STEVEN K. YOUNG
Senior Vice President and Controller

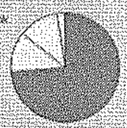
Young is responsible for planning and directing the accounting affairs of Duke Energy, including preparation of financial statements and accounting and regulatory reports. He joined the company in 1980 as a financial assistant.

Duke Energy at a Glance

U.S. Franchised Electric and Gas

EXPECTED 2008 ONGOING EARNINGS BEFORE INTEREST AND TAXES (EBIT) CONTRIBUTION

74%*



BUSINESS DESCRIPTION

U.S. Franchised Electric and Gas (USFE&G) consists of Duke Energy's regulated generation, electric and gas transmission and distribution systems. Its generation portfolio is a mix of fuel sources — coal, oil/natural gas, nuclear and hydro-electric. USFE&G is Duke Energy's largest business segment and primary source of earnings growth.

NOTABLE STATISTICS

Electric Operations

- Owns approximately 28,000 megawatts of generating capacity
- Supplies electric service to approximately 3.9 million customers
- Serves territories in five states — North Carolina, South Carolina, Ohio, Indiana and Kentucky — that total about 47,000 square miles
- Operates 148,700 miles of distribution lines and a 20,900-mile transmission system

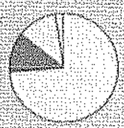
Gas Operations

- Provides regulated transmission and distribution service to approximately 500,000 customers over a 3,000-square-mile service territory in Ohio and Kentucky

Commercial Power

EXPECTED 2008 ONGOING EBIT CONTRIBUTION

12%*



BUSINESS DESCRIPTION

Commercial Power owns, operates and manages nonregulated power plants, primarily in the Midwest. Commercial Power also includes Duke Energy Generation Services (DEGS), which develops, owns and operates generation sources (including wind assets) that serve large energy consumers, municipalities, utilities and industrial facilities.

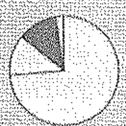
NOTABLE STATISTICS

- Owns and operates a balanced generation portfolio of approximately 8,000 megawatts
- Most of the generation output in Ohio, over 21 million megawatt-hours annually, is supplied to regulated customers
- DEGS has contracted to purchase wind turbines that are capable of generating approximately 240 megawatts when placed in commercial operation beginning in 2008 and 2009

Duke Energy International

EXPECTED 2008 ONGOING EBIT CONTRIBUTION

12%*



BUSINESS DESCRIPTION

Duke Energy International (DEI) operates and manages power generation facilities located in the Central and South American countries of Argentina, Brazil, Ecuador, El Salvador, Guatemala and Peru. DEI also owns equity investments in Saudi Arabia and Greece.

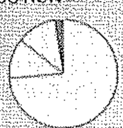
NOTABLE STATISTICS

- Owns, operates or has substantial interests in approximately 4,000 net megawatts of generation facilities
- About 75 percent of DEI's generating capacity is hydroelectric, and approximately 90 percent is either currently contracted or receives a system capacity payment

Crescent Resources

EXPECTED 2008 ONGOING EBIT CONTRIBUTION

2%*



BUSINESS DESCRIPTION

Crescent Resources is effectively a 50-50 joint venture with Morgan Stanley Real Estate Fund. Crescent manages land holdings and develops high-quality commercial, residential and multi-family real estate projects.

NOTABLE STATISTICS

- Located in 10 states, primarily in the southeastern and southwestern United States
- Owns 900,000 square feet of commercial, industrial and retail space, with an additional 500,000 square feet under construction
- Manages approximately 122,608 acres of land

*Percent of 2008 forecasted ongoing total segment EBIT does not include results for the operations labeled as Other.

Non-GAAP Financial Measures

2007 AND 2006 ONGOING DILUTED EARNINGS PER SHARE ("EPS")

Duke Energy's 2007 Summary Annual Report references 2007 and 2006 ongoing diluted EPS of $1.24 and $0.99, respectively. Ongoing diluted EPS is a non-GAAP (generally accepted accounting principles) financial measure, as it represents diluted EPS from continuing operations, adjusted for the per-share impact of special items. Special items represent certain charges and credits which management believes will not be recurring on a regular basis. The following is a reconciliation of reported diluted EPS from continuing operations to ongoing diluted EPS for 2007 and 2006:

	2007	2006
Diluted EPS from continuing operations, as reported	$ 1.20	$ 0.91
Diluted EPS from discontinued operations, as reported	(0.02)	0.66
Diluted EPS, as reported	1.18	$ 1.57
Adjustments to reported EPS:		
Diluted EPS from discontinued operations	0.02	(0.66)
Diluted EPS impact of special items (see detail below)	0.04	0.08
Diluted EPS, ongoing	**$ 1.24**	**$ 0.99**

The following is the detail of the $(0.04) in special items impacting diluted EPS for 2007:

(In millions, except per-share amounts)	Pre-Tax Amount	Tax Effect	2007 Diluted EPS Impact
Convertible debt costs associated with the spinoff of Spectra Energy	$(21)	—	$(0.02)
Costs to achieve the Cinergy merger	(54)	19	(0.03)
IT severance costs	(12)	4	—
Settlement reserves and adjustments	24	(9)	0.01
Total Diluted EPS impact			**$(0.04)**

The following is the detail of the $(0.08) in special items impacting diluted EPS for 2006:

(In millions, except per-share amounts)	Pre-Tax Amount	Tax Effect	2006 Diluted EPS Impact
Settlement reserves	$(165)	58	$(0.09)
Gain on sale of interest in Crescent	246	(124)	0.10
Impairment of Campeche investment	(50)	—	(0.04)
Costs to achieve the Cinergy merger	(128)	45	(0.07)
Tax adjustments		27	0.02
Total Diluted EPS impact			**$(0.08)**

2008 EMPLOYEE INCENTIVE TARGET MEASURE

Duke Energy's 2007 Summary Annual Report references the company's 2008 employee incentive target. The EPS measure used for employee incentive bonuses is based on ongoing diluted EPS. Ongoing diluted EPS is a non-GAAP financial measure as it represents diluted EPS from continuing operations adjusted for the per-share impact of special items. Special items represent certain charges and credits which management believes will not be recurring on a regular basis. The most directly comparable GAAP measure for ongoing diluted EPS is reported diluted EPS from continuing operations, which includes the impact of special items. Due to the forward-looking nature of this non-GAAP financial measure, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to forecast special items for future periods.

ANTICIPATED ONGOING DILUTED EPS GROWTH RATES THROUGH 2012

Duke Energy's 2007 Summary Annual Report references the expected range of growth of 5 to 7 percent in ongoing diluted EPS through 2012 on a compound annual growth rate ("CAGR") basis. These growth percentages are based on anticipated ongoing diluted EPS amounts for future periods. Ongoing diluted EPS is a non-GAAP financial measure as it represents anticipated diluted EPS from continuing operations, adjusted for the impact of special items. Special items represent certain charges and credits which management believes will not be recurring on a regular basis. The most directly comparable GAAP measure for ongoing diluted EPS is reported diluted EPS from continuing operations which includes the impact of special items. Due to the forward-looking nature of ongoing diluted EPS and related growth rates for future periods, information to reconcile this non-GAAP financial measure to the most directly comparable GAAP financial measure is not available at this time, as management is unable to forecast special items for future periods.

FORECASTED 2008 ONGOING SEGMENT AND ONGOING TOTAL SEGMENT EBIT

Duke Energy's 2007 Summary Annual Report includes a discussion of forecasted 2008 ongoing EBIT for each of Duke Energy's reportable segments as a percentage of forecasted 2008 ongoing total segment EBIT. Forecasted 2008 ongoing segment and total segment EBIT amounts are non-GAAP financial measures, as they reflect segment and total segment EBIT, adjusted for the impact of special items. Special items represent certain charges and credits which management believes will not be recurring on a regular basis. The most directly comparable GAAP measure for forecasted ongoing segment EBIT is reported segment EBIT from continuing operations, which includes the impact of special items. The most directly comparable GAAP measure for ongoing total segment EBIT is reported total segment EBIT, which includes the impact of special items. Due to the forward-looking nature of these non-GAAP financial measures for future periods, information to reconcile these non-GAAP financial measures to the most directly comparable GAAP financial measures is not available at this time, as management is unable to forecast special items for future periods.

Investor Information

Annual Meeting

The 2008 Annual Meeting of Duke Energy Shareholders will be:

Date: Thursday, May 8, 2008
Time: 10 a.m.
Place: O.J. Miller Auditorium,
Energy Center
526 South Church Street
Charlotte, NC 28202

Shareholder Services

Shareholders may call 800-488-3853 or 704-382-3853 with questions about their stock accounts, legal transfer requirements, address changes, replacement dividend checks, replacement of lost certificates or other services. Additionally, registered users of DUK-Online, our online account management service, may access their accounts through the Internet.

Send written requests to:
Investor Relations
Duke Energy
P.O. Box 1005
Charlotte, NC 28201-1005

For electronic correspondence, visit www.duke-energy.com/contactIR.

Stock Exchange Listing

Duke Energy's common stock is listed on the New York Stock Exchange. The company's common stock trading symbol is DUK.

Web Site Addresses

Corporate home page:
www.duke-energy.com
Investor Relations:
www.duke-energy.com/investors

InvestorDirect Choice Plan

The InvestorDirect Choice Plan provides a simple and convenient way to purchase common stock directly through the company, without incurring brokerage fees. Purchases may be made weekly. Bank drafts for monthly purchases, as well as a safekeeping option for depositing certificates into the plan, are available.

The plan also provides for full reinvestment, direct deposit or cash payment of dividends. Additionally, participants may register for DUK-Online, our online account management tool.

Financial Publications

Duke Energy's summary annual report, SEC Form 10-K and related financial publications can be found on our Web site at www.duke-energy.com/investors. Printed copies are also available free of charge upon request.

Duplicate Mailings

If your shares are registered in different accounts, you may receive duplicate mailings of annual reports, proxy statements and other shareholder information. Call Investor Relations for instructions on eliminating duplications or combining your accounts.

Transfer Agent and Registrar

Duke Energy maintains shareholder records and acts as transfer agent and registrar for the company's common stock issues.

Dividend Payment

Duke Energy has paid quarterly cash dividends on its common stock for 81 consecutive years. For the rest of 2008, dividends on common stock are expected to be paid, subject to declaration by the Board of Directors, on June 16, Sept. 16 and Dec. 16, 2008.

Bond Trustee

If you have questions regarding your bond account, call 800-275-2048, or write to:
The Bank of New York
Global Trust Services
101 Barclay Street
New York, NY 10286

Send Us Feedback

We welcome your opinion on this summary annual report. Please visit www.duke-energy.com/investors, where you can view and provide feedback on both the print and online versions of this report. Or contact Investor Relations directly.

Duke Energy is an equal opportunity employer. This report is published solely to inform shareholders and is not to be considered an offer, or the solicitation of an offer, to buy or sell securities.

DESIGN: PROPOLS [illegible]ERS PHOTOGRAPHY: MARK GREEN / WWW.MGP2.COM ILLUSTRATION: STEVE ADAMS

Forward-Looking Statement

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are based on management's beliefs and assumptions. These forward-looking statements are identified by terms and phrases such as "anticipate," "believe," "intend," "estimate," "expect," "continue," "should," "could," "may," "plan," "project," "predict," "will," "potential," "forecast," "target," and similar expressions. Forward-looking statements involve risks and uncertainties that may cause actual results to be materially different from the results predicted. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to: state, federal and foreign legislative and regulatory initiatives, including costs of compliance with existing and future environmental requirements; state, federal and foreign legislation and regulatory initiatives that affect cost and investment recovery, or have an impact on rate structures; costs and effects of legal and administrative proceedings, settlements, investigations and claims; industrial, commercial and residential growth in Duke Energy Corporation's (Duke Energy) service territories; additional competition in electric markets and continued industry consolidation; political and regulatory uncertainty in other countries in which Duke Energy conducts business; the influence of weather and other natural phenomena on Duke Energy operations, including the economic, operational and other effects of hurricanes, droughts, ice storms and tornadoes; the timing and extent of changes in commodity prices, interest rates and foreign currency exchange rates; unscheduled generation outages, unusual maintenance or repairs and electric transmission system constraints; the performance of electric generation and of projects undertaken by Duke Energy's nonregulated businesses; the results of financing efforts, including Duke Energy's ability to obtain financing on favorable terms, which can be affected by various factors, including Duke Energy's credit ratings and general economic conditions; declines in the market prices of equity securities and resultant cash funding requirements for Duke Energy's defined benefit pension plans; the level of creditworthiness of counterparties to Duke Energy's transactions; employee workforce factors, including the potential inability to attract and retain key personnel; growth in opportunities for Duke Energy's business units, including the timing and success of efforts to develop domestic and international power and other projects; the effect of accounting pronouncements issued periodically by accounting standard-setting bodies; and the ability to successfully complete merger, acquisition or divestiture plans.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than Duke Energy has described. Duke Energy undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

526 South Church Street
Charlotte, NC 28202-1802
704-594-6200
www.duke-energy.com

OUR DIRECTION IN 2008 AND BEYOND

We must pursue a balanced approach to meeting future energy needs.

- In pursuing new supply options, we consider whether they are available, affordable, reliable and clean.
- By carefully balancing these criteria, we can make the best decisions for our customers and our company.
- Our options include energy efficiency, coal gasification, advanced pulverized coal, nuclear, natural gas-fired generation and renewable energy.

We must balance the reality of a carbon-constrained future with our customers' energy demands.

- Environmental legislation will significantly affect Duke Energy. We aim for fairness for our customers and shareholders.
- In our regulated and commercial businesses, we will pursue low-carbon solutions — like clean coal and natural gas — and no-carbon solutions — like nuclear and renewable energy. We will also pursue innovative energy efficiency and Utility of the Future (advanced power grid) initiatives.
- We will push for the development of new technologies to reduce carbon emissions. Until those technologies are available, we will meet demand with current options.

We must find the path to success during this era of rising costs.

- We expect to see increased costs from modernizing our grid and developing new generation. We will effectively manage the costs of these and other capital projects.
- By running our business well and providing excellent customer service, we can minimize price impacts to our customers and maintain the financial health of the company.

We must deliver on our commitments.

- We will steadily grow earnings — making our company attractive to investors — and achieve our employee incentive target of $1.27 of ongoing diluted earnings per share.
- We will continue to balance our regulated and commercial investments based on the business environment.
- We will strive to be simply the best.

Duke Energy®

Kentucky

The Duke Energy Kentucky 2008 Integrated Resource Plan

July 1, 2008

Volume II

This Transmission Information Volume, Volume II, is an integral part of the Duke Energy Kentucky 2008 Integrated Resource Plan filing. Please see the submittal letters and other specific filing attachments contained in the front of Volume I of the Duke Energy Kentucky 2008 Integrated Resource Plan.

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5. PLANNED SUMMARY

5. (4) Planned Resource Acquisition Summary

There are no currently in-progress or planned transmission system projects affecting any DE-Kentucky facilities that are intended to provide additional resources. Changes to the DE-Kentucky transmission system are based on meeting planning criteria, which are intended to provide reliable system performance in a cost-effective manner. Loss reduction is a secondary goal, which may be considered, when appropriate, in deciding between various alternatives, which serve the primary purpose of maintaining system performance.

8. RESOURCE ASSESSMENT AND ACQUISITION PLAN

8. (2) (a) Options Considered for Inclusion

Changes to the DE-Kentucky transmission and distribution systems are based on meeting planning criteria, which are intended to provide reliable system performance in a cost-effective manner. Loss reduction is a secondary goal, which may be considered, when appropriate, in deciding between various alternatives, which serve the primary purpose of maintaining system performance. In general, projects, which are solely intended to reduce losses, are not cost-effective. The costs for such projects are high, and the loss impacts are too small to materially affect the resource plan.

8. (3) (a) Map of Facilities

MAPS AND TRANSMISSION LINES THERMAL CAPACITY TABLES HAVE BEEN WITHHELD AS CRITICAL ENERGY INFRASTRUCTURE INFORMATION.