EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2005-00089

INFORMATION REQUEST RESPONSE

COMMISSION STAFF'S 1ST DATA REQUEST DATED 6/16/05

ITEM 14

RESPONSIBLE PARTY: MARY JANE WARNER

REQUEST: Describe East Kentucky's 138 kV Eastern Loop, including its purpose, location, elements completed and elements yet to be completed.

RESPONSE: The 138 kV transmission system between Maysville and Richmond in Kentucky presently consists of the following:

- Three 138 kV lines between the Spurlock (EKPC)/Kenton (LGEE) Substations and the Goddard Substation
- A single 138 kV line between the Goddard Substations (EKPC and LGEE) and the Rodburn (LGEE) Substation
- A single 138 kV line between LGEE's Rodburn Substation, Spencer Road Substation, Clark County Substation, and Fawkes Substation
- A radial 138 kV line to feed EKPC's Rowan County and Skaggs 138-69 kV autotransformers
- A radial 138 kV line to feed the Cranston 138-13.2 kV distribution transformer

Therefore, an outage of any section of the 138 kV line between Goddard and Fawkes will segment the 138 kV system into two separate systems. EKPC's long-range conceptual plan for a wholly-owned EKPC 138 kV loop between the Spurlock and JK Smith Substations would provide a 138 kV system parallel to the LGEE 138 kV system, with 138 kV interconnections at Kenton, Rodburn, and Fawkes. Then, during an outage of any section of either EKPC's or LGEE's 138 kV system, the 138 kV system would still be contiguous from Spurlock to JK Smith.

The conceptual plan includes the following sections which are not yet constructed:

- Cranston-Rowan County 138 kV
- Convert Skaggs-Maggard 69 kV to 138 kV
- Maggard-Maytown Junction 138 kV
- Maytown Junction-Powell County 138 kV

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2005-00089

INFORMATION REQUEST RESPONSE

COMMISSION STAFF'S 1ST DATA REQUEST DATED 6/16/05

ITEM 15

RESPONSIBLE PARTY: MARY JANE WARNER

REQUEST: Refer to page 2 of Mr. Rusch's testimony. Describe the "significant operational issues" that would be created during the outage of the KU Goddard-Rodburn line for reconductoring.

RESPONSE: Reconductoring of the Goddard-Rodburn line has the following operational impacts:

- The line has already been upgraded once historically. Reconductoring will probably require fully rebuilding the line as the added structural stresses associated with the increased conductor size will probably require that the structures be replaced. This adds to the construction time as the old line would probably have to be removed and then replaced with the new construction.
- The above would require that sections of the line be removed from service as the construction progresses. This is the same as the outage of the line and results in the overloads and low voltages as described in the April 2002 Report Section 3 and Appendix A.
- The construction outage of Goddard-Rodburn results in the only effective source to Rodburn being from the Fawkes area. An outage of the Fawkes-Clark County 138kV line would then remove all sources to the area other than "weak" 69kV sources that are not adequate to support the Rodburn area.
- During the construction outages, KU and EKPC will have experienced the first contingency. This would necessitate the long term use of the J.K. Smith generation during the construction time period to address the actual problems which are likely to occur on the system, as well as to operate within limits for the next critical contingency.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2005-00089

INFORMATION REQUEST RESPONSE

COMMISSION STAFF'S 1ST DATA REQUEST DATED 6/16/05

ITEM 16

RESPONSIBLE PARTY: MARY JANE WARNER

REQUEST: Did East Kentucky consider any alternatives to the proposed line involving the siting of distributed generation (including that owned by or located on customer host sites) in locations that would resolve local transmission problems? If yes, describe them and explain why they were not considered further. If no, explain in detail.

RESPONSE: Distributed generation was not considered a viable alternative to this transmission project. Generally EKPC does not develop DG alternatives to solve specific transmission problems predicted to occur with normal load growth.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2005-00089

INFORMATION REQUEST RESPONSE

COMMISSION STAFF'S 1ST DATA REQUEST DATED 6/16/05

ITEM 17

RESPONSIBLE PARTY: MARY JANE WARNER

REQUEST: Did East Kentucky consider any alternatives to the proposed line involving demand-side management or load control to reduce electricity demands in locations that would resolve local transmission problems? If yes, describe them and explain why they were not considered further. If no, explain in detail.

RESPONSE: EKPC's planning process utilizes the load reductions from DSM that are reflected in EKPC's forecasted load for each substation. Additional load reductions via DSM are not considered viable alternatives to this transmission project. Such programs are not considered by EKPC to be reasonable alternatives for solving specific transmission problems identified by planning studies designed to assure the reliable performance of the transmission system.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2005-00089

INFORMATION REQUEST RESPONSE

COMMISSION STAFF'S 1ST DATA REQUEST DATED 6/16/05

ITEM 18

RESPONSIBLE PARTY: MARY JANE WARNER

REQUEST: Describe any other alternatives East Kentucky might have considered and explain why they were rejected.

RESPONSE: No additional alternatives were identified which would result in transmission-system performance that complies with NERC, ECAR, LGEE and EKPC criteria and that also compare economically with the alternatives evaluated.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2005-00089

INFORMATION REQUEST RESPONSE

COMMISSION STAFF'S 1ST DATA REQUEST DATED 6/16/05

ITEM 19

RESPONSIBLE PARTY: · MARY JANE WARNER

REQUEST: East Kentucky considered but rejected reconductoring the KU Goddard-Rodham 138 kV line. Describe the age and condition of the existing line and indicate whether the line could be reconductored or whether it would have to be substantially rebuilt.

RESPONSE: KU's Goddard-Rodburn line was originally constructed in 1950 as a 69 kV line, and was later converted to 138 kV. The conductor in the line is 397 MCM ACSR 26/7 conductor (1 conductor per phase). A definitive statement cannot be made as to whether the conductor could be replaced in this line without replacing the structures. A detailed analysis of the line would be required to determine the necessary scope of work. However, EKPC's opinion based on the age and general condition of the line is that the line would have to be rebuilt.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2005-00089

INFORMATION REQUEST RESPONSE

COMMISSION STAFF'S 1ST DATA REQUEST DATED 6/16/05

ITEM 20

RESPONSIBLE PARTY: MARY JANE WARNER

REQUEST: The April 2002 Final Report projected the performance of the proposed line and alternative essentially 5 years (2005-06) and 10 years (2010-11) when the studies were begun. Do the alternatives East Kentucky studied then and found to be adequate over the 10-year planning horizon still perform adequately over the current 10-year planning horizon? Explain in detail.

RESPONSE: Yes.

The April 2002 study tested the system with the Cranston-Rowan County 138 kV line addition through 2010 Summer and 2010/11 Winter. This analysis indicated that the problems that were identified in the area without additional construction were eliminated through that study period. Furthermore, no new problems were created by the line addition through the study period.

EKPC's planning analysis uses a 10-year planning horizon. No problems in the study area have been identified through the current 10-year planning horizon with the Cranston-Rowan County 138 kV line added.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2005-00089

INFORMATION REQUEST RESPONSE

COMMISSION STAFF'S 1ST DATA REQUEST DATED 6/16/05

ITEM 21

RESPONSIBLE PARTY: MARY JANE WARNER

REQUEST: The 2004 Operational Update was intended to reflect changes in the transmission system that occurred since preparation of the 2002 Final Report. Compare the loads used in modeling the April 2002 Report to the loads used in modeling the 2004 Operational Update.

RESPONSE: The responses to Data Requests 21 and 22 are the subject of EKPC's 2nd Petition for Confidential Treatment of Information and the complete Response is contained in that Petition. A redact version is attached as **Data Response 21 and 22.**

DATA RESPONSE 21 and 22

	Cases Used for April 2002 Report																		Cases Used for May 2004 Operational Update			
	2005 Summer			2005 Summer with Spurlock 4			2005/06 Winter			2005/06 Winter with Spurlock 4			2010 Summer			2010/11 Winter			2004/05 Winter			
Resource	Dispatch 0	Dispatch 3	Dispatch 6	Dispatch 0	Dispatch 3	Dispatch 6	Dispatch 0	Dispatch 3	Dispatch 6	Dispatch 0	Dispatch 3	Dispatch 6	Dispatch 0	Dispatch 3	Dispatch 6	Dispatch 0	Dispatch 3	Dispatch 6	Dispatch 0	Dispatch 3	Dispatch 7	Dispatch 7A
Cooper 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cooper 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dale 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dale 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dale 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dale 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
JK Smith CT #1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
JK Smith CT #2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
JK Smith CT #3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
JK Smith CT #4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
JK Smith CT #5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
JK Smith CT #6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
JK Smith CT #7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Laurel Hydro	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Love Hydro	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Spurlock 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Spurlock 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Spurlock 3 (Gilbert Unit)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Spurlock 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Long-term Purchases	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Short-term Purchases	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Short-term Sales	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
EKPC Control Area Load	2219	2219	2219	2219	2219	2219	2731	2731	2731	2731	2731	2731	2641	2641	2641	3219	3219	3219	2310	2310	2310	1905

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2005-00089

INFORMATION REQUEST RESPONSE

COMMISSION STAFF'S 1ST DATA REQUEST DATED 6/16/05

ITEM 22

RESPONSIBLE PARTY: MARY JANE WARNER

REQUEST: Provide the generator output levels and purchase power levels for each of the dispatch cases East Kentucky analyzed.

RESPONSE: The responses to Data Requests 21 and 22 are the subject of EKPC's 2nd Petition for Confidential Treatment of Information and the complete Response is contained in that Petition. A redact version is attached as **Data Response 21 and 22.**

DATA RESPONSE 21 and 22

	Cases Used for April 2002 Report																		Cases Used for May 2004 Operational Update			
	2005 Summer			2005 Summer with Spurlock 4			2005/06 Winter			2005/06 Winter with Spurlock 4			2010 Summer			2010/11 Winter			2004/05 Winter			
Resource	Dispatch 0	Dispatch 3	Dispatch 6	Dispatch 0	Dispatch 3	Dispatch 6	Dispatch 0	Dispatch 3	Dispatch 6	Dispatch 0	Dispatch 3	Dispatch 6	Dispatch 0	Dispatch 3	Dispatch 6	Dispatch 0	Dispatch 3	Dispatch 6	Dispatch 0	Dispatch 3	Dispatch 7	Dispatch 7A
Cooper 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cooper 2																						
Dale 1																						
Dale 2																						
Dale 3																						
Dale 4																						
JK Smith CT #1																						
JK Smith CT #2																						
JK Smith CT #3																						
JK Smith CT #4																						
JK Smith CT #5																						
JK Smith CT #6																						
JK Smith CT #7																						
Laurel Hydro																						
Love Hydro																						
Spurlock 1																						
Spurlock 2																						
Spurlock 3 (Gilbert Unit)																						
Spurlock 4																						
Long-term Purchases																						
Short-term Purchases																						
Short-term Sales																						
EKPC Control Area Load	2219	2219	2219	2219	2219	2219	2731	2731	2731	2731	2731	2731	2641	2641	2641	3219	3219	3219	2310	2310	2310	1905

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2005-00089

INFORMATION REQUEST RESPONSE

COMMISSION STAFF'S 1ST DATA REQUEST DATED 6/16/05

ITEM 23

RESPONSIBLE PARTY: MARY JANE WARNER

REQUEST: It appears that power purchases from the north exacerbate the loading on the Goddard-Rodburn line, whether those purchases are by utilities for use in Kentucky or by regional entities that transport power across Kentucky. Describe how these power purchases or across-state transfers affect the transmission problems in eastern Kentucky, and discuss the amount of north-south power flow across the state, the frequency of that flow, and the implications, if any, on the Cranston-Rowan line.

RESPONSE: The flow on the Goddard-Rodburn 138 kV line responds by about 1% to transfers from north of Kentucky to south of Kentucky. Some level of north-south transfers is common across Kentucky. The amount can vary dramatically, and quantifying the amount is difficult. Transfer levels between 5000 MW and 10000 MW have been experienced a few times over the last 15 years. For ECAR regional assessments, a 4000 MW transfer level has been agreed upon by member companies to create a north-south transfer stress case. If we assume that a 4000 MW transfer from north to south occurs periodically, the resulting impact on the flow on the Goddard-Rodburn 138 kV line would be approximately 40 MVA.

The flow on the Goddard-Rodburn 138 kV line responds by about 6% to a change in generation at EKPC's JK Smith. For every 100 MW decrease in generation at JK Smith – and assuming a purchase from north of Kentucky – the flow on Goddard-Rodburn 138 kV increases by approximately 6 MVA. EKPC currently has a summer installed net capacity of approximately 600 MW at JK Smith. Therefore, the variance in flows on Goddard-Rodburn is about 36 MVA.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2005-00089

INFORMATION REQUEST RESPONSE

COMMISSION STAFF'S 1ST DATA REQUEST DATED 6/16/05

ITEM 24

RESPONSIBLE PARTY: GARY DAVIDSON

REQUEST: To better understand the proposed transmission project in the context of East Kentucky's demand forecasts, supply plans, and demand-side plans, provide the relevant materials from East Kentucky's Integrated Resource Plans or current updates regarding East Kentucky's:

a. Forecasts of peak demand and annual energy requirements.

b. Demand-side management programs, currently in place.

c. Approach to supply planning.

d. Current supply expansion plan.

RESPONSE: See attached **Data Response Exhibit 24a, Data Response Exhibit 24b, Data Response Exhibit 24c, and Data Response Exhibit 24d.**

DATA RESPONSE 24A
East Kentucky Power Cooperative
2004 Load Forecast Report
Executive Summary

1.1 Summary

East Kentucky Power Cooperative Inc. ("EKPC") is a generation and transmission electric cooperative located in Winchester, Kentucky. It serves 16 member distribution cooperatives who serve over 475,000 retail customers. Member distribution cooperatives currently served by EKPC are listed below:

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

In April of 2008, EKPC will begin all requirements service to Warren RECC. This summary contains a 20-year projection of peak demand and energy requirements for EKPC, representing the summation of the load forecasts for each of its 16 member distribution cooperatives and including Warren RECC beginning April 1, 2008.

EKPC's load forecast is prepared every two years in accordance with EKPC's Rural Utilities Service ("RUS") approved Work Plan, which details the methodology employed in preparing the projections. EKPC prepares the load forecast by working jointly with member systems to prepare their load forecasts. 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 marketing analysis, transmission planning, power supply planning, and financial forecasting.

Historical and projected total energy requirements, seasonal peak demands, and annual load factor for the EKPC system are presented in Tables 1-1 through 1-3. Internal demand refers to EKPC's peak demand unadjusted for interruptible loads, and net demand refers to EKPC's firm peak demand, taking all adjustments into account. Both are based on coincident hourly-integrated demand intervals. Load Factor is calculated using net peak demand and energy requirements.

EKPC's load forecast indicates that total energy requirements are projected to increase by 3.6 percent per year over the 2004 through 2024 period. Net winter peak demand will increase by approximately 2,400 MW, and net summer peak demand will increase by approximately 2,100 MW. Annual load factor projections are slightly declining to around 53 percent.

Energy projections for the residential, small commercial, and large commercial classifications indicate that during the 2004 through 2024 period, sales to the residential class will increase by 3.6 percent per year, small commercial sales will increase by 3.6 percent per year, and large commercial sales will increase by 4.5 percent per year. Class sales are presented in Tables 1-4. Please note the energy use projection for Gallatin Steel in Table 1-4. EKPC and Owen Electric (Gallatin Steel's electric provider) expect Gallatin Steel to use 1,000,000 MWh per year, adjusted by 360 hours of interruption each year.

Load Forecast Growth Rates

	2004-2009	2004-2014	2004-2024
Total Energy Requirements	6.5%	4.6%	3.6%
Residential Sales	5.6%	4.2%	3.6%
Small Commercial Sales	6.7%	4.8%	3.6%
Large Commercial Sales	11.5%	7.0%	4.5%
Firm Winter Peak Demand	6.8%	4.8%	3.7%
Firm Summer Peak Demand	7.0%	4.8%	3.7%

Factors considered in preparing the forecast include national, regional, and local economic performance, appliance saturations and efficiencies, population and housing trends, service area industrial development, electric price, household income, and weather.

Table 1-1
Historical and Projected Winter Peak Demand

Season	Total Internal Peak Demand (MW)	Gallatin Steel Interruptible Demand (MW)	Other Interruptible (MW)	Net Peak Demand (MW)
1981 - 82	1,087	0	0	1,087
1982 - 83	845	0	0	845
1983 - 84	1,151	0	0	1,151
1984 - 85	1,125	0	0	1,125
1985 - 86	1,039	0	0	1,039
1986 - 87	983	0	0	983
1987 - 88	1,104	0	0	1,104
1988 - 89	1,114	0	0	1,114
1989 - 90	1,449	0	0	1,449
1990 - 91	1,306	0	0	1,306
1991 - 92	1,383	0	0	1,383
1992 - 93	1,473	0	0	1,473
1993 - 94	1,788	0	0	1,788
1994 - 95	1,621	0	0	1,621
1995 - 96	1,990	75	0	1,915
1996 - 97	2,004	51	0	1,953
1997 - 98	1,789	93	14	1,682
1998 - 99	2,096	108	17	1,971
1999 - 00	2,169	12	17	2,140
2000 - 01	2,322	27	17	2,278
2001 - 02	2,238	129	17	2,092
2002 - 03	2,568	109	24	2,435
2003 - 04	2,612	97	26	2,489
2004 - 05	2,794	135	26	2,633
2005 - 06	2,893	135	26	2,732
2006 - 07	2,999	135	26	2,838
2007 - 08	3,085	135	26	2,924
2008 - 09	3,623	135	26	3,462
2009 - 10	3,726	135	26	3,565
2010 - 11	3,818	135	26	3,657
2011 - 12	3,914	135	26	3,753
2012 - 13	4,033	135	26	3,872
2013 - 14	4,141	135	26	3,980
2014 - 15	4,246	135	26	4,085
2015- 16	4,341	135	26	4,180
2016 - 17	4,466	135	26	4,305
2017 - 18	4,584	135	26	4,423
2018 - 19	4,709	135	26	4,548
2019 - 20	4,823	135	26	4,662
2020 - 21	4,959	135	26	4,798
2021 - 22	5,083	135	26	4,922
2022 - 23	5,208	135	26	5,047
2023 - 24	5,319	135	26	5,158

Table 1-2
Historical and Projected Summer Peak Demand

Season	Total Internal Peak Demand (MW)	Gallatin Steel Interruptible Demand (MW)	Other Interruptible (MW)	Net Peak Demand (MW)
1982	694	0	0	694
1983	789	0	0	789
1984	722	0	0	722
1985	776	0	0	776
1986	857	0	0	857
1987	906	0	0	906
1988	1,055	0	0	1,055
1989	1,010	0	0	1,010
1990	1,079	0	0	1,079
1991	1,164	0	0	1,164
1992	1,131	0	0	1,131
1993	1,309	0	0	1,309
1994	1,314	0	0	1,314
1995	1,518	52	0	1,466
1996	1,540	88	0	1,452
1997	1,650	101	0	1,549
1998	1,675	4	17	1,654
1999	1,754	4	12	1,738
2000	1,941	86	23	1,832
2001	1,980	116	23	1,841
2002	2,120	119	23	1,978
2003	1,996	125	26	1,845
2004	2,197	135	26	2,036
2005	2,294	135	26	2,133
2006	2,377	135	26	2,216
2007	2,461	135	26	2,300
2008	2,930	135	26	2,769
2009	3,017	135	26	2,856
2010	3,098	135	26	2,937
2011	3,174	135	26	3,013
2012	3,250	135	26	3,089
2013	3,341	135	26	3,180
2014	3,426	135	26	3,265
2015	3,508	135	26	3,347
2016	3,584	135	26	3,423
2017	3,680	135	26	3,519
2018	3,773	135	26	3,612
2019	3,870	135	26	3,709
2020	3,955	135	26	3,794
2021	4,059	135	26	3,898
2022	4,155	135	26	3,994
2023	4,249	135	26	4,088
2024	4,340	135	26	4,179

Table 1-3
Historical and Projected Peak Demands And Total Requirements

Season	Net Winter Peak Demand (MW)	Year	Net Summer Peak Demand (MW)	Year	Total Requirements (MWh)	Load Factor (%)
1981 - 82	1,087	1982	694	1982	3,904,954	40.9%
1982 - 83	845	1983	789	1983	4,099,007	55.4%
1983 - 84	1,151	1984	722	1984	4,095,268	40.6%
1984 - 85	1,125	1985	776	1985	4,264,517	43.3%
1985 - 86	1,039	1986	857	1986	4,470,627	49.0%
1986 - 87	983	1987	906	1987	4,710,898	54.7%
1987 - 88	1,104	1988	1,055	1988	5,122,703	53.0%
1988 - 89	1,114	1989	1,010	1989	5,347,081	54.8%
1989 - 90	1,449	1990	1,079	1990	5,489,092	43.1%
1990 - 91	1,306	1991	1,164	1991	5,958,422	52.1%
1991 - 92	1,383	1992	1,131	1992	6,099,308	50.3%
1992 - 93	1,473	1993	1,309	1993	6,860,902	53.2%
1993 - 94	1,788	1994	1,314	1994	6,917,414	44.0%
1994 - 95	1,621	1995	1,466	1995	7,761,980	54.7%
1995 - 96	1,915	1996	1,452	1996	8,505,621	50.7%
1996 - 97	1,953	1997	1,549	1997	8,850,394	51.7%
1997 - 98	1,682	1998	1,654	1998	9,073,950	61.4%
1998 - 99	1,971	1999	1,738	1999	9,825,866	56.9%
1999 - 00	2,140	2000	1,832	2000	10,521,400	56.1%
2000 - 01	2,278	2001	1,841	2001	10,750,900	53.9%
2001 - 02	2,092	2002	1,978	2002	11,456,830	62.3%
2002 - 03	2,435	2003	1,845	2003	11,568,314	54.2%
2003 - 04	2,489	2004	2,036	2004	12,055,905	55.3%
2004 - 05	2,633	2005	2,133	2005	12,506,284	54.2%
2005 - 06	2,732	2006	2,216	2006	12,974,673	54.1%
2006 - 07	2,838	2007	2,300	2007	13,463,856	54.2%
2007 - 08	2,924	2008	2,769	2008	15,509,448	60.6%
2008 - 09	3,462	2009	2,856	2009	16,542,462	54.5%
2009 - 10	3,565	2010	2,937	2010	17,007,296	54.3%
2010 - 11	3,657	2011	3,013	2011	17,433,751	54.4%
2011 - 12	3,753	2012	3,089	2012	17,916,519	54.5%
2012 - 13	3,872	2013	3,180	2013	18,404,516	54.3%
2013 - 14	3,980	2014	3,265	2014	18,896,493	54.1%
2014 - 15	4,085	2015	3,347	2015	19,373,012	54.1%
2015- 16	4,180	2016	3,423	2016	19,861,626	54.2%
2016 - 17	4,305	2017	3,519	2017	20,366,928	54.0%
2017 - 18	4,423	2018	3,612	2018	20,900,624	53.8%
2018 - 19	4,548	2019	3,709	2019	21,459,656	53.9%
2019 - 20	4,662	2020	3,794	2020	22,023,701	53.9%
2020 - 21	4,798	2021	3,898	2021	22,566,676	53.7%
2021 - 22	4,922	2022	3,994	2022	23,125,176	53.5%
2022 - 23	5,047	2023	4,088	2023	23,685,187	53.6%
2023 - 24	5,158	2024	4,179	2024	24,286,700	53.8%

Table 1-4
2004 Load Forecast
Total Member System Retail Energy Sales

Year	Residential Sales (MWh)	Seasonal Sales (MWh)	Small Comm. Sales (MWh)	Public Buildings (MWh)	Large Comm. Sales (MWh)	Gallatin Steel (MWh)	Other Sales (MWh)	Total Retail Sales (MWh)
1990	3,483,232	9,652	813,371	22,879	653,502	0	3,736	4,986,373
1991	3,755,282	9,791	868,032	25,182	722,743	0	4,029	5,385,059
1992	3,798,270	10,100	913,599	26,549	775,544	0	4,305	5,528,366
1993	4,213,871	10,478	980,290	30,060	970,137	0	5,081	6,209,917
1994	4,268,682	10,591	1,014,549	30,347	1,029,178	0	4,156	6,357,502
1995	4,575,282	11,355	1,098,885	33,261	1,119,902	279,070	5,042	7,122,797
1996	4,857,938	12,629	1,082,019	34,242	1,243,107	640,756	5,552	7,876,243
1997	4,883,875	12,075	1,163,683	33,267	1,258,816	755,279	5,663	8,112,659
1998	5,091,880	11,650	1,230,451	34,263	1,349,895	696,051	5,601	8,419,790
1999	5,303,413	11,652	1,337,008	34,947	1,415,803	901,686	5,757	9,010,267
2000	5,607,950	12,648	1,493,650	38,061	1,498,745	917,983	6,160	9,575,197
2001	5,777,378	12,954	1,490,670	39,197	1,686,653	992,711	6,545	10,006,107
2002	5,946,686	14,703	1,571,381	40,725	1,790,693	1,005,493	6,860	10,376,541
2003	6,156,774	15,487	1,581,188	42,689	1,906,861	1,007,676	7,087	10,717,762
2004	6,497,216	14,307	1,630,602	45,531	1,968,664	961,632	7,694	11,125,647
2005	6,682,941	14,825	1,694,044	46,612	2,132,344	960,781	7,949	11,539,497
2006	6,918,457	15,524	1,757,692	47,856	2,261,427	960,951	8,213	11,970,119
2007	7,183,613	16,294	1,822,141	49,201	2,379,982	960,435	8,483	12,420,150
2008	7,963,634	17,003	2,129,583	50,512	3,137,941	961,056	12,482	14,272,210
2009	8,526,792	17,680	2,257,539	51,802	3,394,380	962,376	14,205	15,224,774
2010	8,769,805	18,327	2,328,603	53,030	3,504,926	962,267	14,639	15,651,597
2011	9,005,166	18,968	2,399,739	54,245	3,589,580	960,119	15,077	16,042,894
2012	9,277,560	19,711	2,467,666	55,471	3,689,892	960,160	15,522	16,485,982
2013	9,568,763	20,495	2,534,710	56,735	3,776,751	960,424	15,968	16,933,848
2014	9,849,132	21,220	2,602,619	58,006	3,876,151	961,931	16,418	17,385,477
2015	10,132,987	21,930	2,670,899	59,279	3,959,598	961,610	16,869	17,823,172
2016	10,418,609	22,671	2,738,146	60,548	4,054,635	959,992	17,326	18,271,927
2017	10,734,638	23,534	2,808,274	61,895	4,130,033	959,696	17,787	18,735,857
2018	11,060,111	24,472	2,880,072	63,309	4,220,103	959,191	18,251	19,225,508
2019	11,411,147	25,495	2,952,552	64,796	4,306,388	959,462	18,717	19,738,557
2020	11,759,902	26,543	3,025,190	66,179	4,397,448	961,566	19,194	20,256,022
2021	12,101,252	27,556	3,096,179	67,552	4,480,296	961,698	19,669	20,754,203
2022	12,447,462	28,578	3,166,734	68,928	4,575,322	959,323	20,150	21,266,497
2023	12,811,267	29,677	3,239,421	70,277	4,650,017	959,018	20,637	21,780,314
2024	13,194,533	30,814	3,314,701	71,684	4,740,172	959,015	21,129	22,332,048

Table 1-4 continued
2004 Load Forecast
Energy Sales and Total Requirements

Year	Total Retail Sales (MWh)	Office Use (MWh)	% Loss	EKPC Sales to Members (MWh)	EKPC Office Use (MWh)	Transmission Loss (%)	Total Requirements (MWh)
1990	4,986,373	5,087	5.7	5,295,459	6,287	3.5	5,489,092
1991	5,385,059	5,333	6.3	5,755,588	6,798	3.4	5,958,422
1992	5,528,366	5,242	6.3	5,903,268	7,559	3.2	6,099,308
1993	6,209,917	5,552	6.0	6,612,687	8,026	3.6	6,860,902
1994	6,357,502	5,614	5.4	6,727,959	8,541	2.7	6,917,414
1995	7,122,797	5,711	5.7	7,558,452	9,197	2.6	7,761,980
1996	7,876,243	6,167	5.0	8,301,379	8,856	2.4	8,505,621
1997	8,112,659	6,349	5.1	8,559,022	8,505	3.3	8,850,394
1998	8,419,790	6,121	4.5	8,821,630	7,236	2.8	9,073,950
1999	9,010,267	6,040	4.8	9,472,955	8,157	3.6	9,825,866
2000	9,575,197	6,605	4.4	10,021,053	7,862	4.9	10,521,400
2001	10,006,107	6,752	4.0	10,426,995	8,205	3.0	10,750,900
2002	10,376,541	6,912	4.9	10,913,425	8,246	4.9	11,456,830
2003	10,717,762	6,911	4.8	11,260,295	8,287	2.7	11,568,314
2004	11,125,647	8,382	4.7	11,685,899	8,329	3.0	12,055,905
2005	11,539,497	8,382	4.7	12,122,725	8,370	3.0	12,506,284
2006	11,970,119	8,382	4.8	12,577,021	8,412	3.0	12,974,673
2007	12,420,150	8,382	4.8	13,051,486	8,454	3.0	13,463,856
2008	14,272,210	8,382	5.0	15,035,668	8,497	3.0	15,509,448
2009	15,224,774	8,382	5.0	16,037,649	8,539	3.0	16,542,462
2010	15,651,597	8,382	5.0	16,488,495	8,582	3.0	17,007,296
2011	16,042,894	8,382	5.0	16,902,113	8,625	3.0	17,433,751
2012	16,485,982	8,382	5.0	17,370,355	8,668	3.0	17,916,519
2013	16,933,848	8,382	5.1	17,843,670	8,711	3.0	18,404,516
2014	17,385,477	8,382	5.1	18,320,843	8,755	3.0	18,896,493
2015	17,823,172	8,382	5.1	18,783,024	8,798	3.0	19,373,012
2016	18,271,927	8,382	5.1	19,256,935	8,842	3.0	19,861,626
2017	18,735,857	8,382	5.1	19,747,033	8,887	3.0	20,366,928
2018	19,225,508	8,382	5.1	20,264,674	8,931	3.0	20,900,624
2019	19,738,557	8,382	5.1	20,806,890	8,976	3.0	21,459,656
2020	20,256,022	8,382	5.1	21,353,969	9,021	3.0	22,023,701
2021	20,754,203	8,382	5.1	21,880,610	9,066	3.0	22,566,676
2022	21,266,497	8,382	5.1	22,422,310	9,111	3.0	23,125,176
2023	21,780,314	8,382	5.1	22,965,474	9,157	3.0	23,685,187
2024	22,332,048	8,382	5.1	23,548,897	9,202	3.0	24,286,700

DATA RESPONSE 24b

SECTION 6.0

MARKETING AND DEMAND-SIDE MANAGEMENT

SECTION 6.0
MARKETING AND DEMAND-SIDE MANAGEMENT

6.1 Introduction

EKPC and its 16 member systems have long promoted conservation and cost effective use of electricity. This section of the IRP describes existing marketing programs. Please note that these programs are implemented and managed by member distribution systems, not EKPC. While EKPC supports member systems with analysis, promotional material, and other information, and while EKPC views these programs as part of its overall power supply portfolio, the programs impact EKPC indirectly, through its member systems.

Current marketing programs are listed below, and then described individually.

- Tune-Up HVAC Maintenance Program
- Geothermal Heating & Cooling Incentive Program
- Electric Thermal Storage Incentive Program
- Electric Water Heater Incentive Program
- Air-Source Heat Pump Incentive Program
- Button-Up Weatherization Program
- Manufactured Home Program

6.2 Tune-Up HVAC Maintenance Program

6.2.1 Target Markets

The program is targeted to single-family homes using electric furnaces or electric heat pumps that have exhibited high-energy use. It is also available to multi-family residences, churches and commercial facilities heated by electric furnaces, electric heat pumps, and geothermal units. All facilities must have duct systems at least two years old to quality for incentive payments.

6.2.2 Program Description

This program includes cleaning indoor and outdoor heat-exchanger coils, changing filters, measuring the temperature differential across the indoor coil to determine proper compressor operation, checking the thermostat to verify operation and proper staging, measuring air flows to ensure proper conditioned air distribution, and sealing ductwork either through traditional mastic sealers or the Aeroseal dust sealing system. Duct losses are to be reduced to 10% or less. Duct loss measurement requires the use of a blower door test and the blower door subtraction method, or the approved duct loss measurement test associated with the Aeroseal duct sealing system. Only contractors trained and certified by EKPC may be used.

Table 6-1

Load Impacts Of Tune Up Program

Year	Number	Impact On Total Requirements* (MWh)	Impact On Winter Peak (MW)	Impact On Summer Peak (MW)
1995	589	-1,302	-1	-1
1996	1,546	-3,417	-3	-2
1997	2,459	-5,434	-5	-2
1998	2,736	-6,047	-6	-3
1999	2,850	-6,299	-6	-3
2000	2,979	-6,584	-6	-3
2001	3,081	-6,809	-6	-3
2002	3,255	-7,194	-7	-3
2003	3,375	-7,459	-7	-3
2004	3,495	-7,724	-7	-3
2005	3,615	-7,989	-8	-4
2006	3,735	-8,254	-8	-4
2007	3,855	-8,520	-8	-4
2008	3,975	-8,785	-8	-4
2009	4,095	-9,050	-9	-4
2010	4,215	-9,315	-9	-4
2011	4,335	-9,580	-9	-4
2012	4,455	-9,846	-9	-4
2013	4,575	-10,111	-10	-5
2014	4,696	-10,378	-10	-5
2015	4,818	-10,648	-10	-5
2016	4,941	-10,920	-10	-5
2017	5,065	-11,194	-11	-5

* as compared to target market.

6.3 Geothermal Heating & Cooling Incentive Program

6.3.1 Program Description

The program is designed to encourage homeowners to choose geothermal heating and cooling over less-efficient forms of heating and cooling. For retail members building new homes, it works in conjunction with the All-Seasons Comfort Home building standards. For those retail members replacing existing, less-efficient HVAC equipment, the incentive encourages the consideration of geothermal as a viable HVAC solution.

6.3.2 Target Market

The incentives are available to any residential retail member of participating EKPC cooperatives. Primarily targets are retail members constructing new stick-built homes and retail member homeowners currently heating with electric furnaces, ceiling cables, baseboard heat or fossil fuels.

Table 6-2

Load Impacts Of Geothermal Program

Year	Number	Impact On Total Requirements* (MWh)	Impact On Winter Peak (MW)	Impact On Summer Peak (MW)
1995	3,664	-21,984	-13	-5
1996	4,065	-24,390	-14	-6
1997	4,584	-27,504	-16	-7
1998	4,985	-29,910	-17	-7
1999	5,377	-32,262	-19	-8
2000	5,731	-34,386	-20	-9
2001	6,095	-36,570	-21	-9
2002	6,399	-38,394	-22	-10
2003	6,659	-39,954	-23	-10
2004	6,919	-41,514	-24	-10
2005	7,179	-43,074	-25	-11
2006	7,439	-44,634	-26	-11
2007	7,699	-46,194	-27	-12
2008	7,959	-47,754	-28	-12
2009	8,219	-49,314	-29	-12
2010	8,479	-50,874	-30	-13
2011	8,739	-52,434	-31	-13
2012	8,999	-53,994	-31	-13
2013	9,259	-55,554	-32	-14
2014	9,520	-57,120	-33	-14
2015	9,782	-58,692	-34	-15
2016	10,045	-60,270	-35	-15
2017	10,309	-61,854	-36	-15

* as compared to target market.

6.4 Electric Thermal Storage Incentive Program

6.4.1 Program Description

Electric Thermal Storage (ETS) provides retail members with a cost-efficient means of using electricity for space heating. A time-of-day rate for ETS energy encourages retail members to use heating energy off-peak rather than on-peak. This improves the utility's load factor, reduces energy costs to the retail member, and delays the need for new peak-load capacity construction expense.

6.4.2 Target Market

The incentives are available to any retail member, but are primarily designed for retail members currently using baseboard, ceiling cable and electric furnaces as their primary source of heat. Secondary targets would be retail members using wood, coal or kerosene as primary or secondary sources of heat.

Table 6-3

Load Impacts Of ETS Program

Year	Number	Impact On Total Requirements* (MWh)	Impact On Winter Peak (MW)	Impact On Summer Peak (MW)
1995	3,439	27,512	-10	0
1996	4,065	36,032	-14	0
1997	4,584	42,616	-16	0
1998	4,985	47,216	-18	0
1999	5,377	50,704	-19	0
2000	5,731	55,032	-21	0
2001	6,095	57,664	-22	0
2002	6,399	59,536	-22	0
2003	6,659	61,936	-23	0
2004	6,919	64,336	-24	0
2005	7,179	66,736	-25	0
2006	7,439	69,136	-26	0
2007	7,699	71,536	-27	0
2008	7,959	73,936	-28	0
2009	8,219	76,336	-29	0
2010	8,479	78,736	-30	0
2011	8,739	81,136	-30	0
2012	8,999	83,536	-31	0
2013	9,259	85,936	-32	0
2014	9,520	88,336	-33	0
2015	9,782	90,736	-34	0
2016	10,045	93,136	-35	0
2017	10,309	95,536	-36	0

* as compared to target market.

6.5 Electric Water Heater Incentive Program

6.5.1 Program Description

The electric water heater incentive is designed to encourage residential retail members engaged in new construction to choose a high-efficiency electric water heater over other available options. It is also designed to encourage retail members using a fossil-fuel water heater to convert to a high-efficiency electric water heater. By reducing the cost of choosing a high-efficiency water heater, cooperatives can contribute to lower long-term energy costs and improved satisfaction among residential retail members.

6.5.2 Target Market

The incentive is available to any residential retail member of a participating EKPC cooperative building a new home and installing that home's initial water heater. The incentive is also available to any residential retail member replacing an existing gas or propane water heater with an electric water heater meeting the defined program standards.

Table 6-4

Load Impacts Of Water Heater Program

Year	Number	Impact On Total Requirements* (MWh)	Impact On Winter Peak (MW)	Impact On Summer Peak (MW)
1995	1,291	904	0	0
1996	1,911	1,338	0	0
1997	2,499	1,749	0	0
1998	3,384	2,369	1	0
1999	4,333	3,033	1	0
2000	5,121	3,585	1	0
2001	5,877	4,114	1	0
2002	6,760	4,732	1	1
2003	7,510	5,257	2	1
2004	8,260	5,782	2	1
2005	9,010	6,307	2	1
2006	9,760	6,832	2	1
2007	10,510	7,357	2	1
2008	11,260	7,882	2	1
2009	12,010	8,407	2	1
2010	12,760	8,932	3	1
2011	13,510	9,457	3	1
2012	14,260	9,982	3	1
2013	15,010	10,507	3	1
2014	15,760	11,032	3	1
2015	16,510	11,557	3	1
2016	17,260	12,082	3	1
2017	18,010	12,607	4	1

* as compared to target market.

6.6 Air-Source Heat Pump Incentive Program

6.6.1 Target Markets

The primary targets for this program are retail members building new homes in areas where natural gas heat is an option. An important secondary target is the HVAC retrofit market, offering incentives to retail members to replace electric furnaces and gas or propane heat with high-efficiency electric heat pumps.

Table 6-5

Load Impacts Of Air Source Heat Pump Program

Year	Number	Impact On Total Requirements* (MWh)	Impact On Winter Peak (MW)	Impact On Summer Peak (MW)
1995	0	0	0	0
1996	0	0	0	0
1997	0	0	0	0
1998	131	-121	0	0
1999	522	-483	1	-1
2000	910	-842	2	-1
2001	1,380	-1,277	3	-1
2002	1,950	-1,804	5	-2
2003	2,450	-2,266	6	-2
2004	2,950	-2,729	7	-3
2005	3,450	-3,191	9	-3
2006	3,950	-3,654	10	-4
2007	4,450	-4,116	11	-4
2008	4,950	-4,579	12	-5
2009	5,450	-5,041	14	-5
2010	5,950	-5,504	15	-6
2011	6,450	-5,966	16	-6
2012	6,950	-6,429	17	-7
2013	7,450	-6,891	19	-7
2014	7,951	-7,355	20	-8
2015	8,453	-7,819	21	-8
2016	8,956	-8,284	22	-9
2017	9,460	-8,751	24	-9

* as compared to target market.

6.7 Button-Up Weatherization Program

6.7.1 Program Description

The program requires the installation of insulation materials or the use of other weatherization techniques to reduce heat loss in the home. Any retail member living in a stick-built or manufactured home that is at least two years old and which uses electric as the primary source of heat is eligible.

6.7.2 Target Markets

The primary program targets for this program are older homes exhibiting unusually high usage of electricity. Overall, the program is available for any stick-built or manufactured home using electricity as its primary heating source.

Table 6-6

Load Impacts Of Button Up Program

Year	Number	Impact On Total Requirements* (MWh)	Impact On Winter Peak (MW)	Impact On Summer Peak (MW)
1995	1,653	-4,511	-4	-2
1996	2,734	-7,461	-7	-3
1997	3,606	-9,841	-10	-4
1998	4,301	-11,737	-12	-4
1999	4,782	-13,050	-13	-5
2000	5,309	-14,488	-14	-5
2001	5,787	-15,793	-16	-6
2002	6,265	-17,097	-17	-6
2003	6,765	-18,462	-18	-7
2004	7,265	-19,826	-20	-7
2005	7,765	-21,191	-21	-8
2006	8,265	-22,555	-22	-8
2007	8,765	-23,920	-24	-9
2008	9,265	-25,284	-25	-9
2009	9,765	-26,649	-26	-10
2010	10,265	-28,013	-28	-10
2011	10,765	-29,378	-29	-11
2012	11,265	-30,742	-30	-11
2013	11,765	-32,107	-32	-12
2014	12,266	-33,474	-33	-12
2015	12,768	-34,844	-34	-13
2016	13,271	-36,217	-36	-13
2017	13,775	-37,592	-37	-14

* as compared to target market.

6.8 Manufactured Home Program

6.8.1 Program Summary

This program provides an incentive for retail customers to purchase a more energy efficient manufactured home. It is an energy conservation program. The retail customer pays an additional $1,000 for a more energy efficient manufactured home – the home uses around 5,100 kWh less per year relative to other homes.

Table 6-7

Load Impacts Of Manufactured Home Program

Year	Number	Impact On Total Requirements* (MWh)	Impact On Winter Peak (MW)	Impact On Summer Peak (MW)
1995	0	0	0	0
1996	0	0	0	0
1997	0	0	0	0
1998	0	0	0	0
1999	0	0	0	0
2000	0	0	0	0
2001	0	0	0	0
2002	70	-294	0	0
2003	200	-840	0	0
2004	380	-1,596	-1	0
2005	720	-3,024	-2	-1
2006	1,020	-4,284	-2	-1
2007	1,100	-4,620	-3	-1
2008	1,160	-4,872	-3	-1
2009	1,220	-5,124	-3	-1
2010	1,280	-5,376	-3	-1
2011	1,340	-5,628	-3	-1
2012	1,400	-5,880	-3	-1
2013	1,460	-6,132	-4	-1
2014	1,520	-6,384	-4	-1
2015	1,580	-6,636	-4	-1
2016	1,640	-6,888	-4	-1
2017	1,700	-7,140	-4	-1

* as compared to target market.

Table 6-8

Load Impacts Of All Existing Marketing Programs

Year	Impact On Total Requirements* (MWh)	Impact On Winter Peak (MW)	Impact On Summer Peak (MW)
1995	619	-29	-8
1996	2,102	-38	-10
1997	1,586	-46	-13
1998	1,770	-52	-14
1999	1,644	-55	-16
2000	2,317	-58	-17
2001	1,330	-60	-19
2002	-514	-62	-21
2003	-1,788	-65	-22
2004	-3,271	-67	-24
2005	-5,426	-70	-25
2006	-7,413	-73	-27
2007	-8,476	-75	-29
2008	-9,456	-77	-30
2009	-10,435	-79	-32
2010	-11,414	-81	-33
2011	-12,393	-84	-35
2012	-13,372	-86	-36
2013	-14,352	-88	-38
2014	-15,343	-90	-39
2015	-16,346	-92	-41
2016	-17,360	-94	-42
2017	-18,387	-97	-44

* as compared to target market.

6.9 Benefit/ Cost Analysis

EKPC utilized a computer program called DSMANAGER, which was created by the electric industry research group EPRI, in order to calculate the relative benefits of existing marketing programs. DSMANAGER is relatively well known and has been used by utilities for years to compute a battery of benefit/cost ratios. Appendix B of this IRP provides DSMANAGER output for all of the existing marketing programs. The table below reports two important ratios, the participant test and the total resource cost test. Other ratios are reported in the appendix. Based on the analysis reported in the appendix, EKPC believes that the results achieved in Figure 6-1 above to be cost effective.

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Table 6-9

Benefit / Cost Ratio Summary

Program	Participant Test	TRC Test
Air Source Heat Pump Program Into New Homes	1.64	1.39
Air Source Heat Pump Program Into Existing Homes	1.71	0.59
Efficient Water Heaters Into New Homes	2.23	0.76
Efficient Water Heaters Into Existing Homes	0.77	1.01
Tune Up	2.78	1.82
Button Up	2.46	2.84
Geothermal, New Homes, Non-ASCH	1.34	1.42
Geothermal, New Homes, ASCH	1.00	1.56
ETS Replacing Electric Furnace	1.35	0.86
ETS Replacing Propane	1.14	1.62
Total Program Effects	**1.32**	**1.23**

6.10 New Marketing Programs

In addition to reviewing existing marketing programs, EKPC analyzed new programs. They are the following:

Commercial Lighting
Compact Fluorescent Light Bulbs
Direct Load Control
Demand Response Program

Appendix B reports the benefit/cost tests to be favorable. EKPC and member systems are currently addressing the above 4 programs in the following manner.

6.10.1 Commercial Lighting – Member systems can offer large commercial and industrial customers a commercial lighting option through EnVision.

6.10.2 Compact Fluorescent Light Bulbs – Distribution cooperatives are giving these light bulbs out at annual meetings.

6.10.3 Demand Response Program – Member systems can utilize existing rate structures with their power supplier (EKPC) to approximate most recognized demand response programs.

6.10.4 Direct Load Control – This type of load management has been under almost constant review by EKPC since 1994. In the past, the benefit / cost ratios were much less than one. That is changing somewhat, as is shown in Appendix B. EKPC will continue to keep up with the relative merits of direct load control. Implementation, however, requires both EKPC and member systems to be in complete acceptance and agreement. Because of the high fixed costs involved in this type of demand side management, however, there has to be a commitment to it by all parties.

6.11 Marketing Support of DSM Programs

DSM programs are supported by a wide variety of training programs, trade ally conferences, special events and advertising support materials. Programs are offered to all member cooperatives, with each choosing the combination of materials and participation that best meets their individual service area needs. EKPC also provides technical support for marketing programs.

6.12 Envision Programs for C&I Retail Members

EnVision, a cooperatively owned consulting service, provides load management services to commercial and industrial customers. Services include infrared testing of commercial facilities, blower door testing, energy audits and HVAC engineering advisory services for new facilities and facility retrofits. Electronic energy management devices will be field-tested beginning in 2000, with initial focus being placed on convenience stores and small retail facilities.

6.13 Power Quality Training

Growing levels of electronic devices in both residential and commercial settings have increased the need for training in surge suppression. To meet this need, EKPC will offer member system personnel and their designated contractors regular training seminars on the effects of power surges, lightening protection and how to select appropriate surge protection for specific applications. We will also work with member systems to identify qualified suppliers of surge protection equipment and negotiate package rates to lower prices of such equipment to our end users.

6.14 Promotional Materials for DSM Programs

For DSM programs supported by each member cooperative, and previously listed in this integrated resource plan, EKPC provides print advertisements, bill stuffers and point-of-sale materials to the retail members' use for use in promoting the availability of these services in their local media. EKPC is also participating in an advertising campaign for these programs in Kentucky Living Magazine, listing those co-ops choosing to highlight specific programs during the 2003 time period.

6.14.1 Energy Management Conference

The Energy Management Conference is conducted each January by EKPC and its member systems for the benefit of trade allies in our member systems' service areas. Builders, contractors, dealers, utility personnel, architects and engineers from in and around the state of Kentucky have attended recent conferences. Exhibitors typically include vendors of geothermal systems, insulation products and others interested in energy efficient construction practices. Seminars during the conference offer the latest information on energy efficiency practices, building trends and new HVAC options. Attendance typically exceeds 400 persons each year. To summarize, this conference is a good opportunity to introduce new energy efficient concepts to key personnel.

6.14.2 Home and Garden Shows

EKPC and several of its member cooperatives participate in home and garden shows in Lexington and other communities. Exhibits include information on geothermal heating and cooling, electric thermal storage and the All Seasons Comfort Home.

DATA RESPONSE 24c

Power Supply Planning

EKPC's approach to power supply planning is one of minimizing member system revenue requirements. Because winter power prices have historically been lower than summer prices, EKPC's current power supply strategy is to add resources to meet a minimum of a 12 % reserve margin for the summer peak while keeping any purchases needed to meet the winter peak to a level EKPC believes can be imported reliably, currently about 300 to 400 megawatts. By utilizing this strategy EKPC avoids paying fixed charges year-round for capacity that is primarily needed for a few months in the winter. EKPC's analysis has shown this power supply strategy to be more economical than building generation facilities to serve only its highest peak load situations. With the release of the 2004 Load Forecast Report, the difference in the winter and summer forecasted peak loads increased to about 500 MW. This large seasonal difference requires EKPC to build to more than 12% reserves in summer to hold down purchases in winter. With that large a difference in seasonal peaks and changes in seasonal price relationships, some fine-tuning of the current strategy is under consideration. One option is to purchase as much as 200 MW of capacity for winter only. That would allow EKPC to maintain the strategy of adding resources to meet a 12 percent reserve margin for the summer peak and keep winter purchases to a reasonable level.

Decisions on seasonal purchases are made prior to each peak season in coordination with a recommendation of EKPC's needs done by ACES Power Marketing (ACES) and an evaluation by EKPC staff. Seasonal purchases are expected to be needed primarily for the winter peak season. ACES acts as EKPC's agent to execute purchases at the lowest possible cost.

EKPC's resource planning process is a cycle that begins with the load forecast and includes development of a capacity expansion plan and the potential financial ramifications of implementing the plan. EKPC's Market Research Team develops a load forecast with input from all the member systems every two years in accordance with RUS requirements. The load forecast is the foundation of the planning process and is used to determine EKPC's capacity needs. EKPC develops an Integrated Resource Plan (IRP) every three years as required to file with the Commission. The process of developing the IRP includes an evaluation of capacity needs based on the latest load forecast, a resource technology assessment, a screening analysis of resource alternatives including DSM, an update of fuel and market power prices, and a risk assessment of the expansion plan. The resulting expansion plan is simulated and input to the financial model to determine the impact on margins and rates. This expansion plan becomes the base plan and is re-evaluated as necessary. The next IRP is due to be filed in April 2006. Preliminary work has begun on development of the next base expansion plan. A long-term financial forecast is developed annually and includes updated fuel costs and the base expansion plan with any adjustments. The impact of future rate changes is used in the development of the next load forecast, and the planning cycle starts over.

Future capacity additions are selected through an RFP process following a study of the type of capacity needed. The 2006 IRP that will be filed with the Commission will outline an updated capacity expansion plan and the types of capacity needed. Based on the timing of new capacity additions, RFPs will be issued in accordance with RUS requirements to solicit proposals for new capacity and an evaluation process will determine the best proposals for EKPC to pursue. EKPC advertises nationally and solicits bids from a wide range of sources, including other utilities, independent power producers, and speculative power plant builders. In this process EKPC evaluates potential power purchases, as well as construction of facilities by EKPC or others in making future resource selections.

DATA RESPONSE 24D

EKPC Expansion Plan

The following table is a summary of EKPC's current expansion plan through 2024. The capacity projects listed through Smith CFB 1 have been approved by EKPC's Board and Applications for Certificates of Public Convenience and Necessity and Site Compatibility have been filed with the Commission. Projects listed after Smith CFB 1 are placeholders for future capacity additions and no commitments or definitive plans have been made for those projects.

EKPC is required to file an Integrated Resource Plan in Spring 2006 with the Kentucky PSC.

EKPC Capacity Expansion Plan

Project	Capacity Type	In Service Date	Capacity (MW)	Location
Landfill Gas Projects	Baseload	2005 - 2014	up to 40 additional	Various
Gilbert Unit	Baseload	Mar 2005	268	Spurlock Site Maysville, KY
Smith CT 8	Peaking	Apr 2007	97 (Winter Rating)	J. K. Smith Site Trapp, KY
Smith CT 9-10	Peaking	Nov 2007	97 Each (Winter Rating)	J. K. Smith Site Trapp, KY
Smith CT 11-12	Peaking	Apr 2008	97 Each (Winter Rating)	J. K. Smith Site Trapp, KY
Spurlock 4	Baseload	Apr 2008	278	Spurlock Site Maysville, KY
Smith CFB 1	Baseload	Apr 2009	278	J. K. Smith Site Trapp, KY
New CT 1	Peaking	Apr 2011	98 (Winter Rating)	Undetermined
New CT 2	Peaking	Apr 2012	98 (Winter Rating)	Undetermined
New CT 3-4	Peaking	Apr 2013	98 Each (Winter Rating)	Undetermined
New CT 5	Peaking	Apr 2014	98 (Winter Rating)	Undetermined
New CT 6	Peaking	Apr 2015	98 (Winter Rating)	Undetermined
New CT 7	Peaking	Apr 2016	98 (Winter Rating)	Undetermined
New CT 8	Peaking	Apr 2017	98 (Winter Rating)	Undetermined
New CFB	Baseload	Apr 2018	278	Undetermined
New CT 9-10	Peaking	Apr 2020	98 Each (Winter Rating)	Undetermined
New CT 11	Peaking	Apr 2021	98 (Winter Rating)	Undetermined
New CT 12-13	Peaking	Apr 2022	98 Each (Winter Rating)	Undetermined
New CT 14	Peaking	Apr 2023	98 (Winter Rating)	Undetermined
New CT 15-16	Peaking	Apr 2024	98 Each (Winter Rating)	Undetermined

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2005-00089

INFORMATION REQUEST RESPONSE

COMMISSION STAFF'S 1ST DATA REQUEST DATED 6/16/05

ITEM 25

RESPONSIBLE PARTY: MARY JANE WARNER

REQUEST: Did East Kentucky consider as an alternative a modification to the Cranston Tap proposal, which continues a new 138 kV circuit from the location of the Cranston Tap to Rodburn? This alternative was identified in the consultant's report.

a: Would that alternative be effective electrically to solve the problem East Kentucky is addressing? Explain your answer.

b. How does this alternative compare with East Kentucky's proposed line from a cost standpoint? Explain your answer.

RESPONSE 25: EKPC did not consider the alternative referenced as the Cranston-Parallel Line Alternative on page 46 of the MSB Energy Associates, Inc."Report on the Need for Cranston-Rowan 138 kV Transmission Line Proposed by East Kentucky Power Cooperative, Inc."("MSB Report") to address the system needs in the area.

RESPONSE 25a & 25b: See attached **Data Response Exhibit 25a and Data Response Exhibit 25b**.

DATA RESPONSE 25A

This alternative would not be electrically effective to address the system problems in the area.

The power flow analysis performed by Stanley Consultants identified the occurrence of low voltages at EKPC's Hilda and Elliottville substations for an outage of either the Goddard-Rodburn 138 kV line or the Rodburn-Rowan County 138 kV line. Also, an overload of EKPC's Goddard-Hilda 69 kV line was identified to occur for an outage of the Goddard-Rodburn 138 kV line. And, in addition to this, for an outage of the Rodburn-Rowan County 138 kV line, the loading on the Goddard-Hilda 69 kV line is expected to be as much as 94.5% of the emergency rating without system improvements. The Cranston-Parallel Line Alternative in question would eliminate the problems caused by the Goddard-Rodburn 138 kV line outage. However, it would do nothing to address the low voltage problems and marginal loading issues on Goddard-Hilda 69 kV occurring due to an outage of the Rodburn-Rowan County 138 kV line. These system problems could be temporarily addressed by the installation of capacitor banks at the Rowan County and Elliottville 69 kV busses. However, the Goddard-Hilda 69 kV line is expected to overload shortly beyond the planning horizon even with this alternative implemented, since the flows are approaching the line's limits if there is an outage of the Rodburn-Rowan County 138 kV line.

The MSB Report also listed what were perceived by the Consultant to be several advantages and drawbacks for this alternative (see pages 46 and 47). These perceived advantages and drawbacks are listed below with EKPC's comments on each:

MSB's Perceived Advantages

+ *"It would be electrically very similar to the proposed Cranston-Rowan line, which MSB believes is more robust than the Cranston Tap-KU Line alternative offered by EKPC. "*

  This is not correct. EKPC believes that this alternative is not electrically very similar to the proposed Cranston-Rowan County line because the line is terminated at KU's Rodburn substation in the Consultant's proposed alternative rather than at Rowan County. Therefore, an outage of the 138 kV line between the Rodburn and Rowan County substations still results in an outage of the only 138 kV source for the Rowan County and Skaggs substations.

+ *"It would not require taking the critical KU Goddard-Rodburn line out of service to reconductor it."*

  EKPC agrees that the proposed option would avoid the need for an extended outage to accommodate a reconductor of this line. However, EKPC's proposed project also eliminates the need for this outage.

+ *"It would avoid the cost of reconductoring any part of the KU Goddard-Rodburn line."*

EKPC agrees that the proposed option would avoid the need to reconductor any part of this line. However, EKPC's proposed project also eliminates the need for this reconductoring.

+ *"It would avoid the cost of reconductoring the Goddard-Hilda 69 kV line."*

EKPC agrees that the proposed option would temporarily avoid the need to reconductor the Goddard-Hilda 69 kV line. However, since another 138 kV connection would not be established into the Rowan County substation with this alternative, an outage of the Rodburn-Rowan County 138 kV line will in the near future overload the Goddard-Hilda 69 kV line.

+ *"It would avoid the cost of capacitor banks at Elliottville and Rowan."*

This is incorrect. As shown in EKPC's report detailing its study results, low voltages exist at the Hilda and Elliottville 12 kV buses for an outage of the Rodburn-Rowan County 138 kV line. (See Appendix A, page A-6). The Consultant's proposed alternative does not include mitigation of these problems. Therefore, either the referenced capacitor banks or an additional line to Rowan County would be required to make this a viable alternative.

+ *"It would avoid the cost of siting and building a switching station at the Cranston Tap location."*

EKPC agrees that the Consultant's alternative would avoid the construction of a switching station at this location. However, EKPC's proposed project also avoids construction of this switching station.

+ *"It would complete a second circuit to the Cranston area."*

EKPC agrees that the Consultant's alternative would provide a second source to the Cranston substation. However, EKPC's proposed project does the same.

+ *"It would complete a second circuit to Rodburn."*

EKPC disagrees that this is an advantage of the Consultant's proposed alternative. There are actually already two 138 kV circuits terminating at KU's Rodburn substation. Therefore, for an outage of one of these existing circuits, a 138 kV source will be maintained to the Rodburn substation. Therefore, there is limited value to the addition of a third circuit into the Rodburn substation. Furthermore, power flow studies would be required to determine if overloads of the transformer and 69 kV lines at Rodburn would be created by terminating another line at

Rodburn as the consultant suggests. Also, an evaluation would have to be conducted to determine the feasibility of terminating another line at Rodburn.

+ *"It would be consistent with the concept of the EKPC Eastern 138 kV loop."*

EKPC agrees that the Consultant's proposed alternative is consistent with EKPC's concept of an Eastern 138 kV loop, although it would make this plan more dependent on KU's facilities than does EKPC's proposed alternative. The EKPC conceptual Eastern 138 kV loop plan envisions an EKPC-only 138 kV transmission path between the Spurlock and J.K. Smith Generating Stations. The Consultant's proposed alternative requires the use of the 138 kV bus at KU's Rodburn substation to provide this path. EKPC's proposed plan avoids this by terminating the proposed line at EKPC's Rowan County rather than at KU's Rodburn.

+ *"The portion running parallel to the KU Goddard-Rodburn line would be built on separate structures and as independent circuits. While there would be some risk of common mode failure taking out both circuits, the risk would be less than relying on a single larger circuit to handle the power flows."*

EKPC agrees that the Consultant's proposed alternative provides these benefits compared to the alternative that tapped KU's Goddard-Rodburn line. However, EKPC's proposed Cranston-Rowan County 138 kV line provides these advantages to an even greater degree since this line would not be in close proximity to the Goddard-Rodburn line. The close proximity of the parallel circuits suggested by the consultant would subject each circuit to the same risk of outage from a single weather event or other occurrence in the immediate area.

MSB's Perceived Drawbacks

+ *"It does not provide a second circuit to Rowan. A second circuit would eventually serve Rowan when the conceptual 138 kV loop is fully implemented. If it is determined that a second circuit to Rowan is needed sooner, it may be possible to over-build a 138 kV line on the Rowan-Hilda 69 kV from the point that the 69 kV intersects with the Goddard-Rodburn 138 to Rowan. "*

EKPC agrees that a major disadvantage of the Consultant's proposed alternative is that it does not provide a second 138 kV source for the Rowan County substation. Presently, the Rowan County substation has only one 138 kV source and one 69 kV source. As indicated previously, the power flow studies show that an outage of the 138 kV source between Rodburn and Rowan County causes low voltage problems and near-problem line loadings. Since this alternative does not create a second 138 kV source for the Rowan County substation, these issues are not eliminated.

+ *"The feasibility of sharing a corridor with the existing line in this area has not been studied."*

This is not correct. This feasibility has been studied. One of the routing alternatives considered by the U.S. Forest Service in the EA for EKPC's proposed Cranston-Rowan County 138 kV line was to parallel KU's Goddard-Rodburn 138 kV line. This routing was discarded by both EKPC and the U.S. Forest Service in favor of EKPC's proposed route. While a detailed design would be required to fully assess the feasibility, it is expected that no benefits would be gained by paralleling the KU line for the following reasons:

- The KU line has many instances of long spans of conductor between conductors, which, due to blow-out requirements of the National Electric Safety Code, would require a greater separation distance between the existing line and a new parallel line. This would greatly reduce or eliminate the ability to share existing rights-of-way.
- Access to the area in which the Goddard-Rodburn line would be paralleled is limited by the U.S. Forest Service. Therefore, additional impacts would be created and additional cost would be incurred to create access roads to construct and maintain another line in this area.

+ *"The costs of constructing this alternative have not been determined."*

EKPC agrees that detailed cost estimates have not been determined for this alternative. Additionally, a detailed power flow analysis has not been performed on this alternative. However, general cost estimates have been used to estimate the cost for the Consultant's proposed alternative assuming that it will even work with the addition of the capacitor banks at Rowan County and Elliottville that were discussed earlier. This cost estimate is discussed in Data Response 25b.

+ *"It is longer than the proposed Cranston-Rowan 138 line (9 miles compared to 6.9 miles), which increases costs, although it probably requires less new corridor, which decreases costs."*

EKPC agrees that the Consultant's proposed alternative would result in constructing more than two miles of additional line compared to the Cranston-Rowan County alternative, and EKPC also agrees that this additional line construction will increase the costs. However, EKPC believes that there will be minimal opportunity to share existing rights-of-way, and, furthermore, additional impacts will be created and additional costs will be incurred to provide sufficient construction access roads. Therefore, it is expected that this option will cost significantly more due to the increased line length, as explained further in Data Response 25b. part (b).

DATA RESPONSE 25B

Detailed planning estimates have not been determined for this alternative. Additionally, a detailed power flow analysis has not been performed on this alternative to identify all upgrades that may be necessary to eliminate all system problems. General cost estimates have been used to determine an estimated cost range for the Consultant's proposed alternative assuming that it will work with the addition of the capacitor banks at Rowan County and Elliottville that were discussed in Data Response 25a. This cost range is determined by assuming that the potential savings per mile for the 4.4-mile section of the new line that would parallel the existing Goddard-Rodburn line is somewhere between $0 and $50,0000. Using the same financial parameters as were used in EKPC's original analysis, the cost range for the Consultant's proposed alternative is $5,900,000 to $6,100,000. The cost that EKPC determined for the Cranston-Rowan County Alternate (Alternate 1 in the April 2002 Justification) was $4,947,400. Therefore, assuming that a cost savings of $50,000 per mile could be realized by sharing rights-of-way with the KU Goddard-Rodburn 138 kV line, this alternative would still cost almost $1,000,000 more than EKPC's proposed alternative. Furthermore, this alternative would not be as electrically robust as EKPC's proposed Cranston-Rowan County Alternative and would not address all existing problems in the area, since the line would terminate at Rodburn rather than continuing to Rowan County.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2005-00089

INFORMATION REQUEST RESPONSE

COMMISSION STAFF'S 1ST DATA REQUEST DATED 6/16/05

ITEM 26

RESPONSIBLE PARTY: MARY JANE WARNER

REQUEST 26: Did East Kentucky consider as an alternative the upgrading of the Goddard-Hilda-Rowan 69 kV line to 138 kV to provide a parallel 138 kV circuit to KU's Goddard-Rodburn line? This alternative was identified in the consultant's report.

RESPONSE: EKPC did not consider the alternative referenced as Converting the Existing Goddard-Hilda-Rowan Line to 138 kV on page 50 of the MSB Energy Associates, Inc. ''Report on the Need for Cranston-Rowan 138 kV Transmission Line Proposed by East Kentucky Power Cooperative, Inc'' ("MSB Report") to address the system needs in the area.

REQUEST 26a:

a. Would that alternative be effective electrically to solve the problem East Kentucky is addressing? Explain your answer.

RESPONSE: See attached **Data Response 26a.**

b. How does this alternative compare with East Kentucky's proposed line from a cost standpoint? Explain your answer.

RESPONSE: See attached **Data Response 26b.**

DATA RESPONSE 26A

This alternative would not be electrically effective to address the system problems in the area.

Detailed power flow analysis would be required to determine if this alternative would eliminate the undervoltages and line overloads identified in the area. However, even if this alternative would eliminate those problems, it still would not provide a second circuit to provide backfeed capability to the Cranston substation. EKPC uses a MW-mile index to evaluate the potential risk of exposure of distribution substations to outages. This index value is simply the product of the peak substation demand and the length of the radial line serving the substation. EKPC's threshold for radial service to a substation is 100 MW-miles. EKPC uses this threshold in two ways:

1) EKPC will not make changes to the transmission or distribution system that result in an immediate violation of this threshold.
2) When undervoltages and/or overloads are identified in an area that also has a radial transmission feed that exceeds the 100 MW-mile threshold, only alternatives which eliminate all of these problems will be considered.

Therefore, the Consultant's proposed alternative is not viable since it does not provide a second source for the Cranston substation.

A second major problem with the Consultant's proposed alternative is that it removes one of the two sources for the Rowan County 69 kV bus. The 69 kV bus serves the Elliottville distribution substation through a 69 kV radial line. The existing system has a 138-69 kV autotransformer at Rowan County and the Goddard-Hilda-Rowan County 69 kV line as sources for the Rowan County 69 kV bus. If the Goddard-Hilda-Rowan County 69 kV line is converted to 138 kV, the 138-69 kV autotransformer would be the only source for the Elliottville 69 kV bus. This would be an unacceptable reliability risk. If the autotransformer failed, EKPC would not be able to serve the Elliottville substation until another 138-69 kV autotransformer could be moved to Rowan County, which is likely to be a minimum of several days and as much as a month. To eliminate this risk, EKPC would most likely require a second autotransformer be installed at Rowan County to provide a second source in case of a contingency, with an estimated cost range of $500,000 to $1,000,000.

A third problem is that this configuration would cause a significant amount of transformer capacity to go unutilized at Rowan County. The 138-69 kV autotransformer has a nameplate capacity of 67.5 MVA. The Elliottville peak load is approximately 8 MVA. Therefore, almost 60 MVA of the transformer capacity at Rowan County would go unutilized and therefore wasted. Adding a second transformer to provide acceptable reliability would only increase the amount of wasted transformer capacity installed at Rowan County.

The MSB Report listed what were perceived by the Consultant to be several advantages and drawbacks for this alternative (see pages 50-52). These perceived advantages and drawbacks are listed below with EKPC's comment on each:

MSB's Perceived Advantages

+ *"It would utilize existing rights-of-way. "*

EKPC agrees that the existing right-of-way for the Goddard-Rowan County 69 kV line could be utilized if the line were converted to 138 kV. However, this right-of-way, which is sufficient for 69 kV operation, would need to be widened for 138 kV operation. Therefore, additional right-of-way acquisition would be necessary.

+ *"It would leave the existing KU Goddard-Rodburn 138 kV line intact, thus avoiding the construction and operational issues described above."*

EKPC agrees that the Consultant's proposed alternative would not require any upgrades for the Goddard-Rodburn 138 kV line. However, EKPC's proposed project would also not require any such upgrades.

+ *"There are 138 kV busses at the Goddard and Rowan substations, so that it would not be introducing a new voltage level."*

This is correct. However, this is also true of EKPC's proposed plan.

+ *"It would resolve overload issues on the current 69 kV line, which occur for outages of the KU Goddard-Rodburn 138 kV line or for outages of the Rodburn-Rowan 138 kV line."*

EKPC agrees that the Consultant's proposed alternative would resolve the overload issues on the Goddard-Hilda-Rowan County 69 kV line provided that the conductor would be replaced with larger conductor when the line would be converted. This line currently consists of 266 MCM ACSR 26 x 7 conductor (1 conductor per phase). That conductor would not provide adequate capacity if the line is converted to 138 kV operation. Therefore, the conductor would have to be replaced with at least 795 MCM ACSR 26 x 7 conductor if the line were converted, which would require a complete rebuild of the line.

+ *"It would provide a second 138 kV source to Rowan."*

EKPC agrees that the Consultant's alternative would provide a second 138 kV source to the Rowan County substation. However, this is also true of EKPC's proposed plan.

+ *"It would be consistent with and complete another segment in the conceptual EKPC Eastern 138 kV loop."*

EKPC agrees that the Consultant's proposed alternative is consistent with EKPC's concept of an Eastern 138 kV loop. However, this is also true of EKPC's proposed plan.

+ *"Rebuilding the 69 kV line to 138 kV between Goddard and Rowan would inherently be less risky because the outage of that line does not constitute a first contingency outage that causes any other facility to overload. In the comprehensive studies performed by EKPC (and summarized in Appendix A), there is no single contingency that resulted in overloads or low voltages associated with the outage of any segment of the Goddard-Hilda-Rowan 69 kV line."*

This is not correct. When comparing this alternative to EKPC's proposed plan, there is much more risk during conversion of the Goddard-Hilda-Rowan County 138 kV line than during the construction of the Cranston-Rowan County 138 kV line. The Plummers Landing and Hilda distribution substations would be served from radial lines during conversion of the line, which will greatly decrease the reliability of service to these stations. Also, during the conversion, the transmission system in the area would not have the capacity provided by the 69 kV line available if system conditions resulted in a need for the capacity. EKPC's proposed plan to build Cranston-Rowan County leaves the existing transmission system intact during basically the entire construction process.

+ *"It could be built in segments to minimize the risk of local outage. For example the 69 kV Goddard-Plummers Landing segment could be taken out of service, with Plummers Landing and Hilda being served at 69 kV from Rowan during the construction of the Goddard-Plummers Landing segment. When the reconstruction of that segment to 138 kV standards was complete, it could be energized at either 69 kV or 138 kV to supply Plummers Landing while the next segment from Plummers Landing to Hilda was taken out of service for reconstruction. Hilda would still be served from Rowan at 69 kV until the reconstruction to Hilda at 138 kV standards was complete. Then the Hilda-Rowan segment would be rebuilt."*

EKPC disagrees that this is an advantage of the Consultant's proposed alternative. A plan to maintain service to the distribution stations served by the line has been described, but this is not an advantage of the plan. As explained above, the Plummers Landing and Hilda stations would be subjected to increased exposure and reduced reliability during this construction, which is a disadvantage of the alternative.

MSB's Perceived Drawbacks

+ *"It would not provide a second source to the Cranston area."*

EKPC agrees that a major disadvantage of the Consultant's proposed alternative is that it does not provide a second 138 kV source for the Cranston substation. As explained above, this second source is required to eliminate an excessive exposure level for the Cranston substation.

+ *"The higher voltage would require wider rights of way, which may be difficult to acquire along some parts of the existing line. "*

EKPC agrees that this is a disadvantage of the Consultant's proposed alternative.

+ *"The higher voltage would require higher ground clearance, which may require taller structures. The line may have to be substantially removed and rebuilt. "*

EKPC agrees that it is very likely that the line would have to be substantially removed and rebuilt, for the reasons provided by the Consultant, and because a much heavier conductor will be required for 138 kV operation.

+ *"At about 18 miles, it is longer than the other alternatives. "*

The Goddard-Hilda-Rowan County 69 kV line length is actually 19.1 miles. At this length, and with the work that is likely required to the line alone, in addition to the transformer upgrades and additions that will be required, this alternative will be cost prohibitive.

+ *"MSB has no information regarding the cost at this time. "*

EKPC agrees that detailed planning estimates have not been determined for this alternative. Additionally, a detailed power flow analysis has not been performed on this alternative. General cost estimates have been used to determine an estimated cost for the Consultant's proposed alternative assuming that it will work with the addition of a second autotransformer at Rowan County to provide two sources to feed the Elliottville substation from Rowan County. This is discussed in Data Response 26b.

+ *"No power flow studies modeling the performance of the transmission system in eastern Kentucky with this rebuild in service have been performed. "*

EKPC agrees that a detailed power flow analysis has not been performed on this alternative, and is required to fully assess whether this alternative would solve the problems identified in the area.

DATA RESPONSE 26B

Detailed planning estimates have not been determined for this alternative. Additionally, a detailed power flow analysis has not been performed on this alternative to determine if additional upgrades would be necessary to eliminate all system problems. General cost estimates have been used to determine an estimated cost range for the Consultant's proposed alternative assuming that it will work with the addition of a second 138-69 kV autotransformer at Rowan County.

Assuming that the cost to rebuild the existing 69 kV line to 138 kV operation is only half of the cost to build a new line, the cost of only the line work to convert the line would be $4.2 million. Additional costs of this alternative are 138 kV circuit breakers at Goddard and Rowan County, conversion of the Plummers Landing, Hilda #1, and Hilda #2 from 69-12.5 kV to 138-12.5 kV, and the addition of a second autotransformer at Rowan County. These items are roughly estimated to cost on the order of $3.5 million dollars. Therefore, this alternative is estimated to cost in excess of $7.5 million. The actual cost is likely to be more, since a conservative estimate of the line rebuild cost was provided. Also, this option still would not provide a second source for the Cranston substation. EKPC's option provides this second source at a total cost of slightly more than $4.9 million dollars. Therefore, EKPC's proposed option is much less costly than the Consultant's proposed alternative, and provides a much more reliable system.