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April 20, 2012

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

Dear Mr. Derouen:

Please find enclosed for filing with the Commission an original and ten redacted copies of East Kentucky Power Cooperative, Inc.'s ("EKPC") 2012 Integrated Resource Plan ("IRP") and Technical Appendices. Also enclosed are an original and ten copies of EKPC's Petition for Confidential Treatment of Information. One copy of the designated confidential portions of the responses is enclosed in a sealed envelope.

Very truly yours,

Mark David Goss

Mark David Goss

Cc: Office of Rate Intervention, Office of the Attorney General
Boehm, Kurtz and Lowry

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION RECEIVED

APR 20 2012

PUBLIC SERVICE COMMISSION

In the Matter of:

A REVIEW PURSUANT TO 807 KAR 5:058	)
OF THE 2012 INTEGRATED RESOURCE	)
PLAN OF EAST KENTUCKY POWER	) **CASE NO. 2012-**
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 2012 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 (pages 63 through 72), projections of revenue requirements, interest rates and escalation rates (page 187). 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 provide an unfair commercial advantage to competitors of EKPC.

3. Disclosure of confidential information contained on page 159 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 commercial advantage to competitors of EKPC for the reasons stated and could artificially increase power costs to EKPC's member systems.

4. As part of the IRP filing, on the last page of the IRP, and in compliance with 807 KAR 5:058 Section 8, EKPC has included a map detailing critical system infrastructure. The map, which is entitled "East Kentucky Power Cooperative 2012-2015 Projects," contains all or a combination of the exact geographic locations of EKPC generation stations, existing substations, proposed substations, service centers, high voltage transmission lines exceeding 69kV, and foreign utilities' high voltage transmission lines.

Location data of critical utility structures is very sensitive information and could provide a security risk for EKPC and its Member Systems.

KRS 61.878(1)(k) exempts from the public domain, except through Court Order, "All public records or information the disclosure of which is prohibited by federal law or regulation." Disclosure of transmission line locations, as well as the other types of sensitive data contained on the referenced maps, is specifically protected as Critical Energy Infrastructure Information per certain Orders of the Federal Energy Regulatory

Commission (See, Order numbers 630, 630-A, 643, 649, 662, 683 and 702, and PL02-1-000).

The Commission is requested to afford this map detailing Critical Energy Infrastructure Information confidential treatment.

5. Along with this Petition, EKPC has enclosed one copy of confidential sections of its 2012 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,

Mark David Goss

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Lexington, KY 40507-1749
(859) 231-0000 – Telephone
(859) 231-0011 – Facsimile
Counsel 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 April, 2012. Further, this is to certify that copies of the foregoing Petition for Confidential Treatment of Information in the above-styled case were transmitted by first-class U.S. mail to: Hon. Jennifer B. Hans, Executive Director, Office of Rate Intervention, Office of the Attorney General, 1024 Capital Center Drive, Suite 200, Frankfort, Kentucky 40601-8204; and, Hon. Michael L. Kurtz, Boehm, Kurtz and Lowry, 36 East Seventh Street, Suite 1510, Cincinnati, Ohio 45202, pursuant to 807 KAR 5:001, Section 7(2)(c).

Mark David Goss

Counsel for East Kentucky Power Cooperative, Inc.

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SECTION 1.0

EXECUTIVE SUMMARY

INTEGRATED RESOURCE PLAN

EAST KENTUCKY POWER COOPERATIVE

A Touchstone Energy® Cooperative

SECTION 1.0
EXECUTIVE SUMMARY

1.1 General Overview

807 KAR 5:058 Section 5.(1) Description of the utility, its customers, service territory, current facilities, and planning objectives.

East Kentucky Power Cooperative ("EKPC") is a generation and transmission electric cooperative located in Winchester, Kentucky. It serves 16 member distribution cooperatives who serve more than 520,000 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	Nolin RECC
Cumberland Valley Electric	Owen Electric Cooperative
Farmers RECC	Salt River Electric Coop. Corp.
Fleming-Mason Energy Cooperative	Shelby Energy Cooperative
Grayson RECC	South Kentucky RECC
Inter-County Energy Coop. Corp.	Taylor County RECC

EKPC owns and operates coal-fired generation at Dale Station (196 MW), Cooper Station (341 MW), and Spurlock Station (1,346 MW) and gas-fired generation at Smith Station (1,032 MW winter rating) and six landfill sites (16 MW).

EKPC purchases hydropower from the Southeastern Power Administration ("SEPA") on a long-term basis. Laurel Dam (70 MW) has been reliable capacity. However, due to various repair projects, specifically Wolf Creek Dam, EKPC's 100 MW allocation from the Cumberland System has not provided dependable capacity for several years and is not expected to be considered dependable until 2015. Once the dam repairs are completed, the capacity should return to firm dependable status for the long term.

In total, EKPC owns and/or purchases 3,101 MW of generation and an additional 400 MW of import capability via firm transmission rights from PJM. EKPC's all-time peak demand of 3,152 MW occurred on January 16, 2009.

EKPC owns and operates a 2967-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 is a member of the SERC Reliability Corporation ("SERC"). EKPC maintains 68 normally closed free-flowing interconnections with its neighboring utilities.

1.2 Load Forecast

EKPC's load forecast is prepared every two years in accordance with EKPC's Rural Utilities Service ("RUS") approved Work Plan. The Work Plan details the methodology used in preparing the projections. EKPC prepares its load forecast by working jointly with each member system to prepare their load forecast. Member projections are then summed to determine EKPC's forecast for the 20-year period. Member cooperatives use their load forecasts in developing construction work plans, long range work plans, and financial forecasts. EKPC uses the load forecast in such areas as demand-side management analyses, marketing analyses, transmission planning, power supply planning, integrated resource planning, compliance planning and financial forecasting.

EKPC completed its last official forecast in late 2010. Due to continuing economic downturns and unprecedented load implications, EKPC updated its load forecast again in 2011 with a broad overlook of general conditions. The results of this update, as well as a new DSM analysis, are the basis for the forecast used in this Integrated Resource Plan.

EKPC's weather-normalized load forecast indicates that, through 2026 on an annual average basis, total energy requirements are projected to increase by 1.6 percent, net winter peak demand will increase by approximately 1.0 percent, and net summer peak demand will increase by approximately 0.9 percent. Peak demands are based on coincident hourly-integrated demand intervals.

1.3 Demand Side Management ("DSM")

EKPC evaluated a total of 113 DSM measures, 103 new and 10 existing, for the 2012 Integrated Resource Plan ("IRP"). A two-step process was used in the evaluation: (1) Qualitative Screening, and (2) Quantitative Evaluation.

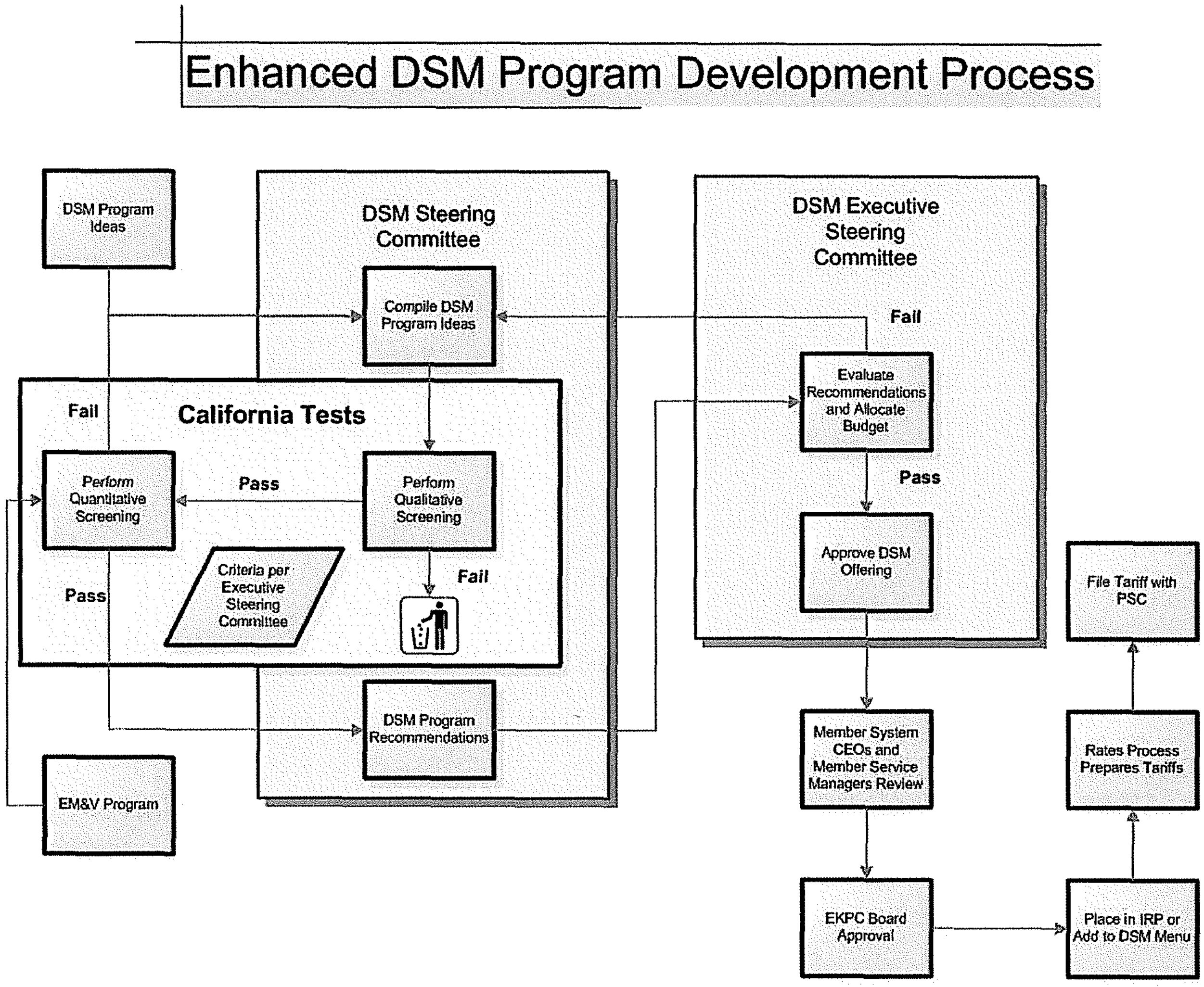
In response to the PSC Staff comments from EKPC's 2009 IRP, EKPC took a more aggressive and flexible approach in considering measures that should be carried into the quantitative analysis. Forty three measures passed the Qualitative Screen and were passed on to Quantitative Evaluation using the DSMore computer program. The results for the cost-effectiveness tests were generally favorable for the DSM programs. The programs were compared against EKPC's marginal energy costs, marginal generation capacity costs, marginal transmission and distribution costs, and carbon related fossil fuel costs. The theoretical results assume mature DSM programs and do not consider customer or behavioral barriers to adoption.

Ten existing programs and 20 new programs were found to be potentially economically viable, based solely on the standard California tests. 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, energy efficiency, load management, demand response, 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 distribution cooperative basis.

EKPC has considered and reported the theoretical potential for DSM; however, it is neither prudent nor practical to expect to achieve all of these results, especially in the short term. EKPC recognizes the importance of DSM programs to its customers and the environment. EKPC has offered DSM programs since the early 1980's and is prepared to invest in and commit resources to achieving reasonable DSM goals. EKPC believes an aggressive but reasonable DSM goal would be to pursue approximately 50 MW over a five year period.

EKPC's analysis has determined the technically feasible, but not necessarily reasonably attainable, amount of DSM that could be potentially available on the EKPC system. The next step is to refine these programs into the most desirable programs for the specific EKPC members and develop reasonable action plans to develop a set of financially feasible programs. EKPC will need to determine the amount of rebate required to ensure program acceptance. EKPC has established a steering committee of Member System CEOs, Member System employees, EKPC employees and EKPC Senior Management to develop the DSM program and program implementation. Each program will be reconsidered given specific EKPC demographic and economic data, as opposed to general industry data. Budget and resource constraints will also be considered. Final program details will then be compiled but will not be complete until late 2012. The diagram below outlines the DSM program development process.



In support of the recommendation by the Collaborative (discussed on pages 9 and 10 of this IRP), EKPC will benchmark with other utilities and do research in preparation of obtaining an evaluation, measurement and verification (EM&V) process for ensuring that savings are captured as they apply to the energy efficiency and demand response programs and initiatives (DSM). EKPC currently measures the impacts but a more robust procedure is warranted. Various solutions and vendors will be researched to find the most suitable for EKPC.

1.4 Power Supply Actions

EKPC desires to keep its plans as flexible as possible to be able to adjust to market and load conditions as needed. EKPC continues to monitor its load and all economic power supply alternatives, including but not limited to, joining a Regional Transmission Organization ("RTO"). As discussed in the previous section, EKPC is still refining its DSM plans and programs. Therefore, EKPC's immediate winter peaking capacity needs are planned to be met with Power Purchase Agreements which can be shaped to best match EKPC's load requirements in the short term. Market conditions currently favor buyers, which also supports this position.

Given current EPA regulations, specifically the Mercury and Air Toxics Standards (MATS) rules, EKPC will be faced with investing a significant amount of capital in its older Dale and Cooper 1 units to comply with proposed environmental regulations or to replace that capacity with a more economic alternative in 2015. EKPC is also considering proposed environmental regulations for water and waste. EKPC plans to issue a Request for Proposals ("RFP") for power supply to determine its most economic course of action for supplying this capacity. EKPC will submit a capital improvement plan for Dale Station and Cooper 1 as an option in the RFP so that the upgrade alternative can be evaluated with all other options on a comparable basis. EKPC will hire an outside consultant to prepare the RFP, solicit and evaluate proposals. Results are expected to be available by the end of 2012. Results of this analysis will help define EKPC's longer term course of power supply action.

1.5 Recommended Plan of Action

807 KAR 5:058 Section 5.(5) Steps to be taken during the next three (3) years to implement the plan.

EKPC's objective of the power supply plan is to develop an economic, reliable plan to serve its Member Systems, while simultaneously mitigating financial and operational risks. EKPC has an on-going planning process and this IRP represents only one snapshot in time of the process. Changing conditions will warrant changes to this IRP.

To meet that objective, EKPC will take the following actions in the near term:

- Continue to monitor economic and load conditions
- Continue to refine its DSM evaluations and develop a reasonable and financially viable comprehensive DSM Plan
- Issue an RFP for Power Supply resources to address the existing capacity affected by the EPA MATS rules
- Continue to evaluate and monitor joint operating opportunities

1.6 Issues or Uncertainties that Could Affect Successful Implementation of Plan

807 KAR 5:058 Section 5.(6) Discussion of key issues or uncertainties that could affect successful implementation of the plan.

As with any plan, there are risks and uncertainties associated with the recommended plan of action.

- *Continue to monitor economic and load conditions.* Today's financial environment provides an economic opportunity to invest in capital infrastructure. If EKPC were to miss significant changes in its load conditions that would warrant investing in capital intensive power supply projects, then the long term impact to member owners will be higher financing costs for future projects. Therefore, monitoring economic and load conditions is critical to EKPC's plans.
- *Continue to refine its DSM evaluations and develop a reasonable and financially viable comprehensive DSM Plan.* EKPC desires to develop reasonable and economic DSM

programs. The technical feasibility analysis provided in this IRP describes the most advantageous of circumstances and assumes that EKPC's service territory is comparable to those areas that have obtained high success with the analyzed programs. EKPC must now refine that analysis and determine how each program could work within the EKPC system and which programs provide the most advantageous results. EKPC's experience indicates that the financial investment required to successfully implement DSM programs exceeds the investment assumed in the California tests, principally due to promotional costs incurred to derive awareness, education and adoption in the EKPC service territory. It is not reasonable to expect to implement many different programs, but rather, EKPC will need to focus on a few highly desirable programs specific to its service territory. EKPC's current strategic goals focus on controlling rate pressures and achieving greater financial stability. Because the short term power market prices are lower than DSM costs due to depressed gas prices and low load levels, EKPC must keep this financial trade off in mind when developing its long term DSM goals. The current power supply plans will need to be adjusted according to the actual amount of DSM realized. EKPC has kept its power supply plans flexible, which will help facilitate DSM implementation, in that EKPC plans to make purchases to cover peaking power supply requirements. These purchases allow for the maximum amount of DSM to be developed while not placing the EKPC power supply system at risk.

- *Issue an RFP for Power Supply resources to address the existing capacity affected by the EPA MATS rules.* EKPC must consider the impacts of the MATS rules on its existing generation fleet. The Spurlock Plant units are state of the art facilities that can be readily modified to meet all of the new rules. Likewise, the Cooper 2 unit with its recent addition of pollution control equipment can also meet the new rules. The oldest units in the EKPC fleet, Dale Station and Cooper 1, will require capital intensive retrofits to meet operating requirements under the MATS rules. EKPC will seek to find the most economic alternative to meet its power supply requirements and meet MATS rules. EKPC will need to mitigate the potential risk of losing approximately 300 MW of existing power supply resources while maintaining economic and reliable power supply to its member owners.
- *Continue to evaluate and monitor joint operating opportunities.* EKPC could potentially mitigate a portion of its operating costs by partnering with others to obtain reasonable

economies of scale. Over the last year, EKPC has evaluated potential Regional Transmission Organization ("RTO") membership to obtain some of these economies. Membership in an RTO would impact the DSM economic evaluations. While EKPC's DSM programs would be operated to manage EKPC's load, the economic drivers within the RTO will be different than the economic drivers analyzed in the IRP and would require many of the programs to be re-evaluated. EKPC will also consider joint unit ownership in its RFP for power supply. Considering only stand alone options tends to increase costs to the EKPC member owners and transfers all ownership and operating risks to EKPC.

1.7 EKPC Demand-Side Management and Renewable Energy Collaborative

The EKPC Demand-Side Management and Renewable Energy Collaborative approved the following recommendations on January 31, 2012, by unanimous vote with the Attorney General abstaining from the vote. The recommendations were then provided to EKPC management. All recommendations are made with the assumption that cost recovery issues will be resolved.

- Partner with distribution member cooperatives and allocate resources for measurement and verification (M&V) of the cooperatives' existing and future DSM efforts. This includes developing a standardized, on-going process to collect data, investigate, and report on dynamic energy and demand impacts.
- Offer generally accepted DSM quantitative and qualitative analytic services to member systems on an individual, group, and/or system average basis using each member cooperative's unique market and cost structures.
- Aggressively help member systems market those DSM programs with the optimal benefit-cost profiles.
- Develop strong educational, marketing and training programs for member systems to promote DSM efforts considering all potential markets and channels for messaging.
- Allocate resources toward becoming and serving as a consultant and expert for member systems in their DSM efforts. Identify best practices, provide research support, and explore partnerships to this end.

- Continually evaluate new and on-going DSM programs, refining efforts to ensure optimal penetration of target market.

1.8 Organization of the 2012 IRP

807 KAR 5:058 Section 4.(2) Each plan filed shall identify the individuals responsible for its preparation, who shall be available to respond to inquiries during the commission's review of the plan.

Individuals responsible for the preparation of the IRP include:

David Crews, Senior Vice President of Power Supply

Craig Johnson, Senior Vice President of Power Production and Construction

Julia Tucker, Director of Power Supply Planning

Jerry Purvis, Director of Environmental Affairs

Jamie Hall, Manager of Load Forecasting

Darrin Adams, Manager of Transmission Planning

Scott Drake, Manager of Corporate Technical Services

Gary Stansberry, Manager of Corporate Performance Measures

Alma Gentry, Load Forecast Analyst

Ann Wood, Director of Regulatory Services

Legal Counsel: Mark David Goss, Frost Brown Todd

807 KAR 5:058 Section 4.(1) The integrated resource plan shall be clearly and concisely organized so that it is evident to the commission that the utility has complied with reporting requirements described in subsequent sections.

EKPC's 2012 IRP is organized in accordance with the sequencing of the planning process, while clearly cross-referencing the appropriate citation to 807 KAR 5:058.

The EKPC IRP Team, which consists of various personnel within the organization, used the PSC Staff Report of the 2009 IRP as a starting point in their analysis for this IRP. The PSC Staff Report recommendations, along with the basic requirements of the Commission's regulations, became the foundation leading to this Integrated Resource Plan.

1.9 Significant Changes from 2009

807 KAR 5:058 Section 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.

Collaborative

In March 2011, EKPC, its 16 owner-member cooperatives, the Sierra Club, the Kentucky Environmental Foundation, and Kentuckians for the Commonwealth formed the Demand-Side Management and Renewable Energy Collaborative. The group will meet quarterly at least through 2012 to evaluate and recommend actions for EKPC to expand deployment of renewable energy and demand side management, and to promote collaboration among the Collaborative members in the implementation of those ideas.

DSMore Software

In 2010, EKPC adopted as its evaluation software the Demand Side Management Option Risk Evaluator (DSMore), by Integral Analytics. DSMore is a modeling tool for energy efficiency, demand side management and demand response that correlates weather, loads and prices on an hourly level. The main benefits are as follows:

- DSMore is able to value DSM programs both in terms of traditional cost-based methods and in terms of supply-side market-based methods.
- DSMore allows EKPC to view results that reflect extremes in weather since results are based on many years of actual hourly weather data and their resulting impact on load savings.
- DSMore utilizes an Excel interface, which improved our process immensely. The former software, DSManager from the Electric Power Research Institute, was no longer supported and was becoming very labor intensive to use.

Duke Energy, LG&E/KU, and other utilities in at least 19 states use DSMore.

Cancellation of Smith Unit 1

As part of Commission Case No. 2010-00238, EKPC relinquished its Certificate of Public Convenience and Necessity on Smith Unit 1. Smith Unit 1 was part of EKPC's proposed expansion plan in the 2009 IRP.

Purchase of 400 MW of Firm Transmission

EKPC has purchased 400 megawatts of long-term transmission; the purchase was originally made from MISO, through EKPC's interconnection with Duke Kentucky, in late 2010. As a result of Duke Kentucky's entry into PJM effective January 1, 2012, EKPC lost its transmission interconnection with MISO and this long-term transmission has now transferred to PJM.

Discussion of differences between 2012 IRP Load Forecast and 2010 RUS Approved Load Forecast and between the 2012 IRP and the 2009 IRP

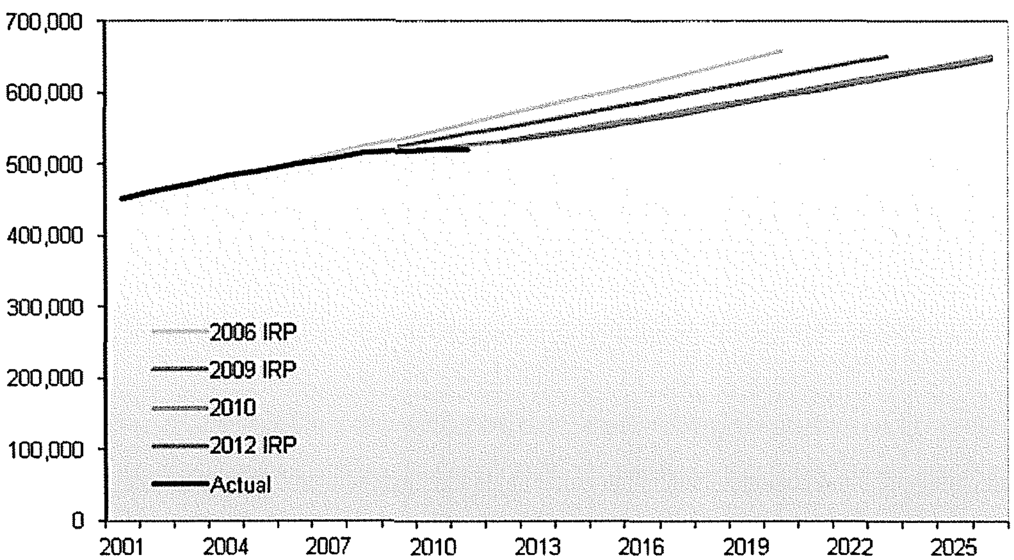
EKPC purchases county level projections of economic and demographic variables from IHS Global Insight, a consulting firm with expertise in economic modeling. Prior to the end of 2007, growth was strong and economic projections did not predict the recession. When the forecast for the 2009 IRP was developed, the member systems had begun to see a slowdown in housing construction in their service territories. However, the full impact of the recession across all sectors was not yet apparent. As a result of the recession, total customer growth weakened and energy use per customer declined and remains below pre-recession levels. Additionally unemployment reached an all time high and is not expected to return to pre-recession levels for nearly 10 years. The forecasts developed for the 2009 IRP were higher than actual levels observed to date. Due to this fact, as well as revisions to the long term economic forecasts, the forecasts were adjusted further downward for the 2010 forecast (submitted as part of Case 2010-00238). Between the 2010 forecast and 2012 IRP, the forecast was reevaluated. Adjustments were made due to slower than predicted residential customer growth, specific anticipated industrial loads that did not occur, and a reduction in existing industrial loads. The most notable update to the 2010 load forecast for the IRP is that the theoretical DSM impacts have been revised upward in the latter portion of the study period.

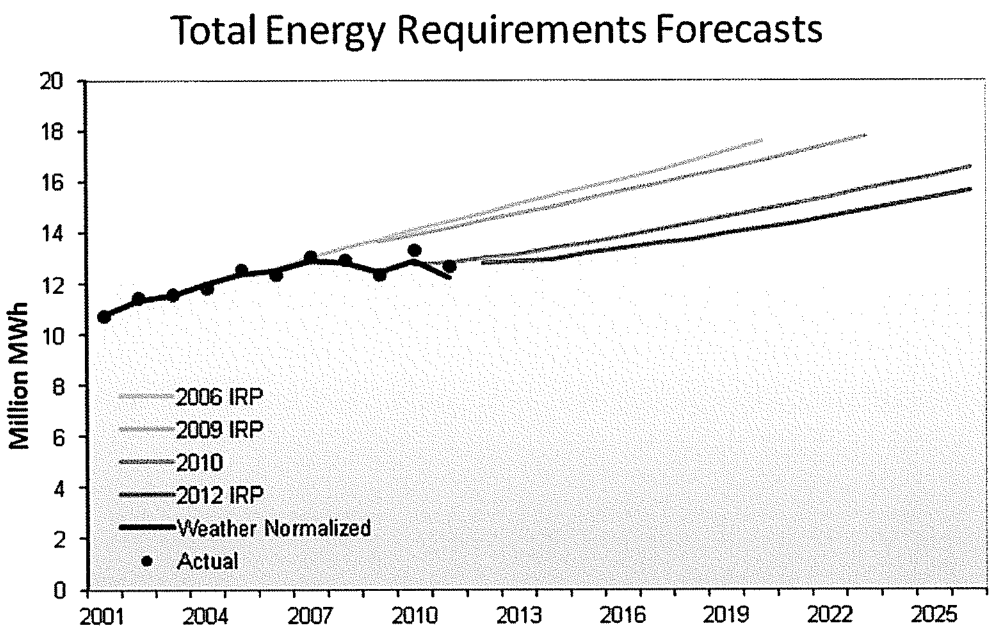
Load Forecast Comparison

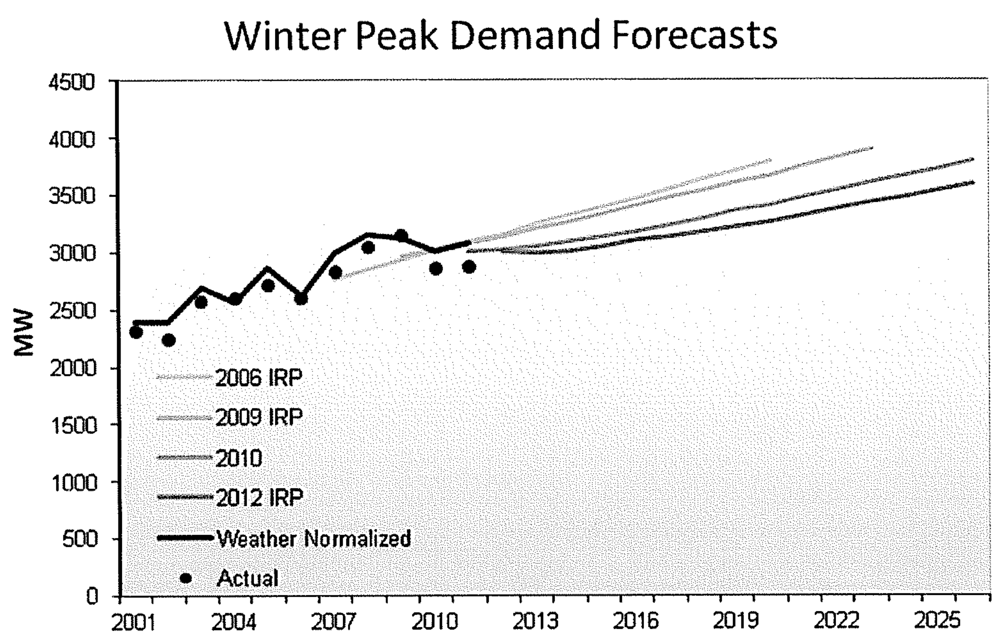
	Year	Actual	2009 IRP	2010	2012 IRP
Total Customers	2009	518,888	526,702		
	2010	520,464	534,970	522,069	
	2011	521,151	543,502	527,619	
	2012		552,192	534,083	532,521
	2017		596,974	574,374	570,886
	2022		643,079	617,499	613,739
Total Energy Requirements MWh[1]	2009	12,449,887	13,647,057		
	2010	12,935,290	13,959,302	12,778,010	
	2011	12,279,621	14,217,198	12,872,562	
	2012		14,511,928	13,061,903	12,860,110
	2017		15,930,390	14,106,559	13,588,573
	2022		17,479,553	15,437,297	14,642,201
Winter Peak MW[1]	2009	3,128			
	2010	3,012	3,029		
	2011	3,083	3,087	3,006	
	2012		3,143	3,033	3,006
	2017		3,482	3,245	3,145
	2022		3,833	3,547	3,379
Summer Peak MW[1]	2009	2,281	2,363		
	2010	2,353	2,406		
	2011	2,313	2,442	2,238	
	2012		2,475	2,263	2,246
	2017		2,737	2,402	2,292
	2022		3,016	2,640	2,469

[1] Weather normalized

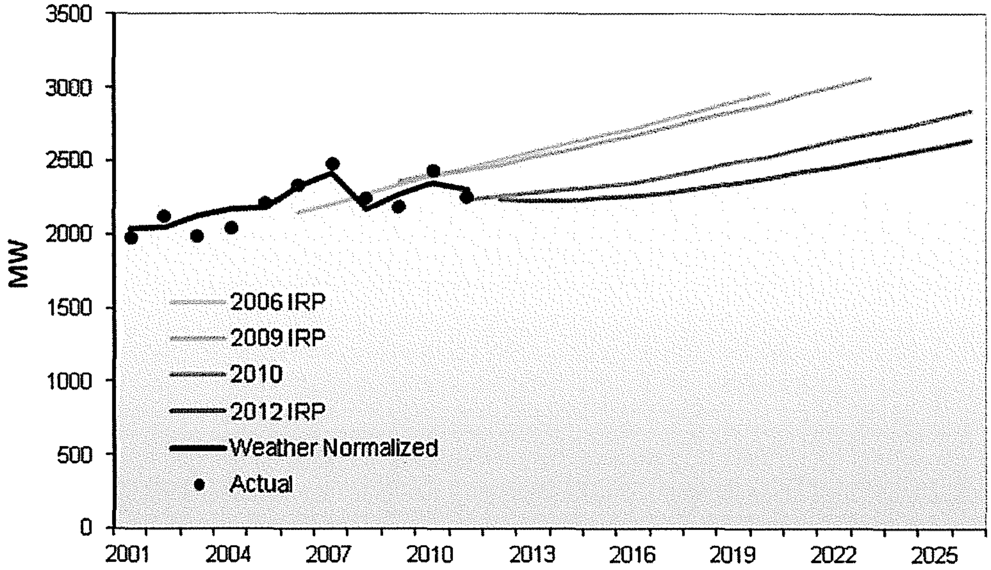
Total Customer Forecasts




Total Energy Requirements Forecasts
Million MWh
20
18
16
14
12
10
8
6
4
2
0
2006 IRP
2009 IRP
2010
2012 IRP
Weather Normalized
Actual
2001
2004
2007
2010
2013
2016
2019
2022
2025

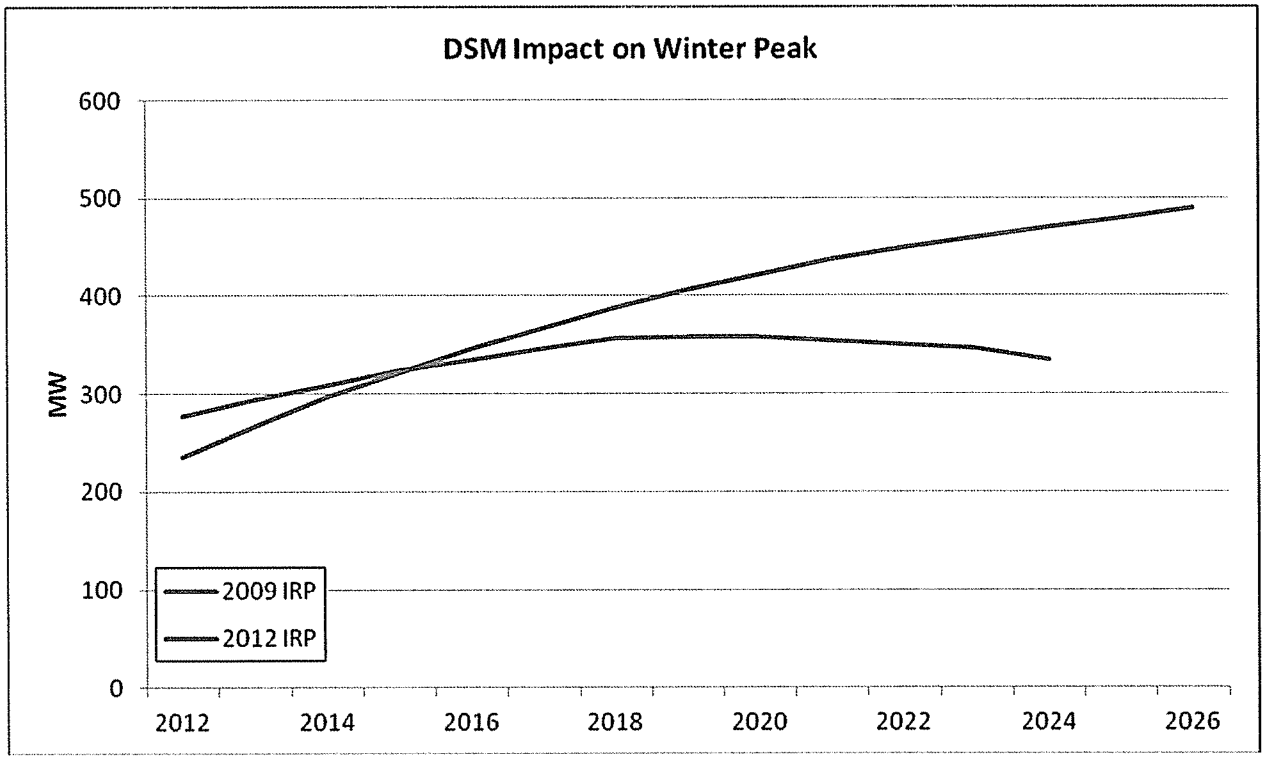

Winter Peak Demand Forecasts
MW
4500
4000
3500
3000
2500
2000
1500
1000
500
0
2006 IRP
2009 IRP
2010
2012 IRP
Weather Normalized
Actual
2001
2004
2007
2010
2013
2016
2019
2022
2025

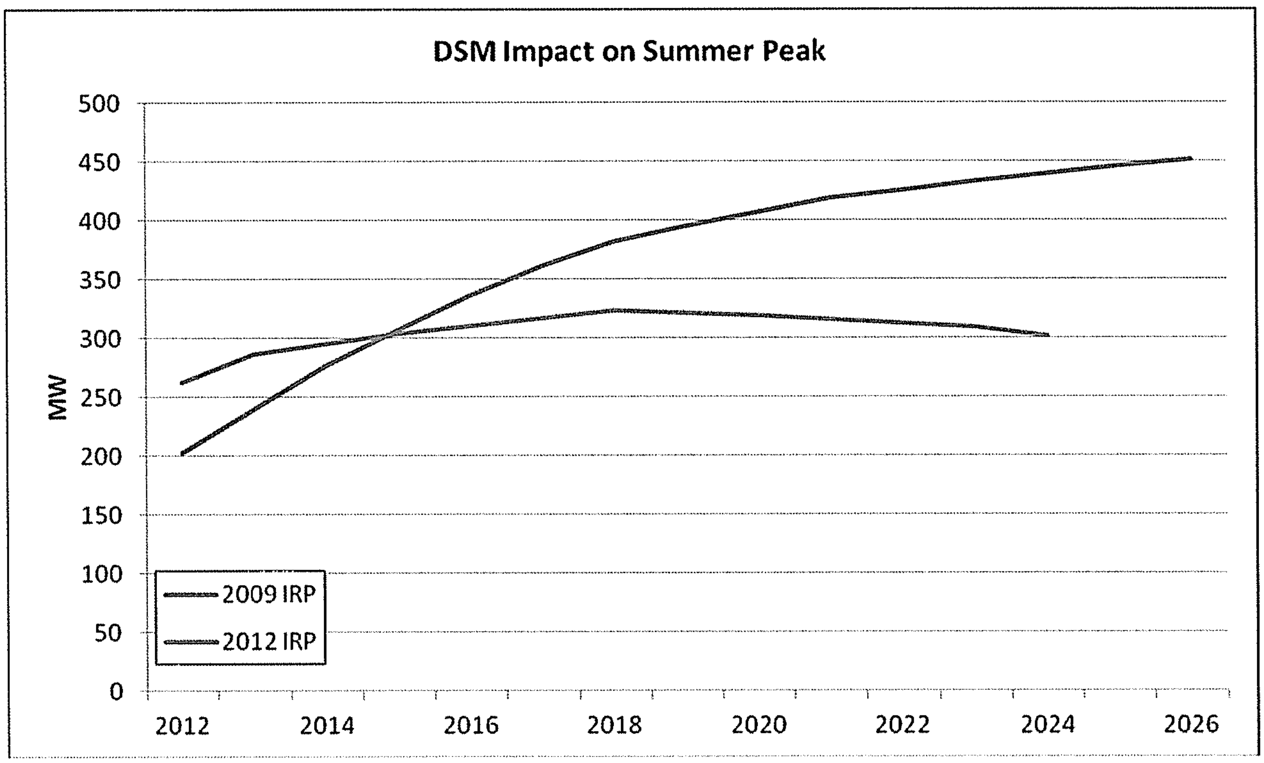
Summer Peak Demand Forecasts



Comparison of DSM Impacts

2009 IRP				2012 IRP			
Year	Impact on Energy Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)	Year	Impact on Energy Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	232,459	277.100	262.300	2012	161,448	236.094	202.433
2013	284,975	294.700	286.600	2013	240,423	267.472	240.270
2014	335,729	309.200	295.400	2014	319,156	297.473	276.352
2015	386,480	323.700	304.200	2015	395,050	321.675	306.649
2016	415,049	334.800	310.500	2016	470,983	345.910	336.956
2017	443,618	345.900	316.800	2017	545,245	367.220	361.250
2018	472,185	357.000	323.100	2018	619,377	387.620	381.604
2019	451,856	357.600	321.200	2019	683,801	405.761	395.409
2020	430,554	358.300	319.200	2020	732,796	421.768	407.358
2021	402,332	354.200	315.800	2021	781,988	437.807	419.329
2022	374,111	350.200	312.300	2022	801,546	448.853	426.039
2023	345,888	346.100	308.900	2023	822,287	460.100	432.883
2024	301,389	334.400	301.200	2024	840,096	469.974	439.292
2025				2025	857,803	479.778	445.670
2026				2026	875,526	489.596	452.051


DSM Impact on Winter Peak
600
500
400
300
200
100
0
MW
2009 IRP
2012 IRP
2012
2014
2016
2018
2020
2022
2024
2026


DSM Impact on Summer Peak
500
450
400
350
300
250
200
150
100
50
0
MW
2009 IRP
2012 IRP
2012
2014
2016
2018
2020
2022
2024
2026

EKPC Projected Major Capacity Additions

2009 IRP
Capacity
Available on
January 1

Winter
Season
Capacity

Year	Baseload Capacity	Peaking/ Intermediate Capacity	Cumulative Capacity Additions
	(MW)		
2009			
2010	278 (Spurlock 4), 2 LFGTE	200 (LMS), 200 Seas Purch	680
2011			680
2012		100	780
2013			780
2014	278 (Smith 1)		1058
2015		50	1108
2016			1108
2017	30		1138
2018			1138
2019		100	1238
2020		100	1338
2021	200		1538
2022			1538
2023	300		1838

2012 IRP
Capacity
Available on
January 1

Winter
Season
Capacity

Year	Baseload Capacity	Peaking/ Intermediate Capacity	Cumulative Capacity Additions
	(MW)		
2009			
2010	278 (Spurlock 4), 2 LFGTE	200 Seas Purch	680
2011		200 (LMS)	680
2012			680
2013		200 Seas Purch	880
2014			880
2015			880
2016		275 *	849
2017			849
2018		100 Seas Purch	949
2019			949
2020		100 Seas Purch	1049
2021			1049
2022		100 Seas Purch	1149
2023		275	1424
2024			
2025			
2026			

** Represents replacement for Dale Station (196 MW) and Cooper Unit 1 (110 MW) if they are not the least cost compliance option for the MATS rules.*

SECTION 2.0

PSC STAFF RECOMMENDATIONS TO EKPC'S 2009 IRP

SECTION 2.0
PSC Staff Recommendations to EKPC's 2009 IRP

2.1 Introduction

EKPC submitted its 2009 IRP (PSC Case No. 2009-00106) to the Commission on April 21, 2009. The report submitted by EKPC provided its plan to meet the power requirements of its 16 member distribution cooperatives over the period from 2009 to 2023. On December 2, 2010, EKPC received the Commission Staff's Report on the 2009 Integrated Resource Plan of East Kentucky Power Cooperative, Inc. The purpose of the report was to review and evaluate EKPC's 2009 IRP in accordance with the requirements of 807 KAR 5:058, Section 11(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.

2.2 PSC Staff Recommendations

Below are the Commission Staff's recommendations and EKPC's responses from the 2009 IRP.

807 KAR 5:058 Section 11.(4) A utility shall respond to the staff's comments and recommendations in its next integrated resource plan filing. (17 Ky.R. 1289; Am. 1720; eff. 12-18-90; 21 Ky.R. 2799; 22 Ky.R. 287; eff. 7-21-95.)

- **Continue to report on how its actual energy and demand levels compare to its forecasted levels.**

Please see this comparison provided on pages 12 through 16.

- **Include a detailed analysis of the potential impact of future environmental requirements that may be applicable to burning fossil fuels (including, but not limited to, restrictions on emissions of carbon dioxide (CO_2) and other greenhouse gases, carbon capture and sequestration, and a tax on carbon), and an explanation of how these potential impacts are incorporated into EKPC's present forecasts or how the potential impacts will be incorporated into future forecasts;**

Please see the detailed discussion of future environmental regulations in Section 9 of this IRP.

- **Include a detailed analysis of how the impact of federal mandatory efficiency improvements for appliances are reflected in its demand forecasts as well as in the energy forecasts for its commercial and industrial customer classes.**

For the small commercial class energy forecast, EKPC has been using a statistical model that estimates total class sales as a function of several explanatory variables, including electricity price, economic activity, number of customers, and prior sales. These regression equations are developed for each member cooperative. EKPC selected this model because it performed best in doing the job of predicting total sales.

EKPC also tested the detailed statistically adjusted end-use (SAE) modeling approach for the small commercial class. This is significant because the SAE model explicitly accounted for the impact of federal mandatory efficiency improvements. In fact, EKPC used data from EIA on efficiency trends as one of the driving variables for its SAE model. But the results of the analysis showed that the SAE model did not perform as well as the model EKPC ultimately selected.

Selecting which forecasting model to use is an art that involves tradeoffs. EKPC chose the model that performed better overall at the job of estimating total class sales, although in so doing it sacrificed the ability to isolate the impacts of certain factors that drive total class sales – such as the impact of federal equipment efficiency standards.

EKPC does a comprehensive update of its load forecast every two years. EKPC is currently preparing the next comprehensive load forecast for 2012. The work scope for the 2012 forecast includes taking a fresh look at the performance of the SAE model approach in the commercial and industrial class. This is timely in light of the most recent developments with efficiency standards.

EKPC has also analyzed studies that have been conducted nationally and by other utilities on the impact of Federal mandatory efficiency improvements on electricity usage. This analysis shows that savings from Federal standards over the next decade could accumulate at faster than the historical rate, because of standards that are being adopted over the 2009-2013 timeframe. This means that some of the savings may not be fully captured in pure econometric forecasts lacking an end-use model or adjustment. While most of the attention has been focused on this impact in the residential class, analysts are beginning to devote attention to the commercial class as well.

In addition, EKPC has examined the work of other utilities in this area.

South Carolina Electric and Gas, SCE&G, in its 2011 IRP explicitly accounted for residential appliance efficiency standards by making an adjustment to sales and peak demand, but did not do so for commercial or industrial equipment efficiency standards.

Louisville Gas & Electric and Kentucky Utilities used statistically adjusted end-use models to forecast commercial electricity consumption for their 2011 Integrated Resource Plan. They explicitly accounted for the expected impacts from the 2007 Energy Independence and Security Act (EISA) in their commercial energy intensity estimates. They projected a 0.5% annual average growth in energy intensity. In the load forecast being submitted with the 2012 IRP, EKPC projects a 0.45% annual average growth in use per customer for the small commercial class.

- **EKPC should take a somewhat more flexible approach in its consideration of the measures that, based on the results of its qualitative screening are carried on to the quantitative analysis.**

EKPC evaluated 113 Demand-Side Management (DSM) measures for the 2012 Integrated Resource Plan (IRP). Of these, 10 represent Existing DSM programs and 103 represent New DSM measures for this plan. A two-step process was used in the evaluation: (1) Qualitative Screening, and (2) Quantitative Evaluation.

Forty-three (43) new measures passed the Qualitative Screen and were passed on to Quantitative Evaluation. In some cases, several measures were combined into one program. Also, a few of the measures did not lend themselves to quantitative analysis or require additional research in order to allow for analysis in the future, or were set aside for other sound reasons that came to light during the study. A total of 33 new DSM Programs were prepared for the Quantitative Evaluation, compared to 25 new programs in 2009.

- **EKPC should consider DSM as an environmental compliance option in addition to a resource option. EKPC should include a detailed discussion in its next IRP of its plans for implementing carbon and greenhouse gas mitigation strategies.**

EKPC has endeavored to identify all major cost-effective demand-side management options and included ambitious goals for its new DSM programs in this 2012 IRP. The cost for environmental compliance is taken into account through the avoided cost calculations utilized in the California tests. The load was then reduced by DSM and the volume of combustion pollutants were reduced throughout the plan based on reduced load to be served. Environmental compliance is a multi-faceted challenge, and DSM does not address all forms of compliance. For example, best available control technology requirements cannot be relaxed because of reduced loadings on a generating unit. However, output based on environmental regulation (cap and trade approaches) are more suitable for considering DSM as a compliance option.

- **In the next IRP, EKPC should provide a specific discussion of the existence of any cogeneration within its service territory and the consideration given to cogeneration in its resource plan.**

There has been limited opportunity for the addition of cogeneration in the EKPC/Distribution Cooperative service territory. Currently, there is one cogeneration facility. This facility began selling electric power to EKPC in 1994 with sales of 563 MWh in 2010 and 980 MWh in 2011. EKPC and its associated Distribution Cooperatives offer a Qualified Cogeneration and Small Power Production Facilities tariff which allows cogeneration facilities to interconnect and sell electric power into the EKPC system. This tariff allows for cogeneration customers with qualifying facilities to sell all or part of their excess power to EKPC or its Member Cooperatives at published rates.

Due to the limited nature of qualified cogeneration facilities and potential for generation, EKPC does not include cogeneration in its resource plan.

- **EKPC should provide a specific identification and description of the net metering equipment and systems installed on each system. A detailed discussion of the manner in which such resources were considered in the resource plan should also be provided.**

Currently, there are approximately 80 net metering customers on the EKPC/Member Distribution Cooperative System. The majority of these are small residential photovoltaic systems ranging in size of 0.7 to 8.96 kW with an average size of approximately 2 kW. One Distribution Cooperative has four 30 kW net metering customers that are non-residential. There are three small wind turbine installations with the largest being 10 kW. In total, net metering accounts for just below 300 kW of installed capacity. In general, conventional photovoltaic installations in the EKPC/Distribution Cooperative service territories realize a 13-14% capacity factor while small wind turbine installations realize a wide range of capacity factors depending on specific installation location.

These resources would be considered by the individual cooperatives in the planning process as part of their load mix and then passed along to EKPC for inclusion in the overall resource plan.

- **EKPC should provide a detailed discussion of the consideration given to distributed generation in the resource plan.**

Due to immature nature of the development of distributed generation resources, no consideration is given by EKPC to distributed generation in the resource plan. Currently there is one distributed generator with 375 kW capacity installed and interconnected with a Distribution Cooperative. That load would be included in that individual cooperative's load forecast then passed along for inclusion in the overall resource plan.

There has been much discussion within the power generation industry concerning "stranded gas" distributed generation potential and eastern Kentucky does have a large potential for development of this form of generation. Since these "stranded gas" reserves would tend to be located within the distribution cooperatives' service territories, EKPC has been in discussions with developers over the past several years. These opportunities are considered on a case-by-case basis and EKPC has found few, if any, economically viable projects to date. EKPC continues to look for economically viable opportunities in distributed generation and continues to look for added value from these projects, such as rural economic development.

- **EKPC should provide a specific discussion of the improvements to, and more efficient utilization of, generation, transmission, and distribution facilities as required by 807 KAR section 8 (2)(a). This information should be provided for the past three years and should address EKPC's plans for the next three years.**

Please see pages 24 through 30.

Generation

For purposes of responding to Commission Staff's comments, EKPC has included generation projects exceeding $500,000, excluding labor, that have made EKPC's generating fleet more efficient.

Past Three Years:

- 2009—Cooper Power Station—Reheater Changeout on Cooper Unit 2, which added an additional loop. The project cost approximated $1.3 million and improved reheater efficiency.
- 2010 and 2011—Spurlock Power Station—Compressed Air System Upgrade on Units 3 and 4. The instrument air backup system was inadequate and could not support the plant due to the addition of the wet flue-gas desulphurization equipment and Units 3 and 4. If Spurlock Station were to lose the main air compressors, it would not be able to supply enough instrument air to run the plant, thereby causing a forced outage on the entire station. Providing additional air compressors on Units 3 and 4 reduced the risk of a forced outage on the entire plant at times of high soot blowing and instrument air demands. The project cost approximated $1.4 million.

Next Three Years:

- 2012—Cooper Power Station—Installation of advanced steam turbine packing during the Unit 2 turbine overhaul. This project will cost approximately $1.2 million and the new technology in packing design will improve the turbine steam sealing system.
- 2012—Spurlock Power Station—Installation of advanced steam turbine packing during the Unit 2 turbine overhaul. This project will cost approximately $1.2 million. This packing is a known steam leak location on General Electric turbines, and this installation will minimize steam by-passing the HP section of the turbine. Forcing the steam not to by-pass will increase the turbine efficiency and lower the heat rate.

Transmission

The EKPC transmission system is designed to transmit output from EKPC-owned generation sources and economic/emergency power purchases to meet expected customer demands. The EKPC transmission system is also designed to provide contracted long-term firm transmission service. Interconnections have been established with other utilities to increase the reliability of the transmission system and to provide potential access to other economic/emergency generating sources. EKPC designs the transmission system to withstand simultaneous forced outages of a transmission facility and a generator during peak conditions.

EKPC routinely identifies transmission facility additions and upgrades required to maintain an adequate, reliable transmission system. These transmission projects are identified through various types of studies, including power flow analysis, outage reviews, condition assessments, and economic analyses.

The EKPC transmission system was improved in the 2009-2011 period through the construction of new substations and transmission lines, as well as through upgrades of existing substations and transmission lines, to meet growing customer demand and to enhance reliability and improve the efficiency of the system.

From 2009-2011, EKPC implemented various transmission projects, summarized as follows:

- Establishment of six (6) new transmission interconnections with neighboring utilities (one at 345 kV, three at 138 kV, and two at 69 kV)
- Construction of 58 miles of new line, including 35 miles of new 345 kV line
- Construction of three (3) 138/69 kV substations
- Installation of a new 345/138 kV autotransformer at J.K. Smith Station
- Re-conductoring/rebuilding 48 miles of existing line using larger(lower impedance, higher capacity) conductor
- Upgrades of two (2) 138/69 kV autotransformers to increase capacity
- Addition of eight (8) new 69 kV capacitor banks totaling 124 MVARs

The interconnections established with other utilities generally have provided stronger sources in specific areas of need within the EKPC system, which avoids the need to construct long, high-voltage transmission lines from the EKPC system. Also, these interconnections typically reduce EKPC's transmission-system losses.

Construction of the new transmission lines generally has resulted in reduction of system losses as well. The J.K. Smith-West Garrard 345 kV line that was constructed in 2009 is a major transmission addition to the EKPC system that provides a substantial reduction in EKPC's system losses estimated at approximately 10,000 MWh per year.

The addition of the three new 138/69 kV substations also provides benefits in loss reductions and reduced transmission line construction requirements. These substations were constructed where existing 69 kV and 138 kV lines cross, which minimized the transmission construction necessary. These substations established new points of injection into the 69 kV transmission system in areas of need, thereby reducing system losses (estimated at approximately 1,000 MWh per year). Installation of the new 345/138 kV autotransformer at J.K. Smith has also reduced system losses (estimated at approximately 1,000 MWh per year) by reducing the impedance between the two busses at J.K. Smith.

Re-conductoring (including rebuilding) existing transmission lines enhances utilization of the existing transmission system by increasing the capacity of the existing lines. EKPC's re-conductor projects typically increase system capacity by 50% to 225%, depending on the sizes of the installed conductor and the replacement conductor that is used. In addition, by installing larger conductors, less voltage drop is seen on the system, deferring the need to construct new facilities to provide voltage support in an area. Transmission-system losses are also reduced due to the lower impedance of the larger replacement conductors. The amount of loss reduction varies, and is dependent on the hourly power flows on each particular line, but typical expectations for loss reduction range from 250,000 to 400,000 kWh per year after a line is re-conductored.

The upgrades of existing substation autotransformers also enhance utilization of the existing transmission capacity by increasing the capacity available at existing substations. The upgrades

EKPC performed in the 2009-2011 period increased transformer capacity by 50% to 110% at two existing substations. These upgrades provide some additional voltage support in these areas, potentially deferring the need to construct new facilities to provide voltage support. Transmission-system losses are also reduced due to the lower impedance of the replacement transformers. The loss reduction magnitude varies, depending on the hourly power flows through the transformers.

The addition of transmission capacitor banks also provides better utilization of the existing transmission system by deferring the need for new transmission lines and/or substations. Transmission capacitor banks can also provide some transmission-system loss reductions when energized.

Further improvements are planned for the EKPC transmission system for the 2012-2014 period. These improvements include the construction of new substations and transmission lines, as well as upgrades of existing substations and transmission lines. These improvements will meet growing customer demand, enhance system reliability, and improve the efficiency of the system.

The planned improvements to the EKPC transmission system for the 2012-2014 period are summarized as follows:

- Establishment of two (2) new transmission interconnections with neighboring utilities (both at 69 kV)
- Construction of 36 miles of new line, all at 69 kV
- Re-conductoring/rebuilding 40 miles of existing line using larger (lower impedance, higher capacity) conductor
- Upgrades of one (1) 161/69 kV autotransformer and one (1) 138/69 kV autotransformer to increase capacity
- Addition of five (5) new transmission capacitor banks totaling 107 MVARs
- Re-sizing and/or relocation of seven (7) existing 69 kV capacitor banks, totaling 161 MVARs of increased reactive capacity

One of the planned interconnections will provide a stronger source in a specific area of need within the EKPC system, which will avoid the need to construct long, high-voltage transmission lines from the EKPC system. The other planned interconnection will be operated normally-open, but will provide an emergency backup source to a substation served by a long radial transmission line.

Construction of new transmission lines typically results in reduction of system losses. EKPC expects to see overall reduction in system losses as a result of the planned construction of 36 miles of new 69 kV line in the 2012-2015 period.

The planned transmission line re-conductors/rebuilds will enhance utilization of the existing transmission system by increasing the capacity of those existing lines. As discussed earlier, replacing existing conductors with larger conductors will also provide increased voltage support and will reduce system energy losses. Similarly, the planned upgrades of substation autotransformers will provide more efficient system utilization by increasing existing capacity, reducing voltage drop and system energy losses.

The addition of transmission capacitor banks will also provide better utilization of the existing transmission system by deferring the need for new transmission lines and/or substations. Transmission capacitor banks can also provide some transmission-system loss reductions when energized.

Distribution

EKPC is responsible for providing distribution substation delivery points to its 16 member-owner systems. The member-owners are responsible for all distribution lines necessary to provide adequate, reliable service to end-use customers.
EKPC evaluates peak substation transformer loads (forecasted and actual) annually. This evaluation identifies necessary distribution improvements to meet the actual or expected customer demands.

EKPC delivery points were improved in the 2009-2011 period through the construction of new substations, as well as through upgrades of existing substations, to meet growing customer demand and to enhance reliability and improve the efficiency of the system.

From 2009-2011, EKPC implemented various distribution substation projects, summarized as follows:

- Construction of two (2) new 14 MVA distribution substations
- Construction of three (3) new 20 MVA distribution substations
- Addition of one (1) new 14 MVA distribution transformer at an existing station
- Addition of one (1) new 20 MVA distribution transformer at an existing station
- Addition of one (1) new 25 MVA distribution transformer at an existing station
- Upgrades of three (3) existing distribution substations to 14 MVA
- Upgrades of three (3) existing distribution substations to 25 MVA

New distribution delivery points enhance the utilization of the existing system by providing a new injection point into the existing distribution system. This will generally provide improved system energy losses, as well as increased voltage support.

Distribution substation transformer additions and upgrades of existing distribution substation transformers also improve system utilization by increasing capacity at an existing facility rather than building new facilities. These additions/upgrades reduce system impedance at the substation, which improves voltage drop and reduces energy losses.

In addition to the substation improvements discussed above, EKPC also worked with its member distribution cooperatives on various power factor improvement projects at the distribution level to increase available substation capacity, defer transmission construction projects, and reduce system losses. EKPC performed a power factor study to identify the substations which would provide the largest benefits to system utilization and efficiency through power factor correction. EKPC and its member systems improved the power factor at many of these substations in this period.

Further improvements are planned for EKPC's distribution substation delivery points for the 2012-2015 period. These improvements include the construction of new distribution substations, as well as upgrades of existing substations. These improvements will meet growing customer demand, enhance system reliability, and improve the efficiency of the system.

The planned improvements to EKPC distribution substations for the 2012-2015 period are summarized as follows:

- Construction of one (1) new 7 MVA distribution substation
- Construction of five (5) new 20 MVA distribution substations
- Construction of one (1) new 25 MVA distribution substation
- Addition of three (3) new 20 MVA distribution transformers at existing substations
- Addition of one (1) new 25 MVA distribution transformer at an existing substation
- Upgrades of six (6) existing distribution substations to 20 MVA
- Upgrades of two (2) existing distribution substations to 25 MVA

These distribution substation enhancements will improve system efficiency and utilization as described above.

In addition to these substation improvements, EKPC and its member distribution cooperatives will continue to coordinate power factor improvement projects at the distribution level to increase available substation capacity, defer transmission construction projects, and reduce system losses. EKPC is in the process of updating its power factor correction study to identify the substations which will provide the largest benefits for system utilization and efficiency through power factor correction. EKPC and its members plan to continue to improve power factor at these locations to realize these benefits whenever feasible.

- **EKPC should include details of the constraints of its transmission system under extreme summer and winter peak conditions**

EKPC annually performs an assessment of its transmission system for both summer and winter peak conditions. EKPC evaluates its system using two load forecasts – a 50/50 probability forecast and a 10/90 probability forecast. When evaluating system performance using a 50/50 forecast, contingency analysis is also performed on the system to ensure that the system is designed to provide adequate service at this load level even with a transmission facility and/or generator out of service. EKPC does not perform a contingency analysis when using the 10/90 probability forecast. EKPC considers an extreme weather event equivalent to a contingency, and therefore does not design its system for a transmission or generator outage in conjunction with this weather event.

EKPC has not identified any constraints on its transmission system due to extreme weather conditions for either summer or winter. Some marginal voltage levels have been identified in specific areas of the EKPC system during extreme winter conditions, and EKPC intends to address those issues. No thermal limitations are anticipated provided that all transmission and generation facilities are in service. The outage of one or more facilities could result in thermal overloads on the EKPC transmission system.

- **EKPC's next IRP should include a detailed analysis of actions taken, or actions that may need to be taken, at each generating station, and the projected costs at each station, if more stringent requirements are imposed on the disposal of coal ash**

New CCR Rule

On June 21, 2010, EPA published the Proposed Rule for Disposal of Coal Combustion Residuals (CCRs) from Electric Utilities. EPA provided two co-proposals for public comment: regulation of CCRs as a hazardous, or "special," waste under RCRA subtitle C and regulation of CCRs as a solid waste under RCRA subtitle D. EPA stated that it supports and has endeavored to maintain beneficial reuse of CCRs under both proposed rules. The Subtitle C alternative has extensive repercussions and there are serious questions as to whether the industry could comply with these requirements.

Given the challenges that would accompany Subtitle C regulation of CCRs, the Subtitle D alternative seems like the most likely course for EPA. This is further supported by recent legislative actions that have been directed towards a state-run Subtitle D approach.

Under the proposed regulations for the Subtitle D approach, EPA is proposing to establish dam safety requirements to address the structural integrity of surface impoundments. Within one year of the effective date of the regulations, all surface impoundments are required to be in compliance with groundwater monitoring and demonstrate locational criteria requirements to continue to accept waste. All impoundments that are not in compliance with the liner requirements of the subtitle D are required to cease accepting waste within five years of the effective date of the regulations. If there were no alternatives for CCR disposal, the five years in which the impoundment must have completed closure may be extended for an additional two years.

Under the proposed regulations, there would be no liner requirement deadline for existing landfills (those that are constructed or substantially constructed), but groundwater monitoring would be required. All new landfills or lateral expansions will be required to have composite liner systems, leachate collection systems, and groundwater monitoring networks.

SECTION 3.0

LOAD FORECAST

SECTION 3.0
LOAD FORECAST

3.1 Summary

807 KAR 5:058 Section 5.(2) Description of models, methods, data, and key assumptions used to develop the results contained in the plan.

The major steps, in general, in developing the load forecasts are:

- EKPC prepares a preliminary load forecast for each member that is based on retail sales forecasts for four classes - residential, small commercial, large commercial, and other. The classifications are taken from the Rural Utilities Service (RUS) Form 7, which contains retail sales data for member systems. In instances where seasonal and public authority classes are reported, these are forecasted separately. Table 1 summarizes the forecast methodology. EKPC's sales to member systems are then determined by adding distribution losses to total retail sales and EKPC's total requirements are estimated by adding transmission losses to sales to members. Seasonal peak demands are determined by summing individual appliance and class loadshapes based on normal EKPC peak day weather.
- EKPC meets with each member to discuss their preliminary forecast. Member system personnel present at the meetings include the President/CEO and other key staff members. During the meeting, preliminary projections are reviewed and, if necessary, revised as mutually agreed upon. Member systems often have access to information not available to EKPC, or member systems may elect to use assumptions different from preliminary forecast assumptions.
- EKPC then compiles its forecast, which is the summation of the 16 member system forecasts.

There is close collaboration between EKPC and its members. This working relationship is vital since both EKPC and member systems have significant input into the load forecast process. Input from member systems includes industrial development, subdivision growth, and other specific service area information. The meeting also provides an opportunity for the member system to critique assumptions used and overall results of the preliminary forecast. The resulting forecasts reflect a combination of EKPC's structured forecast methodology tempered by the judgment and experience of member system staff. The forecast used in the IRP is based upon a revised version of the 2010 Load Forecast and approved in principle with the 2011 financial forecast. See page 52.

Table 1
East Kentucky Power Cooperative
Forecast Model Summary

	Methodology
Residential Sales	Sales for this class are projected as the product of residential customers and residential use per customer. Residential customers are projected by means of regression analysis. Residential use per customer is projected with a statistically-adjusted end-use model.
Small Commercial Sales	Small commercial sales are analyzed and projected with regression analysis. Independent variables include real electric price, economic activity, weather, and residential customer growth. The models vary by member system.
Large Commercial Sales	Sales for this class are projected by both the member systems and EKPC. Member systems project existing large loads. EKPC projects new large loads using a probabilistic approach that is based on historical development, the presence of industrial sites, and the economy of the service territory.
Other Sales	Other sales are projected as a function of residential customers.
Peak Demand	Seasonal peak demands are projected using peak day load factors. Residential load factors are appliance specific. Small and large commercial factors are an aggregate for the class.

For additional information on EKPC's current load forecasting process, please see the 2011 Load Forecast Work Plan in the Load Forecast Technical Appendix.

807 KAR 5:058 Section 7.(7)(f) Research and development efforts underway or planned to improve performance, efficiency, or capabilities of the utility's load forecasting methods.

During the next few years, EKPC plans to conduct a comprehensive review of all aspects of its load forecasting process and evaluate possible enhancements to include using input from multiple economic and weather forecasters, leveraging load research sample meter data for forecasting purposes, incorporating the impact of energy efficiency and direct load control programs directly into hourly forecasting models, and implementing probabilistic forecasting wherever possible.

A description of the load forecasting methodology is discussed in detail in the Load Forecast Work Plan, contained in the Load Forecast Technical Appendix.

3.2 Load Forecast Report

807 KAR 5:058 Section 5.(3) Summary of forecasts of energy and peak demand, and key economic and demographic assumptions or projections underlying these forecasts.

Please see pages 21 through 30 of the Load Forecast Technical Appendix.

Regional Economy

EKPC subscribes to IHS Global Insight, Inc., for analysis regarding regional economic performance. IHS Global Insight, Inc. is a widely used consulting firm with expertise in economic analyses. They collect and monitor data, provide forecasts and analyses, and offer consulting advice to clients in business, financial, and government organizations. IHS Global Insight collects historical Kentucky county level data for many economic variables, develops forecasting models based on the data, and provides the resulting forecasts to EKPC.

The economy of EKPC's service area is quite varied. Areas around Lexington and Louisville have a significant amount of manufacturing industry, although that has declined in recent years due to the recession. 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 areas, with Lake Cumberland and Mammoth Cave National Park contributing to jobs in the service and retail trade industries. This area has also suffered during the recession.

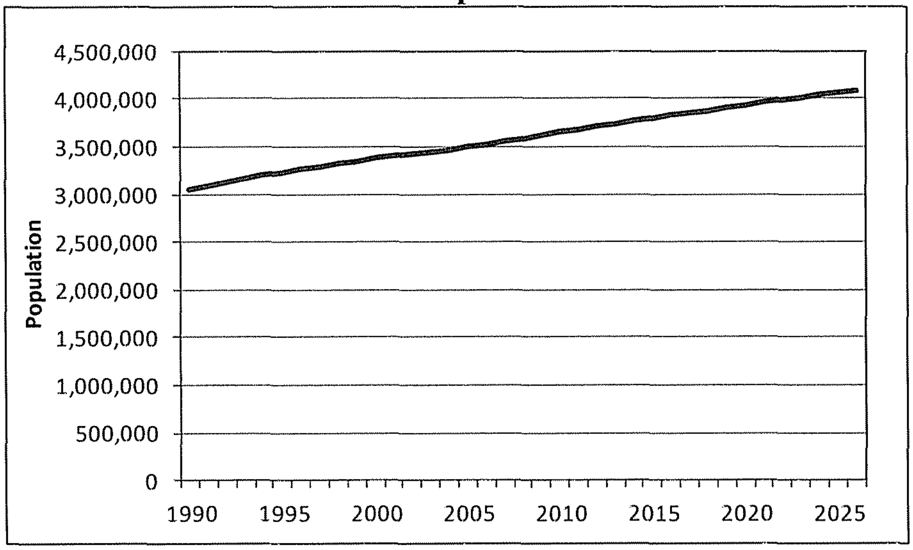
Changes in regional employment and income are important determinants of customer and sales growth. Population forecasts, shown below, are used to project residential class customers; regional household income is used to project residential sales; and regional economic activity is used to project small commercial sales.

Key Load Forecast Variables
Average Annual Growth Rate

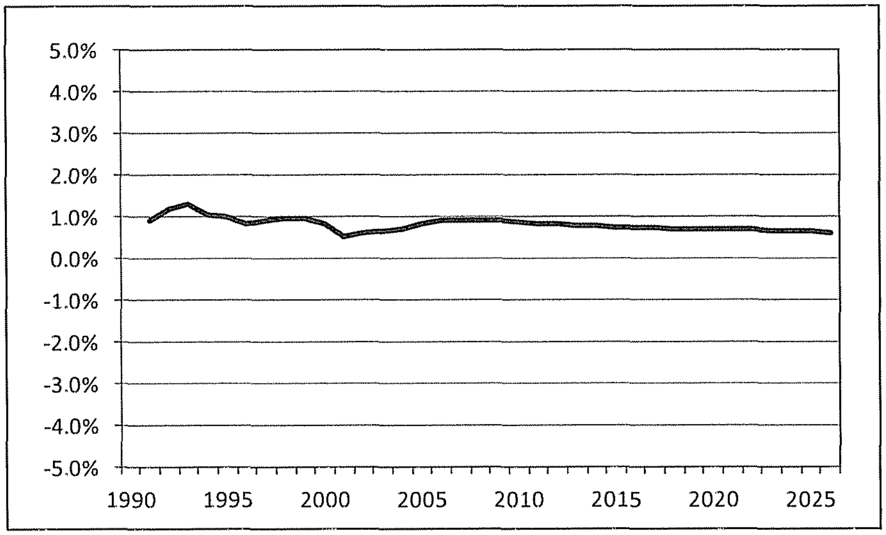
Year	1990-2000	2000-2010	2010-2020	2020-2030
Population	1.0%	0.8%	0.8%	0.6%
Nonfarm Employment	2.2%	-0.3%	1.5%	0.8%
Real Personal Income Per Capita	2.1%	-0.1%	2.2%	2.0%

An important variable that impacts the load forecast is regional population. Population grew rapidly during the seventies and slowed during the second half of the eighties. Given the decline the economy is currently exhibiting, population growth is expected to be low for the next several years.

Total Population

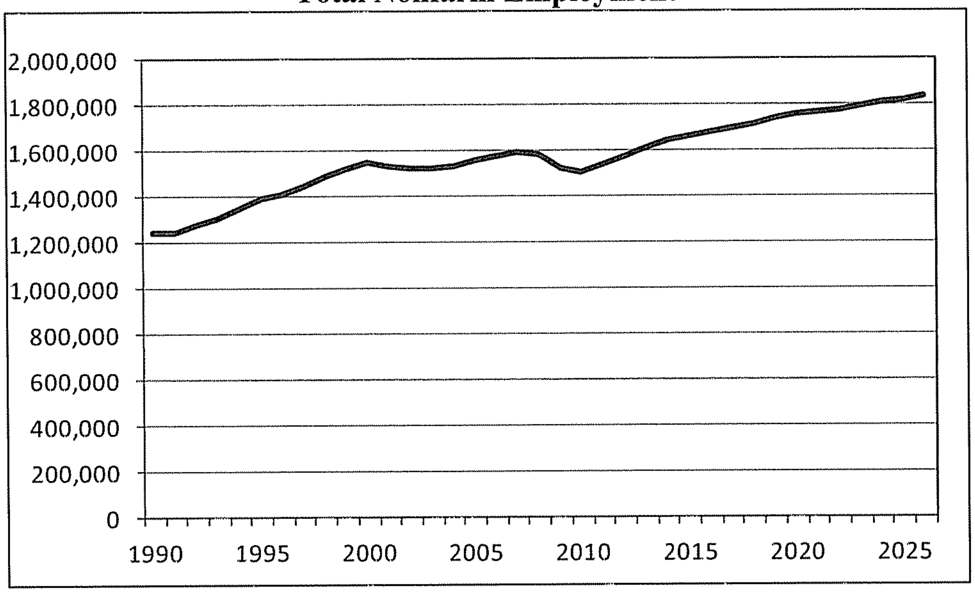


Total Population
Year / Year Growth Rate

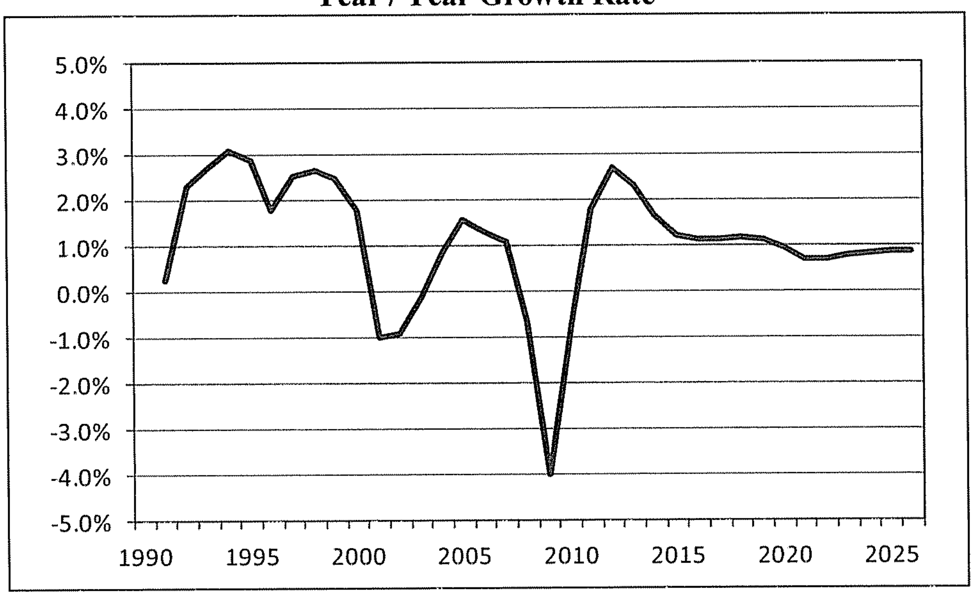


Total regional employment is tied closely to the national economy. The early eighties was a period of depressed job growth. From the mid 80s to the early 2000s, however, total employment grew strongly. During the recent economic downturn, employment fell. The unemployment rate reached an all time high; however, it is expected to recover slowly over the next decade.

Total Nonfarm Employment

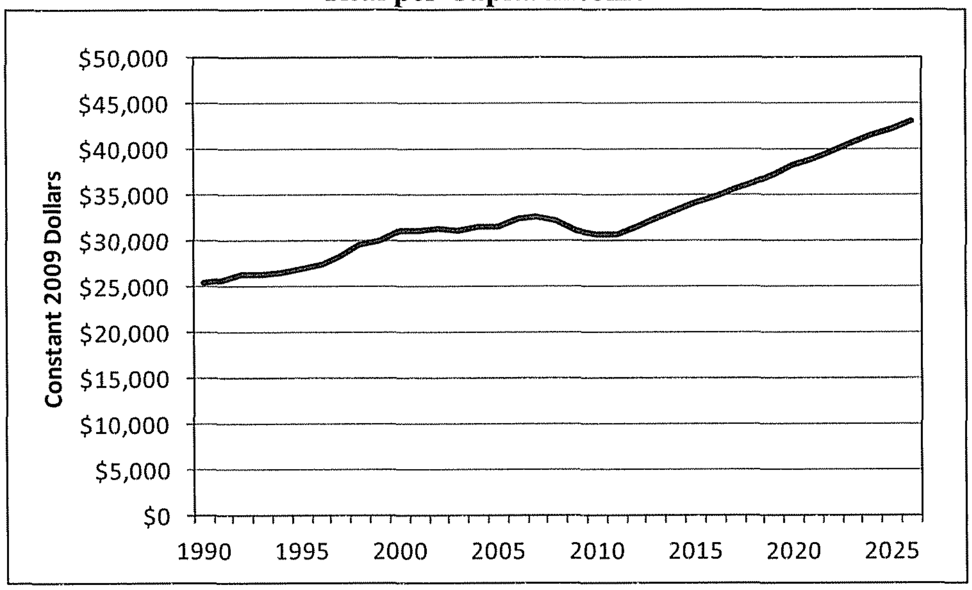


Total Nonfarm Employment
Year / Year Growth Rate

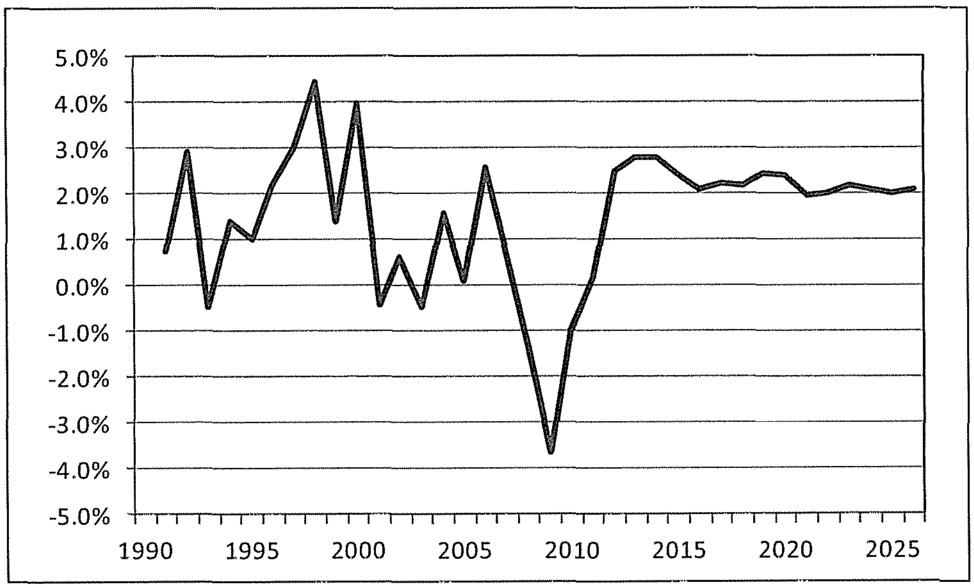


The following figures illustrate the cyclical nature of income growth, and the sensitivity to the national economy exhibited by EKPC's service area. Whenever employment levels decrease or wage levels fall, personal income will be adversely affected. Global Insight's forecast of total regional income is for moderate but steady growth. This variable is important to the load forecast because of its strong effect on appliance purchases and electric usage. Per Capita Income (PCY) is defined as personal income divided by total population. In 2009, regional PCY was $31,000. Global Insight projects this to increase to $47,000 in 2009 constant dollars by 2030.

Real per Capita Income



Real per Capita Income
Year / Year Growth Rate



807 KAR 5:058 Section 7.(1)(a-c) The information shall be provided for the total system and, where available, disaggregated by the following customer classes: (a) Residential heating; (b) Residential non-heating; (c) Total residential (total of paragraphs (a) and (b) of this subsection).

807 KAR 5:058 Sections 7.(2)(a, b, h) The utility shall provide the following historical information for the base year, which shall be the most recent calendar year for which actual energy sales and system peak demand data are available, and the four (4) years preceding the base year: (a) Average annual number of customers by class as defined in subsection (1) of this section; (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; (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.

7.(3) For each of the fifteen (15) years succeeding the base year, the utility shall provide a base load forecast it considers most likely to occur and, to the extent available, alternate forecasts representing lower and upper ranges of expected future growth of the load on its system. Forecasts shall not include load impacts of additional, future demand-side programs or customer generation included as part of planned resource acquisitions estimated separately and reported in Section 8(4) of this administrative regulation. Forecasts shall include the utility's estimates of existing and continuing demand-side programs as described in subsection (5) of this section.

7.(4)(a) The following information shall be filed for each forecast: (a) Annual energy sales and generation for the system and sales disaggregated by class as defined in subsection (1) of this section.

Residential Forecast

Nearly 60 percent of EKPC's member system retail sales are to the residential class. The average number of residential customers served by EKPC is expected to increase from approximately 485,000 in 2010 to 605,000 in 2026. Sales to the residential class are expected to grow 1.4% over the next 20 years. Due to the economy, increasing appliance efficiencies and rising electricity prices, projected average monthly use per customer is lower than previous forecasts and remains relatively flat throughout the forecast period. Residential sales are not classified into heating and non heating.

Residential Class
Historical and Projected Customers and Sales

	Customers			Energy				
	Annual Average	Annual Change	% Change	Actual (MWh)	Weather Normalized (MWh)	% Change	Monthly Average (kWh)	% Change
2007	476,044			7,013,234	6,869,084		1,202	
2008	483,502	7,458	1.6%	7,069,808	6,992,901	1.8%	1,205	0.2%
2009	484,947	1,445	0.3%	6,802,222	6,865,729	-1.8%	1,180	-2.1%
2010	486,362	1,415	0.3%	7,403,156	7,068,881	3.0%	1,211	2.7%
2011	486,869	507	0.1%	6,980,187	6,934,331	-1.8%	1,187	-1.9%
2012	497,343	10,474	2.2%		7,003,557	1.0%	1,173	-1.1%
2013	503,831	6,488	1.3%		7,002,550	0.0%	1,158	-1.3%
2014	510,687	6,856	1.4%		7,089,772	1.2%	1,157	-0.1%
2015	517,838	7,151	1.4%		7,228,575	2.0%	1,163	0.5%
2016	525,178	7,340	1.4%		7,334,020	1.5%	1,164	0.0%
2017	532,736	7,558	1.4%		7,388,272	0.7%	1,156	-0.7%
2018	540,392	7,656	1.4%		7,513,073	1.7%	1,159	0.2%
2019	548,253	7,860	1.5%		7,650,402	1.8%	1,163	0.4%
2020	556,318	8,066	1.5%		7,778,358	1.7%	1,165	0.2%
2021	564,442	8,124	1.5%		7,909,104	1.7%	1,168	0.2%
2022	572,442	7,999	1.4%		8,042,476	1.7%	1,171	0.3%
2023	580,505	8,063	1.4%		8,189,826	1.8%	1,176	0.4%
2024	588,550	8,045	1.4%		8,337,592	1.8%	1,181	0.4%
2025	596,796	8,246	1.4%		8,464,630	1.5%	1,182	0.1%
2026	605,087	8,291	1.4%		8,607,922	1.7%	1,185	0.3%

807 KAR 5:058 Section 7.(1)(d, f, g) The information shall be provided for the total system and, where available, disaggregated by the following customer classes: (d) Commercial; (f) Sales for resale; (g) Utility use and other.

807 KAR 5:058 Section 7.(2)(a, b, h) The utility shall provide the following historical information for the base year, which shall be the most recent calendar year for which actual energy sales and system peak demand data are available, and the four (4) years preceding the base year: (a) Average annual number of customers by class as defined in subsection (1) of this section; (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; (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.

7.(3) For each of the fifteen (15) years succeeding the base year, the utility shall provide a base load forecast it considers most likely to occur and, to the extent available, alternate forecasts representing lower and upper ranges of expected future growth of the load on its system. Forecasts shall not include load impacts of additional, future demand-side programs or customer generation included as part of planned resource acquisitions estimated separately and reported in Section 8(4) of this administrative regulation. Forecasts shall include the utility's estimates of existing and continuing demand-side programs as described in subsection (5) of this section.

7.(4)(a) The following information shall be filed for each forecast: (a) Annual energy sales and generation for the system and sales disaggregated by class as defined in subsection (1) of this section.

Commercial Forecast

The commercial and industrial classes have been significantly impacted by the recent economic downturn. Customer growth has slowed while energy use per customer remains below prerecession levels. The load forecast does reflect the full impact of the recession. Most notably, the unemployment rate reached an all time high and is not expected to reach prerecession levels for nearly 10 years. The automotive industry experienced sharp declines in response to the national economic downturn and in Kentucky due to various Toyota recalls which resulted in lower sales and interruptions in manufacturing the automobiles. EKPC member systems serve many of the satellite industrial and commercial customers that produce parts for Toyota and as a result of the aforementioned circumstances were negatively impacted. Utility use and other classes are not classified separately. Sales for resale (for EKPC purposes, defined as off-systems sales) are not considered in the load forecast.

Commercial Class
Historical and Projected Customers and Sales

	Customers			Energy				
	Annual Average	Annual Change	% Change	Actual (MWh)	Weather Normalized (MWh)	% Change	Monthly Average (kWh)	% Change
2007	32,384			1,896,836	1,880,204		4,838	
2008	33,469	1,085	3.4%	1,916,363	1,911,863	1.7%	4,760	-1.6%
2009	33,803	334	1.0%	1,831,685	1,837,960	-3.9%	4,531	-4.8%
2010	33,977	174	0.5%	1,984,495	1,957,227	6.5%	4,800	5.9%
2011	34,155	178	0.5%	1,940,403	1,934,735	-1.1%	4,720	-1.7%
2012	35,017	862	2.5%		1,949,465	0.8%	4,639	-1.7%
2013	35,549	532	1.5%		1,985,448	1.8%	4,654	0.3%
2014	36,152	602	1.7%		2,024,026	1.9%	4,666	0.2%
2015	36,755	604	1.7%		2,076,229	2.6%	4,707	0.9%
2016	37,362	607	1.7%		2,115,020	1.9%	4,717	0.2%
2017	37,976	614	1.6%		2,143,676	1.4%	4,704	-0.3%
2018	38,600	624	1.6%		2,187,025	2.0%	4,722	0.4%
2019	39,222	622	1.6%		2,233,264	2.1%	4,745	0.5%
2020	39,849	627	1.6%		2,279,875	2.1%	4,768	0.5%
2021	40,484	635	1.6%		2,325,327	2.0%	4,786	0.4%
2022	41,111	627	1.5%		2,371,634	2.0%	4,807	0.4%
2023	41,736	626	1.5%		2,417,651	1.9%	4,827	0.4%
2024	42,362	625	1.5%		2,463,656	1.9%	4,846	0.4%
2025	42,998	636	1.5%		2,508,533	1.8%	4,862	0.3%
2026	43,647	649	1.5%		2,555,519	1.9%	4,879	0.4%

807 KAR 5:058 Section 7.(1)(e) The information shall be provided for the total system and, where available, disaggregated by the following customer classes: (e) Industrial.

807 KAR 5:058 Section 7.(2)(a, b, h) The utility shall provide the following historical information for the base year, which shall be the most recent calendar year for which actual energy sales and system peak demand data are available, and the four (4) years preceding the base year: (a) Average annual number of customers by class as defined in subsection (1) of this section; (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; (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.

7.(3) For each of the fifteen (15) years succeeding the base year, the utility shall provide a base load forecast it considers most likely to occur and, to the extent available, alternate forecasts representing lower and upper ranges of expected future growth of the load on its system. Forecasts shall not include load impacts of additional, future demand-side programs or customer generation included as part of planned resource acquisitions estimated separately and reported in Section 8(4) of this administrative regulation. Forecasts shall include the utility's estimates of existing and continuing demand-side programs as described in subsection (5) of this section.

7.(4)(a) The following information shall be filed for each forecast: (a) Annual energy sales and generation for the system and sales disaggregated by class as defined in subsection (1) of this section.

Industrial Forecast

In 2009, there were 138 retail customers classified as large commercial customers. The total annual usage was greater than the annual usage of the small commercial class. This class experienced substantial growth from 1995 to 2004; however energy sales remain below prerecession levels. Approximately half of EKPC's large commercial customers are manufacturing plants.

Industrial Class
Historical and Projected Customers and Sales

	Customers			Energy				
	Annual Average	Annual Change	% Change	Actual (MWh)	Weather Normalized (MWh)	% Change	Monthly Average (kWh)	% Change
2007	122			3,124,043	3,118,690		2,130,253	
2008	132	10	8.2%	3,083,589	3,083,391	-1.1%	1,946,585	-8.6%
2009	138	6	4.5%	2,831,935	2,833,627	-8.1%	1,711,127	-12.1%
2010	125	-13	-9.4%	2,845,857	2,841,554	0.3%	1,894,369	10.7%
2011	127	2	1.6%	2,889,142	2,886,208	1.5%	1,893,837	-0.1%
2012	147	20	15.7%		3,029,302	5.0%	1,717,292	-9.3%
2013	150	3	2.0%		3,084,187	1.8%	1,713,437	-0.2%
2014	154	4	2.7%		3,140,182	1.8%	1,699,233	-0.8%
2015	156	2	1.3%		3,215,390	2.4%	1,717,623	1.1%
2016	159	3	1.9%		3,365,116	4.7%	1,763,687	2.7%
2017	160	1	0.6%		3,475,489	3.3%	1,810,150	2.6%
2018	163	3	1.9%		3,546,751	2.1%	1,813,267	0.2%
2019	166	3	1.8%		3,617,107	2.0%	1,815,817	0.1%
2020	168	2	1.2%		3,674,845	1.6%	1,822,840	0.4%
2021	171	3	1.8%		3,744,699	1.9%	1,824,902	0.1%
2022	173	2	1.2%		3,800,216	1.5%	1,830,547	0.3%
2023	176	3	1.7%		3,868,657	1.8%	1,831,750	0.1%
2024	179	3	1.7%		3,934,277	1.7%	1,831,600	0.0%
2025	181	2	1.1%		3,997,974	1.6%	1,840,688	0.5%
2026	184	3	1.7%		4,065,600	1.7%	1,841,304	0.0%

807 KAR 5:058 Section 7.(2)(d-f), The utility shall provide the following historical information for the base year, which shall be the most recent calendar year for which actual energy sales and system peak demand data are available, and the four (4) years preceding the base year: d) Total energy sales and coincident peak demand to retail and wholesale customers for which the utility has firm, contractual commitments; (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 non-firm basis; (f) Annual energy losses for the system;

7.(3) For each of the fifteen (15) years succeeding the base year, the utility shall provide a base load forecast it considers most likely to occur and, to the extent available, alternate forecasts representing lower and upper ranges of expected future growth of the load on its system. Forecasts shall not include load impacts of additional, future demand-side programs or customer generation included as part of planned resource acquisitions estimated separately and reported in Section 8(4) of this administrative regulation. Forecasts shall include the utility's estimates of existing and continuing demand-side programs as described in subsection (5) of this section.

7.(4)(a) The following information shall be filed for each forecast: (a) Annual energy sales and generation for the system and sales disaggregated by class as defined in subsection (1) of this section.

Summary of Results

The forecast indicates that for the period 2010 through 2030, total energy requirements will increase by 1.6 percent per year. Winter and summer net peak demand will increase by 2.0 percent and 1.4 percent, respectively. Annual load factor is projected to remain relatively flat at around 50 percent. Sales to the residential class are projected to increase by 1.4 percent per year; total commercial sales are projected to increase by 2.3 percent per year.

Historical and Projected Annual Energy Requirements, Losses, and Generation

Year	Total Retail Sales (MWh)	Office Use (MWh)	Distribution Loss (%)	EKPC Sales to Members (MWh)	EKPC Office Use (MWh)	Transmission Loss (%)	Additional DSM Impact (MWh)	Net Total Requirements (MWh)	Generation (MWh)
2007	12,034,113	10,291	4.3	12,582,260	7,491	3.9		13,080,146	11,493,588
2008	12,069,760	10,431	4.5	12,646,146	7,932	2.3		12,947,087	10,670,423
2009	11,465,842	10,173	4.2	11,981,909	8,247	3.2		12,371,602	10,925,246
2010	12,233,507	10,401	4.4	12,811,906	8,654	4.2		13,354,642	12,570,249
2011	11,809,733	9,742	3.8	12,289,071	2,961	3.1		12,674,890	12,444,859
2012	11,982,324	10,225	4.3	12,525,417	8,417	3.3	104,246	12,860,110	11,311,662
2013	12,072,185	10,225	4.3	12,619,837	8,436	3.3	183,221	12,878,797	11,597,391
2014	12,253,980	10,225	4.3	12,810,663	8,478	3.3	261,954	12,997,446	11,791,378
2015	12,520,194	10,225	4.3	13,089,758	8,521	3.3	337,848	13,210,215	12,700,239
2016	12,814,155	10,225	4.3	13,397,909	8,563	3.3	413,781	13,452,992	13,647,239
2017	13,007,437	10,225	4.3	13,600,783	8,606	3.3	488,043	13,588,573	13,768,550
2018	13,246,849	10,225	4.3	13,852,054	8,649	3.3	562,174	13,774,331	13,518,573
2019	13,500,773	10,225	4.3	14,118,497	8,693	3.3	626,598	13,985,488	13,849,344
2020	13,733,078	10,225	4.3	14,362,254	8,736	3.3	675,594	14,188,613	13,462,571
2021	13,979,130	10,225	4.3	14,620,468	8,780	3.3	724,786	14,406,492	13,462,295
2022	14,214,326	10,225	4.3	14,867,267	8,824	3.3	744,344	14,642,201	13,666,705
2023	14,476,134	10,225	4.3	15,141,985	8,868	3.3	765,085	14,905,598	14,348,144
2024	14,735,525	10,225	4.3	15,414,161	8,912	3.3	782,894	15,169,299	14,386,256
2025	14,971,137	10,225	4.3	15,661,422	8,957	3.3	800,601	15,407,337	14,376,234
2026	15,229,041	10,225	4.3	15,932,043	9,001	3.3	818,324	15,669,518	14,457,969

807 KAR 5:058 Section 7.(2)(c) The utility shall provide the following historical information for the base year, which shall be the most recent calendar year for which actual energy sales and system peak demand data are available, and the four (4) years preceding the base year: (c) Recorded and weather-normalized coincident peak demand in summer and winter for the system;

7.(3) For each of the fifteen (15) years succeeding the base year, the utility shall provide a base load forecast it considers most likely to occur and, to the extent available, alternate forecasts representing lower and upper ranges of expected future growth of the load on its system. Forecasts shall not include load impacts of additional, future demand-side programs or customer generation included as part of planned resource acquisitions estimated separately and reported in Section 8(4) of this administrative regulation. Forecasts shall include the utility's estimates of existing and continuing demand-side programs as described in subsection (5) of this section.

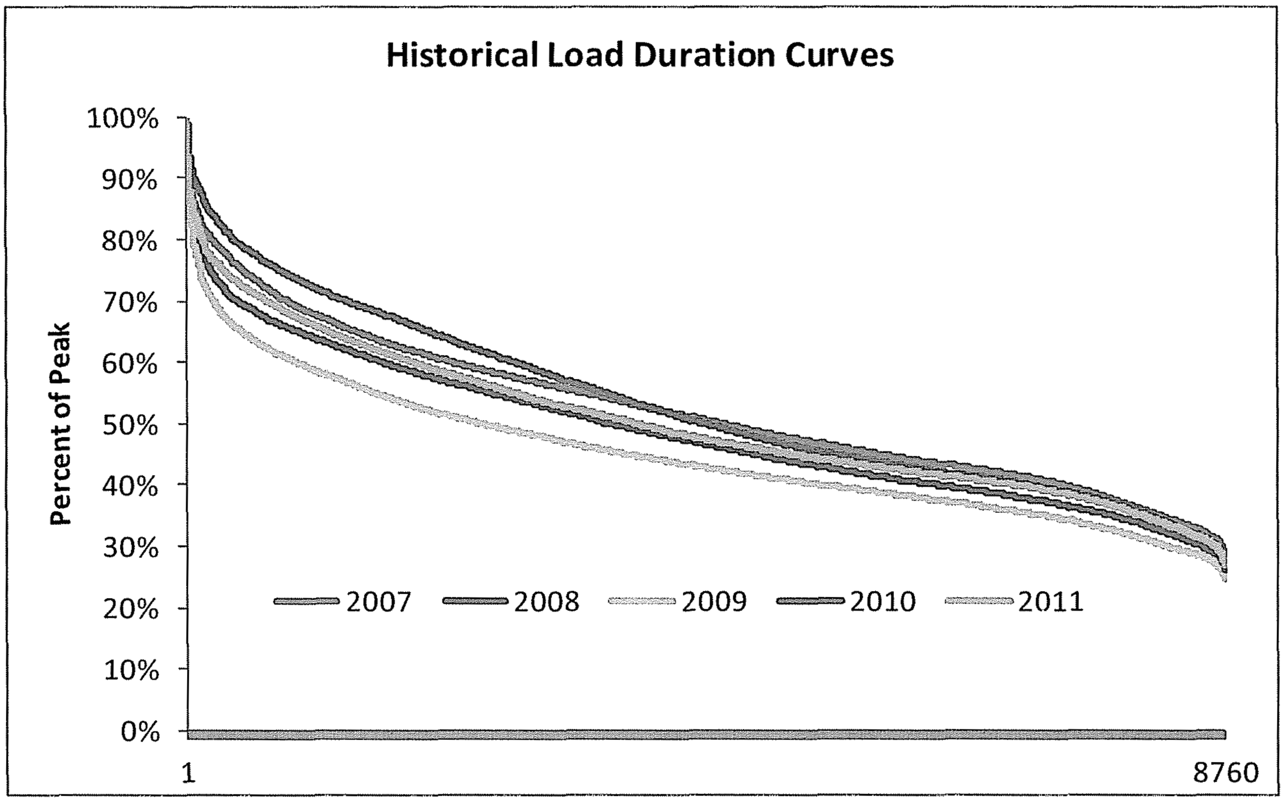
7.(4)(b) The following information shall be filed for each forecast: (b) Summer and winter coincident peak demand for the system.

Historical and Projected Seasonal System Peak Demands

Winter Season	Net Peak Demand (MW)	Weather Normalized (MW)	Summer Season	Net Peak Demand (MW)	Weather Normalized (MW)
2006 - 07	2,840	2,984	2007	2,481	2,423
2007 - 08	3,051	3,163	2008	2,243	2,172
2008 - 09	3,152	3,128	2009	2,195	2,281
2009 - 10	2,868	3,012	2010	2,443	2,353
2010 - 11	2,865	3,083	2011	2,388	2,313
2011 - 12		3,006	2012		2,246
2012 - 13		3,002	2013		2,234
2013 - 14		3,016	2014		2,232
2014 - 15		3,063	2015		2,250
2015 - 16		3,106	2016		2,270
2016 - 17		3,145	2017		2,292
2017 - 18		3,187	2018		2,319
2018 - 19		3,235	2019		2,357
2019 - 20		3,270	2020		2,383
2020 - 21		3,330	2021		2,429
2021 - 22		3,379	2022		2,469
2022 - 23		3,436	2023		2,515
2023 - 24		3,481	2024		2,553
2024 - 25		3,542	2025		2,601
2025 - 26		3,598	2026		2,645

807 KAR 5:058 Section 7.(2)(h) The utility shall provide the following historical information for the base year, which shall be the most recent calendar year for which actual energy sales and system peak demand data are available, and the four (4) years preceding the base year: (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.

807 KAR 5:058 Section 7.(4)(e) The following information shall be filed for each forecast: (e) Any other data or exhibits which illustrate projected changes in load or load characteristics.



807 KAR 5:058 Section 7.(4)(c) The following information shall be filed for each forecast: (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.

Monthly Retail Sales and System Peak Forecast

Year	Month	Residential Sales (MWh)	Commercial Sales (MWh)	Industrial Sales (MWh)	Total Retail Sales (MWh)	Generation (MWh)	Net System Peak Demand (MW)
2012	1	803,625	158,942	247,311	1,209,878	1,114,602	3,006
2012	2	754,502	158,809	247,959	1,161,269	966,138	2,704
2012	3	650,776	159,306	248,607	1,058,689	981,372	2,468
2012	4	522,663	158,728	250,754	932,144	828,903	1,846
2012	5	450,729	158,907	251,402	861,038	842,971	1,922
2012	6	477,972	167,330	253,753	899,056	940,137	2,133
2012	7	559,582	168,210	254,401	982,193	1,028,038	2,246
2012	8	567,118	168,424	255,049	990,591	1,003,451	2,201
2012	9	502,117	168,453	255,697	926,268	766,040	2,085
2012	10	448,007	160,248	254,641	862,896	823,532	1,818
2012	11	536,332	160,646	255,289	952,268	899,853	2,313
2012	12	730,133	161,464	254,438	1,146,035	1,116,627	2,821
Total		7,003,557	1,949,465	3,029,302	11,982,324	11,311,662	
2013	1	802,226	161,900	251,948	1,216,074	1,154,901	3,002
2013	2	754,623	161,725	252,588	1,168,936	1,019,066	2,698
2013	3	653,003	162,307	253,228	1,068,537	990,485	2,465
2013	4	525,579	161,710	255,348	942,637	820,091	1,836
2013	5	451,578	161,912	255,988	869,478	807,169	1,920
2013	6	475,751	170,337	258,311	904,398	891,511	2,121
2013	7	553,448	171,220	258,951	983,619	1,049,182	2,234
2013	8	561,540	171,440	259,591	992,571	1,045,299	2,188
2013	9	499,313	171,457	260,231	931,001	900,654	2,070
2013	10	450,580	163,255	259,188	873,023	837,194	1,820
2013	11	541,189	163,677	259,828	964,693	939,468	2,307
2013	12	733,721	164,508	258,988	1,157,217	1,142,371	2,812
Total		7,002,550	1,985,448	3,084,187	12,072,185	11,597,391	

807 KAR 5:058 Section 7(2)(g) The utility shall provide the following historical information for the base year, which shall be the most recent calendar year for which actual energy sales and system peak demand data are available, and the four (4) years preceding the base year: (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;

7.(4)(d) The following information shall be filed for each forecast: (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.

DSM Impacts (Existing Programs)

Year	Impact on Energy Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2007	14,231	148.500	152.000
2008	17,302	193.300	145.500
2009	30,213	192.250	150.844
2010	43,825	196.328	156.257
2011	57,202	200.175	160.929
2012	89,413	209.400	174.144
2013	125,678	219.968	188.052
2014	161,651	230.621	201.952
2015	196,526	241.145	215.738
2016	231,440	251.701	229.533
2017	266,383	262.282	243.335
2018	301,196	271.951	253.195
2019	330,088	280.121	257.439
2020	343,550	286.157	259.827
2021	357,210	292.224	262.236
2022	350,627	295.619	262.302
2023	345,228	299.214	262.503
2024	339,369	302.470	262.578
2025	333,409	305.656	262.622
2026	327,464	308.857	262.670

807 KAR 5:058 Section 7(2)(d) The utility shall provide the following historical information for the base year, which shall be the most recent calendar year for which actual energy sales and system peak demand data are available, and the four (4) years preceding the base year: (d) Total energy sales and coincident peak demand to retail and wholesale customers for which the utility has firm, contractual commitments.

Energy Sales and Firm Coincident Demand

	2007	2008	2009	2010	2011
Energy Sales (MWh)*	12,582,260	12,646,146	11,981,909	12,811,906	12,289,071
Coincident Peak Demand (MW)**	2,757	2,964	3,126	2,739	2,744

* Total sales to members.
** Firm peak demand.

807 KAR 5:058 Section 7(2)(e) The utility shall provide the following historical information for the base year, which shall be the most recent calendar year for which actual energy sales and system peak demand data are available, and the four (4) years preceding the base year: (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.

Energy Sales and Nonfirm Demand

	2007	2008	2009	2010	2011
Energy Sales (MWh)*	NA	NA	NA	NA	NA
Coincident Peak Demand (MW)	83	87	26	129	121

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

807 KAR 5:058 Section 7.(5)(a-b) The additional following data shall be provided for the integrated system, when the utility is part of a multistate integrated utility system, and for the selling company, when the utility purchases fifty (50) percent of its energy from another company: (a) For the base year and the four (4) years preceding the base year: 1. Recorded and weather normalized annual energy sales and generation; 2. Recorded and weather-normalized coincident peak demand in summer and winter. (b) For each of the fifteen (15) years succeeding the base year: 1. Forecasted annual energy sales and generation; 2. Forecasted summer and winter coincident peak demand.

These sections are not applicable as EKPC is not part of a multistate integrated utility system.

807 KAR 5:058 Section 7.(6) The plan shall include historical and forecasted information regarding loads. A utility shall file all updates of load forecasts with the commission when they are adopted by the utility.

Please see EKPC's 2010 load forecast contained in the Load Forecast Technical Appendix. This load forecast was approved by RUS and by the EKPC Board of Directors. The Executive Summary to the 2010 Load Forecast was provided to the Commission in Case No. 2010-00238. Additionally, the EKPC Board of Directors has approved EKPC's 2011 Load Forecast Work Plan. A copy of this Board resolution is provided in the Load Forecast Technical Appendix.

807 KAR 5:058 Section 7.(7)(a) The plan shall include a complete description and discussion of: (a) All data sets used in producing the forecasts.

Please see pages 7-8 and 16-17 of the Load Forecast Work Plan contained in the Load Forecast Technical Appendix.

807 KAR 5:058 Section 7.(7)(b) The plan shall include a complete description and discussion of: (b) Key assumptions and judgments used in producing forecasts and determining their reasonableness.

Please see the Load Forecast Work Plan contained in the Load Forecast Technical Appendix, throughout report.

807 KAR 5:058 Section 7.(7)(c) The plan shall include a complete description and discussion of: (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).

Please see pages 11-23 of the Load Forecast Work Plan contained in the Load Forecast Technical Appendix.

807 KAR 5:058 Section 7.(7)(d) The plan shall include a complete description and discussion of: (d) The utility's treatment and assessment of load forecast uncertainty.

Please see pages 24-25 of the Load Forecast Work Plan contained in the Load Forecast Technical Appendix.

807 KAR 5:058 Section 7.(7)(e) The plan shall include a complete description and discussion of: (e) The extent to which the utility's load forecasting methods and models explicitly address and incorporate the following factors: 1. Changes in prices of electricity and prices of competing fuels; 2. Changes in population and economic conditions in the utility's service territory and general region; 3. Development and potential market penetration of new appliances, equipment, and technologies that use electricity or competing fuels; and 4. Continuation of existing company and government sponsored conservation and load management or other demand-side programs.

Please see the Load Forecast Work Plan contained in the Load Forecast Technical Appendix.

SECTION 4.0

EXISTING AND COMMITTED CAPACITY RESOURCES SUMMARY

SECTION 4.0
EXISTING AND COMMITTED CAPACITY RESOURCES SUMMARY

4.1 Existing EKPC Generating Facilities

EKPC currently owns and operates almost 3,000 MW of capacity. This capacity is located at four separate sites with a total of 25 generating units. Fuel sources include coal, natural gas and landfill gas.

Coal Fired Units

Dale Station

The first plant built by EKPC was the William C. Dale Station located in Ford, Kentucky, which is on the Kentucky River in Clark County. All four units at Dale Station are pulverized coal fired units. The first two units have a rated capacity of 23 MW each and began commercial operation on December 1, 1954. The third unit is capable of producing 75 MW and began operation on October 1, 1957. The fourth unit is also rated at 75 MW and began operation on August 9, 1960.

Cooper Station

The second plant EKPC built was the John Sherman Cooper Station located near Somerset on Lake Cumberland. The station has one 116 MW unit that became operational on February 9, 1965, and one 225 MW unit that began operating commercially on October 28, 1969. Both units are pulverized coal units. A new pollution control system has recently been added to the Cooper 2 unit and will begin commercial operation by summer 2012.

Spurlock Station

The most recent coal fired plant constructed by EKPC is the Hugh L. Spurlock Station situated near Maysville, Kentucky on the Ohio River. The station consists of four units. The first one is a 300 MW unit that began commercial operation on September 1, 1977. Unit 2 is a 525 MW unit that began operating on March 2, 1981. Both of these units are conventional pulverized coal units with FGD technology.

On March 1, 2005, Unit 3 became operational. It is a 268 MW unit. The fourth unit became operational on April 1, 2009. It is a 278 MW unit. Both units 3 and 4 are fluidized bed boiler technology.

Other

Peaking Capacity

EKPC has three ABB GT 11N2 combustion turbines, four General Electric Co. 7EA combustion turbines, and two General Electric Co. LMS 100 combustion turbines located at the J. K. Smith plant site in eastern Clark County on the Kentucky River. The ABB turbines, which went commercial in 1999, have a summer rating of 110 MW each and a winter rating of 149 MW each. Two of the GE turbines went commercial in 2001 and two in 2005. Each has a summer rating of 70 MW and a winter rating of 100 MW. The two LMS 100 turbines became operational in 2010. Each has a summer rating of 78 MW and a winter rating of 101 MW.

Landfill Gas

EKPC owns and operates 15.2 MW of landfill gas capacity generated at 6 sites throughout Kentucky.

Steam Load

The Inland Container Corporation has a corrugated paper recycling facility adjacent to EKPC's Spurlock Station. The facility has an expected peak electrical load of approximately 24 MW and an equivalent of 29 MW in steam. The steam is supplied from Spurlock Unit 2 on a normal basis but can also be supplied from Spurlock Unit 1 when needed. On average, Inland Container operates 99.1 percent of the time and Spurlock 2 operates at an average of 525 MW. On February 15, 2012, International Paper acquired Temple-Inland, the parent company of Inland Container Corporation.

807 KAR 5:058 Section 8.(3)(b)(1-11) 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.

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

Table 8.(3)(b)(1-11)-2
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	Existing
Commercial Operation	Feb. 9, 1965	Oct. 28, 1969	Sept. 1, 1977	Mar. 2, 1981	March 1, 2005	April 1, 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		FGD/SCR 5/1/2012 217MW				
Retirement Dates						

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

Table 8.(3)(b)(1-11)-4
Generating Plant Data

Smith Combustion Turbines

	Unit 9	Unit 10
Location	Trapp, KY	Trapp, KY
Status	Existing	Existing
Commercial Operation	5/1/10	5/1/10
Type	Gas	Gas
Net Dependable Capability	97 MW	97 MW
Entitlement (%)	100	100
Primary Fuel Type	Natural Gas	Natural Gas
Secondary Fuel Type	N/A	N/A
Fuel Storage (Gallons)	N/A	N/A
Scheduled Upgrades, Deratings, Retirement Dates	N/A	N/A

Table 8.(3)(b)(1-11)-5
Generating Plant Data

	Bavarian	**Green Valley**	**Laurel Ridge #1-4**	**Laurel Ridge #5**	**Hardin Co.**	**Pendleton Co.**	**Mason Co.**
Location	Boone, KY	Greenup Co., KY	Lily, KY	Lily, KY	Hardin Co., KY	Pendleton Co., KY	Mason Co, KY
Status	Existing	Existing	Existing	Existing	Existing	Existing	Existing
Commercial Operation	9/22/03	9/9/03	9/15/03	2/1/06	1/15/06	1/07	11/09
Type	Gas	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	1.6 MW
Entitlement (%)	100	100	100	100	100	100	100
Primary Fuel Type	Methane	Methane	Methane	Methane	Methane	Methane	Methane
Secondary Fuel Type	None	None	None	None	None	None	None
Fuel Storage	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Scheduled Upgrades, Deratings, Retirement Dates	None	None	None	None	None	None	None

Table 8.(3)(b)(1-11)-6
Generating Plant Data

	Future CC 1	Future CC 2
Location	Undetermined	Undetermined
Status	Proposed	Proposed
Commercial Operation	Oct 2015	Oct 2022
Type	Gas/Steam	Gas/Steam
Net Dependable Capability	275 MW	275 MW
Entitlement (%)	100	100
Primary Fuel Type	Natural Gas	Natural Gas
Secondary Fuel Type	None	None
Fuel Storage (Tons)	None	None
Scheduled Upgrades, Deratings, Retirement Dates	N/A	N/A

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807 KAR 5:058 Section 8.(3)(b)(12) Resource Assessment and Acquisition Plan. (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. (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: (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); (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).

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Dale 1	ACTUAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capacity Factor	0.27	0.00	0.00	0.00	0.01											
Availability Factor	0.98	0.46	0.46	0.43	0.43											
Average Heat Rate (Btu/kWh)	12,926	12,656	12,385	12,470	12,451											
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-											
O&M Escalation (%)		0	2.4	2.4	2.4											

Dale 2	ACTUAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capacity Factor	0.26	0.00	0.00	0.00	0.01											
Availability Factor	0.96	0.48	0.48	0.44	0.44											
Average Heat Rate (Btu/kWh)																

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	2011	2012	2013	2014	2015
	12,685	12,347	12,284	12,260	12,245
Fuel Cost ($/MMBtu)	[redacted]				
Variable O&M ($/MWh)					
Fixed O&M ($/kW/Yr)					
Variable Production Cost ($/MWh)					
Capital Cost Escalation (%)		-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4

Dale 3	ACTUAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capacity Factor	0.55	0.00	0.00	0.00	0.01											
Availability Factor	0.91	0.92	0.91	0.91	0.91											
Average Heat Rate (Btu/kWh)	12,192	14,423	12,927	12,381	12,250											
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-											
O&M Escalation (%)		0	2.4	2.4	2.4											

Dale 4	ACTUAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capacity Factor	0.55	0.00	0.00	0.02	0.04											
Availability Factor	0.94	0.92	0.92	0.92	0.92											
Average Heat Rate (Btu/kWh)	11,857	12,668	12,516	12,053	11,946											
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																

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		2012	2013	2014	2015
Capital Cost Escalation (%)		-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4

Cooper 1	ACTUAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capacity Factor	0.77	0.08	0.17	0.28	0.25											
Availability Factor	0.87	0.89	0.91	0.91	0.91											
Average Heat Rate (Btu/kWh)	10,832	10,172	10,138	10,062	10,049											
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-											
O&M Escalation (%)		0	2.4	2.4	2.4											

Cooper 2	ACTUAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capacity Factor	0.70	0.34	0.46	0.55	0.60	0.66	0.70	0.73	0.75	0.75	0.77	0.80	0.83	0.84	0.84	0.84
Availability Factor	0.76	0.75	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92
Average Heat Rate (Btu/kWh)	10,379	10,178	10,099	9,984	9,948	9,919	9,899	9,880	9,869	9,869	9,864	9,861	9,861	9,859	9,859	9,859
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Spurlock 1	ACTUAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capacity Factor	0.73	0.77	0.74	0.83	0.84	0.86	0.86	0.87	0.88	0.89	0.89	0.89	0.89	0.89	0.89	0.89

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Availability Factor	0.87	0.94	0.83	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Average Heat Rate (Btu/kWh)	10,742	10,299	10,206	10,169	10,156	10,131	10,122	10,110	10,101	10,097	10,095	10,097	10,093	10,093	10,091	10,090
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Spurlock 2	ACTUAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capacity Factor	0.81	0.73	0.82	0.80	0.80	0.80	0.80	0.81	0.81	0.81	0.82	0.83	0.83	0.84	0.84	0.85
Availability Factor	0.89	0.82	0.93	0.89	0.89	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)	10,432	9,987	9,992	9,981	9,976	9,972	9,970	9,967	9,964	9,962	9,953	9,945	9,935	9,932	9,928	9,919
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Gilbert Unit	ACTUAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capacity Factor	0.79	0.80	0.81	0.68	0.81	0.81	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82
Availability Factor	0.81	0.89	0.89	0.74	0.89	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)	9,737	9,690	9,686	9,685	9,688	9,684	9,683	9,681	9,680	9,680	9,680	9,680	9,680	9,680	9,679	9,679
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																

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Fixed O&M ($/kW/Yr)	[redacted]															
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Spurlock 4	ACTUAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capacity Factor	0.85	0.82	0.84	0.84	0.83	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84
Availability Factor	0.90	0.89	0.89	0.89	0.89	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)	9,811	9,683	9,677	9,674	9,680	9,677	9,676	9,674	9,674	9,674	9,674	9,673	9,673	9,673	9,674	9,673
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Future Combined Cycle 1	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capacity Factor					0.15	0.59	0.59	0.55	0.58	0.56	0.53	0.51	0.49	0.49	0.49	0.48
Availability Factor					0.99	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Average Heat Rate (Btu/kWh)					7,095	7,088	7,086	7,076	7,071	7,074	7,083	7,092	7,093	7,097	7,100	7,103
Fuel Cost ($/MMBtu)					[redacted]											
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)					2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
O&M Escalation (%)					2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Future Combined Cycle 2	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026

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	2022	2023	2024	2025	2026
Capacity Factor	0.12	0.46	0.45	0.45	0.45
Availability Factor	0.99	0.95	0.95	0.95	0.95
Average Heat Rate (Btu/kWh)	7,084	7,093	7,097	7,101	7,103
Fuel Cost ($/MMBtu)	[redacted]				
Variable O&M ($/MWh)					
Fixed O&M ($/kW/Yr)					
Variable Production Cost ($/MWh)					
Capital Cost Escalation (%)	2.2	2.2	2.2	2.2	2.2
O&M Escalation (%)	2.4	2.4	2.4	2.4	2.4

Smith CT1	ACTUAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capacity Factor	0.0043	0.0060	0.0011	0.0024	0.0072	0.0039	0.0068	0.0030	0.0128	0.0058	0.0075	0.0032	0.0010	0.0015	0.0018	0.0024
Availability Factor	0.99	0.94	0.83	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Average Heat Rate (Btu/kWh)	17,801	12,547	12,246	12,626	13,079	13,362	13,148	12,999	13,207	12,996	13,166	13,272	13,086	12,927	12,795	12,921
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Smith CT2	ACTUAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capacity Factor	0.0066	0.0123	0.0022	0.0028	0.0098	0.0080	0.0101	0.0055	0.0146	0.0085	0.0107	0.0056	0.0031	0.0030	0.0035	0.0043
Availability Factor	0.98	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Average Heat Rate (Btu/kWh)	17,053	12,559	12,375	12,666	13,037	13,550	13,309	13,042	13,229	13,093	13,184	13,297	13,154	13,148	13,107	13,155
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																

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Variable Production Cost ($/MWh)	[redacted]															
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Smith CT3	**ACTUAL 2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Capacity Factor	0.0200	0.0249	0.0055	0.0060	0.0164	0.0107	0.0135	0.0070	0.0159	0.0081	0.0097	0.0060	0.0029	0.0027	0.0032	0.0036
Availability Factor	0.98	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Average Heat Rate (Btu/kWh)	16,834	12,823	12,787	12,768	13,116	13,616	13,467	13,084	13,193	13,062	13,192	13,269	13,282	13,206	13,068	13,159
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Smith CT4	**ACTUAL 2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Capacity Factor	0.06	0.12	0.04	0.05	0.11	0.08	0.10	0.05	0.09	0.05	0.06	0.04	0.02	0.02	0.02	0.03
Availability Factor	0.98	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
Average Heat Rate (Btu/kWh)	12,746	11,301	11,596	11,688	11,664	11,474	11,535	11,726	11,854	12,039	12,161	12,142	12,111	12,145	12,238	12,303
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Smith CT5	**ACTUAL 2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**

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Capacity Factor	0.08	0.17	0.10	0.10	0.13	0.14	0.15	0.10	0.11	0.06	0.06	0.05	0.04	0.04	0.05	0.05
Availability Factor	0.99	0.93	0.93	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)	12,706	11,460	11,722	11,746	11,696	11,589	11,686	11,945	11,988	12,276	12,355	12,296	12,307	12,359	12,361	12,437
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Smith CT6	ACTUAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capacity Factor	0.08	0.15	0.08	0.10	0.12	0.13	0.14	0.09	0.11	0.06	0.06	0.05	0.03	0.03	0.04	0.04
Availability Factor	0.89	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	0.97	0.97
Average Heat Rate (Btu/kWh)	12,170	11,472	11,774	11,717	11,640	11,518	11,595	11,845	11,902	12,176	12,288	12,208	12,227	12,246	12,277	12,391
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Smith CT7	ACTUAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capacity Factor	0.13	0.18	0.10	0.11	0.13	0.10	0.11	0.07	0.10	0.05	0.05	0.04	0.02	0.02	0.02	0.03
Availability Factor	0.99	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	0.97	0.97
Average Heat Rate (Btu/kWh)	12,116	11,509	11,833	11,787	11,716	11,436	11,489	11,717	11,791	12,053	12,147	12,138	12,105	12,146	12,203	12,253
Fuel Cost ($/MMBtu)	[redacted]															

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Variable O&M ($/MWh)	[redacted]															
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Smith CT 9	ACTUAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capacity Factor	0.21	0.45	0.37	0.38	0.39	0.42	0.43	0.38	0.41	0.31	0.30	0.27	0.21	0.22	0.22	0.25
Availability Factor	0.91	-	-	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Average Heat Rate (Btu/kWh)	10,410	8,927	9,245	9,230	9,121	9,020	9,020	9,133	9,087	9,341	9,535	9,744	9,560	9,618	9,681	9,768
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		0.2	1.7	2.9	2.7	2.9	2.7	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5

Smith CT 10	ACTUAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capacity Factor	0.19	0.45	0.35	0.37	0.39	0.41	0.42	0.33	0.39	0.23	0.25	0.23	0.16	0.15	0.16	0.16
Availability Factor	0.86	0.96	0.94	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Average Heat Rate (Btu/kWh)	10,556	8,933	9,344	9,251	9,128	9,019	9,016	9,132	9,090	9,311	9,493	9,726	9,435	9,491	9,549	9,696
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

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Landfill Gas Projects	ACTUAL 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Capacity Factor	0.67	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Availability Factor	0.84	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)	12,655	11,849	11,835	11,828	11,828	11,828	11,828	11,828	11,828	11,828	11,828	11,828	11,828	11,828	11,828	11,828
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

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SECTION 5.0

DEMAND SIDE MANAGEMENT

SECTION 5.0
DEMAND SIDE MANAGEMENT

5.1 Introduction

807 KAR 5:058 Section 8(2)(b) The utility shall describe and discuss all options considered for inclusion in the plan including: (b) Conservation and load management or other demand-side programs not already in place.

For more than 30 years, 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 Demand Side Management Option Risk Evaluator (DSMore), a computer program developed by Integral Analytics, in order to evaluate the benefits of these programs.

EKPC and Member Systems will continue to work together to implement these programs as they fit their organizational goals.

5.2 DSM Planning Process

EKPC evaluated 113 Demand-Side Management (DSM) measures for the 2012 Integrated Resource Plan (IRP). Of these, 10 represent Existing DSM programs and 103 represent New DSM measures for this plan. A two-step process was used in the evaluation: (1) Qualitative Screening, and (2) Quantitative Evaluation.

Forty-three (43) new measures passed the Qualitative Screen and were passed on to Quantitative Evaluation. In some cases, several measures were combined into one program. Also, a few of the measures did not lend themselves to quantitative analysis or require additional research in order to allow for analysis in the future, or were set aside for other sound reasons that came to light during the study. A total of 33 new DSM Programs were prepared for the Quantitative Evaluation.

Significantly more measures have been carried on to the quantitative analysis in this plan in comparison with the 2009 IRP. This is attributable to EKPC's adopting the Staff recommendation that EKPC take a somewhat more flexible approach in its consideration of measures coming out of the qualitative screening.

The results for the cost-effectiveness tests were generally favorable for the DSM programs. Of the 33 DSM Programs that were evaluated, 27 produced a Total Resource Cost test benefit-cost ratio of greater than 1.0. At this stage, EKPC conducted a final strategic review of the portfolio. Two programs were determined to be at the pilot stage, two programs had TRCs less than 1.1, and two required substantial customer investments and yet had relatively low participant test scores. Therefore, no impacts from these six programs are reflected in the final DSM portfolio. Thus, the final DSM portfolio in this 2012 IRP includes 21 "new" programs whose load impacts are not reflected in the base case load forecast.

In addition to these 21 New Programs, EKPC also has thirteen (13) Existing Programs in its DSM portfolio. In keeping with PSC Staff guidance, EKPC in this IRP has reflected the impacts of these programs in the load forecast.

Complete List of DSM Measures (Existing and New)

& Results of Qualitative Screen

Measures that passed the Qualitative Screen are IN BOLD

Residential

1	**Wholistic Weatherization**	**New**
2	**Low income weatherization**	**New**
3	**Enhanced Button-Up (air sealing)**	**Existing**
4	**Enhanced Tune-Up (duct sealing)**	**Existing**
5	**Mobile home retrofit program**	**New**
6	Low flow showerhead with faucet aerator/pipe insulation	New
7	**Direct load control - pool pump**	**New**
8	**Direct Load Control - air conditioners & water heaters**	**Existing**
9	**DLC of heat pump strip heat**	**New**
10	**Beat the Peak**	**New**
11	**Electric Thermal Storage**	**Existing**
12	**Residential Efficient Lighting**	**Existing**
13	High efficiency outdoor lighting	New
14	LED lighting	New
15	**Enhanced Touchstone Home (thermal sealing/bypass)**	**New**
16	**Touchstone Energy Home**	**Existing**
17	**Touchstone Energy Manufactured Home**	**Existing**
18	ENERGY STAR Refrigerator	New
19	ENERGY STAR Room Air Conditioner	New
20	**ENERGY STAR Clothes Washers**	**New**
21	ENERGY STAR Freezers	New
22	ENERGY STAR Home electronics	New
23	ENERGY STAR Windows	New
24	ENERGY STAR Dishwashers	New
25	ENERGY STAR Dehumidifiers	New
26	Room AC exchange & recycle program	New
27	**Refrigerator/Freezer Recycling**	**New**
28	**Remove old second refrigerators**	**New**
29	**Remove old second freezers**	**New**
30	Ceiling Fans	New
31	Heat pump dryer	New
32	Well water pump	New
33	Efficient pool pump	New
34	Cold climate heat pump	New
35	**Heat retrofit/ early replace: resistance to heat pump**	**Existing**
36	**Inefficient heat pump to geothermal early replacement**	**New**
37	**SEER 10 heat pump to SEER 15 early replacement**	**New**
38	**ENERGY STAR Central Air Conditioner**	**New**
39	**Ductless mini-split heat pump**	**New**
40	Inefficient Central Air Conditioner to SEER 15	New
41	High efficiency furnace fan motors	New
42	**Dual Fuel add-on to heat pump**	**New**
43	**Dual Fuel heat pump replacing electric resistance heat**	**New**
44	**Heat pump water heater**	**New**
45	Instantaneous water heater	New
46	Solar water heater	New
47	Passive Solar (new construction)	New

Residential (continued)

48	Photovoltaics (customer sited)	New
48	Wind turbine (customer sited)	New
50	**Home Energy Information Program**	**New**
51	Polarized Refrigerant oxidant agent	New
52	**Time of use rates**	**New**
53	**Inclining block rates**	**New**
54	**Programmable thermostats with electric furnace heat**	**New**
55	**Multi-family program**	**New**

Commercial

1	**Commercial HVAC**	**New**
2	**Demand Response**	**New**
3	**Commercial Building Performance**	**New**
4	**Commercial New Construction**	**New**
5	Efficient refrigeration equipment	New
6	**Small C&I audit program**	**New**
7	Building operator certification program	New
8	**Geothermal heat pump**	**New**
9	Evaporative cooling	New
10	Advanced ventilation	New
11	High efficiency HVAC motors	New
12	Early replacement inefficient unitary/split system HVAC	New
13	Cool roof program	New
14	High performance glazings	New
15	**Duct sealing**	**New**
16	Thermal energy storage	New
17	Heat pump water heaters	New
18	Drain heat recovery water heaters	New
19	**LED exit signs**	**New**
20	**Advanced lighting program**	**Existing**
21	Efficient cooking equipment	New
22	Efficient clothes washers	New
23	ENERGY STAR Vending machines	New
24	**Energy Management Systems**	**New**
25	DLC of irrigation pumps	New
26	**DLC of central air conditioners**	**New**
27	**Energy efficient schools**	**New**
28	Farms program: fans, pumps, irrigation	New
29	**Time of use rates**	**New**
30	Combined heat & power	New
31	Stand-by generation program	New
32	Daylighting	New
33	Solar hot water	New
34	Photovoltaics	New
35	Wind turbine	New

Industrial/Other

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

Note: For screening purposes, the button-up weatherization and the button-up with air sealing (existing programs) were combined. Likewise, for screening purposes, the Wholistic Weatherization and Advanced Weatherization Tiers 2 and 3 (New) were combined.

807 KAR 5:058 Section 8(3)(e)(1) 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. (e) For each existing and new conservation and load management or other demand-side programs included in the plan; (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-6 and DSM-3 in the DSM Technical Appendix.

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

Program Name	Class	End-uses
Button-Up Weatherization	Residential	Space Heating, Space Cooling
Button-Up with Air Sealing	Residential	Space Heating, Space Cooling
Heat Pump Retrofit	Residential	Space Heating, Space Cooling
Electric Thermal Storage	Residential	Space Heating
Direct Load Control of AC & WH	Residential	Space Cooling, Water Heating
Residential Lighting	Residential	Lighting
Touchstone Energy (TSE) Home	Residential	Space Heating, Space Cooling, Water Heating
TSE Manufactured Home	Residential	Space Heating, Space Cooling
Tune-Up HVAC w/ Duct Sealing	Residential	Space Heating, Space Cooling
Commercial Lighting	Commercial	Lighting
Compressed Air	Industrial	Compressed Air
Gallatin Steel Interruptible	Industrial	Various
Other Interruptible	Industrial	Various

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

Program Name	Class	End-uses
"Beat the Peak" demand response	Residential	Various
ENERGY STAR Central Air (1)	Residential	Space Cooling
Geothermal retrofit	Residential	Space Heating, Space Cooling, Water Heating
Home Energy Information	Residential	Various
Low Income Weatherization (1)	Residential	Space Heating, Space Cooling, Hot Water Heating, Lighting
Mobile Home Retrofit (1)	Residential	Space Heating, Space Cooling, Hot Water Heating, Lighting, Refrigeration
Programmable Thermostat	Residential	Space Heating, Space Cooling
DLC for Residential Pool Pump (2)	Residential	Water Pumping (Pool)
Advanced Weatherization Tier 2	Residential	Space Heating, Space Cooling
Advanced Weatherization Tier 3	Residential	Space Heating, Space Cooling
E -STAR Clothes Washer (1)	Residential	Clothes Washing, Clothes Drying, Hot Water Heating
C&I Demand Response (1)	Industrial	Various
Industrial Process	Industrial	Process Loads
Industrial Variable Speed Drives (1)	Industrial	Drive Power
Commercial EMCS	Commercial	Space Cooling, Space Heating, Ventilation, Lighting
DLC for Commercial Central AC (2)	Commercial	Space Cooling
Building Performance	Commercial	Space Cooling, Space Heating, Ventilation
Commercial Duct Sealing	Commercial	Space Cooling, Space Heating, Ventilation
Commercial Efficient HVAC (1)	Commercial	Space Cooling, Space Heating, Ventilation
Commercial New Construction (1)	Commercial	Space Cooling, Space Heating, Ventilation, Lighting
Small C&I Audit	Commercial	Lighting, Space Heating, Space Cooling, Ventilation, Refrigeration

(1) These programs were considered new programs in EKPC's 2009 IRP. These are considered new in 2012 as none of the programs were included in EKPC's DSM marketing plans from 2009 – 2011.

(2) These programs are incorporated in EKPC's Direct Load control tariffs on file with the Commission. However, these programs were not included in EKPC's DSM marketing plans from 2009 – 2011.

807 KAR 5:058 Section 8(3)(e)(2) 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. (e) For each existing and new conservation and load management or other demand-side programs included in the plan; (2) Expected duration of the program.

Expected duration of the program;

The following tables provide the expected duration of the program. For each existing and new program, the number of years that new participants are served is given as well as the lifetime of the measure savings:

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

Program Name	New Participants	Savings Lifetime
Button-Up Weatherization	15 years	15 years
Button-Up with Air Sealing	15 years	15 years
Heat Pump Retrofit	10 years	20 years
Electric Thermal Storage	15 years	20 years
Direct Load Control of AC & WH	7 years	20 years
Residential Lighting	10 years	8 years
Touchstone Energy (TSE) Home	15 years	20 years
TSE Manufactured Home	15 years	20 years
Tune-Up HVAC w/ Duct Sealing	15 years	12 years
Commercial Lighting	15 years	10 years
Compressed Air	15 years	7 years
Gallatin Steel Interruptible	NA	20 years
Other Interruptible	NA	20 years

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

Program Name	New Participants	Savings Lifetime
"Beat the Peak" demand response	5 years	20 years
ENERGY STAR Central Air	15 years	15 years
Geothermal retrofit	5 years	15 years
Home Energy Information	15 years	1 year
Low Income Weatherization	15 years	15 years
Mobile Home Retrofit	15 years	12 years
Programmable Thermostat	15 years	10 years
DLC for Residential Pool Pump	5 years	20 years
Advanced Weatherization Tier 2	15 years	15 years
Advanced Weatherization Tier 3	15 years	15 years
E -STAR Clothes Washer	15 years	12 years
C&I Demand Response	3 years	20 years
Industrial Process	15 years	10 years
Industrial Variable Speed Drives	15 years	15 years
Commercial EMCS	15 years	15 years
DLC for Commercial Central AC	5 years	20 years
Building Performance	15 years	7 years
Commercial Duct Sealing	15 years	15 years
Commercial Efficient HVAC	15 years	15 years
Commercial New Construction	15 years	20 years
Small C&I Audit	15 years	10 years

807 KAR 5:058 Section 8(3)(e)(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. (e) For each existing and new conservation and load management or other demand-side programs included in the plan: (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 annual energy, summer peak demand and winter peak demand changes for each Existing and New DSM program included in the plan. Please note that these tables, except for Gallatin Steel Interruptible and Interruptible Program, do not include the effect of current participants in existing programs.

Load Impacts of DSM Programs

Existing:
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)
2012	1,100	-2,358	-1.6	-0.5
2013	2,570	-5,508	-3.7	-1.3
2014	4,040	-8,659	-5.9	-2.0
2015	5,510	-11,809	-8.0	-2.7
2016	6,980	-14,960	-10.2	-3.4
2017	8,450	-18,111	-12.3	-4.1
2018	9,920	-21,261	-14.5	-4.8
2019	11,390	-24,412	-16.6	-5.5
2020	12,860	-27,562	-18.7	-6.3
2021	14,330	-30,713	-20.9	-7.0
2022	15,800	-33,864	-23.0	-7.7
2023	17,270	-37,014	-25.2	-8.4
2024	18,740	-40,165	-27.3	-9.1
2025	20,210	-43,315	-29.5	-9.8
2026	21,680	-46,466	-31.6	-10.6

Button-Up with Air Sealing Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	80	-237	-0.2	-0.1
2013	187	-553	-0.4	-0.1
2014	294	-870	-0.6	-0.2
2015	401	-1,187	-0.8	-0.3
2016	508	-1,504	-1.0	-0.3
2017	615	-1,820	-1.2	-0.4
2018	722	-2,137	-1.5	-0.5
2019	829	-2,454	-1.7	-0.6
2020	936	-2,770	-1.9	-0.6
2021	1,043	-3,087	-2.1	-0.7
2022	1,150	-3,404	-2.3	-0.8
2023	1,257	-3,720	-2.5	-0.8

2024	1,364	-4,037	-2.7	-0.9
2025	1,471	-4,354	-3.0	-1.0
2026	1,578	-4,670	-3.2	-1.1

Residential 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)
2012	400	-3,254	-0.3	-0.1
2013	933	-7,590	-0.8	-0.3
2014	1,466	-11,925	-1.3	-0.5
2015	1,999	-16,261	-1.7	-0.7
2016	2,532	-20,597	-2.2	-0.8
2017	3,065	-24,932	-2.7	-1.0
2018	3,598	-29,268	-3.1	-1.2
2019	4,131	-33,604	-3.6	-1.4
2020	4,664	-37,940	-4.1	-1.5
2021	5,197	-42,275	-4.5	-1.7
2022	5,197	-42,275	-4.5	-1.7
2023	5,197	-42,275	-4.5	-1.7
2024	5,197	-42,275	-4.5	-1.7
2025	5,197	-42,275	-4.5	-1.7
2026	5,197	-42,275	-4.5	-1.7

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)
2012	70	8	-0.4	0.0
2013	175	19	-1.1	0.0
2014	280	30	-1.7	0.0
2015	385	41	-2.3	0.0
2016	490	53	-3.0	0.0
2017	595	64	-3.6	0.0
2018	700	75	-4.2	0.0
2019	805	87	-4.9	0.0
2020	910	98	-5.5	0.0
2021	1,015	109	-6.1	0.0
2022	1,120	121	-6.8	0.0
2023	1,225	132	-7.4	0.0
2024	1,330	143	-8.0	0.0
2025	1,435	154	-8.7	0.0
2026	1,540	166	-9.3	0.0

Direct Load Control of Residential 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)
2012	6,500	-301	-2.0	-8.4
2013	13,000	-603	-3.9	-16.8
2014	19,500	-904	-5.9	-25.3
2015	26,000	-1,205	-7.9	-33.7
2016	32,500	-1,507	-9.8	-42.1
2017	39,000	-1,808	-11.8	-50.5
2018	42,457	-1,968	-12.8	-55.0
2019	42,457	-1,968	-12.8	-55.0
2020	42,457	-1,968	-12.8	-55.0
2021	42,457	-1,968	-12.8	-55.0
2022	42,457	-1,968	-12.8	-55.0
2023	42,457	-1,968	-12.8	-55.0
2024	42,457	-1,968	-12.8	-55.0
2025	42,457	-1,968	-12.8	-55.0
2026	42,457	-1,968	-12.8	-55.0

Residential Lighting Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	77,000	-13,572	-2.0	-1.5
2013	146,000	-26,950	-4.0	-3.0
2014	207,000	-39,851	-6.0	-4.4
2015	257,000	-51,602	-7.7	-5.7
2016	307,000	-63,352	-9.5	-7.0
2017	357,000	-75,103	-11.3	-8.3
2018	407,000	-86,853	-13.0	-9.6
2019	457,000	-98,603	-14.8	-10.8
2020	430,000	-96,782	-14.5	-10.6
2021	411,000	-95,155	-14.3	-10.5
2022	350,000	-82,253	-12.3	-9.0
2023	300,000	-70,502	-10.6	-7.8
2024	250,000	-58,752	-8.8	-6.5
2025	200,000	-47,002	-7.1	-5.2
2026	150,000	-35,251	-5.3	-3.9

Touchstone Energy New Construction Home

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	573	-1,510	-1.3	-0.4
2013	1,221	-3,218	-2.8	-0.8
2014	1,933	-5,095	-4.5	-1.2
2015	2,663	-7,019	-6.1	-1.7
2016	3,406	-8,978	-7.9	-2.2
2017	4,158	-10,960	-9.6	-2.7
2018	4,914	-12,952	-11.3	-3.1
2019	5,670	-14,945	-13.1	-3.6
2020	6,448	-16,996	-14.9	-4.1
2021	7,227	-19,049	-16.7	-4.6
2022	7,993	-21,068	-18.5	-5.1
2023	8,771	-23,119	-20.2	-5.6
2024	9,545	-25,159	-22.0	-6.1
2025	10,336	-27,244	-23.9	-6.6
2026	11,133	-29,344	-25.7	-7.1

TSE Manufactured Home

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	34	-180	-0.1	0.0
2013	73	-386	-0.2	-0.1
2014	115	-609	-0.3	-0.1
2015	158	-836	-0.4	-0.1
2016	202	-1,069	-0.6	-0.2
2017	247	-1,308	-0.7	-0.2
2018	292	-1,546	-0.8	-0.3
2019	337	-1,784	-0.9	-0.3
2020	383	-2,028	-1.1	-0.3
2021	429	-2,271	-1.2	-0.4
2022	475	-2,515	-1.3	-0.4
2023	521	-2,758	-1.5	-0.5
2024	567	-3,002	-1.6	-0.5
2025	614	-3,251	-1.7	-0.6
2026	661	-3,499	-1.8	-0.6

Tune-Up HVAC with Duct Sealing Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	500	-448	-0.3	-0.1
2013	1,170	-1,049	-0.8	-0.3
2014	1,840	-1,650	-1.2	-0.5
2015	2,510	-2,251	-1.7	-0.6
2016	3,180	-2,852	-2.1	-0.8
2017	3,850	-3,453	-2.5	-1.0
2018	4,520	-4,054	-3.0	-1.1
2019	5,190	-4,655	-3.4	-1.3
2020	5,860	-5,255	-3.9	-1.4
2021	6,530	-5,856	-4.3	-1.6
2022	7,200	-6,457	-4.7	-1.8
2023	7,870	-7,058	-5.2	-1.9
2024	8,040	-7,211	-5.3	-2.0
2025	8,040	-7,211	-5.3	-2.0
2026	8,040	-7,211	-5.3	-2.0

Commercial Lighting Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	1,250	-4,597	-0.5	-0.9
2013	2,500	-9,195	-1.0	-1.8
2014	3,750	-13,792	-1.5	-2.8
2015	5,000	-18,389	-1.9	-3.7
2016	6,250	-22,986	-2.4	-4.6
2017	7,500	-27,584	-2.9	-5.5
2018	8,750	-32,181	-3.4	-6.4
2019	10,000	-36,778	-3.9	-7.4
2020	11,250	-41,376	-4.4	-8.3
2021	12,500	-45,973	-4.9	-9.2
2022	12,500	-45,973	-4.9	-9.2
2023	12,500	-45,973	-4.9	-9.2
2024	12,500	-45,973	-4.9	-9.2
2025	12,500	-45,973	-4.9	-9.2
2026	12,500	-45,973	-4.9	-9.2

Compressed Air Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	1,560	-5,761	-0.5	-1.1
2013	3,640	-13,442	-1.1	-2.7
2014	5,720	-21,123	-1.7	-4.2
2015	7,800	-28,805	-2.3	-5.7
2016	9,880	-36,486	-2.9	-7.2
2017	11,960	-44,167	-3.5	-8.7
2018	14,040	-51,848	-4.1	-10.2
2019	14,560	-53,769	-4.2	-10.6
2020	14,560	-53,769	-4.2	-10.6
2021	14,560	-53,769	-4.2	-10.6
2022	14,560	-53,769	-4.2	-10.6
2023	14,560	-53,769	-4.2	-10.6
2024	14,560	-53,769	-4.2	-10.6
2025	14,560	-53,769	-4.2	-10.6
2026	14,560	-53,769	-4.2	-10.6

Gallatin Steel Interruptible

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	1	0	-120.0	-120.0
2013	1	0	-120.0	-120.0
2014	1	0	-120.0	-120.0
2015	1	0	-120.0	-120.0
2016	1	0	-120.0	-120.0
2017	1	0	-120.0	-120.0
2018	1	0	-120.0	-120.0
2019	1	0	-120.0	-120.0
2020	1	0	-120.0	-120.0
2021	1	0	-120.0	-120.0
2022	1	0	-120.0	-120.0
2023	1	0	-120.0	-120.0
2024	1	0	-120.0	-120.0
2025	1	0	-120.0	-120.0
2026	1	0	-120.0	-120.0

Interruptible Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	4	0	-8.0	-8.0
2013	4	0	-8.0	-8.0
2014	4	0	-8.0	-8.0
2015	4	0	-8.0	-8.0
2016	4	0	-8.0	-8.0
2017	4	0	-8.0	-8.0
2018	4	0	-8.0	-8.0
2019	4	0	-8.0	-8.0
2020	4	0	-8.0	-8.0
2021	4	0	-8.0	-8.0
2022	4	0	-8.0	-8.0
2023	4	0	-8.0	-8.0
2024	4	0	-8.0	-8.0
2025	4	0	-8.0	-8.0
2026	4	0	-8.0	-8.0

New:
"Beat the Peak" Demand Response Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	8,000	-130	-1.7	-1.7
2013	16,000	-259	-3.5	-3.5
2014	24,000	-389	-5.2	-5.2
2015	32,000	-518	-6.9	-6.9
2016	40,000	-648	-8.6	-8.6
2017	40,000	-648	-8.6	-8.6
2018	40,000	-648	-8.6	-8.6
2019	40,000	-648	-8.6	-8.6
2020	40,000	-648	-8.6	-8.6
2021	40,000	-648	-8.6	-8.6
2022	40,000	-648	-8.6	-8.6
2023	40,000	-648	-8.6	-8.6
2024	40,000	-648	-8.6	-8.6
2025	40,000	-648	-8.6	-8.6
2026	40,000	-648	-8.6	-8.6

ENERGY STAR Residential Central Air Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	2,600	-1,337	0.0	-1.2
2013	5,200	-2,674	0.0	-2.5
2014	7,800	-4,011	0.0	-3.7
2015	10,400	-5,348	0.0	-5.0
2016	13,000	-6,684	0.0	-6.2
2017	15,600	-8,021	0.0	-7.4
2018	18,200	-9,358	0.0	-8.7
2019	20,800	-10,695	0.0	-9.9
2020	23,400	-12,032	0.0	-11.1
2021	26,000	-13,369	0.0	-12.4
2022	28,600	-14,706	0.0	-13.6
2023	31,200	-16,043	0.0	-14.9
2024	33,800	-17,380	0.0	-16.1
2025	36,400	-18,716	0.0	-17.3
2026	39,000	-20,053	0.0	-18.6

Residential Geothermal Retrofit program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	200	-1,502	-1.2	-0.5
2013	400	-3,003	-2.4	-1.0
2014	600	-4,505	-3.7	-1.5
2015	800	-6,007	-4.9	-1.9
2016	1,000	-7,508	-6.1	-2.4
2017	1,000	-7,508	-6.1	-2.4
2018	1,000	-7,508	-6.1	-2.4
2019	1,000	-7,508	-6.1	-2.4
2020	1,000	-7,508	-6.1	-2.4
2021	1,000	-7,508	-6.1	-2.4
2022	1,000	-7,508	-6.1	-2.4
2023	1,000	-7,508	-6.1	-2.4
2024	1,000	-7,508	-6.1	-2.4
2025	1,000	-7,508	-6.1	-2.4
2026	1,000	-7,508	-6.1	-2.4

Home Energy Information Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	100,000	-30,534	-8.2	-6.4
2013	100,000	-30,534	-8.2	-6.4
2014	100,000	-30,534	-8.2	-6.4
2015	100,000	-30,534	-8.2	-6.4
2016	100,000	-30,534	-8.2	-6.4
2017	100,000	-30,534	-8.2	-6.4
2018	100,000	-30,534	-8.2	-6.4
2019	100,000	-30,534	-8.2	-6.4
2020	100,000	-30,534	-8.2	-6.4
2021	100,000	-30,534	-8.2	-6.4
2022	100,000	-30,534	-8.2	-6.4
2023	100,000	-30,534	-8.2	-6.4
2024	100,000	-30,534	-8.2	-6.4
2025	100,000	-30,534	-8.2	-6.4
2026	100,000	-30,534	-8.2	-6.4

Low Income Weatherization Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	1,500	-4,862	-3.4	-1.5
2013	3,000	-9,723	-6.8	-3.0
2014	4,500	-14,585	-10.3	-4.5
2015	6,000	-19,446	-13.7	-6.0
2016	7,500	-24,308	-17.1	-7.5
2017	9,000	-29,170	-20.5	-9.0
2018	10,500	-34,031	-23.9	-10.5
2019	12,000	-38,893	-27.3	-12.1
2020	13,500	-43,755	-30.8	-13.6
2021	15,000	-48,616	-34.2	-15.1
2022	16,500	-53,478	-37.6	-16.6
2023	18,000	-58,339	-41.0	-18.1
2024	19,500	-63,201	-44.4	-19.6
2025	21,000	-68,063	-47.9	-21.1
2026	22,500	-72,924	-51.3	-22.6

Mobile Home Retrofit Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	500	-1,714	-0.9	-0.2
2013	1,000	-3,428	-1.8	-0.5
2014	1,500	-5,142	-2.6	-0.7
2015	2,000	-6,856	-3.5	-1.0
2016	2,500	-8,570	-4.4	-1.2
2017	3,000	-10,284	-5.3	-1.5
2018	3,500	-11,998	-6.2	-1.7
2019	4,000	-13,712	-7.1	-2.0
2020	4,500	-15,426	-7.9	-2.2
2021	5,000	-17,140	-8.8	-2.4
2022	5,500	-18,854	-9.7	-2.7
2023	6,000	-20,568	-10.6	-2.9
2024	6,000	-20,568	-10.6	-2.9
2025	6,000	-20,568	-10.6	-2.9
2026	6,000	-20,568	-10.6	-2.9

Programmable Thermostat Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	600	-420	0.0	-0.1
2013	1,200	-840	0.0	-0.2
2014	1,800	-1,260	0.0	-0.2
2015	2,400	-1,680	0.0	-0.3
2016	3,000	-2,100	0.0	-0.4
2017	3,600	-2,519	0.0	-0.5
2018	4,200	-2,939	0.0	-0.5
2019	4,800	-3,359	0.0	-0.6
2020	5,400	-3,779	0.0	-0.7
2021	6,000	-4,199	0.0	-0.8
2022	6,000	-4,199	0.0	-0.8
2023	6,000	-4,199	0.0	-0.8
2024	6,000	-4,199	0.0	-0.8
2025	6,000	-4,199	0.0	-0.8
2026	6,000	-4,199	0.0	-0.8

DLC for Residential Pool Pump

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	1,500	-31	0.0	-1.2
2013	3,000	-62	0.0	-2.4
2014	4,500	-93	0.0	-3.6
2015	6,000	-124	0.0	-4.9
2016	7,500	-156	0.0	-6.1
2017	7,500	-156	0.0	-6.1
2018	7,500	-156	0.0	-6.1
2019	7,500	-156	0.0	-6.1
2020	7,500	-156	0.0	-6.1
2021	7,500	-156	0.0	-6.1
2022	7,500	-156	0.0	-6.1
2023	7,500	-156	0.0	-6.1
2024	7,500	-156	0.0	-6.1
2025	7,500	-156	0.0	-6.1
2026	7,500	-156	0.0	-6.1

Advanced Weatherization Tier 2

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	-	0	0.0	0.0
2013	75	-333	-0.2	-0.1
2014	225	-999	-0.7	-0.2
2015	375	-1,665	-1.1	-0.4
2016	525	-2,331	-1.6	-0.5
2017	675	-2,997	-2.0	-0.7
2018	825	-3,663	-2.5	-0.8
2019	975	-4,329	-2.9	-1.0
2020	1,125	-4,995	-3.4	-1.1
2021	1,275	-5,661	-3.8	-1.3
2022	1,425	-6,326	-4.3	-1.4
2023	1,575	-6,992	-4.8	-1.6
2024	1,725	-7,658	-5.2	-1.7
2025	1,875	-8,324	-5.7	-1.9
2026	2,025	-8,990	-6.1	-2.0

Advanced Weatherization Tier 3

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	-	0	0.0	0.0
2013	50	-296	-0.2	-0.1
2014	150	-888	-0.6	-0.2
2015	250	-1,480	-1.0	-0.3
2016	350	-2,072	-1.4	-0.5
2017	450	-2,664	-1.8	-0.6
2018	550	-3,256	-2.2	-0.7
2019	650	-3,848	-2.6	-0.9
2020	750	-4,440	-3.0	-1.0
2021	850	-5,032	-3.4	-1.1
2022	950	-5,624	-3.8	-1.3
2023	1,050	-6,215	-4.2	-1.4
2024	1,150	-6,807	-4.6	-1.5
2025	1,250	-7,399	-5.0	-1.7
2026	1,350	-7,991	-5.4	-1.8

ENERGY STAR Clothes Washer program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	2,225	-759	-0.2	-0.1
2013	4,450	-1,518	-0.3	-0.1
2014	6,675	-2,277	-0.5	-0.2
2015	8,900	-3,036	-0.6	-0.3
2016	11,125	-3,796	-0.8	-0.3
2017	13,350	-4,555	-0.9	-0.4
2018	15,575	-5,314	-1.1	-0.5
2019	17,800	-6,073	-1.2	-0.5
2020	20,025	-6,832	-1.4	-0.6
2021	22,250	-7,591	-1.5	-0.6
2022	24,475	-8,350	-1.7	-0.7
2023	26,700	-9,109	-1.8	-0.8
2024	26,700	-9,109	-1.8	-0.8
2025	26,700	-9,109	-1.8	-0.8
2026	26,700	-9,109	-1.8	-0.8

C&I Demand Response Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	150	-1,740	-5.7	-5.7
2013	350	-4,061	-13.2	-13.2
2014	500	-5,801	-18.9	-18.9
2015	500	-5,801	-18.9	-18.9
2016	500	-5,801	-18.9	-18.9
2017	500	-5,801	-18.9	-18.9
2018	500	-5,801	-18.9	-18.9
2019	500	-5,801	-18.9	-18.9
2020	500	-5,801	-18.9	-18.9
2021	500	-5,801	-18.9	-18.9
2022	500	-5,801	-18.9	-18.9
2023	500	-5,801	-18.9	-18.9
2024	500	-5,801	-18.9	-18.9
2025	500	-5,801	-18.9	-18.9
2026	500	-5,801	-18.9	-18.9

Industrial Process Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	3	-7,771	-2.1	-2.5
2013	6	-15,542	-4.2	-5.1
2014	9	-23,313	-6.2	-7.6
2015	12	-31,084	-8.3	-10.2
2016	15	-38,854	-10.4	-12.7
2017	18	-46,625	-12.5	-15.3
2018	21	-54,396	-14.6	-17.8
2019	24	-62,167	-16.6	-20.4
2020	27	-69,938	-18.7	-22.9
2021	30	-77,709	-20.8	-25.5
2022	30	-77,709	-20.8	-25.5
2023	30	-77,709	-20.8	-25.5
2024	30	-77,709	-20.8	-25.5
2025	30	-77,709	-20.8	-25.5
2026	30	-77,709	-20.8	-25.5

Industrial Variable Speed Drives Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	53	-4,787	-0.4	-0.5
2013	106	-9,575	-0.7	-1.0
2014	159	-14,362	-1.1	-1.5
2015	212	-19,150	-1.5	-2.1
2016	265	-23,937	-1.9	-2.6
2017	318	-28,725	-2.2	-3.1
2018	371	-33,512	-2.6	-3.6
2019	424	-38,300	-3.0	-4.1
2020	477	-43,087	-3.4	-4.6
2021	530	-47,875	-3.7	-5.2
2022	583	-52,662	-4.1	-5.7
2023	636	-57,449	-4.5	-6.2
2024	689	-62,237	-4.9	-6.7
2025	742	-67,024	-5.2	-7.2
2026	795	-71,812	-5.6	-7.7

Commercial EMCS Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	60	-1,750	-0.4	-0.2
2013	120	-3,499	-0.7	-0.4
2014	180	-5,249	-1.1	-0.6
2015	240	-6,998	-1.4	-0.9
2016	300	-8,748	-1.8	-1.1
2017	360	-10,498	-2.1	-1.3
2018	420	-12,247	-2.5	-1.5
2019	480	-13,997	-2.8	-1.7
2020	540	-15,746	-3.2	-1.9
2021	600	-17,496	-3.5	-2.2
2022	660	-19,246	-3.9	-2.4
2023	720	-20,995	-4.2	-2.6
2024	780	-22,745	-4.6	-2.8
2025	840	-24,494	-4.9	-3.0
2026	900	-26,244	-5.3	-3.2

DLC for Commercial Central AC

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	1,200	-38	0.0	-2.6
2013	2,400	-76	0.0	-5.2
2014	3,600	-115	0.0	-7.8
2015	4,800	-153	0.0	-10.4
2016	6,000	-191	0.0	-13.0
2017	6,000	-191	0.0	-13.0
2018	6,000	-191	0.0	-13.0
2019	6,000	-191	0.0	-13.0
2020	6,000	-191	0.0	-13.0
2021	6,000	-191	0.0	-13.0
2022	6,000	-191	0.0	-13.0
2023	6,000	-191	0.0	-13.0
2024	6,000	-191	0.0	-13.0
2025	6,000	-191	0.0	-13.0
2026	6,000	-191	0.0	-13.0

Commercial Building Performance Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	300	-3,786	-0.8	-0.9
2013	600	-7,572	-1.5	-1.9
2014	900	-11,358	-2.3	-2.8
2015	1,200	-15,144	-3.0	-3.7
2016	1,500	-18,930	-3.8	-4.7
2017	1,800	-22,716	-4.5	-5.6
2018	2,100	-26,502	-5.3	-6.5
2019	2,100	-26,502	-5.3	-6.5
2020	2,100	-26,502	-5.3	-6.5
2021	2,100	-26,502	-5.3	-6.5
2022	2,100	-26,502	-5.3	-6.5
2023	2,100	-26,502	-5.3	-6.5
2024	2,100	-26,502	-5.3	-6.5
2025	2,100	-26,502	-5.3	-6.5
2026	2,100	-26,502	-5.3	-6.5

Commercial Duct Sealing Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	1,000	-2,430	-0.5	-0.6
2013	2,000	-4,860	-1.0	-1.2
2014	3,000	-7,290	-1.5	-1.8
2015	4,000	-9,720	-1.9	-2.4
2016	5,000	-12,150	-2.4	-3.0
2017	6,000	-14,580	-2.9	-3.6
2018	7,000	-17,010	-3.4	-4.2
2019	8,000	-19,440	-3.9	-4.8
2020	9,000	-21,870	-4.4	-5.4
2021	10,000	-24,300	-4.9	-6.0
2022	11,000	-26,730	-5.4	-6.6
2023	12,000	-29,160	-5.8	-7.2
2024	13,000	-31,590	-6.3	-7.8
2025	14,000	-34,020	-6.8	-8.4
2026	15,000	-36,450	-7.3	-9.0

Commercial Efficient HVAC Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	800	-1,257	-0.2	-0.3
2013	1,600	-2,515	-0.4	-0.7
2014	2,400	-3,772	-0.6	-1.0
2015	3,200	-5,030	-0.8	-1.3
2016	4,000	-6,287	-1.0	-1.7
2017	4,800	-7,544	-1.2	-2.0
2018	5,600	-8,802	-1.3	-2.3
2019	6,400	-10,059	-1.5	-2.7
2020	7,200	-11,316	-1.7	-3.0
2021	8,000	-12,574	-1.9	-3.3
2022	8,800	-13,831	-2.1	-3.7
2023	9,600	-15,089	-2.3	-4.0
2024	10,400	-16,346	-2.5	-4.3
2025	11,200	-17,603	-2.7	-4.7
2026	12,000	-18,861	-2.9	-5.0

Commercial New Construction Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	440	-5,987	-0.9	-1.6
2013	880	-11,973	-1.9	-3.3
2014	1,320	-17,960	-2.8	-4.9
2015	1,760	-23,947	-3.8	-6.6
2016	2,200	-29,933	-4.7	-8.2
2017	2,640	-35,920	-5.6	-9.8
2018	3,080	-41,907	-6.6	-11.5
2019	3,520	-47,893	-7.5	-13.1
2020	3,960	-53,880	-8.5	-14.8
2021	4,400	-59,867	-9.4	-16.4
2022	4,840	-65,853	-10.4	-18.0
2023	5,280	-71,840	-11.3	-19.7
2024	5,720	-77,827	-12.2	-21.3
2025	6,160	-83,813	-13.2	-23.0
2026	6,600	-89,800	-14.1	-24.6

Small C&I Audit Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	300	-1,201	-0.2	-0.3
2013	600	-2,403	-0.5	-0.6
2014	900	-3,604	-0.7	-0.9
2015	1,200	-4,805	-1.0	-1.2
2016	1,500	-6,006	-1.2	-1.5
2017	1,800	-7,208	-1.4	-1.8
2018	2,100	-8,409	-1.7	-2.1
2019	2,400	-9,610	-1.9	-2.4
2020	2,700	-10,812	-2.2	-2.7
2021	3,000	-12,013	-2.4	-3.0
2022	3,000	-12,013	-2.4	-3.0
2023	3,000	-12,013	-2.4	-3.0
2024	3,000	-12,013	-2.4	-3.0
2025	3,000	-12,013	-2.4	-3.0
2026	3,000	-12,013	-2.4	-3.0

807 KAR 5:058 Section 8(3)(e)(4) For each existing and new conservation and load management or other demand-side programs included in the plan; (4) Projected cost, including any incentive payments and program administrative costs.

The projected costs for each Existing and New DSM program are shown below in Table 8.(3)(e)(4). Cost values are the present value of the future stream of costs for that element. Distribution system rebates are paid to program participants. More details on program costs and cost-effectiveness can be found in the DSM Technical Appendix.

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

	Program costs	present value, 2012 $		
Existing Program	Distribution System Admin	EKPC Admin	Distribution System Rebates	Customer Investment
Button-Up Weatherization	$4,540,301	$51,581	$8,631,751	$25,092,501
Button-Up with Air Sealing	$581,772	$53,980	$879,569	$2,504,887
Heat Pump Retrofit	$791,901	$24,868	$3,355,514	$20,580,488
Electric Thermal Storage	$450,629	$3,059,390	$1,747,496	$465,324
Direct Load Control of AC & WH	$0	$22,585,417	$14,671,049	$0
Residential Lighting	$0	$302,525	$9,559,464	$14,640,506
Touchstone Energy (TSE) Home	$3,527,374	$185,176	$6,613,826	$15,079,523
TSE Manufactured Home	$113,106	$78,382	$523,640	$1,243,645
Tune-Up HVAC w/ Duct Sealing	$2,973,741	$64,776	$2,045,430	$1,888,089
Commercial Lighting	$0	$599,779	$3,193,823	$14,523,374
Compressed Air	$1,832,311	$359,867	$0	$16,710,672
Totals	$14,811,135	$27,365,741	$51,221,563	$112,729,009

	Program costs	present value, 2012 $		
New Program	Distribution System Admin	EKPC Admin	Distribution System Rebates	Customer Investment
"Beat the Peak" demand response	$0	$5,639,001	$0	$0
ENERGY STAR Central Air	$5,520,366	$119,956	$6,312,358	$13,211,157
Geothermal retrofit	$165,742	$23,410	$1,404,596	$3,558,309
Home Energy Information	$0	$14,644,696	$0	$0
Low Income Weatherization	$44,983,426	$479,823	$0	$0
Mobile Home Retrofit	$1,499,448	$599,779	$4,198,453	$7,197,348
Programmable Thermostat	$107,960	$59,978	$359,867	$662,156
DLC for Residential Pool Pump	$0	$2,634,135	$2,083,272	$0
Advanced Weatherization Tier 2	$730,059	$0	$1,655,642	$4,715,741
Advanced Weatherization Tier 3	$486,706	$0	$1,471,682	$4,191,139
E -STAR Clothes Washer	$400,352	$119,956	$1,334,508	$6,245,499
C&I Demand Response	$3,587,301	$942,006	$7,775,197	$7,464,840
Industrial Process	$0	$5,685,905	$1,439,470	$30,209,429
Industrial Variable Speed Drives	$9,536	$239,912	$3,178,829	$11,753,719
Commercial EMCS	$0	$119,956	$5,398,011	$9,716,420
DLC for Commercial Central AC	$0	$3,314,302	$3,333,236	$0
Building Performance	$1,360,299	$119,956	$6,639,554	$12,615,152
Commercial Duct Sealing	$4,534,329	$119,956	$7,497,238	$13,495,028
Commercial Efficient HVAC	$1,698,574	$119,956	$2,591,045	$4,225,303
Commercial New Construction	$0	$119,956	$11,083,916	$19,951,049
Small C&I Audit	$2,159,204	$599,779	$4,678,276	$3,976,535
Totals	$67,243,304	$35,702,416	$72,435,149	$153,188,825

807 KAR 5:058 Section 8(3)(e)(5) For each existing and new conservation and load management or other demand-side programs included in the plan; (5) Projected cost savings, including savings in utility's generation, transmission and distribution costs.

The projected cost savings for each Existing and New DSM program are shown below in Table 8.(3)(e)(5). Values shown are the benefits in the Total Resource Cost test. 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 Technical Appendix.

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

		present value, 2012 $
Existing Program		Projected Cost Savings
Button-Up Weatherization		$45,877,538
Button-Up with Air Sealing		$4,611,301
Heat Pump Retrofit		$27,618,418
Electric Thermal Storage		$8,772,021
Direct Load Control of AC & WH		$63,066,346
Residential Lighting		$43,105,047
Touchstone Energy (TSE) Home		$47,331,476
TSE Manufactured Home		$4,146,189
Tune-Up HVAC w/ Duct Sealing		$7,485,312
Commercial Lighting		$28,252,376
Compressed Air		$30,923,322
Totals		$311,189,347

		present value, 2012 $
New Program		Projected Cost Savings
"Beat the Peak" demand response		$15,618,770
ENERGY STAR Central Air		$21,982,610
Geothermal retrofit		$9,404,863
Home Energy Information		$25,741,618
Low Income Weatherization		$77,628,657
Mobile Home Retrofit		$17,070,113
Programmable Thermostat		$2,392,450
DLC for Residential Pool Pump		$5,897,134
Advanced Weatherization Tier 2		$8,751,023
Advanced Weatherization Tier 3		$7,778,687
E -STAR Clothes Washer		$7,446,595
C&I Demand Response		$38,104,542
Industrial Process		$60,172,763
Industrial Variable Speed Drives		$33,730,282
Commercial EMCS		$15,399,849
DLC for Commercial Central AC		$12,483,088
Building Performance		$19,504,958
Commercial Duct Sealing		$24,669,253
Commercial Efficient HVAC		$12,517,273
Commercial New Construction		$81,358,219
Small C&I Audit		$8,481,879
Totals		$506,134,626

807 KAR 5:058 Section 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.

Please see pages 6 through 15 and Exhibit DSM-2 in the DSM technical appendix.

All DSM programs are evaluated based on the standard California tests.

5.2 OTHER DEMAND SIDE RESEARCH CONSIDERATIONS

807 KAR 5:058 Section 7.(7)(g) The plan shall include a complete description and discussion of: (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. Technical discussions, descriptions, and supporting documentation shall be contained in a technical appendix.

EKPC conducts an appliance saturation survey every two years. This is an effort to stay apprised of saturation of household appliances. In addition, EKPC has a load research program which consists of over 600 meters on residential, commercial and industrial customers. EKPC and its member systems work together to collect load research data that are needed for various analyses at the retail level, such as the design of marketing programs. Load research data are employed in end-use forecasting methodologies to project sales and demand and also provides information for demand estimates for cost of service studies and/or rate cases for EKPC and the member systems. Standard estimates and statistics are developed for each month of a study including:

- Class Demand at System Peak Hour
- Class Demand at Class Peak Hour
- Hourly Class Demands on System Peak Day
- Hourly Class Demands on Class Peak Day
- Coincidence and Load Factors
- Class Energy Use
- Class Non-Coincident Peak Demands
- Class Time-Of-Use statistics.

The most common method for obtaining load data is metering, usually with a time-of-use or load profile recording meter. To be useful statistically, however, a sample of sufficient size must be metered from EKPC's population base. The advantage of metering is that it provides results explicitly for a particular service area or rate class for a given time period (peak hour). Compared to other alternatives, this method is more expensive and generally takes a longer time to provide meaningful data; however, its reliability is relatively high. Metered data can also become outdated rather quickly, which is why EKPC maintains a continuous load research project, targeted at member system rate classes. EKPC has also used metering in end-use studies such as air source heat pumps, electric thermal storage, and geothermal heating and cooling systems.

Load research projects have and will continue to be a part of EKPC's research efforts. Current on-going load research projects include:

1. Residential: Includes customers that are billed in the residential class. There are 157 load profile meters installed and collecting data.
2. Small Commercial & Industrial: These are nonresidential customers whose demand is less than 50 kW. There are 68 load profile meters installed and collecting data.
3. Medium Commercial & Industrial: Includes customers whose peak demands are between 50 and 350 kW. There are 73 load profile meters installed and collecting data.
4. Large Power: Customers whose peak demands are greater than 350 kW. There are 310 meters installed.

Although not formally approved, the following projects have been proposed for implementation in 2013.

1. Complete analysis to issue reports for internal use of class studies and large power: EKPC plans to compile the historical data looking at growth rates. The reports will include data through 2011.

2. Borrowed data: EKPC will continue to monitor and evaluate the transferability of load data from other utilities.

Real Time Pricing Pilot

Real Time Pricing ("RTP") is an electricity rate structure in which retail energy prices change very frequently, usually hourly, and with short notice, usually day-ahead. These hourly prices are designed to reflect the utility's expected hourly marginal cost of providing incremental load. These hourly costs can also reflect market costs, such as power purchases. RTP assists the customer to make an energy usage decision based upon the utility's true cost of providing incremental energy. RTP also recognizes and allows for the fact that the value of energy is specific to each user and is dynamic.

The Commission approved a 3-year RTP pilot program for EKPC on February 1, 2008. EKPC filed its RTP tariff with the Commission on November 30, 2009. Blue Grass Energy, Licking Valley RECC, Nolin RECC, and Owen Electric filed corresponding RTP tariffs with the Commission on November 30, 2009. The Commission approved all the RTP tariffs and they became effective on January 1, 2010.

Eligible customers must have taken service from an EKPC Member System for at least 1 year, must be able to benefit from hourly price signals, and maintain a peak 15-minute demand not less than 1,000 kW each month. The customer must currently have the MV-90 metering system in place or be willing to allow the EKPC to install and maintain such equipment with interrogation ability for downloads. The customer will be responsible for the incremental costs of installing and maintaining such metering equipment. The customer must possess a personal computer with Internet service. Customers served under the Interruptible Rider are not eligible.

Customers participating in the pilot program must sign a contract with a minimum service term of one year. The customer must provide written notice of intended departure 90 days before contract termination. Contract duration is subject to the time limit of the pilot program. Customers who terminate service under the tariff after the initial 1 year period shall be ineligible to return to the pilot program. Prospective customers may not participate in the program after the conclusion of the second year of the pilot program. In the event that incremental RTP load growth causes a local distribution upgrade to serve the RTP customer, the customer is responsible for these costs.

A customer who participates in the RTP pilot program will pay a bill with four components.

1. <u>Standard Bill:</u> The customer's standard tariff will be applied to the "Customer Baseline Load" (CBL). The CBL is to be developed by EKPC using one complete calendar year of customer-specific hourly firm historical load data. The CBL remains in place permanently and is adjusted to match up weekdays, weekends, and holidays with the

respective calendar year. Modifications to the CBL can be made to reflect permanent removal of major, customer-owned electrical equipment or significant conservation or efficiency enhancements made by the customer, subject to the approval of EKPC, the Member System, and the customer. The tariff prices include the current demand and energy prices, the FAC, the Environmental Surcharge and other applicable riders found in the Commission-approved tariff sheets.

2. Incremental Energy Charge: A Day-Ahead RTP Price ("RTP Price") will be applied to the differences between actual metered load and the CBL for all hours in the billing period. Positive differences will result in hourly charges; negative differences will result in hourly credits and actual metered usage cannot go below zero for billing purposes. The RTP Price reflects day-ahead marginal costs on an hourly basis as determined by EKPC and includes components for hourly estimated marginal generation costs, estimated marginal reliability cost, estimated marginal transmission cost, losses, and a risk adder of 5 mills per kWh (4 mills to EKPC and 1 mill to the Member System). The FAC and Environmental Surcharge do not apply to the incremental energy.

3. RTP Administration Fee: A monthly fee of $150 will cover the costs of providing RTP service, including billing and communications systems to implement the tariff and for data management. EKPC charges the Member System and then the Member System charges the customer.

4. Power Factor Adjustment: This bill component permits charging for power factor in exactly the same manner as the standard retail tariff. The actual power factor for each individual RTP customer will be measured at the time of the current month's 15-minute peak demand for the customer.

EKPC maintains a secure website and RTP prices are posted to the Internet and become firm at 4:00 p.m. ET of the prior business day. (Friday's notice is *firm* for Saturday and *estimates* for Sunday and Monday are posted. These estimates for Sunday and Monday become firm unless an update is provided by 4:00 p.m. ET of the prior day. This methodology also applies for holidays.) The Member System is not responsible for a customer's failure to receive and act upon hourly RTP Prices. If a customer cannot access these prices, it is the customer's responsibility to inform the Member System so that the prices may be provided.

When it submitted its RTP pilot program to the Commission for review and approval, EKPC had estimated that there were only 70 eligible customers among its Member Systems. Since the RTP tariff became effective on January 1, 2010, no customers of the Member Systems have requested to participate in the pilot program and there have been no requests for EKPC to prepare preliminary CBL calculations for potential participants. There have been informal discussions between potential participants and the Member Systems; however, while some potential participants are interested in the concept there are concerns. The potential participants expressed concerns about lacking the flexibility to change their loads, the impact that shifting load could have on employee morale (adjustment to work shifts), and the risk of baselines being changed after the pilot program became permanent. There also appears to be some hesitancy on participating in the program as long as it is a pilot.

Under the terms of the Commission's approval of the RTP pilot program, EKPC is required to file annual reports on the pilot program with the Commission and Attorney General ("AG") by March 31st of 2011, 2012, and 2013. The 3-year RTP pilot program will end on December 31, 2012 and by March 31, 2013 EKPC is to submit a detailed evaluation of the pilot program to the Commission and AG. The Commission will then re-examine the program and determine whether it should be continued.

807 KAR 5:058 Section 8.(5)(e) The resource assessment and acquisition plan shall include a description and discussion of: Existing and projected research efforts and programs which are directed at developing data for future assessments and refinements of analyses.

<u>Heat Load Management Research Project</u>

EKPC's winter peak levels are driven by residential resistant heat loads (i.e. – Electric Furnaces, Heat Pumps with emergency strip heat). Successfully managing resistant heat loads could reduce the need for new peak generating units. EKPC has implemented a research project to determine the feasibility of managing heat loads.

The research project will evaluate the technical capabilities, kW and kWh impacts, and customer comfort impacts when the utility manages heat pumps. Heat Pumps produce heat for the home via the compressor most of the time and with emergency heat strips when the outdoor temperature drops below 30 degrees. Over the next two winters, the research project will evaluate managing both the compressors and the emergency electric resistance heat strips.

The first winter EKPC will evaluate managing heat pump compressors. The technical theory is that the electrical efficiency of the heat pump compressor drop to or near the electrical efficiency of the emergency heat strips when the outdoor air temperature drops to around 5 degrees. The $impleSaver Direct Load Control Program already has load management devices on several thousand heat pump compressor. EKPC has recruited 70 of those existing $impleSaver participants to participate in the heat load management research project.

The research project will continue next winter as EKPC evaluates the impacts of managing the heat pump emergency heat strips.

SECTION 6.0

TRANSMISSION AND DISTRIBUTION PLANNING

SECTION 6.0

TRANSMISSION AND DISTRIBUTION PLANNING

6.1 Introduction

807 KAR 5:058 Section 8(2)(a) The utility shall describe and discuss all options considered for inclusion in the plan including: (a) Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities;

Transmission System

Introduction

EKPC's transmission system is geographically located in roughly the eastern two-thirds of Kentucky. The transmission system approaches the borders of Kentucky in the north, east, and south, and stretches to approximately the Interstate 65 corridor in the west. The system is comprised of approximately 2,967 circuit miles of line at voltages of 69, 138, 161, and 345 kV, and includes 69 free-flowing interconnections with neighboring utilities. EKPC's interconnections with neighboring utilities have been established to improve the reliability of the transmission system and to provide access to external generation resources for economic and/or emergency purchases. Table 8.(2)(a)-1 (page 123) through Table 8.(2)(a)-4 (page 126) list each of EKPC's free-flowing interconnections.

EKPC designs its transmission system to provide adequate capacity for reliable delivery of EKPC generating resources to its member distribution cooperatives, and for long-term firm transmission service that has been reserved on the EKPC system. EKPC's transmission planning criteria specify that the system must be designed to meet projected customer demands for simultaneous outages of a transmission facility and a generating unit during peak conditions in summer and winter.

Interconnections

Interconnections have been established with other utilities to increase the reliability of the transmission system and to provide potential access to other economic/emergency generating sources. EKPC participates in joint planning efforts with neighboring utilities to ascertain the benefits of potential interconnections, which can include increased power transfer capability, local area system support, and outlet capability for new generation. It should be noted that actual transfer capabilities are unique to actual system conditions, as affected by generation dispatch, outage conditions, load level, third-party transfers, etc.

EKPC and Big Rivers Electric Cooperative ("BREC") participated in a joint study in 2010-2011 to evaluate the possible benefits of establishing a new transmission interconnection. The conclusion from this study was that there were insufficient quantifiable benefits to offset the cost of establishing an interconnection between the two systems at the time of the study.

Membership in the SERC Reliability Corporation ("SERC")

EKPC is a member of SERC. From the SERC website (www.serc1.org), SERC is "the regional entity responsible for promoting, coordinating and ensuring the reliability and adequacy of the bulk power supply systems in the area served by the Member Systems. SERC promotes the development of reliability and adequacy arrangements among the systems; participates in the establishment of reliability standards; administers a regional compliance and enforcement program; and provides a mechanism to resolve disputes on reliability issues." Owners, operators, and users of the bulk power system in the SERC footprint cover an area of approximately 560,000 square miles. SERC is one of eight regional entities with delegated authority from the North American Electric Reliability Corporation ("NERC"); the regional entities and all members of NERC work to safeguard the reliability of the bulk power systems throughout North America. NERC has been certified by the Federal Energy Regulatory Commission ("FERC") as the Electric Reliability Organization ("ERO") for North America. NERC has established Reliability Standards that the electric utilities operating in North America must adhere to. There are presently 107 Reliability Standards that have been approved by FERC and are therefore in effect. EKPC is required to comply with 93 of these standards based upon its responsibility for various functions, such as Balancing Authority, Resource Planner, Transmission Operator, etc. Many additional standards are currently under development, and the development of new standards is certain to continue. EKPC continues to identify and refine planning practices that will ensure compliance with these NERC Reliability Standards.

EKPC actively participates in SERC activities and studies. Each year, EKPC participates in SERC assessments of transmission system performance for the summer and winter peak load periods. In these assessments, potential operating problems on the interconnected bulk transmission system are identified. EKPC annually supplies SERC with data needed for development of current and future load flow computer models. These models are used by EKPC and other SERC members to analyze and screen the interconnected transmission system for potential problems.

EKPC adheres to SERC's guidelines for transmission and generation planning and operations. With all of the SERC members following these guidelines, each member system can have a high degree of confidence that the transmission system will be adequate for the normal and emergency (outage) conditions simulated. Participation in SERC enhances the reliability of each member system without having to install excess generation and transmission capacity to provide a comparable level of reliability.

SERC performed an audit of NERC reliability standards at EKPC's offices in March 2012. EKPC received a clean audit with no findings.

Transmission Expansion (2009-2011)

From 2009-2011, EKPC implemented various transmission projects, summarized as follows:

- Establishment of six (6) new transmission interconnections with neighboring utilities (one at 345 kV, three at 138 kV, and two at 69 kV)
- Construction of 58 miles of new line, including 35 miles of new 345 kV line
- Construction of three (3) 138/69 kV substations
- Installation of a new 345/138 kV autotransformer at J.K. Smith Station
- Re-conductoring/rebuilding 48 miles of existing line using larger (lower impedance, higher capacity) conductor
- Upgrades of two (2) 138/69 kV autotransformers to increase capacity
- Addition of eight (8) new 69 kV capacitor banks totaling 124 MVARs

The interconnections established with other utilities generally have provided stronger sources in specific areas of need within the EKPC system, which avoids the need to construct long, high-voltage transmission lines from the EKPC system. Also, these interconnections typically reduce EKPC's transmission-system losses.

Construction of the new transmission lines generally has resulted in reduction of system losses as well. The J.K. Smith-West Garrard 345 kV line that was constructed in 2009 is a major transmission addition to the EKPC system that provides a substantial reduction in EKPC's system losses estimated at approximately 10,000 MWh per year.

The addition of the three new 138/69 kV substations also provides benefits in loss reductions and reduced transmission line construction requirements. These substations were constructed where existing 69 kV and 138 kV lines cross, which minimized the transmission construction necessary. These substations established new points of injection into the 69 kV transmission system in areas of need, thereby reducing system losses (estimated at approximately 1,000 MWh per year). Installation of the new 345/138 kV autotransformer at J.K. Smith has also reduced system losses (estimated at approximately 1,000 MWh per year) by reducing the impedance between the two busses at J.K. Smith.

Re-conductoring (including rebuilding) existing transmission lines enhances utilization of the existing transmission system by increasing the capacity of the existing lines. EKPC's re-conductor projects typically increase system capacity by 50% to 225%, depending on the sizes of the installed conductor and the replacement conductor that is used. In addition, by installing larger conductors, less voltage drop is seen on the system, deferring the need to construct new facilities to provide voltage support in an area. Transmission-system losses are also reduced due to the lower impedance of the larger replacement conductors. The amount of loss reduction varies, and is dependent on the hourly power flows on each particular line, but typical expectations for loss reduction range from 250,000 to 400,000 kWh per year after a line is re-conductored.

The upgrades of existing substation autotransformers also enhance utilization of the existing transmission system by increasing the capacity available at existing substations. The upgrades EKPC performed in the 2009-2011 period increased transformer capacity by 50% to 110% at two existing substations. These upgrades provide some additional voltage support in these areas, potentially deferring the need to construct new facilities to provide voltage support. Transmission-system losses are also reduced due to the lower impedance of the replacement transformers. The loss reduction magnitude varies, depending on the hourly power flows through the transformers.

The addition of transmission capacitor banks also provides better utilization of the existing transmission system by deferring the need for new transmission lines and/or substations. Transmission capacitor banks can also provide some transmission-system loss reductions when energized.

Future Transmission Expansion

Transmission constraints, and the ability to address them in a timely manner, represent important planning considerations for ensuring that peak-load requirements are met reliably. EKPC's Transmission Planning Department works closely with other groups at EKPC -- such as Power Delivery Operations, Engineering, Power Delivery Maintenance, Load Forecasting and Resource Planning -- to coordinate activities and address reliability issues. EKPC also seeks input from other external parties, including potential generation developers regarding issues or needs related to the EKPC transmission system.

EKPC's transmission expansion plan includes a combination of new transmission line and substation facilities and upgrades of existing facilities during the 2012-2026 period to provide an adequate and reliable system for existing and forecasted future native load customers and existing and requested future generation resources.

Transmission expansion plans are developed and updated on an annual basis. Power-flow analysis and reliability indices are used to predict problem areas on the transmission system. Various alternatives for mitigating these problems are then formulated and analyzed. The transmission expansion projects that provide the desired level of reliability and adequacy at a reasonable cost are then added into the plan. Note that transmission planning, like all EKPC planning processes, is ongoing, and changing conditions may warrant changes to the transmission plan.

EKPC's transmission work plan for the 2012-2015 period is based on detailed engineering analyses, and includes transmission projects that are relatively firm in nature. These projects include the construction of new substations and transmission lines, as well as upgrades of existing substations and transmission lines. These improvements will meet growing customer demand, enhance system reliability, and improve the efficiency of the system. A map of EKPC's existing transmission system and of the EKPC transmission system showing interconnected facilities plus EKPC's planned future facilities in 2012-2015 is included on the map at this end of this report.

The planned improvements to the EKPC transmission system for the 2012-2015 period are summarized as follows:

- Establishment of two (2) new transmission interconnections with neighboring utilities (both at 69 kV)
- Construction of 36 miles of new line, all at 69 kV
- Re-conductoring/rebuilding 40 miles of existing line using larger (lower impedance, higher capacity) conductor
- Upgrades of one (1) 161/69 kV autotransformer and one (1) 138/69 kV autotransformer to increase capacity
- Addition of five (5) new transmission capacitor banks totaling 107 MVARs
- Re-sizing and/or relocation of seven (7) existing 69 kV capacitor banks, totaling 161 MVARs of increased reactive capacity

One of the planned interconnections will provide a stronger source in a specific area of need within the EKPC system, which will avoid the need to construct long, high-voltage transmission lines from the EKPC system. The other planned interconnection will be operated normally-open, but will provide an emergency backup source to a substation served by a long radial transmission line.

Construction of new transmission lines typically results in reduction of system losses. EKPC expects to see overall reduction in system losses as a result of the planned construction of 36 miles of new 69 kV line in the 2012-2015 period.

The planned transmission line re-conductors/rebuilds will enhance utilization of the existing transmission system by increasing the capacity of those existing lines. As discussed earlier, replacing existing conductors with larger conductors will also provide increased voltage support and will reduce system energy losses. Similarly, the planned upgrades of substation autotransformers will provide more efficient system utilization by increasing existing capacity, reducing voltage drop and system energy losses.

The addition of transmission capacitor banks will also provide better utilization of the existing transmission system by deferring the need for new transmission lines and/or substations. Transmission capacitor banks can also provide some transmission-system loss reductions when energized.

As mentioned above, EKPC develops a 15-year transmission expansion plan annually. The analysis used to develop the plan beyond the first four years is less detailed than that used to develop the work plan for the next four years. Many of the projects beyond the initial 4-year period are conceptual in nature, and are more likely to change in scope and date, or to be cancelled and replaced with a different project. EKPC's 15-year expansion plan for the 2012-2026 period is included as Table 8.(2)(a)-5 on page 127 through Table 8.(2)(a)-16 on page 138. This 15-year expansion plan includes approximately 132 miles of new line construction (69 kV and higher), 229 miles of existing line re-conductors/rebuilds, and 188 miles of high-temperature conductor upgrades. It also includes the construction of several new switching stations (single voltage level) and substations (two different voltage levels), upgrades of existing transformers, and the installation of a total of 776 MVARs of new transmission capacitor bank capability.

<u>Generation Related Transmission</u>

When evaluating potential power supply resources, the cost of required transmission-system modifications associated with each resource is included in the analysis, if known. Some resource alternatives may be site-specific and transmission plans can be developed that are directly relevant for those resource alternatives. Other resource alternatives are generic units for which no specific site has been yet identified. For those generic units, an average cost of transmission is used in the cost analysis.

EKPC performs studies for transmission requirements for units connected to the EKPC transmission system after an official request has been submitted per EKPC's Open Access Transmission Tariff ("OATT"). This process is performed in a consistent, non-discriminatory manner. Only those projects necessary for firm (committed) generation resources (existing and future) are identified in EKPC's transmission expansion plan.

EKPC's generation expansion plan included in this Integrated Resource Plan identifies new 250/275 MW (summer/winter) combined-cycle gas turbine additions in 2016 and 2023 without identification of the specific location. The actual location at which the generation is sited will determine what the actual transmission costs will be. Until a specific location is identified and a generation interconnection request is made, a generic average cost of $96/kW (2012$) is used for the transmission facilities associated with these future generating unit additions. This generic average cost is based upon historical costs for transmission expansion associated with generation projects on the EKPC system. Using this generic cost, the expected total transmission cost associated with each of these 250/275 MW combined-cycle gas turbine additions is $26,400,000 (2012$).

Import Capability

EKPC routinely assesses the ability to import power from external sources into the EKPC control area. Import capability is assessed from markets to the north and to the south as part of the normal planning process. Also, EKPC performs import capability studies as a participant in SERC's annual system assessments.

EKPC designs its transmission system to be capable of importing at least 500 MW from regions either north or south of Kentucky. Import studies indicate that EKPC's import capability from the LG&E/KU interface ranges from 800 MW up to 3000 MW, depending on the time period being evaluated. The import capability from the PJM interface ranges from 2500 MW to 3000 MW, depending on the time period. Finally, the import capability from the TVA interface ranges from 0 MW up to 2800 MW, depending on the time period. The imports from TVA are limited at certain times by facilities internal to the TVA system.

Although these import studies indicate that EKPC can during many periods import large quantities of power, real-time market and transmission-system conditions may result in system limitations that are significantly different from those predicted in these studies. Available

Transfer Capacity ("ATC") calculations are performed by Regional Transmission Organizations (such as PJM and MISO), Independent Transmission Organizations (such as the SPP ITO) and Reliability Coordinators (such as TVA). These results are coordinated to ensure that the lowest value for a particular path is set as the ATC. Such studies utilize updated data for transmission and generation outages, market transactions, and system load to predict expected system flows. Therefore, it is difficult to predict the availability of transmission capacity for imports into the EKPC system. EKPC generally chooses to procure an adequate amount of transmission from markets to the north and/or south well in advance of peak seasons to ensure import capability.

EKPC routinely experiences import and export transmission limitations on an operational basis due to limited ATC.

Extreme Weather Performance

EKPC annually performs an assessment of its transmission system for both summer and winter peak conditions. EKPC evaluates its system using two load forecasts – a 50/50 probability forecast and a 10/90 probability forecast. When evaluating system performance using a 50/50 forecast, contingency analysis is also performed on the system to ensure that the system is designed to provide adequate service at this load level even with a transmission facility and/or generator out of service. EKPC does not perform a contingency analysis when using the 10/90 probability forecast. EKPC considers an extreme weather event equivalent to a contingency, and therefore does not design its system for a transmission or generator outage in conjunction with this weather event.

EKPC has not identified any constraints on its transmission system due to extreme weather conditions for either summer or winter. Some marginal voltage levels have been identified in specific areas of the EKPC system during extreme winter conditions, and EKPC has plans to address those issues. No thermal limitations are anticipated provided that all transmission and generation facilities are in service. The outage of one or more facilities could result in thermal overloads on the EKPC transmission system during extreme weather conditions.

Distribution System

EKPC is an all-requirements power supplier for 16 member-system distribution cooperatives in Kentucky. In addition to designing, owning, operating, and maintaining all transmission facilities, EKPC also is responsible for all delivery points (distribution substations), including the planning of these delivery points in conjunction with the respective member systems. EKPC monitors peak distribution substation transformer loads seasonally to identify potential loading issues for delivery points to member systems. Furthermore, EKPC and the member systems jointly develop load forecasts for each delivery point that are used to identify future loading issues. EKPC uses a four-year planning horizon for distribution substation planning. EKPC and the member systems use a joint planning philosophy based on a "one-system" concept. This planning approach identifies the total costs on a "one-system" basis – i.e., the combined costs for EKPC and the member system – for all alternatives considered. Generally, the alternative with the lowest one-system cost is selected for implementation, unless there are overriding system benefits for a more expensive alternative.

EKPC delivery points were improved in the 2009-2011 period through the construction of new substations, as well as through upgrades of existing substations, to meet growing customer demand and to enhance reliability and improve the efficiency of the system.

From 2009-2011, EKPC implemented various distribution substation projects, summarized as follows:

- Construction of two (2) new 14 MVA distribution substations
- Construction of three (3) new 20 MVA distribution substations
- Addition of one (1) new 14 MVA distribution transformer at an existing station
- Addition of one (1) new 20 MVA distribution transformer at an existing station
- Addition of one (1) new 25 MVA distribution transformer at an existing station
- Upgrades of three (3) existing distribution substations to 14 MVA
- Upgrades of three (3) existing distribution substations to 25 MVA

New distribution delivery points enhance the utilization of the existing system by providing a new injection point into the existing distribution system. This will generally provide improved system energy losses, as well as increased voltage support.

Distribution substation transformer additions and upgrades of existing distribution substation transformers also improve system utilization by increasing capacity at an existing facility rather than building new facilities. These additions/upgrades reduce system impedance at the substation, which improves voltage drop and reduces energy losses.

In addition to the substation improvements discussed above, EKPC also worked with its member distribution cooperatives on various power factor improvement projects at the distribution level to increase available substation capacity, defer transmission construction projects, and reduce system losses. EKPC performed a power factor study to identify the substations which would provide the largest benefits to system utilization and efficiency through power factor correction. EKPC and its member systems improved the power factor at many of these substations in this period.

Further improvements are planned for EKPC's distribution substation delivery points for the 2012-2015 period. These improvements include the construction of new distribution substations, as well as upgrades of existing substations. These improvements will meet growing customer demand, enhance system reliability, and improve the efficiency of the system.

The planned improvements to EKPC distribution substations for the 2012-2015 period are summarized as follows:

- Construction of one (1) new 7 MVA distribution substation
- Construction of five (5) new 20 MVA distribution substations
- Construction of one (1) new 25 MVA distribution substation
- Addition of three (3) new 20 MVA distribution transformers at existing substations
- Addition of one (1) new 25 MVA distribution transformer at an existing substation
- Upgrades of six (6) existing distribution substations to 20 MVA
- Upgrades of two (2) existing distribution substations to 25 MVA

These distribution substation enhancements will improve system efficiency and utilization as described above.

In addition to these substation improvements, EKPC and its member distribution cooperatives will continue to coordinate power factor improvement projects at the distribution level to increase available substation capacity, defer transmission construction projects, and reduce system losses. EKPC is in the process of updating its power factor correction study to identify the substations which will provide the largest benefits for system utilization and efficiency through power factor correction. EKPC and its members plan to continue to improve power factor at these locations to realize these benefits whenever feasible.

Table 8.(2)(a)-1
EKPC Free-Flowing Interconnection Capability

No.	From (EKPC)	To	Voltage kV	Ratings in MVA Summer Normal	Summer Emergency	Winter Normal	Winter Emergency
AEP							
1	Argentum	Fullerton	138	200	200	200	200
2	Argentum	Grays Branch	69	48	48	54	54
3	Falcon	Falcon	69	36	36	36	36
4	Helechawa	Lee City	69	54	54	54	54
5	Leon	Leon	69	39	46	54	54
6	Morgan County	Morgan County	69	90	115	141	156
7	Thelma	Thelma	69	79	92	103	112
		Total:		546	591	642	666
DP&L							
8	Spurlock	Stuart	345	1255	1374	1255	1374
Duke Energy-OHIO							
9	Boone	Longbranch	138	229	296	362	396
10	Hebron	Hebron	138	96	117	121	139
11	Spurlock	Zimmer	345	1488	1488	1792	1792
12	Webster Road	Webster Road	69-138	96	117	121	139
		Total:		1909	2018	2396	2466
LG&E/KU							
13	Avon	Loudon Avenue	138	224	277	286	287
14	Baker Lane	Baker Lane Tap	69-138	96	117	121	139
15	Beattyville	Beattyville	69	101	124	149	163
16	Beattyville	Beattyville Tap	161-69	58	66	72	72

Table 8.(2)(a)-2
EKPC Free-Flowing Interconnection Capability

				Ratings in MVA			
				Summer		Winter	
No.	From (EKPC)	To	Voltage kV	Normal	Emergency	Normal	Emergency
17	Beattyville-Powell Co.	Delvinta	161	167	201	167	229
18	Bonds Mill Jct.	Bonds Mill	69	101	133	137	137
19	Bonnieville	Bonnieville	69-138	89	109	112	129
20	Boonesboro North Tap	Boonesboro North	69-138	129	143	143	143
21	Bracken Co.	Carntown	69	41	41	72	72
22	Bracken Co.	Sharon	69	35	35	65	65
23	Cedar Grove Ind. Park	Blue Lick	161	248	281	320	329
24	Central Hardin	Hardin County	138	224	277	287	287
25	Central Hardin	Hardinsburg	138	202	248	287	287
26	Clay Village	Clay Village Tap	69	36	38	43	44
27	Cooper	Elihu	161	235	289	279	305
28	Crooksville Jct.	Fawkes	69	103	103	137	137
29	East Bardstown	Bardstown Ind.	69	53	56	81	89
30	Fawkes	Fawkes	138	229	296	287	370
31	Fawkes	Fawkes Tap	138	229	296	355	387
32	Gallatin Co.	Ghent	138	229	267	287	287
33	Garrard Co.	Lancaster	69	72	101	72	101
34	Green Co.	Greensburg	69	53	66	81	87
35	Green Hall Jct.	Delvinta	161	176	201	223	229
36	Hodgenville	Hodgenville	69	53	60	81	89
37	Hodgenville	New Haven	69	49	49	81	89
38	Kargle	Elizabethtown	69	66	66	88	88
39	Laurel Co.	Hopewell	69	72	76	86	89
40	Liberty Church Tap	Farley	69	66	66	72	72
41	Marion Co.	Lebanon	161-138	192	230	242	272
42	Murphysville	Kenton	69	53	66	68	68

Table 8.(2)(a)-3
EKPC Free-Flowing Interconnection Capability

				Ratings in MVA			
				Summer		Winter	
No.	From (EKPC)	To	Voltage kV	Normal	Emergency	Normal	Emergency
43	Murphysville	Sardis	69	41	50	60	66
44	Nelson Co.	Nelson Co Tap	69-138	144	152	172	178
45	North London	North London	69	73	76	86	89
46	North Springfield	Springfield	69	53	54	61	61
47	Owen Co.	Bromley	69	57	57	97	97
48	Owen Co.	Owen Co. Tap	69-138	139	152	172	178
49	Paris	Paris Tap	138-69	129	160	191	196
50	Penn	Scott Co.	69	56	56	72	72
51	Pittsburg Tap	Pittsburg	161-69	116	120	120	120
52	Renaker	Cynthiana Sw.	69	53	66	81	89
53	Rogersville Jct.	Rogersville	69	129	133	143	143
54	Rowan Co.	Rodburn	138	143	194	143	203
55	Sewellton	Union Underwear	69	41	41	75	75
56	Shelby Co.	Shelby Co. Tap	69	90	103	122	126
57	Somerset	Ferguson South	69	89	89	132	132
58	Somerset	Somerset South	69	56	56	78	82
59	Spurlock	Kenton	138	259	281	286	337
60	Stephensburg	East View	69	49	49	64	66
61	Taylor Co.	Taylor Co.	161-69	93	105	120	124
62	Tharp Jct.	Elizabethtown	69	103	103	137	137
63	Union City	Lake Reba Tap	138	245	297	364	396
64	West Garrard	West Garrard	345	1214	1251	1374	1407
		Total:		7053	8023	8931	9516

Table 8.(2)(a)-4
EKPC Free-Flowing Interconnection Capability

				Ratings in MVA			
				Summer		Winter	
No.	**From (EKPC)**	**To**	**Voltage kV**	**Normal**	**Emergency**	**Normal**	**Emergency**
TVA							
65	McCreary Co.	McCreary Co.	69-161	96	117	121	136
66	Russell Co. Tap	Wolf Creek	161	312	312	335	335
67	Summershade	Summershade	161	268	312	415	415
68	Summershade Tap	Summershade	161	207	247	259	279
69	Wayne Co.	Wayne Co.	69-161	122	122	122	122
		Total:		1005	1110	1252	1287
		Grand Total:		11768	13116	14476	15309

Table 8.(2)(a)-5

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2012-2026)	
A. New Transmission Lines and Transmission Substations **Project Description**	**Needed In-Service Date**
Operate the Goldbug-Wofford (LGEE) 69 kV line normally closed	6/2012
Construct a 3-breaker 69 kV switching substation at Hunt Farm Junction.	10/2012
Construct approximately 9.7 miles of 69 kV line, using 556.5 MCM ACSR/TW conductor, between the Keith and Owen County substations. Add 69 kV terminal facilities at Owen County. Operate the Keith-Owen County line normally-open.	12/2012
Construct 8.8 miles of 69 kV line, using 556.5 MCM ACSR/TW conductor, between the Cave City and Bon Ayr distribution substations. Install terminal equipment at the Cave City, Bon Ayr, and Fox Hollow substations to form a 69 kV circuit between the Barren County and Fox Hollow substations.	12/2013
Replace the existing 100 MVA, 161-69 kV transformer bank at Bullitt County substation with a 150 MVA transformer.	12/2013
Construct 8.6 miles of 69 kV line, using 556.5 MCM ACSR/TW conductor, between the Mercer County Industrial and Van Arsdell distribution substations. Construct a 69 kV switching substation ("South Anderson") at Bonds Mill Junction located adjacent to KU's existing Bonds Mill switching substation. Construct 0.12 miles of 69 kV line, using 266.8 MCM ACSR conductor, between the South Anderson substation and the Powell/Taylor 69 kV tap line. Serve the Powell/Taylor distribution substation radially from the South Anderson switching substation.	12/2013
Purchase a spare 345-13.8 kV, 200 MVA GSU transformer for J.K. Smith CTs 9 & 10	12/2013
Construct 2.7 miles of 69 kV line, using 556.5 MCM ACSR/TW conductor, between the Fox Hollow and Parkway substations. Serve the Parkway #1 and #2 distribution substations radially from the Fox Hollow switching substation. Install additional terminal equipment at the Fox Hollow substations.	6/2014
Replace the existing 138-69 kV transformer bank at Plumville substation with a 150 MVA transformer.	12/2014
Construct 0.11 miles of 69 kV line, using 266.8 MCM ACSR conductor, between the Powell County and Stanton substations. Serve the Stanton distribution substation radially from the Powell County switching substation. Install terminal equipment at the Powell County substation.	12/2014
Re-configure the Hunt distribution tap line to serve it normally from the Dale-Powell County 69 kV circuit.	12/2014
Install a new 69 kV breaker at Clay Village for the existing Clay Village-Owen County 69 kV line.	12/2014

Table 8.(2)(a)-6

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2012-2026)	
A. New Transmission Lines and Transmission Substations (continued) **Project Description**	**Needed In-Service Date**
Construct 6.2 miles of 69 kV line, using 266.8 MCM ACSR conductor, from the Oakdale distribution substation to a tap point adjacent to AEP's Jackson substation. Install terminal equipment at the Oakdale and AEP Jackson substations. Operate the Oakdale to AEP Jackson line in the normally open mode.	12/2015
Construct 3.9 miles of 69 kV line, using 795 MCM ACSR conductor, from the Beattyville distribution substation to Oakdale Junction. Construct a 69 kV switching substation at Oakdale Junction.	12/2016
Construct a 2nd 69 kV line, using 556.5 MCM ACSR/TW conductor, from EKPC's Thelma substation to AEP's Thelma #2 substation. Install 69 kV terminal equipment at the EKPC and AEP Thelma (#2) substations.	12/2016
Construct 5.4 miles of 69 kV line, using 266.8 MCM ACSR conductor, from KU's Lynch-Imboden 69 kV line to EKPC's Arkland substation. Operate this line normally open.	12/2016
Construct a 69 kV switching station at the existing Phil distribution substation location.	12/2016
Construct 3.5 miles of 69 kV line, using 266.8 MCM ACSR conductor, from AEP's Morehead-Hayward 69 kV line to EKPC's Elliottville substation. Operate this line normally open.	12/2016
Construct a 69 kV switching substation at the existing Munk Junction location. Operate the Renaker-Williamstown Line in the normally closed mode.	12/2017
Replace the Powell County 138/69 kV, 100 MVA transformer with a 150 MVA transformer.	12/2018
Construct a 161/69 kV substation at a new site ("Clinton County") located between the Snow and Upchurch distribution substations. Construct a 4.5 mile 69 kV line, using 954 MCM ACSR conductor, between the Snow, Clinton County, and Upchurch substations. Construct a 9 mile, 161 kV line, using 795 MCM ACSR conductor, between the Clinton County and Wolf Creek (USACE) substations. Install 161 kV terminal facilities at the Wolf Creek substation. Operate the Albany-Upchurch Junction 69 kV line section in the normally open mode.	12/2019
Construct a 138/69 kV substation at the existing South Jessamine Junction location. Construct a 7.3 mile, 138 kV line, using 795 MCM ACSR conductor, between the South Jessamine Junction and Fayette 138/69 kV substations. Install 138 kV terminal facilities at the Fayette substation.	12/2019
Construct a 138/69 kV substation at or adjacent to the existing Three Links Junction 69 kV switching substation. Construct a 7.5 mile, 138 kV line, using 795 MCM ACSR conductor, between the Three Links Junction and West Berea 138/69 kV substations. Install 138 kV terminal facilities at the West Berea substation.	12/2020

Table 8.(2)(a)-7

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2012-2026)	
A. New Transmission Lines and Transmission Substations (continued) **Project Description**	**Needed In-Service Date**
Construct a 69 kV switching substation at the existing Penn distribution substation. Operate the Keith-Penn line in the normally closed mode.	6/2021
Construct a 2nd 2.9-mile 69 kV line, using 556.5 MCM ACSR conductor, between the Plumville and Rectorville substations. Operate this new line normally closed and the existing line normally open to serve the Rectorville substation radially. Install 69 kV terminal facilities at the Plumville substation.	12/2022
Construct 12.8 miles of 69 kV line, using 556.5 MCM ACSR conductor, from Coburg to Green County. Construct a 69 kV switching substation at Coburg Junction. Install a 69 kV line breaker at Green County Substation.	12/2022
Construct a 2nd 5.7-mile 69 kV line, using 556.5 MCM ACSR conductor, between the Wayne County and Slat substations. Operate this new line normally closed and the existing line normally open to serve the Slat substation radially. Install 69 kV terminal equipment at the Wayne County Substation.	12/2022
Construct approximately 0.5 miles of 138 kV line, using 556.5 MCM ACSR conductor, between the EKPC Thelma and AEP Thelma substations. Install a 138-69 kV, 100 MVA transformer at EKPC's Thelma substation.	12/2022
Construct 10.9 miles of 69 kV line, using 556.5 MCM ACSR conductor, between the Maggard and Magoffin County substations. Construct a 69 kV switching station at Maggard. Install 69 kV terminal equipment at the Magoffin County substation.	12/2023
Construct 3.7 miles of new 69 kV line between Patton Road Junction and Fox Hollow using 556.5 MCM ACSR conductor. Operate this new line as a separate circuit between Summershade and Fox Hollow by connecting to the existing KH line and constructing 0.15 miles of 69 kV line between Summershade and Summershade Junction using 556.5 MCM ACSR conductor. Install 69 kV terminal equipment at the Summershade and Fox Hollow substations.	6/2024
Install two (2) 69 kV circuit breakers at the Zachariah 69 kV Substation.	6/2024
Construct a new 69 kV switching station at Brodhead connecting EKPC's Three Links Junction-Walnut Grove 69 kV line to KU's Lancaster-Mt. Vernon 69 kV line.	12/2024
Construct 17.7 miles of new 138 kV line between Skaggs and Thelma using 795 MCM ACSR conductor. Install 138 kV terminal facilities at Skaggs and Thelma.	12/2024
Construct a 138-69 kV, 100 MVA substation (Rineyville Junction) near the location where EKPC's Elizabethtown-Radcliff 69 kV line crosses KU's Hardin County-Rogersville 138 kV line.	12/2025

Table 8.(2)(a)-8

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2012-2026)	
B. Transmission Line Re-conductor/Rebuild Projects **Project Description**	**Needed In-Service Date**
Re-conductor the 1/0 ACSR conductor in the Clay Village-New Castle 69 kV line section (14.4 miles) using 556.5 MCM ACSR/TW ("ACTW") wire.	12/2013
Re-conductor the 4/0 ACSR conductor in the Brodhead-Three Links Jct 69 kV line section (8.2 miles) using 556.5 MCM ACTW wire.	12/2014
Re-conductor the 1/0 ACSR conductor in the Cynthiana Jct-Headquarters 69 kV line section (10.2 miles) using 556.5 MCM ACTW wire.	12/2014
Re-conductor the 4/0 ACSR conductor in the Norwood Jct-Shopville 69 kV line section (6.3 miles) using 556.5 MCM ACTW wire.	12/2014
Re-conductor the 266.8 MCM portion (1.3 miles) of the Baker Lane-Holloway Jct 69 kV line using 556.5 MCM ACTW wire.	12/2015
Rebuild the 3.16-mile Davis-Fayette 69 kV line using double circuit 138/69 kV construction. Install only the 69 kV conductor using 556.5 MCM ACTW wire.	12/2016
Rebuild the 4.0-mile Davis-Nicholasville 69 kV line using double circuit 138/69 kV construction. Install only the 69 kV conductor using 556.5 MCM ACTW wire.	12/2017
Re-conductor the 3/0 ACSR conductor in the Fort Knox Jct-Rineyville Jct 69 kV line section (0.44 miles) using 556.5 MCM ACTW wire.	12/2017
Re-conductor the 1/0 ACSR conductor in the W.Bardstown-W.Bardstown Jct 69 kV line section (4.5 miles) using 556.5 MCM ACTW wire.	6/2018
Re-conductor the 2/0 ACSR portion (4.2 miles) of the Nelson County-Colesburg Jct 69 kV line section using 556.5 MCM ACTW wire.	12/2018
Re-conductor the 3/0 ACSR conductor in the Charters-Oak Ridge Jct-Goddard 69 kV line section (8.0 miles) using 556.5 MCM ACTW wire.	12/2019
Re-conductor the 4/0 ACSR conductor in the Hillsboro-Peasticks Jct 69 kV line section (10.5 miles) using 556.5 MCM ACTW wire.	12/2019
Re-conductor the 4/0 ACSR and 266 MCM ACSR conductors in the Carrollton-Hunters Bottom Jct 69 kV line section (8.6 miles) using 556.5 MCM ACTW wire.	12/2020
Re-conductor the 266 MCM ACSR conductor in the Goddard-Plummers Landing Jct 69 kV line section (4.2 miles) using 556.5 MCM ACTW wire.	12/2020
Re-conductor the 4/0 ACSR conductor in the Hope-Peasticks Jct 69 kV line section (8.1 miles) using 556.5 MCM ACTW wire.	12/2020
Re-conductor the 266 MCM ACSR conductor in the Lebanon Jct-Woosley 69 kV line section (8.0 miles) using 556.5 MCM ACTW wire.	6/2021
Re-conductor the 2/0 ACSR conductor in the Lyman B. Williams-Tunnel Hill Jct. 69 kV line section (1.5 miles) using 556.5 MCM ACTW wire.	6/2022

Table 8.(2)(a)-9

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2012-2026)	
B. Transmission Line Re-conductor/Rebuild Projects (continued) **Project Description**	**Needed In-Service Date**
Reconductor the 2/0 ACSR conductor in the Etown-Tunnel Hill Jct. 69 line section (3.4 miles) using 556.5 MCM ACSR conductor.	6/2022
Reconductor the 2/0 ACSR conductor in the Colesburg Jct.-Lyman B. Williams 69 kV line section (5.5 miles) using 556.5 MCM ACSR conductor.	6/2022
Reconductor the 266 MCM ACSR conductor in the Dale-Newby 69 kV double-circuit line section (11.1 miles) using 556.5 MCM ACSR conductor.	12/2022
Reconductor the 4/0 ACSR conductor in the Boone-Boone Distribution 69 kV line section (0.1 mile) using 556.5 MCM ACSR conductor.	6/2023
Reconductor the 266.8 MCM ACSR portion of the Kargle-Etown KU 69 kV line section (1.4 miles) using 556.5 MCM ACSR conductor.	6/2023
Re-conductor the 266.8 MCM ACSR conductor in the Murphysville-Plumville 69 kV line (9.9 miles) using 556.5 MCM ACSR conductor.	6/2023
Rebuild the 1/0 ACSR conductor in the Stephensburg-Glendale 69 kV line section (9.0 miles) using 556.5 MCM ACSR conductor.	6/2023
Rebuild the 1/0 ACSR conductor in the Glendale-Hodgenville 69 kV line section (8.7 miles) using 556.5 MCM ACSR conductor.	6/2023
Reconductor the 556.5 MCM ACSR conductor in the Central Hardin-Kargle 69 kV line section (0.6 mile) using 795 MCM ACSR conductor.	6/2023
Reconductor the 266.8 MCM ACSR conductor in the East Somerset-Norwood Jct. 69 kV line (1.3 miles) using 556.5 MCM ACSR conductor.	12/2023
Reconductor the 2/0 ACSR conductor in the Owen County-New Castle 69 kV line section (19.6 miles) using 556.5 MCM ACSR conductor.	12/2023
Reconductor the 2/0 ACSR conductor in the Lees Lick-Penn 69 kV line section (13.6 miles) using 556.5 MCM ACSR conductor.	12/2023
Reconductor the 4/0 ACSR conductor portion (1.5 miles) of the Three Links Junction-Conway Jct. 69 kV line section using 556.5 MCM ACSR conductor.	12/2023
Reconductor the 3/0 ACSR conductor in the Beattyville Distribution-Oakdale Jct. 69 kV line section (3.9 miles) using 556.5 MCM ACSR conductor.	12/2023
Reconductor the 3/0 ACSR conductor in the Leon-Airport Road 69 kV line section (5.7 miles) using 556.5 MCM ACSR conductor	12/2023
Reconductor the 3/0 ACSR conductor in the Fall Rock-Greenbriar Jct. 69 kV line section (3.6 miles) using 556.5 MCM ACSR conductor.	12/2023
Reconductor the 4/0 ACSR conductor in the Albany-Snow Jct. 69 kV line section (4.4 miles) using 556.5 MCM ACSR conductor.	12/2023
Re-conductor the 3/0 ACSR conductor in the Rineyville Junction-Smithersville Junction 69 kV line section (2.9 miles) using 556.5 MCM ACSR conductor.	6/2024

Table 8.(2)(a)-10

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2012-2026)	
B. Transmission Line Re-conductor/Rebuild Projects (continued) **Project Description**	**Needed In-Service Date**
Reconductor the 556.5 MCM ACSR conductor in the Etown KU-Tharp Jct. 69 kV line section (2.1 miles) using 795 MCM ACSR conductor.	12/2024
Reconductor the 4/0 ACSR conductor in the Headquarters-Millersburg Jct. 69 kV line section (5.1 miles) using 556 MCM ACSR conductor.	12/2024
Reconductor the 4/0 ACSR conductor in the Summershade Jct.-Temple Hill 69 kV line section (9.6 miles) using 556 MCM ACSR conductor.	6/2026

Table 8.(2)(a)-11

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2012-2026)	
C. Transmission Line Conductor Temperature Upgrade Projects ***Project Description***	**Needed In-Service Date**
Increase the maximum operating temperature (MOT) of the Bristow Jct-Richardson Jct 69 kV line section to 167°F.	6/2012
Increase the MOT of the Helechawa-Sublett Junction 69 kV line section to 167°F.	12/2012
Increase the MOT of the Bluegrass Parkway Junction-Woodlawn 69 kV line section to 167°F.	12/2012
Increase the MOT of the Pleasant Grove-Pleasant Grove KU Junction 69 kV line section to 167°F.	12/2012
Increase the MOT of the Keith-Penn 69 kV line section to 167°F.	12/2013
Increase the MOT of the Davis Junction-Fayette 69 kV line section to 248°F.	12/2015
Increase the MOT of the Rineyville Jct.-Smithersville Jct. 69 kV line section to 284°F.	6/2016
Increase the MOT of the Griffin-Griffin Junction 69 kV line section to 167°F.	6/2016
Increase the MOT of the Glendale-Hodgenville 69 kV line section to 170°F.	12/2016
Increase the MOT of the Oven Fork Jct.-Scotia 69 kV line section to 167°F.	12/2016
Increase the MOT of the Summershade-Summershade TVA 69 kV line section to 167°F.	12/2016
Increase the MOT of the Booneville-Booneville Junction 69 kV line section to 167°F.	6/2017
Increase the MOT of the Elliottville-Rowan County 69 kV line section to 167°F.	6/2017
Increase the MOT of the Arkland Jct-Oven Fork Jct 69 kV line section to 167°F.	6/2017
Increase the MOT of the South Springfield-South Springfield Junction 69 kV line section to 167°F.	6/2017
Increase the MOT of the Floyd-Floyd KU Junction 69 kV line section to 167°F.	6/2017
Increase the MOT of the Ninevah-Ninevah KU Junction 69 kV line section to 167°F.	6/2017
Increase the MOT of the Oakdale-Oakdale Junction 69 kV line section to 167°F.	6/2017
Increase the MOT of the North Corbin-North Corbin KU Junction 69 kV line section to 167°F.	6/2017
Increase the MOT of the Pelfrey-Pelfrey AEP Junction 69 kV line section to 167°F.	6/2017
Increase the MOT of the Carson-New Liberty 69 kV line section to 167°F.	6/2017
Increase the MOT of the Zula-Zula Junction 69 kV line section to 167°F.	6/2017
Increase the MOT of the Colesburg-Colesburg Junction 69 kV line section to 167°F.	6/2017
Increase the MOT of the Upton-Upton Junction 69 kV line section to 167°F.	6/2017
Increase the MOT of the Mount Olive-Mount Olive Junction 69 kV line section to 167°F.	6/2018
Increase the MOT of the Mount Sterling-Reid Village 69 kV line section to 167°F.	6/2018
Increase the MOT of the Chad-Chad KU Junction 69 kV line section to 167°F.	6/2018
Increase the MOT of the Eberle-Eberle Junction 69 kV line section to 167°F.	6/2018

Table 8.(2)(a)-12

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2012-2026)	
C. Transmission Line Conductor Temperature Upgrade Projects (continued) **Project Description**	**Needed In-Service Date**
Increase the MOT of the Russell Springs #1-Russell Springs #2 69 kV line section to 167°F.	6/2018
Increase the MOT of the Millers Creek-Millers Creek KU Junction 69 kV line section to 167°F.	6/2018
Increase the MOT of the Big Bone-Big Bone Junction 69 kV line section to 167°F.	6/2018
Increase the MOT of the Boone County-Boone Distribution 69 kV line section to 284°F.	6/2018
Increase the MOT of the Loretto-Sulphur Creek 69 kV line section to 167°F.	6/2019
Increase the MOT of the Jellico Creek-Jellico Creek Junction 69 kV line section to 167°F.	6/2019
Increase the MOT of the Loretto-South Springfield Junction 69 kV line section to 167°F.	6/2019
Increase the MOT of the North Springfield-South Springfield Junction 69 kV line section to 167°F.	6/2019
Increase the MOT of the Cave Run-Cave Run KU Junction 69 kV line section to 167°F.	6/2019
Increase the MOT of the Etown EKPC-Tunnel Hill Jct. 69 kV line section to 275°F.	6/2019
Increase the MOT of the Magnolia-Summersville 69 kV line section to 167°F.	6/2020
Increase the MOT of the Bluegrass Parkway Jct.-Owens Illinois Jct. 69 kV line section to 212°F.	6/2022
Increase the MOT of the Stephensburg-Upton Jct. 69 kV line section to 212°F.	6/2022
Increase the MOT of the Glendale-Hodgenville 69 kV line section to at least 266°F.	12/2022
Increase the MOT of the Tharp Junction-Etown EK #1 69 kV line section to at least 284°F.	6/2023
Increase the maximum operating temperature of the 556.5 MCM ACSR Kargle-Etown KU 69 kV line section (2.85 miles) to at least 284°F.	6/2024
Increase the maximum operating temperature of the 2/0 ACSR Tunnel Hill Junction-Lyman B. Williams 69 kV line section (1.45 miles) to at least 275°F.	6/2025
Increase the MOT of the Central Hardin-Kargle-Etown KU 69 kV line section to at least 284°F.	6/2025
Increase the maximum operating temperature of the 556.5 MCM ACSR Etown EK #1-Etown EK #2 69 kV line section (0.04 miles) to at least 284°F.	12/2025
Increase the MOT of the Liberty Church Jct.-Bacon Creek Jct. 69 kV line section to at least 212°F.	6/2026

Table 8.(2)(a)-13

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2012-2026)	
D. Capacitor Bank Additions **Project Description**	**Needed In-Service Date**
Resize the existing Cedar Grove 69 kV capacitor bank from 10.8 to 20.41 MVAR.	6/2012
Install an 8.164 MVAR, 69 kV capacitor bank at Hunt Farm Junction Substation.	10/2012
Relocate the existing Parkway 69 kV, 13.2 MVAR capacitor bank to the planned Bon Ayr distribution substation.	12/2012
Resize the existing Tyner 69 kV capacitor bank from 16.33 to 26.53 MVAR.	12/2012
Install an 8.674 MVAR, 34.5 kV capacitor bank at Gallatin County Substation.	6/2013
Relocate the existing Greenbriar 69 kV capacitor bank to Big Creek Substation and resize it to 6.633 MVAR.	12/2013
Resize the existing HT Adams 69 kV capacitor bank from 7.2 to 15.307 MVAR.	12/2013
Resize the Hunt Farm Jct 69 kV capacitor bank from 8.164 to 16.327 MVAR.	12/2013
Install a 25.51 MVAR, 69 kV capacitor bank at Skaggs Substation	12/2013
Install a 20.409 MVAR, 69 kV capacitor bank at Fox Hollow Substation.	6/2014
Resize the existing Nicholasville 69 kV capacitor bank from 19.8 to 22.96 MVAR.	12/2014
Install a 22.96 MVAR, 69 kV capacitor bank at the West London Substation.	12/2014
Install a 35.72 MVAR, 69 kV capacitor bank at EKPC's Elizabethtown #1 Substation.	12/2015
Resize the existing Headquarters 69 kV capacitor bank from 6.123 to 16.327 MVAR.	6/2016
Install a 28.06 MVAR, 69 kV capacitor bank at EKPC's Hodgenville Substation.	6/2016
Resize the existing Sideview 69 kV capacitor bank from 5.533 to 15.307 MVAR.	6/2016
Install an 11.225 MVAR, 69 kV capacitor bank at Oven Fork substation.	12/2016
Install a 15.307 MVAR, 69 kV capacitor bank at Perryville substation.	12/2018
Install a 14.286 MVAR, 69 kV capacitor bank at Magoffin County Substation.	12/2018
Re-size the existing Leon 69 kV, 13.2 MVAR capacitor bank to 18.37 MVAR.	12/2019
Install a 14.286 MVAR, 69 kV capacitor bank at North Madison Substation.	12/2019
Install a 22.96 MVAR, 69 kV capacitor bank at South Jessamine Substation.	12/2019
Install a 20.409 MVAR, 69 kV capacitor bank at Norwood Junction.	12/2020
Install a 15.31 MVAR, 69 kV capacitor bank at Belleview Substation.	6/2022
Install a 14.29 MVAR, 69 kV capacitor bank at Knob Lick Substation.	6/2022
Install a 38.27 MVAR, 69 kV capacitor bank at the Nelson County Substation.	6/2022
Install a 17.86 MVAR, 69 kV capacitor bank at the EKPC Taylorsville Substation.	12/2022
Re-size the existing Clay Village 9.2 MVAR, 69 kV capacitor bank to 11.225 MVAR	12/2022
Install a 16.33 MVAR, 69 kV capacitor bank at the Arkland Substation.	12/2022
Re-size the existing East Bernstadt 69 kV, 16.2 MVAR capacitor bank to 30.6 MVAR.	12/2022
Re-size the existing Booneville 69 kV, 9.6 MVAR capacitor bank to 13.2 MVAR.	12/2022
Install a 12.25 MVAR, 69 kV capacitor bank at Maggard Substation.	12/2022
Install a 14.29 MVAR, 69 kV capacitor bank at the Campground Substation.	12/2022

Table 8.(2)(a)-14

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2012-2026)	
D. Capacitor Bank Additions (continued) **Project Description**	**Needed In-Service Date**
Install a 16.33 MVAR, 69 kV capacitor bank at the Homestead Lane Substation	12/2022
Move the Slat 20.41 MVAR capacitor bank to Wayne County and resize it to 28.06 MVARs.	12/2022
Install a 14.29 MVAR, 69 kV capacitor bank at the Carpenter Substation	12/2022
Install a 28.06 MVAR, 69 kV capacitor bank at the Hinkle Substation	12/2022
Install a 24.49 MVAR, 69 kV capacitor bank at the Sewellton Junction Substation	12/2022
Re-size the existing Thelma 69 kV, 16.84 MVAR capacitor bank to 30.61 MVAR	12/2022
Install a 16.84 MVAR, 69 kV capacitor bank at the Goodnight Substation	6/2023
Install a 10.72 MVAR, 69 kV capacitor bank at the Elliottville Substation	12/2023
Re-size the Maggard 69 kV, 12.25 MVAR capacitor bank to 15.31 MVAR	12/2023
Re-size the Magoffin County 69 kV, 14.29 MVAR capacitor bank to 16.2 MVAR	12/2023
Install a 24.49 MVAR, 69 kV capacitor bank at the Bonnieville Substation	6/2024
Re-size the existing West Bardstown 69 kV, 13.78 MVAR capacitor bank to 16.84 MVAR	12/2024
Install a 17.86 MVAR, 69 kV capacitor bank at the Phil Substation	12/2024
Install an 8.16 MVAR, 69 kV capacitor bank at the Oakdale Substation	12/2024
Re-size the existing Three Links Jct. 69 kV, 16.2 MVAR capacitor bank to 28.06 MVAR	12/2024
Install a 22.96 MVAR, 69 kV capacitor bank at the Bullitt County Substation	6/2025
Install a 20.41 MVAR, 69 kV capacitor bank at the Glendale Substation	6/2025
Install a 28.1 MVAR, 69 kV capacitor bank at the Murphysville Substation	12/2025
Install a 40.82 MVAR, 69 kV capacitor bank at Rineyville Junction	12/2025

Table 8.(2)(a)-15

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2012-2026)	
E. Terminal Facility Upgrades **Project Description**	**Needed In-Service Date**
Increase the Zone 3 distance relay setting at Three Links Junction (Tyner line) to 74 MVA.	12/2012
Increase the Zone 3 distance relay setting at Dale (Dale-Powell County 69 kV line) to 88 MVA.	12/2015
Change the metering CT setting at Laurel County Substation (KU Hopewell Line) to support increased MVA line flows due to normal load growth.	12/2018
Change the Zone 3 distance relay setting at Murphysville (Plumville line) to 88 MVA.	12/2020
Upgrade the 4/0 copper bus and jumpers at the Green County substation associated with the Green County-KU Greensburg 69 kV line.	6/2022
Upgrade the 300A metering CT at the Stephensburg substation associated with the Stephensburg-KU Eastview 69 kV line.	6/2022
Replace the 138 kV, 1200A line traps at the J.K. Smith and Dale substations associated with the J.K. Smith-Dale 138 kV line.	12/2022
Replace the 138 kV, 1200A line traps at the J.K. Smith and Fawkes substations associated with the J.K. Smith-Fawkes 138 kV line.	12/2022
Upgrade the 69 kV 600A switch S81-605 at the Hickory Plains tap point to 1200A.	12/2022
Replace the 600-amp switch S408-605 near the Russell Springs KU 69 kV tap point with a 1200-amp switch.	12/2022
Upgrade the 4/0 copper bus and jumpers at the East Bardstown substation associated with the East Bardstown-KU Bardstown Industrial 69 kV line.	12/2022
Increase the Zone 3 distance relay setting at the Murphysville substation associated with the Murphysville-KU Kenton 69 kV line to at least 85 MVA.	12/2022
Increase the Zone 3 distance relay setting at the Elizabethtown substation associated with the Elizabethtown-Smithersville Junction 69 kV line to at least 98 MVA.	12/2022
Replace the 600-amp switch N55-605 near the Duro 69 kV tap point with a 1200-amp switch.	12/2024
Increase the overcurrent relay setting on the Powell County 138-69 kV transformer to at least 178 MVA.	12/2024
Replace the 138 kV, 1200A line traps at the J.K. Smith and Powell County substations associated with the J.K. Smith-Powell County 138 kV line.	12/2025
Replace the 138 kV, 1200A metering CTs at the Fawkes substation associated with the Fawkes-KU Fawkes/Lake Reba Tap 138 kV line with a minimum of 1600A equipment.	12/2025

Table 8.(2)(a)-16

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2012-2026)	
F. Distribution Substation Projects (2012-2015 ONLY) **Project Description**	**Needed In-Service Date**
Construct a new West Glasgow #2 69-25 kV, 12/16/20 MVA Substation and associated 69 kV tap line (0.1 mile)	5/2012
Construct a new Cane Ridge 69-12.5 kV, 5.6/7 MVA distribution substation and associated 69 kV tap line (0.1 mile).	6/2012
Construct a new Mercer County Industrial #2 69-12.5 kV, 15/20/25 MVA Substation and associated 69 kV tap line (0.1 mile)	8/2012
Construct a new MBUSA 69-12.5 kV, 15/20/25 MVA Substation and associated 69 kV tap line (0.1 mile)	10/2012
Construct a new Bon Ayr 69-25 kV, 12/16/20 MVA Substation and associated 69 kV tap line (3.0 miles)	12/2012
Construct a new Becknerville 138-25 kV, 12/16/20 MVA Substation and associated 138 kV tap line (0.1 mile)	12/2012
Upgrade the existing Burlington 69-12.5 kV, 11.2/14 MVA Substation to 15/20/25 MVA.	6/2013
Upgrade the existing Turkey Foot 69-12.5 kV, 11.2/14 MVA Substation to 12/16/20 MVA.	6/2013
Upgrade the existing Long Run 69-12.5 kV, 5.6/7 MVA Substation to 12/16/20 MVA.	12/2013
Construct a new Jonesville 69-25 kV, 12/16/20 MVA Substation and associated 69 kV tap line (0.1 mile)	12/2013
Construct a new Pleasant Grove #2 69-12.5 kV, 12/16/20 MVA Substation and associated 69 kV tap line (0.1 mile)	6/2014
Upgrade the existing Rectorville 69-12.5 kV, 11.2/14 MVA Substation to 12/16/20 MVA, and convert to 25 kV low-side.	6/2014
Upgrade the existing Cynthiana 69-12.5 kV, 11.2/14 MVA Substation to 12/16/20 MVA.	6/2014
Construct a new Big Woods 69-12.5 kV, 12/16/20 MVA Substation and associated 69 kV tap line (0.2 mile)	12/2014
Construct a new Roseville 69-25 kV, 12/16/20 MVA Substation and associated 69 kV tap line (3.5 miles)	12/2014
Upgrade the existing Williamstown 69-12.5 kV, 11.2/14 MVA Substation to 15/20/25 MVA.	3/2015
Construct a new Hebron #2 138-12.5 kV, 12/16/20 MVA Substation and associated 138 kV tap line (0.1 mile)	6/2015
Upgrade the existing Jellico Creek 69-13.2 kV, 5.6/7 MVA Substation to 12/16/20 MVA, and convert to 25 kV low-side.	12/2015
Upgrade the Van Arsdell 69-12.5 kV, 11.2/14 MVA Substation to 12/16/20 MVA.	12/2015

SECTION 7.0

PLANS FOR EXISTING GENERATING UNITS

SECTION 7.0

PLANS FOR EXISTING GENERATING UNITS

7.1 Introduction

7.2

807 KAR Section 8(2)(a) The utility shall describe and discuss all options considered for inclusion in the plan including: (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, efficient, and cost effective. EKPC has developed a long-range plan of maintenance needs for each of the existing generating units, which is discussed in the following subsection. Please also see the discussion in Section 1.4, Power Supply Actions, in the Executive Summary of this IRP.

Maintenance of Existing EKPC Generating Units

Current facilities at Dale Power Station were placed in operation in 1954-60, Cooper Power Station in 1965-69, and Spurlock Power Station in 1977-81, with the Gilbert Unit in 2005 and Spurlock Power Station Unit No. 4 in 2009. J.K. Smith Station combustion turbines were placed in operation in 1999, 2001, and 2005, with two new units placed into operation in 2010. 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 were intended to enable 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, while mitigating 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.

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 plants.
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. Depending on the cost of the project, the economic analysis results and justification are then presented to the Board along with a request to approve the project. Smaller projects go through EKPC's normal approval process.

2011 MEAGER Study

The MEAGER Program covers the time frame of 2012 through 2016. Table 8.(2)(a)-1 through Table 8.(2)(a)-14 on pages 141 through 152 in the Support Documentation lists the major projects planned for each plant during this 5-year period.

Table 8.(2)(a)-1

Cooper Power Station

Description	Operating Unit	Date
Replacement of Low Pressure Piping	CP00	2012
High Energy Piping and Testing - Unit No. 2	CP02	2012
Acid Clean on Unit No. 1 Boiler	CP01	2012
Secondary Superheater Outlet Header-Unit No. 1 (Wet Mag Particle Test)	CP01	2012
Overhaul Unit No. 2 Condensate Pumps	CP02	2012
Convert - Automation of Emergency Drain Valves	CP00	2012
Major Overhaul - Unit No. 2	CP02	2012
Overhaul Three Pulverizers	CP00	2012
Overhaul Two Sootblowers on Unit No. 2	CP00	2012
Replace DCS Power Supplies for Unit No. 2	CP02	2012
Installation - Submerged Chain Housing - Unit No. 2	CP02	2012
Cooper Power Station Landfill - New	CP00	2012
Stator Bars for Unit No. 2 - Installation	CP02	2012
Cooper Retrofit Project - Unit No. 2	CP02	2012
Sewage Treatment Plant Improvements	CP00	2012
Ash Handling Scale	CP00	2012
N2 Packing - Turbine Efficiency - Unit No. 2	CP02	2012
Structural Steel Painting	CP00	2013
Secondary Superheater Outlet Header-Unit No. 1 (Wet Mag Particle Test)	CP01	2013
Replace Unit No. 2 Boiler Water Wall Tubes	CP02	2013
Replace Ash Mixers	CP00	2013
Overhaul Four Pulverizers	CP00	2013
Replace No. 2 Traveling Screens	CP02	2013
Cooper Power Station Landfill - New	CP00	2013
Demolition of Unit No. 2 Precipitator	CP02	2013
Mark VI Controls - New System - Unit No. 2	CP02	2013
EX2100 Controls - New System - Unit No. 2	CP02	2013
Ash Mixer Unloaders	CP00	2013
Submerged Drag Chain - Unit No. 2 - Install	CP02	2013

Table 8.(2)(a)-2

Cooper Power Station

Description	Operating Unit	Date
Rebag 1/4 of Baghouse - Unit No. 2	CP02	2014
Wedge Check No. 1 Generator	CP01	2014
Turbine Valve Outage - Unit No. 1	CP01	2014
Upgrade No. 2 Intake Elevator Controls	CP02	2014
Upgrade No. 1 Intake Elevator Controls	CP01	2014
Rebag 1/4 of Baghouse - Unit No. 2	CP02	2015
Replace No. 2 Mechanical Exhauster	CP00	2015
Replace Circulating Water Pump - Unit No. 1	CP01	2015
Refurbish 2B Circulating Water Pump and Motor - Unit No. 2	CP02	2015
Replace No. 1 Mechanical Exhauster	CP00	2016
Replace No. 1 and No. 2 Fluidizing Compressors	CP00	2016
New No. 1 and No. 2 Sootblowing Air Compressors	CP00	2016

Table 8.(2)(a)-3

Dale Power Station

Description	Operating Unit	Date
Purchase New Baskets for Unit No. 3	DA03	2012
Repair Unit No. 4 C Mill and Unit No. 3A Mill	DA00	2012
Acid Clean - Unit No. 4	DA04	2012
Inspect/Rebuild Control Valves - Unit No. 3	DA03	2012
Overhaul 4B Circulating Water Pump	DA00	2012
Precipitator Optimization - Units 3 and 4	DA03&DA04	2012
Purchase New Baskets for Unit No. 4	DA04	2013
Repair Unit No. 4 A Mill and Unit 3B Mill	DA03&DA04	2013
Clean Ash Pond - No. 2	DA00	2013
Inspect/Rebuild Control Valves - Unit No. 4	DA04	2013
Overhaul 3A Circulating Water Pump	DA00	2013
Clean Ash Pond - Completion - No. 2	DA00	2014
No Items for 2015		2015
No Items for 2016		2016

Table 8.(2)(a)-4

Spurlock Power Station

Description	Operating Unit	Date
Office Renovation & Addition	SP00	2012
Replace Unit No. 1 & Unit No. 2 Turbine Room Lighting System	SP00	2012
Replace Pilot Air Line in Unit No. 1 Cooling Tower	SP00	2012
Replace Office Elevator	SP00	2012
Outage Boiler Inspect/Repair - Unit No. 1	SP01	2012
Sootblower Refurbish - Unit No. 1	SP01	2012
Outage Boiler Inspect/Repair - Unit No. 2	SP02	2012
Scaffold Boiler - Unit No. 2	SP02	2012
Overhaul 2B Boiler Feed Pump - Unit No. 2	SP02	2012
Overhaul Spare Circulating Pump - Unit No. 2	SP02	2012
Repair Casing Leak in Dead Air Space - Unit No. 2	SP02	2012
Outage Boiler Inspection - Unit No. 3	SP03	2012
Scaffold Boiler and Miscellaneous Boiler - Unit No. 3	SP03	2012
Outage Boiler Inspection - Unit No. 4	SP04	2012
Scaffold Boiler and Miscellaneous Boiler - Unit No. 4	SP04	2012
Replace Secondary Air & Primary Air Damper Actuators - Unit 4	SP04	2012
Refractory - Unit No. 3	SP03	2012
Vacuuming Out Boiler - Unit No. 3	SP03	2012
Three Cycles (unit off & process when unit is going back on - taking ash out)	SP03	2012
Scaffold Boiler - Environmental - Unit No. 3	SP03	2012
Scaffold Boiler - Environmental Miscellaneous - Unit No. 3	SP03	2012
Scaffold Boiler - Environmental - Unit No. 4	SP04	2012
Scaffold Boiler - Environmental Miscellaneous - Unit No. 4	SP04	2012
Refractory - Unit No. 4	SP04	2012
Vacuuming Out Boiler - Unit No. 4	SP04	2012
Three Cycles (unit off & process when unit is going back on - taking ash out)	SP04	2012
Outage - Precipitator Inspection and Repairs - Unit No. 1	SP01	2012

Table 8.(2)(a)-5

Spurlock Power Station

Description	Operating Unit	Date
Outage - Precipitator Inspection and Repairs - Unit No. 2	SP02	2012
Four Precipitator Expansion Joints and Turning Vanes - Unit No. 2	SP02	2012
Plate Repair in Four J-Duct Casings - Unit No. 3	SP03	2012
J-Duct Turning Vanes - Unit No. 4	SP04	2012
Dredge River	SP00	2012
Inspect and Repair River Cells	SP00	2012
Replace Flights on Stacker Reclaimer Unit No. 2	SP01	2012
Replace Lower Slew Bearing on Stacker Reclaimer Unit No. 1	SP01	2012
Replace Unit No. 3 Crusher Rotor	SP03	2012
WESP SIRS Clean/Inspect/Repair	SP21	2012
Scaffolding WESP	SP21	2012
WESP SIRS Clean/Inspect/Repair	SP22	2012
Scaffolding WESP	SP22	2012
Repair Existing Gravity Filter	SP00	2012
Chemical Clean Re-Boiler	SP00	2012
Clean Closed Cooling Water Heat Exchangers - Five - Unit No. 3	SP03	2012
Overhaul Turbine Valves	SP00	2012
Install Diaphrams for Turbine/Inspection T-1 and T-2 - Unit No. 2	SP02	2012
Reagent Emergency Supply System	SP00	2012
Burner Deck Sprinkler System - Unit No. 2	SP02	2012
Reheater - Unit No. 2	SP02	2012
Safety Valves - Unit No. 3	SP03	2012
Safety Valves - Unit No. 4	SP04	2012
RO and Demineralizer System Upgrade	SP00	2012
Unit No. 2 Absorber System Upgrade	SP02	2012
Site Drainage and Paving Phase 1 and Phase II	SP00	2012

Table 8.(2)(a)-6

Spurlock Power Station

Description	Operating Unit	Date
Baghouse Isolation Damper Unit No. 3 @ J Duct	SP03	2012
Unit No. 2 Hot End Baskets	SP02	2012
Unit No. 1 and Unit No. 2 Fly Ash System Redundancy		2012
Peg's Hill Landfill - to Spurlock Landfill	SP00	2012
Waste Water Management System	SP00	2012
Install Boiler Leak Detector on Unit 4	SP04	2012
Coal Handling Sprinkler System	SP00	2012
Unit No. 1 and No. 2 Emergency Lighting System	SP00	2012
Unit No. 1 Coal Chutes	SP01	2012
Security System	SP00	2012
Replace Unit No. 3 Air Heater Baskets and Support Steel	SP03	2012
JLG 860SJ Boom Lift 4WD	SP00	2012
Outage Boiler Inspect/Repair - Unit No. 1	SP01	2013
Scaffold Boiler - Unit No. 1	SP01	2013
Overhaul Boiler Water Circulating Pump 2C - Unit No. 2	SP02	2013
Outage Boiler Inspect/Repair - Unit No. 2	SP02	2013
Sootblower Refurbishment - Unit No. 2	SP02	2013
Overhaul 2A Boiler Feed Pump - Unit No. 2	SP02	2013
Overhaul on A-Feedpump (Rep & Volute Rebuild Cost)-Unit No. 3	SP03	2013
Outage Boiler Inspection - Unit No. 3	SP03	2013
Scaffold Boiler and Boiler Miscellaneous - Unit No. 3	SP03	2013
Outage Boiler Inspection - Unit No. 4	SP04	2013
Scaffold Boiler and Boiler Miscellaneous - Unit No. 4	SP04	2013
Refractory - Unit No. 3	SP03	2013
Vacuuming Out Boiler - Unit No. 3	SP03	2013
Scaffolding Environmental - Unit No. 3	SP03	2013
Scaffolding Environmental - Miscellaneous - Unit No. 3	SP03	2013
Three Cycles (unit off & process when unit is going back on - taking ash out)	SP03	2013
Refractory - Unit No. 4	SP04	2013
Vacuuming Out Boiler - Unit No. 4	SP04	2013
Three Cycles (unit off & process when unit is going back on - taking ash out)	SP04	2013
Scaffolding Environmental - Unit No. 4	SP04	2013
Scaffolding Environmental - Miscellaneous - Unit No. 4	SP04	2013
Outage - Precipitator Inspection and Repairs - Unit No. 1	SP01	2013
Replacement of Precipitator Control Computers - Unit No. 1	SP01	2013
Outage - Precipitator Inspection and Repairs - Unit No. 2	SP02	2013
Replace Down River Barge Haul Winch Drum Assembly	SP00	2013

Table 8.(2)(a)-7

Spurlock Power Station

Description	Operating Unit	Date
Replace Lower Slew Bearing on Stacker Reclaimer - Unit No. 2	SP02	2013
Replace Flights on Stacker Reclaimer on Unit No. 3	SP03	2013
Outage - WESP Inspection and Repairs - Scrubber Unit No.1	SP21	2013
Ball Mill Overhaul - Scrubber Unit No. 1	SP21	2013
Scaffolding - WESP - Scrubber Unit No. 1	SP21	2013
Outage - WESP Inspection and Repairs - Scrubber Unit No. 2	SP22	2013
Scaffolding - WESP - Scrubber Unit No. 2	SP22	2013
Agitator Repairs - Scrubber Unit No. 2	SP22	2013
Turbine Valve Inspection - Unit No. 1	SP01	2013
Partial Retube of Condensor - Unit No. 1	SP01	2013
Alterex Rectifier Banks - Three - Unit No. 2	SP02	2013
Turbine Overhaul - Unit No. 1	SP01	2013
Unit No. 1 and Unit No. 2 Fly Ash System Redundancy		2013
Waste Water Management System	SP00	2013
Absorber System Upgrade - Unit No. 2	SP02	2013
Absorber System Upgrade - Unit No. 1	SP01	2013
Install Water Wall Panels - Unit No. 1	SP01	2013
Peg's Hill Landfill - to Spurlock Landfill	SP00	2013
SCR Catalyst Replacement - Unit No. 2	SP02	2013
Ash Transfer Station - Unit No. 1 and Unit 2		2013
Security System	SP00	2013

Table 8.(2)(a)-8

Spurlock Power Station

Description	Operating Unit	Date
Replace Intermediate Reheater - Unit No. 1	SP01	2014
Replace Inlet Reheater Lower Loops - Unit No. 1	SP01	2014
Outage Boiler Inspect/Repair - Unit No. 1	SP01	2014
Overhaul Boiler Water Circulating Pump - Unit No. 2	SP02	2014
Outage Boiler Inspect/Repair - Unit No. 2	SP02	2014
Scaffold Boiler - Unit No. 2	SP02	2014
Scaffold Boiler - Unit No. 3	SP03	2014
Boiler and FDA Inspection - Unit No. 3	SP03	2014
Scaffold Boiler - Unit No. 3	SP04	2014
Vacuuming Out Boiler - Unit No. 4	SP04	2014
Boiler and FDA Inspection - Unit No. 4	SP04	2014
Three Cycles (unit off & process when unit is going back on - taking ash out)	SP03	2014
Vacuuming Out Boiler - Unit No. 3	SP03	2014
Refractory - Unit No. 3	SP03	2014
Three Cycles (unit off & process when unit is going back on - taking ash out)	SP04	2014
Refractory - Unit No. 4	SP04	2014
Overhaul Limestone Mills - Unit No. 4	SP04	2014
Outage - Precipitator Inspection and Repairs - Unit No. 1	SP01	2014
Outage - Precipitator Inspection and Repairs - Unit No. 2	SP02	2014
Baghouse Bag Replacement - Unit No. 4	SP04	2014
Hopper Turning Vanes - Unit No. 4	SP04	2014
Barge Unloader Overhaul	SP00	2014
Pump Repairs - Scrubber Maintenance - Unit No. 1 Scrubber	SP21	2014

Table 8.(2)(a)-9

Spurlock Power Station

Description	Operating Unit	Date
Outage - WESP Inspection and Repairs - Unit No. 1 Scrubber	SP21	2014
Rebuild Unit No. 1 Scrubber Recycle Pumps	SP21	2014
Scrubber Ball Mill Reline - Unit No. 2 Scrubber	SP22	2014
Pump Repairs - Scrubber Maintenance - Unit No. 2 Scrubber	SP22	2014
Outage - WESP Inspection and Repairs - Unit No. 2 Scrubber	SP22	2014
Scaffolding - WESP - Unit No. 2 Scrubber	SP22	2014
Retube Reboiler	SP00	2014
Inspect/Overhaul Turbine Valves - Unit No. 1	SP01	2014
Valve Inspection/Overhaul - Unit No. 4	SP04	2014
New Loader	SP00	2014
New Baskets - Unit No. 1	SP01	2014
Peg's Hill Landfill - to Spurlock Landfill	SP00	2014
Fly Ash System Redundancy - Unit No. 1 and Unit No. 2		2014
Absorber System Upgrade - Unit No. 2	SP02	2014
Absorber System Upgrade - Unit No. 1	SP01	2014
Landfill Area C - Liner Development	SP00	2014
Economizer - Unit No. 2	SP02	2014
Waste Water Management System	SP00	2014

Table 8.(2)(a)-10

Spurlock Power Station

Description	Operating Unit	Date
Scaffold Boiler - Unit No. 1	SP01	2015
Outage Boiler Inspect/Repair - Unit No. 2	SP02	2015
Overhaul Boiler Water Circulating Pump 2 D - Unit No. 2	SP02	2015
Scaffold Boiler - Unit No. 3	SP03	2015
Boiler and FDA Inspection - Unit No. 3	SP03	2015
Scaffold Boiler - Unit No. 4	SP04	2015
Boiler and FDA Inspection - Unit No. 4	SP04	2015
Refractory - Unit No. 3	SP03	2015
Vacuuming Out Boiler - Unit No. 3	SP03	2015
Overhaul Limestone Mills - Unit No. 3	SP03	2015
Three Cycles (unit off & process when unit is going back on - taking ash out)	SP03	2015
Vacuuming Out Boiler - Unit No. 4	SP04	2015
Refractory - Unit No. 4	SP04	2015
Three Cycles (unit off & process when unit is going back on - taking ash out)	SP04	2015
Outage - Precipitator Inspection and Repairs - Unit No. 1	SP01	2015
Outage - Precipitator Inspection and Repairs - Unit No. 2	SP02	2015
Baghouse Bag Replacement - Unit No. 3	SP03	2015
Hopper Turning Vanes - Unit No. 4	SP04	2015
Scrubber Ball Mill Reline - Unit No. 1 Scrubber	SP21	2015
Pump Repairs - Unit No. 1 Scrubber Maintenance	SP21	2015
Outage - WESP Inspection and Repairs - Unit No. 1 Scrubber	SP21	2015
Pump Repairs - Unit No. 2 Scrubber Maintenance	SP22	2015
Outage - WESP Inspection and Repairs - Unit No. 2 Scrubber	SP22	2015
Scaffolding - WESP - Unit No. 2 Scrubber	SP22	2015
Valve Inspection/Overhaul - Unit No. 3	SP03	2015
Turbine Inspection/Overhaul - Unit No. 3	SP03	2015
Clean Closed Cooling Water Heat Exchangers - Unit No. 4	SP04	2015
Replace Unit No. 1 Condenser	SP01	2015
Peg's Hill Landfill - to Spurlock Landfill	SP00	2015
Waste Water Management System	SP00	2015

Table 8.(2)(a)-11

Spurlock Power Station

Description	Operating Unit	Date
Outage Boiler Inspect/Repair - Unit No. 1	SP01	2016
Rebuild 1A Boiler Water Circulating Pump - Unit No. 1	SP01	2016
Outage Boiler Inspect/Repair - Unit No. 2	SP02	2016
Scaffold Boiler - Unit No. 2	SP02	2016
Scaffold Boiler - Unit No. 3	SP03	2016
Boiler & FDA Inspection - Unit No. 3	SP03	2016
Boiler & FDA Inspection - Unit No. 4	SP04	2016
Boiler Feed Pump Volute Replacement A - Unit No. 4	SP04	2016
Scaffold Boiler - Unit No. 4	SP04	2016
Vacuuming Out Boiler - Unit No. 3	SP03	2016
Refractory - Unit NO. 3	SP03	2016
Three Cycles (unit off & process when unit is going back on - taking ash out)	SP03	2016
Three Cycles (unit off & process when unit is going back on - taking ash out)	SP04	2016
Vacuuming Out Boiler - Unit No. 4	SP04	2016
Refractory - Unit No. 4	SP04	2016
Outage - Precipitator Inspection and Repairs - Unit No. 1	SP01	2016
Outage - Precipitator Inspection and Repairs - Unit No. 2	SP02	2016
Replace Flights on Stacker Reclaimer - Unit No. 1	SP01	2016
Replace Rotor in Crusher - Unit No. 3	SP03	2016
Replace Flights on SR - Unit No. 3	SP03	2016
Pump Repairs - Unit No. 1 Scrubber Maintenance	SP21	2016
Outage - WESP Inspection and Repairs - Unit No. 1	SP21	2016
Scaffolding - WESP - Unit No. 2 Scrubber	SP22	2016
Scrubber Ball Mill Reline - Unit No. 2 Scrubber	SP22	2016
Pump Repairs - Unit No. 2 Scrubber Maintenance	SP22	2016
Outage - WESP Inspection and Repairs - Unit No. 2 Scrubber	SP22	2016
Clean Closed Cooling Water Heat Exchangers - Unit No. 3	SP03	2016
New Baskets (Material and Labor) - Unit No. 2	SP02	2016
Loader No. 2 Kawasaki JLG	SP00	2016

Table 8.(2)(a)-12

Smith CTs - Station

Description	Operating Unit	Date
Generator Inspection - Unit No. 4	SM04	2012
Unit No. 4 CI Inspection	SM04	2012
Dem - Vacuum Truck & Resin	SM00	2012
Control System - HMI	SM00	2012
Capital Spares - New	SM01orSM02	2012
Smith Special Waste Landfill	SM00	2012
New Catalyst for Unit No. 9 and Unit No. 10	SM09&SM10	2012
Paint Tank	SM00	2013
Generator Inspection - Unit No. 5	SM05	2013
Combustion Inspection - Unit No. 5	SM05	2013
Smith Special Waste Landfill	SM00	2013
New Catalyst for Unit No. 9 and Unit No. 10	SM09&SM10	2013
Major Overhaul - ABB Unit No. 2	SM02	2014
Combustion Inspection - Unit No. 7	SM07	2014
Capital Spares to Support C-Inspection For Unit No. 3	SM03	2014
Catalyst Replacement Units No. 9 and No. 10	SM09&SM10	2015
Hot Gas Path Inspection - Unit No. 5	SM05	2016

Table 8.(2)(a)-13

Landfill Gas - Renewable Energy

Description	Operating Unit	Date
Laurel Ridge - Major Overhaul - Unit No. 2		2012
Laurel Ridge - Major Overhaul - Unit No. 3		2012
Hardin County - Major Overhaul - Unit No. 1		2012
Hardin County - Major Overhaul - Unit No. 2		2012
Hardin County - Major Overhaul - Unit No. 3		2012
Mason County - New Wells		2012
Bavarian - Install 5th Unit		2012
Pendleton - Install 5th Unit - Take Unit from Hardin Co 3516		2012
Laurel Ridge - Major Overhaul - Unit No. 5		2013
Pendleton County - Major Overhaul - Unit No. 1		2013
Pendleton County - Major Overhaul - Unit No. 2		2013
Pendleton County - Major Overhaul - Unit No. 4		2013
Bavarian - Install 5th Unit		2013
Pendleton County - Major Overhaul - Unit No. 2		2014
Green Valley - Major Overhaul - Unit No. 2		2015
Bavarian - Major Overhaul - Unit No. 1		2015
Bavarian - Major Overhaul - Unit No. 2		2015
Bavarian - Major Overhaul - Unit No. 3		2015
Bavarian - Major Overhaul - Unit No. 4		2015
NO ITEMS FOR 2016		2016

Table 8.(2)(a)-14

Environmental

Description	Operating Unit	Date
At this time we do not have any items for 2012 - 2016		

SECTION 8.0

INTEGRATED RESOURCE PLANNING

SECTION 8.0
INTEGRATED RESOURCE PLANNING

The following filing requirements are addressed in this section.

807 KAR 5:058 Section 5.(4) Summary of the utility's planned resource acquisitions including improvements in operating efficiency of existing facilities, demand-side programs, nonutility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities.

807 KAR 5:058 Section 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.

807 KAR 5:058 Section 8.(2)(c) The utility shall describe and discuss all options considered for inclusion in the plan including: (c) Expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units.

807 KAR 5:058 Section 8.(2)(d) The utility shall describe and discuss all options considered for inclusion in the plan including: (d) Assessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resources, and other nonutility sources.

807 KAR 5:058 Section 8(3)(c) 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. (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.

807 KAR 5:058 Section 8(3)(d) 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. (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.

807 KAR 5:058 Section 8.(4)(a) 1-5 and 7-11 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: (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; 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.

807 KAR 5:058 Section 8(4)(a)(6) 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: (a) On total resource capacity available at the winter and summer peak. (6) On planned annual generation: Reductions or increases in energy from new conservation and load management or other demand-side programs.

807 KAR 5:058 Section 8(4)(b) 1-4 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: (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.

807 KAR 5:058 Section 8(4)(b)(5) On planned annual generation: 5. Reductions or increases in energy from new conservation and load management or other demand-side programs.

807 KAR 5:058 Section 8(4)(c) 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: (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.

807 KAR 5:058 Section 8.(5)(a) The resource assessment and acquisition plan shall include a description and discussion of: (a) General methodological approach, models, data sets, and information used by the company.

807 KAR 5:058 Section 8(5)(b) The resource assessment and acquisition plan shall include a description and discussion of: (b) Key assumption and judgments used in the assessment and how uncertainties in those assumptions and judgments were incorporated into analyses.

807 KAR 5:058 Section 8.(5)(d) The resource assessment and acquisition plan shall include a description and discussion of: (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.

807 KAR 5:058 Section 8(5)(g) The resource assessment and acquisition plan shall include a description and discussion of: (g) Consideration given by the utility to market forces and competition in the development of the plan.

8.1 Introduction

EKPC's mission is to serve its member-owned cooperatives by safely delivering reliable and affordable energy and related services. One of its strategic objectives is to carefully manage its portfolio of assets and pursue diversity along two axes – one focused on the diversity of the supply resource (including DSM/EE programs) and one focused on the diversity of the ownership model. EKPC continually evaluates power supply alternatives based on the most recent load forecast projections, market expectations, cost criteria and financial data. Alternatives for supplying future resource needs are evaluated on a present worth of revenue requirements basis, as well as a cash flow basis. Any major power supply acquisition will be made via a Request for Proposals process ("RFP"). The RFP process ensures that EKPC has adequately surveyed available resources in the market for delivery to serve the EKPC load in a reliable and affordable manner.

8.2 Resource Planning Methodology Overview

EKPC develops a detailed load forecast every two years, with the most recent being completed in 2010. This forecast was approved by the Board of Directors and the Rural Utilities Service ("RUS"). Due to the struggling economy, EKPC's members' energy usage continued to change significantly during this time period. The load forecast was updated to reflect known conditions in 2011 and that data has been used in this IRP analysis.

Market and fuel prices are updated on a regular basis to ensure that current expectations are being modeled in the analysis. Based on this input data, then the DSM alternatives are evaluated utilizing the standard California tests. Based on those results, the load is modified to reflect the DSM analyses prior to developing the capacity expansion plan. Additionally, EKPC conducted an environmental assessment of its existing units and included those results in this analysis prior to performing the expansion analysis.

8.3 Load Requirements to be Served

The forecast indicates that for the period 2012 through 2026, total energy requirements will increase by 1.6 percent per year. Winter and summer net peak demand will increase by 1.0 percent and 0.9 percent, respectively. Annual load factor is projected to remain relatively flat at around 50 percent. The DSM alternatives that were evaluated result in the following impacts on load:

Table 8.(4)(b)(5)

DSM Impacts
(New Programs)

Year	Impact on Energy Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2012	72,035	26.693	28.289
2013	114,746	47.504	52.218
2014	157,505	66.852	74.399
2015	198,524	80.530	90.911
2016	239,543	94.209	107.423
2017	278,862	104.938	117.915
2018	318,180	115.668	128.408
2019	353,713	125.640	137.970
2020	389,246	135.611	147.532
2021	424,778	145.583	157.093
2022	450,919	153.234	163.737
2023	477,059	160.886	170.380
2024	500,727	167.504	176.714
2025	524,394	174.122	183.048
2026	548,062	180.740	189.381

Details on the specific programs are provided in the DSM Technical Appendix.

8.4 Supply Side 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 calculates the hour-by-hour operation of the generation system including, unit hourly generation and commitment and power purchases and sales, including economy and day ahead transactions, and daily and monthly options. Generating unit input includes expected outages, Monte Carlo forced outages, unit ramp rates, and unit startup characteristics. The RTSim model uses a Monte Carlo simulation to capture the statistical variations of unit forced outages and deratings, load uncertainty, market price uncertainty, and fuel price uncertainty. Monte Carlo simulation requires repeated simulations (iterations) of the time period analyzed to simulate system operation under different outcomes of unit forced outages and deratings, load uncertainty, market price uncertainty, and fuel price uncertainty. The production cost model is simulating the actual operation of the power system in supplying the projected customer loads using a statistical range of inputs.

For this study, the model used the statistical load methodology. There is one set of load data in the model, which was created from the EKPC Load Forecast. Around this forecasted load, a range of distributions created four additional loads to define the high and low range of the potential loads to be examined. 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, natural gas prices, coal prices, and emission costs are correlated to the load data used in the simulation. Five hundred (500) iterations are used in the model simulations.

RTSim's Resource Optimizer was used to perform the optimization of the resource plan. The Resource Optimizer automatically sets up and runs the RTSim production cost model to perform simulations of a large number of potential resource plans to determine the optimum plan. Because the basic RTSim model is used by the Resource Optimizer model, the Resource Optimizer uses the same data and detailed analysis 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. Resources considered included:

REDACTED

Traditional Resources

Table 8.(2)(c)

Resource	**Capacity Type**	**Capacity (MW)**	**Primary Fuel**	Projected Capital Cost (2012$)	
				$/kW	$M
Circulating Fluidized Bed (Future CFB)	Baseload	278	Coal	[redacted]	
Subcritical Pulverized Coal	Baseload	325	Coal	[redacted]	
LMS100 CT	Peaking	97	Natural Gas	[redacted]	
7EA CT	Peaking	98	Natural Gas	[redacted]	
Combined Cycle	Peaking/Intermediate	275	Natural Gas	[redacted]	
Unit Power Purchase	Baseload	200	Coal	N/A	N/A
Unit Power Purchase	Baseload	200	Emission Free	N/A	N/A

Renewable and Partnering Opportunities

EKPC is currently in discussions with hydro-generation developers, solar developers, and distributed generation developers, and wind data is being collected at one site within the EKPC/Member Distribution Cooperative service territory. EKPC is currently working with the University of Kentucky College of Agriculture/Kentucky Grasslands Council on a switchgrass pilot project and continues to utilize the switchgrass produced by this program as an alternative co-firing fuel at one of its coal-fired generation plants. EKPC is currently in discussions with biomass suppliers to evaluate the feasibility of utilizing these renewable fuels as part of a diverse fuel portfolio. EKPC has also helped to fund biomass supply feasibility studies to determine sources of these alternative fuels within the EKPC/Member Distribution Cooperative service territory. EKPC is also working the University of Kentucky Center for Applied Energy Research on an algae project to determine the feasibility of reducing carbon emissions from coal-fired generating facilities.

EKPC is a member of the National Renewables Cooperative Organization (NRCO). NRCO offers cooperatives access to the necessary resources to thoroughly evaluate renewable energy projects without the expense of a dedicated staff. NRCO is active in the renewable energy marketplace on behalf of its members and customers, providing a centralized source of intelligence and opportunities. NRCO evaluates projects, presenting only the most promising to its members. NRCO facilitates transmission constraint modeling, Renewable Energy Credit market analysis, and engineering studies, and packages these into comprehensive recommendations. NRCO offers an established subscription process to participate in specific projects and can help members and customers with the ongoing operations and maintenance of those projects. By aggregating demand amongst multiple power supply cooperatives, NRCO offers developers a venue for efficiently reaching a larger and more diverse set of buyers. To date, EKPC has participated in the evaluation of out-of-state wind projects but has not found any that fit its generation expansion needs.

The Kentucky River lock and dam system is located throughout the EKPC/Distribution Cooperative service territory. EKPC is currently in discussions with developers who have the rights to develop hydro-generation facilities at these locations. In general, the evaluations of the electric power production potential from these proposed facilities show them not to be viable economically as a low cost form of energy production.

There are some, but limited, opportunities with new landfill gas to energy (LFGTE) projects in the EKPC service territory. EKPC currently has six LFGTE facilities and continues to strive to improve performance at each of these facilities while investigating development of other landfills. 2011 generation from the existing EKPC facilities was approximately 95,000 MWh.
In the next several years, approximately 600 MWh of energy per year will be supplied from cogeneration and 90,000 MWh of energy per year from LFGTE (self-generated).

Table 8.(4)(a)
EKPC Projected Capacity Additions and Reserves
(MW)

Year	Other Cap.	Base Load Capacity Additions		Peaking/ Intermediate Cap. Additions		Total Capacity		Reserves		Reserve Margin	
		Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2012	202					3,450	2,823	361	280	14.77%	20.95%
2013	206.4					3,469	2,819	360	279	15.56%	21.37%
2014						3,473	2,819	362	280	15.17%	20.90%
2015						3,523	2,869	368	285	15.03%	20.77%
2016				275	250	3,526	2,847	373	291	13.54%	17.56%
2017						3,526	2,847	377	295	12.13%	15.75%
2018	100					3,626	2,897	382	300	13.79%	15.94%
2019						3,626	2,897	388	305	12.10%	14.07%
2020	100					3,726	2,947	392	308	13.96%	14.73%
2021						3,726	2,947	400	315	11.90%	12.45%
2022	100					3,826	2,997	405	319	13.24%	12.60%
2023				275	250	4,101	3,247	412	325	19.37%	19.87%
2024						4,101	3,247	418	330	17.82%	18.13%
2025						4,101	3,247	425	336	15.79%	16.10%
2026						4,101	3,247	432	341	13.99%	14.22%

Notes:
Other Capacity is composed of the following:
2MW x 2 expansion of Landfill-Gas-To-Energy and 2.4MW new LFGTE site
200MWx 2 Winter Seasonal Peaking Purchase
100MW x 3 Winter Seasonal Peaking Purchase

A minimum and maximum amount of capacity to be added by the model is 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 2500 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 2026. The results in the following table, Table 8.3, show the five lowest cost plans out of 2500 plans simulated.

Table 8.5 (a)

DSM AFFECTED BASE RESOURCE OPTIMIZATION
Total tries: 2500
Top Cases with specific resource and in-service date

Case 1:		Case 4:	
Seasonal Peaking Purchase	1, 1,2012	Seasonal Peaking Purchase	1, 1,2012
Seasonal Peaking Purchase	1, 1,2013	Seasonal Peaking Purchase	1, 1,2013
Combined Cycle	1, 1,2016	Renewable Hydro Project	1, 1,2014
Seasonal Peaking Purchase	1, 1,2018	Renewable Hydro Project	1, 1,2015
Seasonal Peaking Purchase	1, 1,2020	PEAKING CT	1, 1,2016
Seasonal Peaking Purchase	1, 1,2022	Seasonal Peaking Purchase	1, 1,2016
Combined Cycle	1, 1,2023	Combined Cycle	1, 1,2017
		PEAKING CT	1, 1,2023
		Combined Cycle	1, 1,2025
Case 2:		Case 5:	
Seasonal Peaking Purchase	1, 1,2012	Seasonal Peaking Purchase	1, 1,2012
Seasonal Peaking Purchase	1, 1,2013	Seasonal Peaking Purchase	1, 1,2013
Combined Cycle	1, 1,2016	PEAKING CT	1, 1,2016
PEAKING CT	1, 1,2018	Seasonal Peaking Purchase	1, 1,2016
PEAKING CT	1, 1,2021	Environmental Mod to Existing Unit	1, 1,2016
Combined Cycle	1, 1,2022	Combined Cycle	1, 1,2019
		Emission Free PPA	1, 1,2024
Case 3:			
Seasonal Peaking Purchase	1, 1,2012		
Seasonal Peaking Purchase	1, 1,2013		
Renewable Hydro Project	1, 1,2015		
Combined Cycle	1, 1,2016		
PEAKING CT	1, 1,2019		
Seasonal Peaking Purchase	1, 1,2021		
Combined Cycle	1, 1,2023		

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*
110	0	2012	Base						
			Interm						
			Pking	200	200	200	200	200	200
385	275	2013	Base						
			Interm						
			Pking	200	200	200	200	200	200
671	286	2014	Base						
			Interm						
			Pking				7		
960	289	2015	Base						
			Interm						
			Pking			30	30		
1550	590	2016	Base					110	
			Interm	275	275	275	200	100	275
			Pking					100	
2180	630	2017	Base						
			Interm				275		
			Pking						
2855	675	2018	Base						
			Interm						
			Pking	100	100				100
3580	725	2019	Base						
			Interm					275	
			Pking			100			
4342	762	2020	Base						
			Interm						
			Pking	100					100
5168	826	2021	Base						
			Interm						
			Pking		100	100			
6045	877	2022	Base						
			Interm		275				
			Pking	100					100
6982	937	2023	Base						
			Interm	275		275			275
			Pking				100		
7967	985	2024	Base					200	
			Interm						
			Pking						
9016	1049	2025	Base						

			Interm				275		
			Pking						
10124	1108	2026	Base						
			Interm						
			Pking						

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

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 are 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 correlated 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.

8.5 Reliability Criteria and Projected Capacity Needs

As stated in Section 6, Transmission and Distribution Planning, EKPC is a member of SERC Reliability Corporation ("SERC"). SERC promotes the development of reliability and adequacy arrangements among the systems; participates in the establishment of reliability standards; administers a regional compliance and enforcement program; and provides a mechanism to resolve disputes on reliability issues. As a member of SERC, EKPC plans capacity to meet its peak load expectations plus a 12 percent reserve margin. See the table below for the total amount of capacity expected to be required on the EKPC system.

Table 8.(4)(a)
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
2012	3,006	2,334	361	280	3,367	2,614	3,250	2,821	117	-207
2013	3,002	2,323	360	279	3,362	2,602	3,067	2,813	295	-211
2014	3,016	2,332	362	280	3,378	2,612	3,067	2,813	311	-201
2015	3,063	2,376	368	285	3,431	2,661	3,117	2,863	314	-202
2016	3,106	2,422	373	291	3,479	2,713	2,845	2,591	634	122
2017	3,145	2,460	377	295	3,522	2,755	2,845	2,591	677	164
2018	3,187	2,499	382	300	3,569	2,799	2,845	2,591	724	208
2019	3,235	2,540	388	305	3,623	2,845	2,845	2,591	778	254
2020	3,270	2,569	392	308	3,662	2,877	2,845	2,591	817	286
2021	3,330	2,621	400	315	3,730	2,936	2,845	2,591	885	345
2022	3,379	2,662	405	319	3,784	2,981	2,845	2,591	939	390
2023	3,436	2,709	412	325	3,848	3,034	2,845	2,591	1,003	443
2024	3,481	2,749	418	330	3,899	3,079	2,845	2,591	1,054	488
2025	3,542	2,797	425	336	3,967	3,133	2,845	2,591	1,122	542
2026	3,598	2,843	432	341	4,030	3,184	2,845	2,591	1,185	593

Notes:
1. Existing Resources includes 170MW from SEPA throughout the period.
2. The impact of existing and new DSM programs is included in the load forecast.
3. There is no capacity from non-utility sources.
4. Dale 1-4 and Cooper 1 units are assumed to be retrofitted / replaced with environmentally compliant technology.

Table 5.(4)
EKPC Projected Major Capacity Additions
(MW)

Year	Baseload Capacity	Peaking/Intermediate Capacity	Cumulative Capacity Additions
2012			
2013			
2014			
2015			
2016		275	275
2017			
2018			
2019			
2020			
2021			
2022			
2023		275	275
2024			
2025			
2026			

* Additions are assumed to go in service in October prior to the year shown.

Table 8.(3)(c)

Power Transactions (GWH)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Power Purchases	1545	1198	1130	622	358	391	880	1008	2023	2085	2064	1678	1745	1896	2004
Market Purchase	150	295	357	291	189	217	184	151	43	93	139	220	304	370	423
SEPA	252	258	259	255	259	258	262	259	254	257	257	258	259	259	258
Total Purchases	1947	1750	1746	1168	806	866	1326	1418	2321	2436	2460	2156	2308	2524	2685
Market Power Sales	207	113	113	155	438	414	378	514	783	602	545	625	530	441	399

Table 8.(3)(d)

Non-Utility Generation (GWH)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Non-Utility Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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

In the next several years, approximately 600 MWh of energy per year will be supplied from cogeneration and 90,000 MWh of energy per year from LFGTE (self-generated).

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

Forecast Energy	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Requirements (GWh) (as modeled)	13,192.14	13,235.24	13,423.93	13,713.02	14,014.60	14,220.28	14,467.08	14,753.58	15,000.39	15,296.52	15,581.62	15,879.13	16,164.51	16,459.36	16,743.95
Generation (GWH)															
Coal	9,856.53	10,529.70	11,658.00	12,958.70	14,230.60	15,040.60	15,477.90	16,499.60	16,960.40	17,867.60	18,164.80	18,326.20	18,756.20	19,661.30	19,903.30
Natural Gas	1313.9	904.3	961.8	1467.0	2466.2	2505.2	2152.5	2390.9	1968.3	1920.1	2038.3	2616.0	2594.1	2596.9	2625.6
Landfill Gas	141.3	167.4	185.5	185.5	186.0	185.5	185.5	185.5	186.0	185.5	185.5	185.5	186.0	185.5	185.5
Total	11,311.66	11,601.38	12,805.33	14,611.21	16,882.77	17,731.34	17,815.92	19,075.94	19,114.69	19,973.18	20,388.63	21,127.67	21,536.29	22,443.71	22,714.43
Purchases (GWH)															
Firm Purchases-SEPA	252	258	259	255	259	258	262	259	254	257	257	258	259	259	258
Firm Purchases-Other Utilities	649	438	438	0	0	0	0	0	0	0	0	0	0	0	0
Firm Purchases-Non-Utilities	934	597	523	467	256	282	118	156	99	127	114	92	103	123	142
Total	1835	1293	1219	722	515	540	380	415	353	385	371	350	362	382	400

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Table 8.(4)(c)

Fuel Input (1,000s MBTU)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Coal	97,969	104,394	105,513	109,426	108,709	109,470	110,360	111,169	111,441	111,585	112,101	112,728	113,192	112,913	113,054
Natural Gas	13,063	9,022	9,614	13,722	20,559	21,092	17,769	20,085	16,086	15,925	16,413	19,882	19,787	19,894	20,311
Total	111,032	113,416	115,127	123,149	129,269	130,562	128,129	131,254	127,527	127,509	128,514	132,610	132,979	132,807	133,365
Fuel Input (Physical Units)															
Coal (1,000s Tons)	4,413	4,694	4,730	4,911	4,882	4,915	4,957	4,995	5,010	5,029	5,064	5,107	5,132	5,126	5,147
Natural Gas (1,000s mcf)	12,875	8,892	9,476	13,525	20,263	20,789	17,513	19,796	15,854	15,696	16,177	19,596	19,502	19,607	20,019

807 KAR Section 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 only operates within the state of Kentucky.

SECTION 9.0

COMPLIANCE PLANNING

SECTION 9.0
COMPLIANCE PLANNING

9.1 Introduction

807 KAR 5:058 Section 8(5)(f) The resource assessment and acquisition plan shall include a description and discussion of: (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.

EKPC is currently in compliance with the following CAA rules:

- New Source Performance Standards (NSPS);
- New Source Review (NSR);
- Title IV of the CAA and the rules governing pollutants that contribute to Acid Deposition (Acid Rain program);
- Title V operating permit requirements (Title V);
- Summer ozone trading program requirements promulgated after EPA action on Section 126 petitions and the Ozone SIP Call (Summer Ozone program);
- Clean Air Interstate Rule (CAIR).

On January 28, 2004, the United States filed a complaint alleging that EKPC was out of compliance with the Prevention of Significant Deterioration provisions in Part C of Subchapter I of the Act, 42 U.S.C. §§ 7470-92 (NSR); NSPS, Title V and the federally-enforceable State Implementation Plan ("SIP") developed by the Commonwealth of Kentucky. EKPC and the United States settled this action and entered into a Consent Decree memorializing the terms of the settlement which was entered by the Court on September 27, 2007 (NSR CD).

On June 30, 2006, the United States and the Commonwealth of Kentucky filed a complaint alleging that EKPC was in violation of the Acid Rain Program and Title V. This matter was also settled and the Consent Decree capturing the terms of the settlement was entered by the Court on November 30, 1997 (Acid Rain CD).

EKPC in partnership with the Environmental Protection Agency and the Kentucky Environmental Cabinet has worked diligently to implement the requirements of these two Consent Decrees and is in compliance with each. The relevant provisions of these CDs are in the process of being added to EKPC's Title V permits for Spurlock, Cooper and Dale stations.

New CAA Rules

Looking forward to the 15 years covered by this plan, EKPC anticipates complying with the following future rules or existing CAA rules that will generate future rules or requirements:

- Green House Gas (GHG) Tailoring Rule revisions to NSR;
- Cross-State Air Pollution Rule (CSAPR) promulgated by EPA on remand of CAIR with the goal of replacing CAIR;
- Electric Generating Unit Maximum Achievable Control Technology rule. EPA named this rule the Mercury and Air Toxics Standards (MATS) when the final rule was issued in December of 2011;
- National Ambient Air Quality Standards (NAAQS) for Sulfur Dioxide (SO_2), Nitrogen Dioxide (NO2), Carbon Monoxide (CO), Ozone, Particulate Matter (PM), Particulate Matter 2.5 microns or less (PM 2.5) and Lead;
- Clean Air Visibility (Regional Haze) rule to protect National Parks and pristine areas designated as Class I areas by EPA.

MATS Rule

On March 16, 2011, EPA issued the proposed EGU MACT rule to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. EPA finalized the MATS rule on December 16, 2011 to reduce emissions of heavy metals, including mercury (Hg), arsenic, chromium, and nickel, and acid gases, including hydrogen chloride (HCl) and hydrogen fluoride (HF). The MATS allows sources to control surrogate emissions to demonstrate control of HAP metals and HAP acid gases. Non-Hg metallic toxic air pollutants are represented by PM emission limits because these metals travel in particulate form in boiler gas paths. HCL and /or SO_2 are surrogates for all acid gas HAPs since they are controlled by the same mechanisms.

Under MATS mercury emissions are subject to limits and units must measure mercury emissions directly to demonstrate compliance. EGUs must comply with the mercury, SO_2 or HCL, and PM limits in the MATS beginning in the Spring of 2015. If units are in the process of installing additional pollution control equipment and cannot complete the work by this initial compliance date, an additional year to begin compliance can be granted by Kentucky Cabinet.

EKPC has conducted emissions testing of its units to determine the best way to achieve compliance with the MATS rule. This testing is ongoing and is being conducted as part of an extensive engineering effort to ensure that EKPC's units comply with this rule. The pollution control upgrades on Spurlock 1 and 2 and Cooper 2 as part of NSR CD compliance place EKPC's units ahead of most EGU units for MATS compliance. Likewise, EKPC's new units (Spurlock 3 and 4) are equipped with Best Available Control Technology (BACT) and are likely to meet the MATS rule limits without additional controls.

The Cross-State Air Pollution Rule

On July 6, 2011 the EPA finalized CSAPR to require 27 states (Kentucky included) and the District of Columbia to significantly improve air quality by reducing power plant emissions that contribute to ozone and fine particle pollution in other states. This rule replaces EPA's 2005 CAIR rule that was remanded to EPA by the U.S. District Court of Appeals. CSAPR requires significant reductions in SO_2 and nitrogen oxides (NO_X) emissions that cross state lines. These pollutants react in the atmosphere to form fine particles and ground-level ozone and are transported long distances, making it difficult for other states to achieve the National Ambient Air Quality Standards (NAAQS). The rule called for the first phase emission reduction compliance to begin January 1, 2012 for annual SO_2 and NO_X and May 1, 2012 for ozone season NO_X. The second phase of SO_2 reductions was to begin January 1, 2014.

On December 30, 2011, CSAPR was stayed by the United States Court of Appeals for the District of Columbia in response to industry petitions challenging the rule. Briefing and oral argument in the appeal will be complete on April 13, 2012 and the Court will issue a decision sometime later in 2012. The Court has ordered EPA to continue to administer CAIR while CSAPR is stayed. The earliest that EKPC and other utilities may be subject to CSAPR is 2013 and it is likely to be later. CSAPR is likely to be remanded to EPA for revision which will further delay the CSAPR rule.

GHG Tailoring Rule

On May 13, 2010, the EPA issued a final rule that establishes emission thresholds for addressing GHG emissions from stationary sources under the CAA permitting programs. The GHG Tailoring rule sets GHG thresholds for applicability under the NSR rules and Title V program. GHGs are considered one pollutant for NSR, which is composed of the weighted aggregate of CO_2, N_2O, SF_6, HFCs, PFCs, and methane (CH_4) into a combined CO_2 equivalent (CO_{2e}).

If any of the stations undergo a modification that would result in a net increase of 75,000 tons per year or more of CO_2 equivalents (CO_{2e}), EKPC must obtain an NSR permit for the modification which includes the analysis of Best Available Control Technology (BACT) for GHGs and the implementation of BACT on the modified unit.

EKPC routinely analyzes all capital projects for the potential need to undergo pre-construction NSR permitting. This NSR review process has been expanded to include an analysis of GHG emissions. EKPC's NSR CD also includes a future covenant from EPA that allows EKPC some flexibility with respect to the NSR rules until December 31, 2015.

National Ambient Air Quality Standards (NAAQS)

EPA recently promulgated revisions to the NAAQS for fine particulate matter ($PM_{2.5}$), 1-hour SO_2 and 1-hour nitrogen dioxide (NO_2) that are substantially lower than the existing NAAQS. EPA and the Kentucky Cabinet will work together to determine whether the Commonwealth is in compliance with these standards, as well as existing NAAQS for Ozone, CO, Lead and PM, by analyzing data from monitors stationed across Kentucky that measure the concentration of these pollutants in the air and by computer models that estimate concentrations of these pollutants. If a county or counties are designated to be in nonattainment for a NAAQS, the Cabinet will work with major sources contributing to nonattainment to implement Reasonably Achievable Control Technology (RACT) retrofits to bring the areas into attainment. Further, no permits can be approved by the Cabinet without a NAAQS compliance demonstration which involves submitting computer modeling of emissions that shows that the Commonwealth will stay in attainment despite the permitted activity.

CO

In January 2011, EPA proposed to retain the current primary CO NAAQS of 9 ppm (8-hour) and 35 ppm (1-hour). This rule was finalized in August 2011. As of September 27, 2010, all CO areas have been designated as maintenance areas.

SO_2

EPA revised the primary SO_2 NAAQS in June 2010 to a one-hour standard of 75 ppb. On June 2, 2011, Kentucky made area designation recommendations for the new SO_2 standard. The State recommended that Jefferson County be designated as a non-attainment area and that the remainder of the state be designated as unclassifiable or attainment. Area designations for the new SO_2 standard are expected to be finalized in June 2012. The current secondary 3-hour SO_2 standard is 0.5 ppm. EPA proposed to retain both the SO_2 and NO_2 secondary standards in July 2011 and this rule has not yet been finalized.

NO_2

EPA revised the primary NO_2 NAAQS in January 2010. The new primary NAAQS for NO_2 is a one-hour standard of 100 ppb. EPA retained the existing primary and secondary annual standard of 53 ppb. On January 11, 2011, Kentucky made area designation recommendations for the new NO_2 standard and recommended that areas with monitors showing compliance be designated as in attainment and that the remainder of the state be designated as unclassifiable. On June 28, 2011, EPA responded indicating its intent to designate the entire country as unclassifiable/attainment due to the limited availability of monitoring data. On August 3, 2011, the state responded to EPA's proposed revision requesting that the areas that show compliance with area monitors be designated as attainment and that the remainder of the state be designated as unclassifiable/attainment. Area designations for the new NO_2 standard were expected to be finalized in January 2012 and remain outstanding. Under the new rule, a new monitoring system will be implemented to measure NO_2 concentrations. Three years after the new monitoring system is implemented, EPA will re-evaluate the existing data and re-designate areas as necessary (2016/2017). An initial compliance deadline of 2021/2022 is contemplated.

Ozone

Currently, the 1997 8-hour ozone NAAQS of 80 ppb is in place. In 2008, EPA finalized a revised rule, lowering the standard to 75 ppb. This standard was challenged in court, and as a result EPA undertook a voluntary review of the 2008 ozone NAAQS. The litigation challenging the 2008 standard was held in abeyance while the standard was re-evaluated. In January 2010, EPA proposed that the standard be lowered even further to a range within 60-70 ppb. At the same time, EPA proposed a new seasonal secondary standard in the range of 7 to 15 ppm. Ultimately, the proposed final rule was withdrawn by EPA at the request of President Obama. The standard will now be reviewed during the course of its normal five year review. As such, a new ozone standard is expected to be proposed in the fall of 2013 and finalized during the summer of 2014. In the interim, EPA has turned back to implementation of the 2008 standard and plans to make area designations by May 31, 2012. These area designations will be based on the recommendations made by states in 2009. In 2009, Kentucky recommended that a number of counties be designated as nonattainment. In 2011, Kentucky updated these recommendations and recommended that the entire state be designated as attainment or attainment/unclassifiable. In December 2011, EPA revised the state's recommendation and indicated its intent to designate Boone, Campbell and Kenton counties as non-attainment and the remainder of the state as unclassifiable/attainment.

Particulate Matter ($PM_{2.5}$)

In 1997, EPA adopted the 24-hour fine particulate NAAQS ($PM_{2.5}$) of 65 $\mu g/m^3$ and an annual standard of 15 ug/m3. In 2006, EPA revised this standard to 35 $\mu g/m^3$, and retained the existing annual standard. In December 2004, the following counties were designated as nonattainment under the 1997 standard: Boone, Campbell, Kenton, Boyd, Lawrence (partial), Bullitt, and Jefferson. This was modified in April 2005 and in October of 2009, the entire state of Kentucky was designated as unclassifiable/attainment under the 2006 standard.

Lead

In October 2008, EPA strengthened the primary lead NAAQS from 1.5 $\mu g/m^3$ to 0.15 $\mu g/m^3$. EPA has designated the state of Kentucky as unclassifiable/attainment for the lead NAAQS.

Currently, EKPC's units are not located in any areas that are predicted to be in nonattainment. EKPC anticipates that existing controls on its coal generation and new controls and compliance strategies adopted to comply with the MATS rule and CSAPR will ensure that the fleet will also comply with any future NAAQS requirements.

Regional Haze Rule

The Regional Haze Rule has triggered the first in a series of once-per-decade reviews of impacts on visibility at pristine areas such as national parks, with a focus in the first review on large emission sources put into operation between 1962 and 1977. This first review, just now being completed, targets Best Available Retrofit Technology (BART) controls for SO_2, NO_x, and PM emissions. The threshold for being exempt from BART review is very stringent, such that coal-fired electrical generating stations are almost universally subject to BART.

A BART assessment includes an evaluation of SO_2 controls and post-combustion NO_x controls. Cooper Units 1 and 2 are the only EKPC units subject to BART. EKPC has submitted its Regional Haze compliance plans to the Cabinet and the Cabinet submitted the plan for the Commonwealth to EPA who has proposed to adopt it formally into Kentucky's State Implementation Plan (SIP). EKPC is in the process of installing SO_2, NOx and PM controls on Cooper 2 to comply with the NSR CD, the Regional Haze rule, MATS, CSAPR and any NAAQS requirements. EKPC has committed in the Regional Haze compliance plan to install parallel controls on Cooper 1.

Additional Non-CAA New Rules

For completeness EKPC is providing a summary of new Clean Water Act (CWA) rules and the proposed Coal Combustion Residuals (CCR) rule.

New CWA 316(b) rule

EPA published its proposed rule to regulate cooling water intake structures (CWIS) at existing facilities on April 20, 2011. The rule is scheduled to be finalized in July 2012 and will include several implementation milestones. The proposed rule will set requirements that establish Best

Technology Available (BTA) for minimizing adverse environmental impact from impingement mortality and entrainment mortality due to operation of the CWIS.

Impingement mortality results from impingement of aquatic organisms on the cooling water intake structure, typically traveling water screens used to prevent debris from entering the cooling water circulating pumps and the steam condenser tubes. Entrainment mortality results when organisms that are entrained through the cooling water intake structure die due to the combined effects of mechanical stress from the pumps, thermal stresses from the heat transferred from the condensers, and application of any biocides.

Impingement Mortality

The rule requires that all facilities with existing traveling screens retrofit them with "fish-friendly" Ristroph modifications, consisting of smooth screen mesh, fish buckets installed at the base of each screen panel, low-pressure washes for fish located before the high pressure wash for debris, separate collection troughs for fish and debris with guard rails or barriers, and a fish return system. Continuous rotation of the traveling screens is not required by the proposed rule but this technology may be necessary in the event that numerical impingement mortality standards are relevant to a site.

The intake velocity then dictates the path for compliance with the impingement mortality portion of the rule. For facilities with traveling screens, intake velocity is generally interpreted to be equivalent to the through-screen velocity; otherwise it is the velocity at the point of withdrawal. Facilities that can demonstrate that design intake velocities are equal to or less than 0.5 feet per second (fps) are not subject to the numeric impingement mortality performance standards and are not required to conduct impingement monitoring. Facilities must operate and maintain their intake screen such that no more than 15 percent of the surface area is occluded by debris, and they must ensure that impingeable fish have the means to escape or be returned to the source waterbody. Facilities that cannot demonstrate that the design intake velocity is no more than 0.5 fps must conduct compliance monitoring for intake velocity to demonstrate the actual intake velocity remains below 0.5 fps.

Facilities that have through-screen velocities in excess of 0.5 fps must conduct bi-weekly impingement monitoring and are required to achieve impingement mortality rates of less than 12 percent on an annual basis and less than 31 percent on a monthly basis. The rule indicates that the numerical impingement mortality performance standards apply to "species of concern" but is ambiguous on the definition of this term. There is some question as to whether these performance standards will be included in the final rule.

Entrainment Mortality

Under the proposed rule, facilities that are equipped with closed cycle cooling, including wet or dry cooling towers or closed loop cooling ponds, most likely will be considered to be BTA for entrainment, but the permitting authority will still need to make that determination. Facilities not so equipped must determine if their actual intake flow is greater than 125 million gallons per day (MGD). Under the proposed rule, facilities that have withdrawn an average of over 125 MGD over the last three years would have to prepare four documents evaluating the feasibility, costs, and benefits of potential measures to reduce entrainment and entrainment mortality. The proposed rule does not have a blanket requirement to mitigate entrainment but leaves the decision to require such measures to the permitting authority (e.g., the Kentucky Cabinet). The studies required for facilities with actual intake flows greater than 125 MGD include:

- An Entrainment Characterization Study (proposed at 40 CFR 122.21(r)(9) of the draft rule);
- A Comprehensive Technical Feasibility and Cost Evaluation Study (proposed at 40 CFR 122.21(r)(10));
- A Benefits Evaluation Study (proposed at 40 CFR 122.21(r)(11)); and
- A Non-Water Quality and Other Environmental Impacts Study (proposed at 40 CFR 122.21(r)(12)).

The proposed rule would require that at least two technologies (closed cycle cooling and the use of fine mesh panels on the traveling screens) be evaluated for cost, feasibility, effectiveness, monetized and non-monetized benefits. The Entrainment Characterization Study must be submitted to the permitting authority for review and approval. Under the proposed rule, each of the studies also requires peer review by a third party. Based on the findings of these four studies, the permitting authority establishes BTA on a case-by-case basis. Facilities with actual intake flows less than 125 MGD are not required to perform the studies but are still subject to a BTA determination by the permitting authority. Under the proposed rule, new units placed into service at existing facilities would be required to reduce entrainment mortality to levels commensurate with the use of closed cycle cooling. Retrofitting with closed cycle cooling at an existing facility will be very expensive and will likely result in a very adverse cost-to-monetized benefit ratios. On the other hand, achieving levels of entrainment mortality reduction commensurate with closed cycle cooling using other technologies may be very difficult.

Potential Spurlock Station 316(b) Requirements

Spurlock Station Cooling Water System Description

The cooling system consists of four evaporative mechanical draft cooling towers with a combined makeup water requirement of 21.6 MGD. Spurlock Station withdraws water for cooling tower makeup and other purposes from the Ohio River. The station's CWIS consists of two submerged passive wedgewire intake screens, an intake sump, and three vertical makeup water pumps. The screens consist of welded Type 304 stainless steel wedgewire strainer elements with circumferential 1/8 inch slot construction. They each have a design capacity of 14,050 gallons per minute (gpm) and a maximum through-slot velocity 0.5 fps at design flow. The calculated velocity through the strainer elements is 0.466 fps. Debris collected in the screen is periodically cleaned by a compressed air backwash system which is capable of producing a backwash pressure of 150 pounds per square inch (psi).

Makeup water is withdrawn through the two submerged intake screens by gravity and flows into the intake sump. Each pump is rated for 5,000 gpm at 141.5 feet of head and is driven by a 250 hp/1.15 service factor, 1,180 rpm motor manufactured by General Electric. The cooling water intake structure does not employ traveling water screens.

Spurlock Station Compliance Options

Spurlock Station is not equipped with traveling screens and therefore is not required to retrofit with Ristroph modifications to its CWIS. The station's passive screens have a maximum design through-screen velocity of 0.5 fps and a calculated through-screen velocity of 0.466 fps; therefore under the proposed rule the station would not be required to perform impingement monitoring or be subject to the impingement mortality performance standards. The station would need to submit documentation of meeting the through-screen velocity threshold (i.e., the

Impingement Mortality Reduction Plan required under Section 122.21(r)(6)), which would include velocity monitoring records and documentation of the technologies and operational measures taken to ensure actual intake velocity does not exceed 0.5 fps.

Both the design intake flow (21.6 MGD) and actual intake flow (5.9 MGD for the period January 2008 through December 2010) are significantly less than the 125 MGD actual intake flow threshold that would require the station to conduct the Entrainment Characterization Study and other analyses described in Section 2.1.2. It is still subject to a site-specific determination of BTA for entrainment by the Kentucky Cabinet on a Best Professional Judgment basis. It is unlikely that additional controls for entrainment mortality will be necessary because:

- The facility uses closed cycle cooling which is considered to achieve high levels of reduction in cooling water flow and entrainment rates;
- The cooling water intake structure would be compliant with the requirements of the 316(b) Phase I rule for new facilities;
- The quantity of cooling water relative to the Ohio River discharge is very small indicating that entrainment losses from the ecosystem will be minimal; and
- Passive wedgewire screens were classified as a pre-approved BTA technology in prior EPA rulemakings.

Potential Cooper Station 316(b) Requirements

Cooper Station Cooling Water System Description

The cooling system at the Cooper Station consists of two condensers equipped with once-through cooling systems. The permanent intake structures are located in Lake Cumberland approximately 25 feet from the shoreline and withdraw water at an elevation of 671 feet mean sea level (MSL), which under full pool conditions (723 feet MSL) is approximately 52 feet below the water surface. Ongoing repairs at Wolf Creek Dam which controls the water level in Lake Cumberland required that the lake elevation be lowered to 680 feet MSL, resulting in higher intake temperatures due to the closer proximity of warmer surface waters at the intake. A floating barge intake structure is currently in place during the drawdown period, but no information was available to describe its configuration or operation. A cooling tower was also retrofitted to Unit 2 and brought online in 2009, and is operated during warm water months due to these elevated intake temperatures. For the purposes of planning for Section 316(b) compliance, EKPC anticipates that the reservoir level will return to approximately full pool following the conclusion of dam repairs in 2013.

The once-through cooling water system at Cooper Station has a design intake flow of approximately 208 MGD. Unit 1's intake has a design capacity of 89.2 MGD and consists of two 42-inch intake pipes, two hydraulic turbine pumps to lift water to the elevated screen house, two conventional traveling screens, two 32,000 gallon per minute (gpm) circulating water pumps, and a fish return system. The conventional traveling screens are 10 feet wide, have 3/8-inch screen openings, and a minimum maintained wetted screen depth of 30 feet. The estimated through-screen velocity at design flow is 0.34 fps. The estimated velocity at the two 42 inch intakes located in the lake at design flow is 7.2 fps.

Unit 2's intake has a design capacity of 118.9 MGD and consists of two 48-inch intake pipes, two hydraulic turbine pumps to lift water to the elevated screen house, two conventional traveling screens, two 40,000 gpm circulating water pumps, and a fish return system. The traveling screens are 10 feet wide, have 3/8-inch screen openings, and a minimum maintained wetted screen depth of 30 feet. The estimated through-screen velocity at design flow is 0.45 fps. The estimated through-pipe velocity at the two 48 inch intakes located in the lake at design flow is 7.3 fps.

An 8-cell cooling tower was also retrofitted to Unit 2 in 2007 and brought online in 2009, and is operated during warm water months to offset the elevated intake temperatures at the surface due to the lower lake levels. When operating, the cooling tower has an average makeup water demand of 3.25 MGD, substantially reducing the cooling water supply requirement for Unit 2 and the overall demand for the station. The estimated through-pipe velocity at the Unit 2 intakes drops to 0.2 fps during cooling tower operation and the through-screen velocity drops to an estimated 0.012 fps.

The traveling screens are typically manually operated twice per day but may operate more frequently when the debris loads are high and increased differential pressure across the screens triggers automatic operation. Fish and debris are washed into a trough below the traveling screens and then conveyed through a pipe which releases fish back into the river.

Cooper Station Compliance Options

Impingement Mortality

Cooper Station is equipped with traveling screens and therefore is required by the draft rule to retrofit with Ristroph modifications to its CWIS. The calculated through-screen velocities are less than the 0.5 fps threshold; therefore the station would not be required to comply with the proposed impingement mortality restrictions (if retained in the final rule) unless the definition of "intake velocity" is changed in the final rule to include the inlet pipes.

Entrainment Mortality

Cooper Station has measured the actual intake flow (AIF) for the past three years (2008 through 2010) to be 110 MGD. These actual flows are less than the 125 MGD actual intake flow threshold that would require the station to conduct the Entrainment Characterization Study and other analyses. However, it should be noted that the AIF is likely reduced by operation of the cooling towers for Unit 2 during warmer months and its reduced cooling water requirements (3.25 MGD), substantially less than the once-through design flow of 118.9 MGD.

Potential Dale Station 316(b) Requirements

Dale Station Cooling Water System Description

The cooling system at the Dale Power Station consists of once-through cooling systems using water withdrawn from the east bank of the Kentucky River at river mile 177.5. The CWIS has a total design capacity of 219 MGD and consists of a stop log and trash rack structure, a screen well, six traveling screens, and six circulating water pumps. The trash rack is located at the river bank, while the traveling screens are located approximately 500 feet from the bank.

River water is withdrawn through the stop log and trash rack structure into two 72-in diameter pipes at an intake invert elevation of 557 feet mean sea level (MSL). Based on available river profiles from the U.S. Army Corps of Engineers (USACE) Louisville District, the normal pool elevation at this point in the Kentucky River (Pool 10) is approximately 567.6 feet MSL. This normal pool elevation results in a typical water depth at the inlets of approximately 10 feet.

The pipes convey river water into the screen well at the screen house structure. The screen house structure contains the screen well, traveling screens, and circulating water pumps for all four operating units. Two screens with respective pumps provide cooling water for Units 1 and 2. The remaining four screens and pumps provide cooling water for Units 3 and 4. The conventional traveling screens have 3/8-inch mesh, a wetted depth of 13 feet, and are equipped with high-pressure washes and troughs that flow into an open channel that flows back into the river.

Units 1 and 2 circulating water pumps have a capacity of 22,000 gpm (31.7 MGD) each. Based on a screen width of 4 feet, 13-foot wetted depth, and a 68 percent open area, the estimated through-screen velocity for Units 1 and 2 is 1.39 feet per second (fps). Unit 3 and 4 circulating water pumps each have a capacity of 27,000 gpm (38.9 MGD). Based on a screen width of 9 feet, 13-foot wetted depth, and a 68 percent open area, the estimated through-screen velocity is 0.76 fps.

The circulating water pumps for Units 1 and 2 operate when the units are in operation. Since they discharge to a common header, either pump can be used when only one unit is operating. If both screens are used when only one unit is operating, the through-screen velocity is halved (approximately 0.7 fps). The four circulating water pumps for Units 3 and 4 also discharge to a common header, and all four pumps are typically used for approximately six months of the year. During the colder months of the year, three pumps are sufficient to meet the heat rejection requirements for Units 3 and 4, resulting in a 25 percent reduction in flow across the four traveling screens serving Units 3 and 4 and a through-screen velocity of 0.57 fps.
The screens are operated automatically based on head-loss triggers and typically rotate two hours per day. During periods when debris loads are high the screens may operate continuously. A trough below each traveling screen conveys fish and debris washed from the screens into a pipe which leads from the screenhouse to a trough which returns fish to the Kentucky River through an open, rip-rap lined channel.

Dale Station Compliance Options

Impingement Mortality

Dale Station is equipped with traveling screens and therefore is required to retrofit with Ristroph modifications to its CWIS. The through-screen velocities also exceed the 0.5 fps threshold; therefore the station will be required to comply with the proposed impingement mortality restrictions (if retained in the final rule) unless these intake velocities can be reduced.
Potential options to decrease intake velocities include:

- Additional once-through traveling screens or retrofit with dual flow traveling screens to increase the screen area of the traveling screens;
- Reduce approach velocity at intake inlets in the river;
- Installation of wedgewire screens; and
- Flow reduction through retrofit of cooling towers.

Entrainment Mortality

Dale Station has measured the actual intake flow (AIF) for the past three years (2008 through 2010) to be 148 MGD. These actual flows are greater than the 125 MGD threshold that would require the station to conduct the Entrainment Characterization Study and other analyses. With intake flows greater than 125 MGD, the studies required under 40 CFR 122.21(r)(9) through (12) would need to be undertaken and BTA for entrainment mortality established for Dale Station on a site-specific basis. There are three potential technology-based compliance scenarios for reducing entrainment mortality at the station. The station could install fine-mesh traveling water screens with a fish return system, install wedgewire screens with a mesh fine enough to protect fish eggs and larvae, or retrofit cooling towers.

Entrainment rates during the 2006 to 2007 studies at Dale Station were low and the most frequently entrained species was gizzard shad and unidentified clupeids and unidentified eggs. Based on the timing of the collection of the unidentified eggs and larvae, these unidentified eggs and larvae were also most likely gizzard shad. Given the robust population of gizzard shad in the Kentucky River and the very low entrainment rates of sport fish larvae, white bass and sunfish species, it may be possible to not install entrainment protection equipment at Dale Station based on a cost-benefit analysis.

New CWA Effluent Standards

EPA is expected to issue a draft rule proposing new standards for effluent discharges from electric generating units by November 2012 with final action by January 2014. It is expected that EPA will propose to regulate all effluent streams including fly ash- and bottom ash-derived wastewaters, flue gas desulfurization (FGD) wastewater, and leachate and runoff from coal piles and land-filled or impounded coal combustion residuals (fly ash, bottom ash, boiler slag, and FGD solids).

New CCR Rule

On June 21, 2010, EPA published the Proposed Rule for Disposal of Coal Combustion Residuals (CCRs) from Electric Utilities. EPA provided two co-proposals for public comment: regulation of CCRs as a hazardous, or "special," waste under RCRA subtitle C and regulation of CCRs as a solid waste under RCRA subtitle D. EPA stated that it supports and has endeavored to maintain beneficial reuse of CCRs under both proposed rules. The Subtitle C alternative has extensive repercussions and there are serious questions as to whether the industry could comply with these requirements.

Given the challenges that would accompany Subtitle C regulation of CCRs, the Subtitle D alternative seems like the most likely course for EPA. This is further supported by recent legislative actions that have been directed towards a state-run Subtitle D approach.

Under the proposed regulations for the Subtitle D approach, EPA is proposing to establish dam safety requirements to address the structural integrity of surface impoundments. Within one year of the effective date of the regulations, all surface impoundments are required to be in compliance with groundwater monitoring and demonstrate locational criteria requirements to continue to accept waste. All impoundments that are not in compliance with the liner requirements of the subtitle D are required to cease accepting waste within five years of the effective date of the regulations. If there were no alternatives for CCR disposal, the five years in which the impoundment must have completed closure may be extended for an additional two years.

Under the proposed regulations, there would be no liner requirement deadline for existing landfills (those that are constructed or substantially constructed), but groundwater monitoring would be required. All new landfills or lateral expansions will be required to have composite liner systems, leachate collection systems, and groundwater monitoring networks.

SECTION 10.0

FINANCIAL PLANNING

REDACTED

SECTION 10.0
FINANCIAL PLANNING

Section 9. The integrated resource plan shall, at a minimum, include and discuss the following financial information: (1) Present (base year) value of revenue requirements stated in dollar terms; (2) Discount rate used in present value calculations; (3) Nominal and real revenue requirements by year; and (4) Average system rates (revenues per kilowatt hour) by year.

Table 9-1 provides the Present (base year) value of revenue requirements stated in dollar terms for the 2012 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 below.

The discount rate used in present value calculations is [redacted]. This rate is based on the weighted average cost of EKPC's outstanding long-term debt as of December 31, 2011 multiplied by a 1.50 TIER.

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 2012 $ * ($000)	Total From Members PV @ 6.560% ($000)	Nominal Cents per kWh	Real Cents per kWh Real 2012 $
2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2013						
2014						
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
			**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 12/31/2011.

SECTION 11.0

SYSTEM MAP

SECTION 11.0
SYSTEM MAP

807 KAR 5:058 Section 8.(3)(a) 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. (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.

Please see system map on the following page.

REDACTED

[redacted]