Overland Consulting

RECEIVED

MAR 0 4 2008

PUBLIC SERVICE COMMISSION

Review of the Incentives for Energy Independence Act of 2007 Section 50

Case No. 2007-00477

Prepared for the

Kentucky Public Service Commission

Prepared by

Overland Consulting
10801 Mastin, Suite 420
Overland Park, KS 66210
(913) 599-3323

in Conjunction with
London Economics International LLC

March 4, 2008

OVERLAND CONSULTING

10801 Mastin
Building 84, Suite 420
Overland Park, KS 66210
913 / 599-3323 Fax 913 / 495-9909

March 4, 2008

Ms. Elizabeth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Blvd.
Frankfort, KY 40601

Subject: Submission of Overland Consulting Report in Case No. 2007-00477

Dear Ms. O'Donnell:

Please find our Report to be filed today in the above referenced case. Actual printed paper copies of this document will be provided in a separate transmittal, as discussed and agreed upon.

Sincerely,

Overland Consulting

Howard E. Lubow
President

cc: Service List

TABLE OF CONTENTS

Chapter 1 - Executive Summary

Introduction

For many years, Kentucky consumers have enjoyed electric rates that are among the lowest in the country.[1] However, Kentucky consumers use more energy per customer than most other states.[2]

The increase in fuel prices, recent trends in federal and state legislation on energy efficiency standards, concerns about system reliability, and an increasing focus on environmental risks have all brought about a heightened interest in energy efficiency and renewable resources as economic alternatives to conventional supply-side generation options. The state of Kentucky, the Public Service Commission (KPSC or the Commission), and generating utilities within the state have all recognized the importance of resource planning, including the development of demand-side management (DSM) programs and renewable energy projects.

The Kentucky General Assembly recently passed an initiative to create additional incentives to support new generation technologies, and to address potential impediments to further expansion of DSM programs, renewable energy resources and energy efficiency and conservation associated with utility rates and regulation. This report addresses these subjects, organized as follows:

- Chapter 2 - Review of the Current Regulatory Environment.
- Chapter 3 - Meetings with Stakeholders.
- Chapter 4 – Current Energy Planning and Programs, Analysis and Recommendations – Demand Side Management
- Chapter 5 - Current Energy Planning and Programs, Analysis and Recommendations – Renewables and Distributed Generation
- Chapter 6 - Current Energy Planning and Programs, Analysis and Recommendations – IRP, Certificate Process, and Full-Cost Accounting
- Chapter 7 - Current Energy Planning and Programs, Analysis and Recommendations – Rates and Regulation
- Appendices

Project Background

Overview of House Bill 1 (HB 1)

In a special legislative session that ended August 24, 2007, the Kentucky General Assembly passed legislation known as the "Incentives for Energy Independence Act" (also referred to as the "Energy Act", "House Bill 1" or "HB 1"). The stated purpose of the Energy Act is as follows:

---

[1] Energy Information Administration/Electric Power Annual reports.

[2] Kentucky uses more energy per capita than 42 other states; in part, due to a somewhat higher ratio of industrial usage than the national average.

> The General Assembly hereby finds and declares that it is in the best interest of the Commonwealth to induce the location of innovative energy-related businesses in the Commonwealth in order to advance the public purposes of achieving energy independence, creating new jobs and new investment, and creating new sources of tax revenues that but for the inducements to be offered by the authority to approved companies would not exist.
>
> The purpose of this subchapter is to assist the Commonwealth in moving to the forefront of national efforts to achieve energy independence by reducing the Commonwealth's reliance on imported energy resources. The provisions of this subchapter seek to accomplish this purpose by providing incentives for companies that, in a carbon capture ready manner, construct, retrofit, or upgrade facilities for the purpose of:
>
> (a) Increasing the production and sale of alternative transportation fuels;
>
> (b) Increasing the production and sale of synthetic natural gas, chemicals, chemical feedstocks, or liquid fuels, from coal, biomass resources, or waste coal through a gasification process; or
>
> (c) Generating electricity for sale through alternative methods such as solar power, wind power, biomass resources, landfill methane gas, hydropower, or similar renewable resources.[3]

Substantial tax incentives are identified to facilitate commitments to bring about the stated purposes of the Energy Act. In aggregate, these incentives may equal up to a maximum of 50% of the capital investment for eligible projects.[4]

Section 50

The Energy Act, at Section 50, specifically directs the Commission to review its authority over utilities as it relates to specific identified issues. The following is the specific language contained in Section 50:

> The Public Service Commission shall examine existing statutes relating to its authority over public utilities, and shall, on or before July 1, 2008, make recommendations to the Legislative Research Commission regarding the following issues:
>
> (1) Eliminating impediments to the consideration and adoption by utilities of cost-effective demand-management strategies for addressing future demand prior to Commission consideration of any proposal for increasing generating capacity;

---

[3] House Bill 1, p. 7.

[4] House Bill 1, pp. 8-9.

(2) Encouraging diversification of utility energy portfolios through the use of renewables, and distributed generation;

(3) Incorporating full-cost accounting that considers and requires comparison of life-cycle energy, economic, public health, and environmental costs of various strategies for meeting future energy demand; and

(4) Modifying rate structures and cost recovery to better align the financial interests of the utility with the goals of achieving energy efficiency and lowest life-cycle energy costs to all classes of ratepayers.

KPSC Request for Proposal (RFP) and Project Scope

On October 12, 2007, the Commission issued an RFP soliciting consulting services "to perform an in-depth review of the statutes relating to its authority over public utilities and [to] make findings and recommendations that encompass…" the elements of Section 50 identified above. The RFP was posted on the KPSC website, with notice letters circulated to potential firms qualified to perform the project.

Overland[5] submitted its proposal on October 29, 2007. After Commission requests for additional information, including modifications to the proposed scope and level of effort, Overland submitted revisions to its original proposal on November 7, 2007. Based upon the Commission's selection, Overland entered into an agreement to perform the project effective November 20, 2007.

<u>*Material limitations on project scope.*</u> This project does not address Kentucky statewide planning, per se; as it focuses on the six regulated generating utilities under KPSC jurisdiction. Among the major suppliers excluded from this analysis are the Tennessee Valley Authority (TVA); municipals; and Independent Power Producers (IPPs).

The procedural schedule established by the Commission provided an adequate, albeit limited timeframe, to conduct our review and develop our findings and recommendations. The primary objectives required by our review are developed and addressed in this report. However, the actual implementation of many of the proposed recommendations will require more detailed analysis and further specificity than is contained herein.

Approach to the Project

Stakeholder Interviews

Chapter 3, "Meetings with Stakeholders", identifies the various entities and the specific subject matter of the interviews held in December 2007. Overland met with a total of 26 organizations, including representatives of the six regulated generating utilities. This process was highly beneficial in terms of understanding the range of views of the various parties regarding the subject matter of HB 1, Section 50.

---

[5] Overland is a management consulting firm, providing regulatory policy advice to the Commission based upon the scope of this engagement. Overland is not a law firm, nor are we expressing any legal opinions in this report.

This report reflects an effort to give due consideration to the views and recommendations of the various stakeholders. Our report provides an analysis of the Section 50 subject areas, with recommendations that we believe represent a proper balance of the input of the various parties, but ultimately, are based on our own independent opinions and review of the subject matter. Many of the stakeholders interviewed indicated an intent to participate as a party to the proceedings, and to file testimony. In this regard, Overland assumes that the parties will provide the Commission with their own views of the issues, and make recommendations accordingly.

Written Discovery

In order to develop a more detailed understanding of utility-specific subject matter, Overland issued two rounds of formal discovery requests. The initial discovery was somewhat more generic, and thus, applicable to all utilities. These requests were issued as Appendix A, in the Commission Order establishing this proceeding, dated November 20, 2007.

Supplemental discovery was issued by Overland on a company-specific basis over the period January 3-7, 2008. The utilities provided responsive and timely answers to our requests.

Materials Produced by Stakeholders

Aside from the written discovery, and information gained during the stakeholder interview process, Overland provided all parties with the opportunity to provide any studies, orders, or reference materials that they believed should be considered in the course of our review. A number of parties did, in fact, produce materials for our review in response to this request.

The utilities, as well as other stakeholders, were very helpful in responding to questions and information requests necessary for Overland to fully consider the subject areas required by Section 50 of HB 1. Our review, within the limited time available, would not have been possible, but for the extraordinary efforts and cooperation of the utilities and other involved stakeholders.

Access to Kentucky-Specific and Industry Data

Overland also relied upon documents available on the Commission website, which included utility IRP and DSM filings; Commission Orders; pertinent statutes and regulations; and utility tariffs. In addition to the various sources identified, we also relied on relevant information in the public domain such as data compiled and published by the Federal Energy Regulatory Commission (FERC) and the Energy Information Administration (EIA).[6] We also did research of current practices in other jurisdictions, including interviews of commission staff in various states.

Overland believes that the documents available from these various sources provide an adequate foundation for the subject areas reviewed and the recommendations contained in this report.

[6] Various statistics available from EIA include data on TVA and IPPs not subject to KPSC jurisdiction.

Company Backgrounds

High Level Overview of Regulated Companies

The electricity needs of Kentucky consumers are served primarily by investor-owned utilities, non-profit generation, transmission, and distribution cooperatives, the TVA, IPPs, and municipal electric systems. Of these different types of energy suppliers, only the first two are regulated by the KPSC. The KPSC does not regulate the TVA, municipal electric utility systems, or electric sales of IPPs.

According to the EIA, the top five electricity suppliers in Kentucky during 2006 were:

Figure 1-1
Kentucky
Top Suppliers of Electricity
2006

Entity	Type of Provider	MWh	% of Total
Kentucky Utilities	Investor-Owned	17,786,364	20%
Tennessee Valley Authority	Corporate Agency of USA	14,674,996	17%
Louisville Gas & Electric	Investor-Owned	11,964,643	13%
Kenergy Corp	Non-Profit Cooperative	9,378,878	11%
Kentucky Power Company	Investor Owned	7,122,459	8%

Source: Obtained or derived from State Electricity Profiles 2006, Kentucky Table 3, EIA.

There are several IPPs in the state, primarily with coal and petroleum-fired capacity, although their output represented less than 12 percent of the state's annual electricity supply in 2006 as demonstrated in the following table:

Figure 1-2
Kentucky
Supply of Electricity
2006

Description	GWh	% of Total
Electric Utilities	86,816	87.9%
Independent Power Producers	11,449	11.6%
Industrial and Commercial Generation	526	0.5%
Total	98,791	100.0%

Source: State Electricity Profiles 2006, Kentucky Table 10, EIA.

Given the natural abundance of local coal, the state's fuel mix was over 70 percent coal-based (as measured by net summer capacity) and over 90 percent coal-based (as measured by net generation) in 2006. While obviously substantial, these percentages reflected a decrease in reliance on coal from a decade earlier (1995) when the same fuel mix calculations were approximately 90 percent and 95 percent, respectively.[7]

---

[7] Derived from State Electricity Profiles 2006, Kentucky Tables 4 and 5, EIA.

The map in Appendix A highlights the geographical distribution of existing[8] and proposed generation infrastructure, the fuel mix, and ownership of Kentucky's electric facilities. In addition, the map in Appendix B depicts the electric distribution service areas of the Commonwealth (the two generation and transmission cooperatives discussed below serve the numerous distribution cooperatives displayed on this map).[9]

The following table provides a summary of key statistics for each of the Kentucky regulated generating utilities:

Figure 1-3
Retail Sales, Demand, and Customer Data
2006

Entity	Retail Sales (GWh)	Retail Sales - Weather Adjusted (GWh)	Peak Demand (MW)	Peak Demand - Weather Adjusted (MW)	Retail Customers (as of 12/31/06)
LG&E (A)	11,965	12,136	2,729	2,784	397,748
KU	17,786	18,008	4,207	4,288	501,349
Duke Kentucky	3,880	3,905	881	897	133,535
KPC (B)	7,123	7,248	1,665	1,635	175,750
Big Rivers	3,090	3,132	631	640	109,328
East Kentucky (C)	11,425	N.A.	2,735	2,760	501,839

Sources: Either obtained or derived from: LG&E/KU (DR 02-29), Duke Kentucky (DR 02-31), KPC (DR 02-30), Big Rivers (DR 02-29), and East Kentucky (DR 02-35).

A. Customers are electric only.
B. The Company provided peak demand data for both the 2005/2006 winter and 2006 summer. For purposes of this table, the higher peak demands from the 2005/2006 winter were used.
C. East Kentucky does not weather normalize by class.

This project is confined to issues surrounding the authority of the KPSC over its jurisdictional electric utilities. As such, our focus is on the investor-owned utilities and non-profit generation and transmission cooperatives operating within Kentucky. Following are summaries of these entities, largely based on disclosures made in each utility's respective 2006 annual report or Form 10-K:

Kentucky Power Company (KPC). KPC is a wholly-owned subsidiary of American Electric Power Company (AEP). It represents approximately 4 percent of AEP's system revenues. KPC, headquartered in Frankfort, Kentucky, provides service to approximately 175,000 customers in all or part of 20 eastern Kentucky counties. KPC maintains administrative, regulatory and external affairs offices in Frankfort. Its distribution operations are based in Ashland with service centers in Pikeville and Hazard and area offices in Paintsville and Whitesburg.

---

[8] As of 2005.

[9] In the maps, Duke Energy of Kentucky is listed as Union Light, Heat, and Power Company (ULH&P). With the merger of Duke Energy Corporation and Cinergy Corp. in 2006, ULH&P became known as Duke Energy of Kentucky.

2006 KPC revenues were $586 million, with total assets of $1.3 billion. Aside from 1,060 MW of its own generating capacity, KPC purchases 15 percent (or 390 MW) of the output of the 2,600 MW Rockport Plant. The credit ratings for KPC's senior unsecured debt by Moody's and Standard & Poor's (S&P) at December 31, 2006 were Baa2 and BBB, respectively.

KPC's 1,060 megawatts of coal-fueled generating capacity are located at its Big Sandy Plant. Construction of a scrubber at the Big Sandy Plant has been suspended due to escalations in capital and operating cost estimates. As of November 2007, the scrubber is expected to be installed by 2014.[10] Approximately 68 percent of AEP system capability is coal.

Kentucky was originally identified by AEP as one of three states being considered for construction of an Integrated Gasification Combined Cycle (IGCC) power plant. IGCC is a clean coal technology that offers the potential to achieve the environmental benefits of gas-fired generation with the lower fuel costs associated with coal.

In April 2006, the Public Utilities Commission of Ohio approved AEP Ohio's request to recover pre-construction costs from its Ohio customers for a proposed IGCC facility at the Great Bend site.

Kentucky Utilities (KU). KU is a wholly-owned subsidiary of E.ON. E.ON is the world's largest investor-owned utility, headquartered in Dusseldorf, Germany. KU is based in Lexington, Kentucky, serving customers in 77 Kentucky counties and five counties in Virginia (under the name Old Dominion Power - ODP). KU serves 485,000 electric customers in Kentucky; ODP serves 30,000 electric customers in Virginia. KU's total generation capacity is 4,570 megawatts.

In 1998, KU's parent company, KU Energy, was acquired by LG&E Energy, which owned neighboring utility, Louisville Gas and Electric Company. The acquisition of KU Energy, along with a 25-year lease agreement with Big Rivers Electric Corporation, more than doubled the size of LG&E Energy. UK-based Powergen bought LG&E Energy in 2000, and in 2001, Powergen agreed to be acquired by Germany's E.ON. The deal was completed in 2002. In 2003, E.ON transferred LG&E Energy from Powergen to another subsidiary, E.ON U.S. Holdings.

KU's capacity derives primarily from the following:

- Ghent Generating Station – Coal fired. Four units with a total capacity of 2,000 MW. Equipped with electrostatic precipitators. A scrubber system was installed on Unit #1 in 1994. Scrubbers are currently being installed on Units 2-4.[11]
- Tyrone Generating Station – Coal/Oil fired. Three units with a total capacity of 135 MW. Equipped with electrostatic precipitators.
- E.W. Brown Generating Station. Hydro – 34 MW; 3 coal units – 700 MW; six oil/gas turbine units – 768 MW. A single scrubber is being installed for the 3 coal units.

---

[10] AEP 2007 Fact Book presented at the 42nd EEI Financial Conference, November 4-7, 2007, p. 99.

[11] Case No. 2008-00206 Order dated February 28, 2008, eliminated the scrubber at Ghent Unit #2.

- Green River Generating Station – Coal fired. Four units with a total capacity of 242 MW. Equipped with electrostatic precipitators.
- Approximately 196 MW available from Owensboro Municipal Utilities (OMU).[12]

Both S&P and Moody's changed their outlook on E.ON's long-term debt after its announcement to acquire Endesa in early 2006. S&P put E.ON's bonds on credit watch with negative implications, while Moody's announced it would review its rating for a possible downgrade. S&P's and Moody's most recent long-term debt ratings of E.ON were BBB+ and A3, respectively.

Louisville Gas & Electric (LG&E). LG&E is a wholly-owned subsidiary of E.ON, as described above. It is based in Louisville, Kentucky, providing service to 384,000 electric and 312,000 gas customers in Louisville and 16 surrounding counties. LG&E's generation capacity is 3,514 megawatts primarily located at:

- Trimble County Station – Coal fired. Current generating capacity of 514 MW. Equipped with electrostatic precipitator and wet limestone scrubber. Ownership shared with Illinois Municipal Electric Agency (12.12%) and Indiana Municipal Power Agency (12.88%). 900 MWs (net) of CTs are also located at this station.
- Mill Creek Station – Coal fired. LG&E's largest generating station with a net summer capacity of 1,470 MW. All units are fully scrubbed, which results in 500,000 tons of gypsum by-product.
- Cane Run Station – Coal fired. Consists of three units with a net generating capacity of 563 MW. All three units have scrubbers and sludge-processing plants.
- Ohio Falls Station – Hydroelectric. Its eight units have a net generation of 80 MW.
- Combustion Turbines – Natural gas and fuel oil. LG&E has six units in various locations (Waterside Station, Paddy's Run, Cane Run, and Zorn Avenue). Used to meet peak demand and emergency start-ups.
- KU/LG&E are currently constructing a 750 MW coal-fired unit at LG&E's Trimble County site.

Duke Energy of Kentucky (Duke Kentucky). Duke Kentucky is a wholly-owned subsidiary of Duke Ohio, which is a wholly-owned subsidiary of Duke Energy Holding Corp. It serves 94,000 gas and 133,000 electric customers in seven northern Kentucky counties.

Duke Kentucky has generation capacity of 1,141 megawatts. It holds a 69 percent interest in its East Bend Plant, a 414 MW coal-fired facility located in Boone County, Kentucky. It also owns generation located in Ohio, comprised of the Miami Fort plant – a 163 MW coal-fired unit, and the Woodsdale plant – a 564 MW gas-fired facility. The Duke Kentucky generation capability represents approximately 3 percent of the total Duke Energy system capability in the United States.

[12] 2005 Joint IRP filed by KU and LG&E, pp. 5-37 to 5-38. OMU was expected to provide KU 196 MW of capacity in 2005 under a purchase power agreement. After 2005, this amount was expected to decrease as OMU's customer load increased. In May 2006, OMU notified KU of its intent to terminate the contract in May 2010. (September 30, 2006 KU Form 10-Q)

The credit ratings for Duke Kentucky senior unsecured debt were BBB and Baa1 for S&P and Moody's, respectively.

Big Rivers Electric Corporation (Big Rivers). Big Rivers is an electric generation and transmission cooperative headquartered in Henderson, Kentucky. It is owned by its three distribution cooperative members – Jackson Purchase Energy Corporation, Kenergy Corp., and Meade County Rural Electric Cooperative Corporation. These member cooperatives, in turn, supply power to over 110,000 customers in 22 different western Kentucky counties.

Big Rivers owns 1,459 MW of electric generating facilities and has rights to the HMP&L Station Two facility (an additional 217 MW). Owned facilities include the Kenneth C. Coleman Plant (Unit Nos. 1-3) which is coal-fired and has 455 MW of net capacity, the Robert D. Green Plant (Unit Nos. 1-2) which is coal-fired and has 454 MW of net capacity, the D.B. Wilson Unit No. 1 which is coal-fired and has 420 MW of net capacity, the Robert A. Reid Plant (Unit No. 1) which is coal/natural gas-fired and has a net capacity of 65 MW, and a combustion turbine which is oil/natural gas-fired and has a net capacity of 65 MW. Big Rivers also has 178 MW of hydro capacity available from the Southeastern Power Administration (SEPA).

Currently, all of the generating facilities and rights have been leased to certain affiliates of E.ON U.S. Under this arrangement, E.ON U.S. subsidiaries operate the Big Rivers' facilities, power is purchased from an E.ON U.S. affiliate, and it is distributed by Big Rivers as wholesale electricity to its three member-systems. Recently, Big Rivers signed a letter of intent with E.ON U.S. parties to unwind the 1998 transactions which were originally scheduled to run through 2023.[13]

East Kentucky Power Cooperative (East Kentucky). East Kentucky is a not-for-profit generation and transmission electric utility headquartered in Winchester, Kentucky, and owned by 16 distribution cooperatives. The member distribution systems supply energy to approximately 500,000 customers in 89 different counties.

East Kentucky's generation facilities consist of 2,512 MW and include:

- Dale Station – Coal fired. 196 net MW of generation located in Clark County.
- Cooper Station – Coal fired. 341 net MW of generation located in Pulaski County.
- Spurlock Station – Coal fired. 1,118 net MW of generation located in Mason County.
- Smith Station – Oil/natural gas fired. Combustion turbine peaker units located in Clark County. 626 (Summer) and 842 (Winter) net MW of generation.
- Various landfill gas plants. 15 net MW of generation.

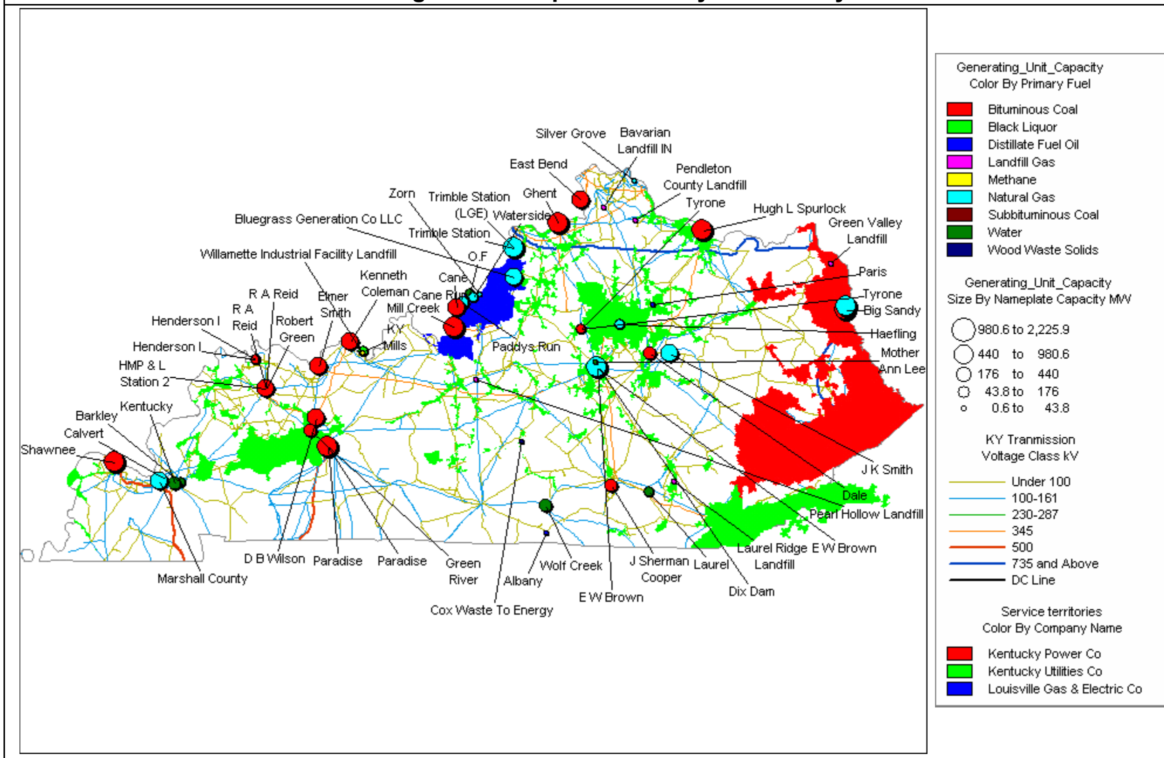
East Kentucky also had 170 MW of hydro power purchases from the SEPA.

East Kentucky is in the process of constructing a 278 MW coal-fired unit at Spurlock, which it plans on completing in the spring of 2009. In 2011, a nearly identical plant will be built at J.K. Smith Station in Clark County. The following map reflects the major generation and transmission facilities in the State.

---

[13] This matter was still pending as of the release date of this report.

Figure 1-4. Map of Kentucky's electricity sector



Kentucky Coal Mining Operations

A recent report indicated that the total economic activity resulting from coal mining in the state approximated $9.7 billion. Estimated total Kentucky tax revenues of $593 million are associated with coal mining operations, taking into account both direct and indirect economic effects. Approximately 80% of Kentucky coal is shipped out of state. About 17,700 jobs in Kentucky are associated with coal mining and processing. These jobs produce approximately $1.0 billion in annual mining wages. Based upon the most recent fiscal year data available, the Coal Severance Tax produces approximately $220 million in annual revenues for the state. This is based upon a gross value of coal mined and processed of $4.9 billion.[14]

Current Kentucky Energy Environment

Kentucky regulated generating utilities (and their parent companies) are committed to economically viable energy efficiency and DSM programs, including consideration of alternative energy sources (renewables). This is evidenced in the strategic planning and resource planning documents filed in this proceeding or available by reference from other filings. Substantial commitments are being made to the mitigation of environmental impacts from coal generation through the installation of environmental facilities costing more than $1.5 billion, and support and implementation of various new technology alternatives. Some examples of these commitments include:

---

[14] Data provided by the Governor's Office of Economic Policy, which included information extracted from Coal Facts.

- Duke Energy Save-A-Watt Program.
- E.ON U.S. commitment as a participant in the FutureGen Alliance, a consortium of global electric utilities and coal companies working with the U.S. Department of Energy to develop the world's first near zero emissions generating facility.[15]
- LG&E pilot program to test "smart meters" and customer reaction to responsive pricing.

Summary of Recommendations

There are no recommendations contained in Chapter 2 – Review of Current Regulatory Environment. This Chapter provides the summary of relevant Statutes, regulations and decisions; which are the foundation for the analysis and recommendations that follow throughout the balance of this report.

The following tables contain the recommendations addressed in this report. While we consider all recommendations to be worthwhile, we have provided a priority ranking. This ranking is based on our opinion of the degree of impact associated with meeting the Section 50 objectives.

Chapter 3		
Recommendation	**Page Reference**	**Priority Level**
In order to properly consider and develop policies, practices and programs adopted by the Commission from recommendations contained in this report, input from non-utility stakeholders, as well as the utilities should be solicited. This input may be developed from workshops sponsored by the Commission Staff, or more formal proceedings, as the Commission deems appropriate.	42	Medium

Chapter 4		
Recommendation	**Page Reference**	**Priority Level**
The Commission should develop a set of standards for how to evaluate the benefits of proposed DSM programs. Such standards should broadly specify the range of benefits to be recognized and the appropriate analytical approaches for evaluating future benefits. The standards should recognize the variety of benefits created by DSM, while also acknowledging that DSM cannot be substituted for power plant development on an undifferentiated basis. The standards should require the development and application of screening models sophisticated enough to systematically compare and contrast the relative attractiveness of alternative DSM options in different settings.	53	High

15 In a recent announcement, DOE has withdrawn its financial support for this $1.8 billion project. DOE was to fund approximately $1.3 billion of the project costs. Electric Utility Week, February 4 and February 11,2008.

Chapter 4		
Recommendation	**Page Reference**	**Priority Level**
The Commission should develop or adopt recognized measurement and verification guidelines, so that actual results of DSM programs can be independently assessed and validated. In order to legitimize program continuation, DSM program benefits should be linked to measured and verified achievements, as much as practically possible,	53	High
The KPSC should consider the need to revise the DSM statute to expressly authorize the KPSC to act on its own initiative or direction to investigate and direct utilities to implement particular DSM programs, the costs of which would be recovered by the surcharge.	54	Medium
Rules governing industrial customer exclusion from DSM program participation should be clarified, standardized, and uniformly applied. It is important that customers who seek to opt-out of the DSM program make a showing of their own energy efficiency efforts, before they are allowed an exemption from the DSM surcharge and related programs.	56	High
As new DSM programs are brought before the Commission that clearly reduce system costs, it should consider if such programs should be more properly allocated to all jurisdictional customers.	57	High
Greater efforts should be made to make utility customers aware of energy conservation and DSM programs. Additional utility resources should be committed to customer education programs sponsored by the utilities or independent third parties. The KPSC may also release public information communications that support energy efficiency programs.	57	High
Assuming that proper utility incentives and recovery mechanisms are in place, utilities should consider providing or expanding rebates or financing programs to support customer investment in energy efficiency and DSM programs; especially those that are likely to reduce peak demand. A set of pre-approved technology types may be promoted to customers through education and incentives showing the expected payback characteristics for each technology.	58	High
The Commission should consider the need to revise the current DSM application and approval process to accelerate the procedural timeline for projects below a defined funding level. The standard of review for modifications to current programs, or programs under a specified budget amount, should be further streamlined to accommodate increased participant interest in successful programs.	58	Medium

Chapter 5		
Recommendation	**Page Reference**	**Priority Level**
The KPSC may wish to consider whether to recommend an RPS target to the General Assembly, consistent with similar initiatives in many other states. If it does so, we recommend that the target be voluntary, providing financial incentives for Kentucky utilities who choose to comply. The target must be realistic and cost effective in light of Kentucky geological constraints, with a range of perhaps 5 to 10% of energy served, graduated to 2020.	69	Medium
The Commission should consider the need to provide for fast track applications for small-scale generation, possibly as part of a more formalized Standard Offer Contract process.	70	Medium
To properly compensate utilities for increased renewables project risks, and to attract utility commitments to these investments, the Commission should consider allowing a premium of up to 300 basis points over the latest authorized rate of return for these investments	71	High

Chapter 5		
Recommendation	**Page Reference**	**Priority Level**
One of the solutions to the renewable market pricing problem could be a KPSC requirement for utilities to use an RFP process for all resources, based on IRP, or just renewables, where the contracts signed with the winners would include a capacity component in the remuneration.	72	Medium
Uniform standards, at least by utility, for net metering and interconnection should be developed, as set forth in a tariff. Current limits on technology restrictions should be reconsidered, as well as limits on total participation levels. Finally, current limits on generating capacity should also be relaxed to facilitate the potential for development of distributed generation projects, sizing projects appropriate to each technology.	73	Medium

Chapter 6		
Recommendation	**Page Reference**	**Priority Level**
We do not believe that Commission responsibility for statewide planning is either practical or particularly beneficial, given the reality that utilities, regulated or not, do not engage in Kentucky-level system planning that would necessarily result in any joint development or operation of generation resources.	83	Low
The current statute defining the CPCN process should be modified to require the consideration of demand and supply-side alternatives including: IPP and merchant power options; energy efficiency and DSM programs; and renewable alternatives.	84	High
Until such time as anticipated federal legislation is formally enacted addressing carbon emission standards, utility IRP and CPCN filings should provide best available estimates of expected carbon impacts in justifying resource selections among portfolio options.	94	Medium
Utilities should be required to file avoided cost data (not less than annually), subject to the review and approval of the Commission. Consideration of energy efficiency and DSM programs, as well as renewables projects, should be measured against the appropriate avoided costs. Programs that reliably reduce peak load should be evaluated against the avoided cost of both demand and energy.	96	High
The Commission should not require the recognition of environmental or public health externalities in the IRP or certificate processes, unless it finds it appropriate to specifically direct a utility (or utilities) to do so.	96	High

Chapter 7		
Recommendation	**Page Reference**	**Priority Level**
Assuming that the results of current pilot programs are positive, TOU rates and RTP should be more broadly applied to industrial customers in the future.	105	High
The current DSM Surcharge mechanism should be modified. Utility expenditures (capital, and operating costs related to the period of the program) should be capitalized, with amortization based on the estimated period of program benefits. Utilities should be allowed a minimum return of 100 bp higher than the most recent authorized rate of return in the utility's last rate proceedings. Utilities should be allowed to receive additional incentives based on the actual benefits achieved relative to appropriate targets from energy efficiency and DSM programs. Assuming that program targets are met, these incentives should provide a reasonable opportunity to earn a graduated return of up to 300 bp over the minimum premium, based on results.	106	High

Chapter 7		
Recommendation	**Page Reference**	**Priority Level**
The DSM statute and advertising regulation should be modified to provide explicit authority for advertising costs associated with DSM and energy efficiency programs. The advertising regulation should be amended with regard to its definition of "promotional advertising" to eliminate potential conflicts with the promotion of energy efficient equipment; programmable thermostats; smart metering devices; etc.	107	Medium
A new surcharge should be created to include and accelerate expenditures associated with efficiency improvements in utility generation facilities. The rate of return on Commission approved projects should be 50 bp higher than the most recent authorized return in the utility's rate proceedings.	108	Low
All regulated Kentucky utilities should be required to develop and offer a "Green Energy" optional tariff for their residential customers.	109	Medium
The Commission should provide for additional staffing, and relevant training, necessary to support increased activities associated with IRP, DSM, Environmental Surcharge, Certificate, and other filings. The Staff additions would also monitor federal and state energy legislation, industry research and programs, and Kentucky regulated utility parent-company activities. Staff resources may need to be further supplemented to support increasing requirements over time.	110	High
The General Assembly should consider explicit support of these Commission initiatives to further encourage the utility industry response, and to limit financial risks associated with these utility commitments.	112	High
In support of the development of Section 50 objectives, the General Assembly may wish to work with utilities in developing securitization bond funding in support of qualifying conservation investments and environmental mandates, including advanced-coal technologies. Access to capital at a reduced cost will help bring these programs to fruition on a more economic basis, and will result in lower energy rates.	113	
Any potential customer increase in rates due to programs effective on or after January 1, 2009, which are recoverable by operation of the proposed surcharges contained in this report, should be considered in light of other cost increases in base rates, FAC, or other charges. If the Commission finds it appropriate to do so, it may impose a rate cap on these costs for a particular period or periods. Approved costs, if any, that exceed the rate cap, should be deferred for future recovery, including appropriate carrying costs.	113	High

Conclusion

As previously noted, Kentucky customers benefit from among the lowest electric rates in the country. This cost advantage does not exist due to sheer coincidence, but rather arises from a number of factors that include: a local fuel resource to support low-cost generation; an aging generation system that results in relatively lower net investment costs for capacity in current rates; and a long-standing record of state regulation that has supported policies and procedures resulting in low-cost, reliable service for Kentucky jurisdictional consumers.

Current prices, however, are likely to rise for a number of reasons. The recent rise in fuel costs are already impacting customer bills, albeit much less than other areas of the country relying more heavily on gas and oil supplies. Costs are also likely to escalate as older facilities will require major upgrade programs or replacement facilities. While uncertain at this time, it is likely that Federal legislation will result in CO_2 restrictions that will cause coal-fired generation costs to increase in the future. Finally, customer growth will require infrastructure investment that will put pressure on current costs, as marginal costs exceed historic embedded costs reflected in current prices.

This report, as identified above, contains a number of recommendations that respond to the objectives of Section 50 of the Energy Act. If implemented, it is not expected that current coal consumption at existing generating facilities will be altered much, if at all. Rather, the commitment to expanded DSM and renewables investment, will:

- reduce the reliance on future commitments to traditional supply-side resources;
- reduce the growth rate of currently forecasted energy and demand;
- create financial incentives for utility commitments to energy efficiency investment;
- maintain the financial condition of Kentucky regulated generating utilities; and
- maintain customer rate stability in relation to changes occurring due to other factors identified above.

[This page intentionally left blank.]

Chapter 2 - Review of Current Regulatory Environment

This chapter provides a summary of Kentucky statutes, as well as Commission regulations, decisions, and reports that are relevant to the subject matter of this report. As such, this chapter helps define the current framework within which resource planning currently occurs within Kentucky; at least with regard to KPSC authority over jurisdictional generating utilities within the State.

Current Legislative Authority

The legislative authority of the Commission over utilities in the state derives from the Kentucky Legislature as contained in the Kentucky Revised Statutes (KRS); specifically at KRS Chapter 278. The Commission has broad powers to exercise its plenary authority as provided in 278.040 Public Service Commission – Jurisdiction – Regulations, as indicated by:

- The jurisdiction of the commission shall extend to all utilities[16] in this state. The commission shall have exclusive jurisdiction over the regulation of rates and service of utilities…

- The commission may adopt…reasonable regulations to implement the provisions of KRS Chapter 278 and investigate the methods and practices of utilities to require them to conform to the laws of this state, and to all reasonable rules, regulations and orders of the commission not contrary to law.

The authority of the Commission is further defined in administrative regulations promulgated by it in Chapter 807 of the Kentucky Administrative Regulations (KARs).

Integrated Resource Planning (IRP) Process

The Kentucky IRP regulation was promulgated in 1990, and is addressed in 807 KAR 5:058.

Initially, resource plans were submitted by utilities to the Commission at two-year intervals. The regulation at that time required the development by Commission Staff of a "statewide" supplement.[17] Consultants were relied upon to provide most of the resources necessary to support this process. Recommendations that developed from the consultant reports over this period were implemented by the utilities, and are generally reflected in current practices. After the first two rounds of IRP filings, the current three-year interval was adopted in 1995.

The current process is a formal process, which includes initiating a formal case and providing a public notice of filing. Interested parties have the right and ability to participate in the IRP case. Formal discovery is served on the utilities. Intervenors may file comments, with the utility filing its reply. Informal conferences may be held. A Staff report is issued, which takes into

---

[16] "Utilities" is defined in KRS 278.010 to include "any person except . . . a city, who owns, controls, operates, or manages any facility used or to be used for or in connection with (1) [t]he generation, production, transmission, or distribution of electricity to or for the public, for compensation, for lights, heat, power, or other uses . . ."

[17] The statewide supplement consisted of a compilation and high-level comparison of the utilities' IRPs, and was not intended as actual "statewide planning" in the context of integrated resource planning.

account the positions and comments of the other parties in the proceeding. The only material difference in this process from other Commission proceedings is the absence of a Commission Order.

The current regulation provides for the inclusion of utility-specific information and reporting requirements, including but not limited to:

- Plan summary.
  - descriptive overview of company, customers, facilities, and planning objectives;
  - description of models, methods, data, key assumptions;
  - summary of energy and demand forecasts;
  - summary of planned resource acquisitions;
  - actions anticipated to implement plans over next three years; and
  - discussion of key issues and uncertainties that could impact the plan.
- Significant changes from the prior plan.
- Load forecasts – projected and historic data.
- Resource assessment and acquisition plan.
  - "The plan shall include the utility's resource assessment and acquisition plan for providing an adequate and reliable supply of electricity ***to meet forecasted electricity requirements at the lowest possible cost.*** The plan shall consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility."
  - Options considered are to be described including: efficiency improvements at existing facilities; new DSM, conservation, and load management programs; non-utility generation; cogeneration; and renewables.
  - A listing and description of existing and planned generating facilities are to be included.
- Financial information, including: the present value of revenue requirements; assumed discount rate; expected revenue requirements; and average system rates.

Siting/Certificate of Public Convenience and Necessity (CPCN) Process

The CPCN process is addressed in KRS 278.020. This process provides for a formal review of a utility application, which may be accepted or rejected, in whole or in part. "The commission, when considering an application for a certificate to construct a base load electric generating facility, may consider the policy of the General Assembly to foster and encourage use of

Kentucky coal by electric utilities serving the Commonwealth." Applicants must provide a showing of the need and demand for service.[18]

The CPCN process has no explicit requirement to consider renewables, energy efficiency or DSM programs as alternatives to conventional generation resource options. However, the Commission does review the most recent IRP, as well as a showing of solicitations for alternative resource projects. This process also includes a review of IPP or merchant project alternatives versus the self-build option. As a matter of practice, this analysis is almost always performed. Although there are no explicit "least cost" criteria in place, when considering a CPCN application, the IRP process does require resource options that provide for electricity needs to be met at "lowest cost", taking into account "potential impacts of selected, key uncertainties."

A CPCN is also required for an electric transmission line with 138 KV or greater capacity, and which is not less than one mile in length.

As addressed in KRS 278.216, provisions require utilities to obtain a site compatibility certificate for generation in excess of 10MW. A site assessment report is generally required; however, the utility may file documentation of compliance with the National Environmental Policy Act (NEPA) instead.

Rules governing generation and transmission siting for merchant power plants are contained in KRS 278.700-716. The three members of the Commission sit on a seven-member board (the Kentucky State Board on Electric Generation and Transmission Siting); the Chairman of the Commission also serving as Chairman of the siting board. The applicant must file, among other things, a site assessment report; an analysis of the potential effect on the transmission system within the state; and an economic impact analysis. There is no requirement within these provisions of a showing that the proposed project is in the public interest.

DSM Filing Process

The statutory authority of the KPSC to review proposed DSM programs and approve cost recovery mechanisms for implementing these programs is specified in KRS 278.285.

Utility DSM filings provide detailed analyses of the costs of implementing DSM programs, net revenues lost due to implementation of the programs and proposed incentives structures for the utilities. While there is no specific schedule as to when and how often the DSM filings need to be submitted to the Commission, the typical frequency has been every one to two years, with annual or semi-annual progress updates.[19] Long-term plans for DSM programs are also included within utility IRP submissions (discussed in more detail in Chapter 6).

---

[18] 807 KAR 5:001. Rules of Procedure; Section 9.

[19] Duke Energy filed its latest DSM application on August 17, 2007. LG&E/KU filed its joint application on July 19, 2007, proposing DSM plans and cost recovery mechanisms for the period 2008-2014. KPC's latest DSM application was made in February 2008.

The statute states that the Commission should consider the following factors in reviewing DSM programs:

- targeted changes in consumption patterns;
- cost and benefit analysis;
- proposed cost recovery of DSM programs in the rates, including net revenues lost, and incentives for utilities to encourage implementation of cost effective programs;
- consistency with long-term Integrated Resource Plans;
- equitable treatment of all customer classes;
- involvement of customer representatives and the Office of Attorney General in the development of the proposed plans; and
- availability and affordability of proposed plans.

Review of DSM filings can be undertaken as dedicated proceedings or as part of hearings for approval of new rate schedules. In Kentucky, the costs of DSM programs are recovered either through general rates as provided for by KRS 278.190 or through the DSM surcharge that is authorized by KRS 278.285. If the Commission approves a new DSM program or extends an existing program, the costs of the program will be incorporated into the DSM surcharge. For approved DSM programs, adjustment mechanisms are employed to true-up the differences between planned and actual costs, when actual expenses and estimates of net lost revenue (based on estimated energy savings) are compared with planned expenses and the difference is recovered in the next cycle.

Customer representatives and the Attorney General's office participate as parties in proceedings involving review of and decision-making on DSM programs and related cost recovery mechanisms, as well as, at least in some cases, in collaboratives or advisory groups.

Investor-owned utilities in Kentucky have organized customer collaboratives/advisory groups to facilitate dialogue and the development of DSM programs that would receive the general support of stakeholders and customers.[20] Duke Energy Kentucky has two such bodies: Residential Collaborative and the Commercial and Industrial Collaborative, while KPC uses only one DSM Collaborative, to address needs and concerns of its different customers and stakeholders. Two companies, LG&E and KU, have organized a joint body, the DSM Joint Advisory Group for LG&E and KU, to work on development of DSM programs. The membership in these Collaboratives varies, but the interests of all classes of customers are usually represented via organizations and bodies such as the Office of Attorney General, industry lobby groups, various local non-governmental organizations, community organizations, and government agencies (e.g. Kentucky Office of Energy Policy).

The two power cooperatives do not have similar customer organizations to coordinate DSM activities as they do not directly serve retail customers; however, they participate in the

[20] One of the conditions for Commission approval of DSM programs and cost recovery mechanisms as noted.

meetings of the Kentucky Energy Efficiency Working Group, which includes other utilities, local government agencies, educational institutions and environmental lobby groups.

It is important to note that while Commission authorization is required for the implementation of DSM programs' cost recovery, the statute language does not expressly authorize the Commission to direct utilities to implement particular programs on its own initiative or direction.

In addition, to date, the Commission practice has not required the utilities to use particular screening models, cost-benefit tests, or input assumptions.

Home heating assistance is part of the DSM statute. However, these some utilities distribute these funds through a third-party agency.

Environmental Surcharge, Recovery of Environmental Costs

KRS 278.183 became effective July 14, 1992. Generally, this statute created a mechanism to recover environmental compliance costs related to coal combustion wastes and by-products. The surcharge provides for the recovery of capital expenditures, including a reasonable return, as well as operating costs (including allowance purchases costs), taxes and depreciation. A six-month procedural schedule is provided for the review and approval of utility environmental compliance plan filings. The Commission maintains oversight of the surcharge mechanism through utility filings at six-month intervals, including hearings and orders based upon these reviews.

Every two years, the Commission reviews the operation of the surcharge, and makes adjustments as appropriate. Amounts found to be just and reasonable are incorporated into utility base rates.

Provisions for Net Metering

KRS 278.465-468 became effective July 13, 2004.[21] Eligible customers may produce not more than 15 KW of solar energy. Total customer participation is potentially limited to not more than one-tenth of one percent of the utility system peak. Any metering and distribution upgrades are installed at the customer's expense. If a customer terminates service, no refund for outstanding credits is required. Excess electricity credits are not transferable between customers or locations. Generating equipment and interconnections are required to meet safety standards. Each utility has filed with the Commission its net metering tariff, as well as terms and conditions, including interconnection standards.

---

[21] The Statute defines net metering as "measuring the difference between the electricity supplied by the electric grid and the electricity generated by an eligible customer-generator that is fed back to the electric grid over a billing period."

Fuel Adjustment Clause (807 KAR 5:056)

The fuel adjustment clause (FAC) is designed to allow the timely recovery of fuel and purchased power costs (excluding capacity or demand charges) by an immediate pass through of such costs, as defined by this regulation. Generally, increased costs are not includable when associated with forced outages in excess of six hours. The Commission reviews fuel charges under this regulation at six-month and two-year intervals.

Other Relevant Statutes and Regulations

KRS 278.010 provides certain definitions that may be relevant to this report.

- "Demand-side management" means 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;

- "Regulated activity" means a service provided by a utility or other person, the rates and charges of which are regulated by the commission;

- "Subsidize" means the recovery of costs or the transfer of value from one (1) class of customer, activity, or business unit that is attributable to another.

KRS 278.212. Filing of plans for electrical interconnection with merchant electric generating facility – Costs of upgrading existing grid. This statute provides that no utility may interconnect with a merchant generating facility in excess of 10 MW without first filing the plans and specifications for interconnection with the Commission.

KRS 278.287. Voluntary energy cost assistance fund. Aside from the home heating assistance program provided in 278.285 (DSM plans), this statute allows for the voluntary support of low-income residential customers. The funds are primarily focused on heating subsidies, but to the extent that sufficient funds are available, air conditioning subsidies are also potentially available.

807 KAR 5:016. Advertising. This regulation distinguishes the nature of advertising costs, which are includable in rates from those that are not. Generally, promotional, political or institutional advertising programs are not permitted as recoverable costs for ratemaking purposes. The regulation applies a "material benefit" standard to identify recoverable costs. Stated examples of recoverable advertising costs include: programs to reduce customer bills or conserve energy; the provision of "factual and objective data programs to educational institutions on the subject of energy technology"; and "advertising which explains a utility's proposed or existing rate structure, its energy-related problems and its public programs and activities, provided such reference includes a description of how a consumer benefits from or is affected by same." As defined by this regulation, "promotional advertising" includes programs that encourage the use or additional use of energy service, "or the selection or installation of any appliance or equipment designed to use such utility's service".

807 KAR 5:054. Small power production and cogeneration. This regulation is relevant to this proceeding, as it addresses recognition of avoided costs in setting the basis of rates for energy

produced from small power production and cogeneration facilities. Avoided costs are defined as "incremental costs to an electric utility of electric energy or capacity or both, if not for the qualifying facility, the utility would generate itself or purchase from another source." Section 5 requires utilities to file avoided cost data at least once every two years. Section 7 provides for a standard offer contract for facilities under 100 KW. For facilities over 100 KW, if rates cannot be negotiated by the parties, the Commission may determine the rate in a proceeding upon holding a hearing on the matter.

Recent Proceedings – Reports; Decisions

"Kentucky's Energy: Opportunities for Our Future, A Comprehensive Energy Strategy", by the Energy Policy Task Force (February, 2005)

In 2003, the Legislative Research Commission's Interim Special Subcommittee on Energy passed a resolution that called for the incoming administration "to craft state policy and insure that developments in the energy field take place in a planned and thoughtful fashion." In response to this resolution, former Governor Ernie Fletcher announced the formation of the Energy Policy Task Force and outlined three principles that guided policy development:

- Maintain Kentucky's low-cost energy;
- Responsibly develop Kentucky's energy resources; and
- Preserve Kentucky's commitment to environmental quality.

In preparing the report, the Task Force recognized certain underlying national trends. At a national level, by 2025:

- U.S. energy consumption was expected to grow by 36%;
- Coal consumption was expected to grow by 35%;
- Renewable energy resources were expected to grow by 38%; and
- Coal was expected to comprise 53% of total electric generation.

As mentioned previously, Kentucky's residents enjoy low-cost electricity rates, largely due to the abundance of coal as a cost-efficient fuel source. However, environmental emission requirements are expected to present a significant challenge to the Kentucky coal industry in the future, especially since much of Kentucky's coal is high in sulfur. Coal industry employment in Kentucky has declined since the 1970s, and a shortage of qualified workers is developing. Other states and the federal government are investing in the coal industry. As a result, Kentucky should not take for granted its comparative advantage. Kentucky's comprehensive energy strategy focused on promoting new growth in Kentucky's coal industry through clean coal technology, targeted investment, and workforce training among other things.[22]

At the time of the task force's report, Kentucky was one of 34 states that allow their utility customers to benefit from net-metering. The growth in renewable resources was expected to occur primarily in the transportation sector rather than in electric generation. Promoting, rather than mandating, the use of renewable energy resources was the focus of Kentucky's comprehensive energy strategy.

From an electric industry perspective, the investment in natural gas infrastructure and the emerging opportunities associated with methane and natural gas would provide another alternative fuel source for electric generation.

The task force produced fifty-four recommendations from its work. These are re-printed in Appendix C.

Administrative Case No. 2005-00090

In response to recommendations made by the Energy Policy Task Force in the report entitled "Kentucky's Energy: Opportunities for Our Future, A Comprehensive Energy Strategy", former Governor Fletcher issued Executive Order 2005-121 on February 7, 2005. This order called for the KPSC to develop a "Strategic Blueprint" to "promote future investment in electric infrastructure in the Commonwealth of Kentucky, to protect Kentucky's low-cost electric advantage, to maintain affordable electricity rates for all Kentuckians and to preserve Kentucky's commitment to environmental protection."[23]

The Executive Order specifically called for a review of the following:

- The current status of generation, transmission and distribution facilities;
- Available sources of electricity supply;
- Projected demand through 2025;
- The existence of barriers to investment in generation, transmission and distribution;
- Barriers to the utilization of technologies in generation, transmission and distribution;
- Strategies for the utilization of technologies to improve the efficiency of electricity service;
- Opportunities to promote utilization of renewable resources; and
- Any other information to "help ensure future investment in electricity infrastructure to meet Kentucky's needs."[24]

---

[22] While Kentucky enjoyed low energy *rates,* this was not reflected in customer bills due to higher than average energy *consumption*.

[23] Executive Order 2005-121, February 7, 2005, at 2.

[24] Executive Order 2005-121, February 7, 2005, at 2.

The resulting report entitled "Kentucky's Electric Infrastructure: Present and Future" was issued on August 22, 2005 and was the focal point of Administrative Case No. 2005-00090. The following discussion summarizes some of the more important features of this 2005 report.

The KPSC has no jurisdiction over Kentucky municipal electric systems, the five distribution cooperatives supplied by the TVA, or merchant generation. In total, these entities served 375,000 customers in Kentucky. This compared to the 1,800,000 served by the jurisdictional electric utilities (investor-owned utilities and non-profit generation, transmission, and distribution cooperatives). The report also noted that the scope of the work performed by the Commission to produce this requested report went ". . . beyond the traditional duties of the Commission."[25]

At the time the report was prepared, Kentuckians paid the lowest electricity rates in the nation. This was attributed to the investment made by Kentucky's utilities in large, coal-fired generating units which accounted for 95 percent of the state's electricity, coupled with an abundant local fuel supply, sound utility management, and a traditional regulatory environment for the state's jurisdictional utilities. However, the KPSC expressed concern over possible effects on Kentucky that decisions made by the federal government and in states that have embraced deregulation might have.

While 7,000 additional MW of generation were expected to be needed by 2025 to meet peak demand, the Commission concluded that Kentucky's utilities (both jurisdictional and non-jurisdictional) had adequately planned for these additions. The projection was based on the assumption that peak demand would increase by an average of 1.7 percent per year. For jurisdictional utilities, the long-range additions primarily consisted of gas-fired combustion turbines (peaking) and pulverized or fluidized bed coal-fired generation (base load).

More concerning to the Commission was the electric transmission system in Kentucky. In isolation, the KPSC felt that the transmission system could reliably serve Kentucky customers, but it was not designed to handle the large blocks of power associated with interstate transfers between utilities that are commonplace in today's competitive wholesale market. In particular, there were constraints on north-south flows.

Because of the low electricity rates available in Kentucky, many DSM programs had not proven to be cost-effective. Energy from renewable sources was offered by some utilities to its customers at a premium to standard rates. All jurisdictional electric utilities had filed net-metering tariffs which promote the use of small scale renewables by residential and commercial customers.

According to the KPSC, Kentucky's energy policy should include incentives to use renewable energy and to promote coal gasification. Incentives could include tax credits, grants, and low-interest loans.

---

[25] Kentucky's Electric Infrastructure: Present and Future prepared by the KPSC, dated August 22, 2005, p. 10.

The Commission does not have the authority to include the full costs of environmental impacts and externalities in the price of coal-fired electricity. The KPSC determined that the identification and quantification of the related costs was impractical.

Uncertainties facing the electric utility industry in Kentucky at the time of the report included the aforementioned potential for federal intervention in transmission siting, federal policies regarding the development of regional electricity markets and air emission standards, factors affecting coal production and the price of coal, and technologies that improve the efficiency of electricity production and use.

The KPSC indicated that it found the IRP process adopted for jurisdictional utilities, which requires filing of plans with the Commission, to be helpful in monitoring and regulating these utilities. Although non-jurisdictional utilities do not have the same filing requirement, the Commission noted that they performed similar studies.

The KPSC expressed its concern over the reliance by jurisdictional utilities on aging generation units. Prospectively, the Commission required that these utilities address these concerns in their future IRPs.

At the time this report was issued, Western Kentucky Energy (WKE) and Dynegy were the only operators of merchant plants in Kentucky. Cumulatively, they had generation capacity of 3,218 MW at nine different sites, which represented approximately 23 percent of Kentucky's total generation capacity. The generation operated by WKE, an affiliate of LG&E, was owned by Big Rivers and was subject to a 25-year lease agreement schedule to expire in 2023. Dynegy owned eight natural gas fired turbines at three generation stations and only operated these units when it was economically feasible to do so. Merchant plants must obtain a certificate from the Siting Board pursuant to legislation passed in 2002. Since its inception, the Siting Board has considered five different proposals to construct base-load merchant plants. At the time of the report, four of the five had been granted conditional approval and the fifth was pending approval.

Cogeneration provided an immaterial amount of capacity to the Kentucky market in 2005 (approximately 140 MW).

Since 1994, jurisdictional utilities have had the opportunity to submit DSM plans and request cost recovery of such plans outside a general rate case through a DSM surcharge. Each of the four investor-owned utilities have done so, while Big Rivers and East Kentucky have developed and offered DSM programs in conjunction with their member cooperatives. As previously noted, due to Kentucky utilities' low-cost generation, many DSM programs have generally not shown to be cost effective. However, as incremental new generation costs increase, as fuel costs increase, and as new environmental requirements increase the cost of all generation, more DSM programs will become feasible. Additionally, the KPSC concluded that "efforts to implement practical DSM and conservation measures can have a positive impact on the environment."[26]

---

[26] Kentucky's Electric Infrastructure: Present and Future prepared by the KPSC, dated August 22, 2005, p. 47.

In this 2005 report, the Commission noted that the non-utility participants suggested that external costs (externalities) should be included in the price of electricity, especially those related to coal. However, the Commission concluded that it does not have jurisdiction under KRS Chapter 278 to explicitly allow for consideration of such externalities.

Other state and federal agencies are responsible for enforcing utility environmental compliance which limits what the KPSC can do. However, the Commission and Commission Staff have some influence on decisions made by utilities on environmental matters through the IRP process, filings made pursuant to the environmental surcharge statute, and CPCN proceedings for approval to construct environmental compliance facility additions. The environmental surcharge is limited to environmental compliance involving coal-fired generation.

Barriers to infrastructure investment identified by the utilities included competition from merchant plants, changes in sales tax policy, environmental compliance, federal vs. state authority, deregulation, and rate uncertainty. With respect to deregulation, several years ago, a previous legislative session concluded that there were few positive benefits to Kentucky and no compelling reason for Kentucky to restructure.

In summary, the Commission concluded that the current statutory and regulatory framework should be preserved. However, this does not guarantee continued low costs because the replacement of aging generation infrastructure will result in increased costs. According to the Commission, "Kentucky should consider policies to protect and insulate Kentucky ratepayers from market uncertainties and the price implications of future environmental restrictions."[27] This should not preclude Kentucky citizens, businesses, and communities the benefit of greater participation in energy markets.

"The Impact of Federal and International Policy on Kentucky's Energy Future" – a Review Conducted Pursuant to Executive Order 2005-120 by the KPSC (August 22, 2005)

On February 7, 2005, former Governor Fletcher issued Executive Order 2005-120 directing the KPSC to "consider, investigate, and issue a report related to the role of the federal government and international institutions as they might bear on an energy policy for the Commonwealth of Kentucky." In addition, "[t]he report shall identify federal and international policies or actions that affect the ability of the [K]PSC to establish in Kentucky electric and natural gas rates that are fair, just and reasonable. The report shall also identify how such policies or actions affect the ability of Kentucky based energy producers to export energy supplies in interstate and international markets."[28]

The electric industry is impacted by a number of federal laws and regulations. The report identifies the following federal laws as significant:

- The Public Utility Regulatory Policies Act (PURPA) of 1978 established a class of non-utility generators referred to as "qualifying facilities" (QFs). Under this law, utilities

[27] Kentucky's Electric Infrastructure: Present and Future prepared by the KPSC, dated August 22, 2005, p. 60.

[28] Executive Order 2005-120.

were required to connect QFs and buy power at prices not to exceed the avoided cost of generation to encourage small renewable generators and congeneration.

- The Energy Policy Act of 1992, along with establishing a category of non-utility generators known as "exempt wholesale generators" (EWGs), required utilities to transmit other suppliers' power across their transmission systems.

- FERC Order 888 implemented the "open access requirement" and introduced the concept of an Independent System Operator (ISO).

- FERC Order 2000 outlined the minimum functions of Regional Transmission Operators (RTOs), which are very similar to ISOs. This order required utilities to file their intentions to join an RTO.

- The Barton-Domenici Energy Policy Act of 2005 contained tax reforms designed to improve electric reliability and spur investment in electricity infrastructure (e.g., modifications to depreciation recovery periods, tax credits for energy efficiency improvements, etc.) It repealed the Public Utility Holding Company Act (PUHCA) and expanded FERC jurisdiction over utility mergers and acquisitions. It also established a new office and programs at the Department of Energy devoted to electricity research and development, preserved the ability of traditional utilities to use their transmission to first meet "native load" customer needs, directed FERC to establish "incentive rates" to reward investment in more efficient and beneficial transmission projects, and gave FERC limited "backstop" authority to site previously identified critical interstate transmission lines.

- The Clean Air Impact Rule issued by the Environmental Protection Agency (EPA) addressed sulfur dioxide and nitrous oxide levels and was estimated to cost Kentucky's electric consumer 3.4 mills/kWh by 2015.

- With its release in 2005, the Clean Air Mercury Rule regulated mercury emissions from coal-fired power plants.

With respect to the electric industry, important findings of this report included:

- Kentucky, unlike many states, has not adopted electric industry "restructuring" or "deregulation."

- FERC is the primary federal agency with jurisdiction over electric utilities. It specifically has jurisdiction, while not necessarily exclusive, over wholesale electric power sales, interstate transmission rates, mergers and acquisitions of utility companies and certain facilities, and hydroelectric power projects.

- Two RTOs have members in Kentucky, the Midwest Independent Transmission System Operator (members included Duke Kentucky and KU/LG&E)[29] and PJM Interconnection, Inc. (members included KPC).

- Attempts to mandate utility participation in RTOs or ISOs was met with resistance by the utility industry and shelved.

- The KPSC is concerned that Kentucky customers are being asked to pay for costs associated with RTOs (pursuant to the "filed rate doctrine") for which they receive limited benefits since Kentucky is largely self-generation sufficient.

- Through the CPCN process, Kentucky utilities are limited to investment that serves their native load customers. RTOs have proposed that generation resources be viewed on a regional basis. This could lead to generation being built in Kentucky that is not needed to serve Kentucky's customers.

Administrative Case No. 2006-00045

The KPSC initiated this administrative proceeding to consider certain requirements of the federal Energy Policy Act of 2005 (EPAct 2005), which among other things, adopted new standards for electric utilities regarding smart metering and interconnection.

EPAct 2005 Section 1252 required that each state regulatory authority conduct a formal investigation and issue a decision on whether or not it was appropriate to implement certain standards. If adopted, the first standard would require each jurisdictional electric utility to offer each customer class a time-based variable rate schedule in which the rates offered would be tied to the utility's variance in cost of service. Time-based rate schedules may include:

- Time-of-use pricing (pricing is pre-determined based on specific time periods during the day);

- Critical peak pricing (time-of-use prices in effect except during peak days; additional discounts may be offered for reducing peak energy consumption);

- Real-time pricing (pricing is set during the day based on the utility's cost of service); or

- Credits for consumers with large loads that enter into agreements to reduce usage during peak loads.

The second standard, if adopted, would require each utility to provide a customer with a meter capable of implementing such time-based rates.

None of the parties submitting testimony or briefs in the proceeding supported mandatory adoption of the Section 1252 smart metering standards, but rather voluntary adoption. The jurisdictional utilities specifically pointed out that the difference in price between time-based

---

[29] KU/LG&E were authorized by the KPSC to withdraw from MISO (Case No. 2003-00266 dated May 31, 2006) and did so in September, 2006.

rates and the already-low-cost current rates offered in the state would be minimal. Historically, few of Kentucky's jurisdictional utilities have offered time-based rate schedules to their residential customers with the exception of certain direct load control and off-peak electric thermal storage tariffs. Residential customer interest in time-of-use rates was said to be inconsequential.

The KPSC concluded that the Section 1252 smart metering standards should not be adopted by Kentucky's jurisdictional utilities. This decision was based on the combination of Kentucky's low rates for electricity, the significant costs, and the uncertainty of benefits. However, the Commission strongly encouraged the jurisdictional utilities to consider broadening the array of DSM programs offered to their customers. It also required that voluntary real-time-pricing pilot programs be developed for large commercial and industrial customers.

The EPAct 2005 Section 1254 interconnection standard, if adopted, would require each electric utility to make interconnection service available to any customer. Interconnection service in this context is service to an electric consumer under which a generating facility on the consumer's premises is connected to the local distribution facilities. The service to be offered is supposed to promote current best practices of interconnection for distributed generation pursuant to Institute of Electrical Electronics Engineers (IEEE) Standard 1547. The electric utilities expressed concern over sole reliance on IEEE 1547, indicating that it was not sufficient.

The KPSC agreed with the jurisdictional electric utilities on this matter and found that a single statewide interconnection standard should not be adopted.

Chapter 3 - Meetings with Stakeholders

Process and Scope of Meetings

In its request for proposals, the Commission identified that: "the consultant will be expected to discuss these issues with Kentucky's six jurisdictional generating utilities, the Office of the Attorney General ("AG"), low income advocacy groups, environmental organizations, economic development representatives and appropriate industry representatives."

The Commission Staff developed a list of parties having a potential interest in this proceeding. The parties were identified by a review of participants in recent cases, or entities whose names were identified by the various issues that are being investigated in this proceeding. The parties were then contacted, and those indicating an interest in an interview meeting were scheduled and accommodated.

Over a period of eight days in December 2007, Overland met with representatives of the six regulated electric generating utilities, the Commission Staff, and twenty organizations representing various interests relevant to Kentucky energy policy, rates and regulation. These interviews were conducted on an informal basis, with the understanding that the purpose of the discussions was to gain an understanding of the various participants' views on matters within the scope of the Overland analysis.

The comments contained in this chapter are intended to indicate the subjects raised by the various stakeholder interests in these proceedings. This narrative is not intended to reflect a complete summary of all points raised by all parties. Further, it is not our intent to represent the formal positions of any parties; but rather to reflect our understanding of the opinions and concerns informally expressed during these discussions.

Interview Participants

Overland, with representatives of the Commission Staff, met with the following stakeholders:

Big Rivers Electric Corporation
Coal Operators and Associates
Duke Energy of Kentucky
East Kentucky Power Cooperative
Governor's Office of Energy Policy
Kentuckians for the Commonwealth
Kentucky Association for Community Action
Kentucky Association of Manufacturers
Kentucky Attorney General, Office of Rate Intervention
Kentucky Coal Association
Kentucky Industrial Utility Customers
Kentucky Power Company (AEP)
Kentucky Resources Council
Kentucky Solar Energy Partnership
Kentucky Utilities (E.ON)

Legal Aid Society
Louisville Gas & Electric (E.ON)
Louisville Cleanenergy
Louisville Climate Action Network
Metro Human Needs Alliance
Municipal Electric Power Association of Kentucky (MEPAK)
People Organized and Working for Energy Reform (POWER)
Sierra Club
Soft Energy Associates
Sunbelievable Services
West Kentucky Coal Association

Overview of Non-Utility Comments

Low Income Groups

Organizations representing low-income energy users are primarily concerned with continued access to affordable utility service. If there are opportunities for DSM or energy efficiency programs to benefit low-income customers, they should be able to participate. However, any cost impacts that might raise energy bills for this customer group should be highly restricted, if allowed at all.

Kentucky Coal Interest Groups

The implementation of "Section 50" will have no impact on coal production within the state. Coal can be exported to other states or countries, should coal fired generation be materially altered by changes in state energy policy.

Environmental Groups

Members of the represented groups believe that there are major barriers to energy efficiency in current rate structures, energy efficiency (EE)/DSM programs as currently defined, and in current standards and requirements for net metering. Incentives for renewables projects are not adequate. They support a deliberate transition from coal generation to renewable energy alternatives.

Municipal Electric Power Association of Kentucky

Municipals are committed to energy efficiency EE and DSM programs, and believe that greater program development and participation can be achieved in Kentucky. They believe that consumers are willing to pay for greener power, if regulations are implemented by the General Assembly. Though not regulated by the Commission, MEPAK is interested in participating in energy efficiency and diversification programs.

Manufacturing; Industrial Groups

Kentucky is a low-cost energy state. Large energy customers are sensitive to energy supply costs in Kentucky relative to other locations. Potential increases in rates, unless such costs are consistently reflected in energy prices in other states (or countries), may adversely affect the economic advantage that currently exists in Kentucky for its large industrial customers.

Attorney General (AG)

Office of Rate Intervention. The AG views its primary role as a participant in Commission proceedings representing and protecting residential and low-income consumers. The AG supports cost-effective DSM and EE programs. It intends to actively scrutinize proposed programs that come before the Commission in future proceedings.

Governor's Office of Energy Policy (GOEP)

The objectives of this office are to promote the efficient use of Kentucky resources; to keep energy costs low; and to protect the environment. Due to lack of coordination with the TVA and municipals, in addition to other constraints, the GOEP did not believe that statewide planning was feasible at this time. DSM programs have been limited due to low energy costs and, at least to some extent, a lack of adequate incentives for utilities to pursue these programs more aggressively. The GOEP does not support recognition of external factors in full-cost accounting, as it would violate one or more of its stated policy objectives.

Third Party Vendors

Representatives of these groups expressed concern that potential renewables projects were not being fairly considered by utilities, given their pricing requirements in negotiations.[30] The existing coal subsidies and legislative support provided to the coal industry further inhibits consideration and implementation of alternative energy projects.

Kentucky Public Service Commission Staff (Staff)

Staff believes that the primary purpose of the IRP process has been and continues to be accomplished – the Commission and interested stakeholders now have a more complete understanding of the resource planning process of the generating utilities under its jurisdiction.

There were a number of points that all parties seemed to agree upon. These included:

- The parties generally concurred that the Commission had broad regulatory authority and powers in its oversight of jurisdictional utilities.

- While the various stakeholders may have differing positions on the implementation of various energy policies and programs, there was a general consensus that any new energy initiatives must be considered in light of potential consequences on customer rates.

- The parties recognized that the Commission does not have the authority to direct utilities to adopt specific renewables projects, or to set a Renewables Portfolio Standard (RPS) target.

---

30 Utilities allegedly recognized no capacity component in proposed prices; and energy costs were quoted in the range of $0.01 to $0.025 per kWh.

Utility Industry Comments:

KPC (AEP)

AEP has a "Climate Strategy" in place that includes participation in the FutureGen Alliance project; and membership in the Chicago Climate Exchange. AEP is committed to green house gas (GHG) reduction through: renewables (biomass co-firing, wind); supply and demand side efficiency; off-system reductions and market credits (forestry, methane, etc.); and commercial solutions of new generation (IGCC, ultra supercritical (USC), FutureGen and carbon capture & storage technologies.

AEP currently has a "Green Energy" tariff in Ohio, but has not introduced one in Kentucky yet.

Duke Kentucky[31]

Duke Energy has recently developed a "Save-A-Watt" program that is designed to develop energy efficiency in lieu of traditional supply side resources. The proposal creates utility incentives to develop and administer these programs, at its risk, based on rate recognition of avoided generating plant costs. Importantly, Duke Energy's proposal represents a new business paradigm in that it shifts participation and efficiency risk from the customer to the utility. This program is now pending review in North Carolina and Indiana.

EE and DSM programs currently have, on average, a participation rate of about 20%. However, under Duke Energy's proposed program, EE and DSM would become an integral part of the customer standard offer tariffs.

Duke Kentucky mentioned that some of its commercial and industrial DSM programs have been fully subscribed, due to imposed budget constraints, within a period of weeks. Under current procedures, the Commission approves a budget for the following year DSM expenditure levels.

Duke Indiana currently has an RFP outstanding in Indiana for 100 MW of renewables. Indiana has approved construction of a 600 MW IGCC unit at an estimated cost of approximately $2 billion, excluding sequestration.

East Kentucky

East Kentucky operates within a public power business model, where its customers and owners are the same. As a result, East Kentucky views DSM and EE program opportunities on a basis equivalent to its power supply options.

Big Rivers

Big Rivers views conservation as its cheapest resource alternative, as it represents utilization within existing, cost-effective capacity. Big Rivers currently has a 50 MW biomass project at a paper mill, which may be expanded.[32]

---

[31] Duke Energy refers to the parent company, utility system.

Big Rivers mentioned that a National Renewables Cooperative is currently in a preliminary stage of development. Solicitation of member support is expected to commence in the first quarter 2008.[33]

LG&E/KU (E.ON)

E.ON is a participant in the FutureGen project. The Company issued an RFP in July 2007 for 750 MW of renewables. E.ON has proposed to triple its DSM/EE program commitments over current levels. This includes funding for third party education programs.

E.ON provides carbon output statistics on its customer bills.

E.ON hosts an "Energy Efficiency Advisory Group" for input on its EE/DSM programs.

E.ON allows DSM to compete directly with supply side resources in its utility IRP.

LG&E is just beginning a three-year "Smart Metering" pilot program. Options will include critical peak pricing, load control, and TOU. It will be a rewards-only program, no penalties. There will be an in-home display of energy consumption and costs. Customers will pay $5 per month to participate in the program. The program costs will be approximately $1.9 million over three years.

At present, approximately 100,000 customers are on the E.ON utility's load control program, which saves over 100 MW of demand.

The Company referenced its proposal in Case No. 2005-00090 to limit the risk of disallowances for capital expenditures associated with projects approved in CPCN cases.

Major Themes Arising from Various Stakeholder Interests

Low-Income Group

Views about the IRP process:

- Many low-income stakeholders believe that the Commission does not have enough authority over the current process.

Views about current EE/DSM programs:

- Current programs offered and participation in such programs are minimal. There is a lot of potential in the state.
- Technologies to reduce consumption and/or reduce peak load such as programmable thermostats or load control devices would be useful in reducing

32 Big Rivers Response to Discovery, DR 02-33.

33 Big Rivers Response to Discovery, DR 02-15.

consumption. Low-income customers have a high incentive to reduce costs. However, lack of education about energy programs is a major barrier to participation.

- Utilities face an inherent conflict in developing DSM and energy efficiency programs, when their core business is based on selling energy.

- The current DSM application process before the Commission should be accelerated.

<u>Views about portfolio diversification:</u>

- The implementation of renewables is inhibited by low avoided costs calculated by the utilities, with little or no recognition of capacity costs. As a result, IPPs cannot justify development of renewables projects.

<u>Views about alternative rate structures; rates and regulation:</u>

- There is a willingness to support a "public good" or energy efficiency surcharge; especially if funds are used for energy programs, not just R&D.

- The KPSC has done a good job in balancing the interests of all stakeholder concerns.

Environmental Groups

<u>Views about the IRP process:</u>

- The IRP process is flawed, and as a result, the planning and approval process is not adequate. Statewide planning should be considered.

- A more formal process should be adopted. They would like to see recognition of societal costs in cost-benefit analyses of options.

- Standardized models should be employed in cost-benefit analyses.

<u>Views about current EE/DSM programs:</u>

- These groups support subsidies such as a Kentucky sales tax to support further investment in DSM and renewables projects. They would like to see the utilities provide funding for the facilities costs of customer-based programs.

- Current education of consumers about EE/DSM programs is not adequate. Customers do not fully understand the value of conservation. The KPSC should be more active in supporting education and public information needs.

- Industrial customers are allowed to opt out of DSM participation without demonstrating that they have implemented EE measures.

- Programs that simply encourage load shifting rather than reduce consumption should not qualify as DSM.

<u>Views about portfolio diversification:</u>

- There is a divergence in how each utility implements net metering services, and this has created obstacles for the development of distributed generation (DG) initiatives, such as solar panels.

- Except for biomass, the capacity for large-scale renewables in the state is quite limited.

- These groups are opposed to development of coal gasification, as sequestration has not been proven in Kentucky. Specifically, funds should no longer be put into R&D for new coal technologies.

- Renewables and DG projects could be supported by utility funding, and the investments would be includable in rate base.

<u>Views about alternative rate structures; rates and regulation:</u>

- Funding for expanded DSM/EE programs should come from a "clean energy fund" or a redistribution of existing coal industry subsidies.

- Energy initiatives should take rate impacts into consideration.

Attorney General's Office

<u>Views about current EE/DSM programs:</u>

- DSM/EE programs need to be cost-effective. Screening models should be standardized and consistently applied.

<u>Views about portfolio diversification:</u>

- The development of large-scale renewables is not currently economically feasible. However, a potential does exist for distributed renewables projects.

Governor's Office of Energy Policy

<u>Views about the IRP process:</u>

- Statewide planning is not practical due to lack of coordination with unregulated interests and the multi-state structure of various utilities operating in Kentucky.

<u>Views about current EE/DSM programs:</u>

- The industrial opt-out provision in the DSM surcharge is deficient, as it leads to selective regulation of manufacturers.

<u>Views about full-cost accounting:</u>

- Not aware of any state commission that currently prices "externalities".

- The role of the KPSC is to review projects that meet standards that protect public health and are in compliance with current regulations.

Manufacturers/Industrial Groups

Views about current EE/DSM programs:

- DSM programs have not materially developed in Kentucky due to low energy rates and a general lack of support by stakeholders involved in the process.

Views about portfolio diversification:

- Wind opportunities in the state are limited. Big Black Mountain is an optimal site, but cannot be used due to environmental issues.
- DG projects may be feasible, but not implemented to date.
- Biomass is a realistic option for Kentucky, based on available resources within the state.

Views about full-cost accounting:

- Only actual costs should be recognized in cost-benefit analyses.
- Utilities should take compliance costs into account once regulations are known. However, regulators should track potential carbon impacts, and customers should be made aware of carbon consumption and the possibility of future impacts on energy costs.
- Carbon costs should be taken into account in current planning for future resource needs, not rates.
- If new technologies are to be considered, the increased risks of such projects must be addressed by statutory support for generators.

Views about alternative rate structures; rates and regulation:

- Low rates in Kentucky are not an accident, but the result of careful management by the state legislature and the KPSC not to over-extend obligations on utilities to the detriment of ratepayers.
- Interruptible tariffs are currently included in utility service offerings. However, the current economic incentives are not sufficient to induce much interest among large industrial users.

Third Party Vendors

Views about portfolio diversification:

- Renewables projects are currently constrained due to unrealistic utility assumptions regarding avoided energy costs, and lack of any recognition of avoided capacity costs.
- Current coal industry subsidies and statutory preferences are an obvious impediment to the economic development of renewables in the state.
- There is a large potential for renewables in Kentucky based upon the amount of agricultural resources and unused landfill sites in the state.

KPSC Staff

Views about the IRP process:

- Prior to its inception, a more formal IRP process was considered. The Staff is generally satisfied with the current process.
- CPCN applications are reviewed for consistency with utility IRP filings.
- A more formal IRP process would put a significant additional burden on Commission resources.

Views about current EE/DSM programs:

- The Staff does not believe that the Commission has authority to require utilities to use particular tests or make specific assumptions in their application of screening models. However, utilities do cooperate in running alternate cases, as requested. The Commission is not obligated to accept the utility tests or results, as filed.

Views about portfolio diversification:

- In determining utility "net metering" offerings, system reliability and safety concerns are important and legitimate elements of utility policies and practices. The Commission has not received any formal complaints to date regarding these offerings.

Views about full-cost accounting:

- It has been the stated position of the Commission that it lacks authority to require consideration of externalities,[34] including environmental and health care costs. The Staff has no reason to believe that this position has changed since the release of the infrastructure report in 2005.

---

[34] Kentucky's Electric Infrastructure: Present and Future, dated August 22, 2005; p. 50.

<u>Views about alternative rate structures; rates and regulation:</u>

- The Staff believes that it is within the Commission's jurisdiction to create an "energy efficiency" surcharge to enhance available funding for energy efficiency and DSM programs within the context of the current DSM statute.

Regulated Generating Utilities

<u>Views about the IRP process:</u>

- The current process works well and should be maintained. The CPCN process is a more formal proceeding that assures proposed projects are in the public interest and are consistent with IRP. To further formalize the IRP process would be redundant in light of the CPCN requirements.

<u>Views about current EE/DSM programs:</u>

- The DSM surcharge and associated process generally work well, but should be modified to include capital expenditures such as "intelligent" metering devices.
- Utilities generally have an active residential "collaborative" or equivalent meeting process to discuss EE/DSM programs. There is currently less interest in commercial programs, and little interest at all among industrial customers.
- Regardless of the incentives implemented to expand DSM opportunities, these programs must continue to be economic and cost-effective. Incentives for utilities must be at least equivalent to supply-side investment. Customers must also be educated and incented to participate in programs.
- An important element of DSM/EE program participation is customer awareness. This must be developed through education programs and advertising. However, advertising costs currently allowed in rates are narrowly defined and highly restricted.

<u>Views about portfolio diversification:</u>

- An RPS is generally opposed by the utilities. Other incentives such as federal tax credits or incremental returns are preferred.

<u>Views about full-cost accounting:</u>

- Utilities currently consider potential carbon cost implications in planning models.
- Externalities are not, and should not, be employed in the IRP process. Quantification is highly speculative, which could lead to improper planning choices and unnecessary and inappropriate increases in customer rates.

Views about alternative rate structures; rates and regulation:

- Time-of-use (TOU) rates have only been implemented on a limited basis. TOU, interruptible and real-time rates should be expanded.

- To date, industrial interruptible rates have not attracted much interest, as economic incentives are not sufficient to tolerate interruptions.

- Utilities are willing to consider support for a "System Benefits" surcharge that is administered by utilities in support of new technologies; and approved DSM and energy efficiency programs.

Major Points Raised by Stakeholders

Scope of Commission Authority to Implement Policies Associated with Section 50

Most stakeholders believe that the Commission has broad powers given to it by existing statutory authority approved by the Kentucky legislature. The consensus is that these powers extend to the potential expansion of DSM programs; changes in customer rate design and rate structures; the implementation of new surcharges associated with energy programs related to Section 50; and the consideration of external costs in the IRP and CPCN processes. However, representatives of the manufacturing and industrial groups tended to view the KPSC authority more narrowly. Attorneys representing the AG's office believed that the Commission's authority is confined to only explicit guidelines established by applicable statutes.

Statewide IRP

While a number of parties expressed an interest in statewide planning, it was also recognized that it was somewhat impractical for several reasons. Most Kentucky utilities are subsidiaries of multi-state utility holding companies. A major component of Kentucky electric energy is provided by entities that are not subject to KPSC regulation. The inherent lag from utility planning to statewide IRP diminishes its value. And finally, current Commission Staff resources are not adequate to coordinate the additional burden that a statewide planning process would impose.

Recognition of DSM & EE in IRP Analyses

Utilities do not necessarily allow EE and DSM programs to compete directly against supply options. To date, the utilities stated that this has been primarily due to the lack of scale associated with these programs. That is, the level of demand reduction has not been sufficient to delay the addition of a base load coal unit, which is typically sized in 600 to 800 MW increments.

Consideration of Avoided Costs

Kentucky utilities currently recognize an avoided cost of energy of about 2.5 cents/KWh, which may be an understatement of such costs. In consideration of renewables projects with third-party vendors, no consideration is given to the avoided cost of capacity.

Greenhouse Gas Emissions

There is a consensus among all parties that federal legislation will soon be adopted to reduce carbon emissions. This legislation is expected to set standards to reduce emissions from current levels, and to impose costs (carbon taxes or cap-and-trade) on future electric generation from fossil fuels in excess of stated caps.

Utilities' Incentives to Support Energy Efficiency Programs

Stakeholders understand that the current utility business model is driven by investment in plant and the sale of energy to generate shareholder earnings. In principle, these groups support the idea of providing incentives sufficient to induce utilities to focus capital and workforce resources on the development and expansion of economic EE/DSM and renewable resources.

Regulatory and Judicial Uncertainty

Utilities face financial and operating risks as they respond to changes in energy policy and utility regulation. An explicit statement of intended delegation of powers to the KPSC by the legislature will reduce these risks. Further, Kentucky utilities currently face a burdensome appellate review process as provided in KRS 278.410 "Action to review order of commission", and KRS 278.450 "Judgment of Circuit Court – Appeal to Court of Appeals".

Adequacy of Transmission System

The transmission system is generally adequate to meet load flows within the state for intrastate customer needs.

On-Going Involvement of Stakeholders[35]

A number of recommendations have been identified that would bring about actions associated with various elements of energy planning, as addressed in this report. These recommendations, in many instances, will require further development and refinement. Based upon the participation of stakeholders in the interviews addressed in this chapter, it is clear that there is a high interest, across various stakeholder organizations, in the development of programs, practices and policies that may arise from Section 50 of HB 1. In its report to the Legislative Research Commission (LRC), the Commission may choose to propose our recommendations, in whole or in part; or it may develop other recommendations that result from the broader record created in this proceeding. In any event, it is possible that there will be revisions to statutes and regulations, as well as changes in policies and procedures based on KPSC initiatives, which relate to various elements of energy planning and generation investment.

[35] See also related discussion and recommendation in Chapter 4, "Coordination with Stakeholders".

<u>Recommendation:</u> **In order to properly consider and develop policies, practices and programs adopted by the Commission from recommendations contained in this report, input from non-utility stakeholders, as well as the utilities should be solicited. This input may be developed from workshops sponsored by the Commission Staff, or more formal proceedings, as the Commission deems appropriate.**

[This page intentionally left blank.]

Chapter 4 – Current Energy Planning and Programs, Analysis and Recommendations Demand Side Management

This chapter reviews the status of demand side management (DSM) planning and current programs. We address DSM issues associated with Section 50, Item 1 of the Energy Act:

> Eliminating impediments to the consideration and adoption by utilities of cost-effective demand-side management strategies for addressing future demand prior to Commission consideration of any proposal for increasing capacity . . .

Information about industry practices with respect to DSM is contained in Appendix D of this report.

Defining DSM

As the name implies, demand side management involves activities that reduce peak demand or overall energy consumption (energy efficiency) in the electricity sector. Although the idea of conservation has been around for decades, the concept of a formal utility DSM initiative was borne in the U.S. in the mid 1970s, in response to the 1973 and 1979 energy crises, and the rising concern about exhaustion of fuel supply and independence from foreign supply. Demand side management is pursued by utilities because of the expected long-term benefits of avoided energy costs from reduced consumption. Conventionally, DSM has also included demand shifting activities, which shift on-peak demand to off-peak periods. It is possible that demand shifting activities will not decrease total energy consumption, but they may, nevertheless, reduce or delay the need for additional network and generation investments. The statutory definition of "demand-side management" under KRS 278.010 does not preclude demand-shifting. Notably, however, this chapter of the Kentucky statutes only applies to public utilities. There is currently no formal statutory approval of third-party, commercial DSM programs.

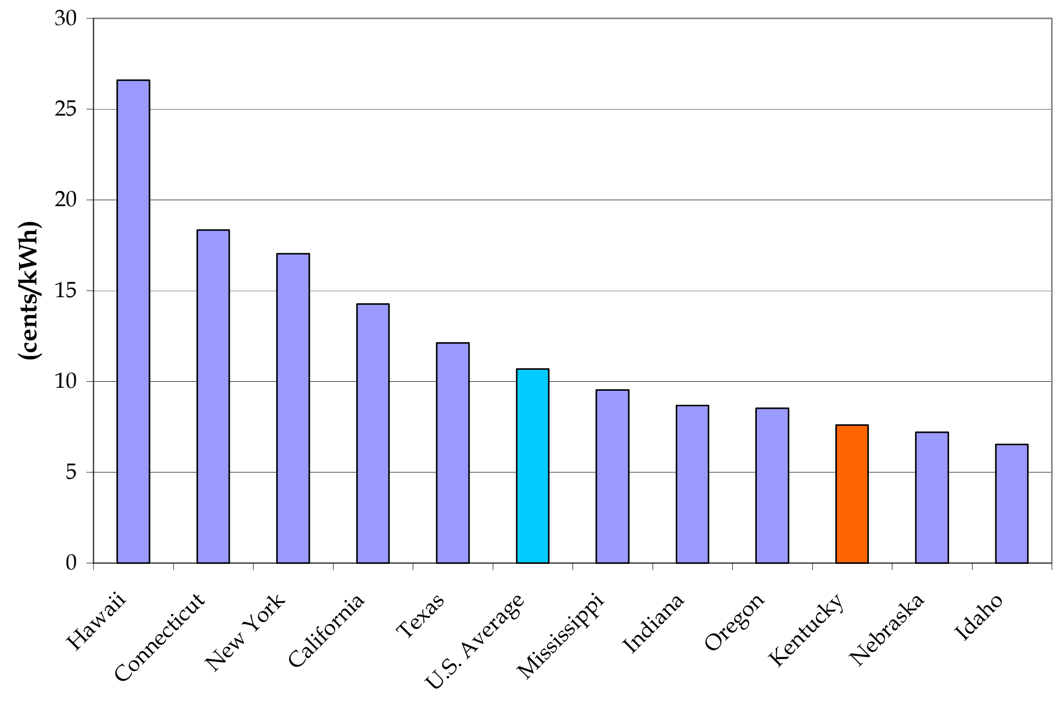
History of DSM in Kentucky

One of the first DSM programs in Kentucky was implemented in 1995, when the KPSC approved an application filed by KPC.[36] However, DSM programs have generally not been as successful in Kentucky as other jurisdictions. The relatively low cost of electricity in the state reduces consumer motivation to conserve. As seen in the following figure, retail residential rates in Kentucky are among the lowest in the nation. In fact, there were only 6 states whose residents paid less per kWh of electricity in November of 2007. The national average was 10.69 cents/kWh, while in Kentucky, the residential rate was 7.60 cents/kWh.

---

[36] LG&E actually filed a DSM program in 1993 before the enactment of the DSM statute (Case No. 93-00150).

Figure 4-1. Average Residential Electricity Rates in Kentucky versus a Sample of Other States



Sample of states; Source: EIA, Table 5.6.A

Current DSM Programs in Kentucky

The Kentucky General Assembly passed legislation in 1994 authorizing surcharges by the state's utilities to recover their costs of implementing DSM programs. DSM plans and cost recovery mechanisms have since been approved for the investor-owned utilities (KPC, LG&E, KU and Duke Kentucky). While the cooperatives, Big Rivers and East Kentucky, have not submitted applications for approval of DSM surcharges, they and their member distribution cooperatives have implemented several DSM programs.

This section summarizes current initiatives in Kentucky. Additional information is contained in Appendix E of this report

Overview of Current Programs

The DSM programs implemented thus far in Kentucky can be broadly grouped into the following four categories:

- energy audits (analyses of energy use patterns; identification of opportunities to save electricity or reduce energy bills; etc.);
- promotion of energy efficient products (home appliances; heating, ventilating, and air conditioning (HVAC) equipment; motors used in manufacturing processes; etc.);
- load management programs (remote control of HVAC equipment; heat pumps; time-of-use tariffs; etc.); and

- financial incentives and financing programs for implementing DSM measures.

Figure 4-2 presents the current DSM programs for the investor-owned utilities. While the names vary, the programs share similar traits across the utilities.

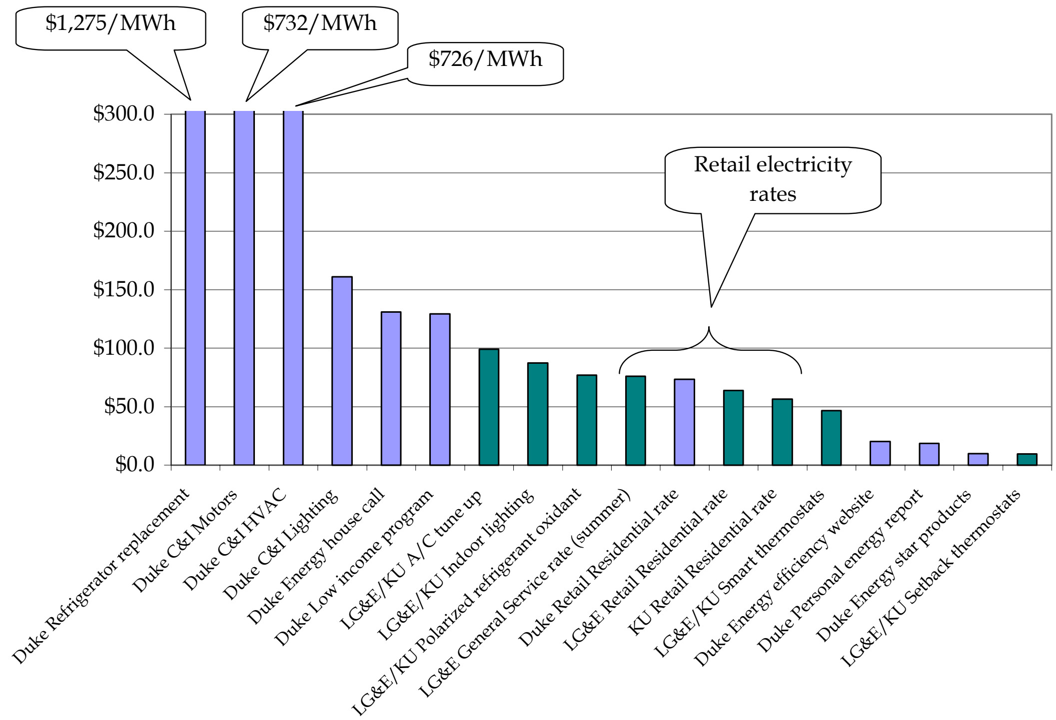
Figure 4-2. Current DSM Programs in Kentucky[37]

<table>
<tr><th>Company</th><th>Customer class</th><th>Programs</th></tr>
<tr><td rowspan="2">AEP (Kentucky Power Company)</td><td>Residential</td><td>Energy Fitness
Targeted Energy Efficiency
Compact Fluorescent Lamps
High-efficiency Heat Pump
Mobile Home New Construction
Modified Energy Fitness</td></tr>
<tr><td>Commercial</td><td>Smart Audits
Smart Financing - Existing Buildings
Smart Financing - New Buildings</td></tr>
<tr><td rowspan="2">Duke Energy Kentucky</td><td>Residential</td><td>Home Energy House Call
Energy Efficiency Website
Energy Star Products
Low Income Program
Refrigerator Replacement
Personalized Energy Report
Power Manager</td></tr>
<tr><td>C&I</td><td>C&I Lighting
C&I HVAC
C&I Motors
Power Share</td></tr>
<tr><td>E.On (Kentucky Utilities, Louisville Gas and Electric)</td><td></td><td>Residential Conservation
Load Management - Res and Comm
Residential Low Income Weatherization
Commercial Conservation</td></tr>
</table>

Figure 4-3 presents average annual DSM program costs for Kentucky utilities and compares them to retail electricity rates in the state.

[37] See Appendix E for more detailed information about DSM programs in Kentucky.

Figure 4-3. Sample DSM Costs versus Retail Prices



Source: DSM costs are calculated from information provided in filings to the KPSC (LG&E/KU – IRP 2005, pp. 8-88 and 8-89, Duke – 2007 DSM filing p. 6 and Appendix J), retail electricity rates as reported on respective websites of the utilities.

Note: Bars in blue are for rates and costs of Duke Kentucky and in green are for LG&E/KU

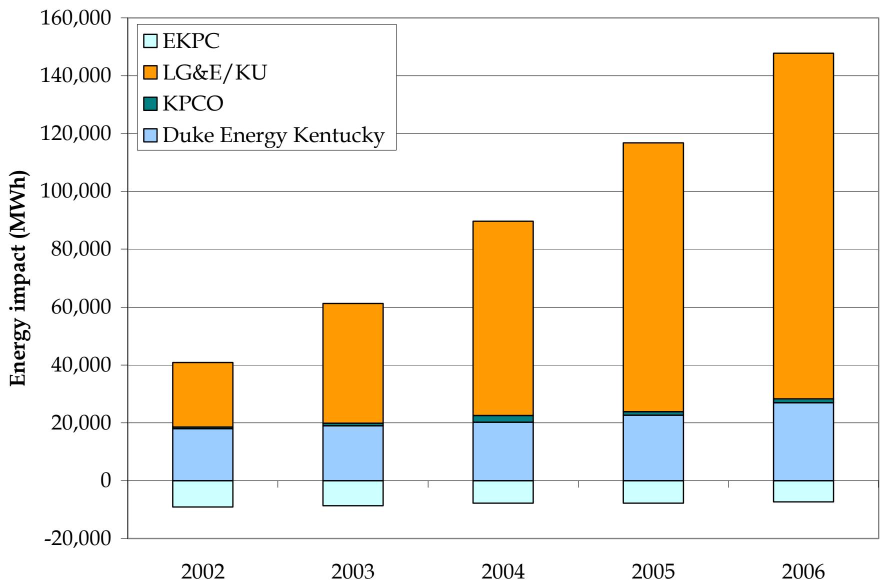
The comparison of DSM program costs to the costs of power can be viewed as a rough metric of program benefits, since a major component of the benefits of DSM is the avoided cost of energy. At the same time, it is important to note that energy cost savings alone do not fully reflect the potential benefits of DSM.[38] It has been widely recognized that DSM initiatives reduce capacity costs by delaying investment in generation and transmission infrastructure and improve reliability by reducing the system reserve requirement (DSM, unlike new generation, does not contribute to additional reserve requirements). DSM also contributes to reduced transmission and distribution losses. However, such additional benefits have generally not been explicitly recognized in the DSM proposals made by utilities in their DSM filings in Kentucky.

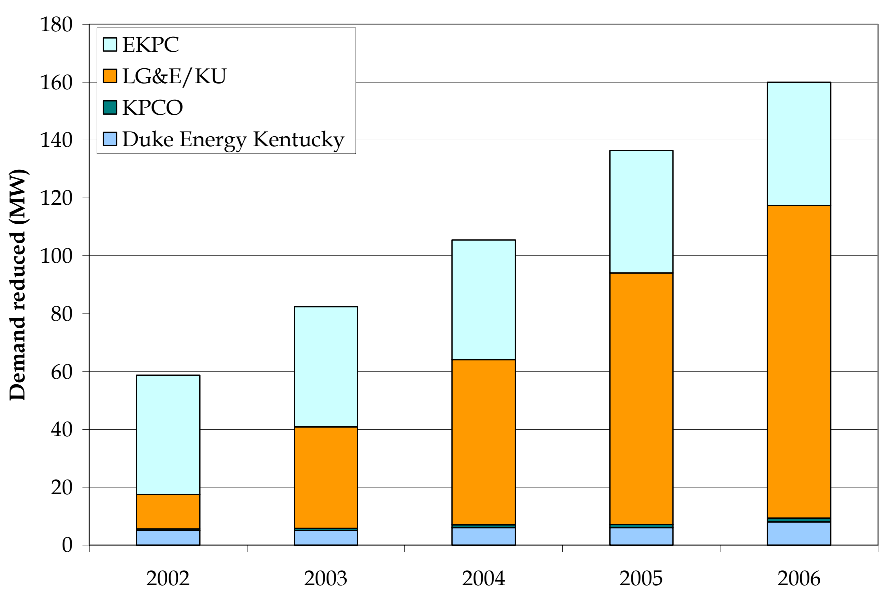
[38] Some DSM programs may be estimated to be more cost efficient than the cost of energy, but they are typically limited in scope and the amount of energy that can be saved. See appendix D for examples.

Effectiveness of Current Programs

As displayed in Figure 4-4, the combined savings for the jurisdictional utilities[39] in 2006 are estimated to be almost 144,000 MWh and 160 MW of displaced peak demand.

Figure 4-4. DSM Results for 2002-2006 Reporting Period for Kentucky's Investor-Owned Utilities and East Kentucky





Source: KPC - Response to discovery, DR-02-15;Duke Kentucky - EIA, Form 861; KU/LG&E - Response to discovery, DR-02-13; East Kentucky – Response to discovery, DR-02-19.
Note: Demand reduced is not coincident. East Kentucky reported that the net effect of DSM programs was an increase in energy consumption on an annual basis.

---

[39] Except Big Rivers, which does not measure the effect of DSM programs implemented by its members.

These are the estimated energy savings as reported by the utilities after taking into account implementation data and limited measurement and verification processes. Unfortunately, there is not enough information – with respect to detailed cost data and estimated savings per program implemented (both in terms of energy saved and demand reduction achieved) - to conduct a comprehensive analysis of the historical effectiveness of the DSM programs.[40] Detailed analysis is also hampered by the absence of uniform reporting requirements for the content, scope, depth and timeframe of reports.[41]

Future Potential

Future potential for DSM is a function of economic rather than technical issues. DSM programs are likely to become cost effective from the customers' perspective when utilities' costs of production rise, or utilities consider more explicitly the time-based nature of costs in providing transmission and distribution services.

Future potential for DSM is also linked to utility incentives and rate design. Several jurisdictional utilities have raised concerns that financial incentives are generally biased towards conventional supply-side resources because capital costs have historically not been reflected in DSM screening models and resulting rates. However, utilities have not requested or been granted returns on capital associated with DSM initiatives.

These issues notwithstanding, stakeholders have identified opportunities for additional DSM in Kentucky.

An Overview of Kentucky's Energy Consumption and Energy Efficiency Potential, a 2007 report by the Kentucky Pollution Prevention Center at the University of Louisville,[42] examines potential energy savings in Kentucky.[43] The main conclusion of the report is presented in the form of energy savings measured in British Thermal Units (Btu) from sources of energy, including natural gas, petroleum and electricity. Using the current estimate of the electric energy consumption of each category of users and the reference heat rate of 10,000 Btu/kWh, we have translated the report findings into electricity saved, over the 10-year period, expressed in MWh, as seen in the following figure

---

[40] Regulation of DSM programs is currently focused on the cost side, particularly reviews of budgeted versus actual expenditures. Comprehensive measurement and verification processes for comparing forecast versus actual savings are currently not required within the reporting process to the KPSC.

[41] Our review of the information provided in response to our requests for data and comparison of such information with data provided to the EIA (Form #861-Annual Electric Power Industry Report) revealed substantial inconsistencies between the two sets of data for all jurisdictional investor-owned utilities in Kentucky. For the discussion above, we have relied upon the information provided by the Kentucky utilities in response to our data requests.

[42] The report was supplied in response to Data Request #6, Dec 7, 2007 and is available on the website of the Governor's Office of Energy Policy (http://www.energy.ky.gov/dre3/efficiency)

[43] As with any targets developed by policy-makers, one would need to be cautious about how realistic they can be. Overland has made no independent analysis to verify the results of this report.

Figure 4-5. Cumulative Electricity Savings (MWh, 2008-2017)

	Minimally aggressive	Moderately aggressive
Residential	11,730,000	41,310,000
Commercial	7,560,000	33,480,000
Industrial	62,400,000	91,800,000
Total	**81,690,000**	**166,590,000**

Taking into account that the range of electricity savings in the figure above covers ten years, the annual average savings range from 8.169 million MWh to 16.659 million MWh. In comparison, Kentucky end-users consumed 98.8 million MWh in 2006. Historically, the Kentucky investor-owned utilities have reported to have saved slightly over 150,000 MWh in 2006 (see figure above). The above report findings suggest that approximately 8% of current annual electricity consumption can be saved over the next ten years, under minimally aggressive techniques; perhaps rising to as much as 16% under somewhat more moderately aggressive methods.

Kentucky utilities have not produced any comprehensive report(s) on the basic issue of DSM potential, with the exception of Big Rivers, who commissioned a report from GDS Associates looking at 2014-2015 levels of savings to be achieved in its service area. The maximum achievable cost effective electric energy efficiency potential in the Big Rivers' service area is presented in Figure 4-6. It is generally consistent with the overall conclusions of the Kentucky Pollution Prevention Center report.

Figure 4-6. 2015 Energy Savings Estimates for Big Rivers' Service Area

Customer class	kWh savings in 2015	Sales forecast for 2015	energy savings as % of sales forecast
Residential	277,744,782	1,780,266,000	15.6%
Commercial and small industria	85,475,300	854,753,000	10.0%
Large industrial	99,758,000	1,159,630,000	8.6%
Total	**462,978,082**	**3,794,649,000**	**12.2%**

Source: Maximum Achievable Cost Effective Potential for Electric Energy Efficiency in the Service Territory of the Big Rivers Electric Corporation, GDS Associates, 2005.

It is notable that some utilities are actively pursuing new DSM programs in the state. E.ON (through its Kentucky jurisdictional utilities) is currently in the application process for expanded funding of DSM, seeking $26 million in annual DSM surcharges, an increase of $16.4 million[44] over current funding. E.ON's application to the Commission projects that this funding will create savings of 303 MW on peak and over 800,000 MWh per annum by 2014.[45] This results in an estimated average program cost of less than $21 per MWh saved per annum.

[44] LG&E - $ 4 million under Case #2004-00488, Kentucky Utilities - $4.6 million under Case #2005-00517.

[45] LG&E/KU Joint Application (Case #2007-00319), p. 9. A Commission decision is now pending.

Duke Energy also expressed interest in targeting additional DSM in Kentucky, based on our interview discussions in December 2007, but Duke Energy would like to receive higher financial incentives, in accordance with its "Save a Watt" model.[46]

DSM Model Assumptions and Screening Tools Relied Upon

Evaluation and screening of potential DSM programs is performed primarily as part of the IRP process. The DSM applications and status reports provide detailed cost analysis and proposed rate surcharges to recover such costs. The internal company cost analysis is typically done in collaboratives (organized by customer classes).

The load forecasting and supply side development analyses within each utility's IRP includes DSM programs and projects. However, not all utilities follow the same format in the evaluation and screening of their DSM programs (e.g., Big Rivers looks at DSM options as a separate exercise and presents the findings in its IRP, while the other five jurisdictional utilities use a two-step process).

California Standard Practice Manual: economic analysis of demand-side programs and projects

First edition released in 1983, latest revision dates to 2002.
Considers four tests:
- ratepayer impact measure test;
- participant test;
- total resource cost test; and
- program administrator test.

The tests are based on a calculation of Net Present Value of impacts.

All the jurisidcitonal utilities in Kentucky employ the California Standard Practice Manual for Economic Analysis of Demand Side Programs[47] (California SPM) in evaluating the direct costs and benefits of DSM programs (see insert), employing four sets of tests as criteria for determining the cost-effectiveness of proposed programs. The California SPM, at least in one instance, has been criticized in recent years, on the basis that the tests have a tendency to overstate the costs and undervalue the benefits of programs.[48]

Figure 4-7 summarizes the DSM screening processes employed by utilities in preparing their IRPs.

---

[46] Duke North Carolina is currently applying to the North Carolina state commission for regulatory approval of its "Save a Watt" model A description of the model is provided in Appendix D.

[47] California Public Utilities Commission and California Energy Commission, Document #P400-87-006, December 1987.

[48] Levy, Roger. *Briefing Paper: Problems with the Standard Practice Methodology*, California Energy Commission, 2003.

Figure 4-7. DSM Screening Processes

Utility	DSM screening process	DSM screening model	Criteria applied for DSM evaluation
Duke Energy Kentucky	2 stage screening	N/A	California Manual for DSM
East Kentucky Power Coop	2 stages: qualitative and quantitative	EPRI DSManager	California Manual for DSM
Big Rivers Coop	separate from IRP	N/A	California Manual for DSM
KU/LG&E	2 stages: qualitative and quantitative	EPRI DSManager	California Manual for DSM
Kentucky Power	2 stage screening	in-house model	California Manual for DSM

N/A signifies "Not Available" because we were not able to determine definitively the process, model, or criteria used from the most recent IRP and DSM filings.

Sources: Most recent IRP and DSM filings. Details on the screening process at Duke Kentucky are based on information provided by the KPSC.

Duke Kentucky

Duke Kentucky's IRP distinguishes between three types of DSM programs: traditional regulated, customer-specific contract options and innovative pricing programs. The latter two programs are variations of pricing programs in which customers are given the opportunity to reduce their load for a financial incentive, usually based on a market price. The company utilizes the NewEnergy Strategist software model to analyze the final integration process, which includes load forecasts, estimated impacts of DSM programs, supply-side resources, and estimated costs of environmental compliance.

East Kentucky

East Kentucky's 2006 IRP categorizes DSM programs as conservation, load management or other. The screening process employed during the planning analysis consists of a two-step evaluation: (i) qualitative screening and (ii) quantitative analysis. The comprehensive list of DSM programs is developed from multiple sources, which are screened using several qualitative criteria. Out of 93 programs in the initial list, 34 passed the qualitative screen in the 2006 IRP. The quantitative analysis utilizes the Electric Power Resource Institute (EPRI) DSManager software package. This software produces a quantitative estimate of the costs and benefits of each of the programs according to the California SPM. The tests performed are: participant cost; ratepayer impact measure; and total resource cost (TRC). A societal cost measure is treated as part of the TRC. The analysis involves not only evaluation of individual test results, but also comparisons of the trade-offs highlighted by the various tests. The quantitative analysis identified 18 programs that had acceptable levels of cost-efficiency in the 2006 IRP.

Big Rivers

Big Rivers contends that its avoided cost of generation capacity is zero because it procures most of its power under a long-term contract with energy-only pricing terms. The IRP process therefore does not combine analysis of supply-side and demand-side resources. DSM programs are not evaluated within the IRP process; instead, they are evaluated in stand-alone DSM studies.

E.ON (KU and LG&E)

The DSM program screening and evaluation process employed by KU/LG&E as part of its integrated resource planning is similar to the process employed by East Kentucky (i.e., a two-step analysis involving qualitative and quantitative analysis). The qualitative screening employs four criteria: customer acceptance, technical reliability, cost effectiveness of energy conservation, and cost effectiveness of peak demand reduction. DSM programs that pass the qualitative screening are fed into the DSManager software package, which analyzes the DSM programs according to the California SPM. The quantitative analysis proceeds in two stages. The first applies a simplified cost-benefit analysis, assuming no administrative costs and that each program has only one participant. The most appealing programs identified from this first stage are then analyzed with best estimates of penetration levels and administrative costs. Selected DSM measures then become part of supply-side and demand analyses performed, with the aid of the Strategist model to develop the IRP scenarios.

KPC (AEP)

KPC's IRP process includes a review and analysis to screen the DSM programs. The tests are based on the California SPM, and the analysis is performed with software developed in-house. Final analysis of the supply-side development and demand needs is performed with the aid of NewEnergy Associates' Promod model.

Evaluation Standards and Measurement Results

To date, the KPSC has not been prescriptive on screening models to be employed by the utilities in evaluating proposed programs, nor has the Commission asked to review program performance after the fact. At the same time, the utilities have raised concerns that the screening models may have a bias towards conventional generation.

Industry practice has evolved to recognize the shortcomings of traditional screening models, and utilities and system operators in other jurisdictions are increasingly attributing additional value drivers to DSM. In some jurisdictions, DSM is viewed as equivalent to generation resources and is evaluated as such in resource planning. Indeed, the FERC has recently proposed that demand response be treated as equivalent to supply-side resources in organized wholesale power markets.[49] Some system operators have also incorporated the avoided capacity reserve margin and avoided transmission losses into the benefit stream of DSM when comparing such resources against traditional supply-side resources.

State regulators have also started to recognize such additional attributes of DSM in their rate–setting processes, allowing for financial incentives that are tied to measures of benefits achieved. Furthermore, policymakers and regulators have demanded more accountability and performance monitoring of DSM programs, once implemented. Guidelines for measurement and verification ("M&V") have arisen (and are summarized in Appendix D. There appears to be very limited M&V currently in place in Kentucky.

---

[49] See http://www.ferc.gov/news/news-releases/2008/2008-1/02-21-08-E-1-factsheet.pdf

<u>Recommendation:</u> **The Commission should develop a set of standards for how to evaluate the benefits of proposed DSM programs. Such standards should broadly specify the range of benefits to be recognized and the appropriate analytical approaches for evaluating future benefits. The standards should recognize the variety of benefits created by DSM, while also acknowledging that DSM cannot be substituted for power plant development on an undifferentiated basis. The standards should require the development and application of screening models sophisticated enough to systematically compare and contrast the relative attractiveness of alternative DSM options in different settings.**[50]

<u>Recommendation:</u> **The Commission should develop or adopt recognized measurement and verification guidelines, so that actual results of DSM programs can be independently assessed and validated. In order to legitimize program continuation, DSM program benefits should be linked to measured and verified achievements, as much as practically possible.**[51]

Recognition of DSM in IRP – Load Reductions; Capacity Planning

The load forecasts relied upon in the IRP process do not take into account the effect of new DSM programs. We did not identify any instances in which utilities considered DSM programs to have had significant impact on capacity planning. There are likely two reasons for this. First, DSM programs are approved for periods significantly shorter than the length of the IRP planning horizon, thereby creating uncertainty about program implementation towards the end of the IRP planning period. Second, if there is not significant shifting in the timing of loads, peak demand reductions may not be as pronounced as reductions in total energy consumption.

Current Impediments to DSM Programs

There are three broad categories of DSM and energy efficiency impediments in Kentucky. First, the "opt-out" provisions of the current regulatory framework have hindered the development of DSM programs among industrial users, and have essentially kept a substantial portion of the electric consumption outside the utility-sponsored DSM activities.

Second, there seems to be an opportunity for more effort among the utilities and third parties to cooperate with relevant stakeholders in the implementation of DSM programs and activities. For instance, there should be opportunities to work with educational institutions, as well as non-governmental organizations (NGOs) and community organizations, in increasing the awareness of conservation and energy efficiency for residential and small commercial users. Such work would be instrumental in instilling "the culture of conservation", which had been identified in other jurisdictions.

Finally, there is potential for utilities to increase reliance on third party contractors in implementing the DSM programs and measures. Although utilities may be best placed to identify the opportunities for DSM work, the actual implementation often requires substantial human resources and specific sets of skills that are not central to most utilities. There are activities (such as fine tuning HVAC equipment, provision of energy audits, etc.) that can likely

---

50 See Appendix D for examples of standards.

51 See Appendix D for a discussion of specific guidelines.

be fulfilled effectively and cost-efficiently by outside contractors, whose credentials can be ascertained through state certification programs.

As previously addressed in Chapter 2, the DSM statute does not expressly authorize the Commission to direct utilities to implement particular programs on its own initiative or direction. However, to assure that its policy directives are being properly implemented, the Commission should have increased latitude in its exercise of oversight authority concerning utility DSM programs.

Recommendation: **The KPSC should consider the need to revise the DSM statute to expressly authorize the KPSC to act on its own initiative or direction to investigate and direct utilities to implement particular DSM programs, the cost of which would be recovered by the surcharge.**

DSM Industrial Opt-Out Provision

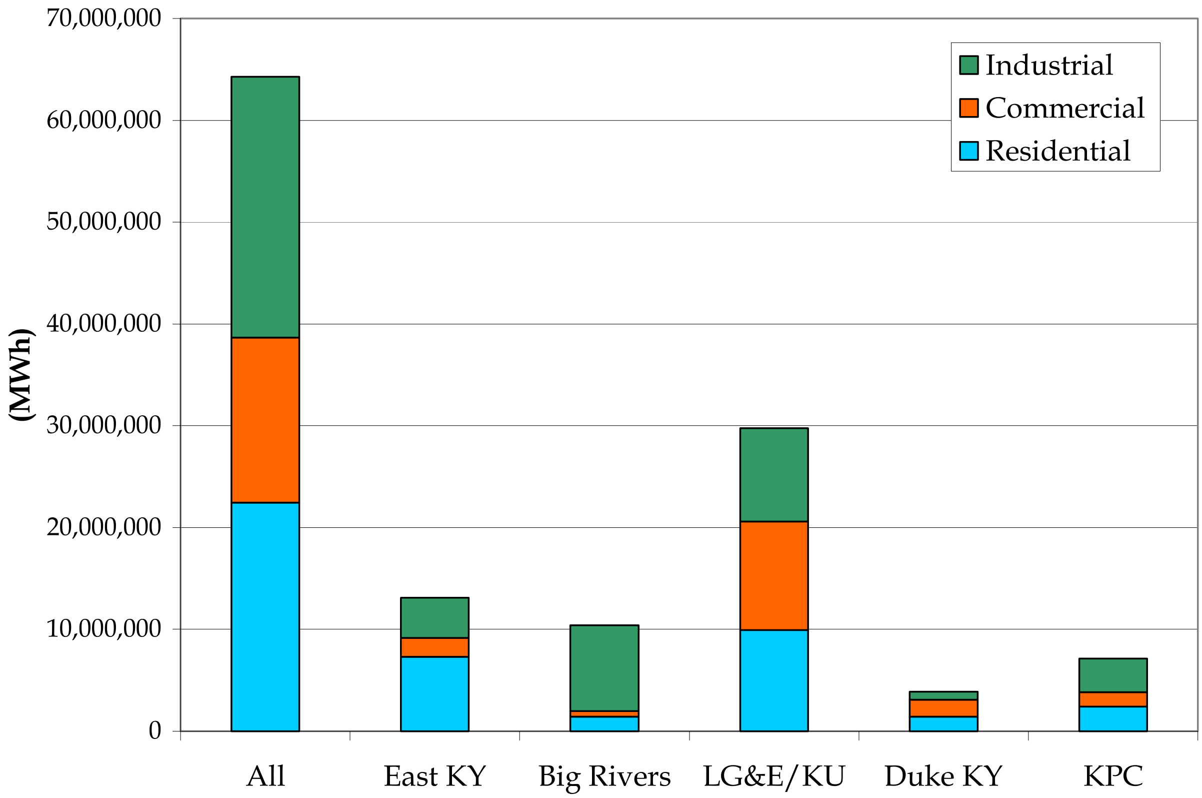
KRS 278.285 addresses the basis for participation and the operation of DSM programs. Item 3 provides:

> …The commission shall allow individual industrial customers with energy intensive processes to implement cost-effective energy efficiency measures in lieu of measures approved as part of the utility's demand-side management programs if the alternative measures by these customers are not subsidized by other customer classes. Such individual customers shall not be assigned the cost of demand-side management programs.

The opt-out was originally rationalized on the underlying presumption that industrial customers will already consider all energy efficiency enhancements so as to minimize their bill. In other words, it was believed that there were cost motivators already in place for these customers to implement potential cost efficiencies; and if funding from a DSM surcharge was imposed, that funding would likely go to those firms that are less efficient and have not taken any independent action to produce efficiency gains, effectively resulting in cross-subsidization. In practice, however, industrial customers have generally not been asked to show proof of their energy efficiency enhancements in exchange for exemption from paying the DSM surcharge. As a result, the extent of achieved energy efficiency improvements by the industrial and commercial sectors in Kentucky is unknown.

Almost all eligible industrial electricity users have opted out of utility-implemented DSM programs. Utilities have therefore stopped offering programs tailored to the needs of large industrial customers. As a result, approximately 40% of energy consumption by customers of jurisdictional utilities is effectively eliminated from the scope of utility-sponsored DSM programs, as seen in the following figure, which illustrates energy sales from the state's regulated utilities, organized by customer class.

Figure 4-8. Annual Energy Sales of Utilities by Customer Class (2006)



Source: Global Energy Decisions Inc.

The following table reflects the level of industrial customer participation in utility DSM programs by utility.

Figure 4-9
Industrial Customers
DSM Participation
As of June 30, 2007

Entity	Number of Opt-Outs	Total Number Of Industrial Customers
LG&E Electric (A)	397	397
LG&E Gas (A)	273	273
KU Electric (A)	1,656	1,656
Duke Kentucky (B)	6	385
KPC (C)	54	1,436
Big Rivers	N.A.	39
East Kentucky	N.A.	78

Sources: LG&E/KU (DR 02-36), Duke Kentucky (DR 02-38), KPC (DR 02-37), Big Rivers (DR 02-37), and East Kentucky (DR 02-42)

(A) The industrial representative on the LG&E/KU DSM Advisory Group and the Kentucky Industrial Utility Customers, who represent the industrial customers, are opposed to a DSM surcharge. As a result, DSM programs are not currently offered to industrial customers.
(B) All industrial customers eligible to opt-out have done so.
(C) The number of customers who have opted out is as of June 19, 1996.

East Kentucky does not currently have any industrial DSM programs for which such customers could opt-out. Neither it nor Big Rivers utilize a DSM surcharge mechanism. Based upon the above data, all industrial customers for LG&E and KU have been excluded.

Recommendation: **Rules governing industrial customer exclusion from DSM program participation should be clarified, standardized, and uniformly applied. It is important that customers who seek to opt-out of the DSM program make a showing of their own energy efficiency efforts, before they are allowed an exemption from the DSM surcharge and related programs.**

As currently stated, KRS 278.285 (Item 3) provides that "The commission shall assign the cost of demand-side management programs only to the class or classes of customers which benefit from the programs…" To date, this has been applied such that DSM program costs have been assigned to customers within the applicable customer class subject to a particular program(s). That is, residential DSM programs are assigned to residential customers; commercial programs to commercial customers, etc.

The assignment of costs for a particular program to a particular class of customers may not necessarily be the most appropriate basis for cost assignment and recovery. Assuming that an expanded program of efficiency measures are employed in the future, a major component of such programs may be classified as focused on demand reduction. Assuming that the scale of such programs is sufficient to delay major supply-side capacity additions, the benefits of the demand reduction will inure to all customers by eliminating the incremental cost of generation capacity that would otherwise be assigned to all customers. Under such circumstances, it is reasonable to allocate residential or commercial programs over all customer classes, as all customers clearly benefit from lower average generation costs due to the avoided marginal cost of the capacity addition.

Recommendation: **As new DSM programs are brought before the Commission that clearly reduce system costs, it should consider if such programs should be more properly allocated to all jurisdictional customers.**

Coordination with Stakeholders

There seems to be limited effort among the utilities to cooperate with relevant stakeholders in the implementation of DSM programs and activities. For instance, there are opportunities to work with educational institutions, as well as NGOs and community organizations, in increasing the awareness of conservation and energy efficiency for residential and small commercial users. Such work would be instrumental in instilling "the culture of conservation", which had been identified in other jurisdictions.

All in all, part of the problem with DSM implementation may be education of individual participants, and understanding of the cost savings that they will achieve with DSM. It is well recognized that competition leads to the most efficient outcomes. DSM programs are often a service that can be provided by competitive suppliers.

Recommendation: **Greater efforts should be made to make utility customers aware of energy conservation and DSM programs. Additional utility resources should be committed to customer education programs sponsored by the utilities or independent third parties. The KPSC may also release public information communications that support energy efficiency programs.**

Funding for Customer Investment in DSM

In response to customer resistance to energy efficiency improvements, Duke Energy is currently developing a plan to provide funding through an "Efficiency Savings Plan (ESP)".

> The ESP concept intends to provide universal access to energy efficiency improvements to all customers, not just those who have adequate disposable income. Research has shown that customers are more likely to make energy efficiency improvement decisions if there are positive savings to their monthly budget when the monthly cost is netted against the monthly savings of improvements. When tested against other financing or payment options, customers have shown a preference for ESP.
>
> Still in the research and development phase, ESP will be developed to provide the lowest possible monthly financing cost for energy efficiency improvements by extending the financing term, providing competitive rates and creating a simple and easy customer experience. Based on customer research completed for ESP, charges are conceived to be applied to the monthly energy bill. In addition, there will be options for a change of residence event (moving) where customers

> may either pay off the remaining balance or convey the charges to the next homeowner. The program would also include a provision for disconnection (if ESP payments are not paid in a timely manner) in order to remain competitive with secured debt rates. It is intended that third parties will provide unsecured financing to support the program.[52]

Recommendation: **Assuming that proper utility incentives and recovery mechanisms are in place, utilities should consider providing or expanding rebates or financing programs to support customer investment in energy efficiency and DSM programs; especially those that are likely to reduce peak demand. A set of pre-approved technology types may be promoted to customers through education and incentives showing the expected payback characteristics for each technology.**

Procedural Timeline for DSM Program Review

The process for the review and consideration of DSM program applications is generally assumed to be adequate. However, there may be instances where it is appropriate to allow for expedited filings. There have been instances where participant response to a new DSM program exceeded expectations, but due to approved budget limitations, and the annual cycle for seeking DSM program changes, the program could not be more fully implemented. On other occasions, approved rebate incentive programs could not be expanded, pending further review by the Commission. Utilities may file a request to expedite an application filed with the Commission. To date, however, no such requests have been made for DSM program approvals or modifications.

Recommendation: **The Commission should consider the need to revise the current DSM application and approval process to accelerate the procedural timeline for projects below a defined funding level. The standard of review for modifications to current programs, or programs under a specified budget amount, should be further streamlined to accommodate increased participant interest in successful programs.**

---

52 Duke Kentucky Response to Discovery DR-02-23.

Chapter 5 – Current Energy Planning and Programs, Analysis and Recommendations
Renewables and Distributed Generation

This chapter reviews the status of renewables and distributed generation. We address renewables and distributed generation issues associated with Section 50, Item 2 of the Energy Act:

> Encouraging diversification of utility energy portfolios through the use of renewables, and distributed generation; …

The term "renewable energy resources" refers to "energy resources that are naturally replenishing but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time."[53] Such resources typically include wind, solar, biomass, geothermal, hydro, ocean thermal, tidal and wave energy.

A "distributed generation" resource is one that is physically positioned close to the load it serves. This type of generator may be connected to the grid (typically the sub-transmission or distribution system) or it may function on a stand-alone basis (e.g., an industrial user's cogeneration facility). Distributed generators utilize a variety of electricity generating technologies, including reciprocal engines (either diesel or natural gas fired), microturbines, combustion gas turbines, fuel cells, and other renewable technologies.

Information about industry practices with respect to renewables is contained in Appendix F of this report

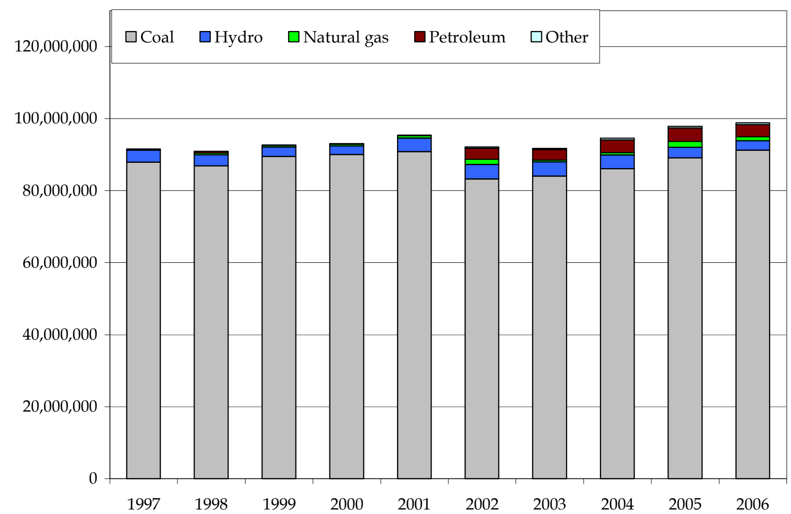
Renewables and Distributed Generation Currently in Kentucky

Use of renewable energy resources in Kentucky is very limited. According to the EIA, and as illustrated in Figure 5-1, of the 98.8 terawatt hours (TWhs = 1,000 gigawatts) of electricity produced in Kentucky in 2006, 92.3% was from coal-fired sources, 2.6% from hydroelectric stations and 0.5% from other renewable resources.

---

[53] Glossary, EIA, Department of Energy.
(http://www.eia.doe.gov/glossary/glossary_r.htm accessed January 28, 2008). HB 1 defines renewable energy as: "Wind power, biomass resources, landfill methane gas, hydropower, or other similar renewable resources to generate electricity in excess of one (1) megawatt and solar power to generate electricity in excess of fifty (50) kilowatts for sale to unrelated entities."

Figure 5-1. Electricity Generation by Source (MWh)



Source: EIA, Department of Energy (http://www.eia.doe.gov/cneaf/electricity/epm/table1_6_a.html accessed January 28, 2008)

As displayed below in Figure 5-2, renewable electricity generation in Kentucky is currently limited to hydroelectric resources and biomass power plants.[54]

Figure 5-2. Renewable Electricity Generation (2006)

Resource		MWh
Conventional hydro		2,574,188
Biomass	MSW/Landfill gas	59,543
	Wood and derived fuels	372,193
	Other biomass	1,691
Total		3,007,616

Source: EIA, Department of Energy (http://www.eia.doe.gov/cneaf/solar.renewables/page/prelim_trends/rea_prereport.html accessed January 28, 2008)

Note: includes output of federally-owned hydroelectric facilities.

Kentucky's currently operational renewable energy power plants are presented in Figure 5-3. The list includes power plants owned by utilities that are under the jurisdiction of the KPSC as well as non-jurisdictional entities. It is important to note that 600 MWs of hydroelectric power plants owned by federal organizations – specifically, the TVA and the U.S. Army Corps of Engineers - are not included in the table.

54 Based on statutory definitions of renewables (and specifically the qualifications for a state's Renewable Portfolio Standard program), the hydroelectric plants in Kentucky are too large to be deemed "renewable."

Figure 5-3. Renewable Energy Power Plants in Kentucky

Type	Company	Plant	Capacity (MW)
Hydro	Kentucky Utilities	Dix Dam	28.3
	Louisville Gas and Electric	Ohio Falls	80.0
Biomass	East Kentucky Power Cooperative	Bavarian Landfill	3.2
	East Kentucky Power Cooperative	Green valley Landfill	2.4
	East Kentucky Power Cooperative	Laurel Ridge Landfill	3.2
	East Kentucky Power Cooperative	Pearl Hollow Landfill	2.4
	East Kentucky Power Cooperative	Pendleton County Landfill	3.2
	Cox Interior, Inc.	Cox Waste to Energy Cogen	5.0
	Weyerhauser Co.	Kentucky Mills	88.0
Total			**215.7**

Source: Platts Global Power Plant Directory, Global Energy Decisions Inc

807 KAR 5:054 provides for standard contracts to be designed by utilities for purchase of power produced by small power producers and cogenerators (less than 100 kW of capacity); however, to our knowledge, no such contract template has yet been submitted to the Commission for approval.

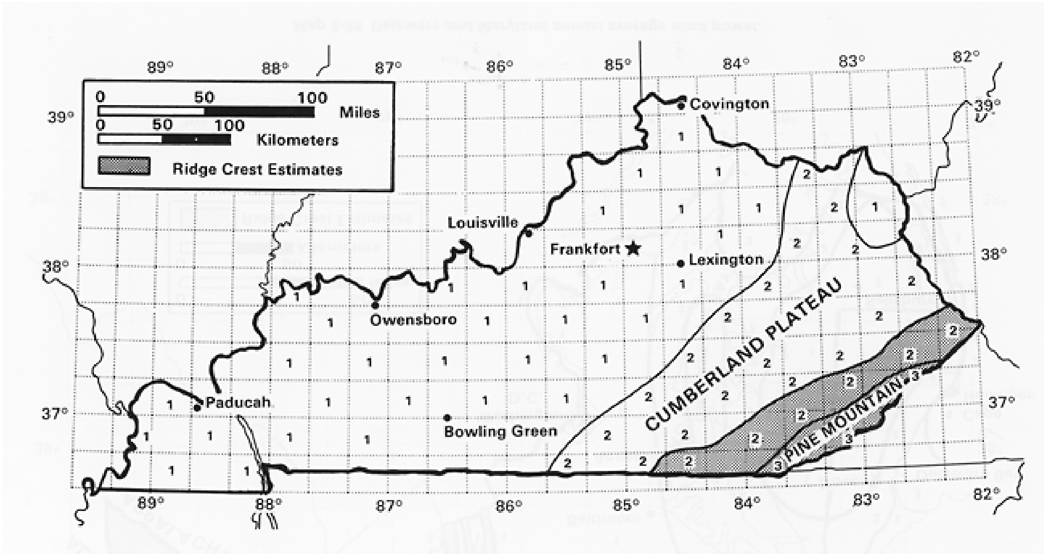
Statistics on distributed generation (DG) are unavailable, implicitly confirming that there is currently no significant distributed generation in the state. Utility investment in DG is typically initiated with respect to advanced energy storage; or in areas of significant transmission constraints, where reliable service from a central generation plant is not feasible. Kentucky does not appear to currently have such geographical load pockets, nor the price profile that can cost effectively support energy storage. It is, therefore, unsurprising that Kentucky investor-owned utilities have not pursued utility-owned DG. Development of third-party DG systems may also be hampered by the lack of more favorable interconnection policies and backup power requirements, including the lack of net metering (for all non-solar installations).

Economics of Renewable and Distributed Generation in the State

Wind Resources

According to the National Renewable Energy Laboratory (NREL), opportunities in Kentucky to utilize wind power are very limited. As displayed in Figure 5-4, most of the territory is rated as Class 1; some portions of eastern Kentucky are Class 2; and there is a very small area with Class 3 potential on the ridges of the Pine Mountains – Kentucky's first state park. Only Class 3 and above are assessed as having adequate wind power potential to make wind power projects economically feasible. Therefore, with current technology, substantial wind development is unlikely.

Figure 5-4. Wind Resources Map of Kentucky



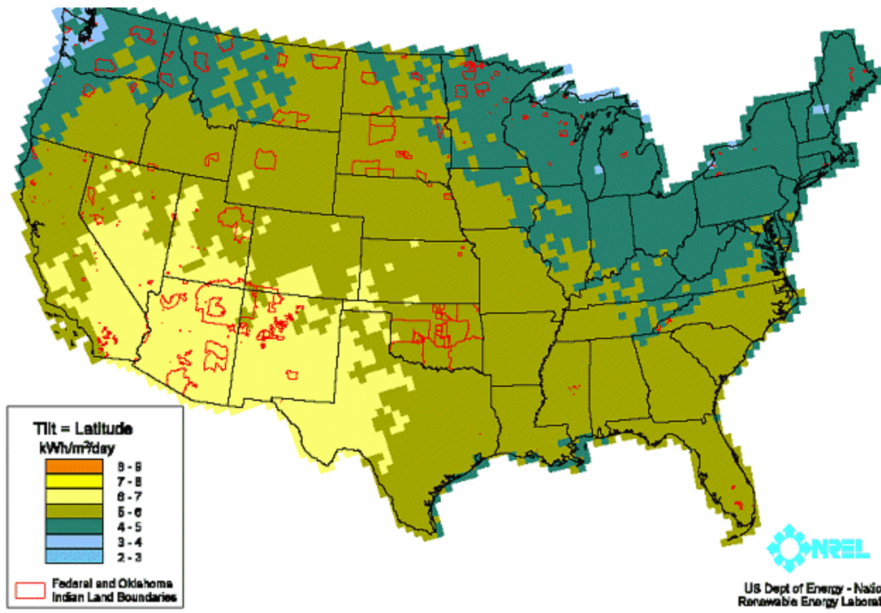
Source: http://rredc.nrel.gov/wind/pubs/atlas/maps/chap3/3-29m.html (accessed January 28, 2008)

Solar

The sun's energy can be converted to electricity through two chief methods: photovoltaic (specially designed cells for converting solar radiation directly to electric current) and thermal (whereby sunlight is concentrated and the heat is used to drive turbines for generating electricity).

Photovoltaic solar energy projects generally require significant capital outlays and large areas of land. Figure 5-5 is adapted from the EIA's website and shows NREL's estimated potential for photovoltaic resources' across the United States. Most parts of Kentucky have little potential (similar to the Northeast US); only the southwestern portion of Kentucky is rated as having medium potential.

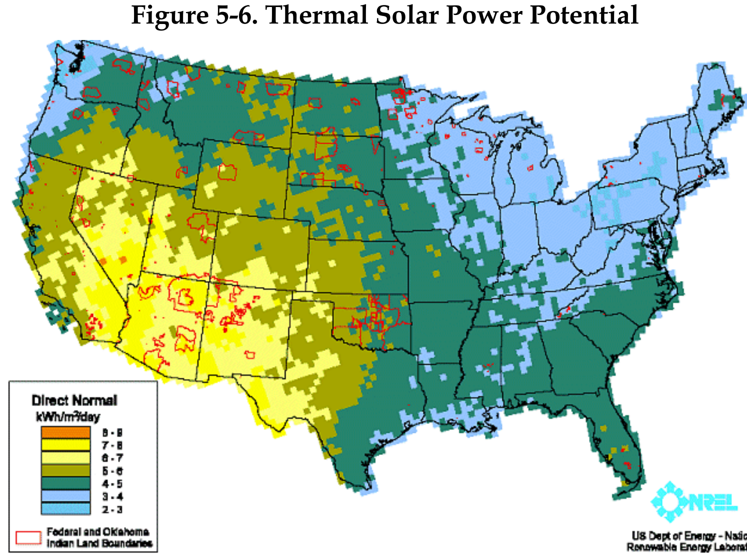
Figure 5-5. Photovoltaic Resource Potential Map



Source: EIA, Department of Energy (http://www.eia.doe.gov/cneaf/solar.renewables/ilands/fig11.html accessed on January 28, 2008)

As with photovoltaic systems, thermal solar power projects require substantial initial capital costs and large areas of land. They also require high capacity factors to achieve economies of scale. The map in Figure 5-6, adapted from the EIA's website, demonstrates the potential for thermal solar power in the United States. Once again, the potential for commercial application of thermal solar power in Kentucky is not significantly greater than that of the U.S. Northeast, and in fact, lower in scale than the opportunity for photovoltaic applications.

Figure 5-6. Thermal Solar Power Potential



Source: EAI, Department of Energy (http://www.eia.doe.gov/cneaf/solar.renewables/ilands/fig12.html accessed January 28, 2008)

Because the costs of solar development, both thermal and photovoltaic, are relatively high, future development will be contingent on financial incentives. All states within the U.S. currently provide financial incentives such as tax credit, rebates, or loans to support programs related to energy efficiency.[55]

Biomass

Biomass-based electricity generation is considered a relatively cost effective renewable technology in Kentucky, but the economics generally require placement near the fuel source (feedstock). The three main varieties of biomass projects, based on type of feedstock, are as follows:

- wood and wood waste;
- municipal solid waste; and
- landfill gas.

Wood and wood waste power plants can utilize, in addition to wood, agricultural residue, forest residue and other dedicated energy crops (e.g. switch grass). The viability of biomass projects is generally limited to the availability of feedstock (with respect to total volume and also distances from source to power plants), and the quality of stock (with respect to heat values and moisture content). While biomass is generally more cost-efficient when co-fired with fossil fuels, this approach also raises some concerns with respect to impacts on the reliability of power plant capacity, operational performance of boilers and premature erosion of air pollution control equipment.

Figure 5-7 presents findings of research into the potential availability of various types of biomass feedstock in the United States. Kentucky, which occupies approximately 1.1% of the land area in the US, is estimated to be able to deliver about 2.2% of the country's feedstock.

Figure 5-7. Estimates of Potential Feedstock Availability (Dry tons, annual estimates)

	Kentucky	% of US	US
Forest residue	883,500	2.0%	44,871,800
Wood and wood waste	1,940,000	2.1%	90,418,000
Agricultural residue	2,280,603	1.5%	150,651,402
Energy crops	5,128,780	2.7%	188,067,187
Total	**10,232,883**	**2.2%**	**474,008,389**
Land area (sq. miles)	40,444	1.1%	3,794,066

Source: Biomass Feedstock Availability in the United States: 1999 State Level Analysis (Marie E. Walsh et al, Oak Ridge National Laboratory; http://bioenergy.ornl.gov/resourcedata/index.html accessed January 28, 2008)

Municipal solid waste (MSW) power plants burn solid refuse from relatively large urban centers. While this type of power plant can be economically feasible, many concerns have been

[55] See the Database of States Incentives for Renewables and Incentives (DSIRE), http://www.dsireusa.org

raised about the environmental safety of burning a multitude of domestic, commercial and industrial waste products whose impacts on air pollution are unknown.

Landfill gas power plants are a variant of MSW technology, where gas from the decomposition of waste is used to fire turbines for electric generation. The economic and technical characteristics of landfill gas projects are highly dependent on the specifics of each location (e.g., landfill size, lead time to generate sufficient volume and quality of gas, duration of sustainable gas generation, etc.).

It must also be noted that biomass facilities are typically smaller scale operations relative to conventional generation. Wood and wood waste and MSW power plants are generally no larger than 50 MW; and landfill gas power plants are seldom larger than 10 MW.

There is currently one new biomass project, Maysville Mason County Landfill, which has been announced to be built by East Kentucky in 2008.[56] Overall, there are 30 different sites in Kentucky that the Environmental Protection Agency (EPA) is tracking as potential landfill gas projects.[57]

Hydro Technologies

The potential for new hydroelectric generation in Kentucky is likely to be limited to small-scale and/or run-of-river hydro projects. Large hydro projects require very long lead times and large capital investments, and usually generate significant stakeholder opposition. There are three currently announced hydroelectric projects:[58]

- Meldahl Locks & Dam (105 MW) by E.ON U.S. LLC;
- Smithland (72 MW) by American Municipal Power Ohio; and
- Taylorsville Lake Dam Hydroelectric Project (17 MW) by BPUS Generation Development LLC.

These projects have not made formal filings with the Kentucky State Board on Electric Generation and Transmission Siting.

In addition, there are two projects that are still in the early stages of development: the Olmstead Locks & Dam Hydroelectric Project[59] (63 MW) and the Fishtrap Project[60] (5 MW). A joint report by Department of the Interior, the Department of the Army and the Department of Energy - "Potential Hydroelectric Development at Existing Federal Facilities" - states that existing federally-owned hydroelectric resources in Kentucky can be upgraded to increase installed

---

[56] Source: Global Energy Decisions, Energy Velocity suite.

[57] http://www.epa.gov/lmop/proj/xls/lmopdataky.xls (accessed February 3, 2008)

[58] Source: Global Energy Decisions, Energy Velocity suite

[59] Ibid.

[60] Kentucky Office of Energy Policy, *Kentucky Energy Watch*, Vol. 8 No. 27, July 5, 2007.

capacity by as much as 526 MW; but these estimates involve only federally-owned hydroelectric facilities outside the jurisdiction of the KPSC.[61]

Geothermal

Kentucky's geological profile does not present opportunities for geothermal generation systems.

Distributed Generation

From the customer's perspective, distributed generation provides it with its own electricity supply, or at least some portion of its energy needs. In addition, distributed generation can provide system-wide benefits in the form of a diversified fuel mix for generation, including renewable resources, also easing the strain on utility transmission and distribution networks. However, there are impediments to successful development of distributed generation:

- excessive requirements and high cost of interconnection;
- utility standby charges for backup power;
- prices for electricity sold by distributed generators are often arbitrary; and
- lack of standard siting requirements that keeps capital costs high.

Some of the main prerequisites of developing distributed generation projects include the availability of uniform interconnection standards and net metering rules, which will address the issue of access to the grid on a basis of economic costs.

Comparison of Economics of Renewable Technologies

We have utilized the cost data from the EIA to compare the relative costs of generation using different technologies, including renewable resources. The capital costs assumptions, shown on the following table, represent the relative costs among the different technologies considered. The analytical model to compare the all-in cost of electricity considers various factors, such as expected typical load factors of different types of power plants, variable and fixed operating and maintenance costs, financing costs, and lead times required to bring the projects online.

61 http://www.usbr.gov/power/data/1834/Sec1834_EPA.pdf (accessed January 28, 2008)

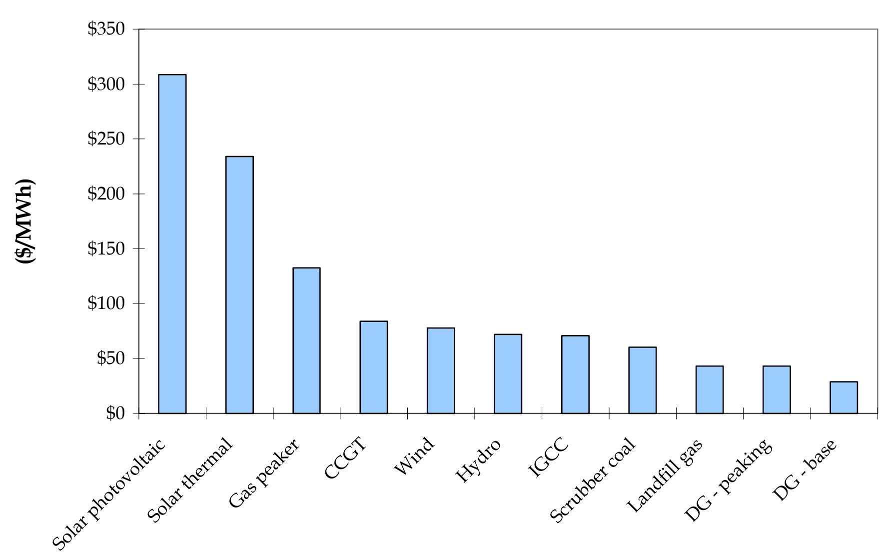
Figure 5-8. Capital Cost Assumptions (in 2005 $)

Technology	Capital costs	Fixed O&M/kW/year	Variable O&M/MWh	Assumed Load factors	Lead times (years)
Solar photovoltaic	4,751	11.0	0.0	25%	2
Solar thermal	3,149	53.4	0.0	25%	3
Gas peaker	420	11.4	3.4	25%	2
CCGT	603	11.8	1.9	65%	3
Wind	1,206	28.5	0.0	30%	3
Hydro	1,500	13.1	3.3	40%	4
IGCC	2,134	36.4	2.8	80%	4
Scrubber coal	1,290	25.9	4.3	80%	4
Landfill gas	1,595	107.5	0.0	90%	3
DG - peaking	1,032	15.1	6.7	50%	2
DG - base	859	15.1	6.7	70%	3

Source: EIA, Annual Energy Outlook Assumptions 2007

The following graph represents the relative all-in costs (defined as levelized fixed costs, including capital costs, plus variable costs of operation) of producing 1 MWh of electricity by different power sources, including both renewable technologies and conventional generation. It is evident that both solar technologies have levelized costs significantly higher than any other technology; mainly due to high capital costs and low load factors, as the power plants are not able to produce electricity during night hours. The combined cycle turbine-based power plants are relatively cheap to build, but their all-in costs are dependent on the price of fuel; natural gas or oil. Landfill gas is one of the renewable sources that has the most potential in Kentucky, as its all-in costs are competitive to the cost of conventional hydroelectric or integrated coal-gasification power plants.

Figure 5-9. Indicative Levelized Costs of Electricity Generation by Technology



Source: LEI calculations based on EIA capital and operational costs assumptions

The above hypothetical analysis is based on assumptions that are currently being used by the EIA, and therefore reflects national averages in terms of labor and equipment costs, as well as siting costs.[62] Estimates for Kentucky-specific projects may vary from the above indicators. For example, Big Rivers estimated that run-of-river hydroelectric development in Kentucky would be in the range of $45/MWh. [63]

The economics of new power projects may also be negatively affected by the requirement that the cost of transmission interconnection of new power plants be borne by the project developers alone, especially as some of the renewables are most likely to be located further away from load areas, and therefore further away from existing transmission networks.

The preceding estimates suggest that coal-fired IGCC power plants may be competitive with other main sources of electricity, including CCGTs and hydroelectric facilities. However, building IGCC power plants with carbon sequestration is limited to areas with suitable geological formations. Kentucky Consortium for Carbon Storage[64] is currently conducting studies of carbon storage potential in Kentucky.

Renewables in the Planning Process: Portfolio Analysis

Based on the consulting team's meetings with utility personnel, and responses provided by the utilities to the second set of discovery requests, the quantitative and statistical analyses currently performed by Kentucky utilities are very similar, both conceptually and mechanically, to the steps in a formal Portfolio Analysis. In particular, the current planning processes of the utilities focus considerable attention on specification of return and risk metrics. All of the utilities also perform sensitivity analyses, although there is a wide range among the utilities in the scope and intensity of their analyses of the impacts of external variables on alternative portfolios. Portfolio analysis is discussed in more detail in Appendix F.

RPS Considerations

At this stage, we do not believe it is practical to recommend mandatory requirements like a carbon cap and trade, carbon tax, or RPS for Kentucky. In any case, any such changes would require legislative involvement, as the KPSC does not have jurisdiction to impose such changes. Instead, we recommend that more subtle adjustments be made to the IRP process so that utilities start to consider renewables more thoroughly as potential alternatives. Additional recommendations to encourage renewables should also incrementally improve the landscape for such investment in Kentucky.

The least cost mandate in the CPCN for utilities is tempered by reference to future market uncertainties. This provides a foundation for incorporating Portfolio Analysis, which if

---

[62] Although Kentucky is a low-cost state in term of labor costs and land costs, the above estimates probably underestimate the current market value of equipment and raw materials. However, such equipment cost trends have generally affected all types of power technologies, and therefore the relative attributes should be very similar to what we present above.

[63] Big Rivers Response to Discovery, DR-02-13.

[64] http://www.uky.edu/KGS/kyccs/

properly applied, can lead to a robust decision-making recommendation that will help diversify the risks facing Kentucky ratepayers. Costs of conventional generation have the potential to increase in the future (for example, coal-fired generation costs can increase due to carbon legislation, while gas-fired generation costs can increase due to gas and oil price volatility). Renewables do not face these same risks. A robust Portfolio Analysis would identify and flesh out such considerations more fully in the IRP.

Based on statements made in responses to discovery, it is clear that utilities are not necessarily opposed renewables power options or mandates. However, an RPS should be both practical, affordable, and in the public interest. The potential for renewables, as well as other carbon limiting technologies should be considered in assessing an appropriate RPS and timeline.[65]

Recommendation: **The KPSC may wish to consider whether to recommend an RPS target to the General Assembly, consistent with similar initiatives in many other states. If it does so, we recommend that the target be voluntary, providing financial incentives for Kentucky utilities who choose to comply. The target must be realistic and cost effective in light of Kentucky geological constraints, with a range of perhaps 5 to 10% of energy served, graduated to 2020.**

Review and Authorization of Renewables Projects

There are no distinct rules/procedures for specifically siting and certificating renewable energy projects, although the net metering standard was intended to facilitate siting of new solar installations under 15 kW.[66]

The review process for siting generating facilities does differentiate between utility and non-utility applicants. Utility applications are reviewed by the KPSC, while non-utility applications are reviewed by the Kentucky State Board on Electric Generation and Transmission Siting (the Siting Board).

- In either case, applicants are required to obtain the following permits from the Kentucky Department for Environmental Protection (KDEP):
  - air emissions;
  - wastewater discharges;
  - water withdrawals; and
  - solid waste disposal (ash management).

The Siting Board applies the following criteria in evaluating applications to construct generating facilities:

---

[65] Duke Kentucky Response to Discovery, DR-02-40; KU/LG&E Response to Discovery, DR-02-38; Big Rivers Response to Discovery, DR-02-38; East Kentucky Response to Discovery, DR-02-26.

[66] KRS 278.465

- impact on scenic surroundings, property values, the development of adjacent property, and surrounding roads;
- anticipated noise levels (from both construction and operation of the facility);
- economic impact on region and state;
- whether the proposed site has an existing generating facility with a capacity of 10 MW or greater;
- whether the facility meets all local zoning and planning regulations, if any;
- whether the additional load adversely affects the reliability of the service for retail customers of utilities regulated by the KPSC;
- whether the facility complies with setback requirements;
- efficacy of any measures to mitigate adverse effects; and
- whether the applicant has a good environmental history. [67]

In addition, the Siting Board is allowed to consider the policy of the Kentucky General Assembly to encourage the use of coal as a principal fuel for electricity generation.

The siting process currently takes up to 5 months, and does involve a stakeholdering process. This timeframe is not outside the normal range for siting processes, based on experience in other states. Indeed, many states have multiple agencies involved in approving siting, allocating permits, and granting approval for ratemaking purposes. Some states do have fast - track processes, that have helped new development in general, but not specifically projects involving new renewables.

Kentucky already has regulations in place to help incentivize non-utility renewables, including mandatory filing of avoided cost data by utility and the potential for a Standard Offer Contract. There may be opportunities to enhance the siting process of small-scale renewables through some reformulation of the Standard Offer Contract. The Standard Offer Contract would also facilitate financing for non-utility projects.

Recommendation: **The Commission should consider the need to provide for fast track applications for small-scale generation, possibly as part of a more formalized Standard Offer Contract process.**

Financial Incentives for Renewable Energy Projects

Statewide incentives for renewable energy are based primarily on the recently enacted House Bill 1, The Incentives for Energy Independence Act. The bulk of funding for the incentives introduced by this legislation is to be provided through a $100 million bond issuance.[68]

---

[67] As stated in KRS 278.710 (1).

[68] The total funding will also provide incentives for biofuel facilities, including tax credits (House Bill1, Section 2 (4)(a) and (b)).

Corporate tax credits at the state level are provided for the following qualifying types of renewable projects: solar (thermal and photovoltaic with capacity at least 50 kW), wind, biomass, landfill gas and hydroelectric (at least 1 MW) resources, whose output is sold to unrelated parties, and for which there is at least $1 million in capital investment.[69] Potential incentives include:

- up to 100% of the Kentucky income tax or limited liability entity tax;
- an incentive of up to 100% of sales and use tax on property bought;
- a wage assessment of up to 4% for associated employees, which then can be taken as a credit against corporate income tax.

Total benefits realized through these incentives may not exceed 50% of the capital investment.[70]

The implementing agency for the incentives packages is the Kentucky Economic Development Finance Authority, which negotiates incentives contracts on a case-by-case basis. Duration of the contracts may not exceed 25 years.

As addressed in the next section of this report, the financial community considers required investment in renewables as neutral to negative in terms of credit quality impact. Aside from potential tax incentives that may induce investment in renewables projects, utilities should be compensated for the incremental financial and operating risks associated with these resource options. While overall generation portfolio risk may be reduced by diversification, specific project risks are not.

Recommendation: **To properly compensate utilities for increased renewables project risks, and to attract utility commitments to these investments, the Commission should consider allowing a premium of up to 300 basis points over the latest authorized rate of return[71] for these investments.[72]**

Siting of Jurisdictional Utility Facilities

KRS 278.020 provides the statutory basis for the KPSC's authority to review and approve siting applications for utility generating facilities.

There are no specific rules on what format the proceedings should follow when considering the applications for a CPCN or Site Compatibility Certificate (SCC). Generally, the KPSC establishes case-by-case schedules for case proceedings that include opportunities for interested parties to participate and voice their opinions and concerns.

---

[69] In this context, capital investments are defined to include various non-capital items such as labor (House Bill 1, Section 1 (9)(a)(1)).

[70] Certain renewable projects may also qualify for Federal tax credits.

[71] Assuming that the return has not been authorized by the KPSC in a rate order within the last two years, the appropriate cost of capital may be set at such time when the Commission considers approval of specific requests for utility renewables projects.

[72] Financial considerations associated with utility investment in energy efficiency programs, including renewables, is further addressed in Chapter 7.

A CPCN and SCC are valid for one year from the date they are granted.

East Kentucky recently built a landfill gas-based power plant - Pendleton LFG unit with 3.2 MW of capacity. However, this construction was undertaken without the CPCN as the utility argued that this was an extension of ordinary activities (i.e. no increase in the retail rates as result of this capital investment and no adverse effects on the financial position of the company).[73] There have been no renewable CPCN applications from utilities.

We can reasonably speculate that the biggest issues for utilities in proposing renewables (leaving aside cost) are that (1) these are normally smaller projects, so there is a smaller return for the same level of effort, as compared to a conventional coal plant; (2) some renewables technologies – like wind – are less firm and require additional expenses for standby power and ancillary services; and (3) there is a risk that a project may be proven not be least cost by intervenors.

Siting of Non-Utility Facilities

The Siting Board's approval is required for construction of merchant plants with installed capacity greater than 10 MW.

The KRS 278.212 (2) states that "any costs or expenses associated with upgrading the existing electricity transmission grid, as a result of the additional load caused by a merchant electric generating facility, shall be borne solely by the person constructing the merchant electric generating facility and shall in no way be borne by the retail electric customers of the Commonwealth." However, FERC Order #2003 (as well as subsequent A, B and C versions) allows the merchant power plant to collect cost recovery charges and transmission credits from utilities for use of transmission facilities that were paid for by this merchant power plant, even if the transmission facility upgrades were not necessary and were required for connecting the new power plant.

RFPs for Renewable Generation Projects

One of the issues that has an impact on the economics of new power projects, including renewable power plants, is the limited opportunity to recover all costs, when no contracting is available; or when the contracting is available for avoided energy costs only.[74] The inability to recover the fixed costs leads to difficulties in securing financing for the new projects.

<u>*Recommendation*</u>: One of the solutions to the renewable market pricing problem could be a KPSC requirement for utilities to use an RFP process for all resources, based on IRP, or just renewables,[75] where the contracts signed with the winners would include a capacity component in the remuneration.

---

[73] Case #2006-00033. The KPSC confirmed in its Order that a CPCN was not required.

[74] Market-based approach to pricing requires that the prices reflect the marginal cost of production.

[75] Requiring a renewable-only RFP would necessitate the adoption of certain targets in the form of set-aside requirements or other approaches to set quasi-RPS targets.

Distributed Generation and Net Metering

Net metering is a service available to consumers deploying for their own use distributed, generally renewable energy facilities, under which electricity generated by the consumer from the facility and delivered to the local utility is credited to the customer in the form of either a sale, or a credit used to offset the costs of electricity provided by the utility to the consumer during the applicable billing period. The word "net" refers to the difference between electricity flowing from and into the distribution system.

Net metering is a critical component of any program supporting the use of distributed energy resources. The two reasons electricity systems have tended to be centralized and integrated are because there have traditionally been substantial economies of scale in power plant development, and integrated systems allow for diversification of load. The most important change in the electric industry over the past few years – deregulation and vertical disaggregation – has been driven partly by the emergence of new generating technologies that have reduced the minimum scale for efficient plant operation. This same technological evolution has led to development of various forms of on-site distributed generation. Enabling small-scale, distributed technologies to be efficient requires that the benefits of diversification be available (i.e., that owners of distributed generators be able to sell excess production through a net metering program).

Utilities are required by the Energy Policy Act of 2005 to provide net metering programs. But the rules vary significantly across jurisdictions with respect to factors such as how long customers can keep their banked credits, how much the credits are worth, whether credit values vary across time periods, etc. The Commission took up this issue in Administrative Case 2006-00045.

The current net metering statute (KRS 278.465) allows only photovoltaic systems with 15 kW or less to qualify for the net metering service offered by utilities. At the present time, net metering service is practically nonexistent. LG&E/KU had one customer in a pilot program, who generated about 30% of its own energy needs and reduced its own coincident peak by almost 50%.[76] Big Rivers, KPC and Duke Kentucky have no net metering customers. East Kentucky has 5 net metering customers, including one commercial customer. Interconnection costs generally included metering equipment at a cost of $400-$800.[77]

<u>Recommendation:</u> **Uniform standards, at least by utility, for net metering and interconnection should be developed, as set forth in a tariff. Current limits on technology restrictions should be reconsidered, as well as limits on total participation levels. Finally, current limits on generating capacity should also be relaxed to facilitate the potential for development of distributed generation projects, sizing projects appropriate to each technology.**

---

[76] KU/LG&E Response to Discovery, DR-02-32.

[77] East Kentucky Response to Discovery, DR-02-38.

Chapter 6 – Current Energy Planning and Programs, Analysis and Recommendations IRP, Certificate Process, and Full-Cost Accounting

This chapter examines the current IRP, CPCN and Siting processes, and issues associated with full-cost accounting, as cited in HB1, Section 50, Item 3:

> Incorporating full-cost accounting that considers and requires comparison of life-cycle energy, economic, public health, and environmental costs of various strategies for meeting future energy demand…

Information about industry practices with respect to resource planning and full-cost accounting is contained in Appendix G of this report.

Integrated Resource Planning

In compliance with 807 KAR 5:058, each of the state's electric generating utilities is to file an IRP triennially unless otherwise permitted by the Commission. The goal of the KPSC in requiring these filings is to ensure that the state's electric utilities can meet future demand with an adequate and reliable supply of electricity at the lowest possible cost for all customers within their service areas while complying with all applicable state and federal laws and regulations. The contents of the filing are to include a plan summary, a summary of significant changes since the previous filing, load forecasts, a resource assessment and acquisition plan, and financial information (e.g., present value of revenue requirements with identified inputs).

Upon receipt of the filing, the Commission Staff reviews the plan and issues a report summarizing its review and offering suggestions and recommendations to the utility for its next plan filing.

In a recent report issued by the Commission Staff, it stated that its goals in the review are to confirm that:

- all resource options are adequately and fairly evaluated;
- critical data, assumptions and methodologies for all aspects of the plan are adequately documented and are reasonable; and
- the selected plan represents the least cost, least risk plan for the ultimate customers served by [the utility], recognizing the need to achieve a balance between the interests of ratepayers and shareholders. [78]

There have been no instances in the IRP Staff reports reviewed to date when KPSC Staff review of an IRP led to changes in the approaches and/or methodologies employed by the utilities in the IRP under consideration. However, it is normally expected that subsequent IRPs will

---

[78] Kentucky Public Services Commission. *Staff Report on the 2005 Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utilities Company Case #2005-00162*, February 2006.

address Staff recommendations. There have been some instances where utilities have not followed Staff recommendations.[79]

A review of KPSC Staff comments on the IRPs filed by the jurisdictional utilities suggests that under the current framework the KPSC does not impose clearly defined standards related to the IRP approaches or methodologies, but rather reviews for "reasonableness", which is then commented on by various interveners such as the Attorney General's office and other interested parties.[80]

The following table summarizes the timing of each utility's most recent filing and next expected filing:

Figure 6-1
Status of IRP Filings

Electric Utility	Most Recent Filing	Next Expected Filing
Kentucky Power Company	November 2002	2009
Kentucky Utilities	April 2005	2008
Louisville Gas & Electric	April 2005	2008
Duke Energy of Kentucky	April 2004	2008
Big Rivers Electric Corporation	November 2002	2010
East Kentucky Power Cooperative	October 2006	2009
Source: IRP filings and discussions with KPSC Staff.		

Most Recent Utility Filings

Pertinent data from each electric utility's IRP is included in the following discussion. Since Kentucky Utilities and Louisville Gas & Electric have common ownership, they file a joint IRP. As such, their joint filing will be discussed as one.

Kentucky Power Company (KPC). For several years prior to the time of the 2002 IRP filing, KPC had been planned and operated on a wholly-integrated basis within the American Electric Power (AEP) - East System which included Appalachian Power, Columbus Southern Power, Indiana Michigan Power, Kingsport Power, Ohio Power, and Wheeling Power. Therefore, the company had suggested that KPC's IRP be considered in the overall context of the AEP-East System.

However, primarily due to the State of Ohio's deregulation of generation, mandated corporate separation, and encouragement of retail competition; at the time of the 2002 filing, KPC proposed that the historical AEP-East System be modified on a going-forward basis to exclude the Ohio operating companies, Columbus Southern Power and Ohio Power. This modified AEP-East System was eventually adopted as part of a FERC settlement. Subsequently, AEP decided to leave its AEP-East System unchanged. The Commission Staff did not issue a report

[79] East Kentucky IRP Case #2003-00051, Staff Report, p. 10.

[80] Staff Reports to IRPs filed by utilities.

on this filed IRP since it was based on inapplicable fundamental assumptions. However, for purposes of this report, we will highlight the IRP as filed by KPC.

With additional supply-side resources obtained from the regional generation market, and benefits realized from the DSM programs documented in its IRP, KPC's overall conclusion was that the AEP-East System would have adequate resources to serve its customers' requirements throughout the forecast period (2002-2016). This conclusion was also based on the assumption that the Wyoming-Jacksons Ferry 765-kV Project would be completed on a timely basis.

In the first half of 2003, AEP intended to transfer functional control of transmission facilities in the Eastern part of its system to the PJM Interconnection, a regional transmission organization (RTO).

Key assumptions made in the preparation of the load forecast, a component of the IRP, included:

- Moderate U.S. economic growth;
- Declining real average electricity prices through 2005; constant real prices thereafter;
- Generally slow growth in the company's service-area population; and
- Normal weather.

KPC concluded that base internal energy requirements increase at an average annual rate of 1.6%; and summer and winter peak demands increase at average annual rates of 1.7% and 1.7%, respectively. This compares to AEP-East System's conclusion that the average annual rates for internal energy requirements, and corresponding summer and winter peak demands, would increase by 1.7% and 1.6%, respectively.[81]

At an AEP-East System level, savings attributed to DSM programs included 328 GWh of annual energy savings, 179 MW of peak demand reductions in the winter and 71 MW of peak demand reductions in the summer. These "savings" were embedded in the base load forecast of the IRP. DSM impacts were assumed to generally increase through the year 2006 and remain relatively stable until 2016 when they then began to decrease. KPC partially attributed this result to the diminished economic viability of new or expanded DSM programs in the face of lower supply side resource costs caused by increased competition.

The AEP System planned to purchase capacity and/or energy from the regional market to provide adequate daily operating reserves, which were 4% at the time of the filing (based on the East Central Area Reliability (ECAR) Coordination Agreement). Given the expected capacity additions in the ECAR region over the next five to six years, only a fraction of the planned additions (less than 25%) would need to be in service for adequate reliability levels to be maintained.

Kentucky Utilities (KU) and Louisville Gas and Electric Company (LG&E). KU and LG&E are wholly-owned subsidiaries of E.ON. According to KU and LG&E, as owners and operators of

[81] KPC's forecast period was 2002-2016. AEP-East System's forecast period was 2003-2016.

interconnected electric generation, transmission, and distribution facilities, they achieve economic benefits and efficiencies through operation as a single interconnected and centrally dispatched system. Their jointly filed IRP covered the time period from 2005 to 2019.

Key assumptions made in the macroeconomic background for the energy sales forecast of the IRP included:

- The economy suffered no major mishaps or exogenous shocks;
- The population projection was consistent with the Census Bureau's "middle projection" for the U.S. (average annual growth of 0.9 percent from 2005 to 2019);
- Except for temporary spikes, the average price of foreign oil was forecast to remain below $31 per barrel until 2009. In the longer term, scarcity would drive the real price of imported oil to $45 per barrel in 2019; and
- Growth in the annual real U.S. Gross Domestic Product was projected to average 3.1% over the period 2005 to 2019.

Key assumptions made in the sales forecast of KU included:

- 0.8% average annual increase in the population;
- 3.7% average annual increase in Industrial value-added;
- 2.0% average annual increase in commercial employment; and
- 3.6% average annual increase in real total personal income.

Key assumptions made in the sales forecast of LG&E included:

- 0.6% average annual increase in the population;
- 2.3% average annual increase in Industrial value-added; and
- 3.5% average annual increase in real total personal income.

For the combined companies, the average annual increase in sales was forecast to be 2.0% over the 15-year period. Peak demand was forecast to reach 8,794 MW in 2019.

The optimal target reserve margin determined by a January 2005 study was 14%. As a result, the companies will require resource additions of approximately 2,400 MW.

The companies filed an application with the FERC for license renewal of the Ohio Falls Station. The current license was set to expire in November 2005. A rehabilitation project was begun in 2001 and scheduled to run through 2012. After completion, the expected capacity output will be 64 MW from the then current value of 48 MW.

70 DSM alternatives were considered. 27 DSM projects passed the initial qualitative screen, but only 4 projects passed the two-phase quantitative screen, which ultimately included inputs for administrative costs and expected levels of penetration for each company. These four included setback thermostats, Smart thermostats, energy efficient indoor lighting, and air conditioning tune-ups.

Various supply-side technologies were reviewed for least cost. Only six were recommended for further evaluation by the companies' consultant – a simple-cycle combustion turbine, a combined-cycle combustion turbine, a hydro power purchase, expansion of Ohio Falls, a Trimble County 2 supercritical pulverized coal unit, and high sulphur pulverized coal unit.

In identifying uncertainties surrounding the successful implementation of the plan, the age of certain generating units was discussed. The companies had nine different generating units that were thirty or more years old as of 2005. In each case, the units were equal to or beyond their typical full life expectancies. Such units have a greater risk of catastrophic failure. As a result, the companies assumed in their supply-side sensitivity analysis that all of these units would be retired in 2010, the first year that the Clean Air Interstate Rule[82] would go into effect. Total summer capacity of these units was 179 MW. If these retirements took place, an additional combustion turbine would be necessary and the timing of another CT would need to be modified.

In December 2004, the companies notified the Midwest Independent Transmission System Operator (MISO) of their intent to withdraw from the organization at the end of 2005. The potential impact of this decision was unknown at the time of the filing.

In summary, the IRP included the implementation of 5 new DSM program initiatives, a purchase power agreement for a renewable resource from W.V. Hydro, and new generation additions (Trimble County Unit 2, six Greenfield combustion turbines, and one Greenfield supercritical high sulfur coal unit). This plan resulted in the lowest Present Value Revenue Requirement (PVRR) of $17.635 billion over 30 years. At the time of the filing, the companies had submitted an application to the KPSC for appropriate certificates for the installation of the second unit at Trimble County. A CPCN was subsequently received.

After reviewing the companies' filed IRP, the KPSC Staff made a number of recommendations, some of which are highlighted here. In addition to noting their overall satisfaction with the load forecasting of these companies, the Staff repeated their previous recommendations for the companies to continue to examine the potential impact of increasing competition and future environmental requirements. The Staff recommended that potential future rate actions (such as the financial impacts of the construction of a significant generation source) be considered in future forecasts, or their exclusion explained. The Staff recommended that the companies place a greater emphasis on DSM and the alternatives ultimately evaluated in all screening phases. The Staff recommended that longer range capacity plans be included in annual filings rather than delayed until the next IRP filing. Finally, the Commission Staff encouraged the companies to consider incorporating renewable energy in their portfolio of supply-side resources.

Duke Energy of Kentucky (Duke Kentucky). When filed in 2004, Duke Kentucky's IRP was filed under its predecessor's name, The Union Light, Heat & Power Company. As mentioned previously, Duke Kentucky assumed its current name after the merger of its ultimate parent, Cinergy Corp., with Duke Energy Corporation in 2006.[83]

---

82 The Clean Air Interstate Rule (CAIR), previously known as the Interstate Air Quality Rule, is a multi-pollutant strategy rule that would require significant additional reductions of SO_s and/or NO_x emissions to further reduce levels of ozone and $PM_{2.5}$ in the atmosphere. The rule generally applies to the eastern half of the United States, including Kentucky, and only affects the electric power generation sector. (KU and LG&E IRP, p. 8-142)

83 For purposes of discussion surrounding the 2004 IRP filing, the utility will be referred to as Duke Kentucky.

Duke Kentucky had no generation resources at the time of its filing. All electric power to its retail customers was obtained from its parent, The Cincinnati Gas & Electric Company (CG&E), pursuant to a market-based fixed-price Power Sales Agreement. The Power Sales Agreement had a term from January 1, 2002 to December 31, 2006. In 2006, Duke Kentucky acquired 1,105 MW of generation from Duke Ohio (formerly CG&E).

In preparing the IRP, the reliability constraints utilized for the IRP included a minimum reserve margin of 15 percent. The forecast period for this IRP was 2003 to 2023 although the primary focus was on the first ten years. Duke Kentucky chose to consider a longer time frame than required by the KPSC because of the unique circumstances of the 2006 expiration of the Power Sales Agreement.

For purposes of developing the IRP, Duke Kentucky assumed that no environmental compliance changes beyond the NO_x State Implementation Plan would require implementation between 2003 and 2012.

Before implementation of any new or incremental DSM programs, Duke Kentucky forecasted that the annual growth rates from 2003 to 2023 for net energy, summer peak, and winter peak would be 1.9%, 1.4%, and 1.5%, respectively.

The incremental impacts of DSM resource programs were incorporated in the IRP analysis. These included Residential Conservation and Energy Education, Residential Home Energy House Call, Residential Comprehensive Energy Education, a low-income home energy assistance program, a direct load control program (Power Manager), customer-specific contract options, and financial incentives offered to customers to reduce electric demand during periods of high demand (PowerShare and Real Time Pricing).

Duke Kentucky did not attempt to forecast specific MW levels of cogeneration activity in its service territory. Sensitivity analysis was performed on supply-side technologies to determine potential resource candidates that were economical. Five technologies passed the initial screen for additional consideration. These included certain combustion turbine units, combined cycle units, pulverized coal units, pressurized circulating fluidized bed units, and fuel cells. Units within these technologies were assumed to be 70 MW or less to ensure that the 15% reserve margin would be adequate.

The IRP selected by Duke Kentucky included the transfer/acquisition of East Bend 2, Miami Fort 6, and Woodsdale 1-6 from its parent in 2004 along with back-up power sales agreements, 75 MWs of cumulative summer purchases in 2011 and 2012, and the additions of various pressurized circulating fluidized bed units and fuel cells beginning in 2013. The "placeholder" units included in the plan beginning in 2013 could be replaced by purchases from various third parties.

In July 2003, Duke Kentucky filed a petition with the KPSC to obtain CPCNs to acquire its parent company units mentioned previously. In December 2003, the KPSC approved these acquisitions and back-up power sales agreements. Approvals from the FERC and SEC were pending at the time of the IRP filing.

The KPSC Staff did not issue a Staff report on the 2004 Duke Kentucky IRP. The KPSC's decision, in the matter concerning the acquisition by Duke Kentucky of the East Bend 2, Miami

Fort 6, and Woodsdale 1-6 units (Case No. 2003-00252), preceded the IRP and required that it would be subject to a formal Commission review. In that decision, the Commission approved the cumulative acquisition by Duke Kentucky of the 1,105 MW of generating capacity at net book value. It also approved a back-up power sales agreement with CG&E.

Big Rivers Electric Corporation (Big Rivers). Due to financial difficulties, Big Rivers entered into a 25-year lease arrangement in July 1998 with various LG&E entities for them to operate its generation facilities. At the time of its IRP filing, Big Rivers continued to own these facilities.

Big Rivers concluded that it would be able to meet all of its demand and energy requirements between 2002 and 2017 through its SEPA and LG&E Energy Marketing, Inc. (LEM) contracts. If necessary, it also had access to the wholesale power markets to buy and sell power.

Underlying assumptions of the base case included average compound increases of 0.7% for total system energy and 1.0% for peak demand. It also assumed that environmental impacts were negligible. The SEPA contract was assumed to be extended when it eventually terminates in 2016. Macroeconomic load forecast assumptions included an average population increase of 0.6% per year, an average increase in real personal income of 2.0% per year, and an average compound rate of inflation of 2.9%.

Although Big Rivers had power purchase agreements from LEM that ran through 2023 and SEPA through 2016 that cumulatively were sufficient to serve expected load, Big Rivers did consider other sources of energy for low cost alternatives. Sixteen different alternatives were analyzed including, but not limited to, coal gasification, combined cycle combustion turbines, distributed generation, and landfill gas. After conducting this exercise, Big Rivers determined that the cost of these new power resources would exceed the cost of power purchased from LEM.

Big Rivers developed a three-year energy efficiency action plan to help its members save energy and money, and to take advantage of the environmental and other benefits of energy efficiency programs. Big Rivers' consultant reviewed 25 residential and 45 commercial DSM options. Economic screening of energy efficiency and load management options produced few measures or programs that passed the Total Resource Cost Test.[84]

Big Rivers reviewed the existing net metering tariffs previously approved by the KPSC along with the LG&E pilot net metering project. At the time of the filing, Big Rivers had decided that it would wait for the final findings and recommendations from the KPSC on the LG&E pilot project before proceeding with its own.

Since its previously filed IRP, a customer in Big Rivers' service territory installed a renewable energy generator that reduced Big Rivers' demand obligations by 50 MW. Big Rivers was also in contact with neighboring utilities to discuss the potential purchase of renewable resource power. In addition, a previously identified capacity deficiency was no longer an issue because of revised load and energy forecasts in this IRP.

---

[84] Big Rivers assumed that the avoided cost of generation was zero (November 2002 IRP, p. ES-4).

In 2002, Big Rivers had the capability of curtailing 35 MW of load through a Voluntary Curtailment Rider involving four industrial customers. This program has since ceased.

In its review of the 2002 IRP filing by Big Rivers, the KPSC Staff reiterated its recommendations from the previous IRP review on load forecasting, agreed with other interested parties that Big Rivers should not wait for LG&E net metering programs to be completed, encouraged Big Rivers to evaluate DSM programs related to improved manufacturing processes in its next IRP, and requested that Big Rivers communicate its intent to file a renewable energy study and high efficiency heating incentive program details. KPSC Staff agreed with the reasonableness of Big Rivers' conclusion that no additional supply-side resources were necessary over the forecast period, but recommended that a co-generation cost estimate and feasibility study be provided in its next IRP.

East Kentucky Power Cooperative (East Kentucky). In preparing its load forecast, the key assumptions in the 2006-filed IRP included:

- An average increase of 2.3% per year in residential customers through 2026, including the addition of Warren RECC as a member in 2008;[85]
- A relatively flat unemployment rate of 6.8%;
- 70% of new households will have electric heat and 85% of new households will have electric water heating; and
- Naturally occurring appliance efficiency improvements will decrease sales by approximately 1,500,000 MWh.

Supply-side capacity alternatives considered by East Kentucky included combustion turbines (peaking), combustion turbines with steam injection option, fluidized bed boiler units (base load), and long-term purchases.

East Kentucky forecasted total energy requirements to increase by 3.0% per year from 2006 to 2026. Net winter peak demand was forecast to increase by approximately 2,400 MW and net summer peak demand by approximately 1,700 MW.

Utilizing a reserve margin of 12%, East Kentucky projected that it would need additions to both baseload and peaking/intermediate capacity beginning in 2009. 278 MW at Spurlock 4 (baseload) was already under construction at the time of the IRP filing. In addition, the KPSC had granted a CPCN to East Kentucky to construct the 278 MW Smith circulating fluidized bed coal-fired unit (baseload) and five 90 MW combustion turbines in Clark County (peaking/intermediate). Under the plan, additional capacity would be needed in 2013, 2015, 2016, 2017, and 2019.

East Kentucky evaluated 93 different DSM measures. Only 34 passed the initial qualitative screen. After combining some of these, 27 were analyzed further using quantitative analysis. Primarily based on the Total Resource Cost Test, 24 measures passed East Kentucky's quantitative evaluation.

---

[85] Shortly after the IRP filing, Warren RECC chose not to become a member.

East Kentucky had a purchase power agreement with Duke Energy to purchase 40 MW of capacity from the Greenup hydro project. This agreement was set to expire in 2006. Negotiations were underway for possible extension.

According to KPSC Staff, a Staff report on the 2006 East Kentucky IRP was released in February, 2008.

Statewide Integrated Resource Planning

Although there are many benefits to the current IRP process, such as reduced regulatory burden (because a Commission Order is not required) and therefore, more timely feedback from KPSC Staff, the major limitation in the current process also relates to this informality. Under the current regulation, the Commission's authority to require changes in the IRP may be interpreted to be limited, since the Commission Staff is authorized to act only in an advisory role. Section 11(3) of 807 KAR 5:058 states: "Based upon its review of a utility's plan and all related information, the Commission Staff shall issue a report summarizing its review and offering suggestions and recommendations to the utility for subsequent filings."

The fact that the Commission cannot require changes to a utility's IRP may impact the CPCN process, where the Commission's authority is more extensive. The results of the IRP will impact the investment strategy chosen by the utility, and in turn, effect the investment proposals that the Commission is asked to review and approve in the CPCN filing.

While the Commission does not have the authority to compel utilities to follow particular policies under the integrated resource planning statute, in practical terms, the utilities have a strong incentive to follow recommendations issued by Commission Staff; partially as the cooperation of the utilities facilitates and interacts with other proceedings, including CPCN proceedings. To the extent that it is necessary for the Commission to issue standards for the IRPs, we believe that utilities will follow those standards.

A statewide perspective was also a component of the IRP process when initially implemented in 1990. This process was modified, however, in 1995, for several reasons. The use of consultants ceased at this time, thus leaving the oversight and review responsibility over the utility filings solely to the KPSC Staff. During this initial period, it also became clear that the utilities had little interest in either resource planning or economic dispatch based upon a statewide joint utility planning model.

Utilities engage in and cooperate on many industry-wide and regional efforts such as system reliability, R&D, and best practices. However, investor-owned utilities operate on an inherently competitive basis, largely independent of each other. Strategic planning among these entities varies dramatically, and such differences clearly exist among the regulated utilities (and their holding company parents) within the state of Kentucky.

While much of the electric energy generated and transmitted within the state is subject to Commission regulation, approximately 25% is not.[86] The operation of the TVA, municipalities

[86] Derived from State Electricity Profiles 2006, Table 9, EIA (based on MWh retail sales).

and IPPs within the state present a major component of electric energy resources that have no statutory requirement to submit to, or necessarily cooperate with, Commission procedures such the current IRP process.

Recommendation: **We do not believe that Commission responsibility for statewide planning is either practical or particularly beneficial, given the reality that utilities, regulated or not, do not engage in Kentucky-level system planning that would necessarily result in any joint development or operation of generation resources.**

Having made this recommendation, we do not mean to imply that periodic assessments of Kentucky energy resources is not appropriate, and indeed, helpful. [87] Such reviews have been performed in recent years by the Governor's Office of Energy Policy.

Certificate of Public Convenience and Necessity

As utilities evaluate resource options, uncertainty associated with new generation technologies such as IGCC will undoubtedly impact such investment decisions. Given the state policy supporting the use of Kentucky coal at utility generating facilities, it seems appropriate for the legislature and the Commission to implement procedures that reduce the financial risk associated with these investments. It is not necessary to guarantee recovery of investment in new technology facilities. However, mechanisms should be developed to reduce construction and operating risks to an equivalent of conventional plant alternatives.

The KPSC is mandated to review and, when appropriate, approve utility applications for CPCNs to build new generating facilities.[88] In addition, in cases when the installed capacity of the proposed power plant is greater than 10 MW, the utilities are also required to obtain a SCC, in addition to the CPCN. There is no Kentucky statute that requires public utilities operating in the state to utilize a competitive bidding process to select new generating power plants.[89] Consequently, jurisdictional utilities may elect to solicit proposals to build power plants from third parties or propose to the KPSC to self-construct new capacity.

Our review of East Kentucky's application to construct a 278 MW coal-fired power plant in Mason County, Kentucky (Case # 2004-00423) indicates that the procedures for obtaining a CPCN and SCC were not separate, and there was one application for both certificates. The Site Assessment Report largely focuses on the siting and environmental aspects of a proposed project, including dust and noise levels, impact on values of adjacent properties, changes in road and rail traffic, as well as any measures necessary to mitigate the identified negative impacts.

---

[87] For example, the report prepared by the KPSC entitled "Kentucky's Electric Infrastructure: Present and Future" issued in 2005 and Administrative Case No. 387 conducted in 2001.

[88] KRS 278.020

[89] KPSC. *Order Regarding East Kentucky Power Cooperative's Application for Certificate of Public Convenience and Necessity, and a Site Compatibility Certificate, for the Construction of a 278 MW Circulating Fluidized Bed Coal Fired Unit in Mason Country, Kentucky.* (p. 6)

The Commission should issue guidelines that clarify and perhaps broaden the current CPCN process so that supply-side and demand-side alternatives are considered by the Commission. Alternatively, the CPCN can be linked to the extensive analysis from the IRP filings.[90] In either case, the Commission will have a more robust basis for evaluating a particular, proposed project.

Recommendation: **The current statute defining the CPCN process should be modified to require the consideration of demand and supply-side alternatives including: IPP and merchant power options; energy efficiency and DSM programs; and renewable alternatives.**

Current Utility Construction Programs

A number of generating units are currently under construction. These include:

Figure 6-2
Jurisdictional Electric Utilities
Kentucky Plants Under Construction

Plant/Unit	Fuel Type	Ownership %	Utility	Nameplate Rating / Capability
Trimble County 2	Coal	14%	LG&E	750
Trimble County 2	Coal	61%	KU	750
Dresden	Natural Gas	100%	AEP East – Zone	540
Spurlock 4	Coal	100%	East Kentucky	300

Source: LG&E DR 02-30 and company website, KU DR 02-30 and company website, KPC DR 02-31, and East Kentucky DR 02-36. (When both a summer and winter nameplate rating was disclosed, the highest amount was disclosed above.)

KU & LG&E. The companies filed an application for a CPCN and SCC in December 2004 to construct Trimble County Unit 2. The application was approved in November 2005. This plant is being built in partnership with the Indiana Municipal Power Agency and the Illinois Municipal Electric Agency, who together will own 25% of the unit. Trimble Unit 2 is a 750 MW super-critical pulverized-coal base load unit.[91] Construction began in 2006, and is currently expected to be placed into commercial operation by spring 2010.

KPC. The Dresden unit under construction is a natural gas-fired, combined cycle facility at the Dresden Station, located in Ohio. It was purchased by AEP in 2007. Commercial operation is expected in the 2009 to 2010 timeframe. It is not expected to be a KPC facility.[92]

East Kentucky. East Kentucky currently has Spurlock Power Station, Unit 4 under construction. This unit is a 300 MW circulating fluidized bed base load coal facility, which is expected to be

---

90 IRPs however, may become somewhat outdated based on the interval between an IRP report and a CPCN filing.

91 KU/LG&E Response to Discovery, DR-02-30.

92 KPC Response to Discovery, DR-02-31.

put into commercial service in 2009.[93] In November 2006, the KPSC granted a CPCN to East Kentucky to construct the 278 MW Smith 1 coal-burning plant in Clark County, Kentucky.[94]

Big Rivers. Big Rivers has no generating facilities currently under construction, nor does it plan to have any generation plant additions through 2019.[95]

Duke Kentucky. Duke Energy Indiana is constructing a new 630 MW IGCC plant at an estimated cost of about $2 billion. This cost is offset by about $460 million in federal, state and local tax incentives.[96] Construction is to commence in Spring 2008. Duke Energy Carolinas is building an 800 MW, highly efficient coal-fired unit at its Cliffside station. Construction is expected to commence in Spring 2008, and be brought on line as early as 2011. The estimated cost is $2.4 billion, including $600 million of AFUDC. This plant includes "extensive emissions controls to ensure the plant will be among the cleanest coal plants in the nation."[97]

Over the next five years, Duke Energy expects to add approximately 6,000 MW of regulated supply.[98] Of this amount, it estimates 900 MW will be met from energy efficiency programs – Duke Energy Carolinas – 675 MW; Duke Energy Indiana – 225 MW.[99] In December 2007, Duke Energy filed an application with the Nuclear Regulatory Commission (NRC) for a construction and operating license to build two 1,117 MW nuclear units at the Lee Nuclear Station in South Carolina. The estimated commercial operation date for the first unit is 2018.[100]

Duke Kentucky has no supply additions planned through 2012.[101]

Major Renewables Commitments

Duke Kentucky. Duke Energy Generation Services, Inc. (DEGS) views investment in wind energy as an attractive opportunity, based on a significant demand for wind generation brought about largely to meet RPS requirements by 2015. DEGS expects attractive returns and low-risk earnings growth from its investment in wind facilities. Duke Energy has 237 MW of current wind energy commitments, and expects to have 1,000 MW in the near-term.[102] [103]

Duke Energy Indiana issued a renewables RFP in November 2005 for 100 MW, which produced six 100 MW wind projects in four states. The successful project located in Benton County,

---

93 East Kentucky Response to Discovery, DR-02-36.

94 East Kentucky press release dated May 11, 2007.

95 Big Rivers Response to Discover, DR-02-30 and 31.

96 Duke Kentucky Response to Discovery, DR-02-039(a), p. 11 of 23.

97 Duke Kentucky Response to Discovery, DR-02-013.

98 Duke Kentucky Response to Discovery, DR– 01-001, p. 17 of 66.

99 Duke Kentucky Response to Discovery, DR– 02-014.

100 Duke Kentucky Response to Discovery, DR-02-016.

101 Duke Kentucky Response to Discovery, DR– 01-001, p. 17 of 66.

102 Duke Kentucky Response to Discovery, DR– 01-001, pp. 48-50 of 66.

103 S&P, however, was not so enthusiastic about Duke's investment in wind, referring to the acquisition of Tierra Energy as "not considered supportive of credit quality, unless properly structured to mitigate the associated increase in business risk. Duke Energy Response to Discovery, DR– 01-02, p. 71 of 75.

Indiana, was approved by the Indiana Commission in December 2006, and will be in commercial operation by June 2008. Duke Energy Indiana issued a second renewable RFP in November 2007 for up to 200 MW. This process is now ongoing.

Duke Energy Carolinas issued an RFP in April 2007 for a supply portfolio of energy and capacity generated from renewables. The company received 26 responses for over 1000 MW of capacity, based on bio-source, solar and wind technologies.

Duke Kentucky has not issued a renewable energy RFP at this time.[104]

Big Rivers. A new organization is currently being developed by approximately 30 generation and transmission power cooperatives (G&Ts) to develop a National Renewables Cooperative ("NRCO"). This organization will allow G&Ts to develop renewable projects in their respective service territories; or have the option of investing in projects elsewhere, being able to obtain renewable energy credits. Big Rivers expects to be a member of NRCO.[105]

Also, in 2005, Big Rivers entered into an agreement to purchase green power from Weyerhaeuser's facility (now Domtar Paper Company) in Hawesville. Big Rivers has been purchasing power under that agreement since early 2006.[106]

Big Rivers has also studied run-of-the-river hydro projects, but found them to be currently uneconomic at a levelized cost of 4.5 cents/KWh.[107]

KPC. KPC has conducted a high-level assessment of the use of biomass fuel for co-firing at its Big Sandy Plant. However, no detailed feasibility study has been conducted to date, pending a triggering event such as implementation of RPS or CO_2 legislation.

KU and LG&E. KU and LG&E issued an RFP in July 2007 for up to 750 MW of renewable capacity. It received 15 responses, seven of which passed an initial screening, and are currently under further consideration. These projects are comprised of 2 wind, 2 biomass, 2 solar and 1 hydro facility.[108]

East Kentucky. East Kentucky is presently evaluating several projects to increase plant efficiency over the next ten years. These generally include: operating steam units at higher temperature and pressures; repowering; and power plant retrofitting.

East Kentucky currently utilizes wood waste to co-fire its Cooper Station facility. Other co-firing options are considered, as they become economically viable. [109]

---

104 Duke Kentucky Response to Discovery DR-02-15.

105 Big Rivers Response to Discovery, DR-01-03.

106 Big Rivers Response to Discovery, DR-01-11.

107 Big Rivers Response to Discovery, DR-02-13.

108 KU/LG&E Response to Discovery, DR-02-12.

109 EKP Response to Discovery, DR-02-48.

Full-Cost Accounting

The motivation for a full-cost accounting approach is to broaden the perspective of planning and related analyses (such as ratesetting) to incorporate not just the values of goods and services traded within a commercial transaction, but also the secondary impacts of the transaction on members of society that had not been directly involved in the transaction. As discussed in Appendix G, these secondary impacts are referred to as externalities. An approach, such as a full-cost accounting analysis, that attempts to systematically account for all externalities is referred to as a social welfare analysis.

Full-cost accounting attempts to account for, and ensure that business decisions are based on, consideration of relevant externalities. Any effort to implement full-cost accounting must proceed within the broader context of cost-benefit analysis.

Cost-Benefit Analytical Framework

The most comprehensive, and probably the most common, approach for evaluating investment opportunities within a broad social-welfare context is cost-benefit analysis (CBA). This methodology establishes a framework to systematically analyze competing alternatives and, ultimately, to choose from among the alternatives. While the framework allows for considerable judgment in the application of various statistical and other quantitative techniques, the analysis generally proceeds as follows:

Step 1 - Define the Analytical Challenge. The focus and scope of examination for any cost-benefit analysis must be defined and documented as precisely as possible.

Step 2 – Identify Stakeholders and Data Sources.

Step 3 – Specify Alternatives. A core set of investment / policy alternatives are specified before any data is analyzed.

Step 4 – Specify Assumptions and Evaluation Criteria. The intention of this part of the analysis is to specify, in advance of projecting the outcomes of various investment / policy alternatives, the bases for evaluating the relative attractiveness of the projected outcomes.

Step 5 – Forecast Outcomes. The expected future impacts of alternative investment / policy proposals must be estimated. There are a variety of statistical and quantitative techniques that can be employed. One of the most common is multi-variable regression analysis. Other techniques include time series analysis, factor analysis and cluster analysis. Some components of the analysis typically require simulations of detailed market dynamics.

Step 6 – Decide. The core decision rule is to undertake an investment if the net present value (NPV) of its annual net social benefits (expected benefits minus costs) is greater than zero. This is summarized arithmetically as:

$$NPV = \frac{B_0 - C_0}{(1+d)^0} + \frac{B_1 - C_1}{(1+d)^1} + \ldots + \frac{B_t - C_t}{(1+d)^t} > 0$$

where:

B_n = social benefits realized in year n

C_n = social costs incurred in year n

d = social discount rate

t = timeframe for the analysis

The social discount rate reflects the willingness of market participants to sacrifice present costs for future gains. In selecting an appropriate value, the collective time preferences of various groups of stakeholders are reflected in a single metric. In the context of utility IRP, the CBA time horizon will approximate the life cycle of the underlying assets. Most often the CBA period will be 10-20 years, with terminal values for operations beyond the study period. The inter-period data will be "discounted" to its net present value (NPV). Utilities typically use a net of tax cost of capital as the discount rate (which may or may not be equal to a regulated rate of return.[110]

Step 7 – Tell the Story. Results must be presented in a way that simultaneously displays analytical rigor, the logic of the underlying methodology, concern for the impact of all stakeholders and full appreciation of the broader context for the analysis.

Social Welfare and Externalities

The numerators in the NPV formula represent estimates of future social welfare in the form of net social benefits. This section briefly reviews the basic construct for evaluating social benefits and costs.

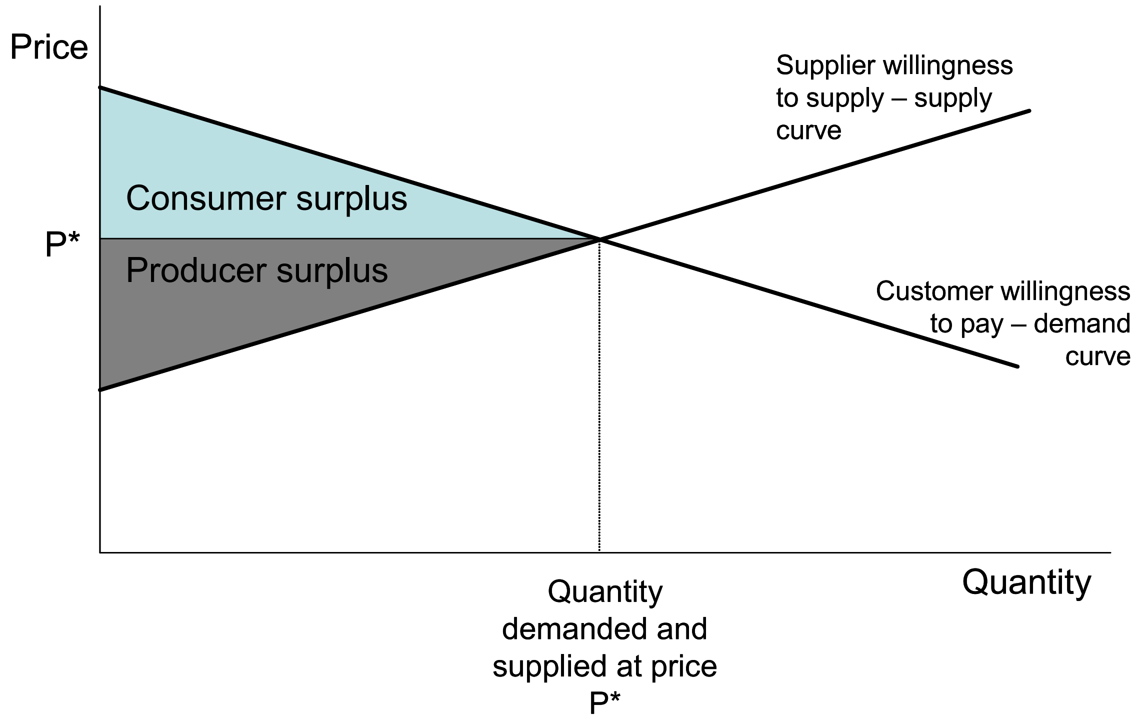
Estimates of annual net benefits, Bn - Cn, are measured with respect to consumer surplus and producer surplus. The former is measured, for each unit of a transaction, as the difference between the value the purchaser places on the unit and the transaction price. The latter is measured, for each unit of a transaction, as the difference between the transaction price and the opportunity cost of production.[111] These two components of social welfare are illustrated schematically in Figure 6-3.

---

110 See also Appendix G for further discussion at the planning process.

111 The opportunity cost of production is equal to the value of all resources utilized in the production process.

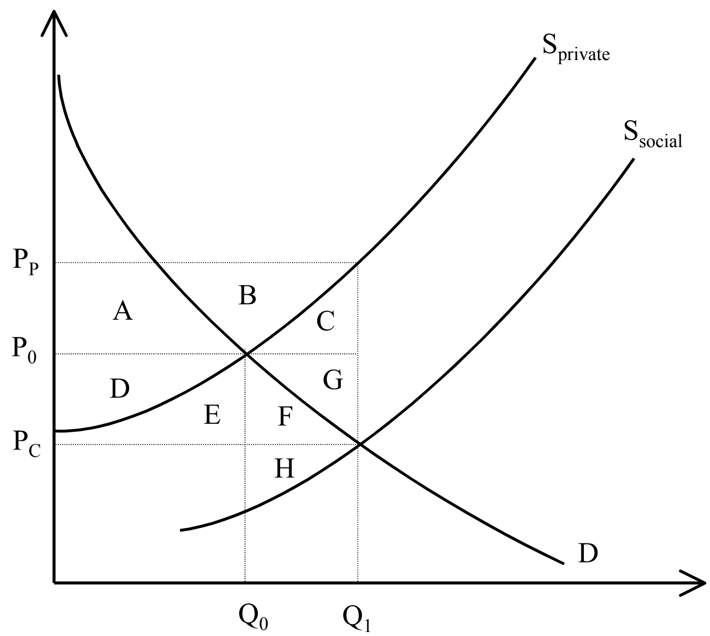
Figure 6-3. Consumer and Producer Surplus



Policymakers are increasingly recognizing the importance of systematically accounting for externalities when evaluating investment / policy alternatives. Externalities are present in many economic activities because of market imperfections. Generally speaking, an externality is defined to occur when an activity or transaction impacts members of society not directly involved in the activity or transaction. A positive externality is one where the non-transacting members of society experience a benefit as a result of the transaction. Conversely, a negative externality is one where the non-transacting members of society experience additional costs as a result of the transaction. Any particular transaction can simultaneously create both positive and negative externalities.

When externalities indirectly impact the welfare of citizens other than those directly involved in the transaction, there is a divergence between private and social opportunity costs. This is illustrated graphically in Figure 6-4. The supply curve reflecting the costs incurred by the seller in the transaction is represented by $S_{private}$. The existence of a positive externality lowers the social cost for each unit of the transaction, resulting in a social supply curve represented by S_{social}. The socially optimal amount of production is Q_1, associated with the intersection of demand with the social supply curve. If the positive externality is not explicitly accounted for, there would be under-production at level Q_0.

Figure 6-4. Effects of Positive Externalities



A full-cost accounting analysis within a social welfare context of the benefits of recognizing and internalizing an externality would proceed by analyzing differences in consumer and producers surpluses. Consumer surplus increases by the area [D+E+F] because consumers pay a lower price than under the purely private equilibrium (i.e., $P_c<P_0$); producer surplus increases by the area [A+B] because producers receive a higher price ($P_P>P_0$). These gains are offset by the subsidy required to motivate consideration of the externality by the contracting parties - this is reflected in the area [A+B+C+D+E+F+G]. The difference between this subsidy and the improvements in consumer and producer is reflected in the area [C+G], suggesting that the costs of recognizing and responding to the externality outweigh the benefits. But this overlooks the broader social benefits, reflected in [C+F+G+H], the area between the two supply curves for the incremental capacity. When all costs are benefits and accounted for, including those associated with parties not directly involved in the transaction, the overall net social value of accounting for the externality is positive, reflected in the area [F+H].

Externalities Potentially Relevant to Kentucky's IRP Process

This illustrates the most effective way of dealing with an externality. Conceptually, all externalities can be addressed this way. The classic example is pollution. If production from the polluting source is taxed, then the tax proceeds can be used to compensate members of society for the harm they experience. But this is an area where what is easy in concept is often very difficult in practice – political and administrative constraints can be overwhelming (imposition of a tax may be politically unacceptable; and the identification of those harmed, quantification of their damages and distribution of their compensatory payments will likely be administratively impossible). The challenge for policymakers comes down to developing ways to internalize externalities to the greatest extent possible.

Categories of potential externalities to be considered within the context of Kentucky's electricity sector have been identified in item (3) of Section 50 of the Energy Act, introducing the concept of full-cost accounting and requiring consideration of "life-cycle energy, economic, public health and environmental costs of various strategies for meeting future energy demand."

The clearest example of an externality associated with the electric industry is pollution in the form of emissions. There are many studies documenting the deleterious environmental effects of power plant emissions.[112] There are also studies allegedly identifying and estimating the public health costs associated with the electric industry.

A summary of the U.S. electric industry's status in dealing with environmental externalities is presented in Appendix G. The particular externality that is being addressed most systematically within the electricity industry today relates to carbon emissions, which we discuss further below.

Status of Current (Federal) Carbon Legislation and Likely Outcomes

The European Union (EU) has led the world in developing institutions and procedures for addressing the environmental impacts of carbon emissions. The EU implemented in January 2005 an emissions trading scheme (ETS) requiring large polluters, including electricity companies, to trade permits allowing them to emit carbon dioxide and other climate-changing pollutants.[113] The ETS covers multiple countries and multiple sectors (not just the energy sector).

While there is currently no corresponding scheme within the United States, most industry participants and observers expect that there will be one soon. Several bills have been proposed, including:

- America's Climate Security Act of 2007, U.S. Senate Bill 2191, sponsored by Senators Lieberman and Warner;
- Climate Stewardship and Innovation Act of 2007, U.S. Senate Bill 280, sponsored by Senator Lieberman;
- Low Carbon Economy Act of 2007, U.S. Senate Bill 1766, sponsored by Senator Bingaman;
- Global Warming Pollution Reduction Act of 2007, U.S. Senate Bill 485, sponsored by Senator Kerry;
- Electricity Utility Cap and Trade Act of 2007, U.S. Senate Bill 317, sponsored by Senator Feinstein;

---

112 See, for example, "The Benefits and Costs of the Clean Air Act, 1970 to1990;" Prepared for U.S. Congress by U.S. Environmental Protection Agency; October 1997.

113 *See* http://ec.europa.eu/environment/climat/emission.htm and *The European Union Emissions Trading Scheme* Review of Environmental Economics and Policy 2007.

- Safe Climate Act of 2007, U.S. House Bill 1590, sponsored by Congressman Waxman; and
- Climate Stewardship Act of 2007, U.S. House Bill 620, Congressman Olver.

There is substantial overlap across these Senate and House bills. A strong consensus has begun to emerge around a trading-based approach, similar in many respects to what has emerged, and is continuing to evolve, in Europe. Attention has focused in particular on S. 2191, the Lieberman Warner Climate Security Act, introduced October 2007. The bill was reported out of the Senate Committee on Environment and Public Works on December 5, 2007. Within the House of Representatives, members of the Committee on Energy and Commerce have stated plans to introduce and act on climate change legislation early in 2008.

S. 2191 divides greenhouse gases into two groups: (i) Group 1, consisting of carbon dioxide, methane, nitrous oxide, sulphur hexafluoride, and perfluorocarbons; and (ii) Group II, hydrofluorocarbons.[114] The objective of the bill is to reduce 2005 levels of emissions of these greenhouse gases by seventy percent by 2050. If enacted, S. 2191 would seek to accomplish this goal by establishing a national "cap and trade" scheme for so-called greenhouse gas emissions that is very similar to the EU's ETS.

Beginning in 2012, the federal government would begin: (i) to annually reduce the number of permits allocated to covered facilities (with separate rates of decline for the two Groups of gases); and (ii) to move towards a scheme where all permits will eventually be distributed through auction rather than allocation.

- The provisions of S. 2191 apply to over 80% of the country's greenhouse gas emissions.

Additional proposals have been put forward in recent months. U.S. Senators Jeff Bingaman and Arlen Specter proposed the Low Carbon Economy Act in July 2007. The primary mechanism this proposal puts forward is the cap and trade system, where polluters are allowed to pay a fee instead of making carbon cuts. This bill also includes price caps on allowances, which start off at \$12 per metric ton of CO_2 in 2012, and rise until they reach \$23.07 per ton in 2030. The analysis by the EIA suggests that this proposed bill would fail to curb carbon emissions and reach its own targets (to limit greenhouse gas emissions at 1990 level in 2030 with intermediate goal of reducing emissions to 2006 levels by 2020) due to the price cap on allowances.

U.S. Senator Bernie Sanders has introduced "The Global Warming Pollution Reduction Act," which is a bill to amend the Clean Air Act to reduce emissions of carbon dioxide, and for other purposes. The bill, which does not include cap-and-trade, applies pollution standards to vehicle emissions, coal production and power plants, and also sets energy efficiency standards to reduce energy consumption. The target is to reduce emissions to 1990 levels by 2020 and further reduce them until 2050.

---

114 See S.2191, "A bill to direct the Administrator of the Environmental Protection Agency to establish a program to decrease emissions of greenhouse gases, and for other purposes."

A summary of notable legislative proposals introduced within the past five years is summarized below in Figure 6-5.[115]

Figure 6-5. Notable Legislative Proposals on Greenhouse Gases

Proposed National Policy	Title or Description	Year Proposed	Emission Targets	Sectors Covered
McCain Lieberman S.139	Climate Stewardship Act	2003	Cap at 2000 levels 2010-2015. Cap at 1990 levels beyond 2015.	Economy-wide, large emitting sources
McCain Lieberman SA 2028	Climate Stewardship Act	2003	Cap at 2000 levels	Economy-wide, large emitting sources
National Commission on Energy Policy (basis for Bingaman-Domenici legislative work)	Greenhouse Gas Intensity Reduction Goals	2005	Reduce GHG intensity by 2.4%/yr 2010-2019 and by 2.8%/yr 2020-2025. Safety-valve on allowance price	Economy-wide, large emitting sources
Sen. Feinstein	Strong Economy and Climate Protection Act	2006	Stabilize emissions through 2010; 0.5% cut per year from 2011-15; 1% cut per year from 2016-2020. Total reduction is 7.25% below current levels.	Economy-wide, large emitting sources
Jeffords S. 150	Multi-pollutant legislation	2005	2.050 billion tons beginning 2010	Existing and new fossil-fuel fired electric generating plants >15 MW
Carper S. 843	Clean Air Planning Act	2005	2006 levels (2.655 billion tons CO2) starting in 2009, 2001 levels (2.454 billion tons CO2) starting in 2013.	Existing and new fossil-fuel fired, nuclear, and renewable electric generating plants >25 MW
Rep. Udall - Rep. Petri	Keep America Competitive Global Warming Policy Act	2006	Establishes prospective baseline for greenhouse gas emissions, with safety	Not available

Source: Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning by Synapse Energy Economics

The consensus view of observers of the Washington political process seems to be that, while many hurdles remain, it is likely that some version of the Lieberman-Warner or Bingaman-Specter bills will be passed this year or early next. A similar consensus view emerged from industry stakeholders that we interviewed in December 2007. Key members of the finance community are now proceeding under the assumption that the U.S. government will cap greenhouse-gas emissions from power plants sometime in the next few years. Citigroup Inc., J.P. Morgan Chase & Co. and Morgan Stanley recently announced that they will require utilities seeking financing for power to prove that the plants will be profitable under potentially stringent federal caps on carbon dioxide.[116]

The key open questions relate to timing and requirement levels of compliance. Once a bill is passed, implementation would likely not start for a number of years. The impact on carbon prices is perhaps least certain. These bills have direct financial incentives for renewables, since the allowances granted could be sold, and therefore monetized.

[115] Big Rivers Response to Data Request dated January 7, 2008 ("*Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning*"; Synapse Energy Economics; p. 24, Table 5.1.)

[116] "Wall Street Shows Scepticism Over Coal;" The Wall Street Journal; February 4, 2008; p. A6.

Carbon Mitigation Technologies; Resource Options

Utilities in Kentucky have begun to assess the potential economic impact of carbon mitigation. While very preliminary in nature, several estimates have indicated a 15-20% premium over non-carbon conventional coal dispatch costs. These estimates are in the process of more robust analysis, though significant uncertainty continues to exist at this time.[117]

Some limited technologies are currently available to mitigate the level of carbon emissions produced from coal-fired generating facilities. However, these technologies will add to current generation costs. Current estimates of capacity and energy reductions associated with carbon reduction or carbon capture include:

- IGCC Unit 15% premium over pulverized coal unit
- Sequestration 60-70% premium over pulverized coal unit

A 60–70% premium over a conventional coal unit represents an approximate equivalent premium of $40 to $50/ton of coal.[118]

Duke Kentucky, East Kentucky, Big Rivers and KPC do not currently consider the potential impacts of carbon taxes, or other carbon cost effects in determining avoided costs, or in any sensitivity analyses associated with such costs.[119]

KU and LG&E considered potential carbon emission impacts in its 2005 IRP. In its 2008 IRP, the Companies intend to provide a more detailed analysis of potential CO_2 impacts, including the economics of carbon capture and sequestration, plant efficiency improvements, and demand reduction programs.[120]

In its most recent IRP cycle, KPC reflected the potential impact of GHG restrictions and potential CO^2 taxes in its base case. These analyses were used to test the reasonableness of the selected plan.[121]

In its 2008 IRP filing, Duke Kentucky expects to model at least one scenario with a CO_2 tax/emission allowance price, as well as a renewable performance standard.[122]

Recommendation: **Until such time as anticipated federal legislation is formally enacted addressing carbon emission standards, utility IRP and CPCN filings should provide best available estimates of expected carbon impacts in justifying resource selections among portfolio options.**

---

[117] East Kentucky Response to Discovery, DR-02-24; Duke Kentucky Response to Discovery, DR-02-21; Big Rivers Response to Discovery, DR-02-21.

[118] KPC Response to Discovery DR-02-19.

[119] Duke Kentucky Response to Discovery, DR-02-20; East Kentucky Response to Discovery, DR-02-22; Big Rivers Response to Discovery, DR-02-20; KPC Response to Discovery, DR-02-18.

[120] KU/LG&E Response to Discovery, DR-02-18.

[121] KPC Response to Discovery DR-02-20.

[122] Duke Kentucky Response to Discovery DR-02-22.

Consideration of Avoided Costs in Investment Analysis

Avoided cost data has historically been filed with the Commission to establish rates applicable to cogeneration. There has been no specific requirement that avoided costs include capacity costs.

Current Kentucky utility avoided costs for energy are in the range of 2.5 to 4.5 cents/kWh. Capacity costs are about $75 to $100/kW.[123] For comparative purposes, the estimated construction cost of various generating facilities is as follows (in $/kW terms):[124]

Combustion Turbine	$ 420
Gas Combined Cycle	$ 603
Wind	$1,206
Scrubbed Coal	$1,290
IGCC	$1,491
Conventional Hydro	$1,500
IGCC/w Sequestration	$2,134
Solar Thermal	$3,149
Photovoltaic	$4,751

These costs are stated in 2005 dollars/kW, and are based on national average data. Each of the technologies represented above have varying heat rates, plant availability factors, fuel and operating costs that must be taken into account in an actual resource plan analysis.

KPC considers the avoided cost of capacity and energy in its cost-benefit analyses; specifically including consideration of DSM or renewable projects.[125] KU and LG&E also reflect the avoided cost of capacity and energy in their cost-benefit analysis. The relative availability and dependability of capacity from technologies such as windpower or solar PV must be recognized in assessing capacity benefit.[126] Duke Kentucky recognizes the avoided cost of capacity in evaluating DSM programs. Renewables projects are evaluated in their optimization model, just as other conventional supply-side resources.[127] East Kentucky recognizes avoided capacity costs in its DSM evaluation based on a weighted average of generation resources matched to anticipated load.[128]

Big Rivers receives the majority of its current power needs under a purchase power agreement with LG&E Energy Marketing. The agreement provides for an energy-only price. As such, Big Rivers maintains that it has no avoided capacity costs, and makes this assumption in its cost-benefit analyses of DSM or renewable energy options.[129]

---

123 This information was generally based upon responses to discovery identified as confidential, and as such, is not specifically quoted or referenced by utility.

124 EIA, 2007 Annual Energy Outlook; page 77; based on 2005 costs.

125 KPC Response to Discovery, DR–02-16.

126 KU/LG&E Response to Discovery, DR-02-16.

127 Duke Kentucky Response to Discovery, DR-02-18.

128 East Kentucky Response to Discovery, DR-02-20.

129 Big Rivers Response to Discovery, DR-02-17.

<u>Recommendation</u>: **Utilities should be required to file avoided cost data (not less than annually), subject to the review and approval of the Commission. Consideration of energy efficiency and DSM programs, as well as renewables projects, should be measured against the appropriate avoided costs. Programs that reliably reduce peak load should be evaluated against the avoided cost of both demand and energy.**

Consideration of Full-Cost Accounting in Kentucky's IRP and Certificate Process

The conceptual framework for cost-benefit analysis, including the identification and quantification of externalities, has been addressed earlier in this chapter. Because of the high probability of near-term legislation to constrain GHG, we have addressed the potential impacts of carbon constraints on generation costs more specifically. However, we have omitted specific analysis of public health or other externalities, as we agree with the past assessment of the Commission that current statutes do not provide for consideration of such costs.

Recognition of externalities in the resource planning process is not generally considered in the U.S. Federal and state policies, as well as the current economics of resource alternatives, however, are providing incentives for the growth of demand-side alternatives and renewable generation options.

To impose recognition of externalities (except in the limited context addressed earlier in this chapter) would arbitrarily and improperly cause energy costs in Kentucky to increase significantly; jeopardize the credit quality of regulated utilities in the State; and hamper economic development

<u>Recommendation</u>. **The Commission should not require the recognition of environmental or public health externalities in the IRP or certificate processes, unless it finds it appropriate to specifically direct a utility (or utilities) to do so.**[130]

---

[130] An example of such a condition is found in a previous recommendation regarding carbon impacts contained in this Chapter.

[This page intentionally left blank.]

Chapter 7 – Current Energy Planning and Programs, Analysis and Recommendations Rates and Regulation

This chapter provides an analysis of rate design opportunities and utility financial incentives, consistent with the Section 50 of the Energy Act, Item 4:

> Modifying rate structures and cost recovery to better align the financial interests of the utility with the goals of achieving energy efficiency and lowest life-cycle energy costs to all classes of ratepayers.

The discussion in this chapter provides an overview of existing rates and rate structures, focusing primarily on the specific mechanisms associated with the provisions contained in Section 50 of HB 1. As required by Item 4, we also provide a review of the financial implications and necessary incentives to create a more favorable environment for utility investment in demand-side programs and renewable energy alternatives.

Information about industry practices with respect to establishment and implementation of alternative rate structures is contained in Appendix H of this report.

Existing Rate Structures and KPSC Statutory Authority

Consistent with KRS 278.030, rates must be fair, just and reasonable; and customer service must be "adequate, efficient and reasonable". KRS 278.170 provides that rates must not "give any unreasonable preference…or maintain any unreasonable difference between localities or between classes of service for doing a like and contemporaneous service under the same or substantially the same conditions." The criteria for the Commission's authority to set utility rates are further defined in KRS 278.270, wherein it provides that rates that are "unjust, unreasonable, insufficient, unjustly discriminatory or otherwise in violation of any of the provisions of this chapter" shall not be permitted.

Pursuant to this statutory framework, all jurisdictional generating utilities provide customer service based upon approved tariffs, including the standard terms and conditions of service. These offerings, including the pricing and pricing mechanisms for customer services, are the result of administrative proceedings arising from the review of various elements of the utilities' operations; most often in the context of general rate applications. However, particular cost elements of utility operations, or program offerings may also be considered by the Commission in proceedings that arise from more narrow aspects of utility operations, such as fuel costs and recovery mechanisms.

Overland believes, as do most parties and stakeholders, in these proceedings that the KPSC has broad statutory authority to implement utility tariffs, including surcharge mechanisms. However, when questions arise concerning the extent of intended authority granted to the Commission, a judicial process is in place to resolve such disputes.

The current appellate review process for KPSC actions is addressed in KRS 278.410. This process provides for both trial court and appellate reviews that impose a burden of resources and time on parties to a proceeding under appeal. Importantly, this results in an atmosphere of regulatory and judicial uncertainty, and thereby contributes to increased operating and financial risk.

The recent downgrade of Duke Kentucky credit from Baa1/Positive to Baa/ Stable is an example of the direct relationship associated with the potential impacts of regulatory uncertainty. In a recent Moody's release, it addressed potential risks associated with alternative rate mechanisms.[131] More specifically, without debating the specific merits of the Duke Kentucky alternative ratemaking decision, which is currently pending judicial review, this case raises issues that directly bear upon this proceeding. The degree of KPSC authority in setting rates, including surcharge mechanisms, should be settled by the legislative intent of powers granted by the General Assembly. The process for judicial review of KPSC decisions, as previously cited, is also defined by current statutes.

Overview of Utility Regulation – Cost of Service; Incentive Regulation

The fundamental purpose of utility regulation in Kentucky, consistent with state regulation throughout the United States, is to provide a surrogate for competition for those services that exist in a monopoly environment. In this context, regulators have the responsibility of setting fair, just and reasonable rates, while assuring safe and reliable service to customers. In achieving these broad objectives, the Commission must balance the interests of all stakeholders. While service is generally priced on a "least-cost" basis, regulators must also take into consideration the financial condition of the utilities providing such services, as well as the right of utilities to earn a fair return on their regulated investments.

Electric utility prices in Kentucky are currently set based upon a traditional rate of return model, where earnings are driven by capital investment in utility plant. The present rate-setting framework creates strong financial incentives for companies to invest in additional infrastructure, including supply-side resources, and to expand energy sales. Absent incentives to respond otherwise, utilities face penalties (loss of sales, return on investment, etc.) for the development of new, or expansion of current, energy efficiency programs.

Regulators have provided incentives to jurisdictional utilities in the past to bring about policy or efficiency objectives such as industry restructuring of generation and transmission services; or implementation of cost containment and operating efficiency programs. More recently, state legislatures and utility regulators have focused on generation planning, energy conservation and efficiency measures necessary to respond to Federal legislation, as well as to state-specific considerations focused on resources required to support energy needs and economic development.

Regulatory policies, supported by utility case law, have long recognized basic rate design objectives that include:

---

[131] Duke Kentucky Response to Discovery, DR-02-39 Update; Moody's Credit Opinion dated January 25, 2008.

- Stability in customer rates;
- Energy conservation;
- Effective recovery of utility costs, including a fair return on investment;
- Fair, just and reasonable rates; and
- Prohibition of undue discrimination.

In establishing customer rates, there is an inherent effort by regulators to develop policies that minimize costs. However, in the utility ratesetting context, this is most often defined as the net present value of such costs over the useful life of employed assets or programs implemented. Consideration of public policy is also a factor in developing "reasonable" rates. These precepts are fundamental to the ratemaking process in general, as well as directly applicable to the subject matter and recommendations contained in this report.

Current Utility Tariffs

The following tariffs (for the Kentucky generating utilities providing direct service to customers) were selected to provide a representation of current rate structures for the primary service offerings across customer classes and varying levels of energy usage.

Figure 7-1
Duke Kentucky
Primary Service Offerings

Description	**Residential Customers**	**Commercial Customers**	**Industrial Customers**
Rate Schedule	**Rate RS**	**Rate DS**	**Rate TT**
Rate Description	Residential Service	Service at Secondary Distribution Voltage (< 500 kW per month)	Time-of-Day Rate for Service at Transmission Voltage
Customer Charge	$3.73 per month	Single Phase Service = $5.00 per month; Three Phase Service = $10.00 per month.	$500.00 per month
Demand Charge		First 15 kW = $0.00 per kW; additional kW = $6.53 per kW	Summer: On Peak kW = $6.52 per kW; Off Peak kW = $1.00 per kW Winter: On Peak kW = $5.33 per kW; Off Peak kW = $1.00 per kW
Energy Charge	Summer Rate: First 1,000 kWh = $0.06562 per kWh; additional kWh = $0.06873 per kWh Winter Rate: First 1,000 kWh = $0.06562 per kWh; additional kWh = $0.05059 per kWh	First 6,000 kWh = $0.06896 per kWh; next 300 kWh = $0.04210 per kWh; additional kWh = $0.03497 per kWh	$0.03485 per kWh
Source: Most recent Duke Kentucky Schedule of Rates, Classifications Rules and Regulations.			

Figure 7-2
LG&E
Primary Service Offerings

Description	Residential Customers	Commercial Customers	Industrial Customers
Rate Schedule	**RS**	**GS**	**LP-TOD**
Rate Description	Residential Service	General Service (< 500 kW)	Large Power Industrial Time-of-Day (> 2,000 kW)
Customer Charge	$5.00 per month	Single-Phase Service = $10.00 per meter per month; Three-Phase Service = $15.00 per meter per month	$120.00 per delivery point
Demand Charge			Basic Demand Charge: Secondary Distribution = $4.88 per kW; Primary Distribution = $3.82 per kW; Transmission Line = $2.66 per kW Peak Period Demand Charge: Secondary Distribution = $10.02 per kW (Summer); $7.43 per kW (Winter); Primary Distribution = $9.32 per kW (Summer); $6.73 per kW (Winter); Transmission Line = $9.31 per kW (Summer); $6.72 per kW (Winter)
Energy Charge	$0.06035 per kWh	Summer Rate = $0.07245 per kWh; Winter Rate = $0.06473 per kWh	$0.02008 per kWh
Source: Most recent LG&E Rates, Terms and Conditions for Furnishing Electric Service.			

Figure 7-3
KU
Primary Service Offerings

Description	Residential Customers	Commercial Customers	Industrial Customers
Rate Schedule	**RS**	**GS**	**LCI-TOD**
Rate Description	Residential Service	General Service (< 500 kW)	Large Commercial / Industrial Time-of-Day Service (> 5,000 kW)
Customer Charge	$5.00 per month	$10.00 per month	$120.00 per month
Demand Charge			Primary: On-Peak = $5.16 per kW; Off-Peak = $0.74 per kW Transmission: On-Peak = $4.97 per kW; Off-Peak = $0.74 per kW
Energy Charge	$0.04865 per kWh	$0.05818 per kWh	$0.02501 per kWh
Source: Most recent KU Rates, Terms and Conditions for Furnishing Electric Service.			

Figure 7-4
KPC
Primary Service Offerings

Description	**Residential Customers**	**Commercial Customers**	**Industrial Customers**
Rate Schedule	**R.S.**	**M.G.S.**	**C.I.P. – T.O.D.**
Rate Description	Residential Service	Medium General Service (10 kW – 100 kW)	Commercial and Industrial – Time-of-Day (>7,500 kW)
Service Charge	$5.86 per month	Secondary = 13.50 per month; Primary = $21.00 per month; Subtransmission = $153.00 per month	Primary = 276.00 per month; Subtransmission = $662.00 per month; Transmission = $1,353.00 per month
Demand Charge		Secondary = $1.31 per kW; Primary = $1.28 per kW; Subtransmission = $1.25 per kW	Primary: On-Peak = $13.79 per kW; Off-Peak = $3.68 per kW Subtransmission: On-Peak = $10.83 per kW; Off-Peak = $0.98 per kW Transmission: On-Peak = $9.35 per kW; Off-Peak = $0.84 per kW
Energy Charge	$0.06002 per kWh	200x kW of monthly billing demand: Secondary = $0.06988 per kWh; Primary = $0.06318 per kWh; Subtransmission = $0.05744 per kWh In excess of 200x kW of monthly billing demand: Secondary = $0.05826 per kWh; Primary = $0.05526 per kWh; Subtransmission = $0.05321 per kWh	Primary = $0.01685 per kWh; Subtransmission = $0.01660 per kWh; Transmission = $0.01640 per kWh
Source: Most recent KPC Schedule of Tariffs, Terms and Conditions of Service Governing Sale of Electricity.			

A number of observations can be made from a review of these tariffs. Over time, utility retail tariff rate designs have moved away from declining block rates, and are now generally flat. The use of seasonal rates is now quite limited. Residential tail-block energy rates are approximately 6 cents/kWh, while large industrial tail-block rates are 2 to 3.5 cents/kWh. These rates compare to avoided energy generation costs of 2.5 to 4.5 cent/kWh.

Lifeline Rates. Kentucky utilities do not offer low-income or "lifeline" rates. However, Home Energy Assistance ("HEA") Programs are in place to assist low-income customers; at least by certain utilities. LG&E and KU have had HEA programs in place since 2004. These programs are based on a 10 cent per residential customer charge, which produces approximately $1.3 million per year in gross proceeds.[132] KPC implemented a similar program in 2006, which

[132] KU/LG&E Response to Discovery, DR-02-34.

charges residential customers 10 cents per month, with such amounts being matched by the Company. It is estimated that the program will raise about $175,000 per year from customers, and an additional $175,000 in a matching contribution from the company.[133]

Duke Kentucky customers may volunteer to support the Winter Care Program, which produced $50,000 in 2006.[134] Several of the East Kentucky member co-ops support the Winter Care or similar programs.[135]

Possible Alternatives to Current Tariff Rate Structures

In considering rate structures that might facilitate energy conservation objectives, it remains important to also recognize other fundamental objectives including: revenue requirement recovery and utility revenue/earnings stability; stability in customer rates; and rate design simplicity. These objectives may create a tension with measures that might be considered in increasing energy efficiency through rate design mechanisms.

Increasing tier block (or inverted block) rates. Inverted rates are sometimes considered as a mechanism to encourage energy efficiency, as prices rise with increasing consumption. Assuming that marginal costs are higher than average energy costs, this arguably provides a better signal for marginal use. There are at least two major problems, however, with inverted rates. Utility earnings are subject to much greater variability with inverted rates, as a greater portion of revenue recovery is subject to the level of tail-block consumption. Inverted rates are not a particularly efficient mechanism to price on-peak versus off-peak consumption. If customer consumption patterns cannot or do not change, inverted rates may result in major increases (or decreases) in customer utility bills.

Seasonal Rates. Seasonal differentials provide for higher rates during defined peak seasonal periods, and thus, encourage energy conservation. Seasonal rate differentials may provide a modest price signal benefit. However, this mechanism is not very efficient in creating a differential for on-peak versus off-peak consumption. Customers may reduce load during off-peak periods without necessarily altering demands during peak-period conditions.

Rate Decoupling. Simply put, the general concept of decoupling is to allow mechanisms for revenue recovery that are independent of sales volume. In the face of policies that may lead to declining sales, this approach may intuitively have some appeal. However, there are serious problems with this methodology that may easily lead to an asymmetric allocation of risks and benefits between the utility and its customers. Given our proposed approach to expand energy efficiency programs, DSM and portfolio diversification, and the package of recommendations to support this approach[136]; it is unnecessary and inappropriate to also consider rate decoupling.

---

133 KPC Response to Discovery, DR-02-35.

134 Duke Kentucky Response to Discovery, DR-02-36.

135 East Kentucky Response to Discovery, DR-02-40.

136 The Overland recommendations provide for financial incentives and recovery mechanisms to mitigate the potential adverse effect of lost sales.

We believe that our proposals form a more efficient foundation for creating customer benefits, while providing utility earnings incentives and financial stability.

Time-of-use and dynamic rate pricing mechanisms are far more efficient in providing accurate pricing signals based on time-differentiated utility energy costs. As such, these mechanisms are also more effective in achieving energy conservation and demand reduction objectives.

Interruptible and Load Control Tariff Options

While all utilities offer various interruptible and load control tariff options for their large commercial and industrial customers, there has been little interest in these service offerings. KPC has no customers currently taking interruptible service.[137] LG&E and KU have approximately twelve customers with approximately 185 MW subject to interruption or control.[138] East Kentucky has five interruptible customers with about 170 MW of maximum peak load subject to interruption.[139]

LG&E/KU have a Demand Conservation program to directly control customer load during system peak periods. There are currently 117,500 residential and 2,500 commercial participants in this program. The estimated reduction in peak load is 118 MW.[140] Duke Kentucky has a residential direct load control DSM program with 7,600 participants.[141]

Time-of-Use Rates and Smart Metering

Time-of-use (TOU) rates establish price differentials by seasonal or time-of-day increments. On-peak prices are generally set to approximate long-run marginal costs. TOU rates will typically reflect major price differentials for peak versus off-peak consumption. Given the constraint that rates must be set to recover a defined revenue level, off-peak rates may encourage load shifting, or even potential increases in energy consumption during off-peak periods. The major benefit of TOU rates is, however, the incentive for customers to reduce peak period demand and energy use.

Dynamic rates are a form of TOU pricing, where prices are set based on real-time market conditions. That is, real-time prices will vary continuously as a function of actual generation dispatch costs. Dynamic rates will also typically allow for critical peak pricing (CPP), where high per unit rates are applied to critical peak periods defined by the utility, for a limited number of days (not specified) occurring during the year.

The following table reflects the current number of customers on time-of-day rates.

---

[137] KPC Response to Discovery, DR-02-21.

[138] KU/LG&E Response to Discovery, DR-02-23.

[139] East Kentucky Response to Discovery, DR-02-29.

[140] KU/LG&E Response to Discovery, DR-02-23.

[141] Duke Kentucky Response to Discovery, DR-02-25.

Figure 7-5
Time of Day Customer Participation

Entity	Customer Class / Tariff	Number of Customers
LG&E / KU	Large Commercial Time-of-Day Service	111
LG&E / KU	Large Mine Power Time-of-Day Service	69
LG&E / KU	Large Industrial Time-of-Day Service	1
Duke Kentucky	Time-of-Day Rate for Service at Transmission Voltage	14
Duke Kentucky	Time-of-Day Rate for Service at Distribution Voltage	223
KPC	Storage / Load Management Water Heating (Residential)	140
KPC	Load Management Time-of-Day (Residential)	196
KPC	Time-of-Day (Residential)	1
KPC	Load Management Time-of-Day: Tariff SGS (Commercial & Industrial)	1
KPC	Recreational Lighting (Commercial & Industrial)	71
KPC	Load Management Time-of-Day: Tariff MGS (Commercial & Industrial)	55
KPC	Time-of-Day (Commercial & Industrial)	75
KPC	Load Management Time-of-Day: Tariff LGS (Commercial & Industrial)	9
KPC	Off-Peak Excess Billing Demand (Commercial & Industrial)	91
KPC	Time-of-Day Billing Demand (Commercial & Industrial)	16
Big Rivers	None	N.A.
East Kentucky	Wholesale Tariff Section B	60
East Kentucky	Wholesale Tariff Section C	13
East Kentucky	Wholesale Tariff Section E: Option 1	25
East Kentucky	Wholesale Tariff Section E: Option 2	272

Sources: LG&E/KU (DR 02-24), Duke Kentucky (DR 02-26), KPC (DR 02-22), Big Rivers (DR 02-24), and East Kentucky (DR 02-30).

Many stakeholders have observed that DSM has not been as successful to date in Kentucky as in other states. The lack of success is typically rationalized by the low overall price and small peak versus off-peak differential in Kentucky's energy costs.[142] However, TOU rates and DSM are inextricably linked elements of policy and rate design. Unless customers can experience power cost increases and decreases on a timescale more frequent than a month, they will not be motivated to change their consumption patterns.

LG&E is currently conducting pilot programs with on/off peak options for customers with smaller loads, including residential customers. These programs will measure the ability to incent customers to reduce consumption and shift loads from peak periods.[143]

---

[142] As an example, KPC indicated that participation in time-of-day or on-peak/off-peak programs is limited by lack of economic benefits sufficient to induce customers to alter existing usage patterns. KPC Response to Discovery, DR-02-23.

[143] KU/LG&E Response to Discovery, DR-02-25.

Duke Energy has also developed a "Utility of the Future Initiative" that assumes deployment of smart meters for all utility customers. Based upon a reasonable scale of deployment, the estimated metering costs are in the range of $260 to $280 per customer. Demand reduction, including load control, is a major expected result, among other benefits such as reduced meter reading costs; improved customer communications; and improved service quality. The program is considered to be cost justified in light of estimated benefits.[144]

Pursuant to the Commission's directive in Administrative Case No. 2006-00045, each of the jurisdictional electric utilities other than Duke Kentucky filed applications in April, 2007 to implement voluntary real-time pricing (RTP) pilot programs for large commercial and industrial customers.[145] Each of the programs is scheduled to run for three years at which time they will be evaluated for continued offering. Deferral of unrecovered costs associated with these pilot programs was authorized by the KPSC. The reasonableness and ultimate recovery of such costs will be determined during the respective utility's next rate filing.

Recommendation: **Assuming that the results of current pilot programs are positive, TOU rates and RTP should be more broadly applied to industrial customers in the future.**

Smart Metering

TOU rates are essential in increasing customer awareness (across all customer classes) of conservation benefits. The deployment of smart meters, meters that provide two-way communication, will enhance the potential type and participation level of DSM programs. Customers will have better pricing information, and will have the ability to control their consumption more efficiently. KPC is currently evaluating the costs and benefits of installing an advanced metering infrastructure, which would include smart meters.[146] LG&E is studying the relative benefits of smart meters in its "Responsive Pricing and Smart Metering Pilot Program", which is currently underway.[147] [148]

Fuel Adjustment Clause

We have reviewed the current fuel adjustment clause mechanism, and do not find any specific impediments caused by continued operation in its present form; provided that our recommendations are implemented regarding modifications to other current recovery mechanisms or the creation of new ones. The current provisions of the FAC have no mechanism that would allow allocation of external costs addressed in Chapter 6, nor does Overland recommend any such recognition of environmental or health costs that do not currently impose a direct cost.

---

144 Duke Kentucky Response to Discovery, DR-02-24. This program has not been requested in Kentucky.

145 Duke Kentucky was exempt from the requirement because it already offered an RTP tariff to commercial and industrial customers.

146 KPC Response to Discovery, DR-02-40.

147 KU/LG&E Response to Discovery, DR-02-22; DR-02-46.

148 In a brief filed with the Commission (Case No. 2006-00045), Big Rivers cited costs for smart metering, including communication, at $250 per installed meter. Big Rivers Response to Discovery, DR-02-39; p. 8.

DSM Surcharge

DSM programs are addressed in Chapter 4. This section addresses issues relevant to the DSM surcharge mechanism only. KRS 278.285 provides for mechanisms to recover DSM program costs, lost revenues, and "incentives designed to provide positive financial rewards to a utility to encourage implementation of cost-effective demand-side management programs". To date, utilities typically have been provided a margin of 5-10% (exclusive of tax gross-up) of approved DSM program expenditures.

DSM programs are currently developed in a collaborative process, or presented directly to the Commission by the utility. The program will typically provide for a recovery of program costs; an estimate of lost revenue to be recognized in the surcharge; and a provision for a return based on a margin allowance.[149] This process meets three important thresholds – it provides for cost recovery; it recognizes potential losses associated with declines in sales; and a provision is made for some contribution to earnings. However, in its present form, this mechanism is not likely to induce utilities to fundamentally change their business model to consider investment in DSM equal to supply side resources. The scale and return of these alternative investments are currently dramatically different.

<u>Recommendation</u>: **The current DSM Surcharge mechanism should be modified. Utility expenditures (capital, and operating costs related to the period of the program) should be capitalized, with amortization based on the estimated period of program benefits. Utilities should be allowed a minimum return of 100 bp higher than the most recent authorized rate of return in the utilities' last rate proceedings.[150] Utilities should be allowed to receive additional incentives based on the actual benefits achieved relative to appropriate targets from energy efficiency and DSM programs. Assuming that program targets are met, these incentives should provide a reasonable opportunity to earn a graduated return of up to 300 bp over the minimum premium, based on results.**

Should modifications to the surcharge mechanism be made, the continuing need for a "lost revenue" provision must be evaluated. Recognition of lost revenues may provide a duplication of earnings considerations and unnecessarily burden program costs, where returns on investments (expenditures) and program incentives are put in place.

Advertising Costs Associated With DSM and Energy Conservation Programs

The recovery of advertising costs associated with DSM and Energy Efficiency is not specifically addressed in KRS 278.285 – Demand-side management plans. While the regulation addressing recoverable advertising costs (807 KAR 5:016) does provide for "energy conservation" and explanations of "proposed or existing rate structure", it also defines advertising of "the selection or installation of any appliance or equipment designed to use" energy as "promotional advertising". Public awareness and educational programs are an important component of effective DSM and EE programs. The current definition of "promotional advertising" directly

---

[149] Big Rivers and East Kentucky do not use a DSM surcharge mechanism to track or recover DSM program costs.

[150] This assumes that the Commission has set the return within the last two years. (see Chapter 5 discussion).

conflicts with programs designed to implement more efficient equipment and appliances. It is important that these impediments, if not outright contradictions, in the guidelines for advertising expenditures be eliminated.

Recommendation: **The DSM statute and advertising regulation should be modified to provide explicit authority for advertising costs associated with DSM and energy efficiency programs. The advertising regulation should be amended with regard to its definition of "promotional advertising" to eliminate potential conflicts with the promotion of energy efficient equipment; programmable thermostats; smart metering devices; etc.**

Environmental Surcharge

This surcharge was established in the early 1990s to create a mechanism for recovery of Clean Air Act and other environmental compliance costs. The following summarizes utility recoveries in 2007.

Figure 7-6
Environmental Surcharge Information

Entity	2007 Collections
LG&E (A)	$9,916,160
KU (A)	42,051,289
Duke Kentucky (B)	N.A.
KPC	3,325,409
Big Rivers (B)	N.A.
East Kentucky (C)	60,275,745

Sources: LG&E/KU (DR 02-26), Duke Kentucky (DR 02-28), KPC (DR 02-24), Big Rivers (DR 02-26), and East Kentucky (DR 02-32).

A. 2007 collections are for the 12-month time period from December 2006 to November 2007.
B. Duke Kentucky and Big Rivers do not have environmental surcharge mechanisms.
C. East Kentucky provided environmental surcharge revenues "billed", not "collected".

Duke does not employ recovery of these costs through the Environmental Surcharge mechanism. Big Rivers has proposed to establish this mechanism in Case No. 2007-00460, which is now pending before the Commission.[151]

The KRS 278.183 language, at Item 1 of the Environmental Surcharge, defines the scope of costs potentially recoverable as follows.

> a utility shall be entitled to the current recovery of its costs of complying with the Federal Clean Air Act as amended and those federal, state, or local

151 Big Rivers Response to Discovery, DR-02-26.

> environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal…

Assuming that additional environmental legislation is passed regarding GHG or other potential restrictions, this surcharge mechanism could provide the structure to accumulate investment costs in facilities that may be required to meet compliance.

Plant Upgrades to Improve Efficiency

Utility investment to improve the operating efficiency of existing generation facilities results, at least indirectly, in mitigation of environmental wastes otherwise created by coal-fired facilities. Kentucky utilities are investigating economic modifications to existing facilities in their current planning. These investments might include: alteration of plant operating characteristics (such as increased steam temperatures and pressures); repowering (which could increase plant capacity and efficiency); or plant retrofitting (generally upgrading older facilities). Co-firing is another option currently under review for existing coal units.[152] Some utilities have already committed capital to plant upgrades.[153]

The implementation of economic upgrades, including co-firing capabilities, should be considered as an integral component of resource planning and environmental mitigation. The Commission can help foster, and possibly accelerate, these capital programs by providing policy support and financial incentives.

Recommendation: **A new surcharge should be created to include and accelerate expenditures associated with efficiency improvements in utility generation facilities. The rate of return on Commission approved projects should be 50 bp higher than the most recent authorized return in the utility's rate proceedings.**

Green Energy Tariff

The Term "green energy" refers to energy produced from what is perceived to be environmentally friendly sources. What qualifies as green energy varies by jurisdiction, but is generally focused on renewables. From the utilities' perspective, if sufficient green energy sources are not available, the utility must either develop new ones or contract with third party suppliers to secure required amounts. A more detailed discussion of green energy tariffs is found in Appendix H.

The following table reflects the current status and description of Green Energy service offerings in the state.

152 East Kentucky Response to Discovery, DR-02-48; Duke Kentucky Response to Discovery, DR-02-46.

153 KPC Response to Discovery, DR-02-46; KU/LG&E Response to Discovery, DR-02-44

Figure 7-7
Green Energy Tariff Information

Entity	Summary of Program
LG&E/KU	Voluntary customer contributions are made over and above standard cost of electric and/or gas service and are used to purchase Renewable Energy Certificates (RECs). Any customer under Standard Rate Schedule RS or GS may elect to contribute in whole multiples of $5. Each $5 customer contribution under Electric Rate Schedule SGE allows the companies to purchase 300 kWh of green energy in the form of RECs. Customers receiving service under a special contract or a standard rate schedule other than RS or GS may contribute in whole multiples of $13 to the purchase of green energy. Each $13 contribution under Electric Rate Schedule LGE will allow the companies to purchase a REC representing the environmental attributes of 1 mWh of generation from a renewable source.
Duke Kentucky	The company has a voluntary "Green Energy" tariff RIDER GP GREEN POWER RIDER, but no customers participate. A new version is expected to be filed in the future. This would include a $2.50 charge per 100 kWh of green energy ($5 minimum).
KPC	The company does not currently offer a green energy tariff. However, it is contemplating offering a voluntary program that would charge a premium over current standard service rates. This premium is expected to mirror that of other utilities -- $2.50 per 100 kWh.
Big Rivers	The entity's Renewable Resources Energy Service Tariff Rider generally makes renewable energy available to its member cooperatives at a cost of $5.50 per 100 kWh in lieu of the standard kWh charge. This rider is available under rate schedules 4, 7, and 10. Offerings to retail customers are subject to the member cooperatives' discretion.
East Kentucky	The entity offers Wholesale Renewable Resource Power Service under Section H of its Wholesale Tariff. This schedule is made available to any load center of a member cooperative where a retail customer contracts for renewable power service in 100 kWh blocks. Fourteen of sixteen member cooperatives off the "green power" program. The retail premium is $2.75 per 100 kWh.
Sources: LG&E/KU (DR 02-28), Duke Kentucky (DR 02-30), KPC (DR 02-29), Big Rivers (DR 02-28), and East Kentucky (DR 02-34)	

There is some evidence (at least in other states), however, that interest is growing in such tariffs, as some competitive suppliers have had increasing success in marketing such products and services. The green tariff also provides an opportunity to educate the consumer about the costs of their electricity consumption preferences.

Recommendation: **All regulated Kentucky utilities should be required to develop and offer a "Green Energy" optional tariff for their residential customers.**

KPSC Resources Required for Regulatory Oversight of IRP; DSM; CPCN and Related Processes

The KSPC Staff currently devotes resources to IRP and DSM proceedings that typically consume the efforts of approximately 4-5 full-time equivalents, plus supervisory personnel; the level of effort varying as a function of the number or filings or proceedings before it at any given time.

The increased focus on energy efficiency programs by both utilities and policymakers, as well as resource options required to meet growth or replace aging facilities, is almost certain to put pressure on existing Staff personnel resources. The utilities regulated by the KPSC have substantial resources committed to the planning function in general, often with groups directly focused on energy efficiency, DSM, portfolio analysis, and advanced technology applications currently evolving.[154]

<u>*Recommendation:*</u> **The Commission should provide for additional staffing, and relevant training, necessary to support increased activities associated with IRP, DSM, Environmental Surcharge, Certificate, and other filings. The Staff additions would also monitor federal and state energy legislation, industry research and programs, and Kentucky regulated utility parent-company activities. Staff resources may need to be further supplemented to support increasing requirements over time.**

Overview of Financial Position of Utilities

The investor-owned utilities in Kentucky are in a reasonably positive financial position, as demonstrated by a recent S&P release ranking U.S. electric utilities. Duke Kentucky is in the top quartile, KU and LG&E in the second quartile, and KPC in the third quartile.[155] The rating agency reports do, however, indicate concerns associated with potential adverse effects associated with major capital programs over the near term, as well as contingent risks regarding the potential for increased generation costs associated with possible federal legislation on GHG emissions.

Credit Ratings

Rating agencies are concerned about the impact of meeting planned generation requirements. Electric utilities now face major capital programs to meet customer capacity requirements. Given the current environmental trends, there is a clear industry interest in the development of nuclear generation, as well as advanced coal-fired generation, including carbon capture and sequestration. From a credit perspective, the development of these generation technologies will increase both business and operating risk. The projects are more complex to build, and have longer construction periods. The potential cost impacts and rate effects may place additional pressure on utility returns. Moody's makes the following observation in a recent release:

> While a constructive regulatory relationship will help mitigate near-term credit pressures, Moody's will remain concerned over the prospects of construction delays, cost over-runs, the implications for rate-shock and future disallowances. Moody's observes that given the long-term time horizon associated with a construction project of this nature, there can be no assurances that tomorrow's regulatory, political, or fuel environments will continue to be as supportive to nuclear power [or advanced coal technologies] as they are currently.[156]

The following table summarizes the current credit ratings of the Kentucky jurisdictional electric utilities:

---

154 KU/LG&E Response to Discovery, DR-02-33; Duke Kentucky Response to Discovery, DR-02-35; KPC Response to Discovery, DR-02-34; Big Rivers Response to Discovery, DR-02-34; and East Kentucky Response to Discovery, DR-02-39.

155 S&P Release on U.S. Electric Utility Companies, Strongest to Weakest, dated November 30, 2007.

156 Duke Kentucky Response to Discovery, DR-01-006(b)(5), p. 2 of 96.

Figure 7-8
Kentucky Jurisdictional Electric Utilities
Credit Ratings

Entity	S&P Rating	Moody's Rating	S&P Rating of Parent (if applicable)	Moody's Rating of Parent (if applicable)
Duke Kentucky	A- / Stable	Baa1 / Stable	A- / Stable	Baa2
East Kentucky	N.A.	N.A.	N.A.	N.A.
Big Rivers	N.A.	N.A.	N.A.	N.A.
KU / LG&E	BBB+ / Stable	A2 / Stable	BBB+ / Stable	A3 / Stable
KPC	BBB / Stable	Baa2 / Stable	BBB / Stable	Baa2 / Stable

Sources: Duke Kentucky (DR-02-039), East Kentucky (DR-01-02), Big Rivers (DR-01-02), KU/LG&E (DR-01-02), and KPC (DR-02-38).

Note 1: East Kentucky and Big Rivers are not rated by S&P or Moody's.
Note 2: Ratings are corporate credit ratings except for Duke Kentucky and KPC/AEP which are related to their Unsecured Debt.

East Kentucky. East Kentucky is not rated by any bond rating agency.[157] After an extended period in which rates have remained stable, East Kentucky now faces financial challenges associated with a major construction program, with the addition of generating assets necessary to meet customer growth. Key components identified by East Kentucky to meeting its financial objectives over the next few years, include expansion of DSM programs, development of economic renewables opportunities, and rate design measures.[158]

KU and LG&E. S&P observed that the utilities benefited from the fuel adjustment and environmental cost recovery mechanisms, as well as a "supportive regulatory environment." Moody's also found these mechanisms to be noteworthy, given expected environmental capital spending in excess of $1 billion through 2009.[159] Importantly, S&P also found that the completion of exiting from the E.ON U.S. commitment to operate the Big Rivers facilities "would lessen the company's exposure to unregulated activities and could lead to an improved business risk profile and higher ratings."[160]

KPC. Consistent with the more generic comments by Moody's above regarding the impact of generation plant expenditures, in a recent AEP credit release, it made the following comment, which is also generally applicable to the industry segment at this time.

> From a credit perspective, Moody's views investments in regulated rate-base positively, and we incorporate a view that regulators will provide meaningful and timely recovery for prudently incurred investments. Nevertheless, we remain cautious as to the scale and scope of capital expenditure plans of this size

157 East Kentucky Response to Discovery, DR-01-02.

158 East Kentucky Response to Discovery, DR-01-01.

159 Moody's Credit Opinion, dated July 10, 2007.

160 S&P Ratings Direct Report, dated January 3, 2007.

> due to the negative free cash flow that will be incurred and the potential regulatory overhang associated with the ultimate impact on end-use customer rates. In our opinion, utilities that are embarking on a capital investment program of this size should also be redoubling their efforts to bolster their balance sheet and cash flow credit metric, in an effort to create enough financial strength to weather potentially distressful environments related to economic conditions, volatility in commodity markets, regulatory changes or other unanticipated developments.[161]

Given the S&P and Moody's expectation of pressures on the credit quality of the Kentucky investor-owned utilities, it is essential to maintain a positive environment for cost consideration and recognition of capital programs and environmental compliance. Of course, the implementation of recommendations to expand energy efficiency programs, and to consider generation resource diversification, must also be made in a manner that does not degrade the financial condition of Kentucky regulated utilities.

The recommendations contained in this report that provide incentive returns for utilities that invest in DSM, renewables, and environmental facilities, do so for two primary reasons. Incremental returns and sharing of program benefits are essential to focus utility strategic and financial planning on programs for which there are inherent disincentives. And secondly, these returns and incentives are also proposed in recognition of increased operating and financial risks that these investment alternatives pose in contrast to traditional supply-side resources.

From a policy perspective, it is in utility customers' interest to maintain, if not improve, the credit position of Kentucky jurisdictional utilities. The implicit cost of maintaining bond and corporate ratings is always lower than rebuilding the financial position of a utility after a credit downgrade. An important part of maintaining low electric rates in Kentucky, is supporting a financially strong position for those utilities providing these electric services.

The Commission likely has the authority to offer incentive returns for utility commitments to proposed energy efficiency, DSM and renewables projects. However, for reasons addressed elsewhere in this report, the legislature should explicitly affirm this authority.

Recommendation: **The General Assembly should consider explicit support of these Commission initiatives to further encourage the utility industry response, and to limit financial risks associated with these utility commitments.**

Certain investments in programs considered may require substantial capital, such as implementation of smart meters as infrastructure for all customers, incremental costs for construction of an IGCC facility, or programs to provide funding for customer investment in energy efficient appliances, weatherization, etc. Access to capital at a reduced cost will help bring these types of programs to fruition on a more economic basis, and will result in lower energy rates. During the period of electric industry restructuring, state legislatures enacted

[161] KPC Response to Discovery, DR-02-38; p. 5 of 7.

programs that provided funding or funding guarantees that substantially reduced the cost of capital for utilities and their customers.

__Recommendation__: **In support of the development of Section 50 objectives, the General Assembly may wish to work with utilities in developing securitization bond funding in support of qualifying conservation investments and environmental mandates, including advanced-coal technologies. Access to capital at a reduced cost will help bring these programs to fruition on a more economic basis, and will result in lower energy rates.**

Customer Impact Considerations

The implementation of programs, policies and procedures contained in this report may cause an increase in charges over current customer rates. It is important to provide protection to customers that rates will not rise precipitously due to the adoption of proposed recommendations. Certain recommendations contain mechanisms to capitalize, or otherwise defer costs associated with various programs addressed. On a net present value levelized cost basis, these programs may in fact be equal to or less than a conventional supply resource alternative. However, as with the addition of a large-scale generating facility, short-term revenue requirement effects may cause a spike in rates.

The addition of conventional generating capacity is highly predictable in terms of capital cost, operating efficiency, operating costs and related impacts on customer rates. The implementation or expansion of new supply-side technologies, DSM, energy efficiency and renewable projects expose the utility to greater uncertainty. Utilities must be assured reasonable opportunity for recovery of costs associated with these programs, as well as appropriate incentives to pursue them. Similarly, customers should be shielded from unanticipated increases in rates as these initiatives are implemented.

__Recommendation.__ **Any potential customer increase in rates due to programs effective on or after January 1, 2009, which are recoverable by operation of the proposed surcharges contained in this report, should be considered in light of other cost increases in base rates, FAC, or other charges. If the Commission finds it appropriate to do so, it may impose a rate cap on these costs for a particular period or periods. Approved costs, if any, that exceed the rate cap, should be deferred for future recovery, including appropriate carrying costs.**[162]

Taken as a whole, the recommendations in this and previous chapters that restructure the accounting and funding for DSM programs, in combination with future investments in renewables and other supply-side resource alternatives should result in a reasonable balance of energy efficiency objectives with least life-cycle costs[163] to all classes of customers.

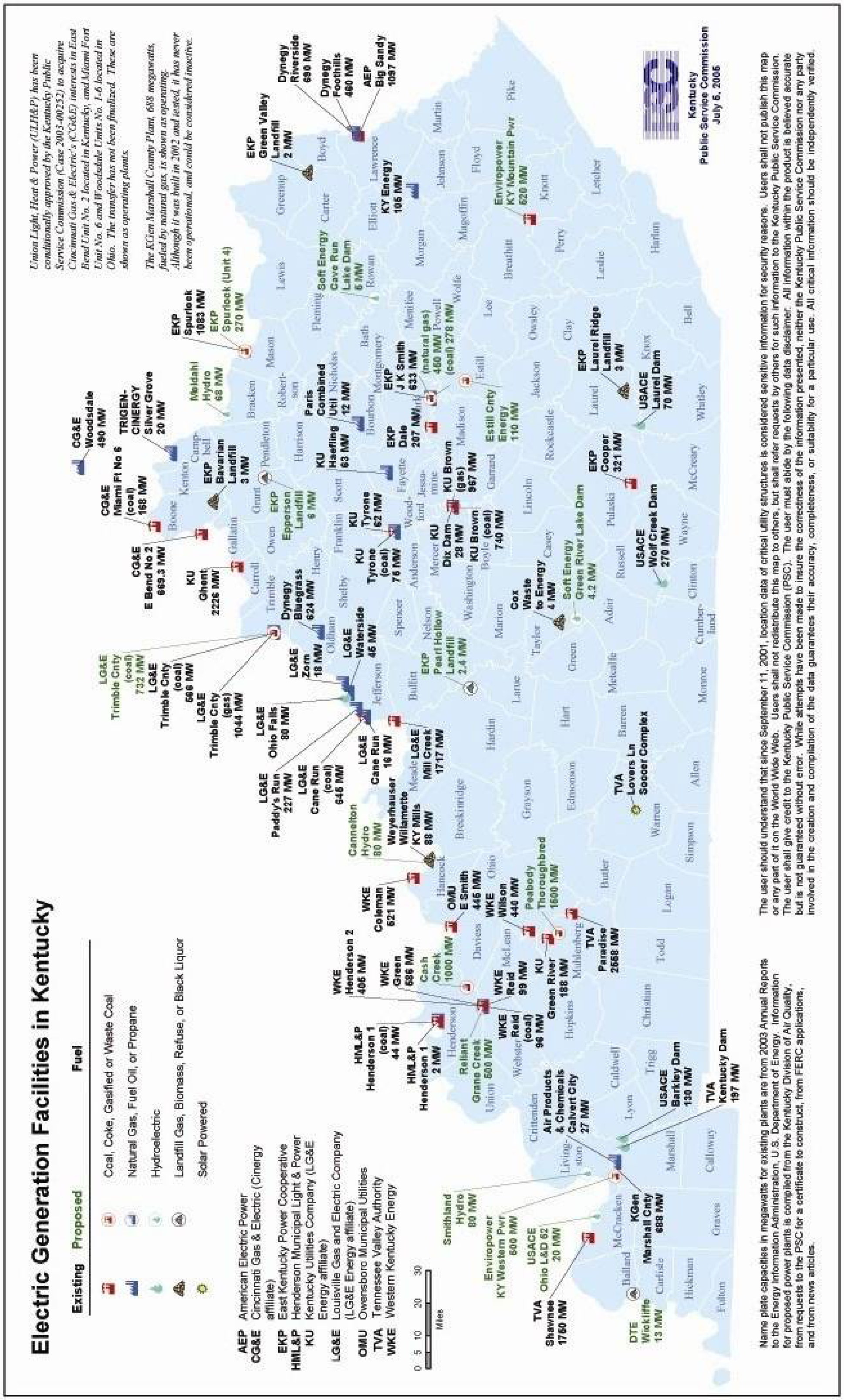
---

162 In proposing this cap on customer rates, with a provision to defer excess costs, the utilities and the KPSC will have to evaluate the reasonableness of the size of such deferrals over time in light of SFAS 71 and other relevant accounting standards.

163 See discussion in Chapter 6, Full Cost Accounting.

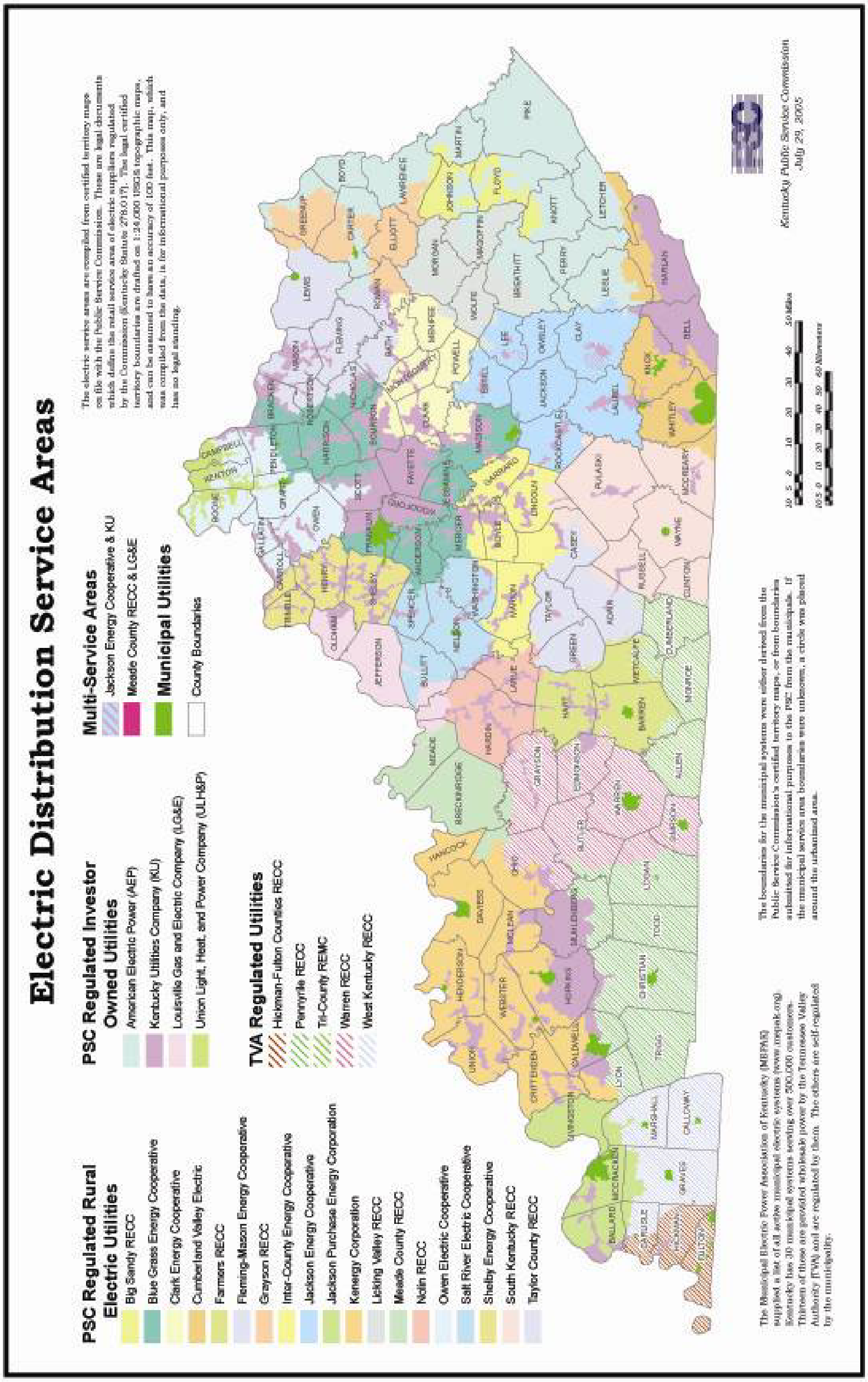
[This page intentionally left blank.]

Appendix A – Electric Generation Facility Map



[This page intentionally left blank.]

Appendix B – Electric Distribution Service Area Map



[This page intentionally left blank.]

Appendix C – Energy Strategy Recommendations By Governor's Energy Policy Task Force

Energy Efficiency: Saving Energy, Saving Money and Protecting the Environment

Recommendation 1:

The Commonwealth of Kentucky, through the Finance and Administration Cabinet, should dedicate staff toward implementing an aggressive and sensible utility savings initiative throughout state government and other state-funded institutions to improve energy efficiency.

Recommendation 2:

The Commonwealth of Kentucky should develop and implement procurement polices that encourage sustainable practices, products and energy efficiency.

Recommendation 3:

The Commonwealth of Kentucky should encourage high performance, energy-efficient design for new construction of state facilities.

Recommendation 4:

The Commonwealth of Kentucky should require interagency cooperation to promote energy efficiency initiatives.

Recommendation 5:

The Commonwealth of Kentucky should encourage the continued development of public-private partnerships dedicated to promoting energy efficiency through education and outreach.

Recommendation 6:

The Commonwealth of Kentucky should work with industries, businesses, schools, universities and communities to promote and give preference to energy-efficient products and practices.

Recommendation 7:

The Commonwealth of Kentucky should support energy assessment initiatives that will help our industries and businesses improve their profitability through energy efficiency and resource management.

Recommendation 8:

The Commonwealth of Kentucky should examine its building codes and specifications to determine if enhanced energy efficiency gains are possible through progressive policy.

Recommendation 9:

The Commonwealth of Kentucky should pursue funding opportunities to strengthen K-12 energy education.

Renewable Energy: A Sustainable Commitment

Recommendation 10:

The Commonwealth of Kentucky should require its state fleet to utilize a 10 percent blend of ethanol (E10) and gasoline and a two percent blend of biodiesel (B2) wherever these clean fuels are available, and encourage Kentucky's post-secondary institutions to adopt similar initiatives.

Recommendation 11:

The Commonwealth of Kentucky should design and implement policies to promote the production, consumption and availability of biodiesel and ethanol within Kentucky.

Recommendation 12:

The Commonwealth of Kentucky should design policies to promote the utilization of a 20 percent blend of biodiesel in the public school bus fleet.

Kentucky's Low Cost Electricity: Strategic Investment

Recommendation 13:

The Commonwealth of Kentucky should develop a comprehensive statewide assessment of Kentucky's electricity infrastructure—generation, transmission and distribution—which includes reasonable projections of future electricity requirements.

Recommendation 14:

The Commonwealth of Kentucky should periodically update the comprehensive statewide assessment to reflect changes in both electric infrastructure and future electricity requirements.

Recommendation 15:

The Commonwealth of Kentucky assessment should serve as a "strategic blueprint" for policymakers to determine future investment requirements in Kentucky's electricity generation, transmission and distribution infrastructure.

Recommendation 16:

The Commonwealth of Kentucky should utilize the "strategic blueprint" to develop policies that promote sufficient investment in electricity infrastructure—generation, transmission and distribution—to sustain Kentucky's low cost electricity into the future.

Recommendation 17:

The Commonwealth of Kentucky should identify impediments to investment in electricity generation, transmission and distribution and develop policies to promote investment while ensuring that appropriate environmental protections are maintained and local voices are heard.

Recommendation 18:

The Commonwealth of Kentucky should design and implement policies that promote, but do not mandate, the use of renewable energy resources in Kentucky's electricity generation portfolio.

Coal: Energy at Kentucky's Feet

Recommendation 19:

The Commonwealth of Kentucky should examine its regulatory policies and traditional economic development incentives to design and implement policies that promote investment in clean coal technology.

Recommendation 20:

The Commonwealth of Kentucky should develop policies to provide incentives for the purchase of Kentucky coal at clean-coal facilities.

Recommendation 21:

The Commonwealth of Kentucky should ensure that the Kentucky Bond Pool Fund is sufficiently enhanced to promote the growth and productivity of Kentucky's coal mining industry.

Recommendation 22:

The Commonwealth of Kentucky should examine its current mine permitting policies and identify streamlining opportunities.

Recommendation 23:

The Commonwealth of Kentucky should design and implement policies to promote electricity generation at Kentucky mine sites.

Recommendation 24:

The Commonwealth of Kentucky should design and implement policies to promote capital investment within the coal industry.

Recommendation 25:

The Commonwealth of Kentucky should support projects and initiatives intended to open new markets for Kentucky coal.

Recommendation 26:

The Commonwealth of Kentucky should partner with post-secondary institutions and industry to develop and invest in a program targeted at workforce development within the coal industry.

Recommendation 27:

The Commonwealth of Kentucky should partner with post-secondary institutions and industry to pursue federal resources to implement workforce development initiatives for the coal mining industry.

Recommendation 28:

The Commonwealth of Kentucky should partner with the Southern States Energy Board to develop a model workforce

development initiative that can be replicated in other coal-producing states.

Recommendation 29:

The Commonwealth of Kentucky should partner with the federal government, the mining industry, employee organizations and with other coal producing states to study the extent of the drug and alcohol problems in the mines.

Recommendation 30:

The Commonwealth of Kentucky should partner with the mining industry and employee organizations to develop policies that promote drug screening and rehabilitation within the mining industry.

Recommendation 31:

The Commonwealth of Kentucky should pursue federal funding opportunities to promote drug screening and rehabilitation within the mining industry.

Recommendation 32:

The Commonwealth of Kentucky should continue to promote progressive reclamation practices through reforestation and the creation of wildlife habitats that support environmental restoration and enhanced economic development and tourism

opportunities.

Recommendation 33:

The Commonwealth of Kentucky should design and implement policies that promote the recovery of the energy resources inherent to abandoned coal refuse and the proper reclamation of those properties.

Recommendation 34:

The Commonwealth of Kentucky should monitor the proposals of the Office of Surface Mining surrounding the issues of area mining and determine what appropriate changes should be made to the current state regulatory program to bring it in line with proposed federal rule changes.

Recommendation 35:

The Commonwealth of Kentucky should support dialogue between appropriate energy and environmental parties to determine the policy options related to area mining within the context of the proposed federal rule changes.

Recommendation 36:

The Commonwealth of Kentucky should design and implement policies to promote the transformation of waste into valueadded products, particularly directed at opportunities to reduce the environmental impact of coal-fired emissions.

Kentucky’s Natural Gas: Untapped Potential

Recommendation 37:

The Commonwealth of Kentucky should develop and implement policies that encourage investment in intrastate natural gas pipelines, gathering lines and distribution capacity.

Recommendation 38:

The Commonwealth of Kentucky should determine the opportunities for increased natural gas storage capacity and, if appropriate, promote its development.

Recommendation 39:

The Commonwealth of Kentucky should promote research to accurately determine the extent of coal bed methane and natural gas reserves in Kentucky and its prominent locations.

Recommendation 40:

The Commonwealth of Kentucky should design and implement policies to promote the recapture of methane from the state’s landfills.

Recommendation 41:

The Commonwealth of Kentucky should identify the potential of coal bed methane value-added industries and, if feasible, design economic development strategies to grow those industries around the state’s coal bed methane reserves.

Kentucky’s Energy Future: A Perpetual Commitment

Recommendation 42:

The Commonwealth of Kentucky should place a high-level emphasis on energy policy to continue the vital work necessary to ensure Kentucky’s low cost energy future, the responsible development of Kentucky’s energy resources and Kentucky’s commitment to environmental quality.

Recommendation 43:

The Commonwealth of Kentucky should engage federal regulatory and energy agencies to ensure that the state has a “place at the table” while energy issues are being discussed.

Recommendation 44:

The Commonwealth of Kentucky should investigate the emerging impact of global and national policies and institutions on Kentucky's energy future.

Recommendation 45:

The Commonwealth of Kentucky should partner with post-secondary institutions, industry and the federal government to develop and invest in programs targeted at workforce development within the energy industry.

Recommendation 46:

The Commonwealth of Kentucky should partner with community-action agencies and the energy industry to provide energy assistance to Kentucky's neediest citizens.

Recommendation 47:

The Commonwealth of Kentucky should promote the awareness of utility check-off programs and encourage widespread participation.

Recommendation 48:

The Commonwealth of Kentucky should partner with the state's universities, private industry and non-profit organizations to aggressively pursue federal research and development resources that are dedicated—but not limited—to clean-coal technology, energy efficiency, hydrogen technology and renewable energies.

Recommendation 49:

The Commonwealth of Kentucky should initiate a full-scale effort to attract and site the federal FutureGen facility in Kentucky.

Recommendation 50:

The Commonwealth of Kentucky should encourage and assist the state's universities, private industry and non-profit organizations to leverage available federal energy research and development resources.

Recommendation 51:

The Commonwealth of Kentucky should promote greater collaboration between Kentucky's universities to synergize ongoing energy research efforts at individual institutions.

Recommendation 52:

The Commonwealth of Kentucky should partner with the federal government, local governments and private industry to promote enhanced security of Kentucky's critical energy infrastructure.

Recommendation 53:

The Commonwealth of Kentucky should partner with local governments and private industry to pursue federal funding opportunities that promote enhanced security of Kentucky's critical energy infrastructure.

Recommendation 54:

The Commonwealth of Kentucky should partner with the federal government to enhance the nation's energy security through research and development directed at transforming Kentucky's energy resources into the resources that fuel the nation.

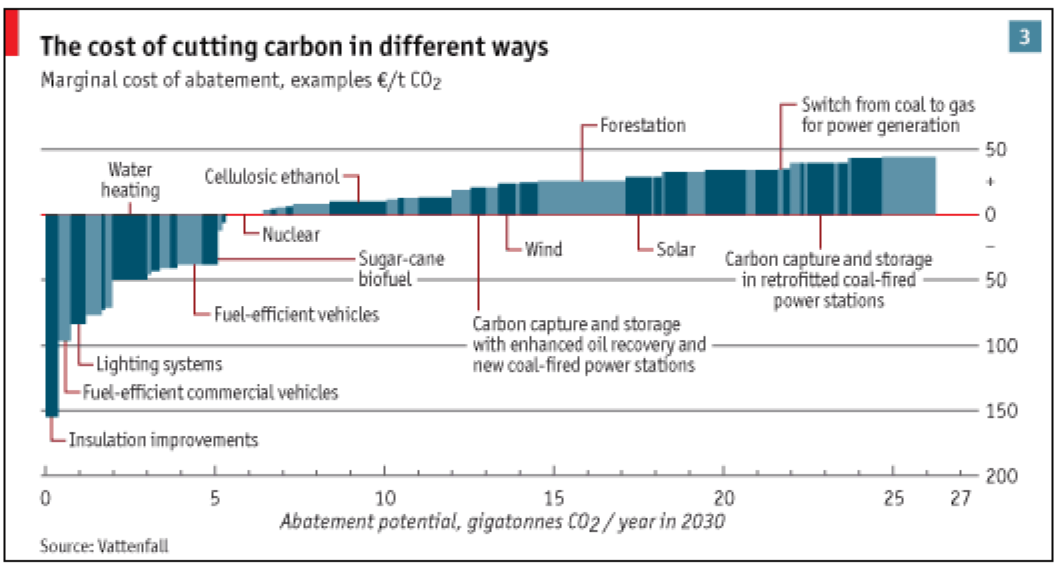
Appendix D - Industry Practices on Demand Side Management

Overview

The purpose of a DSM program is to encourage consumers to modify their levels and patterns of electricity consumption. The intended results are system-wide reductions in both total annual energy deliveries and conventional capacity required to support peak-period demand. Because utilities, like any other business, generate revenues and profits through the delivery of products and services, the financial incentives for utilities to support such programs can be – and, upon first consideration, seemingly are – perverse.

There is substantial evidence that some DSM programs can be extremely cost-effective. Figure D-1 below – prepared by Vattenfall, a Swedish electricity utility, and recently reprinted in The Economist magazine – illustrates the nature of the opportunities relative to alternative approaches to reducing environmental impact.[164] The vertical axis measures the marginal cost of reducing emissions. Moving from left to right along the horizontal axis moves from the most to the least cost-effective approaches. Energy efficiency measures tend not only to be significantly more cost effective than supply side measures, but they often have negative abatement costs – i.e., undertaking them not only reduces carbon emissions, but also saves money for the participant (for example, improving home insulation tends to cost homeowners less than the present value of associated reductions in their energy bills).[165] This implies that programs can often be structured that provide both consumers and utilities appealing financial incentives to act in ways that improve the environment. Indeed, many jurisdictions within the U.S. and internationally, have successfully done exactly that.

Figure D-1. Excerpt from Economist Article



164 "Irrational Incandescence", The Economist, May 31, 2007.

165 Efficiency and conservation opportunities were characterized in a similar way in a recent report issued by the management consulting firm, McKinsey & Company. See "Reducing U.S. Greenhouse Gas Emissions: How Much at What Cost?", December 2007.

Most states within the U.S. currently provide financial incentives such as tax credits, rebates, or loans to support programs related to energy efficiency.

Figure D-2 below presents information about DSM programs for a select group of states within the U.S. DSM programs have become quite common, deployed, or about to be deployed, within the eighteen states we surveyed. While the programs have often been required by a regulator, it is not at all unusual for jurisdictional utilities to implement programs voluntarily. There is no clear trend with respect to treatment of costs (expensed versus capitalized) and the design of tariff mechanisms to pass through costs. A range of options has been utilized. Eligibility is usually extended to all customers. While incentives to utilities are often provided, this practice cannot at this point be characterized as common; and there are a few, but not yet many, instances of rate decoupling.

Figure D-2

State	Existing Program (s)?	Cost Treatment	Tariff Mechanism	Eligibility	Rate Decoupling?	Financial Incentives
Georgia	Program already existing	Costs are included in rate base	Rate rider	All customers	No	None
Indiana	Program already existing	Costs are generally expensed	Embedded in customer's monthly bill.	All customers of utilities providing programs participate	Yes	Tailored to each utility
Idaho	One pilot program (Idaho Power) so far	-N/A	Rate rider (1.5%)	All customers	-N/A	No, they try to establish a performance-based financial incentive, but it proves to be hard to implement it.
Iowa	Program already existing	Expensed	Rate pass-through, reconciled annually	All customers	No	Discontinued upon deregulation.
Kansas	One large utility is implementing a program; others are planning to do so	Approach being developed	Rate rider	Standards being developed	Approach being developed	None

Figure D-2						
State	**Existing Program (s)?**	**Cost Treatment**	**Tariff Mechanism**	**Eligibility**	**Rate Decoupling?**	**Financial Incentives**
Kentucky	Programs already existing	Expensed	Rate rider	Residential and commercial customers	No	Yes
Louisiana	Not required; two utilities voluntarily provide programs for residential customers	No standard; at the discretion of utilities	Rate rider	All customers	Decided by each utility	None
Oregon	Program already existing	Expensed	Rate rider	All customers	No	None
Maryland	Program already existing	Approach being developed	Approach being developed	Standards being developed	Approach being developed	Approach being developed
Michigan	Bill passed the Senate but not yet the House	Approach being developed	Approach being developed	Standards being developed	Approach being developed	Approach being developed
Nevada	Program already existing	Capitalized	Utilities are allowed to embed program costs in tariffs	At least 15% of savings must come from residential customers	No	Five percent premium to authorized rate of return for saved energy
North Carolina	DSM programs are not yet finalized	Approach being developed	Approach being developed	Standards being developed	Approach being developed	Approach being developed
North Dakota	Not required; some have been developed voluntarily	Expensed	Embedded in rates	Decided by each utility	No	None

Figure D-2						
State	**Existing Program (s)?**	**Cost Treatment**	**Tariff Mechanism**	**Eligibility**	**Rate Decoupling?**	**Financial Incentives**
Ohio	Program already existing	Expensed	Rate rider	Large customers implementing their own energy efficiency programs can opt out	Not now, but being considered	Utilities are rewarded upon reaching 65% of their targets (in terms of customers participation or market penetration)
Texas	Energy Efficiency Program (EEP) which encompasses DSM issues	The commission would establish an energy efficiency cost recovery factor for ensuring timely and reasonable costs recovery for utilities. This factor will adjust every year to enable utilities to match revenues against energy-efficiency costs	Utilities provide market-based standard offer programs to retail electric providers and competitive energy service providers to acquire cost-effective energy efficiency	All customers	N/A	The commission should provide an incentive to utilities to reward them when they exceed the minimum statutory requirement.
Utah	Program already existing	Expensed	Rate rider	Large customers implementing their own energy efficiency programs can opt out	No	None
Virginia	Task force is developing an approach; considering an energy efficiency target of 20% by 2022	Approach being developed	Approach being developed	Standards being developed	Approach being developed	Approach being developed

Figure D-2						
State	**Existing Program (s)?**	**Cost Treatment**	**Tariff Mechanism**	**Eligibility**	**Rate Decoupling?**	**Financial Incentives**
Washington	Program already existing	Expensed	Rate rider	All customers	Yes	The commission shall adopt a policy allowing an incentive rate of return on investment. This would be an increment of two percent to the rate of return on common equity on the company's other investments
Wyoming	One program has been filed and is under review	Expensed	For the program currently under review, proposed a rate rider of 1%	Standards being developed	Approach being developed	None

Figure D-3 below presents examples of DSM spending by several North American utilities.

Figure D-3:. DSM Spending (2006)

Company	DSM Spending	Revenues	DSM as Percent of Revenues	State	Average Retail Price by State in ct/kWh
AEP Texas Central Company	$ 6,334,949	$ 542,001,484	1.17%	Texas	10.39
BC Hydro	$ 90,000,000	$ 4,300,000,000	2.09%	British Columbia	4.54
Consolidated Edison Co - NY Inc	$ 31,000,000	$ 7,052,000,000	0.44%	New York	15.34
Fitchburg Gas & Electric	$ 3,600,000	$ 225,200,000	1.60%	Massachusetts	15.48
Fortis BC	$ 1,457,000	$ 207,602,000	0.70%	British Columbia	4.54
Idaho Power	$ 11,484,013	$ 920,473,000	1.25%	Idaho	4.94
NSTAR*	$ 67,890,000	$ 3,577,702,000	1.90%	Massachusetts	15.48
Northeast Utilities	$ 6,500,000	$ 6,884,388,000	0.09%	Connecticut	14.71
Virginia Electric & Power	$ 10,000,000	$ 16,482,000,000	0.06%	Virginia	6.88
EON (KU and LG&E)	$ 8,460,000	$ 1,947,000,000	0.43%	Kentucky	5.43
		Average:	0.56%		

* NSTAR's DSM figure includes renewable energies programs
** BC average retail prices based on Vancouver electricity rates in effect April, 2006 (prices in USD, 1 CAD=0.8533 USD, as of April 3, 2006)
Sources: Companies' websites, EIA, HydroQuebec

The remainder of this appendix identifies and characterizes the approaches regulatory agencies within and outside the U.S. have applied to motivate utilities to undertake, and to effectively implement, DSM programs.

Motivating Demand Side Management

The six core regulatory issues to be addressed in designing DSM programs are how to: (i) account for expenses; (ii) deal with revenue loss; (iii) structure utility incentives; (iv) organize the associated regulatory processes; (v) fund and coordinate the programs; and (vi) monitor and verify performance.

The first question turns on whether the actual costs of the program are expensed or capitalized, and, if capitalized, whether the utility earns a return on them. The second issue centers on how to assure that a utility meets its revenue requirement if its rates are based on volumes that are reduced by DSM initiatives. The third issue relates to the design of incentives for utilities, both to encourage innovation and also to ensure that DSM programs are administered efficiently. The fourth issue addresses how programs are presented for regulatory review. The fifth issue addresses how programs (or portions of programs) that are not self-financed are funded, and the extent to which required activities are implemented by a utility and/or third-party contractors. The sixth issue relates to ongoing evaluation of program performance.

Each of these issues is discussed in more detail below.

Accounting for Expenses

DSM operating and capital costs can either be expensed or capitalized, and the alternative treatments impact rates differently. Expensing costs impacts rates more immediately, while capitalization treatment, recognizing that the benefits of a DSM program are long-term in nature, distributes the pricing impact over time.

Allocating DSM costs among customer classes is complicated by concern over non-participant rate impacts. This is often true for large industrial customers who are sophisticated about energy efficiency and have independently undertaken significant cost-effective investments in DSM. They will receive few benefits from a utility-administered program and can be put in a position of subsidizing customers (perhaps including business competitors) that had previously been less diligent about energy efficiency.

It has been argued that there are positive externalities in DSM investments. Thus, even an industrial consumer which has exhausted its DSM opportunities can still expect to benefit from economic DSM efforts by others if such efforts help to reduce overall generation costs (market prices for power) to lower levels than would otherwise have been experienced and to further secure the reliability of system-wide operations. Thus, customers who argue that they are paying for DSM initiatives for which they receive no benefit may be taking an overly narrow view of DSM potential.

Costs can be allocated among customers on the basis of demand (per kW), energy (per kWh), or some combination of both. They can also be allocated on the basis of DSM savings by class or by the DSM budgets allocated for each class. All of these methods, however, cause differential impacts of one sort or another. Energy allocations, for instance, could impose costs disproportionately on industrial load. Allocation to participating customers only would serve as a disincentive to program participation.

Rate cases sometimes result in adjustments to existing rate design to better reflect DSM demand and energy impacts at the class level. Any reduction in the demand and energy allocators for DSM participants would result in an increase in the fixed cost responsibility of non-participants. Some argue that such adjustments ignore the long-term benefits that program participants receive from DSM. Supporters of this argument advocate the assignment of direct costs to participant classes or that class allocators be developed based on pre-DSM class demand.

Revenue Lost Adjustment

When utilities engage in DSM, they not only incur the cost of those programs, but they are also subject to a potential loss in revenues because of the reduced energy sales, energy not consumed as a result of DSM. Any portion of the reduced revenue not offset by reduced costs leads to reduced earnings. Regulators need to put mechanisms in place to mitigate this financial disincentive to DSM implementation by allowing utilities to recover some portion of the revenues they would have recovered had they not promoted sales reductions through energy efficiency.

The two main types of lost revenue adjustment mechanisms employed in ratemaking are surcharges and a deferral accounts.

Surcharges. Surcharges also known as rate riders or trackers, reflect treatment of DSM program costs as expensed. They can be prospective and retrospective. Prospective mechanisms aim to provide recovery of lost revenue in the same rate period as the losses occur, usually annually and sometimes quarterly. This requires reliance on financial forecasts and also an ex-post reconciliation process to account for inevitable differences between forecasts and actual results. Retrospective surcharges base recovery on actual observed losses from previous periods. In either case, the surcharge can be levied on all customers or to specific customer classes. Two examples of surcharges are presented below.

Electric Utilities in Maryland. A good example of a surcharge and the impact it has on rates is illustrated in a filing to the Maryland Public Utility Commission on DSM funding mechanisms. Until 2000, the majority of utilities in Maryland used a public benefits charge (PBC) to recover lost revenue. The surcharge is expressed in mils/kWh terms. The estimated revenues associated with this surcharge in Maryland in 1998 are summarized in Figure D-4. This table indicates that a 1 mil surcharge collected from all ratepayers results in approximately $57 million of revenues.

Figure D-4. Total Annual Revenues of Alternative PBCs in 1998

	1998 Sales (GWh)	3 mils/kWh	2 mils/kWh	1mil/kWh	0.5mil/kWh	0.1/kWh	Total 1998 Retail Sales
Residential	22,444	$ 67,332,000	$ 44,888,000	$ 22,444,000	$ 11,222,000	$ 2,244,400	$ 1,877,000,000
Commercial	25,222	$ 75,666,000	$ 50,444,000	$ 25,222,000	$ 12,611,000	$ 2,522,200	$ 904,000,000
Industrial	9,733	$ 29,199,000	$ 19,466,000	$ 9,733,000	$ 4,866,500	$ 973,300	$ 1,225,000,000
Total	**57,399**	**$ 172,197,000**	**$ 114,798,000**	**$ 57,399,000**	**$ 28,699,500**	**$ 5,739,900**	**$ 4,006,000,000**

Source: Maryland PUC

The rate impact of the surcharge is further explored in Figure D-5 which compares the impact of a 1 mil/kWh surcharge on typical monthly bills of the four largest investor-owned utilities in Maryland.

Figure D-5. Bill Impact of 1 mil PBC for Typical Customers by Utility in 1998[166]

Monthly Bill (Without PBC)	Usage (kWh)	BGE	DPL	PE	Pepco	Simple Average Maryland
Residential	750	$ 78	$ 71	$ 55	$ 79	$ 72
Commercial	12,500	$ 1,173	$ 1,244	$ 955	$ 1,351	$ 1,208
Industrial	200,000	$ 16,047	$ 12,448	$ 11,352	$ 16,268	$ 14,364
Bill Impact of 1 mil PBC	PBC/month	% Change	% Change	% Change	% Change	% Change
Residential	$ 2.25	1.0%	1.1%	1.4%	0.9%	1.0%
Commercial	$ 37.50	1.1%	1.0%	1.3%	0.9%	1.0%
Industrial	$ 600.00	1.2%	1.6%	1.2%	1.2%	1.4%

Source: Maryland PUC

This table indicates that a 1 mil/kWh surcharge has the effect of increasing average bills by approximately 1-1.4% depending on the customer class.

Massachusetts Utilities. Distribution utilities in Massachusetts also have a surcharge mechanism in place. Each year, they submit their DSM plan to the Department of Trade and Energy which, based on calculations for lost revenue, energy savings and total cost, assigns a surcharge to be applied to customer rates. Figure D-6 illustrates the average surcharge for residential customers in Massachusetts.

Figure D-6. Average Surcharge for Residential Customers in Massachusetts

Year	**DSM Surcharge (¢/kWh)**	**Average Residential Price (¢/kWh)**	**Surcharge (% of avg. price)**
1998	0.33	10.64	3.10%
1999	0.31	9.71	3.19%
2000	0.285	10.53	2.71%
2001	0.27	12.16	2.22%
2002	0.25	11.17	2.24%

Source: DTE

Other examples of utilities using a surcharge include Bonneville Power Administration, Buckeye Power, Madison Gas & Electric, Northeast Utilities, Portland General Electric, and various municipal utilities including the City of Austin, Texas and the City of Phoenix, Arizona.

In addition, utilities are often provided performance incentives, where achievement of defined targets is rewarded. Figure D-7 below is adapted from the National Action Plan for Energy Efficiency (2007).

166 The typical bill was calculated for each utility according to load and consumption parameters developed by Edison Electric Institute.

Figure D-7. Examples of Utility Performance Incentive Mechanisms

State	Type of Utility Performance Incentive Mechanism	Details
AZ	Shared savings	Share of net economic benefits up to 10 percent of total DSM spending
CT	Performance target; Savings and other programs goals	Management fee of 1 to 8 percent of program costs (before tax) for meeting or exceeding predetermined targets. One percent incentive is given to meet at least 70 percent of the target, 5 percent for meeting the target, and 8 percent for 130% of the
GA	Shared savings	15 percent of the net benefits of the Power Credit Single Family Home Program
HI	Shared savings	Hawaiian Electric must meet four energy efficiency targets to be eligible for incentives calculated based on net system benefits up to 5 percent
IN	Shared savings/rate of return (utility specific)	Southern Indiana Gas and Electric Company may eran up to 2 percent added ROE on its DSM invetsments if performance targets are met with one percent penalty otherwise
KS	Rate of return	2 percent additional ROE for energy efficient investments
MA	Performance target; Multi-factor performance targets, savings, value, and performance	5 percent of program costs are given to the distribution utilities of savings targets are met on a program-by-program basis
MN	Shared savings; Energy savings goal	Specific share of net benefits based on cost-effectiveness test is given back to the utilities. At 150 percent of savings target, 30 percent of the conservation expenditure budget can be earned
MT	Rate of return incentives	Two percent added ROE on capitalized demand response programs possible
NV	Rate of return	Five percent additional ROE for energy efficiency investments
NH	Shared savings; Savings and cost-effectiveness goals	Performance incentives of up to 8 to 12 percent of total program bdgets for meeting cost-effectiveness and savings goals
RI	Performance targets; Savings and cost-effectiveness goals	Five performance-based metrics and savings targets by sector. Incentives from at least 60 percent of savings target up to 125 percent
SC	N/A	Utility-specific incentives for DSM programs allowed

Source: National Action Plan for Energy Efficiency (2007). National Action Plan for Energy Efficiency Vision for 2025: Developing a Framework for Change (www.epa.gov/eeactionplan)

Deferral Accounts. Deferral accounts, which are more common than surcharges, treat DSM program costs as capitalized expenses, which must be recovered over time. Lost revenues are recovered over time. The accounts are internal record-keeping tools used to keep track of claims to be recovered from, or refunded to, ratepayers. A tracking system records monthly net lost revenue estimates, and the utility periodically receives authorization, generally within the context of a rate case, to charge or to remit portions of the account to customers. The utility usually files an estimate of the net lost revenue incurred between rate cases as part of its general rate case filing.

An example of a deferral account is provided by Otter Tail Power Company (OTP), an investor-owned utility that provides electric service to over 250,000 customers throughout Minnesota, North Dakota and South Dakota. OTP owns generation assets in addition to the transmission and distribution infrastructure. As part of the IRP rules adopted in Minnesota in 1990, each of the state's utilities with more than 1,000 retail customers is required to file biennial resource plans. These biennial DSM resource plans, referred to as Conservation Improvement Plans

(CIP), have tracker accounts (deferral accounts) that are used for DSM program cost recovery. The CIP tracker accounts record actual CIP collections and expenditures to ensure a dollar-for-dollar recovery at ratemaking time. Thus, over-and under-collections are reconciled at the time of the next rate case. During each rate case, the Minnesota Public Utilities Commission (PUC) will evaluate the DSM programs expenditures and will adjust the deferred account by reconciling the account balance to rates. Additionally, the PUC allows OTP to accrue carrying charges on the balance of its CIP account. This means that OTP is able to recover interest (or cost of capital) from its ratepayers for the balance in the CIP tracker account.

Financial Incentives

Historically, DSM program benefits have been passed on to customers in their entirety. However, utilities and regulators have correctly recognized that such pass-throughs do not motivate utilities to provide additional DSM. Financial incentives (offering the potential for increased profits resulting from DSM program implementation) are often used to motivate utilities to maximize resource savings per dollar spent on energy efficiency measures.

Any incentive scheme results in a marginal incentive rate (i.e., the additional incentive achieved for an additional dollar in net benefits). High marginal incentive rates should provide greater incentive to utilities to maximize the effectiveness of their Conservation and DSM programs. Incentive rates, however, can be too high, leading utilities to underestimate net benefits so they can capture the incremental net benefits at the high incentive rate. Regulators have attempted to counter these pitfalls by introducing fixed charges that decouple the incentive rate from the total incentive payment.

There are three basic incentive mechanisms employed for DSM programs: shared savings, bonuses, and markups. There are also hybrid mechanisms that combine elements of each. The challenge is always to align government policy, regulatory objectives and utility financial self-interest.

Shared Savings. The shared savings mechanism uses an incentive payment equal to a percentage share of the net avoided cost of energy and capacity (i.e. avoided energy costs minus program and participant costs) minus fixed costs. This is the most common type of incentive mechanism as it provides the most direct link between the policy objective of maximizing societal benefits and the utility's objective of maximizing profit. The basic formula for the shared savings incentive is as follows:

$$I = \lambda\,(AQ - C_U - C_P) - F$$

where:

I = incentive payment

λ = incentive rate

A = per unit avoided energy and capacity cost

Q = quantity of energy and capacity saved

C_U = utility program costs

C_P = participant costs

F = fixed payment

The fixed payment, F, establishes a minimum savings target for the DSM program. The utility benefits only if it achieves savings equal to or greater than that amount; if it achieves less, it pays a penalty equal to the value of F minus the achieved savings.

Within this framework, the definition and estimation of net benefits is very important. Computing net benefits based solely on utility costs may maximize energy savings, but not societal benefits. Some utilities are therefore required to include the cost of environmental benefits, which also implicitly captures diversification attributes of DSM. Social benefits of DSM can also include reliability benefits, as those will accrue to the system as a whole rather than to an individual participant. Recognition of reliability benefits has typically been estimated by using a multiplier on gross capacity to account for the avoided transmission losses and the fact that DSM avoids increasing the capacity margin obligations of the system (such methods have been recognized in New England by the ISO when establishing the value of capacity towards resource adequacy provided by DSM resources). Computing program costs is more straightforward - they typically fall into four categories: administration costs, evaluation costs, rebate costs, and incremental participant costs. Many utilities exclude monitoring and evaluation costs because those activities take place after the conclusion of the DSM program. Incremental customer costs are also frequently omitted because they are difficult to measure and estimate.

Duke Energy has developed the "Save a Watt" program that establishes incentives through an extension of the shared savings approach.[167] This program provides for a return on 90 percent of the generation investment avoided as a result of successful DSM programs. This return will, it is argued, provide compensation for program costs and lost margins, and also establish financial incentives. The utility would earn the return for each year DSM programs are expected to provide results, and subsequent year DSM riders will be adjusted, based on independent measurement and verification studies, to compensate for over- or under-collection.

Two examples of shared savings mechanisms in place within North America are presented below.

FortisBC (formerly Aquila Networks Canada). FortisBC operates under a performance-based regulation (PBR) framework in which multi-year DSM targets are set. FortisBC adopted its Shared Savings (SSM) in 1999 and derives incentive payments in accordance with the basic shared savings formula displayed previously. The utility receives a share of net benefits from DSM, where net benefits are defined as the difference between program benefits and program costs. Fortis BC defines benefits as the value of avoided energy and capacity costs and deferred capital expenditures. Penalties are incurred for not achieving a threshold level of net benefits.

The benefits are calculated over the lifetimes of the DSM measures put into place. FortisBC receives a share of the total net present value of these life-cycle benefits with the typical lifespan ranging from 5 to 20 years. As of August 2004, the avoided cost at FortisBC was valued at 2.6

---

[167] Versions of this program have been filed with and are currently being reviewed by regulators in Indiana, North Carolina and South Carolina. The company is considering filing similar proposals in Ohio and Kentucky.

cents for each kWh of energy savings, $30 for each annual kW of capacity savings, and $36 for each annual kW saved from peak which represents (deferred capital expenditures).

FortisBC receives a share of the net present value of the DSM net benefits annually in the form of a rate adjustment. Various incentives or penalties are assessed based on FortisBC's actual performance in each of the three customer sectors – residential, general service, and industrial. Incentive payments are made for performance of 100 percent to 150 percent of the planned net benefits. No incentive payment is made for performance between 90 percent and 100 percent of planned net benefits. Varying penalties are levied for performance of less than 90 percent, with the maximum penalty applied to performance of less than 50 percent of planned net benefits. If the sum of the incentives and penalties across customer sectors is greater than zero, then that sum is the DSM incentive. If the sum is less than zero, then there is no DSM incentive for FortisBC for the year, and a penalty is charged. The range of DSM-related incentives and penalties are set out in Figure D-8.

Figure D-8. FortisBC DSM Incentive and Penalty Schedule

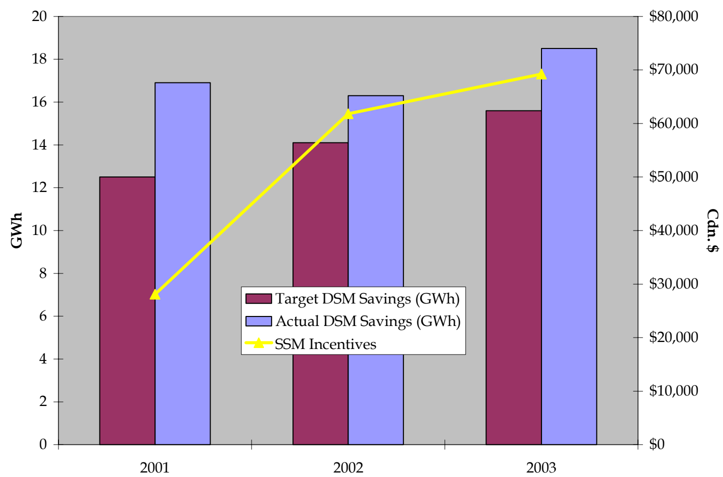
% of Target Net Benefits	<50%	<70%	<90%	90-100%	>100%	>110%	>120%
Residential	-6.0%	-4.5%	-3.0%	0.0%	3.0%	4.5%	6.0%
General Service	-4.0%	-3.0%	-2.0%	0.0%	2.0%	3.0%	4.0%
Industrial	-3.0%	-2.0%	-1.0%	0.0%	1.0%	2.0%	3.0%

Source: FortisBC

Actual DSM savings from 2001 through 2003 were above targeted figures. As displayed in Figure D-9 below, incentive payments in 2002 and 2003 were much larger than 2001. This is because, in those years, most of the savings occurred in the residential sector, where the incentive payment is higher.[168] Actual DSM net benefits from 2001 through 2003 ranged from $2,143,000 to $2,301,000. This was about 13% to 20% above targeted levels.

[168] The incentive payment is higher in the residential sector because Fortis/Aquila's earlier attempts at DSM focused primarily on the industrial sector rather than residential customers. This is an example of how regulators can fine tune incentives to influence utility behaviour.

Figure D-9. Historical SSM Payments. Fortis BC



Source: Fortis BC

While the SSM payments have increased, the associated savings have not necessarily increased commensurately. In 2002, incentive payments increased 120%, but overall DSM savings actually declined 4%. In 2003, however, incentive payments increased 12%, while actual DSM savings increased 13%.

The relative size of the incentive payments to FortisBC is extremely small when compared to total revenue. In 2001, incentive payments represented 0.2% of revenue from all customers and in 2002 and 2004 they represented 0.4%.

San Diego Gas & Electric. San Diego Gas & Electric (SDG&E) was the first of California's four large investor-owned utilities granted incentives for DSM. Initially, the California Division of Ratepayer Advocates urged the CPUC to penalize SDG&E should it not meet the target set forth in its 1989 rate case. SDG&E argued that if they were to be penalized for underperforming, they should be rewarded for overperforming.

Under the DSM mechanism devised in 1993, SDG&E is subject to a penalty if net benefits fall below 50% of the forecast. They are awarded positive incentives when they achieve benefits in excess of 50% of the forecast. At higher benefit levels, the savings share increases steeply at first, then at a slower rate, finally leveling off when benefits reach 130% of forecast. There is no cap on the total amount SDG&E can earn from this incentive mechanism.

SDG&E's share of the savings varies with performance in an S-shaped pattern (S-curve). The S-curve for each program is uniquely determined by its projected cost effectiveness. The curves are calculated so that if the company reaches 100% of its savings goal for a particular program, its savings share is the percentage that will yield the company an amount equal to its program cost times the authorized rate of return on rate base.

Bonus Mechanism. With a bonus mechanism, an incentive payment is made equal to the incentive rate times the quantity of energy and capacity saved. This is the second most common mechanism used and the basic formula is as follows:

$$I = \lambda Q - F$$

The only difference between this approach and the shared savings mechanism is that program and participant costs are excluded. Because this motivates the utility to maximize its own benefits rather than total benefits to society by increasing spending on DSM programs beyond the point where they yield net benefits, the bonus incentive does not work well when DSM costs are significant. Three examples of bonus mechanisms are presented below

Northern States Power (Xcel Energy). Northern States Power (NSP) of Minnesota is an investor-owned utility that provides gas and electric service to 1.3 million customers throughout five states in the Midwest. NSP owns generation assets in addition to the transmission and distribution infrastructure. The utility operates in a state that has yet to deregulate its power sector and continues to operate under a cost of service regime. In the early 1990's, NSP ran a bonus-based DSM program targeted towards commercial and industrial customers.

NSP's bonus rate of return mechanism allowed the utility to capitalize and amortize over a five-year period almost all DSM project expenditures, with the exception of research and load management. NSP was allowed to earn a 5% bonus rate of return on the unamortized portion of the capitalized expenditures. This amount was deemed by the Minnesota Public Utilities Commission (MPUC) to be high enough to provide an incentive without being excessive. Moreover, lost revenue recovery was not allowed as the 5% bonus was viewed as a means of offsetting such losses. The MPUC also retained the right to adjust the incentive based on DSM activity and performance over time.

In order to receive the incentive payment, NSP had to show cost effectiveness results equal to at least 50% of its target net avoided revenue requirement, a concept similar to avoided cost. If that threshold was met, then the utility would have to meet either savings goals for direct impact projects or weighted participation goals for indirect impact projects. The actual bonus payment was scaled linearly from 0% at 50% of goal achievement, to 5% for 100% or more of goal achievement.

NSP's expenditures on their DSM programs ranged from about $7 million in 1990 to about $13 million in 1991. In 1992, expenditures increased significantly to $24.6 million. These were relatively large amounts when compared to other utilities. In 2003, for example, FortisBC expended an average of US$66 per MWh saved, whereas NSP expended an average of $141/MWh saved in 1992. Figure D-10 shows that the efficiency of NSP's DSM program improved over time. However, if you compare the $141 cost per MWh saved for NSP, with the average retail price of electricity in Minnesota which was $55/MWh in 1992, it is not clear that the program was cost-effective. It is important to note that without factoring in the opportunity cost of supply, however, it is difficult to determine whether it was truly cost-effective.[169]

Figure D-10. Efficiency of NSP Bonus-Based DSM Program

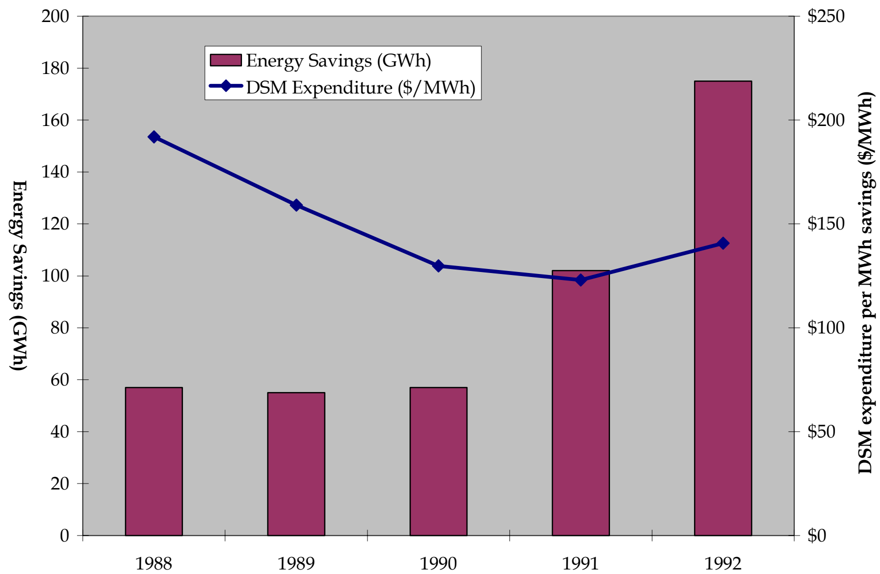


Figure D-10. Annual DSM Expenditures and Savings

Year	DSM Expenditure ($ 000)	Energy Savings (GWh)
1988	$10,938	57
1989	$8,748	55
1990	$7,400	57
1991	$12,549	102
1992	$24,621	175

Source: *NSP*

Niagara Mohawk Power Company. Niagara Mohawk, currently owned by National Grid, provides electric service to approximately 1.5 million customers in upstate New York. NIMO implemented a bonus mechanism in 1989 and was one of the first utilities in North America to do so.

NIMO's bonus mechanism works in a similar way to that of NSP in the sense that the mechanism they have in place allows them to earn an incentive equal to 5% of the net resource savings attributable to DSM programs.

169 i.e., if the unused energy would otherwise have been consumed at super-peak periods when the cost of energy may have exceeded $141/MWh, than the program may still have been cost effective.

The regulator defined the net resource saving as the present value of lifetime avoided costs, plus a $0.0157/kWh adjustment for environmental externalities, less the utility program's costs inclusive of incentives paid to the customers.

Connecticut Light and Power (CL&P). CL&P distributes electricity to more than 1.1 million customers in Connecticut. CL&P has an incentive mechanism as a result of a 1988 state statute. The incentive rewards the utility for minimizing costs and maximizing electricity savings in the implementation of its DSM programs. The mechanism allows CL&P to recoup its expenditures over a ten-year period at its normal rate of return plus a bonus rate which is based upon the aggregate success of its DSM programs. There are no penalties for poor performance.

The bonus rate of return is determined by a unique DSM scoring system. Each of the applicable programs contributes to the DSM performance score which is based on the following factors:

- Planned Cost Rate (PCR) – the expected annual program cost divided by the expected lifetime energy or capacity savings of measures to be installed that year.
- Actual Cost Rate (ACR) – the actual annual program cost divided by the committed lifetime energy or capacity savings of actual measures installed that year.
- Program Performance Ratio (PPR) – PCR/ACR.
- Program Weight – the fourth root of the product of the program budget and the square of the ratio of costs to benefits. The sum of all program weights is 100.
- Program Score – PPR * Program Weight.
- Performance Score – the sum of all Program Scores. This value defines the aggregate success of CL&P's DSM programs and is used to calculate the bonus rate of return.

Markups. The markup mechanism involves an incentive payment equal to the incentive rate times the utility program costs. The basic formula is as follows:

$$I = \lambda C_U - F$$

The core problem with markups is that they reward spending per se and can thereby provide perverse incentives to spend without careful evaluation of the associated benefits. That said, markups can be, and have often been, employed as a good initial model for motivating utilities to implement programs, providing a foundation for moving to more sophisticated models at later date (in a manner similar to what has been a very common transition from straightforward cost-of-service ratemaking to more sophisticated incentive-based ratemaking approaches).

Markups can also be effectively applied in place of more sophisticated (and data-intensive) approaches when quantifications of energy savings, which are required for the shared savings and bonus mechanisms, are difficult to measure and verify.

Pacific Gas & Electric (PG&E) provides an example of a utility markup with a mechanism. In 1994, its DSM programs were grouped into three categories: Resource, Equity, and Demonstration. Resource programs, in which the utility directly buys energy resources from its customers, were eligible for earnings incentives. Equity programs, including educational programs, were also eligible for earnings incentives, but to a lesser degree. Demonstration programs were unproven resource alternatives, and thus not eligible for incentive returns. Although PG&E's Demonstration programs did not incorporate an incentive payment, they could be viewed as falling into this category (with a zero markup incentive).

PG&E's Pacific Energy Center (PEC) is a leading energy research center . PEC opened in 1991 and develops technology and advanced techniques for electric and gas efficiency. The impact of such an energy center, however, is difficult to quantify. Thus, PEC was deemed an information program with the costs recovered dollar for dollar rather than capitalized and incorporated into the ratebase as an asset. If the California Public Utilities Commission (CPUC) wished to incent this type of program, however, it could have incorporated a markup payment. This would essentially be some sort of guaranteed return on the utility investment. It is clear that use of such incentives would require a project-by-project evaluation process with some sort of cap on spending. Effectively, this would be similar to traditional cost of service ratemaking, with DSM activities simply representing another regulatory asset on which the utility receives a return.[170]

Hybrids. Various hybrid incentive models, combining two or more of the pure-form mechanisms discussed above, have been tailored by regulators and utilities within various jurisdictions to target specific objectives. For example, in the early 1990s, the New England Electric System (NEES) implemented DSM programs across Rhode Island, New Hampshire, and Massachusetts. These programs utilized hybrid incentive mechanisms that combined elements of shared savings and bonuses. In 1990, Rhode Island and New Hampshire utilized two-part incentive mechanisms. The utility companies, Narragansett Electric and Granite State Electric, employed a bonus incentive equal to 5% of the value created (adjusted for customer direct costs and evaluation costs). The shared savings incentive allowed the utilities to earn 10% of the net value of the DSM program.

Massachusetts Electric Company (MECO) used only a bonus incentive in 1990. The Massachusetts Department of Public Utilities (MDPU)[171] established a per kW and kWh payment for each kW and kWh saved above pre-set minimum performance thresholds. For example, MECO had to meet a target of 50% of projected energy in order to qualify for the bonus incentive payment. In 1992, MECO's DSM incentive plan was changed to a two-part mechanism in conformity with the other NEES utilities. The bonus was reduced to 50% of the expected value, with the remaining 50% achieved through an efficiency incentive based on the target benefit/cost ratio. The incentive mechanisms employed by NEES produced an upside for the company, though incentive payments remain small when considering that sales revenue is nearly $2 billion a year (about 0.5% of sales revenue).

[170] Note that, if the DSM activity is already being capitalized, it is likely already receiving a mark-up.

[171] The regulator is now known as the Massachusetts Department of Telecommunications and Energy.

Regulatory Process

Regulators generally require utilities to file a DSM Plan. The plan should include a range of demand forecasts, assuming no DSM programs, organized within customer classes. Analyses of alternative DSM programs should be described in the plan, including estimated impact on demand, administrative costs, and results of standardized cost-benefit tests (like the TRC). Analyses should be performed over the lifetime of the programs and discounted to net present value terms is the most common method employed.

DSM programs proposed by a utility will typically be subject to review and comment by the regulator and other stakeholders. The utility sometimes seeks stakeholder input prior to a formal regulatory filing by engaging in focus groups or other consultative processes.

Annual reports are usually required from utilities that use a surcharge to recover DSM costs. These reports should include data on program costs, achieved reductions in deliveries of electricity and demand, and resulting revenue reductions. Utilities using a prospective surcharge are often required to submit quarterly or semi-annual DSM reports to allow the regulator to monitor the application of the surcharge, and to allow for the true-up of lost revenues. Utilities using a deferral account mechanism need to provide periodic statements of activity in the account.

There are specific data needs associated with utility incentive mechanisms. As part of the initial regulatory review, incentive rates to be used, and the basis for allocating net benefits must be specified. Some incentive mechanisms are more data-intensive than others. Hybrid mechanisms, for example, require a wide range of information on program costs. Annual reports generally include information on the disbursement of benefits under the incentive program over time.

Funding and Coordination

The ideal DSM program is one that is self-financing – i.e., savings to customers are greater than the costs of administering the program. Figure D-1 above displays several examples of energy efficiency measures with "negative abatement costs". When programs are not self financing, but are still deemed desirable on environmental and/or equity grounds, there are several funding sources that can and, in various jurisdictions, have been employed. The two broad approaches are: (i) customer subsidization, where utilities provide initial outlays in anticipation of future recovery customers, either those directly benefiting from the program and/or customers providing cross-subsidies; and (ii) direct subsidies from municipal, state and federal sources. No best practices have been established in this area.

While utilities sometimes take on full responsibility for implementation of DSM programs, many have pursued the alternative of contracting with independent third parties to provide a range of services including, for example, marketing, education and implementation. The logic, as with many outsourcing arrangements, is that specialized firms can bring focused expertise that is outside the core competencies of utilities. Contracting arrangements are sometimes established through bilateral negotiations; in other cases, auctions and related market mechanisms enable utilities to organize competitions among potential providers for the rights to provide services.[172]

Monitoring and Verifying Benefits

One of the most challenging aspects of establishing well-functioning incentive mechanisms is determining "what might have been." When utilities are provided financial incentives, it is important to be sure that clear benefits have been achieved in exchange for the incentive payout. Many of the incentive mechanisms discussed above require an estimate of volumes expected in the absence of a DSM program. Simply observing decreased consumption after implementation of a DSM program does not prove success; conversely, increased consumption does not prove failure. Benefits must be monitored and verified systematically.

The main benefits of a DSM program can be broadly categorized into two groups: decreasing need for (or delaying the construction of) installed capacity and reducing the energy consumption, thus contributing to reduction of emissions.

Measurement and Verification sample process

1. establish baseline load and energy consumption;
2. establish the quantity and quality of DSM program participants;
3. establish the assumptions (analytically or statistically) on effectiveness of DSM programs for each program and each customer category (or sub-categories where applicable);
4. apply the assumptions to determine the energy savings and demand reductions;
5. compare the results of analysis and actual energy use with load forecasts to determine whether the DSM estimates can explain actual energy consumption.

Independent System Operators as well as Regional Transmission Organizations have come to recognize that DSM measures also provide benefits in terms of contributing to capacity margins in their respective systems and reduced transmission losses. For instance, load curtailment and other demand response programs can be designed to be highly reliable resources, allowing for reductions in peak system demand and reliance on supply-side resources. As an example, New England ISO's latest 2005 Triennial Review of Resource Adequacy takes into account the effects of load management programs in their load forecasts.[173] Similarly, California Energy Commission Staff Load Forecast Report 2007 states that "[t]he uncommitted demand side management (DSM) forecast of load impacts from programs or other actions is treated as a resource to allow comparison of DSM to other resource options."[174] PJM categorizes DSM resources as a "demand resource", and it is considered as part of the supply-side resources in the resource adequacy analysis.[175] FERC is

---

172 See, for example, "Third-party contracting for demand-side management capacity"; H. Michaels and E. Hicks; Power Systems, IEEE Transactions; Volume 3, Issue 4, Nov 1988; pp.1827-1832.

173 2005 Triennial Review of Resource Adequacy, New England ISO, Footnote 2, p. 8.

174 California Energy Commission. *California Energy Demand 2008-2018, Staff Revised Forecast*, November 2007, p. 41.

175 PJM. *PJM Manual 20: PJM Resource Adequacy Analysis*, June 2007, p. 10.

also proposing to give DSM resources more equivalent status to supply-side resources in its reforms of organized electricity markets.[176]

DSM plans and programs have also received recognition by regulators as part of renewable resources, for instance, Connecticut's RPS requirements include 3 classes of resources, where conservation and load management are included in the Class III RPS portfolio, along with distributed CHP units and waste heat recovery systems. Also, the Department of Public Utility Control of Connecticut (CT DPUC) issued an RFP in 2006 for new or additional generation resources, including demand response and conservation. The main goal of this RFP was to decrease electricity rates for Connecticut consumers. In evaluating the proposals, CT DPUC considered DSM measures as equivalent to supply-side resources and awarded extra points to DSM projects for "environmental attributes".

The estimation and calculations of achieved energy efficiency and demand reduction is a complex endeavour that requires an analysis of the program characteristics, electricity usage patterns by different types of customers as well as the detailed analysis of the customer base. The approach to Measurement and Verification (M&V) of DSM programs would be different depending on the type of the programs. Some types of DSM programs may be measured easier than the others; for example, load curtailment and load management programs often can be measured using the data when these programs were triggered. Other measures, especially conservation, need more detailed and scrupulous work to reasonably estimate the amount of saved energy and demand reduced, relying in large part on the assumptions on the effectiveness and on customers implementing the programs. The approach to M&V would also depend on the purpose of such work and if the participants are paid incentives to curtail or shift their load. Then normally independent M&V consultants either provide calculations or certify calculations presented by demand response program participants.

From the customer's perspective, the most direct and immediate benefit is reduced electricity use and correspondingly reduced bills.

In the past decade, there have been efforts to bring together various approaches and methodologies to form common standards. The most notable work in this regard is International Performance Measurement and Verification Protocol (IPMVP) released in 1997. The IPMVP was a collaborative effort that included government agencies, including the U.S. Department of Energy (which provided initial funding), industry associations (e.g. National Association of Energy Service Companies) from Europe, Asia, Latin and North Americas. Currently, the work on the IPMVP continues through a non-governmental body, Efficiency Valuation Organization,[177] based in San Francisco, California. The latest edition of the IPMVP was issued in 2007 and it includes extensive discussion on concepts of M&V, various options available for M&V processes, etc. The principles outlined in this document may provide useful basis for the development of a regulatory framework on measurement and verification of demand side management activities. There are also other documents and guidelines developed

---

176 www.ferc.gov/news/news-release/2008.

177 www.evo-world.org

by various organizations, including independent system operators (M&V procedures for demand control products and services), the U.S. Environmental Protection Agency (Energy Star certification program), U.S. Green Building Council (USGBC) Leadership in Energy and Environmental Design (LEED) program for certifying buildings, etc., that can be useful and valuable.

[This page intentionally left blank.]

Appendix E – Description of DSM Programs Currently Being Offered by Kentucky Utilities

Kentucky Power Company (KPC)

KPC offers the following DSM programs:

- Targeted Energy Efficiency Program: provides energy audits, consultations, and installation of weatherization, and conservation measures for eligible low-income customers in conjunction with not-for-profit organizations;

- High Efficiency Heat Pumps: financial incentives for mobile home customers to replace the heat systems with high efficiency heat pumps;

- Mobile Home New Construction: financial incentives for buyers of new mobile homes with specified levels of insulation and 12 SEER[178] air conditioners; and

- Modified Energy Fitness Program: energy audits for residential customers designed to evaluate existing energy efficiency levels and suggest measures to improve the energy efficiency.

As displayed in Figure E-1 below, KPC's programs are focused largely on residential customers.

Figure E-1. KPC's DSM Achievements

Program	Energy savings (MWh)	Participation
Residential		
Energy Fitness		
Targeted Energy Efficiency	988	726
High-efficiency Heat Pump	517	218
Mobile Home New Construction	1,355	383
Modified Energy Fitness	2,021	1,912
Subtotal	*4,881*	*3,239*
Commercial		
Smart Financing - Existing Buildings	644	15
Smart Financing - New Buildings	416	9
Subtotal	*1,060*	*24*
Total utility	**5,941**	**3,263**

Source: KPC Response to Data Request, Item 4, dated Nov 29, 2007

178 "Seasonal Energy Efficiency Ratio" – SEER, a measure of efficiency of air conditioning units, higher number denotes better efficiency.

Kentucky Utilities (KU) / Louisville Gas & Electric (LG&E)

KU and LG&E currently offer the following DSM programs:

- Residential Conservation: evaluates and suggests measures to improve the energy efficiency of residential dwellings, including single family homes, apartments or condominia;
- Commercial Conservation: evaluates and suggests measures to improve the energy efficiency for commercial customers;
- Residential and Commercial Load Management: reduces peak demand and energy use through installation of load controlling devices on residential and commercial customer equipment, including central air conditioning, heat pumps, electric water heaters and pool pumps; and
- Residential Low Income Weatherization: evaluates the energy efficiency levels and needs of low-income customers,[179] includes energy audits and education.

The results of these programs are summarized in Figure E-2 below.

Figure E-2. KU/LG&E's DSM Achievements

Program	Demand reduction (kW)	Energy savings (MWh)	Participation
Residential Conservation		2,698	7,334
Load Management - Res and Comm	107,000		
Residential Low Income Weatherization		6,843	3,835
Commercial Conservation	3,375	14,052	880
	110,375	**23,593**	**12,049**

Source:KU/LG&E Joint DSM Application, Case 2007-00319.

Duke Energy Kentucky (Duke Kentucky)

Duke Kentucky currently offers the following DSM programs:

- Residential Conservation and Energy Education (Low Income Weatherization): energy audit services for LIHEAP eligible customers;
- Residential Home Energy House Call: energy audit and installation of basic energy saving measures;

179 Eligibility determination was made based on LIHEAP Guidelines (Low Income Home Energy Assistance Program)

- Residential Comprehensive Energy Education (NEED): educational program implemented through schools;
- Residential Power Manager: load control program for residential air conditioners;
- Residential Energy Star Products: provides incentives to purchase Energy Star-compliant appliances;
- Refrigerator Replacement: free installation of energy efficient refrigerators, when customers replace old units;
- Energy Efficiency Website: provides energy saving information and tips, as well as allowing to perform energy audit using online questionnaire;
- High Efficiency Incentive for Commercial and Industrial: provides incentives to install or retrofit lighting, heating, ventilation, air-conditioning and motors for small commercial and industrial users; and
- Power Share: a load curtailment program designed for large users, where participants agree to shed a fixed quantity of load up to 12 times a year for a financial incentive.

As illustrated in Figure E-3 below, these programs have been largely focused, and had the biggest impact, on residential customers.

Figure E-3. DSM Achievements of Duke Kentucky

	Program	Demand reduction (kW	Energy savings (MWh)	Participation
Residential				
	Home Energy House Call	132	441	697
	Energy Efficiency Website	14	46	203
	Energy Star Products	2,248	5,745	49,560
	Low Income Program	4	14	22
	Refrigerator Replacement	14	48	44
	Personalized Energy Report	370	1,164	9,059
	Power Manager	3,291	-	3,164
Subtotal		*6,073*	*7,458*	*62,749*
C&I				
	C&I Lighting	561	1,929	12,742
	C&I HVAC	15	12	20
	C&I Motors	1	3	4
	Power Share	1,722	-	2
Subtotal		*2,299*	*1,944*	*12,768*
Total utility		**8,372**	**9,402**	**75,517**

Source: Duke Energy Kentucky, Annual DSM Cost Recovery Filing, Case # 2007-00369

Big Rivers Electric Corporation (Big Rivers)

Members of the Big Rivers cooperative currently offer a number of DSM products and services, including:

- Energy efficiency workshop;
- Energy use assessment;
- Operation assessment;
- Customer billing review;
- Commercial lighting evaluation;
- Power factor correction assistance;
- Power quality assessment;
- Power quality correction;
- Energy use summary;
- Remote meter data collection;
- Customized billing services; and
- Residential energy auditing.

However, given that this cooperative does not charge for DSM activities in its rates, no reports of estimated impact of such activities on energy sales and peak demand exist.

East Kentucky Power Cooperative (East Kentucky)

Members of the East Kentucky Power Cooperative offer the following DSM products and services to residential customers:

- Electric thermal storage propane;
- Electric thermal storage furnace;
- Electric water heater retrofit;
- Geothermal heating & cooling;
- Air source heat pump new construction;
- Air source heat pump retrofit;
- Tune-up of HVAC; and
- Button-up weatherization.

The cumulative effect of these DSM programs is shown in the table below. According to the estimates provided by East Kentucky, the net effect of DSM programs on energy consumption was an increase, instead of the savings, while peak demand was estimated to have reduced.

Figure E-4. Impact on Energy and Peak Demand by East Kentucky DSM Programs

	2002	2003	2004	2005	2006
Energy increased (MWh)	(9,131)	(8,712)	(7,765)	(7,807)	(7,301)
Demand reduced (MW)	41.2	41.6	41.5	42.3	42.7

Source: Response to Data Request #19, January 4, 2008

Appendix F - Industry Practices on Renewables

Policy Approaches for Encouraging Renewables

There is a wide variety of incentive mechanisms and mandatory requirements aimed at encouraging the development of the renewable resource-based electricity generation. The experience to date in the United States at fostering the renewable generation can be broadly divided into two categories: voluntary incentives for developers (tax credits, including subsidies) and mandatory system-wide requirements (Renewable Portfolio Standards, interconnection and net-metering rules, fuel composition disclosure requirements).

Voluntary Measures

The incentive mechanisms aimed at fostering development of renewable resources through direct subsidization encompass two major types: tax credits and direct subsidies.

Tax credits can take a variety of different incentives from a tax perspective:

- corporate income tax deductions for the costs of renewable projects (ranging from 10% to 100% of applicable project costs depending on type of renewable technology, duration of allowed carry-over and often subject to a total maximum amount of deductions or a maximum percentage of tax liability – e.g. up to 50% of total tax liability) (e.g. New York, Oregon, etc.); There is also a federal equivalent – Invest Tax Credit;

- personal income tax deductions for the cost of installing private renewable energy generators, i.e., renewable distributed generation (again ranging from 10% to 100% of applicable project costs depending on type of renewable technology, etc.; restrictions often similar to the corporate tax deductions in nature, but at different threshold levels) (e.g. Maryland, Montana, etc.);

- sales tax exemptions (often applies only to specific renewable technologies, e.g. solar, wind; sometimes, applies to a specific type of project sponsor, e.g. community wind projects) (e.g. Texas, Utah, etc.);

- property tax incentives can be in a form of a total exemption for certain varieties of renewables, or a reduced rate (e.g. preferential assessment) or tax abatement (for a limited period) (e.g. Rhode Island, Pennsylvania, etc.);

- production tax credits, when certain types of renewables qualify for tax credits per kWh produced (these are typically federal but also exist at the state level in New Mexico, California, Florida, etc.); and

- tax credits for capital costs of manufacturing facilities to build renewable energy systems (often up to 50% of eligible costs) (e.g. Texas, New Jersey, etc.).

In lieu of or in addition to tax-driven incentives, which some renewable developers cannot easily take advantage of until after commercial operation,[180] many states (e.g. Oregon, Colorado, Minnesota, Indiana, etc.) have set up funds to finance a magnitude of incentive packages ranging from subsidized loans for start-up projects to grants for qualified projects and sponsors. Some of these funds are collected through universal surcharges (Public Benefit Funds) on end-users or via state budget appropriations (either directly or through state agencies and corporations). For instance, Vermont has created a funding mechanism that combines federal, state and utility sources of financing to promote renewable projects.

Mandatory Measures

Renewable Portfolio Standards

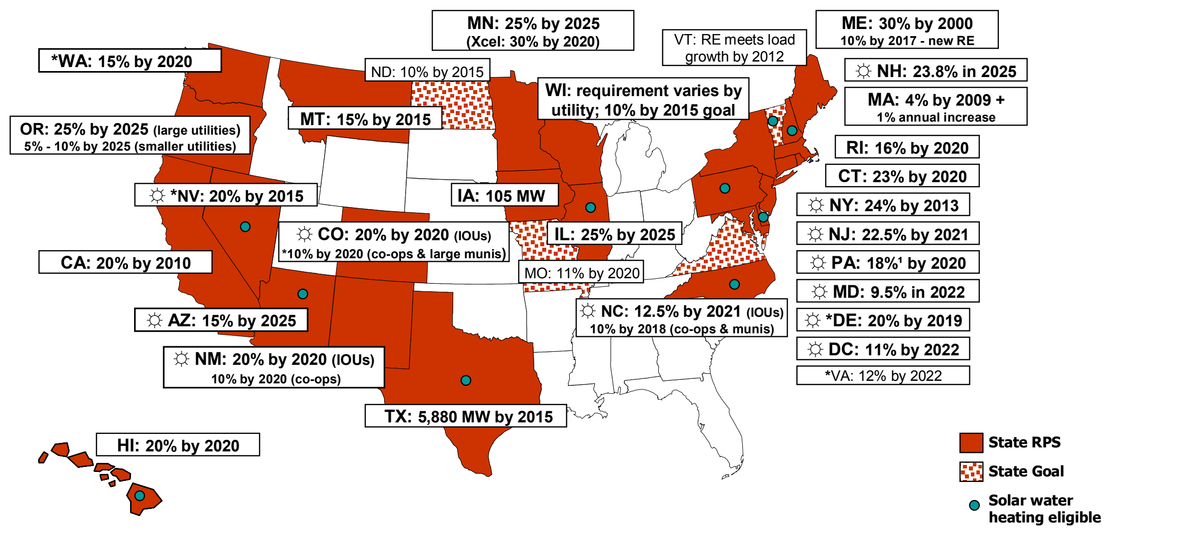
Renewable Portfolio Standards are mandatory requirements to provide a certain share of electricity from renewable resources; often state-level requirements that apply to all or some of the utilities operating in that state.

Out of 50 states (and Washington DC), 27 jurisdictions have Renewable Portfolio Standards, as highlighted in the map below. There is a great variation on the intensity of RPS targets/requirements (ranging from 10% in North Dakota to 33% in California), and in the length of time allowed to reach the ultimate targets. Most states have statewide RPS targets, while some have so far required only certain Investor-Owned Utilities to reach the RPS targets in their retail sales, or have set different (mostly lower) targets for municipally-owned and/or cooperative utilities.

---

[180] Tax credits or deductions are useful only if the tax entity is "profitable." While in development, tax credits are usually difficult to realize, as most developments are not selling any output and therefore do not have any income to shield from taxes. However, renewables developers, especially non-utility independent power producers, are most in need of funding support at the critical construction stage or even pre-development stage. Some monetization of future tax benefits can occur at financial closing (before construction) through structured tax transactions, but these are highly complicated and may not be economic for small scale projects.

Figure F-1. States with RPS



Source: DSIRE (http://www.dsireusa.org

The majority of states have set RPS target as fixed percentage of future retail sales (e.g. California – 33% by 2020), however, there are states that have set absolute amounts equal to certain percentage of reference year sales to be achieved in the future (e.g. Virginia – 12% of 2007 retail sales, to be achieved by 2022).

While the majority of RPS targets are set in terms of energy that needs to be derived from renewable resources, some states have also opted to specify renewable resources' installed capacity (either total capacity to be achieved by a certain year or the amount of **new** capacity needed to come online from a reference year). For example, Maine has recently introduced an RPS requirement based on a percentage of installed capacity.

Some states have made provisions for trading arrangements to facilitate cost efficient compliance. For instance New York recognizes that it is likely to be a net importer of renewable energy to be able to meet its RPS targets; and therefore, allows for out-of-state renewable projects participation in the RPS trading. There are also arrangements between multiple states to facilitate trading in renewable energy to meet RPS requirements through existing electricity markets, such as New England Pool Generation Information System (NEPOOL GIS) and PJM Generator Attributes Tracking System (PJM GATS),

Regional Greenhouse Gas Initiative is an example of **carbon "cap and trade" system**, where Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont (District of Columbia, Massachusetts, Pennsylvania, Rhode Island, the Eastern Canadian Provinces, and New Brunswick as observers) have joined forces develop a cap and trade system for power plant emissions.

Generation fuel mix disclosure requirement is currently implemented in 19 states, including Massachusetts, Nevada, Oregon, etc.

Interconnection and net-metering rules: Currently implemented by 35 and 38 states, respectively, including Georgia, Virginia, Montana, etc.

Resource access laws exist in many states (although there are variations on the extent of rights guaranteed or resources qualified), including Wisconsin, New Mexico, Virginia, etc.

Procurement regulations are in force for state agencies in New York, Illinois, Indiana, etc.

which allow member states to track and account for renewable energy compliance in each of the states.

Other Mandatory Measures

The additional forms of mandatory measures aimed at promoting renewable technologies and projects include:

- carbon 'cap and trade' regimes, where cost of conventional power would increase, as consequence, so would most likely raising the avoided cost and or market prices for renewable energy;

- Standard offer contracts guaranteeing the off-take of power produced by renewable projects;

- requirements for disclosure of generation fuel mix and emissions data (normally twice a year to all retail customers) by utilities;

- enforcement of simplified (and minimal cost) interconnection and net-metering rules for connecting distributed and renewable generation power plants. Often these two rules are connected, where maximum capacity for interconnection and net-metering are identical. Many states impose the ceiling on how much renewable or distributed capacity can be connected, often as percentage of utility's peak demand (ranging from 0.1% to 1%);

- resource access laws, where property owners can create binding solar (or wind) easements for the purpose of protecting and maintaining proper access to sunlight and wind resources.

- state agency energy procurement regulations, where state agencies are required to procure electricity from renewable producers for all state building use (ranging from 10% in Wisconsin to 50% Maine).

Employing Portfolio Analysis to Systematically Identify Benefits of Renewables

Portfolio Analysis, initially developed with a sole focus on financial securities, has since been applied to several types of assets and industries, including the electric industry. It is useful in formulating strategies about future investment (and divestment) in order to optimize returns (to the firm or industry) given the prevailing risks. The central thesis of Modern Portfolio Theory, the theoretical foundation for Portfolio Analysis, is that the risk of a portfolio of assets can be systematically reduced, with no corresponding reduction in expected return on the portfolio. Risk is reduced through a specific type of diversification of the assets in the portfolio – in particular, by combining assets in a portfolio that are inversely correlated with respect to so-called unsystematic (or unique) risk.[181]

The basic principles of Modern Portfolio Analysis have been applied to the power sector planning process – in particular, the development of portfolios of electricity generators - within several electricity sectors, including, for example, the United States, Canada, Europe and South America. Because this approach focuses so directly on the benefits of combining assets with different characteristics, its application has tended to identify the benefits of combining renewable technologies within generating portfolios otherwise dominated by conventional fuel resources.

Unfortunately, electricity capacity expansion planning in the US, even when coordinated within broader Integrated Resource Planning procedures, is still largely focused on evaluating development alternatives with respect to only stand-alone costs. While there has been some progress in this regard, the basic principles and mechanics of Portfolio Analysis have not yet become ingrained throughout the industry. Nevertheless, individual utilities and generating companies have started to use the key principles of Portfolio Analysis in their strategic planning. Regulatory agencies and system planners are therefore likely to follow.

Application of a Portfolio Analysis approach to develop optimal portfolios of generating assets does not require a significant departure from the types of sensitivity analyses conducted by Kentucky utilities as part of their current planning process (most of which are perfectly consistent with Portfolio Analysis). Its use in Kentucky would advance the goals of Section 50 by institutionalizing application of an analytical approach that explicitly accounts for the risk mitigation benefits of adding renewable technologies to portfolios dominated by traditional generating plants dependent on fossil fuel whose future value is uncertain.

The five analytical issues to be addressed in order to systematically incorporate Portfolio Analysis within existing planning processes are: (i) selecting an objective function or measure of "returns"; (ii) measuring volatility (risk); (iii) constructing portfolios of generating assets; (iv) identifying an efficient frontier of portfolios; and (v) selecting an optimal portfolio.[182] Each of these is discussed briefly below.

---

181 The theory is that the total risk associated with any asset can be systematically broken into two components: unsystematic (or unique) risk reflects the portion of the asset's overall volatility that is uncorrelated with returns in the overall market, while systematic (or market) risk reflects the portion of the asset's overall volatility that is correlated with returns in the overall market. In financial, rather than statistical terms, market risks are driven by broad macroeconomic factors (such as, for example, long-term interest rates) that impact all assets (within whatever geographic regions comprise the "market") in essentially the same way. In contrast, unique risks reflect factors that affect some assets but not all, and affect assets in different ways (for example, if the price of corn goes up, this is good news for a corn farmer, bad news for a ethanol producer, and of no consequence to television manufacturers).

182 Some of these components of portfolio analysis are performed within the IRP process of many utilities – in Kentucky and elsewhere – without being formally organized as a comprehensive portfolio analysis.

Return Metric

There are two choices for the return metric. The first, reflecting the utility's interest in profit maximization, is the financial return on generating assets – i.e., (electricity price – fuel costs - operating costs) / investment cost. An alternative is to focus more directly on the interest of consumers in maximizing the benefits received by consumers (in the form of electricity) in exchange for their provision of payment – i.e., price/kWh. Either of these two metrics require price forecasts.

Volatility

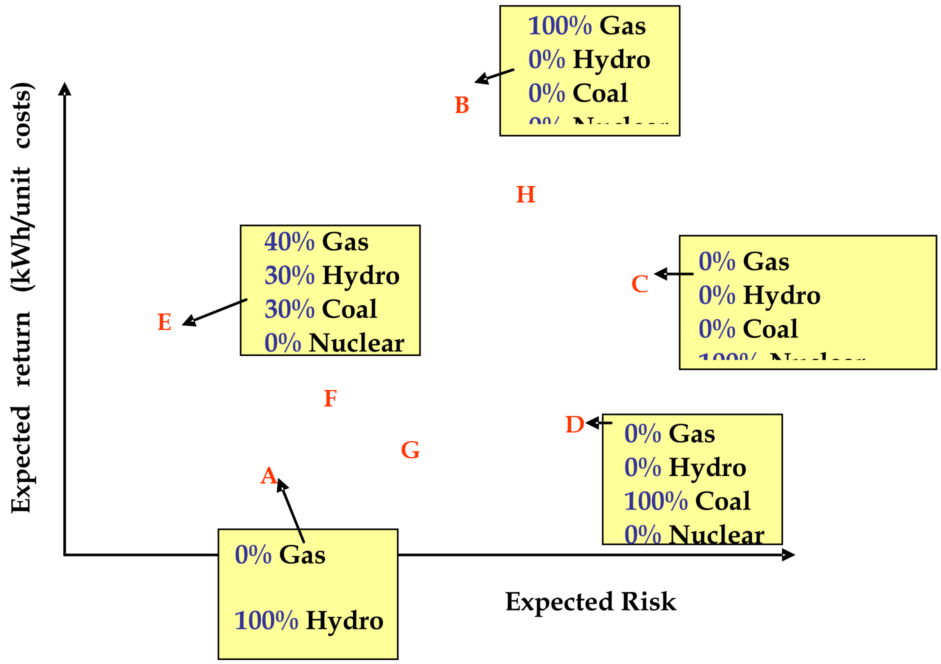
Portfolio volatility is measured with respect to the standard deviation of the distribution of the selected return metric as determined by the running of various scenarios and/or Monte Carlo simulations. Some commentators have claimed that renewable generators can be treated as essentially risk-free assets.[183] While this approach would treat renewables too favourably within the process, it is true that a Portfolio Analysis does account for the volatility-reducing benefits of renewable generation more systematically and quantitatively than alternative conventional approaches such as sensitivity analysis.

Constructing Generator Portfolios

Portfolios of generating assets can be defined at various levels of aggregation including, for example, individual generating units, generating plants or combinations of generating plants sharing the same technology and fuel source. The latter is appropriate to the extent generating plants sharing a common technology / fuel source also share a common cost structure. Figure F-2 illustrates hypothetical results of this process for the generation asset classes of natural gas, hydro, coal, and nuclear. A small selection of portfolio combinations are displayed, each reflecting a distinct weighting of the four fuel categories. Each portfolio's positioning on the graph reflects its return-risk characteristic.

183 See, for example, "Applying Portfolio Theory to EU Electricity Planning and Policy-Making," Shimon Awerbuch and Martin Berger, IEA/EET Working Paper, February 2003. The basic argument is that unit fixed and variable O&M costs tend to vary little and, in any case, collectively comprise a relatively small portion of aggregate unit costs; and fuel costs, which generally drive the bulk of the volatility for generating assets, are fixed at zero for renewables. This argument ignores the risk of renewable generators not being able to deliver energy at various times when needed (for example, wind generation may not be available during the hottest part of the day). At these times, the owner / operator of the renewable generator must meet its obligation by securing replacement energy, through either a market purchase or reliance on installed backup generation. In these instances, the unit cost in the denominator of the return metric associated with the renewable asset is equal to the market price (which reflects either the price paid for replacement energy or the revenue foregone by diverting the production of backup generators from market sales). This introduces volatility and, by extension, risk.

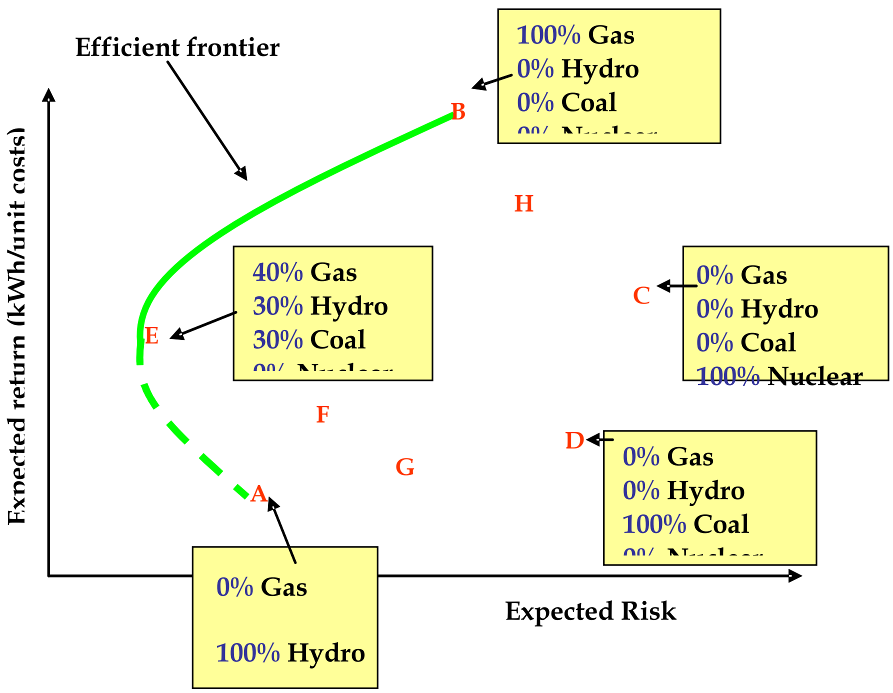
Figure F-2. Plotting a Set of Generation Asset Portfolios



Identifying the Efficient Frontier

Once all potential portfolio combinations have been plotted, the so-called efficient frontier (i.e., the set of portfolios for which the risk-reward profile cannot be unambiguously improved) is identified. Each generator potentially incorporated within the portfolio is assigned, based on appropriate historical analysis, metrics reflecting estimates of expected future average return and expected future volatility of returns. Then the full range of potential portfolio combinations are arithmetically identified and graphically displayed, as illustrated below in Figure F-3. Portfolios E and B are two examples of efficient portfolios located on the frontier.

Figure F-3. Plotting the Efficient Frontier



Selecting an Optimal Portfolio

Choosing between portfolios on an efficient frontier is based entirely on risk tolerance (whether a high-risk / high return option is preferred, or a low-risk / low-return option, or something in between), not considerations of relative efficiency. In theory, all portfolios not on the frontier should not be considered as viable options. With respect to analysis of financial securities, it is generally accepted that financial return captures all factors impacting risk. In employing Portfolio Analysis within the electric industry, there may be occasions where portfolios off the efficient frontier have desirable attributes not reflected in the established return metric. In these instances, broader strategic and societal considerations should perhaps be factored into the analysis of generating options. For example, choice of a particular plant might offer environmental benefits; the opportunity to strengthen a relationship with a strategic partner; or the opportunity to experiment with a new generating technology that, while costly in the short-term, is expected to create substantial commercial opportunities over the longer-term. These sorts of considerations are not reflected in the narrow financial return metric introduced above.

Conceptually, it is possible, perhaps even desirable, to establish quantitative estimates of exactly these sorts of expected benefits and systematically incorporate them within the analysis by expanding the scope of the return metric. But, as a practical matter, to date, there have been limits as to what regulators and utility managers are willing to attempt to quantify. The more long-term, strategic and societal-focused are factors affecting choices among generators, the more likely it is that decision-makers will want to account for them by applying relatively informal adjustments to the analysis.

This issue often comes up in the context of environmental impact of emissions such as CO_2, NOx and SOx. When it is considered difficult or impossible to reduce the impacts of such emissions to dollars, the alternative is to informally compare the financial results to non-financial (but generally quantitative) measures of environmental impact. The criterion for evaluation should be established at the early stages of the study. Several firms employ a score-card; an analytical device that structures the analysis by assigning scores (what are essentially weights) to various financial and non-financial factors deemed to be important. This approach clearly incorporates considerable elements of subjectivity. Some see this as a weakness (in that it does not even attempt to establish a common, and seemingly objective, basis for comparison; others see it as a strength in that invites a richer dialogue on the issues than would likely result from a more reductionist approach.

Status of Renewables Experience within the U.S.

Most states have begun to establish some combination of programs to encourage and provide financial support for renewables. A variety of approaches have emerged.

Figure F-4 below presents information about renewables policy for U.S. states as of the end of 2007.

Figure F-4. Renewable Policies in the US

State	RPS targets (% of energy sales, unless otherwise noted)	Other requirements/incentives	Interconnection rules	Net metering rules	Tax incentives for renewable projects	Tax/other incentives for manufacturers
Alabama	N/A	Biomass Energy Program - grants upto $75,000 - interesidentialt subsidy	N/A	N/A	100% tax deduction for wood burning system	
Alaska	N/A	N/A	N/A	N/A	N/A	N/A
Arizona	since 2006, 15% by 2025 (30% of renewables to come from DG)		N/A	N/A	corporateorate and personalonal tax credit - 10% of investment costs for solar and wind projects, upto $25,000 per building; property tax exemption for solar projects; sales tax exemption for solar and wind projects	
Arkansas	N/A		upto 25 kW (residential), 300 kW (commercial)	upto 25 kW (residential), 300 kW		
California	since 2003, current plans - 33% by 2020 (20% by 2010)	State rebate programs for solar systems, wind and fuel cell projects, plus Cogen/CHP as DG; all financed through Public benefit fund surcharge	upto 10 MW DG and renewables	upto 1 MW for wind, solar, landfill gas; upto 10 MW for biogas digesters	Property tax exemption for solar systems, personalonal deduction	
Colorado	since 2004 - 20% by 2020	Clean Energy Fund, fuel mix disclosure	upto 10 MW (3 levels)	upto 2 MW	property tax assessment - rate varies;	
Connecticut	1998, 27% by 2020 (3 classes of residentialources)	Clean Energy Fund - grants loans, fuel mix disclosure	100 kW for net-metered, 20 MW - DG	2 MW	property tax exemption; sales tax exemption for solar and geo	
DC	2005, 11% by 2022	Renewable Energy Demonstration Project - grants; fuel mix disclosure; Reliable Energy Fund	100 kW	100 kW		
Delaware	2005, 20% by 2019	Green Energy Fund State Grant Program (35% of costs); fuel mix;	1 MW	25 kW (residential), 2 MW		
Florida	N/A	General Revenue Funds - solar incentives (PV $100,000); fuel mix disclosure	10 kW - photovoltaics only	N/A	production tax credit; investment tax credit 75%, can be carried forward until 2012; sales tax exemption	
Georgia	N/A		10 kW (residential), 100 kW (commercial)	10 kW (residential), 100 kW	sales tax exemption for biomass	
Idaho	N/A	financing from Idaho Energy residentialources Authority	N/A	N/A	personalonal tax deduction 40% 1st year, 20% for 3 years, upto $20,000 total; property tax exemption for wind; sales tax exemption for renewables	
Illinois	since 2007, 25% by 2025 (75% from wind)	Renewable Energy residentialources Program (funded through public benefit surcharge) - grants for renewable projects (varies), includies "clean" coal; generation fuel mix and emissions disclosure	N/A	upto 40 kW	Property tax assessment - preferential for commercial wind, exemption for solar projects	
Indiana	N/A	Alternative Power and Energy Grant Program - upto $25,000; geothermal heat pump rebates - state financing	no limit (3 levels)	upto 10 kW	property tax exemption	
Iowa	N/A	fuel mix disclosure; state agenices are required to procure 10% from renewable sources, 105 MW of renewables procurement for two main IOUs	pending	upto 500 kW	production tax credit; excise tax exemption; preferential property tax assessment; sales tax exemption	
Kansas	N/A		N/A	N/A	property tax exemption	

Appendix F

State	RPS targets (% of energy sales, unless otherwise noted)	Other requirements/incentives	Interconnection rules	Net metering rules	Tax incentives for renewable projects	Tax/other incentives for manufacturers
Maryland	2004, 9.5% by 2022	wind project state grants; fuel mix and emissions; 6% for government renewable procurement	2 MW (total 1,500 MW)	2 MW (total 1,500 MW)	production tax credit (personalonal corporateorate); property tax exemption - solar, sales tax exemption for wood burning	
Massachusetts	since 1997, 4% of new capacity by 2009, plus 1% each year	Renewable Energy Trust Fund - loans and grants; Sustainable Energy Economic Development - seed funds for new projects; fuel mix and emissions	no limit	60 kW	patent/royalty income is tax deductible; solar wind expenses excise tax exemption; partial credit for solar heat; personalonal 15% deduction - solar, wind; sales tax exemption	
Michigan	N/A	generation fuel mix and emissions disclosure	no limit (5 levels)	upto 30 kW		Tax credits; Property tax exemption for businesses located in special zone and engaged in renewable activities (residentialearch, manufacturing)
Minnesota	since 2007 - 30% by 2020	Renewable Development Fund (production incentive); fuel mix and emissions disclosure	upto 10 MW (40 kW for net-metered systems)	upto 40 kW	photovoltaic and wind property tax exemption; sales tax exemption	
Mississippi	N/A		N/A	N/A		
Missouri	N/A	production credit for wood energy	upto 100 kW	upto 100 kW		
Montana	since 2005, 15% by 2015	pending legislature to require fuel mix and emissions disclosure	upto 50 kW	upto 50 kW	tax (corporateorate and personalonal) credit 35% of investment costs, no maximum; 100% of geothermal projects for personalonal taxes; 50% property tax abatement for 5 years, declinign rate for next 10 years	property tax 50% tax abatement for manufacturing facilities for renewable systems
Nebraska	N/A		N/A	N/A	tax credit - upto $750,000 (corporateorate or personalonal); sales tax exemption for commercialunity wind projects	
Nevada	since 1997, 20% by 2015	Portfolio Energy Credits (PEC) - renewable energy producers earn PEC to be sold to utilities (no trading is permitted); fuel and emissions disclosure	upto 20 MW	upto 1 MW (utilities can impose fees for systems larger 100 kW)	Property tax exemption	
New Hampshire	since 2007, 23.8% by 2025	System Benefits Charge	100 kW, 1% of peak demand	100 kW, 1% of peak demand		
New Jersey	2001, 22.5% by 2021	production incentives - Solar RECs; Office of Sustainabiloty loans; rebates; fuel mix disclosure	2 MW for net-metered	2 MW		Loans for manufactureresidential,
New Mexico	since 2007, 20% by 2020	REC purchase program for photovoltaic systems (less than 10 kW)	upto 80 MW (including CHP)	upto 80 MW (including CHP)	Production tax credit (min 1 MW); soalr - 6% upto $60 million; sales tax exemption;	5% of expenditureresidential tax credit for manufacturers
New York	since 2004, 24% by 2013	New York System Benefits Charge - DG incentives (inc. CHP), load erduction measuresidential; production and new equipment incentives - anaerobic digesters; RPS Surcharge - PV incentive; disclosure program;	2 mW	10 kW - solar, 25 kW residential wind, 125 kW farm wind, 400 kW farm biogas	corporate and personal tax credit "Green Building"; personalonal tax credit for solar and fuel cell; property tax exemption - solar, wind, biomass; sales tax exemption solar	upto 50% of project costs, upto $200,000 incentives; cost sharing for manufacturing
North Carolina	since 2007, 12.5% by 2021 for IOU, 10% by 2018 for coops and municipals		upto 20 kW (residential), 100 kW (non-residential); total upto 0.2% of peak demand)	upto 20 kW (residential), 100 kW (non-residential); total upto 0.2% of peak demand)	tax credits (corporateorate and personalonal) - 35% of project costs upto $2.5 million (commercial), $10,000 (residential - varies); property tax assessment preferential	
North Dakota	since 2007, 10% by 2015		N/A	upto 100 kW	Tax credit - 15% (personalonal and corporateorate); 70-80% property tax reduction for wind; geothermal, soalr, solar - 100% property tax exemption	
Ohio	N/A	production incentives for producers and locally manufactured wind turbines; Ohio Advanced Energy Fund - grants for DG (upto $150,000); fuel mix and emission disclosure	upto 20 MW	no limit (overall upto 1% of peak demand)	property tax exemption, corporateorate tax exemption, sales tax exemption - no limit	

State	RPS targets (% of energy sales, unless otherwise noted)	Other requirements/incentives	Interconnection rules	Net metering rules	Tax incentives for renewable projects	Tax/other incentives for manufacturers
Oklahoma	N/A		N/A	upto 100 kW or 25,000 kWh/year, whichever is less	Production tax credit	tax credit for manufacturers of small wind turbines
Oregon	since 2007, large utilities 25% by 2025, smaller utilities 10% by 2025; also 8% of electricity should come from small renewable projects 20 MW or less by 2025	Energy Trust of Oregon (financed from Oregon's public purpose charge) rebates for installations of solar and wind systems; utilities are required to provide fuel mix and emissions disclosure	upto 2 MW of renewable systems (3 levels of systems)	available for upto 2 MW systems	corporateorate tax credit for upto 50% of investment costs (10% per year for 5 years) for renewable projects, max $10 million; personalonal tax credit for installing renewable systems; property tax exemption	tax credit for manufacturers of renewable systems - 50% of investment costs, upto $10 million
Pennsylvania	since 2005, 18% by 2020	State grant program for renewables; fuel mix disclosure	no limits	50 kW (residential), 3 MW (non-residential), 5 MW (emergency)	property tax exemption - wind projects	
Rhode Island	since 2004 , 16% by 2020	Renewable Energy Fund; fuel mix disclosure	25 kW, upto 1 MW total, but not state requirement	1 MW, 25 kW (total 1 MW)	tax credit (corporateorate and residential.) 25% of costs ($15,000 solar); solar - property tax exemption; sales tax exemption - renewable	
South Carolina	N/A	production incentives for biomass - paid from state' general fund; Renewable Energy Infrastructure Development Fund - grants,loans,	upto 20 kW (residential), 100 kW (non-residential);		tax credit - 25% of elgible costs upto $650,000 (not more than 50% of tax liability) for biomass - carried forward 10 years; $3,500 for solar (both corporate and personal); sales tax exemption for fuel cell	
South Dakota	N/A		N/A	N/A	preferential property tax assessment for wind, 50% exemption for commercialercial projects renewable; 100% for residentialidential	
Tennessee	N/A	Economic and commercialunity Development Energy Division offers grants for 40% of projects costs, upto $75,000 - commercialercial projects only; low interesidentialt loans for upto $300,000 upto 7 years	N/A	N/A	property tax exemption - wind	
Texas	since 1999, 5,880 MW by 2015	fuel mix and emission disclosure	upto 10 MW	upto 100 kW for QF, 50 kW for renewables	franchise tax deduction; property tax exemptions	franchise tax exemption for manufacturers
Utah	N/A		upto 25 kW	upto 25 kW	renewable tax credit (corporateorate 10% upto $50,000, personalonal 25%, upto $2,000; sales tax exemption	
Vermont	since 2005, capped at 10% of 2005 sales, to be achieved by 2012, if not, then it becomes mandatory in 2013	Clean Energy Development Fund - loans; state funded loand as well, joint funding for solar rebates (state, federal, utility; fuel mix and emissions	15 kW, 150 kW (farm systems)	15 kW, 150 kW (farm systems)	Sales tax exemption	
Virginia	since 2007, 12% of 2007 sales by 2022	Solar manufacturers incentive grant program; fuel mix and emissions	upto 10 kW (residential), upto 500 kW (non-residential), overall system limit upto 1% of peak demand	upto 10 kW (residential), upto 500 kW (non-residential), overall system limit upto 1% of peak demand		grants for solar panel manufacturers
Washington	since 2006, 15% by 2020 (3% by 2012, 9% by 2016) - includes multiple varieties of renewable plus CHP cogen	Utilities have to provide Generation fuel mix disclosure; utilities with more than 25,000 customers should offer option of renewable energy purchases	upto 300 kW of capacity, above 300 kW and upto 20 MW - FERC standards	Available for systems upto 100 kW	sales tax exemption for renewable systems	40% reduction of business and occupation taxes
West Virginia	N/A			upto 25 kW		
Wisconsin	since 1999, 10% by 2015 (varies)	Public Benefits Fund - grants for renewable projects (upto $260,000); cash backs for 25% of project costs and upto $35,000; state agenices have to procure 10% of energy from renewable residential sources	upto 15 MW (4 categories)	upto 20 kW	property tax exemption - solar	
Wyoming	N/A		upto 25 kW	upto 25 kW	Sales tax exemption;	

Figure F-5 below provides a scoring of states based on a simple approach of assigning a value of one when an incentive is present in a state and zero otherwise (regardless of the extent of the incentives and whether all types of renewables and/or customers/project developers qualify). While this comparison is not designed to be a comprehensive comparative analysis, it does, nevertheless, present a useful framework for assessing the extent of renewable policies being implemented in the US. The State of Kentucky implements 4 different categories of renewable support policies, while New York ranks the highest with 10 out of 12 categories considered.

Figure F-5. Simplified State Ranking on Renewables Policy Support

	RPS	Interconnection rules	Net-metering rules	Corporate tax incentives	Personal tax incentives	Production tax credits	Production incentives/RECs	Sales tax incentives	Property tax incentives	Public Benefit Funds	Incentives for manufacturers	Fuel mix and emissions disclosure
New York	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	
Oregon	✓	✓	✓	✓	✓				✓	✓	✓	✓
Rhode Island	✓	✓	✓	✓	✓			✓	✓	✓		
Maryland	✓	✓	✓	✓	✓			✓	✓			✓
Montana	✓	✓	✓	✓	✓				✓		✓	
New Mexico	✓	✓	✓			✓	✓	✓			✓	
Texas	✓	✓	✓					✓	✓		✓	✓
Minnesota	✓	✓	✓					✓	✓	✓		✓
Ohio		✓	✓	✓				✓	✓		✓	✓
Massachusetts	✓	✓	✓	✓				✓		✓		✓
New Jersey	✓	✓	✓				✓			✓	✓	✓
Washington	✓	✓	✓					✓			✓	✓
Nevada	✓	✓	✓				✓		✓			✓
North Carolina	✓	✓	✓	✓	✓				✓			
Pennsylvania	✓	✓	✓						✓	✓		✓
Connecticut	✓	✓	✓					✓	✓			✓
California	✓	✓	✓			✓				✓		
Arizona	✓			✓	✓			✓	✓			
Utah		✓	✓	✓	✓			✓				
Colorado	✓	✓	✓						✓			✓
North Dakota	✓		✓	✓	✓				✓			
Iowa			✓			✓		✓	✓			✓
Louisiana		✓	✓	✓	✓				✓			
Illinois	✓		✓						✓	✓		✓
Wisconsin	✓	✓	✓						✓	✓		
Virginia	✓	✓	✓								✓	✓
South Carolina		✓		✓			✓	✓		✓		
Florida		✓		✓		✓		✓		✓		
Vermont	✓	✓	✓					✓		✓		
Delaware	✓	✓	✓							✓		✓
DC	✓	✓	✓							✓		✓
Idaho					✓			✓	✓	✓		
Kentucky			✓	✓				✓			✓	
Indiana		✓	✓						✓	✓		
Michigan		✓	✓								✓	✓
Maine	✓	✓								✓		✓
New Hampshire	✓	✓	✓							✓		
Wyoming		✓	✓					✓				
Nebraska				✓	✓			✓				
Oklahoma			✓			✓					✓	
Missouri		✓	✓			✓						
Georgia		✓	✓					✓				
Arkansas		✓	✓									
Alabama				✓						✓		
Tennessee									✓	✓		
South Dakota									✓			
Kansas									✓			
West Virginia			✓									
Alaska												
Mississippi												

Source: Database of State Incentives for Renewables and Efficiency, NC State University (http://www.dsireusa.org accessed January 28, 2008)

[This page intentionally left blank.]

Appendix G - Industry Practices on Resource Planning and Full-Cost Accounting

Integrated Resource Planning

Integrated resource planning (IRP) is a process for utilities to rigorously evaluate supply and demand options. This approach was, within the US, initially developed for and applied by vertically integrated utilities, a structure which was very much the norm at the time of industry restructuring of the generation and transmission markets, and continues to this day in many states, such as Kentucky. The process involved analysis by the utility of supply-demand dynamics within its franchise area, and a projection of investment needs for generation and transmission. IRP documents were typically filed with the state regulator for review and/or approval. IRPs were frequently completed on a set schedule, annually (at the most frequent) to, more often, bi-annually or even tri-annually. For example, utilities in Indiana, North Dakota and Washington (among others) submit their plans bi-annually, while utilities in Georgia and Nevada (amount others) submit every three years.

As restructuring has proceeded within many jurisdictions, leading to many utilities being vertically disaggregated, the IRP process has been slightly modified. The major modification has been an expansion of the range of considerations to include a broader focus on various forms of procurement through markets and contracts (rather than or in addition to ownership and operation). In addition, over time, the process has become more complicated as technological developments continue to make feasible a more robust range of options to meet projected demand needs. The range of options, beyond conventional generation, encompasses renewables, distributed generation, and demand side management. A sample of utilities that have recently addressed these issues within their IRP processes are presented in Figure G-1:

Figure G-1: Resource Planning beyond Conventional Generation

States	Utilities	Integration of DSM/Renewables in Most Recent IRPs
Idaho	Idaho Power	Renewables/DSM
Georgia	Georgia Power	Renewables/DSM
Minnesota	Xcel Energy	Renewables/DSM
Nevada	Nevada Power Company	Renewables
Oregon	Pacificorp	Renewables/ DSM
Utah/Wyoming/Idaho	Rocky Mountain Power*	Renewables/ DSM
Washington	Avista	Renewables/ DSM

Rocky Mountain Power is a subsidiary of Pacificorp; Wyoming does not require IRP

Source: Companies' websites

It is now common for ISOs/RTOs to prepare the system-wide, forward looking resource planning strategic plans, instead of the individual utilities (the major exception to this in North American markets is MISO, where long term planning and resource adequacy analysis is still a state-level activity (although MISO is developing a mechanism for tracking resource adequacy on a market-wide basis). Although the organizations that run IRPs and approve IRPs has changed in some restructured jurisdictions, the fundamental essence of the process - considering a full range of supply-side and demand-side options, and systematically assessing them against a common set of planning objectives and criteria – has not changed. Planning documents for a sample of state ISOs is displayed below in Figure G-2.

Figure G-2. Sample System Planning Documents

ISO	Name of the plan	Duration	Link
CAISO	CAISO Transmission plan	10 years	http://www.caiso.com/1f52/1f52d6d93a3e0.pdf
CEC	California Integrated Energy Policy Report	10 years	http://www.energy.ca.gov/2005publications/CEC-100-2005-007/CEC-100-2005-007-CMF.PDF
MISO	The MISO Transmission Expansion Plan	6 years	http://www.midwestiso.org/publish/Document/5d42c1_1165e2e15f2_-7ba40a48324a/MTEP07_Report_10-04-
NE-ISO	Regional System Plan	10 years	http://www.iso-ne.com/trans/rsp/2007/rsp07_final_101907_public_version.pdf
NYISO	Comprehensive Reliability Planning Process	10 years	http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/2004_planning_trans_report/2007_RNA.pdf
PJM	Regional Transmission Expansion Planning Process	15 years	http://www.pjm.com/about/downloads/20061129-regional-transmission-expansion-plan.pdf
SPP	Regional Transmission Expansion Plan	10 years	http://www.spp.org/publications/2006%20Expansion%20Plan%20ReportMOPC_01-17-07PUBLIC.pdf

Source: respective websites of organizations

Another core characteristic of the IRP process is stakeholder participation. As practiced in most jurisdictions, regulators oversee and direct a process that is meant to be transparent, to encourage the presentation of information by utilities, and to elicit comments and concerns from interested stakeholders. In some jurisdictions, these processes are fairly brief, while in others, the stakeholdering and development of final recommendations spans the entire cycle – one to two years. Sample timeframes for stakeholder participation processes are displayed in Figure G-3 below.

Figure G-3. Sample Timeframes for Stakeholder Engagement in IRP Development

IRP	Timeframe for stakeholder engagement
California Integrated Energy Policy Report 2005	about 10 months - series of public workshops and stakeholder engagements
Ontario Integrated Power System Plan 2008	over 1 year - continous involvement during the process of development of the plan
New York ISO Comprehensive Reliability Planning Process	continuous engagement - planning document updated annually
Portland General Electric Company Integrated Resource Plan	6 months of stakeholder feedback period

Source: Websites of respective companies and organizations

Overall, the planning process varies with respect to its details across jurisdictions, but a typical process for implementing an IRP proceeds in accordance with the following steps:

Step 1 – Specify Objectives and Evaluation Criteria

The core objective of an IRP is to define a least cost portfolio of necessary investments to meet projected demand. As implied by the name, the primary criteria are economic efficiency or "least cost" (from ratepayers' perspective) and reliability (as implied by the word "necessary"), Additional objectives are also specified, often qualitatively, to account for regulatory requirements and appropriate considerations of relevant stakeholders; these often include, for example, environmental protection, reduction of long-term risk factors; and equity (across various customer classes and also present versus future customers). The bases for evaluating the extent to which specific objectives have been met should be specified as comprehensively and precisely, with as much reliance on quantitative metrics, as possible. Cost, technical and reliability objectives can almost always be quantified, while broader social objectives often require ordinal, rather than cardinal, rankings.

Step 2 – Forecast Demand

Demand forecasts, within the context of an integrated resources plan, should range from the medium- to long-term (up to 25 years), although a 10 year outlook is perhaps the most common. The forecasting process should be as data-driven as possible. The most common types of analyses are trending (or sometimes somewhat more sophisticated time-series) analyses, relying exclusively on extrapolations of past behaviour, and econometric models, relying on the specification of structural relationships between variables of interest. Hybrid models are possible, as well as more sophisticated techniques such as Monte Carlo simulation. An overview and comparison of alternative approaches is provided below in Figure G-4.

Figure G-4. Comparison of Various Forecasting Methodologies

Forecast models	Methodology	Advantages	Weaknesses
Trending	Econometric extrapolation, based on specifications of structural relationships between variables	Often best suited for complex relationships, better applicability for short-term analysis	Accuracy diminishes with longer time horizons analyzed; highly dependent on quality of historical data
Scenario	Judgemental analysis of likely relationships between variables	Can account for new variables and changes in relationships between variables	Highly subjective
Monte Carlo	Simulation technique that generates a universe of probable outcomes based on a range of possible values of variables	Allows to rank and compare outcomes based on probability of occurrence	Very computationally intensive
Hybrid	A combination of different methods	Allows to customize the analysis to specific situation	May be difficult to design

Step 3 – Examine Supply-Side Options

Supply-side options are examined both from an economic and technical perspective. This portion of the analysis focuses on alternative ways of meeting a given level of demand. Generating resources are often organized within categories - such as fuel type and/or dispatch order – and technical and operating characteristics (e.g., capacity, ramp rates) and constraints e.g., minimum load levels) are specified. Economic analysis typically focuses on the net present value of costs, and perhaps levelization of such costs, so that different technologies with different operating profiles/utilization rates can be compared side-by-side. Simulation models are commonly employed to provide input to this analysis. The analysis of generation and transmission (and distribution) is complicated by the fact that they are sometimes complements and sometimes substitutes. The challenge is to construct alternative portfolios of assets to be included in candidate supply plans (for further evaluation). A screening process is often applied to quickly rule out clearly unattractive options, after which, production cost simulation models are traditionally used to yield estimates of future costs and benefits, as discussed further below.

Step 4 – Examine Demand-Side Options

Traditionally, demand-side options have not been intensively incorporated into IRPs, but rather exogenously specified and used as a static input. Supply-side options are then layered to meet projected demand less the viable demand-side options.

Over recent years, in response to more dynamic DSM programming, analytical processes have become more sophisticated. Demand-side analysis focuses on alternative ways of controlling demand as a way of managing supply constraints. The focus is on reductions in both overall level of electricity usage and peak demand (requiring shifting of usage across time periods). From a commercial and financial perspective, investments that reduce demand are entirely comparable to investments in supply-side resources (the former eliminates the need for the latter). As with supply-side resources, a comprehensive list of all potential options, characterized with respect to economic and technical characteristics, is compiled and filtered down to a shorter list for more detailed study. This short list of demand-side options is then analyzed side-by-side with the short-list of supply-side options.

Step 5 – Prepare and Assess Supply and DSM Plans

Once short lists of supply and demand-side options have been established from the applications of high-level screening criteria, the feasible options are compiled into candidate supply and DSM portfolios. Even when there are relatively limited individual options, the number of potential portfolio combinations can be large. Selecting a manageable number of candidate portfolios generally requires a combination of art, in the form of analytical judgement, and science, by use of computer-based sampling models. Analysis of candidate portfolios proceeds with the support of dispatch simulation models and reliance on the criteria specified in Step 1. An advanced approach to the analysis of portfolio options is presented later in this chapter.

Step 6 – Prepare Report

The selected integrated resource plan is documented in considerable detail. Technical appendices - including input data and model outputs – are usually included.

Step 7 – Regulatory and Stakeholder Review

A core characteristic of the IRP process, relative to alternative utility planning approaches, is that it is designed to encourage stakeholder participation and interaction. Utilities generally submit their plans to their regulators for review within formal proceedings. Consumer representatives and organized environmental and other interest groups are generally provided the opportunity to participate in regulatory hearings, including providing testimony.

Step 8 - Procurement of Resources Selected in the IRP

IRPs conclude with the procurement of resources recommended and approved in the IRP. In the traditional, vertically-integrated environment, the utility typically builds the necessary transmission and generation investment, incorporating the cost of investment into ratebase. With deregulation, and the advent of independent power producers (IPPs), utilities and regulators have been given another option – to purchase the energy and associated products from IPPs.

Requests for Proposals

An electric utility issues a request for proposals (RFP) when it wishes to evaluate prospects for contracting with a third party to develop, and perhaps also operate, a generating plant, as an alternative to developing and/or operating its own plant. This process has been prominent within the electricity industries of developing countries for many years, often because government-owned utilities lacked the financial capital to build generating plants, and/or recognized that international developers could bring superior expertise to the construction and/or operation of a plant.

The issuance of RFPs became more standard within the U.S. after passage in 1978 of the Public Utility Regulatory Policies Act in 1978, which required utilities to buy power from non-utility generators. Since that time, two additional forces have driven utilities to issue RFPs. First, as part of broad-based industry restructuring schemes instituted in various jurisdictions or regions within the U.S., many utilities were forced or otherwise motivated to disaggregate all or significant portions of their previous portfolios of generating assets in favour of reliance on a combination of short-term purchases through power markets and longer-term contracting organized through RFPs. Second, regulators may require that utilities that want to build their own generation must first implement an RFP process to determine if less expensive options are available; and to collect information, providing a basis for assessing the reasonableness of costs in the self-build option.

The procurement process design is inherently linked to the underlying goals of the solicitation. Therefore, goals must be clearly defined before the procurement structure and process is designed. Principles commonly applied as objectives in design of a competitive solicitation and implementation include:

- **Clarity**: products and services required should be clearly defined
- **Transparency**: Bidders should understand how RFP process will function and how bids are being evaluated
- **Fairness**: all bidders should be treated fairly
- **Independence**: independent third-party monitoring or management of RFP
- **Confidentiality**: protecting bidder confidential information

The RFP process generally consists of five basic phases, as follows:

Step 1 – Specification of terms

RFPs can be issued for the building and/or operation of a new generating plant, or the provision of one or more services (e.g., energy capacity, ancillary services, etc.) from an existing plant. In either case, the purpose of the RFP is to seek solicitations from respondents to address identified needs, which are specified in the form of economic, technical and legal terms and conditions. In practice, the needs to be addressed can and are specified with varying degrees of specificity. The issuing utility may know (and specify) exactly what it wants (in terms of, for example, timing of deliveries, price range, etc.); or it might characterize its interests broadly and generally with the hope and expectation that respondents will present creative solutions.

The RFP documentation is very important. A badly formulated RFP could result in too few bids. The terms and conditions must balance the objectives of the issuing utility with consideration of the capabilities and limitations of potential bidders.

Bidder pre-qualification standards (specifically with respect to financial pre-qualification) must be clearly specified.

Step 2 - Solicitation process

This phase begins with development of a marketing strategy. A sound marketing and promotion plan for the RFP (including, for example, initial notice and dissemination of invitations through multimedia channels or participant lists) needs to be coordinated so as to effectively reach the largest possible number of qualified bidders.

Before an RFP can be issued, an internal communications protocol needs to be established to ensure impartiality and efficient distribution of information to qualified bidders throughout the process. Once the document has been distributed, the issuing utility must manage interactions with potential bidders very carefully. Formal routines, such as "road show" presentations and maintenance of a "data room" are often employed.

Step 3 – Develop and test evaluation criteria and procedures

Some criteria for evaluating bids are specified in the RFP document. But there is always a more complete set of standards and a process for bid evaluation, usually supported by computer-based models that are not fully specified in the document. A standardized bid evaluation framework must be developed and tested. This is a critically important component of the overall process. Both quantitative and qualitative are usually employed.

It is preferable to apply quantitative analysis to the greatest extent possible. This is often possible for core economic elements such as the impact of a proposed project on energy prices, life-cycle costs, etc. However, it should be noted that these are not trivial tasks. Economic impact analysis will require simulation of market dynamics with and without the proposed project. The key for systematic analysis is to run each of the projects through the same rigorous analysis, using a consistent set of assumptions on market development and fundamentals.

System reliability can be measured through engineering analysis, network simulation and use of well accepted reliability measures and benchmarks. Certain environmental criteria can sometimes be measured and evaluated quantitatively – for example, pollution emissions can be estimated and related back to public health measures of safety and statutory and regulatory limits on emissions.

Other elements of a complete evaluation framework will be inherently more qualitative in nature and must be addressed through relative measures and indices, rather than units denominated in currency or other metrics. For example, it is difficult to objectively and quantitatively measure some of the aesthetic and quality of life considerations that are sometimes identified within an RFP as a consideration of the issuing utility. In these instances, indices must be designed that can be used to compare projects with respect to broad social factors in a fair and systematic way. Use of impartial benchmarks is one way of handling the objectivity problem. In addition, proxy scoring routines and surveys can be created which address the issue by analyzing the elements indirectly or by polling a large independent audience who are representative of the issuing utility's constituency as a whole. For example, instead of looking at aesthetic characteristics in general, projects can be ranked in relationship to more objective characteristics, such as consistency with surrounding environment and architecture, i.e., use of color tones, dimensionality. Or alternatively, through survey methods, a random pool of people can be asked to rank the projects given certain criteria. The randomness element should ensure that the population's preferences are well represented in the sample.

Whatever system is developed also needs to be tested on mock proposals before application to actual received bids.

Step 4 – Bid evaluation

Once the standardized assessment framework is designed, tested, and prototyped, the actual evaluation of bids becomes manageable, even if dozens of bids are received. The evaluations are conducted by a specified team consisting of utility personnel and, often, contracted consultants. This stage of the process also requires the development and application of protocols for announcing winning bids and codes of conduct for public awareness, especially when some period of anonymity is deemed to be necessary. For example, if one of the energy alternatives is a power sales agreement from a power marketer dealing only in renewable electricity, then that marketer may want to have some short period of time where his acceptance is not acknowledged publicly so that he can safely arrange his position to meet the obligations of his bid.

Step 5 - Follow-on monitoring and evaluation

The performance of winning bids should be systematically evaluated over time to ensure compliance with agreed terms and also to provide feedback that can be used to improve future solicitations. Tracking measures should include project status, public commentary and ongoing tracking of the quantitative measures employed during bid evaluation. Monitoring protocols should be documented.

Full Cost-Accounting

The objective of a full-cost accounting approach is to account systematically for all costs associated with an economic activity – this includes not only the traditional 'private' costs reflected in traditional business accounting systems, but also the full range of social costs (and benefits) embodied within the construct of externalities introduced above in Chapter 4.

This is a controversial area within the electric industry. While it is generally acknowledged that electric generation is associated with significant externalities, particularly in the environmental area, many feel that it is inappropriate for utilities and their regulators to attempt to internalize the externality beyond whatever mandates have been established through legislation.

In the mid-1990s, when utilities were still mostly vertically integrated and were generally conducting traditional integrated resource planning exercises, regulators in seven states initiated procedures to systematically account in the utility planning process for environmental costs not yet directly addressed through federal or state legislation.[184] These states are California, Massachusetts, Minnesota, Nevada, New York, Oregon and Wisconsin. California, for example, specified externality values for five categories of emissions: nitrogen oxide, sulfur dioxide, particulate matter, reactive organic gases and carbon; and Wisconsin specified monetary values for only greenhouse gas emissions.

These differences notwithstanding, the analytical undertakings were essentially identical across the states. Cost estimates input to planning models included not just traditional accounting costs (capital operations and maintenance, general and administrative, etc.), but also the estimated costs associated with emissions. Outputs of the planning analyses – identifying

---

[184] *See* Awad, M. Broad, S. Casey, K.E. Jing Chen Geevarghese, A.S. Miller, J.C. Perez, A.J. Sheffrin, A.Y. Mingxia Zhang Toolson, E. Drayton, G. Rahimi, A.F. Hobbs, B.F. Wolak, F.A. *The California ISO transmission economic assessment methodology (TEAM): principles and application to Path 26.* Dept. of Grid Planning, CAISO, Folsom, CA, USA; Power Engineering Society General Meeting, 2006. IEEE -22 June 2006.

preferred system development approaches – thereby reflected the impacts of designated emissions.

The requirements to incorporate externalities in the resource planning process generally had negligible impacts on the resource mixes selected by the utilities. There was some additional movement towards natural gas capacity, but this primarily enhanced a pre-existing trend (natural gas prices were very low at the time) rather than fundamentally shifting planning orientations. There was also some, albeit limited, additional movement towards renewable capacity. This is also a reflection of market conditions at the time – renewable capacity was substantially more expensive than traditional capacity.

Within the same time period, Ontario Hydro, one of the largest North American utilities, initiated a program, without any regulatory requirement having been imposed, to account for environmental costs within its planning process. The approach the company used was methodologically the same as described above for the U.S. utilities – monetary values for designated activities were specified and incorporated within the planning process.

Outside of North America, the European Union has established a research project, called ExternE, for developing estimates of the monetary cost of various polluting activities. These estimates serve as independently established estimates that can be employed by utilities in the manner described above, although utilities are not under any obligation to do so.

Once deregulation occurred across regional markets in the U.S. energy industry in the 1990s, and the local generation sector became competitive, integrated resource planning for generation became obsolete in certain regions, replaced by private sector analysis of market opportunities, with the objective of maximizing expected profits. It is therefore unsurprising that there is no recent history of such cost-benefit analysis being used in those states that had experimented with such analysis in the 1990s.

In the context of utility planning and cost-benefit analysis in the electricity sector, focus in the U.S. has transitioned to transmission investment, which is centrally coordinated, even in deregulated markets. The issue of accounting for externalities has specifically been tackled by planners in the context of 'economic' transmission projects, which are being proposed for economic rather than reliability reasons (i.e., to improve market efficiency). Planners, therefore, need to measure the expected net benefits of such projects. Benefits can come from productive efficiency gains as economic transmission projects will remove congestion and allow for lower cost resources to be used to meet demand, and therefore, reduce market prices for energy. In addition, there are indirect benefits that accrue to society as a whole from such transmission projects which planners have now started considering, such as benefits from amelioration of market power. Environmental benefits arise through positive externalities associated with transmission, and are measured on the basis of market dynamics. For example, in the case where transmission is a substitute for generation, and therefore, displaces polluting generation, the benefits of transmission investment should include the market value of the avoided pollution. Alternatively, in the case where transmission complements renewable, emissions free generation (for example, with a trunkline transmission investment, more wind generation can be deployed), the market value of that emission-free generation produces a measure of social benefits of the transmission line. CAISO has employed such methods for evaluating transmission.[185]

Indeed, even FERC has specifically required that positive externalities of high-voltage transmission investment be considered in the rate setting process for transmission. In an April 19, 2007 decision,[186] FERC approved a postage stamp rate methodology for new, high voltage transmission in PJM, because such transmission investment is likely to produce substantial benefits (improved reliability and market efficiency) to all customers of transmission within the system in addition to those customers using directly the new transmission capacity. Given the presence of such a positive externality, FERC ruled that all ratepayers should pay for this investment. Albeit not related to generation, this is an example of how externalities have directly affected and been taken into account in utility planning and resulting rate structures.

Status of Resource Planning Experience within the U.S.

Figure G-5 below presents information about utility planning policies and procedures for a select group of states within the US. States that have deregulated and whose utilities are members of ISOs or RTOs generally no longer have any IRPs, since the generation markets are no longer regulated and transmission planning is managed by the ISO/RTO. For example, of the states sampled in this survey, Maryland, Texas, Michigan and Ohio have no IRP requirements. The major exception is MISO members. This is not surprising since there are many vertically integrated utilities that are part of MISO and are also regulated by their state commissions. California is another exception. Although the CAISO is responsible for transmission planning and generation is deregulated, there is still some coordinated state-level resource analysis. The California Energy Commission is mandated by the legislature to do an integrated energy plan every two years, with supply and demand forecasts, which then serves as the basis for the CPUC's analysis and approval of the investor owned utilities' procurement plans. In Texas, ERCOT is required by the PUCT to put out a medium term outlook, evaluating the supply-demand balance, but there is no resource planning component to that outlook; rather, it is a survey of existing supply and a forecast of demand. In addition, state legislation obligates utilities to achieve certain levels of efficiency gains over 5 years.

---

[185] *See* Awad, M. Broad, S. Casey, K.E. Jing Chen Geevarghese, A.S. Miller, J.C. Perez, A.J. Sheffrin, A.Y. Mingxia Zhang Toolson, E. Drayton, G. Rahimi, A.F. Hobbs, B.F. Wolak, F.A. *The California ISO transmission economic assessment methodology (TEAM): principles and application to Path 26*. Dept. of Grid Planning, CAISO, Folsom, CA, USA; Power Engineering Society General Meeting, 2006. IEEE -22 June 2006.

[186] FERC - Docket#: EL05-121-000, Order, April 19, 2007

Figure G-5. IRP Experience in the US							
State	**Plans Submitted to Regulator?**	**Frequency**	**Carbon Cost Expectations Accounted For?**	**Portfolio Analysis Employed?**	**State Level Planning?**	**Criteria for Approval of New Generation or Transmission Plans**	**Required to Issue RFPs?**
Georgia	Yes, by all the investors-owned utilities	3 years	No prescribed standards, but utilities have included cost expectations in their forecasts	Yes	No	Companies file to obtain "certificates" to develop new infrastructure	yes
Indiana	Utilities submit plans to the Commission for review but not approval	2 years	Yes	Yes	Yes	The commission is not in charge of approving the different plans but they make sure that the different plans meet in such an extent criteria of Public necessity and reasonableness	No
Idaho	Yes	2 years	Yes	The planning model incorporates risks	No	Certificate of public convenience and necessity	Yes
Kansas	Required but not yet implemented	---	Not required	---	No	Need must be proven, and approval received from the Southwest Power Pool	Yes

Figure G-5. IRP Experience in the US

State	Plans Submitted to Regulator?	Frequency	Carbon Cost Expectations Accounted For?	Portfolio Analysis Employed?	State Level Planning?	Criteria for Approval of New Generation or Transmission Plans	Required to Issue RFPs?
Kentucky	Utilities submit plans to the Commission for review, but not approval	3 years	Not required	Not required	No	Certificate of Public Convenience and Necessity	No
Louisiana	Utilities submit plans to the Commission for review but not approval	The law does not specify a requirement	Not required	No, utilities are required to use cost/benefit analysis	No	Plans are reviewed by FERC, the state Commission, and state environmental agencies that evaluate relative to specified environmental criteria	No
Oregon	Yes; Commission will acknowledge or not acknowledge each utility's IRP	2 Years	Planning procedures requiring testing a range of carbon costs in portfolio evaluation	Yes	No	Public interest, as expressed in Oregon and Federal Energy Policies	Yes. The utility has to submit a bid, and bids are evaluated by an independent entity. Commission is currently investigating if there is a systematic bias in favour self-build.

Figure G-5. IRP Experience in the US

State	Plans Submitted to Regulator?	Frequency	Carbon Cost Expectations Accounted For?	Portfolio Analysis Employed?	State Level Planning?	Criteria for Approval of New Generation or Transmission Plans	Required to Issue RFPs?
Nevada	Yes for the two largest utilities, but not for municipal utilities	3 years	Being considered	Not required, but some utilities do	No	---	---
North Carolina	Approach being developed	Approach being developed	Approach being developed	Approach being developed	Approach being developed	Approach being developed	Approach being developed
North Dakota	Yes, but the Commission does not approve the plans	2 years	No	No	No	Reasonableness	No
Utah	Only for one large utility	2 years	Yes	Yes, utilities required by law to consider all types of risks and resources	No	Reasonableness and public interest	Yes
Virginia	Approach being developed as the state moves from deregulation to re-regulation	Approach being developed	Approach being developed	Approach being developed	Approach being developed	Approach being developed	Approach being developed
Washington	Yes	2 years	Yes	No	No	Reasonableness and public interest	Yes

Figure G-5. IRP Experience in the US							
State	**Plans Submitted to Regulator?**	**Frequency**	**Carbon Cost Expectations Accounted For?**	**Portfolio Analysis Employed?**	**State Level Planning?**	**Criteria for Approval of New Generation or Transmission Plans**	**Required to Issue RFPs?**
Wyoming	Not required, but one utility (Rocky Mountain Power) submits	2 years	Rocky Mountain Power does, but is not required	Rocky Mountain Power does, but is not required	No	Reasonableness	Not required, but Rocky Mountain Power does

Source: LEI survey of state commission staff, January 2008

Appendix H - Industry Practices on Alternative Rate Structures

Rate Design Principles

The foundational set of policy criteria with respect to utility tariff design is as follows:

- ***Allocative Efficiency*:** goods and services should be produced when the costs of production are less than the value to consumers, and they should be delivered to those consumers that value them most;
- ***Financial Solvency:*** companies should, when operated prudently, be compensated for the full costs of service provision, including the cost of capital;
- ***Dynamic Efficiency*:** incentives for ongoing technological innovation and cost minimization should be consistently maintained;
- ***Equity:*** rates should be supportive of fundamental social objectives;
- ***Administrative Efficiency*:** the tariff system should be implemented, including all data collection and computation, at a reasonable cost.

These goals are inherently in conflict. For example, the first principle - allocational efficiency - requires that each consumer be confronted with prices that reflect all costs - and only those costs - incurred in the provision of service to that customer. Taken to the extreme, this requires that each individual customer be charged a price for each element of service that precisely compensates for the associated costs. However, since it is not possible to allocate costs in sufficient detail, the goal of allocational efficiency must be tempered by administrative practicality.[187] Even when it is administratively possible to allocate costs to the customers driving the costs, concerns over equity may mitigate against such treatment. Broader societal goals – such as a commitment to providing "fair", "just", "equitable", and "stable" rates – almost always factor into the considerations of pricing a product as fundamentally important to consumers as electricity. For example, several states have mandated the established of a so-called "system benefit charge" – i.e., a charge placed on a customer's utility bill to pay for the costs of designated public benefits such as energy efficiency.

The challenge for policymakers and regulators – in Kentucky and elsewhere – is to balance the tradeoffs inherent in the criteria above in the most effective way.

Lifeline Rates

It is possible that some actions taken to meet the goals of Section 50 of the Act will raise cost of service for Kentucky ratepayers in the aggregate. Ensuring universal service at affordable rates

---

[187] Each customer is not treated individually, but rather is grouped within a class of customers that can be expected to display similar demand patterns with respect to the primary drivers of cost. Costs are not allocated precisely either across or within the customer classes, but rather are approximated based on the information available within the available accounting system.

will therefore likely become a higher priority as progress is made towards achieving the Section 50 goals.

Lifeline tariffs are the most prevalent type of subsidy scheme for supporting electricity consumption by low-income and other disadvantaged consumers. A lifeline tariff is a quantity-based consumption subsidy, where the price consumers pay per kWh of electricity varies with the total quantity consumed per period. It is designed to provide electricity up to a certain pre-established limit at a lower tariff rate, and provides amounts above this limit at a higher rate. The amount of consumption is typically measured in blocks, where an average first block would include up to 150 kWh consumption. There are several possible types of lifeline tariffs, including increasing block tariffs (IBT), a few variations within the IBT structure, volume-differentiated tariffs (VDT), and a capacity subsidy.

Energy Efficiency Tariffs

The key to an efficient pricing structure is that it be cost-reflective. This requires allocation of costs across fixed and volumetric components, and also allocation of volumetric costs across operational hours. This latter issue requires more attention than has normally been paid.

Because network size is driven by peak needs, the volumetric portion of rates should be allocated primarily or entirely to peak hours. However, a subset of peak hours – the so-called "super peak" (generally accounting for approximately 15% of total hours) drives overall load growth; and thus, the traditionally employed "peak" category should be further segmented. A three tier volumetric rate schedule can be designed whereby off-peak usage faces no volumetric charges. This effectively acknowledges the fact that the marginal cost of usage during off peak periods is zero. The demand charges are allocated solely to peak usage, and can be further differentiated during daily peak periods to distinguish between the 'normal' peak and super-peak hours.

Under such a design, energy rates would be highest during the four highest demand hours of the day, and lower during the remaining 12 peak hours. The objective of such a scheme would be to ensure that those most responsible for causing new investment to be made are also responsible for paying for it. In effect, the pricing plans would begin to resemble those that have become common for cell phone users, where off-peak usage is free and the costs of peak usage are allocated through a variety of alternative approaches. This is a version of time-of-use pricing.

The ability to establish improved rate designs is very much a function of new and less expensive information technology. Historically, rate designs have evolved as new technology was brought to bear on the question of how to charge customers in a more economically efficient fashion. The rise of cheaper and more powerful IT tools makes it much easier to design and implement – and encourage active customer engagement for time-of-use rates. Recent experimentation with such tools (some equivalent or very similar to tools to be employed in

E.ON's upcoming pilot program) have produced encouraging results.[188] Improved IT tools have also helped eliminate the need for defining customer classes based on customer activity distinctions. The result is that tariffs can be designed that impose fixed charges by voltage level connection (rather than by traditional customer class) and volumetric charges based on time of use (rather than fixed across all time periods).

Green Energy Tariffs

The term "green energy" refers to energy produced from what is perceived to be environmentally friendly sources. What qualifies as green energy varies by jurisdiction, but is generally focused on renewables. Some governments and regulators have documented very specific definitions and criteria.

Under a "green energy tariff", customers are given the option of purchasing green or environmentally-friendly energy – at a premium to the standard rates. Customers willingly pay a premium, recognizing – and compensating utilities for the fact that – electricity from renewable sources tends to be more expensive than electricity produced from fossil fuels. The tariffs incorporating such premiums are always voluntary. The specific motivations for consumers to select this option - thereby imposing an additional cost burden on themselves – vary across individuals, but are generally driven by a personal concern for the environment and a desire to make a contribution towards protecting the environment by helping to finance broader deployment of green energy sources by utilities. This sort of tariff option has become very common, although customer adoption is often limited. Examples of green tariffs are presented below in Figure H-1.

[188] See, for example, "Digital Tools Help Users Save Energy, Study Finds;" New York Times; January 10, 2008. This article reports the results of research indicating that, when households have digital tools to set temperature and price preferences, peak loads on utility grids can be trimmed by up to 15 percent a year.

Figure H-1. Examples of Green Tariffs[189]

State	Name	Type of eco-friendly energy	Start date	Premium
Alabama	Green Power Choice	Landfill Gas	2006	2.0 cents/kWh
Arizona	Green Choice	Wind and Geothermal	2007	1.0 cents/kWh
Florida	SunshineEnergy	Biomass, Wind, PV	2004	0.975 cents/kWh
Illinois	EcoEnergy	Wind	2005	3.0 cents/kWh
Kentucky	Green Energy	Hydro	2007	1.67 cents/kWh
North Carolina	NC Green Power	Biomass, Hydro, Landfill gas, PV, Wind	2003	2.5 - 4.0 cents/kWh
New Mexico	Renewable Resource Power Service	Wind Hydro	2001	0.8 cents/kWh
Ohio	Green resource Program	Various	2007	0.5 cents/kWh
Oklahoma	WindWorks	Wind	2004	0.5 cents/kWh
Oregon	Green Power	Landfill Gas	1998	1.8 - 2.0 cents/kWh
Utah	Blue sky	Wind	2003	0.71 - 1.94 cents/kWh
Tennessee	Green Power Switch	Landfill gas, PV, Wind	2000	2.67 cents/kWh

Source: Department of Energy (http://www.eere.energy.gov/)

If a utility does not directly control enough renewable capacity to supply customers that have selected, and paid a premium for a green energy tariff, then it must, in the short-term, contract with third party suppliers and, over the longer-term, either develop new sources of capacity or enter into long-term contracts to secure reliable supplies. All utilities offering green tariff programs are certified by national auditors, such as the Center for Resource Solutions, and are required to, through an annual audit, confirm that customers are in fact receiving the green power that they have paid for.

Rate Design Experience within the U.S.

Figure H-2 below presents information about utility rate design for a select group of states within the US. Green power programs are increasingly being set up across the US. They proceed either from utilities' initiatives or from policy mandates. Among our sample of states, only a few provide a supportive policy toward energy R&D. In states like Texas or Louisiana, utilities are entitled to fund such programs with state commission approval. In most of the sampled states, rate programs or tariff design has been established to subsidize low income consumers. Some states – e.g., Nevada and Ohio - go further in their policies by embedding in customer bills a surcharge for financing funds devoted to helping low-income households.

189 The data of this table were last updated on June 2007

Figure H-2

State	Green Tariff	Support of R&D	Tariff Mechanism to Assist Customers	Programs to Assist Customers
Georgia	Voluntarily participation in a "Renewable Tariff Program" where co-generators sell excess production from renewables to utilities at special tariffs	No	No	Utilities offer weatherization programs and discount plans
Indiana	Optional; customers can choose to pay a surplus to utilities for purchase of renewable certificates	No	In the process of establishing a Lifeline Assistance Program, expected to be operational in 2009 - eligible customers will receive subsidies	Energy Assistance Program pilots in place to help low income people.
Idaho	No	No	No	The Low Income Home Energy Assistance and Weatherization Assistance Programs help cover eligible customers' heating costs
Iowa	No	Yes; 0.1% of utility revenues goes to the Iowa Energy Center	No	Shareholders are required to fund programs to help needy customers, and customers can contribute voluntarily

Figure H-2

State	Green Tariff	Support of R&D	Tariff Mechanism to Assist Customers	Programs to Assist Customers
Kansas	No	Dismantled upon deregulation	No	The Low Income Home Energy Assistance and Weatherization Assistance Programs help cover eligible customers' heating costs; and the Red Cross program Project Deserve assists with utility bills
Kentucky	Offered by some of the utilities	No	No	Energy assistance programs for low income families are offered
Louisiana	Programs can be developed at the discretion of utilities	Not required, but utilities can provide funding at their discretion and with Commission approval	No	Customers contribute voluntarily to help low income customers
Michigan	Approach being developed	No	No	A fund was recently created for bill-paying assistance
Nevada	No	No	"Universal Energy Charge" payable by all customers	The state administers programs for the community
North Carolina	Voluntary participation in a "Green Power Program" whereby consumers pay a green tariff rider per block of 100 kWh	Yes	No	Weatherization Assistance Program which aims at reducing energy use and costs improving energy efficiency of low-income persons' home

Figure H-2

State	Green Tariff	Support of R&D	Tariff Mechanism to Assist Customers	Programs to Assist Customers
North Dakota	One utility has proposed a program where customers can chose to pay an extra for electricity generated fro the wind turbines owned by the utility	Not required, but utilities can provide funding at their discretion and with Commission approval	No	Customers can contribute on a voluntary basis to help support low income customers
Ohio	Optional; so far only 5% of customers have participated	No	Yes, there is a tax surcharge paid on a monthly basis by all customers	Utilities contribute to funds dedicated to subsidizing the gas and electric bills of eligible customers
Oregon	2007 law requires all suppliers and utilities to provide green tariffs	Yes, customers pay a monthly 3% surcharge in the form of a "public purpose charge"	Monthly surcharge paid by all customers	The state administers programs for the community. For instance Energy Assistance is a federally funded program for qualified households which provides a one-time benefit (per program year) to assist with heating costs
Texas	No	Utilities may use money approved by the Commission to perform necessary energy efficiency research and development	No	Texas Department of Housing and Community Affairs administer Payment Assistance and Weatherization Assistance programs

Figure H-2

State	Green Tariff	Support of R&D	Tariff Mechanism to Assist Customers	Programs to Assist Customers
Utah	Voluntary participation in a "Blue Sky Program" whereby consumers pay a monthly surcharge to support a fund for developing wind power	No	Flat rate, varying across customers classes	The state administers several programs for the community
Virginia	Planned to be established this year	No	No	Yes, various programs administered by the State
Wyoming	At the discretion of utilities; requires Commission approval	No	No	A private foundation administrated by the utilities raises funds for distribution to low income customers