EAST KENTUCKY POWER COOPERATIVE

October 20, 2006

HAND DELIVERED

Ms. Elizabeth O'Donnell
Executive Director
Public Service Commission
211 Sower Boulevard
Frankfort, KY 40602

RECEIVED
OCT 20 2006
PUBLIC SERVICE COMMISSION

Re: East Kentucky Power Cooperative, Inc.
2006 Integrated Resource Plan
PSC Case No. 2006-~~00017~~ 00471

Dear Ms. O'Donnell:

Please find enclosed for filing with the Commission documents relating to the 2006 Integrated Resource Plan ("IRP") of East Kentucky Power Cooperative, Inc.("EKPC"). This filing includes an original and ten copies of EKPC's Petition for Confidential Treatment of Information. Attached to the original Petition are sections of the 2006 EKPC IRP containing confidential information. Redacted copies of the 2006 EKPC IRP filing are attached to the ten copies of the Petition. Additionally, one unbound redacted copy of the IRP is enclosed.

Intervenors in EKPC's 2003 IRP case have been notified of this filing.

Very truly yours,

Charles A. Lile

Charles A. Lile
Senior Corporate Counsel

Enclosures

RECEIVED
OCT 10 2006
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

A REVIEW PURSUANT TO 807 KAR 5:058	)
OF THE 2006 INTEGRATED RESOURCE	)
PLAN OF EAST KENTUCKY POWER	) **CASE NO. 2006-~~00017~~-00471**
COOPERATIVE, INC.	)

PETITION FOR CONFIDENTIAL
TREATMENT OF INFORMATION

Comes now the petitioner, East Kentucky Power Cooperative, Inc. ("EKPC") and, as grounds for this Petition for Confidential Treatment of Information (the "Petition"), states as follows:

1. This Petition is filed in conjunction with the filing of EKPC's 2006 Integrated Resource Plan ("IRP") in this case, and relates to confidential information contained in that filing that is entitled to protection pursuant to 807 KAR 5:001 Section 7 and KRS §61.878 (1) (c) 1 and related sections.

2. The information designated as confidential in the IRP includes projected fuel costs, projected capital costs of potential generation facilities, and projected operations and maintenance costs (IRP Section 8), and projections of revenue requirements, interest rates and escalation rates (IRP Section 9). Disclosure of this information to utilities, independent power producers and power marketers that compete with EKPC for sales in the bulk power market, would allow such competitors to determine EKPC's power production costs for specific periods of time under various operating conditions and to

use such information to potentially underbid EKPC in transactions for the sale of surplus bulk power, which would constitute an unfair competitive disadvantage to EKPC.

3. Disclosure of confidential information contained in IRP Section 8 relating to the estimated costs of future generation projects to potential bidders in future EKPC requests for proposals for generating capacity, or disclosure of confidential projections of fuel costs to potential fuel suppliers, could facilitate manipulation of bids, resulting in less competitive proposals and potentially higher future generation costs for EKPC. Such a situation would create an unfair disadvantage for EKPC in making future competitive sales of surplus power, and would increase power costs to EKPC's member systems.

4. Disclosure of the estimated costs of future plant maintenance projects, contained in IRP Section 8, would be valuable to potential bidders for the work and could result in less than competitive bids. EKPC would be unfairly competitively disadvantaged in the bulk power market if bid manipulation for such major maintenance work resulted in higher costs, which could increase EKPC's costs of power production. EKPC's review of recent IRP filings by other electric utilities in Kentucky shows that similar projections of future plant maintenance expenses are not included. Therefore, disclosure of such projections by EKPC poses a distinct competitive disadvantage for EKPC.

5. Along with this Petition, EKPC has enclosed one copy of confidential sections of its 2006 IRP, with the confidential information identified by highlighting or other designation, and 10 copies with the confidential information redacted. The identified confidential information is not known outside of EKPC and is distributed within EKPC only to persons with a need to use it for business purposes. It is entitled to confidential treatment pursuant to 807 KAR 5:001 Section 7 and KRS §61.878(1)(c) 1, for the reasons

stated hereinabove, as information which would permit an unfair commercial advantage to competitors of EKPC if disclosed. The subject information is also entitled to protection pursuant to KRS §61.878(1)(c) 2 c, as records generally recognized as confidential or proprietary which are confidentially disclosed to an agency in conjunction with the regulation of a commercial enterprise.

WHEREFORE, EKPC respectfully requests the Public Service Commission to grant confidential treatment to the identified information and deny public disclosure of said information.

Respectfully submitted,

~~DALE W. HENLEY~~
Charles A. Lile
CHARLES A. LILE

P. O. BOX 707
WINCHESTER, KY 40392-0707
(859) 744-4812

ATTORNEYS FOR EAST KENTUCKY
POWER COOPERATIVE, INC.

CERTIFICATE OF SERVICE

This is to certify that an original and 10 copies of the foregoing Petition for Confidential Treatment of Information in the above-styled case were hand delivered to the office of the Public Service Commission, 211 Sower Boulevard, Frankfort, KY 40601 this 20th day of October, 2006.

Charles A. Lile
CHARLES A. LILE

EAST KENTUCKY POWER COOPERATIVE

RECEIVED
OCT 20 2006
PUBLIC SERVICE COMMISSION

Integrated Resource Plan

Case No. 2006-~~00017~~ 00471

REDACTED

October 21, 2006

A Touchstone Energy Cooperative

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SECTION 4

FORMAT

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4. FORMAT

4.(1) Organization

This plan is organized by using the Section and Subsection numbers found in the Administrative Regulation 807 KAR 5:058, "Integrated Resource Planning by Electric Utilities." This report is filed with the Public Service Commission of Kentucky in compliance with the aforementioned regulation.

The format of the report is outlined below.

I. Integrated Resource Plan – Case No. 2006-00017 (Bound Herein)

1) Table of Contents
2) Section 4. Format
3) Section 5. Plan Summary
4) Section 6. Significant Changes
5) Section 7. Load Forecasts
6) Section 8. Resource Assessment and Acquisition Plan – Two (2) EKPC Interconnected System Maps (Bound Herein)
7) Section 9. Financial Information

II. 2006 Load Forecast Report (Bound Separately)

1) Section 1.0 Executive Summary
2) Section 2.0 Load Forecast Methodology
3) Section 3.0 Load Forecast Discussion
4) Section 4.0 Regional Economic Model
5) Section 5.0 Residential Customer Forecast
6) Section 6.0 Residential Sales Forecast
7) Section 7.0 Commercial and Other Sales Forecast
8) Section 8.0 Peak Demand Forecast and High and Low Case Scenarios

III. East Kentucky Power Cooperative 2006 Load Forecast Report, Appendices A & B (Bound Separately)

1) Appendix A: Section 1 – RUS Form 341
2) Appendix A: Section 2 – Member System Load Forecast Reports
3) Appendix B: Section 3 – Customer and Energy Model Definitions and Results

IV. Technical Appendix (Demand-Side Management Analysis – Bound Separately)

1) Executive Summary
2) Major Enhancements since last IRP
3) Introduction
4) Comprehensive DSM Measure List
5) Qualitative Screening Process
6) Qualitative Screening Results
7) Quantitative Evaluation Process
8) Quantitative Screening Results
9) Recommendations
10) Estimated Impacts
11) Factoring Environmental Cost Considerations into DSM Evaluation

4.(2) Identification of individuals responsible for preparation of the plan.

James Lamb, Vice-President, Coordinated Planning
Frank Oliva, Manager, Finance and Risk Management
Charles A. Lile, Senior Corporate Counsel
Darrin Adams, Transmission Planning Supervisor
Gary Davidson, Resource Planning Supervisor
Sally Witt, Forecast and Market Analysis Supervisor
Stephanie Cornett, Senior Analyst
George Markins, Senior Analyst

SECTION 5

PLAN SUMMARY

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5. PLAN SUMMARY

5.(1) Description of the utility, its customers, service territory, current facilities, and planning objectives.

East Kentucky Power Cooperative Inc. (EKPC) is a generation and transmission electric cooperative located in Winchester, Kentucky. It serves 16 member distribution cooperatives who serve approximately 495,000 retail customers. Member distribution cooperatives currently served by EKPC are listed below:

Big Sandy RECC	Jackson Energy Cooperative
Blue Grass Energy Coop. Corp.	Licking Valley RECC
Clark Energy Cooperative, Inc.	Nolin RECC
Cumberland Valley Electric	Owen Electric Cooperative, Inc.
Farmers RECC	Salt River Electric Cooperative
Fleming-Mason Energy Cooperative, Inc.	Shelby Energy Cooperative, Inc.
Grayson RECC	South Kentucky RECC
Inter-County Energy Coop. Corp.	Taylor County RECC

In April of 2008, Warren RECC will become a member of EKPC.

EKPC owns and operates three coal fired generating stations – Dale Station (196 MW), Cooper Station (341 MW), and Spurlock Station (1,118 MW). EKPC's newest coal fired unit is the E.A. Gilbert Unit at Spurlock Station (268 MW) that began commercial operation on March 1, 2005. EKPC has three 150 MW gas fired combustion turbines (450 MW - winter rating) and four 98 MW gas fired combustion turbines (392 MW – winter rating) at Smith Station. EKPC also purchases 170 MW of hydropower from the Southeastern Power Administration (SEPA) on a long-term basis. In addition, EKPC owns and operates 12 MW of landfill gas generating plant capacity resulting in a total of 2,679 MW of capacity (winter rating).

EKPC has one purchase contract (other than the purchase from SEPA) in its portfolio that extends through 2006. New capacity additions were selected through an RFP process that began in April 2004 to meet EKPC's capacity needs through 2010.

EKPC owns and operates a 2,759-circuit mile network of high voltage transmission lines consisting of 69 kV, 138 kV, 161 kV, and 345 kV lines, and all the related substations. EKPC was a member of the East Central Area Reliability Council ("ECAR") until late 2005. ECAR and three other regional reliability councils were replaced by a larger regional reliability council made up primarily of members of the Midwest ISO and PJM. EKPC evaluated its options for selecting a new reliability council and decided to join the Southeastern Electric Reliability Council ("SERC"). EKPC maintains 59 normally closed free-flowing interconnections with its neighboring utilities.

In 2005, EKPC's peak load was 2,477 MW and energy requirements for sales to its members were 12,528 GWh.

EKPC submitted its 2003 IRP (PSC Case No. 2003-00051) to the Commission on April 21, 2003. The report submitted by EKPC provided its plan to meet the power requirements of its 16 member distribution cooperatives over the period from 2003 to 2017. On September 14, 2004, EKPC received the Commission Staff's Report on the 2003 Integrated Resource Plan of East Kentucky Power Cooperative, Inc. The purpose of the report was to review and evaluate EKPC's 2003 IRP in accordance with the requirements of 807 KAR 5:058, Section 12(3), which requires the Commission Staff to issue a report summarizing its review of each IRP filing and offer suggestions and recommendations to be considered in subsequent filings.

The EKPC IRP Team, which consists of various personnel within the organization, used the PSC Staff Report as a starting point in their analysis for the next IRP. The PSC Staff Report recommendations along with the basic requirements of the Commission's regulations become the foundation leading to this Integrated Resource Plan ("IRP").

EKPC states that the objective of the power supply plan is to minimize the cost to serve its Member Systems.

The following summary of recommendations from the PSC Staff Report on EKPC's 2003 IRP was used as guidance in the development of EKPC's 2006 IRP. EKPC's response follows each recommendation.

Load Forecasting:

1. Provide a complete description of each model, component and variable for each model including the class models, regional economic model, peak models and the high / low variation in peak demand.

   Please see the 2006 Load Forecast Report, Section 8.0 and Appendix B, Section 1 and Section 3.

2. Provide a complete description of how the economic and demographic data is constructed for the six economic regions, including how the data is manipulated so as to be useful for forecasting individual member system class usage.

   Please see the 2006 Load Forecast Report, Section 2.0 and Section 4.0 and Appendix B, Section 1.

3. Provide a complete description of the assumptions made to produce the high and low case variations in the seasonal peak demand forecasts.

   Please see the 2006 Load Forecast Report, Section 8 and Appendix B, Section 2 – Data CD.

Demand Side Management:

1. Discuss the results of any dialogue East Kentucky has with the AG, KDOE, or other parties related to DSM issues prior to filing the IRP and explain how the parties' concerns are incorporated in the IRP.

   In late 2005, representatives of EKPC met with the Office of the Attorney General and had telephone discussions with the Kentucky Department of Energy Policy, Division of Renewable Energy and Energy Efficiency regarding EKPC's proposed Direct Load Control ("DLC") DSM program.

   Currently, EKPC participates in an energy efficiency working group consisting of utilities, the Attorney General, the Sierra Club, and the Division of Renewable Energy and Energy Efficiency.

2. Report on efforts to evaluate and support local integrated resource planning, cogeneration and distributed generation, and other initiatives of the type advocated by KDOE.

   EKPC has a cogeneration tariff that is evaluated and typically updated every five years. EKPC has a 3,200 kW distributed generating unit in Clinton County. EKPC has landfill generating units in Boone, KY, Lily, KY, and in Greenup County, Hardin County, and Pendleton County. In 2005, EKPC assisted its member systems in developing a net-metering tariff. And, EKPC has conducted numerous transmission open houses that allow for public input.

   Section 8 of this report describes both supply-side and demand-side power supply analysis. Several demand-side programs have shown strong benefit/cost ratios, in particular, direct load control of water heaters and air-conditioners. EKPC and two of its member systems are currently engaged in the aforementioned DLC demonstration project. The objective of this project is to better understand how

DLC can be an explicit part of EKPC's power supply. DLC is not shown as an explicit part of the resource plan but that could change as the demonstration project provides more insights.

The remaining DLC programs in Section 8 that have relatively high benefit/cost ratios will be discussed and further evaluated with EKPC member systems. EKPC is utilizing DSM options in its power supply.

3. Explicitly discuss how it has factored environmental cost considerations into its DSM evaluation, or at minimum, provide an explanation for why it has not or cannot do so.

   EKPC explicitly includes environmental externalities in its analysis. See Section 8.(5)(c) of this IRP.

Supply-Side Resource Assessment:

1. East Kentucky should include an analysis in its next IRP on what planning reserve margin is optimal. In addition to regional capacity or reserve margins, this analysis should be based upon probabilistic criteria such as Loss of Load Expectation or Probability, the size of its largest generating unit, forced outage rates, import capability, ECAR operating reserve requirements, etc. In the alternative, if East Kentucky believes that these criteria are inappropriate, it should explain why.

   A reserve margin study is discussed in Section 8.(5)(d).

2. East Kentucky's next IRP, scheduled to be filed in the spring of 2006, should reflect its plans for serving its growing system demand, including the addition of WRECC.

WRECC is an explicit part of EKPC's planning resource process. WRECC is addressed in Section 8.(2)(c) of the IRP.

3. In its next IRP, East Kentucky should provide more discussion about the supply alternatives it selects to analyze. This discussion should identify all criteria, assumptions, etc. relied upon in making these selections and explain the basis for the criteria, assumptions, etc.

   Section 8.(2)(c) discusses supply-side alternatives.

4. East Kentucky should consider using methods, such as described above, or other methods, to levelize or otherwise mitigate the effects that very "lumpy" investments have in studies of this type.

   Section 8.(5)(a) discusses annualized fixed costs.

5. East Kentucky should carefully evaluate the potential of the Gilbert Unit to burn a mix of wood waste and coal. It should also consider carbon dioxide emissions, or the absence thereof, when evaluating hydro generation options.

   EKPC is currently evaluating the economics and technical feasibility of using wood waste at the Gilbert Unit. Please see Section 8.(5)(f) for a discussion of carbon dioxide emissions.

5.(2) Description of models, methods, data, and key assumptions used to develop the results contained in the plan.

Load Forecast

EKPC's load forecast methodology includes regional economic modeling that incorporates historical data on population, income, employment levels and wages. This data is collected county by county from the U. S. Bureau of Labor Statistics ("BLS") and the U.S. Bureau of Economic Analysis ("BEA").

EKPC uses Metrix products for forecasting hourly load, annual energy, and seasonal peaks. MetrixND uses monthly weather and calendar data inputs to produce seasonal peaks and energy. MetrixLT uses historical hourly load data and daily weather and calendar data to calibrate to the forecasted seasonal peak demands and energy.

Key forecast assumptions used in developing the EKPC and member system load forecasts are:

1. EKPC's member systems will add approximately 260,000 residential customers by 2026. This represents an increase of 2.3 percent per year. This includes Warren RECC beginning April 2008.

2. EKPC uses an economic model to help develop its load forecast. The model uses data for 89 Kentucky counties in seven geographic regions. The economy of these counties will experience modest growth over the next 20 years. The average unemployment rate will remain relatively flat at 6.8 percent during the 2006 to 2026 timeframe. Total employment levels will rise by 330,000 jobs. Manufacturing employment will decrease to from 272,000 jobs in 2004 to 210,000 jobs in 2020. Regional population will grow from 3.5 million people in 2006 to 4.0 million people in 2026, an average growth of 0.7 percent per year.

3. From 2006 through 2026, approximately 70 percent of all new households will have electric heat. Eighty-five percent of all new households will have electric water heating. Nearly all new homes will have electric air-conditioning, either central or room.

4. Over the forecast period, naturally occurring appliance efficiency improvements will decrease retail sales by nearly 1,500,000 MWh. Appliances particularly affected are refrigerators, freezers, and air conditioners.

5. Residential customer growth and local area economic activity will be the major determinants of small commercial growth.

6. Forecasted load growth is based on the assumption of normal weather, as defined by the National Oceanic and Atmospheric Administration, occurring over the next 20 years. Seven different stations are used depending on geographic location of the member system.

Demand-Side Management

Over the past 25 years, East Kentucky Power Cooperative, Inc. (EKPC) member systems have offered various demand-side management ("DSM") marketing programs to the retail consumer. These programs have been developed to meet the needs of the end consumer and to delay the need for additional generating capacity. In order to satisfy these needs, a diverse menu of marketing programs has been developed and deployed.

This IRP evaluates the benefits and costs of existing DSM marketing programs and screens new marketing programs to be implemented in partnership with member systems. EKPC utilizes DSMANAGER, a computer program created by the Electric Power Research Institute ("EPRI"), in order to evaluate the relative benefits of these programs.

New DSM/marketing programs are reviewed and discussed in Section 7. EKPC and Member Systems will continue to work together to implement these programs as they fit their organizational goals.

Supply Side Resources

EKPC's existing capacity consists of base load coal fired units and peaking units (SEPA hydro and combustion turbines).

EKPC utilizes several computer models in the Resource Planning Process. EKPC uses EPRI's Technical Assessment Guide – Supply Side Technologies Software ("TAG-

Supply") for use in detailed cost information as well as estimates based on current projects. The RTSim model is used for detailed production costing and emission estimating studies. This program simulates system operation on an hourly chronological basis.

RTSim's Resource Optimizer was used to produce EKPC's optimal expansion plan. The optimizer evaluated a variety of resource options, startup dates, and market and load conditions to produce the lowest cost plans. Supply side capacity alternatives considered in this study included:

- Combustion Turbines (Peaking)
- Combustion Turbines with Steam Injection Option
- Fluidized Bed Boiler Units (Base Load)
- Long Term Purchases to be evaluated in RFP's as needed

In general, the construction cost for peaking units is the least, with intermediate capacity and base load capacity costing progressively more. The reverse is true, however, for variable costs, with base load capacity having the lowest variable production costs.

5.(3) Summary of forecasts of energy and peak demand, and key economic and demographic assumptions or projections underlying these forecasts.

EKPC's most recent load forecast (*EKPC 2006 Load Forecast Report, August 2006*) projects that total energy requirements are expected to increase by 3.0 percent per year over the 2006 through 2026 period. Net winter peak demand will increase by approximately 2,400 MW, and net summer peak demand will increase by approximately 1,700 MW. Annual load factor projections are remaining steady at approximately 53 percent. Below and in Table 5.(3) are summaries of projected energy and peak growth rates.

Energy and Peak Growth Rates			
	2006-2011	2006-2016	2006-2026
Total Energy Requirements	5.6%	3.9%	3.0%
Residential Sales	4.7%	3.5%	2.9%
Total Commercial and Industrial Sales (Excluding Gallatin Steel)	8.2%	5.2%	3.6%
Firm Winter Peak Demand	6.3%	4.2%	3.2%
Firm Summer Peak Demand	5.8%	3.9%	3.0%

Table 5.(3)

Season	Net Winter Peak Demand (MW)	Year	Net Summer Peak Demand (MW)	Year	Total Requirements (MWh)	Load Factor (%)
2005 - 06	2,477	2006	2,151	2006	12,556,759	58%
2006 - 07	2,773	2007	2,213	2007	12,956,841	53%
2007 - 08	2,848	2008	2,643	2008	14,793,556	59%
2008 - 09	3,346	2009	2,721	2009	15,716,559	54%
2009 - 10	3,439	2010	2,791	2010	16,133,913	53%
2010 - 11	3,520	2011	2,852	2011	16,499,166	54%
2011 - 12	3,595	2012	2,907	2012	16,879,983	54%
2012 - 13	3,694	2013	2,978	2013	17,261,436	53%
2013 - 14	3,775	2014	3,036	2014	17,621,408	53%
2014 - 15	3,856	2015	3,096	2015	17,981,314	53%
2015- 16	3,931	2016	3,153	2016	18,370,418	53%
2016 - 17	4,031	2017	3,225	2017	18,744,186	53%
2017 - 18	4,118	2018	3,290	2018	19,129,686	53%
2018 - 19	4,209	2019	3,359	2019	19,539,698	53%
2019 - 20	4,299	2020	3,423	2020	19,977,370	53%
2020 - 21	4,408	2021	3,505	2021	20,408,388	53%
2021 - 22	4,503	2022	3,577	2022	20,837,354	53%
2022 - 23	4,597	2023	3,648	2023	21,258,006	53%
2023 - 24	4,678	2024	3,709	2024	21,683,180	53%
2024 - 25	4,781	2025	3,788	2025	22,086,886	53%
2025 - 26	4,869	2026	3,853	2026	22,475,651	53%

Key economic and demographic assumptions underlying these forecasts are:

1. moderate growth in population;

2. steady growth in regional income;
3. an increase in per capital income in the region from $29,000 in 2006 to $32,500 in constant dollars by 2026; and
4. moderate growth in employment.

5.(4) Summary of the utility's planned resource acquisitions including improvements in operating efficiency of existing facilities, demand-side programs, non-utility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities.

Planned Resource Acquisitions

EKPC's resource planning process evaluates the economics of available options to meet the needs of our Member Systems at the lowest practical cost. Utilizing a reserve margin of 12%, the plan resulting from the IRP is shown below in Table 5.(4)-1 and is detailed in Section 8. Table 5.(4)-1 lists annual peak demand figures and compares resulting capacity requirements with existing and committed resources. The Table shows that EKPC will need to provide over 2,100 MW of additional resources to serve projected loads by 2020.

Table 5.(4)-2 shows the expected capacity additions based on the 2006 IRP. EKPC's IRP has identified the need for 900 MW of additional baseload capacity and 200 MW of peaking capacity from 2013 through 2020.

Improvement in Operational Efficiency of Existing Facilities

EKPC recognizes that maintenance management for existing units is vital to keeping facilities efficient. EKPC has developed a long-range plan of maintenance needs for each of the existing generating units. This plan is discussed in Section 8 of the IRP.

Table 5.(4)-1

EKPC Projected Capacity Needs

(MW)

Year	Projected Peaks		12% Reserves		Total Requirements		Existing Resources		Capacity Needs	
	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2006	2,673	2,151	321	258	2,994	2,409	2,752	2,543	242	-134
2007	2,773	2,213	333	266	3,105	2,479	2,719	2,505	386	-26
2008	2,848	2,643	342	317	3,190	2,960	2,721	2,505	469	455
2009	3,346	2,721	401	327	3,747	3,048	2,693	2,477	1,054	571
2010	3,439	2,791	413	335	3,851	3,126	2,683	2,467	1,168	659
2011	3,520	2,852	422	342	3,942	3,194	2,683	2,467	1,259	727
2012	3,595	2,907	431	349	4,027	3,256	2,683	2,467	1,344	789
2013	3,694	2,978	443	357	4,137	3,335	2,683	2,467	1,454	868
2014	3,775	3,036	453	364	4,228	3,400	2,683	2,467	1,545	933
2015	3,856	3,096	463	372	4,318	3,467	2,683	2,467	1,635	1,000
2016	3,931	3,153	472	378	4,403	3,531	2,683	2,467	1,720	1,064
2017	4,031	3,225	484	387	4,515	3,612	2,683	2,467	1,832	1,145
2018	4,118	3,290	494	395	4,612	3,685	2,683	2,467	1,929	1,218
2019	4,209	3,359	505	403	4,714	3,762	2,683	2,467	2,031	1,295
2020	4,299	3,423	516	411	4,814	3,834	2,683	2,467	2,131	1,367

Demand-Side Management

The plan described in Table 5.(4)-2 includes the evaluation of new DSM programs. EKPC evaluated 93 DSM measures for the 2006 IRP. Thirty-four measures passed the Qualitative Screen and were passed on to Quantitative Evaluation. After combining several programs, twenty-seven programs were prepared for Quantitative Evaluation. Detailed analyses of these programs are discussed in Sections 7 and 8 of the IRP.

Table 5.(4)-2

EKPC Projected Major Capacity Additions

(MW)

Year	Baseload Capacity	Peaking/Intermediate Capacity	Cumulative Capacity Additions
2006			
2007			
2008			
2009	278 (Spurlock 4)	485 (Smith CTs 8-12)	763
2010	278 (Smith 1)		1,041
2011			
2012			
2013	300*		1,341
2014			
2015	300*		1,641
2016		100*	1,741
2017		100*	1,841
2018			
2019	300*		2,141
2020			

*Rounded. Exact MWs are modeled in Section 8.

Non-Utility Sources of Generation

The plan described in Table 5.(4)-2 does not include non-utility generation.

EKPC is working very diligently to seek power supply options other than construction its own generation. This includes discussions with other utilities and non-utilities. The discussions have covered partnerships, joint ventures, and long-term power purchase contracts. This work is ongoing.

New Power Plants

As shown in Table 5.(4)-2, Spurlock 4, 278 MW of capacity, is already under construction. In an Order dated August 29, 2006 in Case No. 2005-00053, the Commission granted a Certificate of Convenience and Necessity ("CPCN") to EKPC to construct the 278 MW Smith circulating fluidized bed coal-fired unit ("Smith CFB") and five 90 MW combustion turbines ("Smith CTs 8-12") in Clark County.

The plan calls for 300 MW of base load capacity to be added in 2013, 2015, and 2019. Additionally, the plan calls for 100 MW of intermediate/peaking capacity in 2016 and 100 MW in 2017.

Transmission Improvements

EKPC regularly identifies transmission projects and upgrades that are required for maintaining the capability of its transmission system in order to meet the demands of its Member Systems. Transmission projects are discussed in Section 8 of this IRP.

Bulk Power Purchases and Sales

EKPC has a purchase power agreement with Duke Energy to purchase the output of the Greenup hydro project for approximately 40 MW of capacity that expires at the end of 2006. Negotiations are underway to possibly extend this agreement through 2010.

Interconnections with other Utilities

EKPC and Big Rivers Electric Corporation (BREC) intend to establish a free-flowing interconnection at the D.B. Wilson Power Plant in 2008. EKPC is constructing more than 90 miles of 161 kV transmission line from its Barren County Substation through the Bowling Green area to connect the Warren Rural Electric Cooperative (WRECC) to the EKPC system.

To provide system support and reliability, EKPC is also adding four free-flowing interconnections to utilities with existing transmission facilities in the area.

5.(5) Steps to be taken during the next three (3) years to implement the plan.

Spurlock 4, with 278 MW of baseload capacity, is expected to be online in 2009. Smith CTs 8-12 are expected to be online by 2009 and the 278 MW Smith 1 CFB generating unit in 2010. EKPC anticipates that a Request for Proposals ("RFP") for additional baseload capacity will be issued in the first quarter of 2007.

Demand-Side Management

The DSM alternatives are complex endeavors. DSM programs that may be implemented will require a rigorous program design effort. A demonstration or pilot program may precede complete implementation to test the validity of the program concept.

5.(6) Discussion of key issues or uncertainties that could affect successful implementation of the plan.

EKPC's 2006 load forecast methodology uses historic relationships between electric consumption and key determinants of that consumption, e.g. population, income, employment levels, and wages.

The load forecast assumes that these relationships will continue into the future. EKPC updates its load forecast annually in order to test whether these relationships continue to hold.

The implementation of DSM programs may exceed the target peak reduction that is incorporated in this IRP due to variations in the peak reduction per customer and customer participation.

While the power supply plan identifies the need for baseload and peaking resources, it has not yet addressed the uncertainties of carbon dioxide regulation, significant increases in transmission expenses, partnerships, and generation construction cost uncertainty. These points are either still evolving or will be addressed via the RFP.

SECTION 6

SIGNIFICANT CHANGES

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6. SIGNIFICANT CHANGES.

All integrated resource plans, shall have a summary of significant changes since the plan most recently filed. This summary shall describe, in narrative and tabular form, changes in load forecasts, resource plans, assumptions, or methodologies from the previous plan. Where appropriate, the utility may also use graphic displays to illustrate changes.

Major Differences Between EKPC's 2006 and 2004 Load Forecasts

There are three major changes in the 2006 Load Forecast: 1.) Gallatin Steel will be interrupted 360 hours each year as a result of contract negotiations. The 2004 forecast assumed 500 hours. 2.) Based on the most recent End-Use Survey, the assumption for electric furnace saturation is higher than in the 2004 Load Forecast. 3.) Household growth is growing at a more moderate rate than in the 2004 forecast.

Table 6-1

Forecast Comparison
2006 Versus 2004

		2006	2004	Difference
Residential Sales, MWh				
	2007	6,865,831	7,183,613	-317,783
	2012	8,650,448	9,277,560	-627,113
	2017	9,681,304	10,734,638	-1,053,334
Total Commercial and Industrial Sales, MWh				
	2007	4,102,027	4,202,123	-100,095
	2012	5,917,350	6,157,558	-240,208
	2017	6,603,307	6,938,307	-335,000
Gallatin Steel, MWh per Year	2007-2017	982,000	960,000	22,000
Residential Customers				
	2007	477,298	486,697	-9,399
	2012	580,588	600,127	-19,539
	2017	635,513	666,258	-30,745
Firm Winter Peak, MW				
	2007	2,773	2,838	-65
	2012	3,595	3,753	-158
	2017	4,031	4,305	-274
Firm Summer Peak, MW				
	2007	2,213	2,300	-87
	2012	2,907	3,089	-182
	2017	3,225	3,519	-294

Note: Warren becomes member in April 2008.

Table 6-2 shows a comparison of the resource plan in the 2003 IRP and the 2006 IRP. The 2003 IRP plan relies more heavily on gas-fired resources than the 2006 IRP plan. A significant increase in natural gas prices occurred shortly after development of the 2003 IRP plan that would have driven that plan more toward baseload generation. The 2006 IRP plan shows the impacts of the higher cost of gas-fired generation compared to coal-fired generation. The 2006 IRP plan includes the necessary capacity to serve the needs of Warren RECC beginning in 2008.

Table 6-2
Resource Plan Comparison
(Winter Ratings shown)

Year	2003 IRP		2006 IRP	
	Base	Peaking	Base	Peaking/Int
2003			---	---
2004			---	---
2005	Gilbert 268 MW	Smith CT 6-7 200 MW	---	---
2006		Smith CT 8 100 MW		
2007		Smith CT 9-10 200 MW		
2008		Smith CT 11 100 MW		Smith CTs 8-10 291 MW
2009		Smith CT 12 100 MW	Spurlock 4 278 MW	Smith CTs 11-12 194 MW
2010			Smith 1 278 MW	
2011	Coal-fired 268 MW			
2012				
2013		CT 13-14 200 MW	*Smith 2 278 MW	
2014		CT 15 100 MW		
2015		CT 16-17 200 MW	*Coal fired 278 MW	
2016		CT 18 100 MW		*CT-STIG 1 109 MW
2017				*CT-STIG 2 109 MW
2018	---	---		
2019	---	---	*Coal fired 278 MW	
2020	---	---		*

*Expected commercial operation date is October of previous year.

Major Enhancements Since Last IRP

EKPC has made several improvements to its DSM planning since the 2003 IRP. They include:

(1) More comprehensive set of DSM measures evaluated, incorporating feedback from the Attorney General, Kentucky Division of Energy, and other parties.
(2) More explicit factoring of environmental costs.
(3) Updated avoided costs for capacity to match current plans for transmission, distribution, and generation investment (including environmental compliance costs).
(4) Changing load impacts to account for changes in Federal appliance efficiency standards.
(5) Explicit design features to achieve defined shares of technical potential estimates by market for new DSM programs, using updated electricity sales, measure savings, and market share data.
(6) Recognition of enhancements made to existing EKPC and member cooperative DSM programs (such as the Touchstone Energy homes).
(7) Factoring updated national and regional results for load impacts and costs into new DSM program models.
(8) New end-use load profiles, based on end-use metering where available, to more accurately model new DSM programs in the package.
(9) More detailed modeling of retail and wholesale rates, including the new environmental surcharge.
(10) The use of a resource optimization model to develop the resource plan.

SECTION 7

LOAD FORECAST

Table of Contents

7. LOAD FORECASTS

7.(1) Historical and Forecasted Information Requirements Disaggregated by Customer Class.

7.(1)(a) Residential heating.

7.(1)(b) Residential nonheating.

7.(1)(c) Total residential (total of paragraphs (a) and (b) of this subsection).

7.(1)(d) Commercial.

7.(1)(e) Industrial.

7.(1)(f) Sales for resale.

7.(1)(g) Utility use and other.

The data provided in the following subsections conform to the specifications given unless otherwise noted.

7.(2) Specification of Historical Information Requirements

7.(2)(a) Average annual number of customers by class as defined in subsection (1) of this section.

EKPC Average Number of Customers by Class, 2001-2005

Year	Residential*	Commercial	Industrial**	Utility Use and Other***	Total Customers
2001	426,018	25,129	112	330	451,588
2002	436,707	26,340	111	353	463,511
2003	446,542	26,661	133	366	473,701
2004	456,679	28,125	136	377	485,316
2005	463,694	30,613	139	389	494,835

Notes: * Residential Class consists of Residential, Seasonal and Public Buildings.
EKPC does not have heating versus non-heating residential customer counts.

** Industrial is labeled "Large Commercial" in EKPC's Load Forecast Report.
*** Utility Use and Other includes lighting.

7.(2)(b) Recorded and weather-normalized annual energy sales and generation for the system, and sales disaggregated by class as defined in subsection (1) of this section.

Table 7.(2)(b)-1 below shows recorded sales by class and total requirements. EK does not weather normalize by class, however, Table 7.(2)(b)-2 below shows actual and weather normalized for total retail sales and total requirements.

Table 7.(2)(b)-1

EKPC Recorded Annual Energy Sales (MWh) and Energy Requirements (MWh), 2001-2005					
Year	2001	2002	2003	2004	2005
Residential Heating*	4,225,591	4,457,043	4,303,313	4,440,045	4,750,463
Residential Non-Heating*	1,603,938	1,744,209	1,937,250	1,934,512	2,032,589
Total Residential**	5,829,529	6,201,252	6,240,563	6,374,557	6,783,052
Commercial	1,505,480	1,577,590	1,550,248	1,598,111	1,733,280
Industrial***	2,658,852	2,803,845	2,881,720	3,037,246	3,013,754
Utility Use and Other****	6,545	7,107	7,447	7,498	7,711
Total Sales	10,000,406	10,589,794	10,679,978	11,017,413	11,537,797
Office Use	6,793	7,562	7,681	8,289	8,629
% Loss	4.0	4.3	4.5	4.5	4.2
EKPC Sales to Members	10,427,269	11,071,863	11,190,811	11,540,687	12,049,271
EKPC Office Use	8,205	8,818	9,123	9,106	8,902
Transmission Loss (%)	2.9	3.3	3.2	2.7	3.7
Total Requirements	10,750,900	11,456,830	11,568,314	11,865,797	12,527,829

Notes:

* Actual residential heating and non-heating energy use is not available. Estimates presented in the table are based on results from Statistically Adjusted End Use models, a methodology used in the forecasting process.

** Total Residential Class consists of Residential, Seasonal and Public Buildings use.

*** Industrial is labeled "Large Commercial" in EKPC's Load Forecast Report.

**** Utility Use and Other includes lighting.

Table 7.(2)(b)-2

EKPC Weather Normalized Annual Energy Sales (MWh) and Energy Requirements (MWh), 2001-2005					
	2001	2002	2003	2004	2005
Total Retail Sales by Member Cooperatives					
Recorded	10,000,406	10,589,794	10,679,978	11,017,413	11,537,797
Weather Normalized	10,433,025	10,769,604	11,393,687	11,652,942	11,763,380
EKPC Total Requirements					
Recorded	10,750,900	11,456,830	11,568,314	11,865,797	12,527,829
Weather Normalized	11,215,986	11,651,361	12,341,388	12,550,265	12,772,769

7.(2)(c) Recorded and weather-normalized coincident peak demand in summer and winter for the system.

Year	Season	Actual Peak	Adjusted Peak
		MW	MW
2001	Winter	2,322	2,402
	Summer	1,980	1,979
2002	Winter	2,217	2,392
	Summer	2,120	2,056
2003	Winter	2,568	2,696
	Summer	1,996	2,134
2004	Winter	2,610	2,562
	Summer	2,052	2,179
2005	Winter	2,719	2,863
	Summer	2,220	2,198

7.(2)(d) Total energy sales and coincident peak demand to retail and wholesale customers for which the utility has firm, contractual commitments.

	2001	**2002**	**2003**	**2004**	**2005**
Energy Sales (MWh)*	NA	NA	NA	NA	NA
Coincident Peak Demand (MW)	2,278	2,092	2,435	2,489	2,615

* Interruptible energy is not recorded separately.

7.(2)(e) Total energy sales and coincident peak demand to retail and wholesale customers for which service is provided under an interruptible or curtailable contract or tariff or under some other nonfirm basis.

	2001	**2002**	**2003**	**2004**	**2005**
Energy Sales (MWh)*	NA	NA	NA	NA	NA
Coincident Peak Demand (MW)	44	146	133	123	104

* Interruptible energy is not recorded separately. Decrease in sales due to interruption is small.

7.(2)(f) Annual energy losses for the system.

	Distribution Loss at Member System Level		Transmission Loss	
	% Loss	Energy Loss (MWh)	% Loss	Energy Loss (MWh)
2001	4.0%	420,070	2.9%	315,426
2002	4.3%	474,507	3.3%	376,149
2003	4.5%	503,151	3.2%	368,380
2004	4.5%	514,985	2.7%	316,004
2005	4.2%	502,845	3.7%	469,656

7.(2)(g) Identification and description of existing demand-side programs and an estimate of their impact on utility sales and coincident peak demands including utility or government sponsored conservation and load management programs.

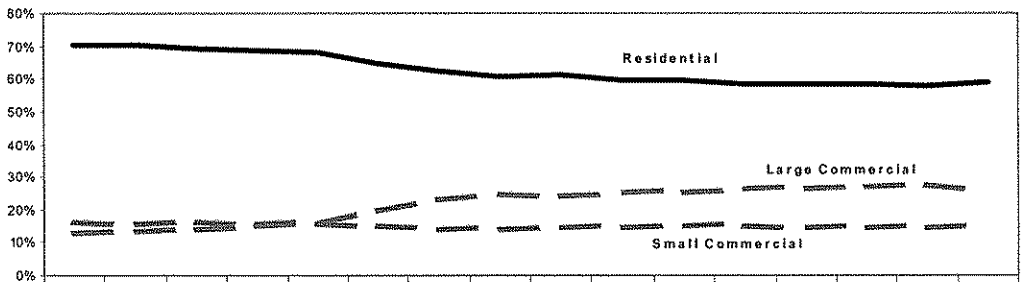
Identification and description of existing demand-side programs are presented in Section 8, Table 8.(3)(e)(1)-1. For program by program demand and sales impacts, see response in Section 8, 8.(3)(e)(3). Details of the estimates are presented in the *Technical Appendix* in a report entitled *Demand Side Management Analysis*. See table DSM-7.

7.(2)(h) Any other data or exhibits, such as load duration curves or average energy usage per customer, which illustrate historical changes in load or load characteristics.

Historical sales and customer data represent the summation of the 16 member systems data from the RUS Form 7s. EK Data is as reported on the RUS Form 12. Unless otherwise noted, all data is actual, not weather normalized.

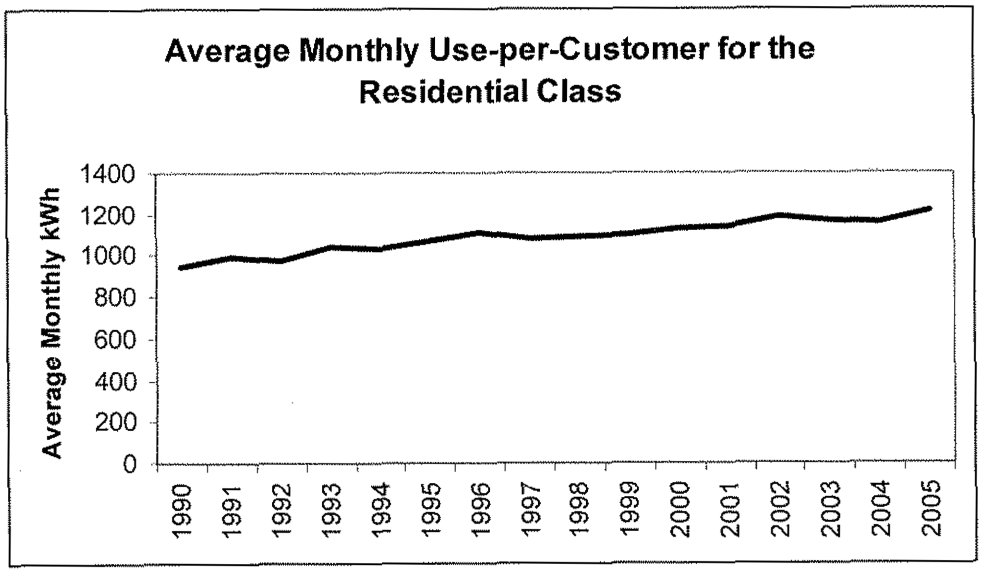
The historical percentage share of class sales is shown below. While the EK member systems continue to be predominantly residential, large commercial sales have increased. This is largely due to the addition of Gallatin Steel.

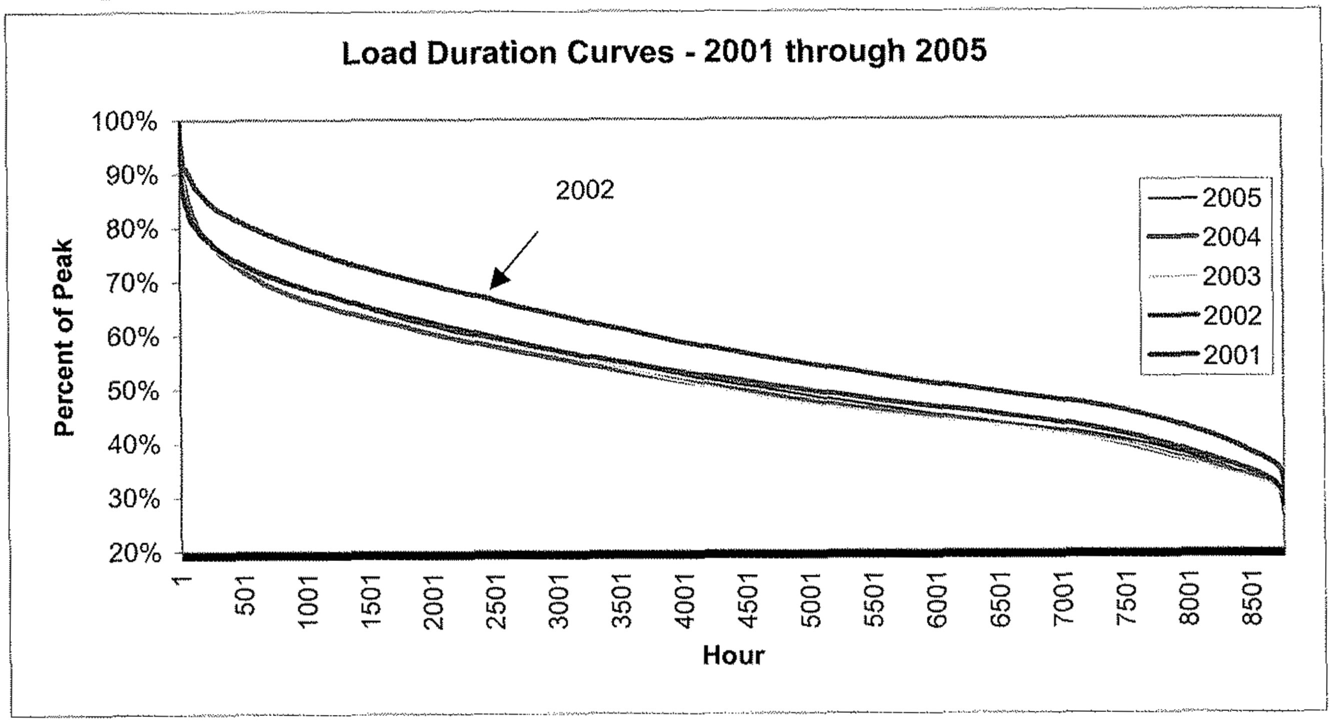
Percent of Total Sales by Class



	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Residential	71%	70%	69%	69%	68%	65%	62%	61%	61%	59%	59%	58%	59%	58%	58%	59%
Small Commercial	16%	16%	17%	16%	16%	15%	14%	14%	15%	15%	15%	15%	15%	15%	15%	15%
Large Commercial	13%	13%	14%	16%	16%	20%	23%	25%	24%	26%	25%	27%	26%	27%	28%	26%

Given EK member systems have nearly 55% of electric heat saturation, over 95% with some form of air conditioning and 87% with electric water heaters, average use per household is continuing to increase. The following shows actual historical use per customer. Given these high saturations of weather sensitive appliances, weather extremes can impact sales significantly.





The forecast data presented in the following sections is taken from EKPC's 2006 Load Forecast, which is provided in its entirety, along with *Appendices A and B*. The forecast projects total energy requirements to increase by 3.0 percent per year over the 2006 through 2026 period. Net winter peak demand will increase by approximately 2,400 MW, and net summer peak demand will increase by approximately 1,700 MW. Annual load factor projections are remaining steady at approximately 53 percent. Sales to the residential class are projected to increase by 2.9 percent per year, commercial and industrial sales are projected to increase by 3.6 percent per year. These growth rates do include Warren RECC as a new member beginning April 2008.

Projected Energy and Peak Demand Growth
Compound Annual Rates of Change

				With Warren			Without Warren		
	Historical Growth Rates			2006 Forecast Growth Rates			2006 Forecast Growth Rates		
	2000-2005	1995-2005	1985-2005	2006-2011	2006-2016	2006-2026	2006-2011	2006-2016	2006-2026
Total Energy Requirements	3.6%	6.3%	7.2%	5.6%	3.9%	3.0%	2.8%	2.5%	2.3%
Firm Winter Peak Demand	4.6%	5.3%	4.5%	6.3%	4.2%	3.2%	3.5%	2.9%	2.6%
Firm Summer Peak Demand	2.3%	3.7%	5.3%	5.8%	3.9%	3.0%	2.7%	2.4%	2.3%

Energy and Peak Growth Rates			
	2006-2011	2006-2016	2006-2026
Total Energy Requirements	5.6%	3.9%	3.0%
Residential Sales	4.7%	3.5%	2.9%
Total Commercial and Industrial Sales (Excluding Gallatin Steel)	8.2%	5.2%	3.6%
Firm Winter Peak Demand	6.3%	4.2%	3.2%
Firm Summer Peak Demand	5.8%	3.9%	3.0%

In EKPC's service area, electricity is the primary method for water heating and home heating. Currently, around 85 percent of all homes have electric water heating, and about 54 percent have electric heat. In 2005, 58 percent of EKPC's member retail sales were to the residential class and residential customer use averaged 1,234 kWh per month. While

EKPC's load can be considered primarily residential in nature, commercial/industrial customers make up an increasingly larger share of total retail sales.

The economy of EKPC's service area is quite varied. Areas around Lexington and Louisville have a significant amount of manufacturing industry. The region around Cincinnati contains a growing number of retail trade and service jobs while the eastern and southeastern portions of EKPC's service area are dominated by the mining industry. Tourism is an important aspect of EKPC's southern and southwestern service area, with Lake Cumberland and Mammoth Cave National Park contributing to jobs in the service and retail trade industries. Textile and apparel manufacturing employ a significant number of workers throughout the service area, particularly in the northeastern and southern portions.

7.(3) Specification of Forecast Information Requirements

Information pertaining to energy sales and peak demand forecasts conform to the specifications outlined in Section 7.3 to the fullest extent possible.

7.(4) Energy and Demand Forecasts

7.(4)(a) Annual energy sales and generation for the system and sales disaggregated by class as defined in subsection (1) of this section.

Please see Table 7.(4)(a)-1 and Table 7.(4)(a)-2.

Table 7.(4)(a)-1

Year	Residential Sales (MWh)	Seasonal Sales (MWh)	Small Comm. Sales (MWh)	Public Buildings (MWh)	Large Comm. Sales (MWh)	Gallatin Steel (MWh)	Other Sales (MWh)	Total Retail Sales (MWh)
2006	6,702,645	14,445	1,780,456	25,185	2,116,434	981,378	7,945	11,628,489
2007	6,865,831	14,945	1,844,468	25,880	2,257,560	981,718	8,157	11,998,559
2008	7,576,749	15,470	2,143,068	26,578	2,927,518	982,351	12,341	13,684,074
2009	8,036,352	16,009	2,271,045	27,330	3,187,814	981,697	13,773	14,534,020
2010	8,246,901	16,493	2,330,473	28,023	3,301,354	981,659	14,125	14,919,028
2011	8,432,930	16,911	2,387,349	28,674	3,396,327	981,566	14,469	15,258,226
2012	8,650,448	17,466	2,443,562	29,377	3,473,788	981,425	14,817	15,610,882
2013	8,868,278	18,016	2,499,753	30,115	3,550,403	981,156	15,156	15,962,877
2014	9,069,536	18,535	2,555,818	30,813	3,625,976	981,046	15,492	16,297,216
2015	9,270,396	19,050	2,612,249	31,491	3,700,886	981,063	15,824	16,630,959
2016	9,479,347	19,593	2,669,288	32,174	3,792,252	981,254	16,155	16,990,064
2017	9,681,304	20,098	2,727,493	32,868	3,875,814	981,077	16,484	17,335,138
2018	9,900,800	20,637	2,786,650	33,574	3,951,703	980,691	16,815	17,690,869
2019	10,120,469	21,220	2,846,226	34,287	4,052,080	980,619	17,140	18,072,040
2020	10,371,328	21,880	2,905,708	34,941	4,143,897	980,793	17,466	18,476,014

Assumptions: Gallatin will be interrupted 360 hours per year;
Warren will become a member April 1, 2008.

Estimates of heating and non-heating residential energy use are presented below. As previously mentioned, these are based on results from Statistically Adjusted Modeling used in the load forecast.

Year	Residential Heating Sales (MWh)	Residential Non-Heating Sales (MWh)	Total Residential Sales (MWh)
2006	1,996,283	4,706,362	6,702,645
2007	2,019,015	4,846,816	6,865,831
2008	2,219,209	5,357,540	7,576,749
2009	2,350,805	5,685,547	8,036,352
2010	2,409,169	5,837,732	8,246,901
2011	2,460,656	5,972,274	8,432,930
2012	2,516,771	6,133,677	8,650,448
2013	2,578,799	6,289,479	8,868,278
2014	2,634,196	6,435,341	9,069,536
2015	2,690,174	6,580,222	9,270,396
2016	2,746,105	6,733,241	9,479,347
2017	2,802,539	6,878,764	9,681,304
2018	2,862,704	7,038,096	9,900,800
2019	2,921,500	7,198,968	10,120,469
2020	2,984,341	7,386,987	10,371,328

Table 7.(4)(a)-2

Year	Total Retail Sales (MWh)	Office Use (MWh)	% Loss	EKPC Sales to Members (MWh)	EKPC Office Use (MWh)	Transmission Loss (%)	Total Requirements (MWh)
2006	11,628,489	8,819	4.4	12,170,871	9,185	3.0	12,556,759
2007	11,998,559	8,819	4.4	12,558,905	9,231	3.0	12,956,841
2008	13,684,074	9,489	4.5	14,340,472	9,277	3.0	14,793,556
2009	14,534,020	9,489	4.5	15,235,692	9,370	3.0	15,716,559
2010	14,919,028	9,489	4.6	15,640,431	9,464	3.0	16,133,913
2011	15,258,226	9,489	4.5	15,994,633	9,558	3.0	16,499,166
2012	15,610,882	9,489	4.5	16,363,929	9,654	3.0	16,879,983
2013	15,962,877	9,489	4.6	16,733,842	9,750	3.0	17,261,436
2014	16,297,216	9,489	4.5	17,082,918	9,848	3.0	17,621,408
2015	16,630,959	9,489	4.5	17,431,928	9,946	3.0	17,981,314
2016	16,990,064	9,489	4.5	17,809,259	10,046	3.0	18,370,418
2017	17,335,138	9,489	4.6	18,171,714	10,146	3.0	18,744,186
2018	17,690,869	9,489	4.6	18,545,547	10,248	3.0	19,129,686
2019	18,072,040	9,489	4.5	18,943,156	10,350	3.0	19,539,698
2020	18,476,014	9,489	4.6	19,367,595	10,454	3.0	19,977,370

Assumptions: Gallatin will be interrupted 360 hours per year;
Warren will become a member April 1, 2008.

7.(4)(b) Summer and winter coincident peak demand for the system.

Net Peak Demands			
Winter	MW	Summer	MW
2006 - 07	2,773	2006	2,151
2007 - 08	2,848	2007	2,213
2008 - 09	3,346	2008	2,643
2009 - 10	3,439	2009	2,721
2010 - 11	3,520	2010	2,791
2011 - 12	3,595	2011	2,852
2012 - 13	3,694	2012	2,907
2013 - 14	3,775	2013	2,978
2014 - 15	3,856	2014	3,036
2015- 16	3,931	2015	3,096
2016 - 17	4,031	2016	3,153
2017 - 18	4,118	2017	3,225
2018 - 19	4,209	2018	3,290
2019 - 20	4,299	2019	3,359

7.(4)(c) If available for the first two (2) years of the forecast, monthly forecasts of energy sales and generation for the system and disaggregated by class as defined in subsection (1) of this section and system peak demand.

Table 7.(4)(c)

Year	Month	Residential Sales (MWh)	Small Comm. Sales (MWh)	Large Comm. Sales (MWh)	Other Sales (MWh)	Total Retail Sales (MWh)
2006	1	734,636	143,314	169,921	667	1,048,538
2006	2	705,886	144,296	169,624	662	1,020,468
2006	3	625,183	141,897	172,112	658	939,850
2006	4	514,162	141,340	171,618	654	827,775
2006	5	446,259	141,812	172,770	656	761,497
2006	6	473,558	149,154	180,317	653	803,682
2006	7	543,076	157,550	180,221	656	881,503
2006	8	553,383	161,235	184,912	656	900,187
2006	9	490,556	158,713	183,520	662	833,451
2006	10	437,293	147,095	178,598	665	763,651
2006	11	532,568	144,921	175,665	674	853,828
2006	12	685,715	149,128	177,156	682	1,012,682
Total		6,742,275	1,780,456	2,116,434	7,945	10,647,110
2007	1	761,382	150,440	183,753	677	1,096,252
2007	2	735,886	151,015	182,253	677	1,069,830
2007	3	641,536	148,730	184,327	675	975,268
2007	4	530,365	147,202	183,649	674	861,890
2007	5	456,631	147,234	185,666	675	790,206
2007	6	479,633	154,158	192,086	675	826,552
2007	7	542,721	162,268	191,611	677	897,277
2007	8	554,791	165,480	195,850	678	916,799
2007	9	498,016	162,038	193,555	682	854,290
2007	10	456,721	152,318	189,555	684	799,277
2007	11	548,318	149,975	187,305	689	886,287
2007	12	700,658	153,610	187,951	694	1,042,912
Total		6,906,656	1,844,468	2,257,560	8,157	11,016,841
2008	1	775,751	156,363	192,919	700	1,125,733
2008	2	746,932	156,543	191,577	701	1,095,753
2008	3	656,848	154,805	193,700	700	1,006,053
2008	4	609,177	176,865	249,575	1,126	1,036,743
2008	5	521,153	175,973	253,059	1,136	951,321
2008	6	542,417	184,723	264,515	1,141	992,796
2008	7	614,838	196,182	265,792	1,146	1,077,958
2008	8	632,915	200,552	272,633	1,145	1,107,245
2008	9	571,963	194,802	271,215	1,140	1,039,120
2008	10	530,458	183,102	260,645	1,138	975,343
2008	11	622,743	178,961	257,561	1,134	1,060,399
2008	12	793,602	184,196	254,326	1,134	1,233,258
Total		7,618,797	2,143,068	2,927,518	12,341	12,701,724

Note: The Large Commercial Sales column does not include Gallatin Steel. Gallatin uses approximately 81,780 MWh per month each year.

7.(4)(d) The impact of existing and continuing demand-side programs on both energy sales and system peak demands, including utility and government sponsored conservation and load management programs.

Program by program demand and sales impacts are shown in Section 8, 8.(3)(e)(3). Details of the estimates are presented in the *Technical Appendix* in a report entitled *Demand Side Management Analysis*. See table DSM-7.

7.(4)(e) Any other data or exhibits which illustrate projected changes in load or load characteristics.

In 2008, Warren RECC will become a member of EK. Warren RECC is approximately a 400 MW system, winter and summer. While Warren's load shape is very similar to EK's member systems, the customer base is different: 48% of total sales in 2005 was to the residential class versus 58% for the EK system.

7.(5) Historical and Forecast Information for a Multistate Utility System

Section 7.(5) does not apply to EKPC.

7.(6) A utility shall file all updates of load forecasts with the commission when they are adopted by the utility.

The *2006 Load Forecast Report* and appendices are included. EKPC's Board of Directors approved the 2006 Load Forecast Report at its September 2006 Meeting. RUS approval is pending.

7.(7) Description and Discussion of Data, Assumptions and Judgments, Methods and Models, Treatment of Uncertainty, and Sensitivity Analysis Used in Producing the Forecast.

7.(7)(a) All data sets used in producing the forecasts.

A complete list of all datasets is included in the appendix. The most crucial datasets include: regional economic data, historical sales and customer data, electric price history and forecast, historical weather, appliance saturation and efficiency data.

7.(7)(b) Key assumptions and judgments used in producing forecasts and determining their reasonableness.

Key forecast assumptions used in developing the EKPC and member system load forecasts are:

- EKPC's member systems will add approximately 260,000 residential customers by 2026. This represents an increase of 2.3 percent per year. This includes Warren RECC beginning April 2008.
- EKPC uses an economic model to help develop its load forecast. The model uses data for 89 Kentucky counties in seven geographic regions. The economy of these counties will experience modest growth over the next 20 years. The average unemployment rate will remain relatively flat at 6.8 percent during the 2006 to 2026 timeframe. Total employment levels will rise by 330,000 jobs. Manufacturing employment will decrease from 272,000 jobs in 2004 to 210,000 jobs in 2020. Regional population will grow from 3.5 million people in 2006 to 4.0 million people in 2026, an average growth of 0.7 percent per year.
- From 2006 through 2026, approximately 70 percent of all new households will have electric heat. Eighty-five percent of all new households will have electric water heating. Nearly all new homes will have electric air conditioning, either central or room.
- Over the forecast period, naturally occurring appliance efficiency improvements is expected to decrease retail sales nearly 1,500,000 MWh. Appliances particularly affected are refrigerators, freezers, and air conditioners.
- Residential customer growth and local area economic activity will be the major determinants of small commercial growth.
- Forecasted load growth is based on the assumption of normal weather, as defined by the National Oceanic and Atmospheric Administration, occurring over the next

20 years. Seven different stations are used depending on geographic location of the member system.

7.(7)(c) The general methodological approach taken to load forecasting (for example, econometric, or structural) and the model design, model specification, and estimation of key model parameters (for example, price elasticities of demand or average energy usage per type of appliance).

EKPC prepares a load forecast by working jointly with its member systems in preparing their individual load forecasts. The general steps followed by EKPC in developing its load forecast are summarized as follows:

1. EKPC prepares a preliminary forecast for each of its member systems which is based on retail sales forecasts for six classes: residential, seasonal, small commercial, public buildings, large commercial, and other. The classifications are taken from the Rural Utilities Services (RUS) Form 7, which contains publicly available retail sales data for member systems. EKPC's sales to member systems are then determined by adding distribution losses to total retail sales. EKPC's total requirements are estimated by adding transmission losses to total sales. Seasonal peak demands are determined by applying peak factors for heating, cooling, and water heating to energy. The same methodology is used in developing each of the 16 member system forecasts.

2. EKPC meets with each member system to discuss their preliminary forecast. Member system staff at these meetings include the manager and other key individuals. The RUS General Field Representative (GFR) is also invited to attend the meetings.

3. The preliminary forecast is usually revised based on mutual agreement of EKPC staff, member system's Manager and staff, and the RUS GFR. This final forecast is approved by the board of directors of each member system.

4. The EKPC forecast is the summation of the forecasts of its 16 members.

EKPC has divided its members' service area into six economic regions with economic activity projected for each. Regional forecasts for population, income and employment are developed and used as inputs to residential customer and small commercial customer and energy forecasts. Therefore, EKPC's economic assumptions regarding its load forecast are consistent.

Energy sales are forecasted using regression analysis for each class as reported on the RUS Form 7. Variables include electric price, economic activity, and regional population growth. Customer growth is also projected with regression analysis using economic variables such as population.

Seasonal peak demands are projected using the summation of monthly energy usages and load factors for the various classes of customers. Residential energy usage components include heating, cooling, water heating, and other usage. Using load factors, demand is calculated for each component and then summed to obtain the residential portion of the seasonal peak. Small commercial and large commercial classes use load factors on the class usage to obtain the class contribution to the seasonal peak. High and low case projections have been constructed around the base case forecast. Weather and customer growth assumptions are two significant inputs to the high and low cases.

Part of EKPC's load forecast methodology includes regional economic modeling. Historical data on population, income, employment levels, and wages are collected at the county level from the U.S. Bureau of Labor Statistics ("BLS") and the U.S. Bureau of Economic Analysis ("BEA") and historical data on labor force size and the unemployment rate are collected at the county level from state sources. The historical county data are combined into seven economic regions, and are analyzed and projected into the future. EKPC subscribes to the forecast services of Global Insight, an established consulting firm that supplies economic forecasts to thousands of U.S. firms. Regional economic activity is modeled using Global Insight's forecast of the U.S. economy as a driver. Consistent regional forecasts for population, income, and employment are developed. Population forecasts are used to project residential class customers; regional household income is used to project residential sales; and regional economic activity is used to project small commercial sales.

An important variable that is projected by the regional model is regional population. Overall, EKPC's forecast is for moderate growth in population. Household growth is an important variable as well. Income growth and the sensitivity to the national economy exhibited by EKPC's service area are also analyzed in the regional model. EKPC's forecast of total regional income is for moderate but steady growth. This variable is important to the load forecast because of its strong effect on appliance purchases. Total regional employment is tied closely to the national economy. The early eighties was a period of depressed job growth. Since 1986, however, total employment has grown strongly and EKPC's forecast of total employment levels is for moderate growth.

Projections of regional economic activity enhance the sales forecasting and strategic planning of EKPC because changes in regional employment and income are important determinants of customer and sales growth. EKPC's regional models use quarterly county-level data to produce regional forecasts of income, employment, wages, population, labor force, and the unemployment rate. The analysis is performed with ordinary least squares regression. Historical regional data are common series and are available from government sources. The quarterly data is then converted to monthly values to use in the load forecasting models.

Some natural regions exist within the EKPC territory. For example, the Central Economic Region defined by EKPC fits closely within the Lexington Standard Metropolitan Statistical Area ("SMSA"). The BEA defines SMSA's as areas of interrelated economic activity that go beyond a single county's boundaries. EKPC's Eastern Region is dominated by the coal mining industry. The Northern Region includes Kentucky counties that border Cincinnati.

The Large Commercial Class is forecasted using input from member systems as well as a modeling approach. New industrial customers that member systems expect in the next few years are explicitly input into the models. To estimate total new large loads at the system level, a regression approach is used. A probabilistic model is then used to distribute these customers among the 16 member systems. A prototype load of 1.5 MW and 60% load factor is assumed for these new loads. This methodology for forecasting new large commercial customers and energy provides a robust and defensible projection at the member system level as well as the system level.

7.(7)(d) The utility's treatment and assessment of load forecast uncertainty.

In addition to the forecasted peaks, high and low cases around the base case are developed. The assumptions include:

1. Weather – assumed 2 standard deviations above and below the base case heating and cooling degree day (HDD and CDD) assumptions
2. Electric price – assumed the residential rate would be 15% higher than the base case rate, which results in lower usage, for the low case and 15% lower for the high case
3. Residential customers – assumed 2 standard deviations above and below the base case annual average residential customers
4. Appliance saturation projections for the residential class
5. Small and Large Commercial energy – energy was modeled probabilistically, assuming a normal distribution and a standard deviation based on the historical data; the resulting 90%/10% output was used as the forecasted class energy

Using these assumptions results in different customer forecasts, which in turn results in different energy forecasts. For the small and large commercial classes, the customer and energy forecasts for the high and low case are produced using probabilistic modeling in @RISK. The customer and energy forecasts are added to the residential forecast to produce the system forecast, which is then used to create the hourly forecasts.

Table 7.(7)(d)-1

Total Winter Peak Demand (MW)				Total Summer Peak Demand (MW)				Total Requirements Includes Gallatin Steel (MWh)			
Season	Low Case	Base Case	High Case	Year	Low Case	Base Case	High Case	Year	Low Case	Base Case	High Case
				2006	1,829	2,159	2,423	2006	11,362,043	12,556,759	13,743,274
2006 - 07	2,461	2,781	3,134	2007	1,894	2,221	2,490	2007	11,632,503	12,956,841	14,101,331
2007 - 08	2,486	2,856	3,207	2008	2,252	2,651	2,883	2008	13,595,326	14,793,556	16,227,134
2008 - 09	2,876	3,354	3,675	2009	2,382	2,729	3,025	2009	14,248,260	15,716,559	16,942,950
2009 - 10	3,005	3,447	3,838	2010	2,452	2,799	3,099	2010	14,658,388	16,133,913	17,397,030
2010 - 11	3,090	3,528	3,948	2011	2,513	2,860	3,161	2011	15,007,769	16,499,166	17,774,167
2011 - 12	3,162	3,603	4,039	2012	2,571	2,915	3,223	2012	15,393,533	16,879,983	18,202,463
2012 - 13	3,232	3,702	4,131	2013	2,638	2,986	3,299	2013	15,757,977	17,261,436	18,627,485
2013 - 14	3,320	3,783	4,249	2014	2,695	3,044	3,362	2014	16,098,941	17,621,408	19,016,207
2014 - 15	3,391	3,864	4,344	2015	2,755	3,104	3,424	2015	16,447,962	17,981,314	19,398,083
2015 - 16	3,462	3,939	4,437	2016	2,810	3,161	3,486	2016	16,817,895	18,370,418	19,823,838
2016 - 17	3,527	4,039	4,525	2017	2,876	3,233	3,558	2017	17,160,817	18,744,186	20,210,546
2017 - 18	3,608	4,126	4,632	2018	2,941	3,298	3,628	2018	17,540,219	19,129,686	20,631,709
2018 - 19	3,686	4,217	4,734	2019	3,009	3,367	3,701	2019	17,930,178	19,539,698	21,065,767
2019 - 20	3,765	4,307	4,839	2020	3,071	3,431	3,771	2020	18,348,908	19,977,370	21,552,290

Note: This table shows total peak demand which assumes no loads are interrupted. Response to 7.(4)(b) shows net peak which assumes loads are interrupted.

7.(7)(e) Sensitivity Analysis

7.(7)(e)(1) *Changes in prices of electricity and prices of competing fuels.*

Price is an input into the energy models as is price elasticity.

7.(7)(e)(2) Changes in population and economic conditions in the utility's service territory and general region.

EK relies on regional economic conditions. See Response 7.(7)(c).

7.(7)(e)(3) Development and potential market penetration of new appliances, equipment, and technologies that use electricity or competing fuels.

In order to understand trends, EK does conduct an appliance saturation survey every two years. EK also is a member of the Energy Forecasters' Group (EFG). This main goal of this group is to understand and model appliance efficiency trends.

7.(7)(e)(4) Continuation of existing company and government sponsored conservation and load management or other demand-side programs.

Existing programs will continue to be offered until analyses show there is no benefit to do so. As described in Section 8, benefits can be seen for EKPC, the member system, or the consumer. Some programs are beneficial for all three.

7.(7)(f) Research and development efforts underway or planned to improve performance, efficiency, or capabilities of the utility's load forecasting methods.

Plans are to evaluate the process for the sensitivity analyses for the next forecast.

7.(7)(g) Description of and schedule for efforts underway or planned to develop end-use load and market data for analyzing demand-side resource options including load research and market research studies, customer appliance saturation studies, and conservation and load management program pilot or demonstration projects.

As previously stated, EK does conduct an appliance saturation survey every two years. This is an effort to stay apprised of saturation of household appliances. EK has a load research program which consists of over 600 meters on residential, commercial and industrial customers. Currently, EK is conducting a direct load control pilot project. The project involves two member systems and air conditioning and water heating devices are being controlled. Data collection will continue through September 2007 with analysis and a report to follow.

SECTION 8

RESOURCE ASSESSMENT
AND
ACQUISITION PLAN

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8. RESOURCE ASSESSMENT AND ACQUISITION PLAN.

8.(1) 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.

The resource planning process at EKPC is based on a least cost approach and also incorporates a risk evaluation. The planning cycle begins with the load forecast that is developed every two years. A new load forecast was developed in 2006. Based on the load forecast, EKPC's capacity needs are evaluated to determine the timing, quantity, and proper mix of resources. An evaluation of the status of technologies is part of the planning process. EKPC continually evaluates power supply alternatives based on the most recent load forecast and current cost and financial data. The current resource plan is shown in Section 5(4). Alternatives for supplying future resource needs are evaluated on a present worth of revenue requirements basis. Both supply-side options and demand-side programs are evaluated during the planning process. EKPC is required by RUS under most circumstances to undergo an RFP process to evaluate resource alternatives. Various alternatives such as self-build options, power purchases, construction of new capacity by other companies, unit participation proposals, distributed generation, and DSM proposals are typically evaluated during the RFP process.

The optimization module in EKPC's production cost model, RTSim, was used to develop the resource plan in the 2006 IRP. The RTSim Resource Optimizer incorporates risk analysis, optimization, and detailed production cost simulation to determine the lowest cost plans.

EKPC also completed a reserve margin study that is included in Section 8.(5)(d). The study indicates that a 12% reserve margin over the annual peak is adequate for reliably serving EKPC's members. This is a change from previous years and will make EKPC less market dependent in the winter months. It will take several years for the winter reserve margins to build up to the 12% level, but the current projects under construction or approved for construction will move EKPC in the direction of reducing market dependence.

8.(2) The utility shall describe and discuss all options considered for inclusion in the plan including:
8.(2)(a) Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities;

Existing Generation

Maintenance management for existing generation is vital to keeping the generating facilities reliable, productive, and efficient. EKPC has developed a long-range plan of maintenance needs for each of the existing generating units, and that plan is discussed in the following subsection. EKPC has also considered retirement and repowering options. These topics are addressed later in this section.

Maintenance of Existing EKPC Generating Units

Current facilities at Dale Station were placed in operation in 1954-60, Cooper Station in 1965-69, and Spurlock Station in 1977-81, with the Gilbert Unit in 2005. J. K. Smith Station combustion turbines were placed in operation in 1999, 2001, and 2005. Each of EKPC's generating plants were state-of-the-art at the time of their construction and were designed to operate under conditions existing at that time. The continued operation of these plants requires both normal maintenance and a systematic review of current conditions needed for continued operation.

In 1987, EKPC began work on a formal maintenance program called MEAGER 2000 (Maintaining Electrical and Generating Equipment Reliability). MEAGER 2000 was intended to allow EKPC to reach the year 2000 by operating existing facilities in the most cost-effective manner. The objective of MEAGER 2000 was to develop a coordinated program of condition assessment and analysis of the fitness of EKPC's generating equipment and facilities. Revised now to MEAGER 2027, it mitigates escalating energy costs by identification of issues. Through proper planning and implementation, EKPC effectively manages operations, while meeting environmental compliance regulations, to provide reliable, economical electric service to its member systems and their retail consumers.

This plan for maintenance was developed following the review of various plant subsystems, assimilation of operational data, and review of past operating history. The plan explores the cost of options available for construction. These cost options look at the age of the facility, fuel cost, EKPC reserve margin, EKPC's overall financial condition, the ability to purchase and/or sell power during this period, and changes that may be required by environmental and regulatory agencies.

Methodology for MEAGER Program

The MEAGER Program was developed in 1987 and is updated on a regular basis by EKPC personnel. It was formally updated in 1993 by Stanley Consultants. The areas addressed in the development of the current plan include generating plant performance, operation, and maintenance. To prepare the update this year, the following tasks were completed:

1. Reviewed the original MEAGER 2000 Study.

2. Reviewed the most current annual update prepared by EKPC.

3. Meetings and phone calls were made during the year to discuss future needs for each individual plant.

4. The best-known options were recommended, priced in current-year dollars, and assigned an estimated completion date.

5. Prepared a final report to be submitted to EKPC's Board of Directors.

Each specific major project scheduled in the MEAGER Study is again reviewed and justified prior to requesting approval from the EKPC Board of Directors for implementation of the project. Prior to requesting this approval, an economic analysis is conducted taking into account costs and timing of the project, to ensure that completion of the proposed project is the most economical decision for EKPC. Justifications are developed based on the economic analysis and any other benefits such as safety or regulatory requirements. The economic analysis results and justification are then presented to the Board along with a request to approve the project. Subsequent to the approval, technical specifications are prepared and requests for bids are solicited. The bids are then evaluated, and a recommendation is made to the Board to proceed with the project. Assuming the project is approved, a letter is sent to RUS for their approval of the project, when required. After all approvals are received, work is completed under EKPC supervision.

2007 MEAGER Study

The MEAGER 2007 Program covers the time frame of 2007 through 2027. Tables 8.(2)(a)–1 through 8.(2)(a)–5 in the Supporting Documentation at the end of Section 8 contain lists of the major projects planned for each plant during this 20-year period and estimated costs in 2006 dollars.

Unit Repowering Options

As units age and become less reliable and economical, or it becomes apparent that a boiler will have to be replaced, repowering with different fuels and/or technologies could prove to be economical. Repowering units could also be a feasible alternative for compliance with emission restrictions. EKPC looked at its units to see if any appeared to be likely candidates for repowering.

Dale Station is the oldest of EKPC's generating facilities and would be the most likely candidate for repowering. There is no apparent need to replace the boiler at any of the Dale units. Repowering was originally considered for Units 3 and 4 as a compliance option in the "Clean Air Act Compliance Study," that was an attachment to the 1993 IRP.

At that time both units were evaluated with an atmospheric fluidized bed option and a combustion turbine/combined cycle option. Natural gas pipelines are located in the vicinity near Dale Station, making it a viable fuel alternative. Repowering these units with either option would provide relatively high reduction in SO_2 emissions when viewed on a percent removal basis. However, due to the small size of these units, the relative SO_2 removal cost is significantly higher for the repowering option than for fuel switching to Central Appalachia low sulfur coal. There is limited space at the Dale plant site and no adjacent property is available for reasonable expansion possibilities. Repowering the units would require significantly more space than is available at the site. For these reasons, repowering is not currently considered a feasible alternative. EKPC will continue to evaluate this issue.

Cooper Station is EKPC's next oldest power generating station, over 30 years old, with Unit 1 becoming available for commercial operation on February 9, 1965, and Unit 2 on October 28, 1969. The units have been reliable and very economical, and there is no apparent need for boiler replacements. There have been no operating problems to indicate that EKPC should consider retirement or repowering based solely on previous operations. Both Cooper units were affected by Phase I of the Clean Air Act Amendments of 1990 and have had to operate under a reduced emissions limitation along with Spurlock Unit 1. Spurlock Unit 2 and Dale Units 3 and 4 are Phase II units under the Clean Air Act. Repowering the Cooper units was considered as a compliance option. The units currently can emit approximately 3.3 pounds of SO_2 for each MMBtu of Central Appalachia medium-sulfur coal that is burned. Repowering could effectively reduce that emission rate to almost zero. There are currently no natural gas lines in the Cooper Station vicinity and a significant investment would have to be made to make combustion turbines or combined cycle units feasible alternatives. The cost was prohibitive for these options and they were discarded as repowering options. EKPC is currently evaluating whether or not atmosphere fluidized bed option could be feasible or economic for Cooper Station. The installation of an SCR unit and SO2 scrubber has been considered and is a feasible alternative.

Spurlock Units No. 1 and No. 2 are SCR equipped and will have scrubbers operational by 2009. Neither units are near retirement or have plans for repowering.

Smith Station currently has seven combustion turbines and space available for five additional combustion turbines, and they are likely to be installed in 2008/2009.

Existing Generation Summary

Based on various analyses, EKPC does not plan to retire or repower any of its seven existing coal-fired units during the 20-year planning horizon, through 2027, with the exception of the two Cooper Power Station units that are being evaluated for repowering with CFB units, or for an SCR with scrubber.

Transmission System

The historical purpose of the EKPC transmission system has been to reliably transmit electrical energy from EKPC's generating stations to EKPC's member systems. The transmission system is designed to deliver power from EKPC's generating stations to meet projected customer demands. EKPC often purchases power from external sources to supplement its own generating resources. The transmission system is also designed to facilitate a certain level of economic and/or emergency power purchases. Also, the transmission system is planned to provide any contracted long-term firm transmission services. Furthermore, the transmission system is designed to withstand simultaneous forced outages of a transmission facility and a single generating unit during peak-demand conditions.

Interconnections have been established with other utilities to increase the reliability and efficiency of the transmission system and to provide access to external generating resources. These interconnections usually provide the desired level of reliability while minimizing the amount of transmission line and/or substation construction required. EKPC has many interconnections with Kentucky Utilities, due to the close proximity of the two companies' facilities throughout most of Kentucky. EKPC routinely evaluates opportunities to establish interconnections with other utilities in the state to provide efficient utilization of the transmission network in the state.

EKPC performs annual assessments of its transmission system to identify transmission expansion and upgrade projects needed to maintain an adequate and reliable transmission system based on its design criteria and methodologies. When transmission system problems are identified, EKPC considers a wide range of potential solutions, including upgrades of existing facilities.

EKPC and Big Rivers Electric Corporation (BREC) intend to establish a free-flowing interconnection at the D.B. Wilson Power Plant in 2009. EKPC is constructing more than 90 miles of 161 kV transmission line from its Barren County Substation through the Bowling Green area to connect the Warren Rural Electric Cooperative (WRECC) to the EKPC system. The Aberdeen-Wilson 161 kV line is a critical segment of this Project to provide adequate system support and reliability. This interconnection provides system benefits to BREC as well. The Aberdeen-Wilson line provides another outlet from the D.B. Wilson Power Plant, which is needed for certain contingency situations. This interconnection will have approximately 550 MW of capacity. Once the interconnection is established, direct energy transactions between EKPC and BREC will be possible.

EKPC is planning to construct/upgrade more than 90 miles of 161 kV line to connect to the existing Warren RECC system. This 161 kV Project consists of the following segments:

- Barren County-Magna
- Magna-General Motors
- General Motors-Memphis Junction

- General Motors-East Bowling Green
- Memphis Junction-Aberdeen
- Aberdeen-Wilson

Warren RECC has existing 161 kV delivery points at Magna, General Motors, East Bowling Green, Memphis Junction, and Aberdeen. Therefore, the EKPC planned project constructs a 161 kV line from the closest EKPC 161 kV node (Barren County) to the Warren RECC existing 161 kV delivery points.

EKPC has two 345 kV projects planned that will provide critical improvements to both the local EKPC transmission system as well as the statewide grid. These projects are the J.K. Smith-North Clark 345 kV line and the J.K. Smith-West Garrard 345 kV line.

The J.K. Smith-North Clark 345 kV line will connect the existing J.K. Smith Generating Station to the Spurlock-Avon 345 kV line. This project will provide a more direct connection between EKPC's significant power plants in northern and central Kentucky. This will provide added reliability and stability for the generation and transmission facilities in the area. In addition, constrained facilities in the Lexington area will be mitigated.

The J.K. Smith-West Garrard 345 kV line will provide substantial outlet capability for planned generation additions at J.K. Smith. Furthermore, this project will connect the EKPC 345 kV system extending from Spurlock to the E.ON 345 kV system that crosses the state. This will provide a new 345 kV path from the northern Kentucky border into the central Kentucky area. This project will increase transfer capability across the state, which will mitigate the transmission constraints experienced by the utilities in Kentucky particularly during periods of high north-south transfers.

As described above, EKPC is planning to construct/upgrade more than 90 miles of 161 kV line to connect to the existing Warren RECC system. To provide system support and reliability, EKPC is also adding four free-flowing interconnections to utilities with existing transmission facilities in the area. One of these interconnections is a new 161 kV interconnection at BREC's Wilson Power Plant. The other three new interconnections will be with TVA at East Bowling Green, Memphis Junction, and Salmons. The East Bowling Green and Memphis Junction Substations are existing delivery points where TVA provides service to Warren RECC. The Salmons Substation will be a new 161-69 kV substation adjacent to an existing Warren RECC 69-13 kV substation. The Salmons interconnection is necessary to replace an existing 69 kV interconnection that Warren RECC has with the City of Franklin at its Franklin 161-69 kV Substation.

Distribution System

EKPC delivers wholesale power to its member systems through delivery point substations that are centrally located with respect to retail loads. The delivery point substations are owned and maintained by EKPC with the member systems owning and maintaining the connecting distribution feeders. Because of this ownership arrangement, it is necessary for EKPC and its member systems to jointly plan the respective distribution systems.

The member systems routinely perform planning studies to identify potential system problems at forecasted load levels. When multiple problems are identified in a given area on the distribution system, and/or when the load on the delivery point substation serving the area is approaching its maximum capacity, EKPC and the member system perform a joint planning study to determine the most cost-effective solution for the area using a one-ownership approach. In using the one-ownership approach, all costs for each alternate plan in the study are treated as an expense that the retail members ultimately incur, regardless if it is an EKPC expense or a member system expense.

The primary objectives of the joint planning study is to eliminate projected overloads of existing facilities, to increase service reliability and to add sufficient capacity to meet future load growth in the problem area. The member system provides cost estimates for distribution improvements and calculates system losses for each study alternative. EKPC provides cost estimates for transmission and substation facilities and performs an economic analysis for each study alternative.

A twenty-year present-worth economic analysis is prepared for each competing alternative in the study. The analysis includes all annual costs associated with required capital investments and system losses. The annual costs for a given capital investment consists of expenses related to operating and maintaining the facility, interest on borrowed money, taxes, insurance and depreciation. The total annual cost of system losses is determined by applying EKPC's avoided capacity rate and avoided energy rate to demand and energy losses, respectively. The economic analysis produces the total twenty-year cost of each plan in present-day dollars. An economic comparison of each plan identifies the most cost-effective solution to implement.

The joint distribution planning process has resulted in ten new delivery point substations and associated transmission tap lines each year, on average, since 1995. EKPC believes the construction of new delivery point substations will continue at this rate as long as its member systems continue to experience high growth rates.

8.(2)(b) Conservation and load management or other demand-side programs not already in place;

East Kentucky Power Cooperative (EKPC) evaluated 93 Demand-Side Management (DSM) measures for the 2006 Integrated Resource Plan (IRP). A two-step process was used in the evaluation: (1) Qualitative Screening, and (2) Quantitative Evaluation.

Thirty-four (34) measures passed the Qualitative Screen and were passed on to Quantitative Evaluation. In several cases, measures were combined so that a total of 27 DSM Programs were prepared for the Quantitative Evaluation.

The results for the cost-effectiveness tests were generally favorable for the DSM programs. Of the 27 DSM Programs that were evaluated, 24 produced a Total Resource Cost test benefit-cost ratio of greater than 1.0. Of the 24 cost-effective programs, 18 are considered "new" programs that would produce load impacts that are not reflected in the load forecast.

This 2006 IRP for EKPC includes 18 proposed New DSM programs (not already in place) for meeting future customer demand.

Demand-side management (DSM) resources consist of customer energy programs that seek to change the power consumption of customer facilities in a way that meets planning objectives. They include conservation, load management, and other demand-side programs.

EKPC's DSM analysis is conducted on an aggregate basis, with all member cooperatives combined, rather than on an individual cooperative basis.

For this 2006 IRP, EKPC developed a comprehensive list of 93 DSM measures to consider. This set of DSM measures covers all classes and major end-uses, and includes a robust set of available technologies and strategies for producing energy and capacity savings. This list was produced after careful review of several sources, including (1) PSC staff recommendations from the 2003 IRP; (2) feedback from Kentucky Department of Energy, the Attorney General's office, and other relevant state agencies; (3) the current programs and IRPs of other Kentucky utilities; and (4) best practice DSM programs offered by utilities around the country.

The following three Tables (one for each major customer class) present the list of 93 DSM measures that were considered as DSM resource options:

Table 8.(2)(b)-1
Complete List of DSM Measures

Residential

1	Button-Up
2	Tune-Up
3	Geothermal Touchstone Energy Home
4	Geothermal Heat Pump
5	Air Source Heat Pump Touchstone Energy Home
6	Air Source Heat Pump Retrofit
7	Air Source Heat Pump New construction
8	Water heater - new construction
9	Water heater – retrofit
10	Electric Thermal Storage – Furnace
11	Electric Thermal Storage – Propane
12	Touchstone Energy Manufactured Home Program
13	Compact Fluorescent Lighting
14	Direct Load Control - air conditioners
15	Direct Load Control - water heaters
16	Dual fuel heating
17	Cold climate heat pump
18	High efficiency furnace fan motors
19	Low income weatherization
20	Ceiling Fans
21	Programmable thermostats
22	Polarized Refrigerant oxidant agent
23	ENERGY STAR Refrigerator
24	ENERGY STAR Room Air Conditioner
25	ENERGY STAR Clothes Washers
26	ENERGY STAR Central Air Conditioner
27	ENERGY STAR Dishwashers
28	Refrigerator/Freezer Recycling
29	Efficient pool pump
30	Well water pump
31	High efficiency outdoor lighting
32	Direct load control - pool pump
33	Direct load control - smart thermostat
34	Multi-family program
35	Mobile home program
36	Time of use rates
37	Inclining block rates
38	Passive Solar (new construction)
39	Solar water heater
40	Photovoltaics
41	Wind turbine

Table 8.(2)(b)-2

Commercial

1	Commercial Lighting
2	Demand Response
3	Commercial HVAC
4	Geothermal heat pump
5	Cool roof program
6	High performance glazings
7	Heat pump & A.C. Tune-up
8	Duct sealing
9	Polarized Refrigerant Oxidant Agent
10	Efficient refrigeration equipment
11	Efficient cooking equipment
12	Efficient clothes washers
13	ENERGY STAR Vending machines
14	LED exit signs
15	Energy Management Systems
16	DLC of irrigation pumps
17	DLC of central air conditioners
18	Thermal energy storage
19	Commercial New Construction
20	Energy efficient schools
21	Retro-commissioning
22	Farms program: fans, pumps, irrigation
23	Time of use rates
24	Combined heat & power
25	Stand-by generation program
26	Daylighting
27	Solar hot water
28	Photovoltaics
29	Wind turbine

Table 8.(2)(b)-3
Industrial/Other

1	Demand Response
2	Motors
3	Variable speed drives
4	Compressed air
5	Industrial process
6	Process cooling
7	Refrigerated Warehouse
8	High efficiency transformers
9	Automotive and transportation sector equipment
10	Livestock, equine, poultry and meat processing sector
11	Chemicals sector
12	Machinery/machine tools sector
13	Aluminum sector
14	Plastics sector
15	Computer and electronics sector
16	Interruptible Rates
17	Combined heat and power
18	Other onsite generation (conventional)
19	Photovoltaics
20	Wind turbine
21	LED Traffic signals
22	Water/Wastewater Treatment facilities
23	Conservation Voltage Reduction

Additional detail on the evaluation of DSM resources for inclusion in this 2006 Integrated Resource Plan (IRP) is contained in the report titled *Demand-Side Management Analysis*, which can be found in the *Technical Appendix*.

8.(2)(c) Expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units;

EKPC issued RFP 2004-01 in April 2004 to evaluate resource options to meet capacity needs through approximately the 2010 timeframe. The RFP included the capacity needs of Warren RECC, a distribution cooperative expected to join the EKPC system on April 1, 2008. As a result of RFP 2004-01, EKPC filed for certificates of public convenience and necessity and site compatibility for a new 278 MW circulating fluidized bed coal-fired unit at Spurlock Station (Spurlock 4), and a new 278 MW circulating fluidized bed coal-fired unit at Smith Station (Smith 1) and five of the new GE LMS100 combustion turbines, also at Smith Station (Smith CTs 8-12). EKPC filed for the certificates for Spurlock 4 on October 28, 2004 (PSC Case No. 2004-00423), and for the certificates for the Smith capacity on January 31, 2005 (PSC Case No. 2005-00053). The PSC approved

Case No. 2004-00423 on September 13, 2005, and Case No. 2005-00053 on August 29, 2006. Details of the evaluation process and specific RFP results can be found in the various filings associated with these two cases.

Following is a discussion and listing of resource alternatives considered in this integrated resource plan. The following resources were included in the optimization model for consideration:

Table 8.(2)(c)

Resource	Capacity Type	Capacity (MW)	Primary Fuel	Projected Capital Cost (2007$)	
				$/kW	$M
Circulating Fluidized Bed (Smith 2)	Baseload	278	Coal	[redacted]	[redacted]
Circulating Fluidized Bed (New Site)	Baseload	278	Coal	[redacted]	[redacted]
Subcritical Pulverized Coal	Baseload	325	Coal	[redacted]	[redacted]
Unit Power Purchase	Baseload	100	Coal	Not Applicable	Not Applicable
LMS100 CT	Peaking	97	Natural Gas	[redacted]	[redacted]
LMS100 CT-with Steam Injection	Peaking/ Intermediate	109	Natural Gas	[redacted]	[redacted]

Other power supply resources that were considered but not explicitly modeled were supercritical pulverized coal units, coal-gasification units, hydropower, windpower, and landfill gas to energy projects. EKPC is currently utilizing the circulating fluidized bed technology to take advantage of lower quality, lower cost coals. In the future EKPC will do a more detailed evaluation of supercritical coal units to determine their suitability for meeting EKPC's capacity needs.

Integrated Gasification Combined Cycle (IGCC) technology has received a lot of attention in recent years. All indications are that this technology will work for electric generation. The interest in this technology has grown with the announcements by AEP and Duke Energy to build GE/Bechtel type IGCC plants. However, it is expected that both of those companies will utilize significant federal and state incentives to offset the higher financial cost and risk of IGCC. Several groups have developed partnerships (suppliers and utilities) to improve the design of IGCC plants. Designs have improved and costs have come down for IGCC equipment and processes. However, the rise in labor and steel costs has more than offset design cost savings.

EKPC has evaluated several Ohio River hydro projects in the past and sees value in run of river projects. Those projects were evaluated in RFP No. 2004-01 but have not been re-evaluated recently. EKPC currently purchases the output of the Greenup Hydro project from Duke Energy.

In 2002 EKPC commissioned a study to determine whether the mountains in southeastern Kentucky offered a viable source of wind power that could become a cost effective alternative to be included in EKPC's renewable portfolio. The initial Site Screening and Selection Study was done by AWS Scientific (AWS) of Albany, New York, recognized within the renewable power industry as one of the leading experts around the world in wind assessment studies. AWS used existing topographic data and airport wind collection information to identify fifteen sites in Kentucky where wind speed and availability could potentially support economical wind turbine activity and used certain evaluation criteria such as transmission proximity, land use conflicts, visual impact, and site accessibility to evaluate those sites. A total of ten sites were visited in February 2002 to assess their viability. Based on the rating scale already developed, these sites were ranked for their development potential. The USDOE and the Kentucky Division of Energy (KDOE) provided financial assistance to conduct the original study. EKPC selected two initial test sites and in December 2002, erected 50-meter test towers with anemometers on these sites. USDOE provided additional financial assistance to help pay for the subsequent data collection. Readings were taken from the sites for up to twelve months to see if the sites were feasible for wind energy development. Subsequently, the two sites were re-deployed and a third site was added. At this time, data continues to be collected from these three sites. The study indicated that there is potential for wind energy development. However, the area studied is now part of an environmentally sensitive area and it is unclear if windpower development can move forward in this area.

EKPC currently has an ongoing program to develop landfill gas to energy projects. The capacity of the four existing plants is 12MW, and an additional 3.2MW is currently under construction and expected to be operational by February 2007. EKPC's long range plan is to develop as much as 50MW of this type of renewable resource.

EKPC is required by the Rural Utilities Service to undergo an RFP process to evaluate capacity resources to meet future needs. EKPC has used this process successfully for a number of years and plans to continue to use the RFP process. The RFP allows both utility and non-utility generators or developers to propose capacity resources to EKPC of a variety of technologies and quantities of capacity. EKPC will evaluate those proposals as set forth in the RFP. The evaluation is based on economics, reliability, maturity of technology, and risk associated with the proposal.

8.(2)(d) Assessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resources, and other nonutility sources.

EKPC will continue to consider non-utility generation on a case by case basis or as part of an RFP process as discussed above in Section 8.(2)(c).

8.(3) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs.

EKPC is not part of a multi-state system nor does it purchase more than fifty (50) percent of its energy needs from another company.

8.(3)(a) A map of existing and planned generating facilities, transmission facilities with a voltage rating of sixty-nine (69) kilovolts or greater, indicating their type and capacity, and locations and capacities of all interconnections with other utilities. The utility shall discuss any known, significant conditions which restrict transfer capabilities with other utilities.

See attached maps in the back of this IRP.

8.(3)(b) A list of all existing and planned electric generating facilities which the utility plans to have in service in the base year or during any of the fifteen (15) years of the forecast period, including for each facility:

1. **Plant name;**
2. **Unit number(s);**
3. **Existing or proposed location;**
4. **Status (existing, planned, under construction, etc.);**
5. **Actual or projected commercial operation date;**
6. **Type of facility;**
7. **Net dependable capability, summer and winter;**
8. **Entitlement if jointly owned or unit purchase;**
9. **Primary and secondary fuel types, by unit;**
10. **Fuel storage capacity;**
11. **Scheduled upgrades, deratings, and retirement dates;**

See Table 8.(3)(b)1.-11. at end of Section 8 for information regarding Section 8.(3)(b)1-11.

12. Actual and projected cost and operating information for the base year (for existing units) or first full year of operations (for new units) and the basis for projecting the information to each of the fifteen (15) forecast years (for example, cost escalation rates). All cost data shall be expressed in nominal and real base year dollars.

a. Capacity and availability factors;
b. Anticipated annual average heat rate;
c. Costs of fuel(s) per millions of British thermal units (MMBtu);
d. Estimate of capital costs for planned units (total and per kilowatt of rated capacity);

See table in Section 8.(2)(c).

e. Variable and fixed operating and maintenance costs;
f. Capital and operating and maintenance cost escalation factors;
g. Projected average variable and total electricity production costs (in cents per kilowatt-hour).

See Table 8.(3)(b)12. at end of Section 8 for information regarding Section 8.(3)(b)12 a,b,c,e,f,g.

8.(3)(c) Description of purchases, sales, or exchanges of electricity during the base year or which the utility expects to enter during any of the fifteen (15) forecast years of the plan.

See Table 8.(3)(c) at end of Section 8.

8.(3)(d) Description of existing and projected amounts of electric energy and **generating capacity from cogeneration, self-generation, technologies relying on renewable resources, and other nonutility sources available for purchase by the utility during the base year or during any of the fifteen (15) forecast years of the plan.**

See Table 8.(3)(d) at end of Section 8.

8.(3)(e) For each existing and new conservation and load management or other demand-side programs included in the plan:

This 2006 IRP includes nine Existing DSM programs and eighteen New DSM programs.

DSM program design and implementation are complex and dynamic undertakings. Furthermore, EKPC is a wholesale company and does not serve retail customers directly. DSM programs that are ultimately launched will first be subjected to a much more rigorous program design effort. In certain cases, a demonstration or pilot project may precede full-scale implementation to test the validity of the program concept. This could mean that certain program concepts are modified, and some may not ultimately be implemented, and some will be accelerated.

8.(3)(e)(1). Targeted classes and end-uses;

The following tables provide the targeted classes and end-uses for the Existing and New DSM programs included in the plan. More detailed program descriptions can be found in Exhibits DSM-8 and DSM-9 in report titled *Demand-Side Management Analysis*, which can be found in the *Technical Appendix.*

Table 8.(3)(e)(1)-1
Existing Programs

Program Name	Class	End-uses
Electric Thermal Storage Propane	Residential	Space Heating
Electric Thermal Storage Furnace	Residential	Space Heating
Electric Water Heater New Construction	Residential	Hot Water Heating
Electric Water Heater Retrofit	Residential	Hot Water Heating
Geothermal Heating & Cooling	Residential	Space Heating, Space Cooling, Hot Water Heating
Air Source Heat Pump New Construction	Residential	Space Heating, Space Cooling
Air Source Heat Pump Retrofit	Residential	Space Heating, Space Cooling
Tune-Up HVAC Maintenance	Residential	Space Heating, Space Cooling
Button-Up Weatherization	Residential	Space Heating, Space Cooling

Table 8.(3)(e)(1)-2
New Programs

Program Name	Class	End-uses
Compact Fluorescent Lighting	Residential	Lighting
Touchstone Energy Geothermal Heat Pump Home	Residential	Space Heating, Space Cooling, Hot Water Heating
Touchstone Energy Air Source Heat Pump Home	Residential	Space Heating, Space Cooling, Hot Water Heating
Touchstone Energy Manufactured Home	Residential	Space Heating, Space Cooling
Direct Load Control for Air Conditioners and Water Heaters	Residential	Space Cooling, Hot Water Heating
ENERGY STAR Clothes Washer	Residential	Clothes Washing, Clothes Drying, Hot Water Heating
ENERGY STAR Room Air Conditioner	Residential	Space Cooling
ENERGY STAR Refrigerator	Residential	Refrigeration
Programmable Thermostat with Electric Furnace Retrofit	Residential	Space Heating, Space Cooling
Dual Fuel Air Source Heat Pump with Propane Retrofit	Residential	Space Heating
Commercial Lighting	Commercial	Lighting
C&I Demand Response	Commercial, Industrial	Various
Commercial Efficient HVAC	Commercial	Space Cooling, Space Heating
Commercial Building Performance	Commercial	Space Cooling, Space Heating, Ventilation
Commercial New Construction	Commercial	Lighting, Space Cooling, Space Heating
Commercial Efficient Refrigeration	Commercial	Refrigeration
Industrial Premium Motors	Industrial	Drive Power
Industrial Variable Speed Drives	Industrial	Drive Power

8.(3)(e)(2). Expected duration of the program;

The following tables provide the expected duration of the program both in terms of serving new participants and the lifetime of the measure savings:

Table 8.(3)(e)(2)-1
Existing Programs – Duration

Program Name	New Participants	Savings Lifetime
Electric Thermal Storage Propane	10 years	20 years
Electric Thermal Storage Furnace	10 years	20 years
Electric Water Heater New Construction	10 years	12 years
Electric Water Heater Retrofit	10 years	12 years
Geothermal Heating & Cooling	10 years	20 years
Air Source Heat Pump New Construction	10 years	20 years
Air Source Heat Pump Retrofit	10 years	20 years
Tune-Up HVAC Maintenance	10 years	12 years
Button-Up Weatherization	10 years	15 years

Table 8.(3)(e)(2)-2
New Programs – Duration

Program Name	New Participants	Savings Lifetime
Compact Fluorescent Lighting	10 years	7 years
Touchstone Energy Geothermal Heat Pump Home	10 years	20 years
Touchstone Energy Air Source Heat Pump Home	10 years	20 years
Touchstone Energy Manufactured Home	10 years	20 years
Direct Load Control for Air Conditioners and Water Heaters	10 years	20 years
ENERGY STAR Clothes Washer	10 years	12 years
ENERGY STAR Room Air Conditioner	10 years	15 years
ENERGY STAR Refrigerator	10 years	15 years
Programmable Thermostat with Electric Furnace Retrofit	10 years	11 years
Dual Fuel Air Source Heat Pump with Propane Retrofit	10 years	20 years
Commercial Lighting	10 years	10 years
C&I Demand Response	3 years	20 years
Commercial Efficient HVAC	10 years	15 years
Commercial Building Performance	10 years	7 years
Commercial New Construction	10 years	20 years
Commercial Efficient Refrigeration	10 years	10 years
Industrial Premium Motors	10 years	15 years
Industrial Variable Speed Drives	10 years	15 years

8.(3)(e)(3). Projected energy changes by season, and summer and winter peak demand changes;

Load changes for the Existing programs have been accounted for in the Load Forecast.

The following tables provide the projected energy, summer and winter peak demand changes for each Existing and New DSM program included in the plan:

Table 8.(3)(e)(3)

Load Impacts of DSM Programs

Existing:

Electric Thermal Storage Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
1995	1,885	12,131	-6.9	0.0
1996	2,950	18,981	-10.8	0.0
1997	4,032	25,933	-14.7	0.0
1998	4,602	29,595	-16.8	0.0
1999	5,038	32,396	-18.4	0.0
2000	5,579	35,879	-20.3	0.0
2001	5,908	38,000	-21.5	0.0
2002	6,142	39,503	-22.4	0.0
2003	6,347	40,827	-23.1	0.0
2004	6,479	41,675	-23.6	0.0
2005	6,723	43,242	-24.5	0.0
2006	6,973	44,906	-25.4	0.0
2007	6,973	44,906	-25.4	0.0
2008	6,973	44,906	-25.4	0.0
2009	6,973	44,906	-25.4	0.0
2010	6,973	44,906	-25.4	0.0
2011	6,973	44,906	-25.4	0.0
2012	6,973	44,906	-25.4	0.0
2013	6,973	44,906	-25.4	0.0
2014	6,973	44,906	-25.4	0.0
2015	6,973	44,906	-25.4	0.0
2016	6,973	44,906	-25.4	0.0
2017	6,973	44,906	-25.4	0.0
2018	6,973	44,906	-25.4	0.0
2019	6,973	44,906	-25.4	0.0
2020	6,973	44,906	-25.4	0.0
2021	6,973	44,906	-25.4	0.0

Table 8.(3)(e)(3) Continued

Electric Water Heater Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
1995	1,003	101	0.0	0.0
1996	1,622	166	0.0	0.0
1997	2,596	264	0.1	0.0
1998	3,479	353	0.1	0.0
1999	4,428	452	0.1	0.0
2000	5,216	534	0.1	0.0
2001	5,972	614	0.1	0.1
2002	6,855	703	0.2	0.1
2003	7,731	796	0.2	0.1
2004	8,417	861	0.2	0.1
2005	9,095	927	0.2	0.1
2006	9,785	854	0.2	0.1
2007	9,785	854	0.2	0.1
2008	9,785	854	0.2	0.1
2009	9,785	854	0.2	0.1
2010	9,785	854	0.2	0.1
2011	9,785	854	0.2	0.1
2012	9,785	854	0.2	0.1
2013	9,785	854	0.2	0.1
2014	9,785	854	0.2	0.1
2015	9,785	854	0.2	0.1
2016	9,785	854	0.2	0.1
2017	9,785	854	0.2	0.1
2018	9,785	854	0.2	0.1
2019	9,785	854	0.2	0.1
2020	9,785	854	0.2	0.1
2021	9,785	854	0.2	0.1

Table 8.(3)(e)(3) Continued

Geothermal Heating & Cooling Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
1995	1,544	-4,480	-7.4	-1.6
1996	1,941	-5,632	-9.3	-2.0
1997	2,416	-7,010	-11.5	-2.4
1998	2,824	-8,194	-13.5	-2.9
1999	3,221	-9,346	-15.4	-3.3
2000	3,582	-10,394	-17.1	-3.6
2001	3,954	-11,473	-18.9	-4.0
2002	4,261	-12,364	-20.4	-4.3
2003	4,451	-12,915	-21.3	-4.5
2004	4,608	-13,371	-22.0	-4.7
2005	4,752	-13,789	-22.7	-4.8
2006	4,902	-14,224	-23.4	-5.0
2007	4,902	-14,224	-23.4	-5.0
2008	4,902	-14,224	-23.4	-5.0
2009	4,902	-14,224	-23.4	-5.0
2010	4,902	-14,224	-23.4	-5.0
2011	4,902	-14,224	-23.4	-5.0
2012	4,902	-14,224	-23.4	-5.0
2013	4,902	-14,224	-23.4	-5.0
2014	4,902	-14,224	-23.4	-5.0
2015	4,902	-14,224	-23.4	-5.0
2016	4,902	-14,224	-23.4	-5.0
2017	4,902	-14,224	-23.4	-5.0
2018	4,902	-14,224	-23.4	-5.0
2019	4,902	-14,224	-23.4	-5.0
2020	4,902	-14,224	-23.4	-5.0
2021	4,902	-14,224	-23.4	-5.0

Table 8.(3)(e)(3) Continued

Air Source Heat Pump Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
1995	161	129	0.4	-0.1
1996	204	163	0.5	-0.1
1997	260	208	0.6	-0.1
1998	344	275	0.8	-0.1
1999	688	549	1.6	-0.2
2000	1,077	858	2.6	-0.3
2001	1,547	1,232	3.7	-0.5
2002	2,117	1,684	5.0	-0.7
2003	2,763	2,198	6.6	-0.9
2004	3,579	2,846	8.5	-1.1
2005	4,094	3,256	9.7	-1.3
2006	4,754	3,783	11.3	-1.5
2007	4,754	3,783	11.3	-1.5
2008	4,754	3,783	11.3	-1.5
2009	4,754	3,783	11.3	-1.5
2010	4,754	3,783	11.3	-1.5
2011	4,754	3,783	11.3	-1.5
2012	4,754	3,783	11.3	-1.5
2013	4,754	3,783	11.3	-1.5
2014	4,754	3,783	11.3	-1.5
2015	4,754	3,783	11.3	-1.5
2016	4,754	3,783	11.3	-1.5
2017	4,754	3,783	11.3	-1.5
2018	4,754	3,783	11.3	-1.5
2019	4,754	3,783	11.3	-1.5
2020	4,754	3,783	11.3	-1.5
2021	4,754	3,783	11.3	-1.5

Table 8.(3)(e)(3) Continued

Tune-Up HVAC Maintenance Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
1995	494	-729	-0.6	-0.2
1996	1,428	-2,108	-1.6	-0.6
1997	2,068	-3,052	-2.4	-0.9
1998	2,341	-3,455	-2.7	-1.0
1999	2,455	-3,623	-2.8	-1.1
2000	2,584	-3,814	-2.9	-1.1
2001	2,686	-3,964	-3.1	-1.2
2002	2,860	-4,221	-3.3	-1.3
2003	3,198	-4,720	-3.6	-1.4
2004	3,706	-5,470	-4.2	-1.6
2005	4,037	-5,958	-4.6	-1.8
2006	4,387	-6,467	-5.0	-1.9
2007	4,387	-6,467	-5.0	-1.9
2008	4,387	-6,467	-5.0	-1.9
2009	4,387	-6,467	-5.0	-1.9
2010	4,387	-6,467	-5.0	-1.9
2011	4,387	-6,467	-5.0	-1.9
2012	4,387	-6,467	-5.0	-1.9
2013	4,387	-6,467	-5.0	-1.9
2014	4,387	-6,467	-5.0	-1.9
2015	4,387	-6,467	-5.0	-1.9
2016	4,387	-6,467	-5.0	-1.9
2017	4,387	-6,467	-5.0	-1.9
2018	4,387	-6,467	-5.0	-1.9
2019	4,387	-6,467	-5.0	-1.9
2020	4,387	-6,467	-5.0	-1.9
2021	4,387	-6,467	-5.0	-1.9

Table 8.(3)(e)(3) Continued

Button-Up Weatherization Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
1995	1,559	-4,084	-3.2	-1.2
1996	2,640	-6,916	-5.3	-2.1
1997	3,515	-9,208	-7.1	-2.8
1998	4,210	-11,029	-8.5	-3.3
1999	4,691	-12,289	-9.5	-3.7
2000	5,218	-13,670	-10.6	-4.1
2001	5,696	-14,922	-11.5	-4.5
2002	6,174	-16,174	-12.5	-4.9
2003	6,670	-17,474	-13.5	-5.2
2004	7,167	-18,776	-14.5	-5.6
2005	7,585	-19,871	-15.4	-6.0
2006	8,085	-21,181	-16.4	-6.4
2007	8,085	-21,181	-16.4	-6.4
2008	8,085	-21,181	-16.4	-6.4
2009	8,085	-21,181	-16.4	-6.4
2010	8,085	-21,181	-16.4	-6.4
2011	8,085	-21,181	-16.4	-6.4
2012	8,085	-21,181	-16.4	-6.4
2013	8,085	-21,181	-16.4	-6.4
2014	8,085	-21,181	-16.4	-6.4
2015	8,085	-21,181	-16.4	-6.4
2016	8,085	-21,181	-16.4	-6.4
2017	8,085	-21,181	-16.4	-6.4
2018	8,085	-21,181	-16.4	-6.4
2019	8,085	-21,181	-16.4	-6.4
2020	8,085	-21,181	-16.4	-6.4
2021	8,085	-21,181	-16.4	-6.4

Table 8.(3)(e)(3) Continued

New:

Compact Fluorescent Lighting

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2006	37,700	-3,698	-0.6	-0.4
2007	75,400	-7,395	-1.2	-0.8
2008	113,100	-11,093	-1.9	-1.2
2009	150,800	-14,790	-2.3	-1.7
2010	188,500	-18,488	-2.9	-2.1
2011	226,200	-22,186	-3.5	-2.5
2012	263,900	-25,883	-4.1	-2.9
2013	301,600	-25,883	-4.1	-2.9
2014	339,300	-25,883	-4.1	-2.9
2015	377,000	-25,883	-4.1	-2.9
2016	377,000	-22,186	-3.5	-2.5
2017	377,000	-18,488	-2.9	-2.1
2018	377,000	-14,790	-2.3	-1.7
2019	377,000	-11,093	-1.7	-1.2
2020	377,000	-7,395	-1.2	-0.8
2021	377,000	-3,698	-0.6	-0.4

Table 8.(3)(e)(3) Continued

Touchstone Energy Geothermal Home

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2006	40	-244	-0.3	-0.1
2007	80	-489	-0.7	-0.1
2008	120	-733	-0.7	-0.2
2009	160	-977	-1.3	-0.2
2010	200	-1,222	-1.7	-0.3
2011	240	-1,466	-2.0	-0.3
2012	280	-1,710	-2.4	-0.4
2013	320	-1,955	-2.7	-0.4
2014	360	-2,199	-3.0	-0.5
2015	400	-2,443	-3.4	-0.5
2016	400	-2,443	-3.4	-0.5
2017	400	-2,443	-3.4	-0.5
2018	400	-2,443	-3.4	-0.5
2019	400	-2,443	-3.4	-0.5
2020	400	-2,443	-3.4	-0.5
2021	400	-2,443	-3.4	-0.5

Table 8.(3)(e)(3) Continued

Touchstone Energy Heat Pump Home

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2006	100	-238	-0.2	-0.1
2007	200	-476	-0.3	-0.1
2008	300	-713	-0.5	-0.2
2009	400	-951	-0.6	-0.3
2010	500	-1,189	-0.7	-0.3
2011	600	-1,427	-0.8	-0.4
2012	700	-1,665	-1.0	-0.5
2013	800	-1,903	-1.1	-0.5
2014	900	-2,140	-1.2	-0.6
2015	1,000	-2,378	-1.4	-0.6
2016	1,000	-2,378	-1.4	-0.6
2017	1,000	-2,378	-1.4	-0.6
2018	1,000	-2,378	-1.4	-0.6
2019	1,000	-2,378	-1.4	-0.6
2020	1,000	-2,378	-1.4	-0.6
2021	1,000	-2,378	-1.4	-0.6

Table 8.(3)(e)(3) Continued

Touchstone Energy Manufactured Home

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2006	10	-56	0.0	0.0
2007	20	-112	-0.1	0.0
2008	30	-169	-0.1	0.0
2009	40	-225	-0.1	0.0
2010	50	-281	-0.2	-0.1
2011	60	-337	-0.2	-0.1
2012	70	-393	-0.2	-0.1
2013	80	-450	-0.3	-0.1
2014	90	-506	-0.3	-0.1
2015	100	-562	-0.3	-0.1
2016	100	-562	-0.3	-0.1
2017	100	-562	-0.3	-0.1
2018	100	-562	-0.3	-0.1
2019	100	-562	-0.3	-0.1
2020	100	-562	-0.3	-0.1
2021	100	-562	-0.3	-0.1

Table 8.(3)(e)(3) Continued

Direct Load Control for Air Conditioners and Water Heaters

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2006	5,000	-76	-5.6	-7.6
2007	10,000	-153	-11.3	-15.3
2008	15,000	-229	-16.9	-22.9
2009	20,000	-305	-22.5	-30.5
2010	25,000	-381	-28.1	-38.2
2011	30,000	-458	-33.8	-45.8
2012	35,000	-534	-39.4	-53.4
2013	40,000	-610	-45.0	-61.0
2014	45,000	-686	-50.7	-68.7
2015	50,000	-763	-56.3	-76.3
2016	50,000	-763	-56.3	-76.3
2017	50,000	-763	-56.3	-76.3
2018	50,000	-763	-56.3	-76.3
2019	50,000	-763	-56.3	-76.3
2020	50,000	-763	-56.3	-76.3
2021	50,000	-763	-56.3	-76.3

Table 8.(3)(e)(3) Continued

ENERGY STAR Clothes Washer

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2006	500	-191	0.0	0.0
2007	1,000	-381	-0.1	0.0
2008	1,500	-572	-0.1	-0.1
2009	2,000	-763	-0.2	-0.1
2010	2,500	-954	-0.2	-0.1
2011	3,000	-1,144	-0.2	-0.1
2012	3,500	-1,335	-0.3	-0.1
2013	4,000	-1,526	-0.3	-0.2
2014	4,500	-1,716	-0.4	-0.2
2015	5,000	-1,907	-0.4	-0.2
2016	5,000	-1,907	-0.4	-0.2
2017	5,000	-1,907	-0.4	-0.2
2018	5,000	-1,716	-0.4	-0.2
2019	5,000	-1,526	-0.3	-0.2
2020	5,000	-1,335	-0.3	-0.1
2021	5,000	-1,144	-0.2	-0.1

Table 8.(3)(e)(3) Continued

ENERGY STAR Room Air Conditioner

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2006	600	-65	0.0	-0.1
2007	1,200	-131	0.0	-0.2
2008	1,800	-196	0.0	-0.3
2009	2,400	-262	0.0	-0.3
2010	3,000	-327	0.0	-0.4
2011	3,600	-392	0.0	-0.5
2012	4,200	-458	0.0	-0.6
2013	4,800	-523	0.0	-0.7
2014	5,400	-588	0.0	-0.8
2015	6,000	-654	0.0	-0.9
2016	6,000	-654	0.0	-0.9
2017	6,000	-654	0.0	-0.9
2018	6,000	-654	0.0	-0.9
2019	6,000	-654	0.0	-0.9
2020	6,000	-654	0.0	-0.9
2021	6,000	-588	0.0	-0.8

Table 8.(3)(e)(3) Continued

ENERGY STAR Refrigerator

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2006	900	-88	0.0	0.0
2007	1,800	-177	0.0	0.0
2008	2,700	-265	0.0	0.0
2009	3,600	-353	0.0	-0.1
2010	4,500	-441	0.0	-0.1
2011	5,400	-530	-0.1	-0.1
2012	6,300	-618	-0.1	-0.1
2013	7,200	-706	-0.1	-0.1
2014	8,100	-794	-0.1	-0.1
2015	9,000	-883	-0.1	-0.1
2016	9,000	-883	-0.1	-0.1
2017	9,000	-883	-0.1	-0.1
2018	9,000	-883	-0.1	-0.1
2019	9,000	-883	-0.1	-0.1
2020	9,000	-883	-0.1	-0.1
2021	9,000	-794	-0.1	-0.1

Table 8.(3)(e)(3) Continued

Programmable Thermostat with Electric Furnace Retrofit

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2006	650	-530	0.0	-0.1
2007	1,300	-1,061	0.0	-0.1
2008	1,950	-1,591	0.0	-0.2
2009	2,600	-2,121	0.0	-0.3
2010	3,250	-2,652	0.0	-0.4
2011	3,900	-3,182	0.0	-0.4
2012	4,550	-3,713	0.0	-0.5
2013	5,200	-4,243	0.0	-0.6
2014	5,850	-4,773	0.0	-0.7
2015	6,500	-5,304	0.0	-0.7
2016	6,500	-5,304	0.0	-0.7
2017	6,500	-4,773	0.0	-0.7
2018	6,500	-4,243	0.0	-0.6
2019	6,500	-3,713	0.0	-0.5
2020	6,500	-3,182	0.0	-0.4
2021	6,500	-2,652	0.0	-0.4

Table 8.(3)(e)(3) Continued

Dual Fuel Air Source Heat Pump Retrofit

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2006	100	436	0.0	0.0
2007	200	872	0.0	0.0
2008	300	1,309	0.0	0.0
2009	400	1,745	0.0	0.0
2010	500	2,181	0.0	0.0
2011	600	2,617	0.0	0.0
2012	700	3,054	0.0	0.0
2013	800	3,490	0.0	0.0
2014	900	3,926	0.0	0.0
2015	1,000	4,362	0.0	0.0
2016	1,000	4,362	0.0	0.0
2017	1,000	4,362	0.0	0.0
2018	1,000	4,362	0.0	0.0
2019	1,000	4,362	0.0	0.0
2020	1,000	4,362	0.0	0.0
2021	1,000	4,362	0.0	0.0

Table 8.(3)(e)(3) Continued

Commercial Lighting

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2006	570	-2,788	-0.3	-0.4
2007	1,140	-5,577	-0.6	-0.8
2008	1,710	-8,365	-0.9	-1.3
2009	2,280	-11,153	-1.2	-1.7
2010	2,850	-13,941	-1.5	-2.1
2011	3,420	-16,730	-1.8	-2.5
2012	3,990	-19,518	-2.1	-2.9
2013	4,560	-22,306	-2.4	-3.4
2014	5,130	-25,095	-2.7	-3.8
2015	5,700	-27,883	-3.0	-4.2
2016	5,700	-25,095	-2.7	-3.8
2017	5,700	-22,306	-2.4	-3.4
2018	5,700	-19,518	-2.1	-2.9
2019	5,700	-16,730	-1.8	-2.5
2020	5,700	-13,941	-1.5	-2.1
2021	5,700	-11,153	-1.2	-1.7

Table 8.(3)(e)(3) Continued

Commercial & Industrial Demand Response

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2006	150	-1,716	-5.7	-5.7
2007	350	-4,005	-13.4	-13.4
2008	500	-5,721	-19.1	-19.1
2009	500	-5,721	-19.1	-19.1
2010	500	-5,721	-19.1	-19.1
2011	500	-5,721	-19.1	-19.1
2012	500	-5,721	-19.1	-19.1
2013	500	-5,721	-19.1	-19.1
2014	500	-5,721	-19.1	-19.1
2015	500	-5,721	-19.1	-19.1
2016	500	-5,721	-19.1	-19.1
2017	500	-5,721	-19.1	-19.1
2018	500	-5,721	-19.1	-19.1
2019	500	-5,721	-19.1	-19.1
2020	500	-5,721	-19.1	-19.1
2021	500	-5,721	-19.1	-19.1

Table 8.(3)(e)(3) Continued

Commercial Efficient HVAC

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2006	150	-228	0.0	-0.1
2007	300	-455	0.0	-0.1
2008	450	-683	-0.1	-0.2
2009	600	-911	-0.1	-0.3
2010	750	-1,139	-0.1	-0.4
2011	900	-1,366	-0.1	-0.4
2012	1,050	-1,594	-0.2	-0.5
2013	1,200	-1,822	-0.2	-0.6
2014	1,350	-2,049	-0.2	-0.7
2015	1,500	-2,277	-0.2	-0.7
2016	1,500	-2,277	-0.2	-0.7
2017	1,500	-2,277	-0.2	-0.7
2018	1,500	-2,277	-0.2	-0.7
2019	1,500	-2,277	-0.2	-0.7
2020	1,500	-2,277	-0.2	-0.7
2021	1,500	-2,049	-0.2	-0.7

Table 8.(3)(e)(3) Continued

Commercial Building Performance

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2006	200	-670	-0.1	-0.1
2007	400	-1,340	-0.3	-0.3
2008	600	-2,011	-0.4	-0.4
2009	800	-2,681	-0.5	-0.6
2010	1,000	-3,351	-0.7	-0.7
2011	1,200	-4,021	-0.8	-0.8
2012	1,400	-4,691	-0.9	-1.0
2013	1,600	-4,691	-0.9	-1.0
2014	1,800	-4,691	-0.9	-1.0
2015	2,000	-4,691	-0.9	-1.0
2016	2,000	-4,021	-0.8	-0.8
2017	2,000	-3,351	-0.7	-0.7
2018	2,000	-2,681	-0.5	-0.6
2019	2,000	-2,011	-0.4	-0.4
2020	2,000	-1,340	-0.3	-0.3
2021	2,000	-670	-0.1	-0.1

Table 8.(3)(e)(3) Continued

Commercial New Construction

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2006	80	-872	-0.1	-0.2
2007	160	-1,744	-0.2	-0.4
2008	240	-2,615	-0.2	-0.6
2009	320	-3,487	-0.3	-0.8
2010	400	-4,359	-0.4	-1.0
2011	480	-5,231	-0.5	-1.2
2012	560	-6,103	-0.6	-1.4
2013	640	-6,975	-0.7	-1.6
2014	720	-7,846	-0.7	-1.8
2015	800	-8,718	-0.8	-2.0
2016	800	-8,718	-0.8	-2.0
2017	800	-8,718	-0.8	-2.0
2018	800	-8,718	-0.8	-2.0
2019	800	-8,718	-0.8	-2.0
2020	800	-8,718	-0.8	-2.0
2021	800	-8,718	-0.8	-2.0

Table 8.(3)(e)(3) Continued

Commercial Efficient Refrigeration

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2006	35	-458	0.0	-0.1
2007	70	-915	-0.1	-0.1
2008	105	-1,373	-0.1	-0.2
2009	140	-1,831	-0.2	-0.3
2010	175	-2,289	-0.2	-0.3
2011	210	-2,746	-0.3	-0.4
2012	245	-3,204	-0.3	-0.5
2013	280	-3,662	-0.4	-0.5
2014	315	-4,119	-0.4	-0.6
2015	350	-4,577	-0.5	-0.7
2016	350	-4,119	-0.4	-0.6
2017	350	-3,662	-0.4	-0.5
2018	350	-3,204	-0.3	-0.5
2019	350	-2,746	-0.3	-0.4
2020	350	-2,289	-0.2	-0.3
2021	350	-1,831	-0.2	-0.3

Table 8.(3)(e)(3) Continued

Industrial Premium Motors

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2006	50	-676	-0.1	-0.1
2007	100	-1,351	-0.1	-0.1
2008	150	-2,027	-0.2	-0.2
2009	200	-2,703	-0.2	-0.3
2010	250	-3,378	-0.3	-0.4
2011	300	-4,054	-0.3	-0.4
2012	350	-4,730	-0.4	-0.5
2013	400	-5,405	-0.4	-0.6
2014	450	-6,081	-0.5	-0.7
2015	500	-6,757	-0.5	-0.7
2016	500	-6,757	-0.5	-0.7
2017	500	-6,757	-0.5	-0.7
2018	500	-6,757	-0.5	-0.7
2019	500	-6,757	-0.5	-0.7
2020	500	-6,757	-0.5	-0.7
2021	500	-6,081	-0.5	-0.7

Table 8.(3)(e)(3) Continued

Industrial Variable Speed Drives

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2006	35	-3,753	-0.3	-0.4
2007	70	-7,506	-0.6	-0.8
2008	105	-11,260	-0.9	-1.2
2009	140	-15,013	-1.2	-1.6
2010	175	-18,766	-1.5	-2.0
2011	210	-22,519	-1.8	-2.4
2012	245	-26,272	-2.1	-2.9
2013	280	-30,026	-2.4	-3.3
2014	315	-33,779	-2.7	-3.7
2015	350	-37,532	-3.0	-4.1
2016	350	-37,532	-3.0	-4.1
2017	350	-37,532	-3.0	-4.1
2018	350	-37,532	-3.0	-4.1
2019	350	-37,532	-3.0	-4.1
2020	350	-37,532	-3.0	-4.1
2021	350	-33,779	-2.7	-3.7

8.(3)(e)(4). Projected cost, including any incentive payments and program administrative costs;

The projected costs for each Existing and New DSM programs are shown below in Table 8.(3)(e)(4)-1. Cost values are the present value of the future stream of costs for that element. More details on program costs and cost-effectiveness can be found in the Exhibits of the report titled *Demand-Side Management Analysis*, which can be found in the Supporting Documentation.

Table 8.(3)(e)(4)-1
Existing and New DSM Program Costs

Program Costs
Present value, 2006 $

Existing Program	Distribution System Admin	EKPC Admin	Distribution System Rebates	EKPC Rebates	Customer Investment
Electric Thermal Storage Propane	$ 212,993	$ 181,174	$ 597,176	$ 298,588	$ 1,890,062
Electric Thermal Storage Furnace	$ 196,609	$ 176,198	$ 496,116	$ 248,058	$ 1,744,673
Electric Water Heater New Construction	$ 318,494	$ 18,750	$ 734,986	$ 367,493	$ 563,489
Electric Water Heater Retrofit	$ 24,882	$ 7,013	$ 57,421	$ 28,710	$ 47,851
Geothermal Heating & Cooling	$ 291,698	$ 118,869	$ 516,787	$ 258,394	$ 2,340,471
Air Source Heat Pump New Construction	$ 445,892	$ 18,750	$ 734,986	$ 367,493	$ 3,429,935
Air Source Heat Pump Retrofit	$ 473,760	$ 7,013	$ 780,923	$ 390,461	$ 3,644,306
Tune-Up HVAC Maintenance	$ 696,705	$ 26,100	$ 696,705	$ 348,353	$ 803,891
Button-Up Weatherization	$ 535,927	$ 30,915	$ 1,148,416	$ 574,208	$ 2,155,193

Table 8.(3)(e)(4)-1 Continued

New Program	Program Costs Present value, 2006 $ Distribution System Admin	EKPC Admin	Distribution System Rebates	EKPC Rebates	Customer Investment
Compact Fluorescent Lighting	$ -	$ 641,505	$ -	$ -	$ -
Touchstone Energy Geothermal Heat Pump Home	$ 55,736	$ 46,480	$ 214,371	$ 107,185	$ 903,420
Touchstone Energy Air Source Heat Pump Home	$ 139,341	$ 179,420	$ 382,805	$ 191,403	$ 1,626,922
Touchstone Energy Manufactured Home	$ 13,934	$ 24,369	$ 22,968	$ 11,484	$ 76,561
Direct Load Control for Air Conditioners and Water Heaters	$ 8,066,519	$ 8,066,519	$ 11,841,491	$ 5,920,745	$ -
ENERGY STAR Clothes Washer	$ 38,281	$ 15,312	$ 191,403	$ 95,701	$ 918,732
ENERGY STAR Room Air Conditioner	$ 45,937	$ 15,312	$ 114,842	$ 57,421	$ 344,525
ENERGY STAR Refrigerator	$ 68,905	$ 15,312	$ 137,810	$ 68,905	$ 217,051
Programmable Thermostat with Electric Furnace Retrofit	$ 49,765	$ 7,656	$ 124,412	$ 62,206	$ 395,256
Dual Fuel Air Source Heat Pump with Propane Retrofit	$ 139,341	$ 7,013	$ 229,683	$ 114,842	$ 2,679,636
Commercial Lighting	$ -	$ 807,719	$ 1,160,819	$ 2,902,046	$ 4,974,937
C&I Demand Response	$ 1,612,953	$ 443,368	$ 4,939,467	$ 4,939,467	$ 2,923,276
Commercial Efficient HVAC	$ 11,484	$ 30,624	$ 373,235	$ 462,237	$ 746,470
Commercial Building Performance	$ 398,117	$ 30,624	$ 823,797	$ 779,391	$ 1,646,062
Commercial New Construction	$ 122,498	$ 91,873	$ 1,714,967	$ 2,082,460	$ 3,429,935
Commercial Efficient Refrigeration	$ 2,680	$ 30,624	$ 234,468	$ 760,481	$ 468,936
Industrial Premium Motors	$ 3,828	$ 15,312	$ 382,805	$ 1,148,416	$ 856,718
Industrial Variable Speed Drives	$ 2,680	$ 76,561	$ 2,636,762	$ 6,699,091	$ 4,482,496

8.(3)(e)(5). Projected cost savings, including savings in utility's generation, transmission and distribution costs.

The projected cost savings for each Existing and New DSM programs are shown below in Table 8.(3)(e)(5)-1. Values shown are the benefits in the Total Resource Cost test. In the case of multi-fuel programs, cost increases are netted against savings. Cost values are the present value of the future stream of costs for that element. More details on program costs and cost-effectiveness can be found in the Exhibits of the report titled *Demand-Side Management Analysis*, which can be found in the *Technical Appendix*.

Table 8.(3)(e)(5)-1
Existing and New DSM Program Cost Savings

Present value, 2006 $

Existing Program	Projected Cost Savings
Electric Thermal Storage Propane	$ 3,688,051
Electric Thermal Storage Furnace	$ 4,937,634
Electric Water Heater New Construction	$ 1,653,361
Electric Water Heater Retrofit	$ (632,374)
Geothermal Heating & Cooling	$ 12,760,302
Air Source Heat Pump New Construction	$ (1,126,029)
Air Source Heat Pump Retrofit	$ (2,079,785)
Tune-Up HVAC Maintenance	$ 6,414,153
Button-Up Weatherization	$ 18,502,602

Table 8.(3)(e)(5)-1 Continued

New Program	Projected Cost Savings
Compact Fluorescent Lighting	$ 13,774,682
Touchstone Energy Geothermal Heat Pump Home	$ 4,702,338
Touchstone Energy Air Source Heat Pump Home	$ 3,207,651
Touchstone Energy Manufactured Home	$ 660,843
Direct Load Control for Air Conditioners and Water Heaters	$ 83,237,789
ENERGY STAR Clothes Washer	$ 1,818,058
ENERGY STAR Room Air Conditioner	$ 703,499
ENERGY STAR Refrigerator	$ 535,164
Programmable Thermostat with Electric Furnace Retrofit	$ 2,054,915
Dual Fuel Air Source Heat Pump with Propane Retrofit	$ 8,783,894
Commercial Lighting	$ 14,735,786
C&I Demand Response	$ 30,195,053
Commercial Efficient HVAC	$ 1,867,741
Commercial Building Performance	$ 3,068,878
Commercial New Construction	$ 6,891,259
Commercial Efficient Refrigeration	$ 2,163,487
Industrial Premium Motors	$ 4,163,546
Industrial Variable Speed Drives	$ 22,973,281

DSM Integration into Resource Plan

The aggregated DSM load impacts for new programs were modeled in RTSim to evaluate potential savings in production costs based on the new IRP expansion plan. Table 8.(3)(e)5-2 below is a summary of the production cost savings. The net present value of savings varies from $872,000 at a 5% discount rate to -$684,000 at a 7% discount rate, and essentially break-even at a 6% discount rate. Since there were no changes made to the IRP expansion plan as far as delays in commercial operation dates of new resources due to the DSM programs, it is possible that there could be additional savings due to capacity resources being deferred a year or so. DSM programs that are not currently existing are not included in the long range plan due to the timing and/or uncertainty in implementing the programs. However, as new programs are implemented by EKPC's member systems, the program impacts are included in the load forecasting process that occurs every two years.

Table 8.(3)(e)5-2
Production Cost Savings Due to DSM
($1,000s)

Year	Production Cost Savings	DSM Cost to EKPC & Member Systems	Net Production Cost Savings
2006	1,138	3,807	(2,669)
2007	1,730	4,144	(2,414)
2008	2,695	4,513	(1,818)
2009	3,217	4,667	(1,450)
2010	3,959	4,898	(939)
2011	4,822	5,130	(308)
2012	5,400	5,364	36
2013	5,597	5,600	(3)
2014	6,189	5,632	557
2015	6,314	5,861	453
2016	6,141	2,357	3,784
2017	6,208	2,365	3,843
2018	5,636	2,373	3,263
2019	5,280	2,381	2,899
2020	4,726	2,388	2,338

8.(4) The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast:

8.(4)(a) On total resource capacity available at the winter and summer peak:

1. **Forecast peak load;**
2. **Capacity from existing resources before consideration of retirements;**
3. **Capacity from planned utility-owned generating plant capacity additions;**
4. **Capacity available from firm purchases from other utilities;**
5. **Capacity available from firm purchases from nonutility sources of generation;**
6. **Reductions or increases in peak demand from new conservation and load management or other demand-side programs;**
7. **Committed capacity sales to wholesale customers coincident with peak;**
8. **Planned retirements;**
9. **Reserve requirements;**
10. **Capacity excess or deficit;**
11. **Capacity or reserve margin.**

8.(4)(a)1.-5., 7.-11.
EKPC Projected Capacity Needs
(MW)

Year	Projected Peaks		12% Reserves		Total Requirements		Existing Resources		Capacity Needs	
	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2006	2,673	2,151	321	258	2,994	2,409	2,754	2,543	240	-134
2007	2,773	2,213	333	266	3,106	2,479	2,754	2,543	352	-64
2008	2,848	2,643	342	317	3,190	2,960	2,754	2,543	436	417
2009	3,346	2,721	401	327	3,747	3,048	2,726	2,515	1,021	533
2010	3,439	2,791	413	335	3,852	3,126	2,716	2,505	1,136	621
2011	3,520	2,852	422	342	3,942	3,194	2,681	2,465	1,261	729
2012	3,595	2,907	431	349	4,026	3,256	2,681	2,465	1,345	791
2013	3,694	2,978	443	357	4,137	3,335	2,681	2,465	1,456	870
2014	3,775	3,036	453	364	4,228	3,400	2,681	2,465	1,547	935
2015	3,856	3,096	463	372	4,319	3,468	2,681	2,465	1,638	1,003
2016	3,931	3,153	472	378	4,403	3,531	2,681	2,465	1,722	1,066
2017	4,031	3,225	484	387	4,515	3,612	2,681	2,465	1,834	1,147
2018	4,118	3,290	494	395	4,612	3,685	2,681	2,465	1,931	1,220
2019	4,209	3,359	505	403	4,714	3,762	2,681	2,465	2,033	1,297
2020	4,299	3,423	516	411	4,815	3,834	2,681	2,465	2,134	1,369

Notes:

1. Existing Resources includes 170MW from SEPA throughout the period.
2. Greenup Hydro output given credit for providing 35MW winter capacity and 40 MW summer capacity through 2010.
3. The impact of existing DSM programs is included in the load forecast.
4. There is no capacity from non-utility sources.
5. There are currently no planned retirements.
6. New DSM programs are not included.

8.(4)(a)1.-5., 7.-11. Continued
EKPC Projected Capacity Additions and Reserves
(MW)

Year	Land-fill Gas Cap.	Base Load Capacity Additions		Peaking/ Intermediate Cap. Additions		Total Capacity		Reserves		Reserve Margin	
		Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2006						2,754	2,543	81	392	3.0%	18.2%
2007	3					2,757	2,546	-16	333	-0.6%	15.0%
2008	3				166	2,760	2,715	-88	72	-3.1%	2.7%
2009	3		278	388	249	3,123	3,217	-223	496	-6.7%	18.2%
2010	3	278	278	97		3,491	3,488	52	697	1.5%	25.0%
2011	3	278				3,737	3,451	217	599	6.2%	21.0%
2012	3					3,740	3,454	145	547	4.0%	18.8%
2013	3	278	278			4,021	3,735	327	757	8.9%	25.4%
2014	3					4,024	3,738	249	702	6.6%	23.1%
2015	3	278	278			4,305	4,019	449	923	11.7%	29.8%
2016	3			109	92	4,417	4,114	486	961	12.4%	30.5%
2017	3			109	92	4,529	4,209	498	984	12.3%	30.5%
2018	3					4,532	4,212	414	922	10.0%	28.0%
2019		278	278			4,810	4,490	601	1,131	14.3%	33.7%
2020						4,810	4,490	511	1,067	11.9%	31.2%

The following table provides the reductions in peak demand from New DSM programs:

Table 8.(4)(a) 6.
Reductions in Peak Demand from New DSM Programs
(negative value = reduction in load)

Year	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2006	-13.4	-15.5
2007	-28.7	-32.8
2008	-42.0	-48.3
2009	-49.8	-58.0
2010	-57.5	-67.8
2011	-65.2	-77.5
2012	-72.9	-87.3
2013	-79.9	-96.5
2014	-86.9	-105.7
2015	-93.9	-114.8
2016	-92.8	-113.8
2017	-91.7	-112.7
2018	-90.6	-111.5
2019	-89.6	-110.4
2020	-88.5	-109.3
2021	-87.0	-107.5

8.(4)(b) On planned annual generation:

1. **Total forecast firm energy requirements;**
2. **Energy from existing and planned utility generating resources disaggregated by primary fuel type;**
3. **Energy from firm purchases from other utilities;**
4. **Energy from firm purchases from nonutility sources of generation; and**

See Table 8.(4)(b)1-4 at end of Section 8 for information regarding Section 8.(4)(b)1-4.

5. Reductions or increases in energy from new conservation and load management or other demand-side programs;

The following table presents the reductions in energy from New DSM programs:

Table 8.(4)(b)5.
Reductions in Energy from New DSM Programs
(negative value = reduction in load)

Year	Impact on Energy Requirements (MWh)
2006	-15,911
2007	-32,396
2008	-48,307
2009	-62,502
2010	-76,698
2011	-90,893
2012	-105,088
2013	-114,917
2014	-124,740
2015	-134,571
2016	-126,958
2017	-118,813
2018	-110,478
2019	-102,145
2020	-93,808
2021	-80,662

8.(4)(c) For each of the fifteen (15) years covered by the plan, the utility shall provide estimates of total energy input in primary fuels by fuel type and total generation by primary fuel type required to meet load. Primary fuels shall be organized by standard categories (coal, gas, etc.) and quantified on the basis of physical units (for example, barrels or tons) as well as in MMBtu.

See Table 8.(4)(c) at end of Section 8 for information regarding Section 8.(4)(c).

8.(5) The resource assessment and acquisition plan shall include a description and discussion of:
8.(5)(a) General methodological approach, models, data sets, and information used by the company;

Supply Side Resource Optimization and Modeling

The primary model used in developing the resource plan was RTSim from Simtec, Inc., of Madison, WI. The RTSim production cost model produces a simulation of chronological operating conditions, unit commitment, Monte Carlo forced outages, unit ramp rates, and unit startup characteristics. The Monte Carlo simulation of unit forced outages and deratings means the entire capacity of the unit, or a portion of the unit's capacity, is removed from service for a period of time and its capacity has to be replaced by alternate resources. The production cost model is simulating the actual operation of the power system in supplying the projected customer loads. RTSim also simulates power purchases and sales, including economy and day ahead transactions, and daily and monthly options.

When simulating the operation of the system, the model uses statistical load methodology. There are ten sets of load data in the model. One of those is the 2006 LFR forecast, and the others are actual hourly load files from 1997 through 2005, adjusted to 2006, and then escalated to correspond to the new load forecast. The model draws load data a few days at a time from the different forecasts (to represent weather patterns) to assemble the hourly loads to be simulated. Each iteration of the model draws a new load forecast to simulate. Actual and forecasted market prices and natural gas prices synchronized to the load data are used in the simulation. Up to 500 iterations may be simulated by the model.

RT Sim's Resource Optimizer can perform simulations of a large number of potential resource plans to determine the optimum plan. The Resource Optimizer uses the same data that is used in the production cost model simulation, except that future units are set as resource alternatives. Any future resources to be considered by the Resource Optimizer are set up with several potential future commercial operation dates. The annualized fixed costs for capital are included along with the variable costs associated with a particular resource. A minimum and maximum amount of capacity to be added by the model are specified to correspond to a specified reserve margin. The Resource Optimizer can simulate thousands of combinations of potential resources to determine the lowest cost plans. The new resources have to be simulated in operation with the current resources to determine the optimum expansion for the system. The lowest cost plans are determined from the present value of total production cost and annual fixed costs of future alternatives.

The Resource Optimizer constructs expansion plans to meet certain criteria, then simulates each plan and calculates the present value of each plan as compared to doing nothing. Some of the inputs needed by the Resource Optimizer are the minimum and maximum future capacity needs, resource alternatives, the annualized fixed cost of the resource alternatives, and the potential in-service dates for the alternatives. The resource alternatives are modeled with the same detail as the existing and committed units in the model. In development of this IRP, the Resource Optimizer was set to try up to 3500 unique expansion plans, with each of those simulated with 5 iterations. Each iteration varies loads, fuel and market prices, and forced outages. The Resource Optimizer was run for the time period 2012 through 2022. Since EKPC's resource needs through 2011 will be met through capacity additions as a result of RFP No. 2004-01, there was no need to start the optimizer before 2012. The optimizer was run through 2022, two years beyond the timeframe of the IRP. The results of the Resource Optimizer run are included below. This includes the five lowest cost plans out of 3500 plans simulated. Table 8.(5)(a) is a summary of the top five plans, followed by the model output of those plans as shown in Figures 8.(5)(a)1.-5.

These five plans were reviewed to determine if the operation dates of the near term resources were in fact achievable based on recent experience. Resources were placed in EKPC's expansion plan spreadsheet based on these plans in order to build up to a 12% reserve margin. The criteria for minimum capacity additions in the model is actually just below 12% to allow some flexibility in timing of units. However, units can be added in some years when only a small amount of capacity was needed. Therefore, shifting of units was made to allow some flexibility in the reserve margin and to eliminate or defer higher cost gas-fired units.

Since market prices and natural gas prices are synchronized to the load data, and the load data simulates various weather patterns including periods of high and low loads, the result is a robust simulation of a variety of load and market conditions. Risk analysis is thereby incorporated into the simulation.

Table 8.(5)(a)

Resource Optimizer Plan Summary

Cumulative Min Cap	Incremental Cap	Year	Type	Plan 1	Plan 2	Plan 3	Plan 4	Plan 5	Final Plan*
271	0	2012	Base	**278**	**278**	**278**	**278**	**278**	
			Interm						
			Pking			97		97	
370	99	2013	Base	**278**					**278**
			Interm						
			Pking		97		97		
453	83	2014	Base		**278**	**278**			
			Interm				109	109	
			Pking						
535	82	2015	Base				**278**	**278**	**278**
			Interm						
			Pking						
613	78	2016	Base						
			Interm			109			109
			Pking	194					
717	104	2017	Base						
			Interm				109		109
			Pking		97				
807	90	2018	Base						
			Interm	109	109				
			Pking			97		97	
901	94	2019	Base					**278**	**278**
			Interm						
			Pking	97	97	97	97		
995	94	2020	Base		**278**		**278**		
			Interm						
			Pking	97		97			
1109	114	2021	Base						
			Interm			109			
			Pking	97					
1210	101	2022	Base	**278**		**278**			
			Interm					109	
			Pking						
		Total Thru 2020=>		1,053	1,234	1,053	1,246	1,137	1,052

* All additions in the Final Plan are assumed to go in service in October prior to the year shown.

Resource Optimizer Results

Figure 8.(5)(a)-1

```
*****************************************************
            Base Case
*****************************************************

TRANSACTION OPTIMIZATION FILE -> C:\IRP2006Opt\Opt06Base.t_o

CASE MANAGER FILE -> C:\IRP2006Opt\IRP2006Opt.cas
```

```
PLAN 1
Transaction Optimization--  Risk level: 19   Risk factor:  9999.000
Seed:  1    Total tries:   3500    Narrow solution space   0 times
Best 1:  System profit:   22610796.    Try:    810    Risk:     0.074
2012 - 2022
Smith 2 CFB         1.000
  ***Unit Installation Date:  1-01-2012   ***Unit Retirement Date: 12-31-2098
FB5                 1.000
  ***Unit Installation Date:  1-01-2013   ***Unit Retirement Date: 12-31-2098
FB6                 0.000
FB7                 1.000
  ***Unit Installation Date:  1-01-2022   ***Unit Retirement Date: 12-31-2098
NewSubCritCoal      0.000
GEN LMS CT 1        0.000
GEN LMS CT 2        0.000
GEN LMS CT 3        1.000
  ***Unit Installation Date:  1-01-2016   ***Unit Retirement Date: 12-31-2098
GEN LMS CT 4        1.000
  ***Unit Installation Date:  1-01-2016   ***Unit Retirement Date: 12-31-2098
GEN LMS CT 5        0.000
GEN LMS CT 6        1.000
  ***Unit Installation Date:  1-01-2019   ***Unit Retirement Date: 12-31-2098
GEN LMS CT 7        1.000
  ***Unit Installation Date:  1-01-2021   ***Unit Retirement Date: 12-31-2098
GEN LMS CT 8        1.000
  ***Unit Installation Date:  1-01-2020   ***Unit Retirement Date: 12-31-2098
Gen LMS 100STIG     0.000
Gen LMS 100STIG - 2   1.000
  ***Unit Installation Date:  1-01-2018   ***Unit Retirement Date: 12-31-2098
Unit-Purchase       0.000
```

Figure 8.(5)(a)-2

```
PLAN 2
Transaction Optimization--  Risk level: 19   Risk factor:  9999.000
Seed:  1    Total tries:   3500    Narrow solution space   0 times
Best 2:  System profit:   22572858.    Try:   1701    Risk:    0.083
2012 - 2022
Smith 2 CFB          1.000
  ***Unit Installation Date:  1-01-2012   ***Unit Retirement Date: 12-31-2098
FB5                1.000
  ***Unit Installation Date:  1-01-2014   ***Unit Retirement Date: 12-31-2098
FB6                0.000
FB7                1.000
  ***Unit Installation Date:  1-01-2020   ***Unit Retirement Date: 12-31-2098
NewSubCritCoal        0.000
GEN LMS CT 1          0.000
GEN LMS CT 2          1.000
  ***Unit Installation Date:  1-01-2013   ***Unit Retirement Date: 12-31-2098
GEN LMS CT 3          0.000
GEN LMS CT 4          0.000
GEN LMS CT 5          1.000
  ***Unit Installation Date:  1-01-2019   ***Unit Retirement Date: 12-31-2098
GEN LMS CT 6          1.000
  ***Unit Installation Date:  1-01-2017   ***Unit Retirement Date: 12-31-2098
GEN LMS CT 7          0.000
GEN LMS CT 8          0.000
Gen LMS 100STIG        0.000
Gen LMS 100STIG - 2    1.000
  ***Unit Installation Date:  1-01-2018   ***Unit Retirement Date: 12-31-2098
Unit-Purchase         0.000
```

Figure 8.(5)(a)-3

```
PLAN 3
Transaction Optimization-- Risk level: 19 Risk factor: 9999.000
Seed: 1 Total tries: 3500 Narrow solution space 0 times
Best 3: System profit: 22413236. Try: 2225 Risk: 0.075
2012 - 2022
Smith 2 CFB 1.000
 ***Unit Installation Date: 1-01-2012 ***Unit Retirement Date: 12-31-2098
FB5 1.000
 ***Unit Installation Date: 1-01-2014 ***Unit Retirement Date: 12-31-2098
FB6 0.000
FB7 1.000
 ***Unit Installation Date: 1-01-2022 ***Unit Retirement Date: 12-31-2098
NewSubCritCoal 0.000
GEN LMS CT 1 1.000
 ***Unit Installation Date: 1-01-2012 ***Unit Retirement Date: 12-31-2098
GEN LMS CT 2 0.000
GEN LMS CT 3 0.000
GEN LMS CT 4 0.000
GEN LMS CT 5 1.000
 ***Unit Installation Date: 1-01-2018 ***Unit Retirement Date: 12-31-2098
GEN LMS CT 6 1.000
 ***Unit Installation Date: 1-01-2019 ***Unit Retirement Date: 12-31-2098
GEN LMS CT 7 0.000
GEN LMS CT 8 1.000
 ***Unit Installation Date: 1-01-2020 ***Unit Retirement Date: 12-31-2098
Gen LMS 100STIG 1.000
 ***Unit Installation Date: 1-01-2016 ***Unit Retirement Date: 12-31-2098
Gen LMS 100STIG - 2 1.000
 ***Unit Installation Date: 1-01-2021 ***Unit Retirement Date: 12-31-2098
Unit-Purchase 0.000
```

Figure 8.(5)(a)-4

```
PLAN 4
Transaction Optimization--  Risk level: 19   Risk factor:  9999.000
Seed:  1     Total tries:   3500    Narrow solution space   0 times
Best 4:  System profit:   22408884.    Try:    1485     Risk:    0.096
2012 - 2022
Smith 2 CFB          1.000
  ***Unit Installation Date:  1-01-2012   ***Unit Retirement Date: 12-31-2098
FB5                  1.000
  ***Unit Installation Date:  1-01-2015   ***Unit Retirement Date: 12-31-2098
FB6                  0.000
FB7                  1.000
  ***Unit Installation Date:  1-01-2020   ***Unit Retirement Date: 12-31-2098
NewSubCritCoal       0.000
GEN LMS CT 1         1.000
  ***Unit Installation Date:  1-01-2013   ***Unit Retirement Date: 12-31-2098
GEN LMS CT 2         0.000
GEN LMS CT 3         0.000
GEN LMS CT 4         0.000
GEN LMS CT 5         0.000
GEN LMS CT 6         0.000
GEN LMS CT 7         1.000
  ***Unit Installation Date:  1-01-2019   ***Unit Retirement Date: 12-31-2098
GEN LMS CT 8         0.000
Gen LMS 100STIG      1.000
  ***Unit Installation Date:  1-01-2014   ***Unit Retirement Date: 12-31-2098
Gen LMS 100STIG - 2  1.000
  ***Unit Installation Date:  1-01-2017   ***Unit Retirement Date: 12-31-2098
Unit-Purchase        0.000
```

Figure 8.(5)(a)-5

```
PLAN 5
Transaction Optimization-- Risk level: 19   Risk factor: 9999.000
Seed:  1    Total tries:   3500    Narrow solution space   0 times
Best 5: System profit:   22281484.    Try:    3386    Risk:    0.108
2012 - 2022
Smith 2 CFB          1.000
  ***Unit Installation Date:  1-01-2012   ***Unit Retirement Date: 12-31-2098
FB5              1.000
  ***Unit Installation Date:  1-01-2015   ***Unit Retirement Date: 12-31-2098
FB6              0.000
FB7              1.000
  ***Unit Installation Date:  1-01-2019   ***Unit Retirement Date: 12-31-2098
NewSubCritCoal       0.000
GEN LMS CT 1         0.000
GEN LMS CT 2         0.000
GEN LMS CT 3         1.000
  ***Unit Installation Date:  1-01-2012   ***Unit Retirement Date: 12-31-2098
GEN LMS CT 4         0.000
GEN LMS CT 5         1.000
  ***Unit Installation Date:  1-01-2018   ***Unit Retirement Date: 12-31-2098
GEN LMS CT 6         0.000
GEN LMS CT 7         0.000
GEN LMS CT 8         0.000
Gen LMS 100STIG       1.000
  ***Unit Installation Date:  1-01-2014   ***Unit Retirement Date: 12-31-2098
Gen LMS 100STIG - 2    1.000
  ***Unit Installation Date:  1-01-2022   ***Unit Retirement Date: 12-31-2098
Unit-Purchase        0.000
```

```
*******************************************************
          RTSIM Case Summary
*******************************************************
 Base Case Completed Without Errors;          Total Costs:         0.
```

Demand-Side Management Resource Screening and Assessment

DSM resources consist of customer energy programs that seek to change the power consumption of customer facilities in a way that meets planning objectives. They include conservation, load management, and other demand-side programs.

EKPC's DSM analysis is conducted on an aggregate basis, with all member cooperatives combined, rather than on an individual cooperative basis.

EKPC has used a two-step process to screen and evaluate DSM resources for inclusion in this plan: (1) Qualitative Screening, and (2) Quantitative Evaluation.

The first step, Qualitative Screening, is a qualitative assessment of a large number of potential DSM measures. This set of DSM measures covers all classes and major end-uses, and includes a robust set of available technologies and strategies for producing energy and capacity savings. This list was produced after careful review of several sources, including (1) PSC staff recommendations from the 2003 IRP; (2) feedback from Kentucky Department of Energy, the Attorney General's office, and other relevant state agencies; (3) the current programs and IRPs of other Kentucky utilities; and (4) best practice DSM programs offered by utilities around the country.

In the Qualitative Screening step, each measure is scored against four criteria (see Table 8.(5)(c)-1 for a listing of the criteria).

Measures which pass the Qualitative Screening move on to the second step, which is a more rigorous Quantitative Evaluation. Measures are turned into DSM programs. In some cases, measures are combined into one program. The Quantitative Evaluation considers all quantifiable benefits and costs of the program, and scores each program according to standard cost-effectiveness tests.

EKPC uses the EPRI *DSManager* software package to conduct the more detailed quantitative evaluation. *DSManager* calculates the impact of DSM programs on utilities and their customers. *DSManager* produces a quantitative estimate of the costs and benefits for each of the parties using simplified but powerful and flexible models of the electric system and its customers. *DSManager* determines the cost-effectiveness of DSM programs by reporting results according to the cost-benefit tests established in the California Standard Practice Manual for Economic Analysis of Demand Side Programs[1].

DSM programs which pass the Quantitative Evaluation are passed on to the integrated analysis for inclusion in the IRP.

Additional detail on this process is contained in the report titled *Demand-Side Management Analysis*, which can be found in the *Technical Appendix*.

8.(5)(b) Key assumption and judgments used in the assessment and how uncertainties in those assumptions and judgments were incorporated into analyses;

See 8.(5)(a).

[1] California Public Utilities Commission and California Energy Commission, "Standard Practice Manual for Economic Analysis of Demand-Side Management Programs," Document Number P400-87-006, December 1987.

8.(5)(c) Criteria (for example, present value of revenue requirements, capital requirements, environmental impacts, flexibility, diversity) used to screen each resource alternative including demand-side programs, and criteria used to select the final mix of resources presented in the acquisition plan;

See 8.(5)(a) for information regarding selection of the supply side resources.

Demand-Side Management Screening

EKPC has used a two-step process to screen and evaluate DSM resources for inclusion in this plan: (1) Qualitative Screening, and (2) Quantitative Evaluation. A detailed report of this DSM analysis titled *Demand-Side Management Analysis* can be found in the *Technical Appendix.*

The first step is a qualitative assessment of a large number of potential DSM measures. In the Qualitative Screening step, each measure is scored against four criteria. Measures which pass the Qualitative Screening move on to the second step, which is a more rigorous Quantitative Evaluation. Measures are turned into DSM programs. In some cases, measures are combined into one program. The Quantitative Evaluation considers all quantifiable benefits and costs of the program, and scores each program according to standard cost-effectiveness tests. DSM programs which pass the Quantitative Evaluation are passed on to the integrated analysis for inclusion in the IRP.

EKPC developed four criteria it would use to screen DSM measures in the Qualitative Screening step. The four criteria chosen capture the major considerations as to whether a measure is suitable for robust quantitative analysis. The criteria consider the customer, the measure itself, the savings, and the economics. Each potential DSM measure was evaluated based on a scale of 1 to 5 against each of the four criteria.

The four criteria and a description of each are shown as Table 8.(5)(c)-1.

Table 8.(5)(c)-1
Qualitative Screening criteria

Scoring system: 1 – 5 , where 1 means POOR and 5 means EXCELLENT

Criteria	Comments/Examples
1. **Customer Acceptance**	What will the response of customers be to the offer to participate in the program or to install the measure(s) in their facilities? POOR = measures that reduce the quality of the energy service equipment, are excessively difficult to install, or might interfere with vital activities in the establishment (home, business, industrial plant).
2. **Measure Applicability**	Have the efficiency gains been superseded by standards or code requirements? Is the measure commercially available today? Measures that are still in the R&D stage or that are no longer manufactured would score low on this criteria. Will the measure save energy or demand in the EKPC climate? Is the measure a good fit for the DSM objectives that EKPC has? Is there a better measure available for the same end-use application? Example: Triple glazed windows versus low e double pane window.
3. **Savings Potential**	How substantial are the savings likely to be? How measurable or quantifiable are the savings? Is the measure technically reliable such that savings are assured? Is the marketplace capturing the savings already without a utility program? POOR = Savings are small or not easily quantified
4. **Cost Effectiveness**	Given typical savings, typical measure costs, and a conservative (high) estimate of future avoided energy and capacity costs, how cost effective is this program likely to be using the Total Resource Cost test? POOR = clearly below 1 (say 0.3 on the TRC using a high estimate of future avoided costs) EXCELLENT = clearly above 1 (say 3-5 or higher on the TRC)

DSM measures which received a combined score of 15 or higher were passed on to the next phase, the Quantitative Evaluation Process.

EKPC uses the EPRI *DSManager* software package to conduct the more detailed quantitative evaluation. *DSManager* calculates the impact of DSM programs on utilities and their customers. *DSManager* produces a quantitative estimate of the costs and benefits for each of the parties using simplified but powerful and flexible models of the electric system and its customers.

DSManager determines the cost-effectiveness of DSM programs by reporting results according to the cost-benefit tests established in the California Standard Practice Manual for Economic Analysis of Demand Side Programs[2].

EKPC uses these tests to examine cost-effectiveness from three major perspectives: participant cost (PC), ratepayer impact measure (RIM), and total resource cost (TRC). A fourth perspective, the societal cost (SC), is treated as a variation on the TRC test. The results of each perspective can be expressed in a variety of ways, but in all cases, it is necessary to calculate the net present value of program impacts over the life cycle of those impacts. *DSManager* uses this information to calculate the benefit/cost (b/c) ratio for each of these four tests.

These tests are not intended to be used individually or in isolation. The results of tests that measure efficiency, such as the TRC and the SC, must be compared not only to each other, but also to the RIM test. This multi-perspective approach will require reviewers to consider tradeoffs between the various tests.

EKPC is a full requirements Generation and Transmission provider for its 16 member cooperatives. Each cooperative is an independent non-profit corporation and operates distinct from EKPC. As a result, it is necessary to examine the impacts of DSM programs separately for EKPC and for the typical distribution cooperative. *DSManager* has the functionality to enable the user to separately report the RIM test for EKPC and for the distribution cooperative.

Time is a critical element in DSM analysis. It is important to represent time within a year and over a period of many years. *DSManager* divides the year into seasons and representative days. These days are usually related to weather and to patterns of human activity. EKPC has selected 48 representative days to model the calendar year, four for each month. Each day is modeled using 24 hourly loads. This is true both for the utility system, individual end-uses, and DSM program impacts.

The daytypes are: High Weekday, Medium Weekday, Low Weekday, and Weekend. High, medium, and low refer to the EKPC system loads.

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[2] California Public Utilities Commission and California Energy Commission, "Standard Practice Manual for Economic Analysis of Demand-Side Management Programs," Document Number P400-87-006, December 1987.

Each of the 27 DSM programs was modeled in detail with *DSManager*. The model includes for each DSM program:

- 48-daytype hourly load profiles for targeted end-uses with and without the program
- Lifetime of the measure savings
- Incremental measure costs (participant costs)
- EKPC and distribution cooperative administrative costs
- Rebates to customers, and from EKPC to the cooperative
- Detailed retail and wholesale rate schedules
- Customer participation levels

In addition to the detailed modeling of the DSM programs, *DSManager* also includes a detailed model of the supply side costs. Major categories of supply side costs that are accounted for by the model include:

- Marginal energy costs (by year, daytype, and hour)
- Marginal generation capacity costs (by category and year, including seasonal allocation)
- Marginal transmission & distribution capacity costs (by year, incl. seasonal allocation)
- Fossil fuel (natural gas & propane) costs (by year)
- Environmental externality costs (costs not internalized in energy or capacity costs; chiefly carbon related)

Factoring Environmental Cost Considerations into DSM Evaluation

EKPC has explicitly factored environmental costs into this evaluation of DSM resources. There are three major categories of environmental cost: (1) the cost of purchasing allowances; (2) the capital costs of compliance at power plants; and (3) externality costs.

EKPC has accounted for all three categories of environmental cost in its DSM evaluation. Table 8.(5)(c)-2 describes how this was accomplished:

Table 8.(5)(c)-2
Accounting for Environmental Costs

Environmental Cost	Where accounted for	Specifics
Allowance purchases	Marginal energy costs	SOx and NOx
Capital investments for compliance	Marginal capacity costs	Primarily Scrubbers, SCRs, other controls
Externalities	Externality adder	Used in Societal Cost test; value is set to $10/MWh. Value determined by examining allowance prices in markets (primarily Europe) with cap and trade policies for carbon.

8.(5)(d) Criteria used in determining the appropriate level of reliability and the required reserve or capacity margin, and discussion of how these determinations have influenced selection of options;

EKPC Reserve Margin Analysis

Introduction

EKPC has been using a 12% reserve margin since prior to the filing of the 2003 Integrated Resource Plan (2003 IRP). The reserve margin is the amount of capacity in excess of that required to meet the projected peak load. Reserves are necessary to reduce the risks posed by forced outages, transmission constraints, load forecast deviations or other unforeseen events that can prevent a utility from being able to meet its load requirements.

Although EKPC is a winter peaking utility, the 12% reserve margin has been applied to the summer peak. Any additional capacity required to meet the winter peak was purchased on a seasonal basis. This strategy was adopted when summer market power prices were much higher than winter market power prices. This strategy minimized high cost summer power purchases, and also allowed EKPC to minimize capital investment in resources available all year. The lower cost market power available in the winter could be purchased for two or three months and the 16-hour blocks of power were a better fit for EKPC's loadshape during the winter season than the summer season.

Since there is currently no clear trend of seasonal market power prices being higher in one peak season than the other, and considering that EKPC has imported significant amounts of power during the winter season, a change of strategy was adopted to reduce the market power dependence. EKPC is now moving toward adding capacity to meet a

12% winter reserve margin. This analysis was performed to see if a 12% reserve margin is reasonable or if an adjustment to the reserve margin is needed.

Methodology

EKPC used the production cost model RTSim and its resource optimization module to perform the reserve margin analysis. The optimizer was used to select the optimum expansion plan for a range of potential reserve margins. The model provides results for the best plans based on the highest system profit. The system profit is the cost of doing nothing (making no capacity additions) minus the cost of a particular plan. The plans with the highest profit are the lowest cost plans.

Assumptions

The model assumptions were consistent with the last completed financial forecast except for changes as discussed below. For a reliability study it was assumed that limited outside purchases were available during on-peak hours. One of the significant input assumptions for this methodology is the value of unserved energy. The value of unserved energy was based on a study performed in 2000 by Christensen Associates entitled "Value of Reliability to Customers", and an EKPC report for 2004 entitled "Member System Consumers and Energy Sales". The Christensen Associates study results are based on surveys of EKPC's member cooperatives' customers.

Scenarios

Base case scenario runs were made that provided an expansion plan for each of the following reserve margin scenarios: 4%, 6%, 8%, 10%, 12%, 14%, and 16%. After the optimum reserve margin was selected from the base case, sensitivity cases were run with an unserved energy value 25% lower and 25% higher than in the base case.

Results

The results of the base case and the two sensitivity cases are shown in the Figure 8.(5)(d). The 9%, 10%, and 11% reserve margins provide the highest system profit in the base case and the two sensitivity cases. A 10% reserve margin would be the likely choice based on this type of analysis. Since the difference in capacity requirements of cases with reserve margins that are only 1% or 2% apart are relatively small, the resulting optimum expansion plans may be the same for several cases or very similar.

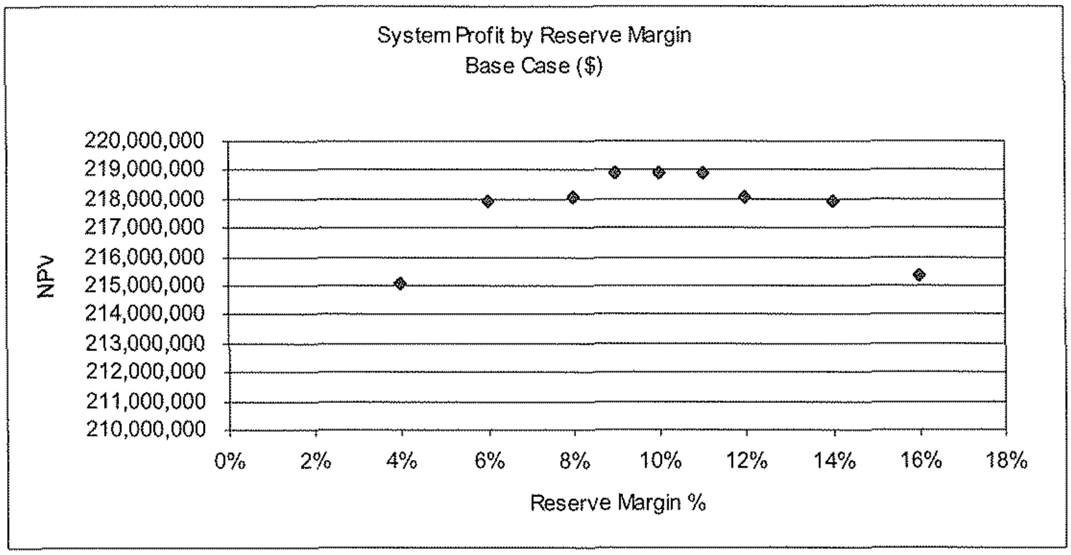
Conclusion

This methodology provides an economic evaluation of the optimum reserve margin. Other methodologies focus on reliability by calculating the loss of load hours (LOLH) or loss of load energy (LOLE) for different levels of reserve margin to compare to a standard issued by a regulatory body. The above analysis indicates that EKPC could reduce its reserve margin to 10%, which would likely be in the lower range of common practice today. However, at this time EKPC has chosen to remain at the 12% level for several reasons. Those reasons are as follows:

1. The difference in the capacity requirements at the 12% and 10% reserve margin levels in the year 2020 are about 90 MW based on the winter peak, which is very similar to the capacity of a one combustion turbine (either GE 7EA or GE LMS100).
2. EKPC has a substantial amount of new capacity in the study, especially in the early years. It is expected that this new capacity will be very reliable, but it could take a few years before it reaches the level of reliability of existing units. (The Gilbert Unit went commercial in March 2005, Spurlock 4 and Smith CFB 1 are expected to be commercial in 2009 and 2010, respectively, and Smith CTs 8-12 are expected to become commercial in 2008 and 2009).
3. EKPC is adding a new member cooperative with a peak load of approximately 400 MW in 2008.
4. Other methodologies should be considered before making a significant change.

EKPC plans to remain at the 12% level until additional reserve margin analysis is completed in a few years or regulations require a specific standard be followed.

Figure 8.(5)(d)


System Profit by Reserve Margin
Base Case ($)
NPV
220,000,000
219,000,000
218,000,000
217,000,000
216,000,000
215,000,000
214,000,000
213,000,000
212,000,000
211,000,000
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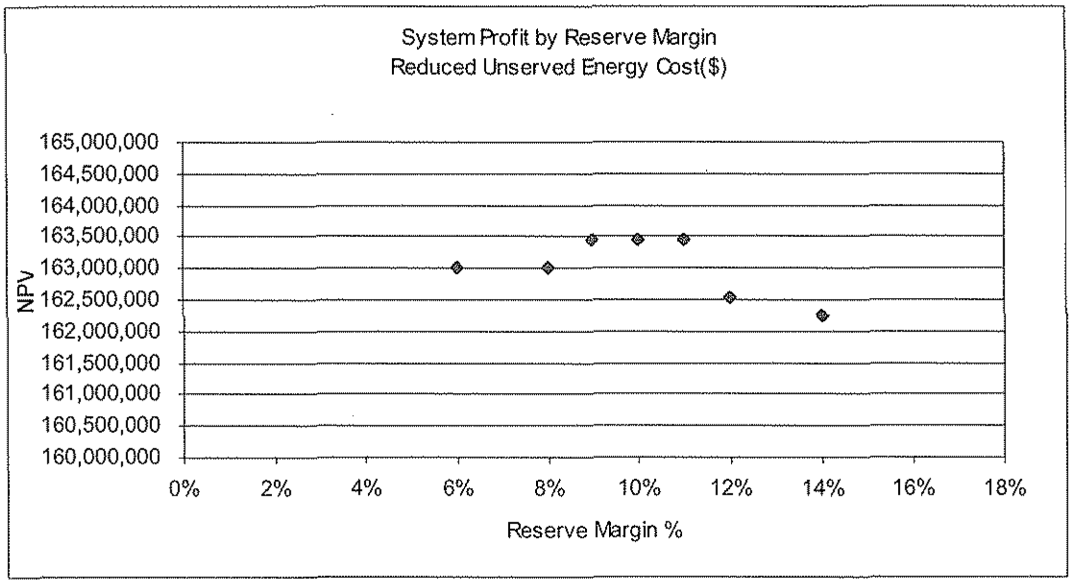
2%
4%
6%
8%
10%
12%
14%
16%
18%
Reserve Margin %


System Profit by Reserve Margin
Reduced Unserved Energy Cost($)
NPV
165,000,000
164,500,000
164,000,000
163,500,000
163,000,000
162,500,000
162,000,000
161,500,000
161,000,000
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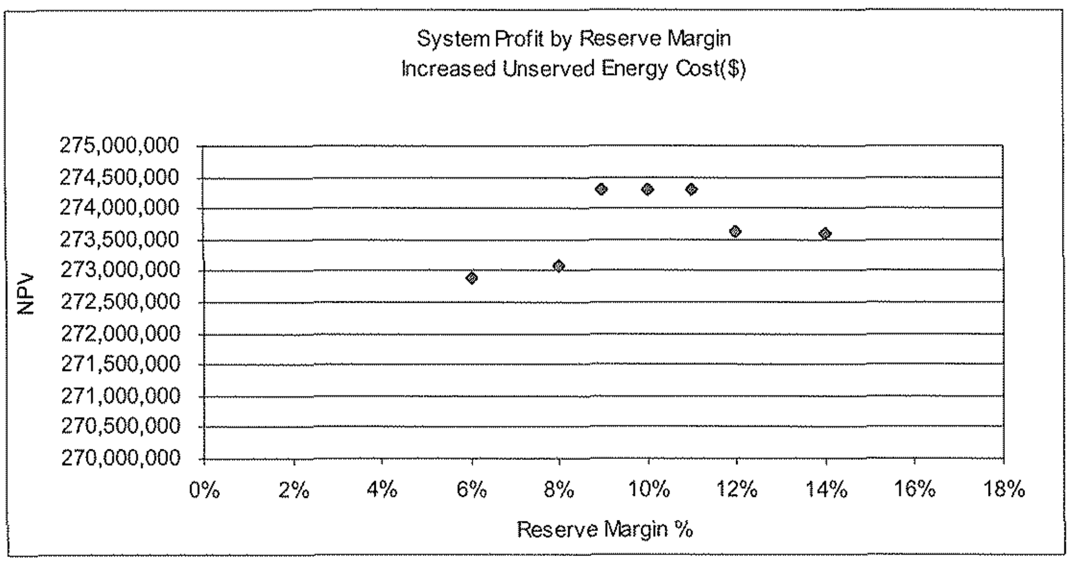
2%
4%
6%
8%
10%
12%
14%
16%
18%
Reserve Margin %


System Profit by Reserve Margin
Increased Unserved Energy Cost($)
NPV
275,000,000
274,500,000
274,000,000
273,500,000
273,000,000
272,500,000
272,000,000
271,500,000
271,000,000
270,500,000
270,000,000
0%
2%
4%
6%
8%
10%
12%
14%
16%
18%
Reserve Margin %

8.(5)(e) Existing and projected research efforts and programs which are directed at developing data for future assessments and refinements of analyses;

The RTSim production cost model and its Resource Optimizer are updated frequently by Simtec, Inc., based on its view of the power industry and how to account for risk and uncertainty analysis, and also based on the needs of the users of the model. RTSim offers a great deal of flexibility in how inputs are modeled and many inputs are distributions of values. The statistical load data and corresponding fuel prices and market prices, and probability distributions for forced outages and other inputs, provide a distribution of possible outcomes rather than just an expected value. EKPC plans to continue to refine and improve its modeling data, fuel market forecasts, and emission market forecasts.

8.(5)(f) Actions to be undertaken during the fifteen (15) years covered by the plan to meet the requirements of the Clean Air Act amendments of 1990, and how these actions affect the utility's resource assessment; and

EKPC plans to fully comply with the Clean Air Act amendments of 1990 as well as subsequent environmental legislation such as the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). CAIR was issued in 2005 and sets new annual reductions of SO2 and NOx emissions. There is a two-phase implementation of the CAIR rules as follows:

NOx Phase I: Begins 1/1/2009
SO2 Phase I: Begins 1/1/2010
NOx Phase II: Begins 1/1/2015
SO2 Phase II: Begins 1/1/2015

CAMR was also issued in 2005 and is a two phase reduction in mercury emissions timed as follows:

Phase I: Begins 1/1/2010
Phase II: Begins 1/1/2018

Phase I mercury reductions are assumed to be a co-benefit of adding emission control equipment for NOx and SO2. Implementing Phase II mercury reductions may require new technology.

A cap and trade system is in place for SO2 and NOx emissions. EKPC has a system limit for SO2 and NOx emissions that it must meet and if it exceeds the limit it must purchase emission allowances from the market to cover any emissions in excess of the limit.

EKPC has installed selective catalytic reduction systems (SCRs) on Spurlock Units 1 & 2 that substantially reduce NOx emissions in order to comply with emissions regulations. EKPC has also received the necessary regulatory approvals to add flue gas desulfurization units (scrubbers) to Spurlock Units 1 & 2 by 2009 that will substantially reduce SO2 emissions prior to CAIR SO2 Phase I implementation. The Gilbert Unit at Spurlock Station utilizes the circulating fluidized bed boiler (CFB) technology that produces very low emissions without the need for an SCR or scrubber. The Spurlock 4 and Smith 1 units will also utilize CFB technology when they begin operation (expected to be 2009 and 2010, respectively).

Dale Station and Cooper Station are EKPC's oldest plants and operate under their permitted emission levels. However, in order for EKPC to meet future system emission limits, changes may be required at these plants. The projected operating data for 2006 through 2020 assumes that a single scrubber is installed to capture SO2 from both units at Cooper Station. An SCR is also assumed to be installed on Cooper Unit 2 for NOx control. Studies are underway to determine the best strategy for reducing emissions from these plants. The alternatives under consideration include fuel switching, emission control equipment, repowering, and retirement. At this time EKPC has no plans to retire any of its plants.

The production of carbon dioxide and any future regulations regarding carbon dioxide were not explicitly factored into development of this resource plan. EKPC recognizes that some regulation of carbon dioxide could become a reality in future years. Carbon dioxide mitigation and sequestration is being studied through use of EPRI research on this topic. IGCC plants are being promoted in part for controlling production of carbon dioxide. However, the advantage of IGCC is not that the process produces less carbon dioxide, but that IGCC plants have the ability to capture carbon dioxide more economically than other coal burning technologies today. EKPC will continue to research carbon dioxide issues and monitor improvements in technology for controlling its production.

8.(5)(g) Consideration given by the utility to market forces and competition in the development of the plan.

EKPC is constantly monitoring fuel and market power prices and analyzing the data. EKPC also monitors various industry publications to see what actions other companies in the power industry are undertaking or considering. In addition EKPC participates in seminars or training opportunities offered by various consultants on current topics. EKPC is also a member of the Electric Power Research Institute (EPRI) and participates in research projects and has access to the vast amount of research done by EPRI.

Section 8

Supporting Documentation

Table 8.(2)(a) –1
Major MEAGER Projects Planned 2007 – 2027
Spurlock Station

Description	Cost Estimate (2006$)	Estimated Completion Date
Scrubber - Unit No. 2 (continues from 2006)	[redacted]	2007
Major Overhaul - Unit No. 2	[redacted]	2007
Landfill Expansion	[redacted]	2007
Install Coal Line Monitors Unit No. 1	[redacted]	2007
Install Nash Air Removal Pump on Unit No. 1	[redacted]	2007
Replace Portion DMW's Unit No. 2 Boiler	[redacted]	2007
Inspect/Overhaul Unit No. 1 Turbine Valves	[redacted]	2007
Replace Cooling Tower - Unit No. 2	[redacted]	2007
Install Circulating Water Linings – Unit No. 2	[redacted]	2007
Spurlock Unit No. 4 Construction and Equipment	[redacted]	2007
Scrubber - Unit No. 1 (continues from 2006)	[redacted]	2007
Install Additional Turbine Room Crane (W.O. #0S251)	[redacted]	2007
Unit No. 2 Ammonia Slip Analyzer	[redacted]	2007
Unit No. 2 Add Economizer Sootblowers	[redacted]	2007
New Material Handling System For Limestone	[redacted]	2007
Unit No. 3 Platforms	[redacted]	2007
Unit No. 1 Ammonia Slip Analyzer	[redacted]	2007
Additional Office Space	[redacted]	2007
Install Unit No. 3 Welding System	[redacted]	2007
Replace Unit No. 3 Bed Ash Mixter	[redacted]	2007
Install Unit No. 1 NOx Analyzer	[redacted]	2007
Install Unit No. 2 NOx Analyzer	[redacted]	2007
Install Reboiler Makeup Water Softener	[redacted]	2007
Replace Unit No. 3 Cooling Tower Bolts	[redacted]	2007
Replace 3A and 3B Battery Banks	[redacted]	2007
Unit No. 3 Turbine Bypass System	[redacted]	2007
Scrubber - Unit 2 (completion)	[redacted]	2008
Inspect/Overhaul Unit No. 2 Turbine Valves	[redacted]	2008
Spurlock Unit No. 4 Construction and Equipment	[redacted]	2008
Scrubber - Unit No. 1 (continues)	[redacted]	2008
Drill New Well	[redacted]	2008
Inspect/Overhaul Turbine Valves Unit No. 3	[redacted]	2008
Paint Elevated Storage Tank	[redacted]	2008

Table 8.(2)(a) –1 Continued
Major MEAGER Projects Planned 2007 – 2027
Spurlock Station

Description	Cost Estimate (2006$)	Estimated Completion Date
Unit No. 1 Upgrade/New Primary/Secondary Air Flow Monitor	[redacted]	2008
New Material Handling System For Limestone (continues)	[redacted]	2008
Unit No. 1 Additional SSH Sootblowers	[redacted]	2008
Replace Unit No. 1 and No. 2 Air Dryers	[redacted]	2008
Replace Unit No. 1 Fans Monitoring Equipment	[redacted]	2008
Install Unit No. 1 SCR Catalyst	[redacted]	2008
Install Unit No. 2 SCR Catalyst	[redacted]	2008
New Layer SCR Catalyst for Unit No. 1 and Unit No. 2	[redacted]	2008
Retube Reboiler	[redacted]	2009
Inspect/Overhaul Unit No. 1 Turbine Valves	[redacted]	2009
Spurlock Unit No. 4 Construction and Equipment	[redacted]	2009
Scrubber - Unit No. 1 (completion)	[redacted]	2009
New Materials Handling System for Limestone (cont.)	[redacted]	2009
Replace Unit No. 1 Water Walls	[redacted]	2009
Replace Unit No. 1 Burners	[redacted]	2009
Replace Dozer	[redacted]	2010
Replace Refractory Unit No. 3	[redacted]	2010
Inspect/Overhaul Unit No. 2 Turbine Valves	[redacted]	2011
Inspect/Overhaul Turbine Valves Unit No. 3	[redacted]	2011
Inspect/Overhaul Unit No. 1 Turbine Valves	[redacted]	2012
Turbine Overhaul - Unit No.1	[redacted]	2014
Generator Field Rewind - Unit No. 1	[redacted]	2014
Replace Unit No. 1 Condenser	[redacted]	2014
Replace Scraper	[redacted]	2014
Replace Secondary Superheater – Unit No. 1	[redacted]	2014
Inspect/Overhaul Unit No. 2 Turbine Valves	[redacted]	2014
Replace Unit No. 1 Interm. Reheater	[redacted]	2014
Inspect/Overhaul Turbine Valves Unit No. 3	[redacted]	2014
Replace Unit No. 1 Inlet Reheater Lower Loops	[redacted]	2014
Replace Unit No. 1 Feedwater Heater No. 6	[redacted]	2014
Inspect/Overhaul Unit No. 1 Turbine Valves	[redacted]	2015
Refractory Unit No. 3	[redacted]	2015
Inspect/Overhaul Unit No. 1 Turbine Valves	[redacted]	2016
Major Overhaul - Unit No. 3 Turbine Generator	[redacted]	2016

Table 8.(2)(a) –1 Continued
Major MEAGER Projects Planned 2007 – 2027
Spurlock Station

Description	Cost Estimate (2006$)	Estimated Completion Date
Major Overhaul – Unit No. 2	[redacted]	2017
Replace Dozer	[redacted]	2017
Build Dam C Landfill	[redacted]	2017
Inspect/Overhaul Unit No. 2 Turbine Valves	[redacted]	2017
Replace Reheater Unit No. 2	[redacted]	2017
Replace Unit No. 2 Cold End Air Heater Baskets	[redacted]	2017
Inspect/Overhaul Turbine Valves Unit No. 3	[redacted]	2017
Replace Unit No. 1 Cold End Air Heater Baskets	[redacted]	2018
Inspect/Overhaul Unit No. 1 Turbine Valves	[redacted]	2019
Inspect/Overhaul Unit No. 2 Turbine Valves	[redacted]	2020
Inspect/Overhaul Unit No. 3 Turbine Valves	[redacted]	2020
Inspect/Overhaul Unit No. 1 Turbine Valves	[redacted]	2022
Inspect/Overhaul Unit No. 2 Turbine Valves	[redacted]	2023
Inspect/Overhaul Unit No. 3 Turbine Valves	[redacted]	2023
Turbine Overhaul - Unit No. 1	[redacted]	2024
Inspect/Overhaul Turbine Valves Unit #1	[redacted]	2024
Inspect/Overhaul Unit No. 1 Turbine Valves	[redacted]	2025
Major Overhaul Unit No. 3 Turbine Generator	[redacted]	2026
Inspect/Overhaul Unit No. 2 Turbine Valves	[redacted]	2026
Major Overhaul Unit No. 2	[redacted]	2027
Spurlock Total MEAGER Projects 2007 – 2027	[redacted]	

*Includes Preliminary — Spurlock Unit No. 4 and Scrubber for Unit No. 1 and Unit No. 2 Costs

Table 8.(2)(a) –2
Major MEAGER Projects Planned 2007 – 2027
Cooper Station

Description	Cost Estimate (2006$)	Estimated Completion Date
Replace Submerged Drag Chain Units No. 1 and No. 2	[redacted]	2007
Replace Air Heater Baskets Unit No. 2	[redacted]	2007
Replace 4160 Switchgear Trip Device	[redacted]	2007
High Energy Hanger and Piping Testing - Unit No. 1	[redacted]	2008
Replace Primary Superheat Panels - Unit No. 2	[redacted]	2008
Turbine Valve Outage – Unit No. 2	[redacted]	2008
Rebuild Circulating Water Pumps Unit No. 2	[redacted]	2009
Replace Submerged Drag Chain - Units No. 1 and No. 2	[redacted]	2009
Rebuild Precipitators - Unit No. 1	[redacted]	2010
Major Overhaul - Unit No. 1	[redacted]	2010
Replace Primary Superheater - Unit No. 1	[redacted]	2010
Replace Reheat Panels - Unit No. 1	[redacted]	2010
Replace Economizer – Unit No. 1	[redacted]	2010
Condenser Tubes - Unit No. 1	[redacted]	2010
No. 2 Feedwater Heater - Unit No. 1	[redacted]	2010
Scaffold Boiler - Unit No. 1	[redacted]	2010
Replace Unit No. 1 Mechanical Dust Collectors	[redacted]	2010
High Energy Hanger & Piping Testing-Unit No. 1	[redacted]	2011
SCRs and Scrubbers - Units No. 1 and No. 2	[redacted]	2011
Replace Submerged Drag Chain on Units No. 1 and No. 2	[redacted]	2012
Major Overhaul - Unit No. 2	[redacted]	2013
High Energy Hangers & Piping Testing - Unit No. 1	[redacted]	2013
Replace Primary Superheat Panels – Unit No. 2	[redacted]	2013
Replace Reheat Panels – Unit No. 2	[redacted]	2013
Replace Economizer – Unit No. 2	[redacted]	2013
Condenser Tubes – Unit No. 2	[redacted]	2013

Table 8.(2)(a) –2 Continued
Major MEAGER Projects Planned 2007 - 2027
Cooper Station

Description	Cost Estimate (2006$)	Estimated Completion Date
Replace Submerged Drag Chain on Units No. 1 and No. 2	[redacted]	2014
Replace Switchgear – Unit No. 2	[redacted]	2014
Turbine Valve Outage – Unit No. 1	[redacted]	2015
Secondary Superheat Unit No. 1	[redacted]	2015
Rebuild Circulating Water Pump Unit No. 1	[redacted]	2015
High Energy Hanger & Piping Testing Unit No. 2	[redacted]	2016
Replace Submerged Drag Chains – Units No. 1 and No. 2	[redacted]	2016
High Energy Hanger & Piping Testing - Unit No. 1	[redacted]	2018
Replace Submerged Drag Chains – Units No. 1 and No. 2	[redacted]	2018
Turbine Valve Outage-Unit No. 2	[redacted]	2018
Rebuild Circulating Water Pump Unit No. 2	[redacted]	2019
Replace Submerged Drag Chain - Units No. 1 and No. 2	[redacted]	2020
Major Overhaul - Unit No. 1	[redacted]	2020
Rebuild Circulating Water Pump Unit No. 1	[redacted]	2020
High Energy Hanger and Piping Testing - Unit No. 1	[redacted]	2021
Replace Submerged Drag Chain - Units No. 1 and No. 2	[redacted]	2022
High Energy Hangers & Piping Unit No. 1	[redacted]	2023
Hydraulic Turbine Unit No. 1	[redacted]	2023
Major Overhaul Unit No. 2	[redacted]	2023
Replace Submerged Drag Chain - Units No. 1 and No. 2	[redacted]	2024
Hydraulic Turbine Unit No. 2	[redacted]	2024
Turbine Valve Outage Unit No. 1	[redacted]	2025
Rebuild Circulating Water Pump Unit No. 2	[redacted]	2025
High Energy Hanger & Piping Testing Unit No. 2	[redacted]	2026
Replace Submerged Drag Chain Units No. 1 and No. 2	[redacted]	2026
Low Pressure Feedwater Heater	[redacted]	2027
Cooper Total MEAGER Projects 2007 – 2027	[redacted]	

Table 8.(2)(a) –3
Major MEAGER Projects Planned 2007 - 2027
Dale Station

Description	Cost Estimate (2006$)	Estimated Completion Date
Major Overhaul - Unit No. 3	[redacted]	2007
Upgrade Regeneration Tubers & Refractory No. 3	[redacted]	2007
No. 3 Generator Stator Rewind	[redacted]	2007
Clean No. 2 Ash Pond	[redacted]	2007
Install Low NOx Burners for Units No. 1 and 2	[redacted]	2007
Clean No. 4 Ash Pond	[redacted]	2008
Major Overhauls - Units No. 1 and No. 2	[redacted]	2008
Acid Clean - Unit No. 3 Boiler	[redacted]	2009
Inspect/Rebuild Control Valves Unit No. 4	[redacted]	2009
Retube Condensers - Units No. 1 and No. 2	[redacted]	2010
Clean No. 2 Ash Pond	[redacted]	2010
Inspect/Rebuild Control Valves Unit No. 3	[redacted]	2010
Retube Condenser - Unit No. 3	[redacted]	2011
Inspect/Rebuild Control Valves Units No. 1 and No. 2	[redacted]	2011
Clean No. 4 Ash Pond	[redacted]	2012
Inspect/Rebuild Control Valves Unit No. 4	[redacted]	2012
Acid Clean - Unit No. 4 Boiler	[redacted]	2013
Inspect/Rebuild Control Valves Unit No. 3	[redacted]	2013
Economizer & Primary Superheater Upgrade - Unit No. 4	[redacted]	2014
Clean No. 2 Ash Pond	[redacted]	2014
Inspect/Rebuild Control Valves Units No. 1 and No. 2	[redacted]	2014
Major Overhaul - Unit No. 4	[redacted]	2016
Clean No. 4 - Ash Pond	[redacted]	2016
Acid Clean - Unit No. 3	[redacted]	2017
Major Overhaul - Unit No. 3	[redacted]	2017
Clean No. 2 Ash Pond	[redacted]	2018
Major Overhauls - Units No. 1 and No. 2	[redacted]	2018
Upgrade Regeneration Tubes and Refractory No. 1 and No. 2	[redacted]	2018
Inspect/Rebuild Control Valves - Unit No. 4	[redacted]	2019
Clean No. 4 Ash Pond	[redacted]	2020
Inspect/Rebuild Control Valves - Unit No. 3	[redacted]	2020

Table 8.(2)(a) –3 Continued
Major MEAGER Projects Planned 2007 - 2027
Dale Station

Description	**Cost Estimate (2006$)**	**Estimated Completion Date**
Clean No. 2 Ash Pond	[redacted]	2022
Inspect/Rebuild Control Valves - Unit No. 4	[redacted]	2022
Acid Clean Unit No. 4	[redacted]	2023
Inspect/Rebuild Control Valves - Unit No. 3	[redacted]	2023
Clean No. 4 Ash Pond	[redacted]	2024
Inspect/Rebuild Control Valves Units No. 1 and No. 2	[redacted]	2024
Clean No. 2 Ash Pond	[redacted]	2026
Major Overhaul Unit No. 4	[redacted]	2026
Major Overhaul Unit No. 3	[redacted]	2027
Dale Total MEAGER Projects 2007 - 2027	[redacted]	

Table 8.(2)(a) –4
Major MEAGER Projects Planned 2007 - 2027
Smith Station

Description	**Cost Estimate (2006$)**	**Estimated Completion Date**
Unit No. 3 Major Inspection	[redacted]	2007
Unit No. 5 Combustion Inspection	[redacted]	2007
Controls System Upgrade	[redacted]	2007
Smith Unit 1 Coal-Fired Unit	[redacted]	2007
Combustion Turbines Units No. 8-12	[redacted]	2007
Maintenance Building - Units No. 6 and No. 7	[redacted]	2007
Unit No. 4 Combustion Inspection	[redacted]	2008
Smith Unit 1 Coal-Fired Unit	[redacted]	2008
Combustion Turbine Units No. 9-12	[redacted]	2008
Unit No. 6 Combustion Inspection	[redacted]	2008
Unit No. 7 Combustion Inspection	[redacted]	2008
Smith Unit 1 Coal-Fired Unit	[redacted]	2009
Combustion Turbine Units No. 8-12	[redacted]	2009
Unit No. 5 Combustion Inspection	[redacted]	2010
Smith Unit 1 Coal-Fired Unit	[redacted]	2010
Unit No. 4 Hot Gas Path Inspection	[redacted]	2011
Unit No. 6 Combustion Inspection	[redacted]	2011
Unit No. 7 Combustion Inspection	[redacted]	2011
Catalyst Replacement Units No. 8 - 12	[redacted]	2011
Unit No. 2 Major Inspection	[redacted]	2012
Unit No. 1 Major Inspection	[redacted]	2013
Unit No. 5 Hot Gas Path Inspection	[redacted]	2013
Unit No. 3 Major Inspection	[redacted]	2014
Unit No. 6 Hot Gas Path Inspection	[redacted]	2014
Unit No. 7 Hot Gas Path Inspection	[redacted]	2014
Unit No. 4 Combustion Inspection	[redacted]	2014
Catalyst Replacement Units No. 8-12	[redacted]	2014
Unit No. 5 Combustion Inspection	[redacted]	2016
Unit No. 6 Combustion Inspection	[redacted]	2017
Unit No. 7 Combustion Inspection	[redacted]	2017
Unit No. 4 Combustion Inspection	[redacted]	2017
Catalyst Replacement Units No. 8-12	[redacted]	2018

Table 8.(2)(a) –4 Continued
Major MEAGER Projects Planned 2007 - 2027
Smith Station

Description	Cost Estimate (2006$)	Estimated Completion Date
Unit No. 2 Major Inspection	[redacted]	2019
Unit No. 5 Combustion Inspection	[redacted]	2019
Unit No. 6 Combustion Inspection	[redacted]	2020
Unit No. 7 Combustion Inspection	[redacted]	2020
Unit No. 4 Major Inspection	[redacted]	2020
Unit No. 1 Major Inspection	[redacted]	2020
Unit No. 6 Major Inspection	[redacted]	2020
Smith Unit No. 1 Coal-Fired Unit Major Overhaul	[redacted]	2020
Catalyst Replacement/Hot Gas Path - Units No. 8 - 12	[redacted]	2021
Unit No. 3 Major Inspection	[redacted]	2021
Unit No. 5 Major Inspection	[redacted]	2022
Unit No. 7 Major Inspection	[redacted]	2023
Unit No. 4 Combustion Inspection	[redacted]	2023
Unit No. 6 Major Inspection	[redacted]	2023
Catalyst Replacement Units No. 8-12	[redacted]	2024
Unit No. 5 Combustion Inspection	[redacted]	2025
Unit No. 2 Major Inspection	[redacted]	2026
Unit No. 4 Combustion Inspection	[redacted]	2026
Unit No. 6 Combustion Inspection	[redacted]	2026
Unit No. 7 Combustion Inspection	[redacted]	2026
Unit No. 1 Major Inspection	[redacted]	2027
Catalyst Replacement Units No. 8-12	[redacted]	2027
Smith Total MEAGER Projects 2007 - 2027	[redacted]	

*Includes Preliminary — Smith Unit No. 1 and CTs 8-12 Costs

Table 8.(2)(a) –5
Summary of Major MEAGER Projects Planned 2007 – 2027 (2006$)

Spurlock Total MEAGER Projects 2007 – 2027	[redacted]
Cooper Total MEAGER Projects 2007 – 2027	[redacted]
Dale Total MEAGER Projects 2007 – 2027	[redacted]
Smith Total MEAGER Projects 2007 – 2027	[redacted]
Total	[redacted]

Table 8.(3)(b)1.-11.

Generating Plant Data

	Dale Station			
	Unit 1	**Unit 2**	**Unit 3**	**Unit 4**
Location	Ford, KY	Ford, KY	Ford, KY	Ford, KY
Status	Existing	Existing	Existing	Existing
Commercial Operation	Dec. 1, 1954	Dec. 1, 1954	Oct 1, 1957	Aug 9, 1960
Type	Steam	Steam	Steam	Steam
Net Dependable Capability	23 MW	23 MW	75 MW	75 MW
Entitlement (%)	100	100	100	100
Primary Fuel Type	Coal	Coal	Coal	Coal
Secondary Fuel Type	None	None	None	None
Fuel Storage (Tons)	70,000 for Plant Site	70,000 for Plant Site	70,000 for Plant Site	70,000 for Plant Site
Scheduled Upgrades, Deratings, Retirement Dates*	None	None	None	None

* Please see Table 8.(2)(a)-3.

Table 8.(3)(b)1.-11. (continued)

Generating Plant Data

	Cooper Station		Spurlock Station			
	Unit 1	**Unit 2**	**Unit 1**	**Unit 2**	**Gilbert**	**Unit 4**
Location	Somerset, KY	Somerset, KY	Maysville, KY	Maysville, KY	Maysville, KY	Maysville, KY
Status	Existing	Existing	Existing	Existing	Existing	Under Construction
Commercial Operation	Feb. 9, 1965	Oct. 28, 1969	Sept. 1, 1977	Mar. 2, 1981	March 1, 2005	2009
Type	Steam	Steam	Steam	Steam	Steam	Steam
Net Dependable Capability	116 MW	225 MW	325 MW	525 MW	268 MW	278 MW
Entitlement (%)	100	100	100	100	100	100
Primary Fuel Type	Coal	Coal	Coal	Coal	Coal	Coal
Secondary Fuel Type	None	None	None	None	None	None
Fuel Storage (Tons)	250,000 for Plant Site	250,000 for Plant Site	105,000	175,000	105,000	105,000
Scheduled Upgrades, Deratings, Retirement Dates*						

* Please see Tables 8.(2)(a)-1 and 8.(2)(a)-2.

Table 8.(3)(b)1.-11. (continued)

Generating Plant Data

	Smith Combustion Turbines						
	Unit 1	**Unit 2**	**Unit 3**	**Unit 4**	**Unit 5**	**Unit 6**	**Unit 7**
Location	Trapp, KY	Trapp, KY	Trapp, KY	Trapp, KY	Trapp, KY	Trapp, KY	Trapp, KY
Status	Existing	Existing	Existing	Existing	Existing	Existing	Existing
Commercial Operation	3/1/99	1/1/99	4/1/99	11/10/01	11/10/01	1/12/05	1/12/05
Type	Gas	Gas	Gas	Gas	Gas	Gas	Gas
Net Dependable Capability	150 MW	150 MW	150 MW	98 MW	98 MW	98 MW	98 MW
Entitlement (%)	100	100	100	100	100	100	100
Primary Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Secondary Fuel Type	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil
Fuel Storage (Gallons)	4 million total	4 million total	4 million total	4 million total	4 million total	4 million total	4 million total
Scheduled Upgrades, Deratings, Retirement Dates*	None	None	None	None	None	None	None

*Please see Table 8.(2)(a)-4.

Table 8.(3)(b)1.-11. (continued)

Generating Plant Data

	Smith Combustion Turbines				
	Unit 8	**Unit 9**	**Unit 10**	**Unit 11**	**Unit 12**
Location	Trapp, KY	Trapp, KY	Trapp, KY	Trapp, KY	Trapp, KY
Status	Committed	Committed	Committed	Committed	Committed
Commercial Operation	2008	2008	2008	2009	2009
Type	Gas	Gas	Gas	Gas	Gas
Net Dependable Capability	97 MW	97 MW	97 MW	97 MW	97 MW
Entitlement (%)	100	100	100	100	100
Primary Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Secondary Fuel Type	N/A	N/A	N/A	N/A	N/A
Fuel Storage (Gallons)	N/A	N/A	N/A	N/A	N/A
Scheduled Upgrades, Deratings, Retirement Dates	N/A	N/A	N/A	N/A	N/A

Table 8.(3)(b)1.-11. (continued)

Generating Plant Data

	Smith 1	Smith 2
Location	Trapp, KY	Trapp, KY
Status	Committed	Proposed
Commercial Operation	2010	Oct. 2012
Type	Steam	Steam
Net Dependable Capability	278 MW	278 MW
Entitlement (%)	100	100
Primary Fuel Type	Coal	Coal
Secondary Fuel Type	None	None
Fuel Storage (Tons)	230,000	230,000
Scheduled Upgrades, Deratings, Retirement Dates	N/A	N/A

Table 8.(3)(b)1.-11. (continued)

Generating Plant Data

	Bavarian	Green Valley	Laurel Ridge #1-4	Laurel Ridge #5	Hardin Co.	Pendleton Co.
Location	Boone, KY	Greenup Co., KY	Lily, KY	Lily, KY	Hardin Co., KY	Pendleton Co., KY
Status	Existing	Existing	Existing	Existing	Existing	Proposed
Commercial Operation	9/22/03	9/9/03	9/15/03	2/1/06	1/15/06	1/07
Type	Gas	Gas	Gas	Gas	Gas	Gas
Net Dependable Capability	3.2 MW	2.4 MW	3.2 MW	0.8 MW	2.4 MW	3.2 MW
Entitlement (%)	100	100	100	100	100	100
Primary Fuel Type	Methane	Methane	Methane	Methane	Methane	Methane
Secondary Fuel Type	None	None	None	None	None	None
Fuel Storage	N/A	N/A	N/A	N/A	N/A	N/A
Scheduled Upgrades, Deratings, Retirement Dates	None	None	None	None	None	None

Table 8.(3)(b)1.-11. (continued)

Generating Plant Data

	Generic CFB 1	Generic CFB 2	Generic LMS 100STIG	Generic LMS 100STIG-2
Location	Undetermined	Undetermined	Undetermined	Undetermined
Status	Proposed	Proposed	Proposed	Proposed
Commercial Operation	10/2014	10/2018	10/2015	10/2016
Type	Steam	Steam	Gas	Gas
Net Dependable Capability	Approx 300 MW (Modeled as 278MW)	Approx 300 MW (Modeled as 278MW)	Approx 100 MW (Modeled as 109MW)	Approx 100 MW (Modeled as 109MW)
Entitlement (%)	100	100	100	100
Primary Fuel Type	Coal	Coal	Natural Gas	Natural Gas
Secondary Fuel Type	None	None	None	None
Fuel Storage (Tons)	230,000	230,000	N/A	N/A
Scheduled Upgrades, Deratings, Retirement Dates	N/A	N/A	N/A	N/A

Table 8.(3)(b)12.

Dale 1	ACTUAL 2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	0.71	0.72	0.78	0.57	0.54	0.42	0.37	0.36	0.28	0.29	0.25	0.27	0.29	0.28	0.25	0.26
Availability Factor	0.91	0.94	0.94	0.79	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Average Heat Rate (Btu/kWh)	12,163	13,172	12,281	13,305	13,611	14,358	14,594	14,807	15,416	15,455	15,794	15,446	15,201	15,467	15,732	15,506
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Dale 2	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	0.74	0.79	0.86	0.69	0.60	0.43	0.42	0.39	0.32	0.32	0.28	0.30	0.32	0.32	0.28	0.29
Availability Factor	0.93	0.95	0.95	0.79	0.91	0.91	0.91	0.91	0.90	0.91	0.91	0.91	0.90	0.91	0.91	0.91
Average Heat Rate (Btu/kWh)	11,967	12,308	11,891	12,137	13,160	14,050	14,135	14,468	14,999	15,009	15,262	14,968	14,869	14,863	15,276	15,258
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Table 8.(3)(b)12. (continued)

Dale 3	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	0.71	0.40	0.36	0.46	0.47	0.41	0.41	0.38	0.33	0.34	0.28	0.30	0.32	0.31	0.27	0.29
Availability Factor	0.92	0.92	0.83	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.89	0.90
Average Heat Rate (Btu/kWh)	11,608	13,052	12,906	12,670	12,562	12,914	12,993	13,080	13,354	13,319	13,667	13,496	13,327	13,369	13,679	13,498
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Dale 4	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	0.79	0.39	0.33	0.48	0.51	0.48	0.46	0.45	0.40	0.40	0.34	0.36	0.38	0.37	0.33	0.35
Availability Factor	0.98	0.83	0.76	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.90	0.91	0.91
Average Heat Rate (Btu/kWh)	11,725	12,867	12,989	12,557	12,391	12,463	12,613	12,626	12,847	12,816	13,027	12,936	12,831	12,907	13,062	12,942
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Table 8.(3)(b)12. (continued)

Cooper 1	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	0.74	0.80	0.76	0.75	0.73	0.82	0.80	0.77	0.68	0.66	0.60	0.62	0.64	0.62	0.58	0.59
Availability Factor	0.87	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Average Heat Rate (Btu/kWh)	10,100	9,906	9,888	9,949	10,014	10,215	10,218	10,239	10,324	10,369	10,457	10,443	10,428	10,460	10,523	10,501
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Cooper 2	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	0.67	0.74	0.64	0.68	0.68	0.80	0.72	0.68	0.75	0.75	0.72	0.73	0.73	0.73	0.71	0.72
Availability Factor	0.92	0.91	0.90	0.91	0.91	0.90	0.90	0.91	0.90	0.91	0.91	0.90	0.90	0.91	0.90	0.91
Average Heat Rate (Btu/kWh)	10,151	10,186	10,217	10,230	10,233	10,389	10,430	10,463	10,370	10,375	10,393	10,386	10,379	10,383	10,399	10,391
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Table 8.(3)(b)12. (continued)

Spurlock 1	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	0.82	0.81	0.82	0.87	0.87	0.83	0.84	0.85	0.82	0.83	0.80	0.81	0.82	0.81	0.80	0.80
Availability Factor	0.99	0.92	0.91	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.90	0.91	0.91	0.90	0.90	0.90
Average Heat Rate (Btu/kWh)	10,136	10,411	10,309	10,219	10,428	10,489	10,471	10,462	10,496	10,491	10,525	10,512	10,503	10,509	10,538	10,534
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Spurlock 2	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	0.84	0.70	0.75	0.89	0.87	0.82	0.83	0.84	0.81	0.80	0.78	0.79	0.80	0.79	0.76	0.77
Availability Factor	0.91	0.94	0.82	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Average Heat Rate (Btu/kWh)	9,782	10,817	10,445	10,383	10,639	10,715	10,688	10,688	10,730	10,737	10,777	10,757	10,745	10,754	10,804	10,782
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Table 8.(3)(b)12. (continued)

Gilbert Unit	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	0.60	0.73	0.82	0.90	0.89	0.83	0.85	0.85	0.84	0.84	0.82	0.83	0.83	0.83	0.82	0.82
Availability Factor	0.74	0.76	0.87	0.93	0.93	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89
Average Heat Rate (Btu/kWh)	9,758	9,834	9,831	9,827	9,827	9,832	9,828	9,828	9,830	9,829	9,833	9,832	9,831	9,831	9,833	9,832
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%
Spurlock 4	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	-	-	-	-	0.67	0.82	0.87	0.88	0.87	0.86	0.85	0.85	0.86	0.86	0.84	0.84
Availability Factor	-	-	-	-	0.91	0.86	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89
Average Heat Rate (Btu/kWh)	-	-	-	-	9,830	9,833	9,827	9,826	9,828	9,828	9,830	9,830	9,829	9,828	9,831	9,830
Fuel Cost ($/MMBtu)	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Table 8.(3)(b)12. (continued)

Smith 1 (CFB)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	-	-	-	-	-	0.52	0.82	0.84	0.81	0.80	0.76	0.77	0.78	0.77	0.74	0.74
Availability Factor	-	-	-	-	-	0.91	0.86	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89
Average Heat Rate (Btu/kWh)	-	-	-	-	-	9,832	9,832	9,833	9,845	9,848	9,860	9,858	9,854	9,857	9,868	9,866
Fuel Cost ($/MMBtu)	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%
Smith 2 (CFB)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	-	-	-	-	-	-	-	0.18	0.77	0.80	0.76	0.77	0.78	0.77	0.74	0.74
Availability Factor	-	-	-	-	-	-	-	0.88	0.86	0.89	0.89	0.89	0.89	0.89	0.89	0.89
Average Heat Rate (Btu/kWh)	-	-	-	-	-	-	-	9,838	9,849	9,848	9,859	9,857	9,855	9,857	9,867	9,866
Fuel Cost ($/MMBtu)	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Table 8.(3)(b)12. (continued)

Generic CFB 1	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	-	-	-	-	-	-	-	-	-	0.19	0.82	0.85	0.86	0.85	0.84	0.84
Availability Factor	-	-	-	-	-	-	-	-	-	0.88	0.86	0.89	0.89	0.89	0.89	0.89
Average Heat Rate (Btu/kWh)	-	-	-	-	-	-	-	-	-	9,833	9,833	9,830	9,829	9,829	9,831	9,830
Fuel Cost ($/MMBtu)	-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Generic CFB 2	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	0.23	0.84	0.85
Availability Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	0.94	0.89	0.89
Average Heat Rate (Btu/kWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	9,832	9,831	9,830
Fuel Cost ($/MMBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	-	-	-	-	-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Table 8.(3)(b)12. (continued)

Gen LMS 100STIG	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	-	-	-	-	-	-	-	-	-	-	0.04	0.20	0.18	0.17	0.14	0.16
Availability Factor	-	-	-	-	-	-	-	-	-	-	0.95	0.95	0.95	0.95	0.95	0.95
Average Heat Rate (Btu/kWh)	-	-	-	-	-	-	-	-	-	-	8,998	9,041	8,978	8,950	9,063	9,025
Fuel Cost ($/MMBtu)	-	-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	-	-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	-	-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	-	-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Gen LMS 100STIG-2	2005.00	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	0.04	0.22	0.21	0.18	0.19
Availability Factor	-	-	-	-	-	-	-	-	-	-	-	0.95	0.95	0.95	0.95	0.95
Average Heat Rate (Btu/kWh)	-	-	-	-	-	-	-	-	-	-	-	8,989	9,013	8,997	9,111	9,091
Fuel Cost ($/MMBtu)	-	-	-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	-	-	-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Table 8.(3)(b)12. (continued)

Smith CT1	2005.00	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	0.02	0.17	0.22	0.18	0.05	0.04	0.04	0.03	0.02	0.02	0.01	0.02	0.01	0.01	0.01	0.01
Availability Factor	0.90	0.84	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
Average Heat Rate (Btu/kWh)	14,510	10,457	10,457	10,392	10,382	10,479	10,512	10,568	10,482	10,568	10,511	10,464	10,285	10,360	10,236	10,336
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Smith CT2	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	0.05	0.14	0.16	0.14	0.05	0.04	0.04	0.04	0.03	0.03	0.02	0.01	0.02	0.02	0.01	0.01
Availability Factor	0.83	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
Average Heat Rate (Btu/kWh)	14,759	10,382	10,347	10,351	10,434	10,526	10,558	10,561	10,531	10,542	10,530	10,414	10,309	10,420	10,319	10,385
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Table 8.(3)(b)12. (continued)

Smith CT3	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	0.02	0.11	0.12	0.11	0.06	0.06	0.06	0.06	0.04	0.04	0.03	0.02	0.02	0.03	0.01	0.02
Availability Factor	0.84	0.93	0.83	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
Average Heat Rate (Btu/kWh)	15,187	10,323	10,291	10,306	10,493	10,526	10,583	10,610	10,631	10,623	10,607	10,533	10,492	10,485	10,514	10,552
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Smith CT4	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	0.11	0.04	0.04	0.04	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Availability Factor	0.97	0.99	0.97	0.99	0.99	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
Average Heat Rate (Btu/kWh)	12,257	14,626	14,586	14,392	13,822	14,095	14,156	14,098	14,078	14,125	14,388	13,962	13,610	13,782	14,218	13,790
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Table 8.(3)(b)12. (continued)

Smith CT5	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	0.06	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Availability Factor	1.00	0.95	0.97	0.99	0.99	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
Average Heat Rate (Btu/kWh)	11,726	14,197	14,272	14,110	14,417	14,471	14,507	14,558	14,340	14,535	14,807	14,094	13,990	14,088	14,079	14,256
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Smith CT6	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	0.11	0.02	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Availability Factor	0.99	0.97	0.95	0.99	0.99	0.97	0.97	0.97	0.97	0.97	0.96	0.97	0.97	0.97	0.97	0.97
Average Heat Rate (Btu/kWh)	11,531	14,106	14,075	13,945	14,342	14,171	14,324	14,432	14,366	14,588	14,899	14,099	13,395	13,792	13,930	13,967
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Table 8.(3)(b)12. (continued)

Smith CT7	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	0.08	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Availability Factor	1.00	0.99	0.97	0.99	0.99	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
Average Heat Rate (Btu/kWh)	12,072	14,063	13,915	13,888	14,204	14,049	14,194	14,222	14,259	14,390	14,689	14,320	13,761	14,082	13,883	13,971
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Smith CT8	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	-	-	-	0.14	0.11	0.10	0.10	0.09	0.08	0.08	0.05	0.05	0.04	0.05	0.03	0.04
Availability Factor	-	-	-	0.99	0.99	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
Average Heat Rate (Btu/kWh)	-	-	-	10,604	10,172	10,223	10,269	10,240	10,397	10,377	10,519	10,523	10,477	10,461	10,490	10,533
Fuel Cost ($/MMBtu)	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Table 8.(3)(b)12. (continued)

Smith CT9	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	-	-	-	0.09	0.15	0.13	0.13	0.12	0.10	0.10	0.07	0.06	0.06	0.06	0.04	0.05
Availability Factor	-	-	-	0.99	0.99	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
Average Heat Rate (Btu/kWh)	-	-	-	10,541	10,244	10,274	10,339	10,302	10,436	10,440	10,557	10,558	10,529	10,507	10,584	10,577
Fuel Cost ($/MMBtu)	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Smith CT10	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	-	-	-	0.00	0.21	0.20	0.19	0.18	0.15	0.15	0.10	0.08	0.08	0.08	0.06	0.06
Availability Factor	-	-	-	1.00	0.99	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
Average Heat Rate (Btu/kWh)	-	-	-	10,215	10,324	10,363	10,413	10,383	10,493	10,488	10,614	10,583	10,581	10,557	10,607	10,640
Fuel Cost ($/MMBtu)	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Table 8.(3)(b)12. (continued)

Smith CT11	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	-	-	-	-	0.25	0.26	0.25	0.24	0.20	0.20	0.15	0.11	0.11	0.10	0.09	0.09
Availability Factor	-	-	-	-	0.99	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.96	0.97	0.97
Average Heat Rate (Btu/kWh)	-	-	-	-	10,371	10,390	10,439	10,435	10,533	10,529	10,630	10,629	10,630	10,625	10,679	10,664
Fuel Cost ($/MMBtu)	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Smith CT12	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	-	-	-	-	0.07	0.08	0.07	0.07	0.06	0.05	0.04	0.06	0.03	0.04	0.02	0.04
Availability Factor	-	-	-	-	0.99	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.96	0.97	0.97	0.97
Average Heat Rate (Btu/kWh)	-	-	-	-	10,196	10,184	10,251	10,231	10,344	10,331	10,448	10,614	10,450	10,404	10,412	10,469
Fuel Cost ($/MMBtu)	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Table 8.(3)(b)12. (continued)

Landfill Gas Projects	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Capacity Factor	0.85	0.95	0.95	0.95	0.94	0.95	0.95	0.95	0.94	0.95	0.95	0.95	0.95	0.95	0.95	0.94
Availability Factor	0.89	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
Average Heat Rate (Btu/kWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fuel Cost ($/MMBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Variable O&M ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
O&M Escalation		2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%

Table 8.(3)(c)

Power Transactions (GWH)															
Power Purchases	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Market Purchase	1,236.7	1,245.8	1,817.0	1,332.8	860.6	676.7	627.4	430.3	365.9	267.4	252.5	285.9	266.9	169.1	202.0
Duke Energy (Greenup)	302.0	301.9	302.9	302.1	302.1	-	-	-	-	-	-	-	-	-	-
SEPA	263.5	257.9	260.7	257.2	254.1	259.7	256.0	257.2	256.8	257.8	258.7	257.1	256.9	258.0	259.2
Total Purchases	1,802.1	1,805.6	2,380.6	1,892.1	1,416.7	936.4	883.4	687.5	622.8	525.2	511.2	542.9	523.8	427.2	461.2
Market Power Sales	270.5	189.7	95.5	225.1	495.4	482.1	528.6	786.2	858.9	1,198.6	1,216.4	1,148.0	1,212.8	1,466.1	1,407.5

Table 8.(3)(d)

Non-Utility Generation (GWH)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Non-Utility Generation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewables*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

* Generation from landfill gas to energy projects are included in the response to 8.(3)(b) and 8.(4)(c).

Table 8.(4)(b)1-4

Forecast Energy	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Requirements (GWh) (as modeled)	12,503.2	12,892.3	14,837.0	15,672.7	16,178.7	16,509.8	16,839.6	17,296.3	17,626.9	17,972.6	18,391.0	18,766.0	19,155.2	19,542.8	19,947.7
Generation (GWH)															
Coal	10,323.0	10,529.7	11,658.0	12,958.7	14,230.6	15,040.6	15,477.9	16,499.6	16,960.4	17,867.6	18,164.8	18,326.2	18,756.2	19,661.3	19,903.3
Natural Gas	550.9	623.1	741.1	868.2	821.5	783.1	747.8	610.8	591.1	440.5	565.9	653.8	670.3	502.8	572.4
Landfill Gas	97.8	123.6	152.8	178.8	205.3	231.9	259.2	284.6	311.6	337.8	365.5	391.0	417.6	417.6	418.3
Total	10,971.7	11,276.4	12,551.8	14,005.7	15,257.4	16,055.5	16,484.9	17,395.1	17,863.1	18,645.9	19,096.2	19,371.0	19,844.1	20,581.7	20,894.0
Purchases (GWH)															
Firm Purchases-SEPA	263.5	257.9	260.7	257.2	254.1	259.7	256.0	257.2	256.8	257.8	258.7	257.1	256.9	258.0	259.2
Firm Purchases-Other Utilities	302.0	301.9	302.9	302.1	302.1	-	-	-	-	-	-	-	-	-	-
Firm Purchases-Non-Utilities	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	565.4	559.8	563.6	559.2	556.2	259.7	256.0	257.2	256.8	257.8	258.7	257.1	256.9	258.0	259.2

Table 8.(4)(c)

Fuel Input (1,000s MBTU)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	108,652	109,235	120,716	134,956	148,036	155,881	160,143	170,135	174,699	183,573	186,509	188,103	192,336	201,212	203,631
Natural Gas	5,998	6,691	7,960	9,075	8,596	8,235	7,863	6,462	6,247	4,632	5,682	6,404	6,590	4,933	5,628
Total	114,650	115,925	128,676	144,032	156,631	164,116	168,006	176,597	180,946	188,205	192,191	194,507	198,926	206,145	209,259
Fuel Input (Physical Units)															
Coal (1,000s Tons)	4,591	4,624	5,095	5,651	6,695	7,277	7,629	8,509	8,728	9,097	9,235	9,312	9,497	9,871	9,985
Natural Gas (1,000s mcf)	6,333	7,065	8,406	9,583	9,077	8,696	8,303	6,824	6,596	4,891	6,000	6,763	6,959	5,209	5,943

SECTION 9

FINANCIAL INFORMATION

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9. FINANCIAL INFORMATION

Table 9-1 provides the Present (base year) value of revenue requirements stated in dollar terms for the 2006 Integrated Resource Plan and the Nominal and Real Revenue Requirements (in $millions) from the Member Systems. The Average Rate for each of the forecast years included in the plan is defined as the Nominal Revenue Requirements divided by the total Sales to Members (in cents/kWh) and is also included in Table 9-1.

The discount rate used in present value calculations is [redacted]%. This rate is based on a long-term debt rate of [redacted]% and a Times Interest Earned Ratio of [redacted].

TABLE 9-1

EAST KENTUCKY POWER COOPERATIVE, INC.

REVENUE REQUIREMENTS AND AVERAGE SYSTEM RATES

Year	Sales to Members (MWh)	Total From Members Nominal $ ($000)	Total From Members Real 2006 $ * ($000)	Total From Members PV @ 7.15% ($000)	Nominal Cents per kWh	Real Cents per kWh Real 2006$
2006	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2007	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2008	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2009	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2010	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2011	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
			**PV =	[redacted]		

* Assumes an annual inflation rate of [redacted]%.

** Present value of revenue requirements using EKPC's discount rate of [redacted]% and a base date of 12/31/05.