Kentucky Utilities Company
and
Louisville Gas & Electric Company

2005 Analysis of Reserve Margin Planning Criterion

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2005 ANALYSIS OF
RESERVE MARGIN PLANNING CRITERION

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2005 ANALYSIS OF RESERVE MARGIN PLANNING CRITERION
EXECUTIVE SUMMARY

The Companies 2002 Integrated Resource Plan (Case No. 2002-00367) stated that maintaining a 13%-15% reserve margin was the optimal range, and 14% was recommended for planning purposes. The need to maintain a level of capacity in reserve is well established in the utility industry. Additional generation capacity must be available should there be an unexpected loss of generation, reduced generation capacity due to equipment problems, unanticipated load growth, variances in load due to extreme weather conditions, and/or disruptions in contracted purchased power.

The key variables for studies of this type are: (1) the number and length of planned generating unit outages and maintenance outages, (2) generating unit forced/equivalent forced outage rates, (3) the availability of purchase power capacity for import, (4) the customers perceived cost of unserved/emergency energy and (5) the expected system load. The availability of the Companies' existing units is based on historical data and expected performance. The availability of proposed generating units is such that it falls within the accepted availability for units of a given type, size and class. Since there is no industry standard for the cost of unserved energy, the Companies' analysis utilized unserved energy costs similar to those found in the 2002 IRP. It is based upon an EPRI study and adjusted to reflect market volatility to determine a base unserved energy cost. Sensitivity values around the base customer perceived value of unserved energy cost was evaluated, as were market purchases, a high annual load forecast, and unit availability sensitivities. The Strategist® computer model was utilized in the evaluation and the least cost present value of revenue requirements (PVRR) was used as the primary decision factor.

Optimizations were utilized to create a least cost ordering of supply-side options for various reserve margin levels given each set of key variables. This methodology was repeated for all possible combinations of the key variables over a range of reserve margins. Reserve margins with PVRR within 0.5% of the minimum PVRR were considered as economically equivalent.

Given the base case assumptions used in this study, together with the detailed sensitivity analysis performed on the purchase power market, unit availability, customer perceived unserved energy cost, annual load forecast, a target reserve margin in the range of 12%-14% is considered optimal. It is recommended that the Companies maintain a target reserve margin in the upper portion of the optimal range. Therefore, a target reserve margin of 14% is recommended for planning purposes.

INTRODUCTION

The Companies 2002 Integrated Resource Plan (Case No. 2002-00367) stated that maintaining a 13%-15% reserve margin[1] was the optimal range, and 14% was recommended for planning purposes. The need to maintain a level of capacity in reserve is well established in the utility industry. Additional capacity must be available (either physical generators or purchase power) should there be an unexpected loss of generation, reduced generation capacity due to equipment problems, unanticipated load growth, variances in load due to extreme weather conditions, and/or disruptions in contracted purchase power.

This study was conducted to evaluate and document the economics of maintaining various target reserve margin levels given the aforementioned challenges. As a result of this study, a recommendation of a target reserve margin for planning purposes is made.

The study was conducted using the Strategist® computer model. Strategist® is a capital and production costing computer model with the capability to compute total fuel, fixed and variable operating costs and emission related expenses for existing and future units, as well as the capability to develop a least-cost resource plan for future years. Strategist® can also evaluate the reliability of electricity power supply and model power transactions. Finally, Strategist® calculates an annual and study period PVRR for all computer simulations. A minimum present value criterion over the study period (30 years) will be used in this study as the principal economic decision parameter.

This report will: (1) provide a summary of the study methodology and assumptions; (2) detail assumptions that most strongly influence margin analysis; (3) describe scenarios and sensitivities developed; and finally, (4) recommend the least-cost target reserve margin level for the combined KU/LG&E system.

1 Reserve Margin %= (Total Supply Capability – Peak Load) / Peak Load

STUDY METHODOLOGY

The methodology used in the analysis consisted of using Strategist® to create an optimized (or least cost) supply strategy for a specified reserve margin level and a given set of assumptions and key variables. This least-cost resource plan is commonly referred to as the "optimal" expansion plan. Strategist® optimizations were made for both a base set of assumptions and sensitivities (discussed later) at target reserve margin levels ranging from 7% to 18% in 1% increments. The 7% and 18% levels are selected as reasonable minimum and maximum reserve margins based on results in the 2002 IRP. The optimization process determines the least-cost resources from those available to satisfy the user input target reserve margin level. The objective of the optimizations is to balance costs associated with maintaining a reliable supply system with the customers' perceived cost of unserved energy. The result of the optimization is a least-cost supply-side plan for a given set of assumptions (i.e. reserve margin, load forecast, unit availability, etc.). The reserve margin level, which yields the minimum PVRR for each set of assumptions and key variables, can then be determined. The reserve margin levels suggested by the individual optimizations can then be reviewed to determine the least-cost reserve margin planning level for the Companies.

STUDY ASSUMPTIONS

Appendix A of this report provides detailed information describing inputs utilized in the modeling of KU, LG&E and Owensboro Municipal Utilities (OMU) generating systems. Utilizing the multi-area production costing capability of Strategist®, OMU is modeled separately. This allows for more accurate simulation of contractual arrangements between KU and OMU.

Several inputs strongly influence resource expansion studies of this nature. These inputs include: (1) the number and length of planned generating unit outages and maintenance outages, (2) generating unit forced and equivalent forced outage rates, (3) the availability of purchase power capacity for import, (4) the customers perceived cost of unserved or emergency energy, and (5) load forecast and load factor.

Key Input 1: Unit Planned Outages

A planned outage (PO) is defined as the removal of a generating unit from service to perform work on specific components scheduled well in advance with a predetermined start date and duration. The guidelines for the scheduling of major and minor planned outages on baseload units in the KU/LG&E system at the time this analysis was conducted are shown in Table 1. A major maintenance typically refers to work on both the steam turbine and generator while minor maintenance typically refers to boiler inspection and smaller balance of plant equipment maintenance.

Table 1
KU/LG&E Planned Outage Practices on Baseload Units

	Minor Maintenance		Major Maintenance	
	Duration	Time Between	Duration	Time Between
Mill Creek	5 weeks*	~ 2 years	8 weeks	~ 7 years
Trimble Co. 1	4 weeks	~ 2 years	8 weeks	~ 7 years
All Other Units	3 weeks	~ 1 year	8 weeks	~ 7 years

* - 4 weeks every other year and 1 week in years between

As shown in Table 1, the Companies anticipate that on average, most units will be out 3 weeks for minor planned maintenance work every year, while at Trimble County and Mill Creek minor planned maintenance events are expected to last approximately 4 and 5 weeks, respectively every two years. All baseload units are expected to require an average of 8 weeks to complete major planned outages every 7 years.

In this analysis, maintenance was not re-optimized for any sensitivity run. The planned maintenance schedule that exists in each series is identical for the existing units regardless of what target reserve margin is being evaluated or what sensitivity evaluation is being performed. Optimization of unit maintenance is a highly computer intensive task which would not significantly affect studies of this type. This analysis assumes that the Companies' current major and minor maintenance needs (weeks) will not change over time.

Key Input 2: Unit Forced Outages/Equivalent Forced Outages

Forced outages are events that require the full unit be removed from service unexpectedly and immediately. Forced outage rates (FORs) are defined as the total number of forced outage hours divided by the sum of (total number of forced outage hours + total number of service hours). Equivalent forced outage rates (EFORs) are similar to FORs but include hours in which the unit is derated (capable of operating but unable to operate at full load). FORs and EFORs provide information on how frequently particular events cause unit outages or derates. The rates are developed via a Generator Availability Data System (GADS) for KU/LG&E. GADS is a database that contains historical unit outage information for each unit. The forced outage rate and the equivalent forced outage rate for each unit were calculated based on GADS data for each year in the units' major maintenance cycle. Gathering GADS data over a units' maintenance cycle allows the improvements in availability that normally occur after a major maintenance to be reflected in the Strategist® model as well as the tendency for unit availability to decrease in years immediately preceding the next anticipated major maintenance.

A maintenance outage (MO) is defined as the removal of a generating unit from service to perform work on specific components which could have been delayed beyond the end of the next weekend, but requires that the unit be removed from service before the next major or minor planned outage. Maintenance outages, like forced outages and forced derates, may occur at any time during the year, may have flexible start dates, and may or may not have a predetermined duration. To capture the random nature of events that trigger a MO and to maximize the effect of the MO event on system capacity (i.e. reduce the generating system capability during the weekday when load is greatest instead of on the weekend), maintenance outage hours have been included in the modeled forced outage rates of the units.

Table 2 shows modeled base forced outage rates and modeled base equivalent forced outage rates for baseload units.

Table 2
Modeled FOR and EFOR

Unit	FOR %	EFOR %
Brown 1	3.50%	4.36%
Brown 2	3.50%	4.56%
Brown 3	4.00%	5.13%
Cane Run 4	4.50%	8.38%
Cane Run 5	4.50%	9.39%
Cane Run 6	4.50%	8.70%
Ghent 1	3.50%	4.75%
Ghent 2	3.50%	6.30%
Ghent 3	3.50%	5.43%
Ghent 4	3.50%	5.51%
Green River 3	6.00%	8.10%
Green River 4	6.00%	8.50%
Mill Creek 1	4.50%	7.72%
Mill Creek 2	4.50%	7.79%
Mill Creek 3	4.50%	7.75%
Mill Creek 4	4.50%	8.03%
Trimble 1 (75%)	3.30%	5.90%
Tyrone 3	6.00%	6.20%

As part of this evaluation, two unit availability sensitivities were performed. One decreased the availability of the coal units by increasing each coal unit's EFOR by 5% annually, and the second decreased the availability of the peaking units by increasing each CT's EFOR by 10% annually.

Key Input 3: Availability of Firm/Non-Firm Purchase Capability

The Companies are interconnected through their transmission system with eight other control areas. Currently, the Companies have contracted for the purchase of firm summer capacity from the following three entities: Electric Energy Incorporated (EEI), Ohio Valley Electric Corporation (OVEC) and OMU. The dispatch of purchase power units in Strategist® approximates the actual dispatch of the purchase capacity. All three contracts are assumed to extend through the last year of the study period and these were the only existing purchase power alternatives available in the base series of runs.

The EEI and OVEC purchases are modeled in Strategist® as purchase power units. KU's future purchases from OMU are modeled using Strategist®'s multi-area modeling feature, which parallels the actual dispatching of all units. However, in order to model a least-cost dispatch of the combined KU/LG&E and OMU generating systems, a detailed model of the OMU generation system is required. The details of the OMU generation system model and the amount of on-peak capacity available from OMU by year during the study period can be found in Appendix A.

Like unit availability, a sensitivity was also performed on purchase power. While the base assumption limited purchase power only to the above three purchase power contracts, this sensitivity allowed purchase power from the wholesale power market to be evaluated. A maximum of 200 MW of weekday on-peak (5x16) spot purchase power was made available. Spot purchases are short-term market purchases that can have a large energy cost and very little or no demand cost associated with them. This cost profile is utilized because spot purchases generally have a short turnaround between notification and physical delivery. This evaluation assumes that spot purchases are considered to be non-firm capacity. This study assumes that spot purchases are 5 times the monthly firm forward price for the 5x16 period. The spot/hourly market may not have power available on rare occasions; therefore, the spot market was assumed to have 95% availability. Table 3 and Appendix A convey information associated with the purchases modeled in Strategist®.

Table 3
Modeled Purchase Information

Supplier	MW	EFOR	Term
OMU	*	Smith 1 – 13.6% Smith 2 – 14.51%	Throughout Study Period
EEI	200 MW	9.74%	Throughout Study Period
OVEC	179 MW	NA	Throughout Study Period
Spot	200 MW	5.00%	Weekday On Peak Periods Only Throughout Study Period

* - Changes annually to reflect OMU's load growth

Aside from the contractual and spot purchases discussed above, one additional purchase type is automatically modeled in Strategist®: emergency (unserved) energy.

Key Input 4: Customer Perceived Cost of Emergency/Unserved Energy

Emergency energy is automatically determined by the Strategist® model and is a direct measure of the system's inability to meet its load demands; therefore, emergency energy purchases are a key factor in determining the optimal target reserve margin level for use in resource planning studies. The cost of emergency/unserved energy is defined as the cost (whether real or perceived) to a customer during an outage on the transmission or distribution system, or for capacity shortages, which result in a power outage. The perceived and realized cost of this type of energy is highly dependent on customer type (i.e., residential, commercial, industrial), the duration of the outage, and the frequency at which outages occur. A residential customer who might only be inconvenienced by an outage would likely place a lower value on this type of energy than an industrial customer who may incur a substantial economic loss due to an outage. Likewise, within customer classes, the value of unserved energy can vary greatly due to individual customer needs. In addition to variations customers place on unserved energy, the following attributes of the outage or curtailment may affect the overall perceived value by the customer: timing (hour, season), duration, magnitude (partial or total), advance notice given, frequency, and coverage (area affected).

An EPRI report titled "Cost Benefit Analysis of Power System Reliability Determination of Interruption Costs" addresses the issue of determining a value for customer outages. By analyzing the results of a detailed survey of 27 utilities, the report determined the value those utilities place on unserved energy for reliability planning. The survey results help to determine the value for customer outages that can be applied to unserved energy in this study. Average unserved energy values calculated for each customer class in the EPRI study are shown below in Table 4. The approximate percentage of the Companies' energy sales by class during 2003 is applied to the survey results and a weighted average unserved energy cost estimate is calculated.

Table 4
Customer Perceived Outage Cost Estimates

CLASS	AVERAGE ($/UNSERVED kWh)	LG&E/KU CUSTOMER SALES (%)	WEIGHTED COST ($/UNSERVED kWh)
Residential	1.5	34	0.50
Commercial	11.8	36	4.25
Industrial	19.4	30	5.82
		Weighted Sum	10.6
		Est. Base Cost of Unserved Energy	*~11.0*

Therefore, based on the results as shown in Table 4, a base cost of $11 per kWh for unserved energy is used in this study. An estimate of customer load (kWh) not served during power outages or capacity shortages is determined by the Strategist® model and labeled as "Unserved Energy". The unserved kWh is then multiplied by the unserved energy cost ($/kWh) to determine the cost associated with the power outage or capacity shortfall from the customer's perspective. To consider the sensitivity of results to the base assumption of $11/kWh value for unserved energy, values of $7/kWh and $15/kWh were also evaluated in this study.

Key Input 5: Higher than Expected Load Forecast

A system load factor that is higher than forecasted could also change the optimal mix of supply-side technologies. This change could force units such as peakers, normally considered alternatives with low capital cost but high operating expense, to operate at capacity factors that would have made baseload units (such as combined cycles or coal-fired units) the better choice. The change in supply-side technologies could affect the optimal system reserve margin target due to the inherent difference in the capacity and availability of combustion turbines, combined cycles and coal-fired units. Therefore, in recognition of the fact that precise load forecasting is unlikely, an annual load forecast sensitivity was performed. This sensitivity allows for a more thorough strategy and possibly less exposure to the higher prices that can be experienced during the summer period. Anytime load sensitivities are used in this evaluation, the resulting reserve margins shown in the tables and the figures are calculated based on the installed capacity and the base load forecast and not the new forecast. This is done to more fully represent the situation where the Companies are anticipating the load reflected by the base load forecast but the observed peak loads are higher than expected.

The high load forecast developed by the Market Forecasting department has higher peaks and energies than the base forecast in each and every month and is developed using the same methodology that went into developing the base load forecast. Appendix A contains additional detail on the Base and High Load Forecasts.

STRATEGIST® ANALYSIS

Combinations of the above variables (unit availability, load forecast, load factor, unserved energy cost and purchase power) were used to develop a series of cases that enabled the determination of a least cost reserve margin under various conditions. (Note: A series is defined as an optimization for a fixed set of variables over the range of 7-18% minimum reserve margin.) Table 5, summarizes the key variables for each of the 24 series of cases evaluated. For each series, twelve optimizations were performed with a minimum target reserve margin ranging from 7% to 18% (in 1% increments). Each optimization produced the least-cost supply-side strategy for that given set of assumptions (including minimum target reserve margin) for the key variables.

Table 5
Identification of Key Variables Evaluated

Series #	Coal Unit Availability	Combustion Turbine Availability	Load Forecast	Unserved Energy Cost ($/kWh)	5x16 Purchase Modeled
1	Base	Base	Base	7	No
2	Base	Base	Base	11	No
3	Base	Base	Base	15	No
4	Low	Base	Base	7	No
5	Low	Base	Base	11	No
6	Low	Base	Base	15	No
7	Base	Base	High	7	No
8	Base	Base	High	11	No
9	Base	Base	High	15	No
10	Base	Low	Base	7	No
11	Base	Low	Base	11	No
12	Base	Low	Base	15	No
13	Base	Base	Base	7	Yes
14	Base	Base	Base	11	Yes
15	Base	Base	Base	15	Yes
16	Low	Base	Base	7	Yes
17	Low	Base	Base	11	Yes
18	Low	Base	Base	15	Yes
19	Base	Base	High	7	Yes
20	Base	Base	High	11	Yes
21	Base	Base	High	15	Yes
22	Base	Low	Base	7	Yes
23	Base	Low	Base	11	Yes
24	Base	Low	Base	15	Yes

Optimizations were conducted to determine the reserve margin level that yields the minimum PVRR under all scenarios. At each target reserve margin level from 7% to 18%, all other key variables were held constant. The optimization quantifies the cost and reliability effects of all combinations of potential generating technologies and results in expansion plans, all of which meet both the pre-specified user constraints and the specific target reserve margin criterion. The capital and production costs (including the cost of unserved energy) of each plan is determined by the Strategist® model, and the expansion plan with the lowest PVRR is selected as the least-cost plan for that case. The next case is developed by increasing the target reserve margin by 1% and performing another optimization. This methodology is repeated until the target reserve margin being evaluated would exceed 18%, at which time a key variable is changed and the process begins anew at a 7% reserve margin. Performing optimization simulations at each reserve margin level assures that the optimal (least costly) ordering of units is maintained. The results of the optimizations determine the reserve margin level at which the minimum PVRR occurs for each series.

As an example, consider the results of the optimization process for Series 1, 2 and 3 shown in Figure 1. The larger values of PVRR at the high or low end of the reserve margin curve shown in Figure 1 reflect the increase in costs due to capital expenditures or unserved energy respectively. The increase in PVRR on the upper ends of the curves (i.e. occurring at the higher reserve margin levels) is a function of increased capital/operating expenditures for generation construction associated with maintaining the higher reserve margin. Conversely, the increase in PVRR values at the lower target reserve margin levels is a function of both the amount of unserved energy and the value placed on unserved energy. The minimum PVRR (indicated by the arrows in Figure 1), which for Series 1 and 2 occurs at 8% reserve margin and for Series 3 occurs at 11% reserve margin, strikes a balance between capital/operating expenditures associated with maintaining a target reserve margin and the value placed on unserved energy. Notice also in Figure 1 that the PVRR values are relatively the same near and around the minimum PVRR. For example, using the $11/kWh (Series 2) curve in Figure 1, there is less than 0.5% difference between the PVRR associated with maintaining an 8% reserve margin and maintaining a 7% to 13% reserve margin level. The overall flatness of the curves around the minimum PVRR value suggests reserve margin levels with a PVRR within a small variance of the minimum PVRR could be considered economically identical or nearly identical to the lowest PVRR. This indicates a greater level of system reliability, as measured by reserve margin, can be attained with minimal increase in cost and for this reason, it is difficult to recommend a single target reserve margin point based solely on the minimum PVRR for each series. Figure 2 graphically displays all reserve margins for Series 1-3 that are within 0.5% of each respective Series' minimum

PVRR. It suggests that, based solely on Series 1-3, that a reserve margin range of 7-12% is optimal. The reserve margin range is determined by observing the reserve margin levels that are common to each case. Maintaining a reserve margin within this range guarantees that given the base assumptions for load, unit availability and purchase power, the least-cost case possible is maintained under all assumptions for unserved energy.

If we now add Series 4-12 to Figure 2, a better overall picture of how the sensitivities affect both the reserve margin ranges and cost can be observed (see Figure 3). Figure 3 stops at Series 12 because it is a convenient break point for graphing purposes in that it is the last case without the purchase option. (Note that for convenience the legend associated with Figure 3 lists each Series in the order that it appears in the chart, i.e.: the least cost case is at the bottom of the legend box and the most costly case is at the top). As one would expect, the least costly case without market purchases is Series 1 where unserved energy cost is $7/kWh. Increasing the Companies' load forecast when unserved energy is assumed to cost $15/kWh (Series 9) is the most expensive sensitivity evaluated. All others sensitivities without the market purchase alternative fall somewhere in between. Figure 4 completes the process for the remaining Series 13-24. Again the base Series with unserved energy at $7/kWh is the least costly series while increasing the Companies load forecast when unserved energy is assumed to be $15/kWh is the most expensive.

To re-emphasize, Figure 3 and 4 are graphical representations of economically equivalent reserve margins for each evaluated where a Series is defined by a fixed set of key variable assumptions evaluated over a span of minimum reserve margin values. The reserve margin ranges shown in Figures 3 and 4 are considered economically equivalent because they exceed the series minimum by less than 0.5%. Considering costs within a range of 0.5% allows for a more narrow analysis of possible reserve margin planning levels while insuring that proper consideration is given to the other possible values of the key variables. Table 6, below, shows the range of reserve margin levels for all Series 1-24 and is a tabular form of the data contained in Figures 3 and 4. Essentially, Table 6 summarizes the ranges of reserve margins for each set of case assumptions (or Series) where the cost of maintaining the reserve margin range is equivalent.

Table 6
Economically Equivalent Reserve Margin Levels

Series #	Coal Unit Availability	Combustion Turbine Availability	Load Forecast	Unserved Energy Cost ($/kWh)	5x16 Purchase Modeled	Economically Equivalent Reserve Margin
1	Base	Base	Base	7	No	7% to 12%
2	Base	Base	Base	11	No	7% to 13%
3	Base	Base	Base	15	No	7% to 14%
4	Low	Base	Base	7	No	11% to 18%
5	Low	Base	Base	11	No	14% to 18%
6	Low	Base	Base	15	No	14% to 18%
7	Base	Base	High	7	No	12% to 14%
8	Base	Base	High	11	No	12% to 14%
9	Base	Base	High	15	No	12% to 14%
10	Base	Low	Base	7	No	7% to 15%
11	Base	Low	Base	11	No	10% to 17%
12	Base	Low	Base	15	No	11% to 18%
13	Base	Base	Base	7	Yes	7% to 12%
14	Base	Base	Base	11	Yes	7% to 13%
15	Base	Base	Base	15	Yes	7% to 13%
16	Low	Base	Base	7	Yes	10% to 17%
17	Low	Base	Base	11	Yes	12% to 18%
18	Low	Base	Base	15	Yes	13% to 18%
19	Base	Base	High	7	Yes	12% to 13%
20	Base	Base	High	11	Yes	12% to 14%
21	Base	Base	High	15	Yes	12% to 14%
22	Base	Low	Base	7	Yes	8% to 15%
23	Base	Low	Base	11	Yes	9% to 16%
24	Base	Low	Base	15	Yes	10% to 17%

Based on the information in Table 6 and Figures 3 and 4, the most appropriate reserve margin range that would best balance the costs of maintaining a high reserve margin with the cost of unserved energy can be determined. Again, Figures 3 and 4 can greatly assist in this process. Just as was done for Series 1-3 (in Figure 2), the reserve margin range can be determined by first counting the number of times that each Series identifies a specific reserve margin as being included as that series' economically equivalent PVRR. This process is repeated for all Series and the number of times that a particular reserve margin level is included as that series' economically equivalent PVRR is accumulated. For example if Figure 3 is examined, it can be seen that a 12% reserve margin was identified in ten Series, that 13% was identified in nine Series, 14% was identified in ten separate Series, and so on. Table 7 and Table 8 (below) summarizes the frequency of occurrence of each reserve margin level in the suggested reserve margin range of each Series in Figure 3 and Figure 4 respectively. If a specific reserve margin was within the economically equivalent reserve margin range, a "1" would be placed in the table at the appropriate location.

Table 7
Number of Times Reserve Margin is
Identified in Economically Equivalent Range
(No Market Purchase Alternative)

	Minimum Reserve Margin											
Series #	7%	8%	9%	10%	11%	12%	13%	14%	15%	16%	17%	18%
1	1	1	1	1	1	1						
2	1	1	1	1	1	1	1					
3	1	1	1	1	1	1	1	1				
4					1	1	1	1	1	1	1	1
5								1	1	1	1	1
6								1	1	1	1	1
7						1	1	1				
8						1	1	1				
9						1	1	1				
10	1	1	1	1	1	1	1	1	1			
11				1	1	1	1	1	1	1	1	
12					1	1	1	1	1	1	1	1
Sub-Total	**4**	**4**	**4**	**5**	**7**	**10**	**9**	**10**	**6**	**5**	**5**	**4**

Table 8
Number of Times Reserve Margin is Identified in Economically Equivalent Range
(With Market Purchase Alternative)

	Minimum Reserve Margin											
Series #	7%	8%	9%	10%	11%	12%	13%	14%	15%	16%	17%	18%
13	1	1	1	1	1	1						
14	1	1	1	1	1	1	1					
15	1	1	1	1	1	1	1					
16				1	1	1	1	1	1	1	1	
17						1	1	1	1	1	1	1
18							1	1	1	1	1	1
19						1	1					
20						1	1	1				
21						1	1	1				
22		1	1	1	1	1	1	1	1			
23			1	1	1	1	1	1	1	1		
24				1	1	1	1	1	1	1	1	
Sub-Total	**3**	**4**	**5**	**7**	**7**	**11**	**11**	**8**	**6**	**5**	**4**	**2**

Figures 5 and 6 incorporate Tables 7 and 8 respectively with the addition of the dashed line. Table 9 (graphically presented in Figure 7) summarizes the data in Tables 7 and 8 revealing that a reserve margin range of 12-14% would be suggested by eighteen or more (or 3/4) of the cases evaluated.

Table 9
Total Number of Times Reserve Margin is Identified in Economically Equivalent Range
(All Series)

	Minimum Reserve Margin											
	7%	8%	9%	10%	11%	12%	13%	14%	15%	16%	17%	18%
No Market	4	4	4	5	7	10	9	10	6	5	5	4
With Market	3	4	5	7	7	11	11	8	6	5	4	2
Total (All)	7	8	9	12	14	21	20	18	12	10	9	6

SUMMARY AND RECOMMENDATION

Key variables representing a base case series of simulations and sensitivities were analyzed in optimization studies. The key variables were evaluated over a range of target reserve margin levels.

For each series, the minimum reserve margin level was determined. This minimum value strikes the best balance between the perceived cost to the customer of unserved energy and capital/operational expenditures for generation construction or purchased power options. The balance between unserved energy cost and capital expenditures/purchase power is apparent through graphical analysis as the relatively flat region near and around the minimum PVRR value for each case. This suggests that reserve margins in this region of values can be maintained at or near the same cost. Therefore, the value for reserve margin at the high end of the range of reserve margins can be recommended as the planning reserve margin because it represents the maximum system reliability at the lowest cost. The analysis summarized in Table 6, Table 7, Table 8 and Table 9 suggest a 12%-14% reserve margin range would provide the most flexibility to minimize the cost impacts associated with decreasing unit availabilities, variances in seasonal or annual load projections and the wholesale power market. Therefore, given the assumptions and sensitivities analyzed in this study this analysis suggests an optimal target reserve margin in the range of 12% - 14% and that 14% be the Companies target reserve margin for planning purposes.

2005 Reserve Margin

APPENDIX A

DATA ITEMS USED IN OPTIMAL MARGIN ANALYSIS

Existing System Data

The Strategist® computer program is used to model Louisville Gas & Electric's (LG&E) and Kentucky Utilities Company's (KU) generating systems. The model simulates the dispatch of both companies generating units and other purchases to serve load, and of Owensboro Municipal Utilities' (OMU) generating units and purchases to serve OMU's load while simultaneously maintaining the KU/LG&E reserve margin requirements. The remaining generation available from OMU's units after meeting their requirements is economically dispatched by the Companies. The following sections outline the information and the sources of the information used in the programs to model the KU, LG&E and OMU generating systems.

A) General Data Items

1. Base Year - 2004

2. Study Period - 2004 to 2033 (with no end effects)

3. Economic Assumptions

   Revenue requirements are determined on an annual basis and discounted to the base year giving a present worth of revenue requirements. Discounting is performed using a discount rate, which is assumed to remain constant for all years.

4. Financial Parameters:

a. Discount Rate:	7.14%
b. Capital/O&M costs Escalation Rates:	2.0%/2.0%
c. Combined Federal and State tax rate:	40.36%

5. Retirements

   This evaluation reflects the recent retirements of Green River 1 and 2. The operating life of all other existing units is extended beyond the end of the study period.

6. Unserved Energy Cost

   The cost placed on unserved energy is varied from the base value of $11/kWh (2004 dollars) to $7 and $15/kWh (no escalation is applied in the model).

7. Load Forecast - See Appendix A Table 1a

Base LG&E and KU: March 1, 2004 Energy and Demand Forecast 2004-2033 (Load Forecasting)

OMU: Developed May 5, 2004. OMU forecast 2004- 2009 extended thru 2033.

High Load Forecast: See Appendix A Table 1b.

Forecasting and Marketing developed a High Demand and Energy forecast for KU/LGE in association with the March 1, 2004 Demand and Energy Forecast.

8. Hourly Load File Used

Market Forecasting provides LG&E and KU typical hourly loads files with any forecast they develop. OMU typical hourly loads files are developed based on an OMU historical load shape.

9. KU/LG&E Unit Data

a. Installed/Existing Capacity - See Appendix A Table 2

b. Equivalent Forced Outage Rate - See Appendix A Table 2

Average GADS data using historical data over a number of years that includes a major planned outage on each unit (or maintenance cycle). EFORs have been increased by inclusion of maintenance outage hours (MOHs) to better reflect actual unit availability.

c. Heat Rates - See Appendix A Table 2

d. Fuel Cost - See Appendix A Table 3

e. Maintenance Schedules -

Maintenance inputs were determined by reviewing the Companies' projected maintenance as of Spring 2004. Planned outages are scheduled to optimize reserves and reliability over all months of each year.

10. OMU Unit Data

a. Installed Net Capacity

OMU (Smith Unit 1): 145/147 (summer/winter)
OMU (Smith Unit 2): 270/278 (summer/winter)

b. Equivalent Forced Outage Rate

OMU (Smith Unit 1): 13.6%
OMU (Smith Unit 2): 14.5%

Based on OMU historical GADS data

c. Heat Rates (Full Load)-

OMU (Smith Unit 1): 10,626 Btu/kWh
OMU (Smith Unit 2): 10,092 Btu/kWh

d. Heat Content of Fuel: 10,700 Btu/lb

e. Maintenance Schedules -

Planned outage inputs were developed with the assistance of OMU.

f. Contracted MW Demand Sale to KU - See Appendix A Table 4.

g. Fuel Cost - See Appendix A Table 5.

Fuel costs include associated costs for fuel handling and limestone.

h. OMU Scrubber O&M (Smith Units 1 & 2)
   i. Variable O&M: Limestone charges included in fuel cost.
   ii. Removal Efficiency: 92%

11. Other Purchases
   a. Contract Demand - See Appendix A Table 4
      EEInc. (Firm): 200 MW each year
      OVEC (Firm): 2004 through March 2006 is 209 MW, April 2006 and beyond is 179 MW
      5x16 On-Peak Market Purchase; Weekday On-Peak Hrs, All Months (Non-Firm): 200 MW

b. Forced Outage Rates

EEInc.: - 9.74% partial FOR (for example, EEI will supply less than 200 MW 9.74% of the time); Note: KU owns 20% of six units at Joppa. A single purchase unit was used to model KU's portion of the six units. Each unit was assumed to have the same FOR and the probability of KU's 20% being available was assigned to the purchase unit.

OVEC: 20.33% partial FOR

5x16 On-Peak Market Purchase: 5.0%

c. Full Load Heat Rate (Btu/kWh)

EEInc: 10,000
OVEC: 10,000
5x16 On-Peak Market Purchase: 10,000

For these transactions, which were modeled as purchase power units, the fuel price was input such that the fuel price times the heat rate would result in the expected energy cost of the purchase. A heat rate of 10,000 Btu/kWh is not meant to reflect the "real life" heat rate of the units associated with these transactions.

d. Heat Content of Fuel (Btu/lb)

EEInc: 10,800
OVEC: N/A
5x16 On-Peak Market Purchase: N/A

e. Fuel/Energy Cost

See Appendix A Table 5

Table 1a - 2005 Reserve Margin Appendix A
Base Forecast: Peak (MW) /Annual Energy (GWh)

	LGE Forecast		KU Forecast		OMU Forecast	
Year	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)
2004	2,579	12,417	3,967	21,273	184	909
2005	2,629	12,657	4,067	21,812	185	914
2006	2,673	12,870	4,153	22,273	186	923
2007	2,705	13,024	4,275	22,930	186	933
2008	2,756	13,266	4,387	23,530	187	941
2009	2,800	13,478	4,472	23,983	188	946
2010	2,850	13,722	4,549	24,399	189	950
2011	2,910	14,011	4,646	24,920	190	955
2012	2,964	14,269	4,731	25,376	191	959
2013	3,029	14,584	4,830	25,909	192	963
2014	3,088	14,865	4,925	26,420	192	967
2015	3,147	15,151	5,012	26,883	193	972
2016	3,203	15,421	5,089	27,298	194	976
2017	3,264	15,713	5,184	27,810	195	981
2018	3,333	16,047	5,290	28,377	196	985
2019	3,401	16,374	5,393	28,933	197	989
2020	3,466	16,686	5,499	29,496	198	994
2021	3,528	16,983	5,579	29,923	199	998
2022	3,606	17,362	5,697	30,564	199	1,003
2023	3,674	17,687	5,794	31,082	200	1,007
2024	3,762	18,110	5,918	31,752	201	1,012
2025	3,830	18,440	6,031	32,357	202	1,016
2026	3,914	18,841	6,147	32,974	203	1,021
2027	3,990	19,209	6,250	33,526	204	1,025
2028	4,080	19,641	6,384	34,252	205	1,030
2029	4,172	20,086	6,521	34,991	206	1,034
2030	4,269	20,553	6,654	35,706	207	1,039
2031	4,362	21,001	6,790	36,432	208	1,044
2032	4,453	21,439	6,905	37,048	208	1,048
2033	4,608	22,186	7,061	37,891	209	1,053

Peaks and energy forecast reflect effects of interruptible/CSR but not DSM.

Table 1b - 2005 Reserve Margin Appendix A
High Forecast: Peak (MW) /Annual Energy (GWh)

Year	LGE Forecast Peak (MW)	LGE Forecast Energy (GWh)	KU Forecast Peak (MW)	KU Forecast Energy (GWh)
2004	2,588	12,460	3,972	21,299
2005	2,655	12,779	4,093	21,950
2006	2,715	13,069	4,198	22,516
2007	2,757	13,275	4,347	23,313
2008	2,825	13,600	4,481	24,040
2009	2,885	13,890	4,586	24,594
2010	2,953	14,219	4,681	25,107
2011	3,033	14,604	4,798	25,740
2012	3,106	14,955	4,901	26,290
2013	3,193	15,372	5,022	26,937
2014	3,273	15,759	5,137	27,560
2015	3,353	16,144	5,244	28,124
2016	3,430	16,510	5,338	28,635
2017	3,512	16,907	5,454	29,256
2018	3,604	17,349	5,582	29,945
2019	3,694	17,783	5,708	30,620
2020	3,782	18,207	5,836	31,303
2021	3,870	18,630	5,934	31,833
2022	3,971	19,119	6,078	32,606
2023	4,065	19,569	6,196	33,235
2024	4,177	20,108	6,347	34,051
2025	4,277	20,593	6,484	34,784
2026	4,387	21,120	6,625	35,540
2027	4,492	21,623	6,752	36,221
2028	4,610	22,193	6,915	37,097
2029	4,736	22,797	7,082	37,997
2030	4,863	23,414	7,243	38,865
2031	4,991	24,031	7,408	39,748
2032	5,115	24,625	7,550	40,509
2033	5,322	25,623	7,739	41,530

Peaks and energy forecast reflect effects of interruptible/CSR but not DSM.

Table 2 - 2005 Reserve Margin Appendix A
Louisville Gas and Electric/ Kentucky Utilities Generator Data

Unit	Installed Year	Summer Rating (MW)	EFOR %	Avg Heat Rate at Max Load (Mbtu/MWh)
Brown 1	1957	101	4.36%	11.024
Brown 2	1963	167	4.56%	9.624
Brown 3	1971	429	5.13%	10.388
Brown 5	2001	117	8.00%	12.006
Brown 6	1999	154	8.00%	10.409
Brown 7	1999	154	8.00%	10.409
Brown 8	1995	106	8.00%	12.173
Brown 9	1994	106	8.00%	12.173
Brown 10	1995	106	8.00%	12.173
Brown 11	1996	106	8.00%	12.173
Ghent 1	1974	475	4.75%	10.349
Ghent 2	1977	484	6.30%	10.132
Ghent 3	1981	493	5.43%	10.776
Ghent 4	1984	493	5.51%	10.684
Green River 3	1954	68	8.10%	13.009
Green River 4	1959	95	8.50%	11.553
Tyrone 1	1947	27	5.89%	14.189
Tyrone 2	1948	31	4.50%	14.189
Tyrone 3	1953	71	6.20%	12.674
Dix 1-3	1925	24	N/A	N/A
Haefling 1-3	1970	36	66.19%	17.021
Cane Run 4	1962	155	8.38%	10.634
Cane Run 5	1966	168	9.39%	10.772
Cane Run 6	1969	240	8.70%	10.100
Mill Creek 1	1972	303	7.72%	10.396
Mill Creek 2	1974	301	7.79%	10.793
Mill Creek 3	1978	391	7.75%	10.431
Mill Creek 4	1982	477	8.03%	10.535
Trimble 1 (75%)	1990	383	5.90%	10.084
Trimble 5	2002	160	8.00%	10.066
Trimble 6	2002	160	8.00%	10.066
Trimble 7	2004	160	8.00%	10.066
Trimble 8	2004	160	8.00%	10.066
Trimble 9	2004	160	8.00%	10.066
Trimble 10	2004	160	8.00%	10.066
Cane Run 11	1968	14	50.00%	18.000
Paddys Run 11	1968	12	50.00%	18.000
Paddys Run 12	1968	23	50.00%	18.000
Paddys Run 13	2001	158	8.00%	9.815
Waterside 7	1964	11	50.00%	17.000
Waterside 8	1964	11	50.00%	17.000
Zorn 1	1969	14	50.00%	18.000
Ohio Falls	1928	48	N/A	N/A

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Table 3 - 2005 Reserve Margin Appendix A

Louisville Gas and Electric/ Kentucky Utilities Fuel Costs ($/Mbtu)

Year	Brown Units 1-3	Gr River Units 1-4	Tyrone Unit 3	Ghent	Cane Run Units 4-6	Mill Creek Units 1-4	Trimble	Oil	Gas *	Haeffling Units 1-3 Gas*
2004	[redacted]									
2005										
2006										
2007										
2008										
2009										
2010										
2011										
2012										
2013										
2014										
2015										
2016										
2017										
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2023										
2024										
2025										
2026										
2027										
2028										
2029										
2030										
2031										
2032										
2033										

* Indicates a seaonal profile applies. Price shown is July price.

Table 4 - 2005 Reserve Margin Appendix A
Kentucky Utilities/Louisville Gas and Electric
Purchases During Peak Month (MW)

Year	EEI (Firm)	OMU (Firm)	OVEC (Firm)	5x16 Purch (Non-Firm)
2004	200	184	209	200
2005	200	196	209	200
2006	200	195	179	200
2007	200	193	179	200
2008	200	193	179	200
2009	200	192	179	200
2010	200	191	179	200
2011	200	190	179	200
2012	200	189	179	200
2013	200	188	179	200
2014	200	187	179	200
2015	200	186	179	200
2016	200	185	179	200
2017	200	184	179	200
2018	200	183	179	200
2019	200	182	179	200
2020	200	181	179	200
2021	200	180	179	200
2022	200	179	179	200
2023	200	178	179	200
2024	200	177	179	200
2025	200	176	179	200
2026	200	175	179	200
2027	200	174	179	200
2028	200	173	179	200
2029	200	172	179	200
2030	200	171	179	200
2031	200	170	179	200
2032	200	169	179	200
2033	200	168	179	200

5x16 Purchase was a sensitivity

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Table 5 - 2005 Reserve Margin Appendix A

Modeled Energy Costs Associated with Purchase Alternatives ($/Mbtu)

Year	EEI (Firm)	OMU (Firm)	OVEC (Firm)	5x16 Purchase (Non-Firm)
2004	[redacted]			Market Based
2005				Market Based
2006				Market Based
2007				Market Based
2008				Market Based
2009				Market Based
2010				Market Based
2011				Market Based
2012				Market Based
2013				Market Based
2014				Market Based
2015				Market Based
2016				Market Based
2017				Market Based
2018				Market Based
2019				Market Based
2020				Market Based
2021				Market Based
2022				Market Based
2023				Market Based
2024				Market Based
2025				Market Based
2026				Market Based
2027				Market Based
2028				Market Based
2029				Market Based
2030				Market Based
2031				Market Based
2032				Market Based
2033				Market Based

Figure 1

Base Availability; Base Load; No Market Purchase Available

Present Value Revenue Requirement vs Margin

Base Case with Unserved Energy at 7, 11 & 15 $/kWh

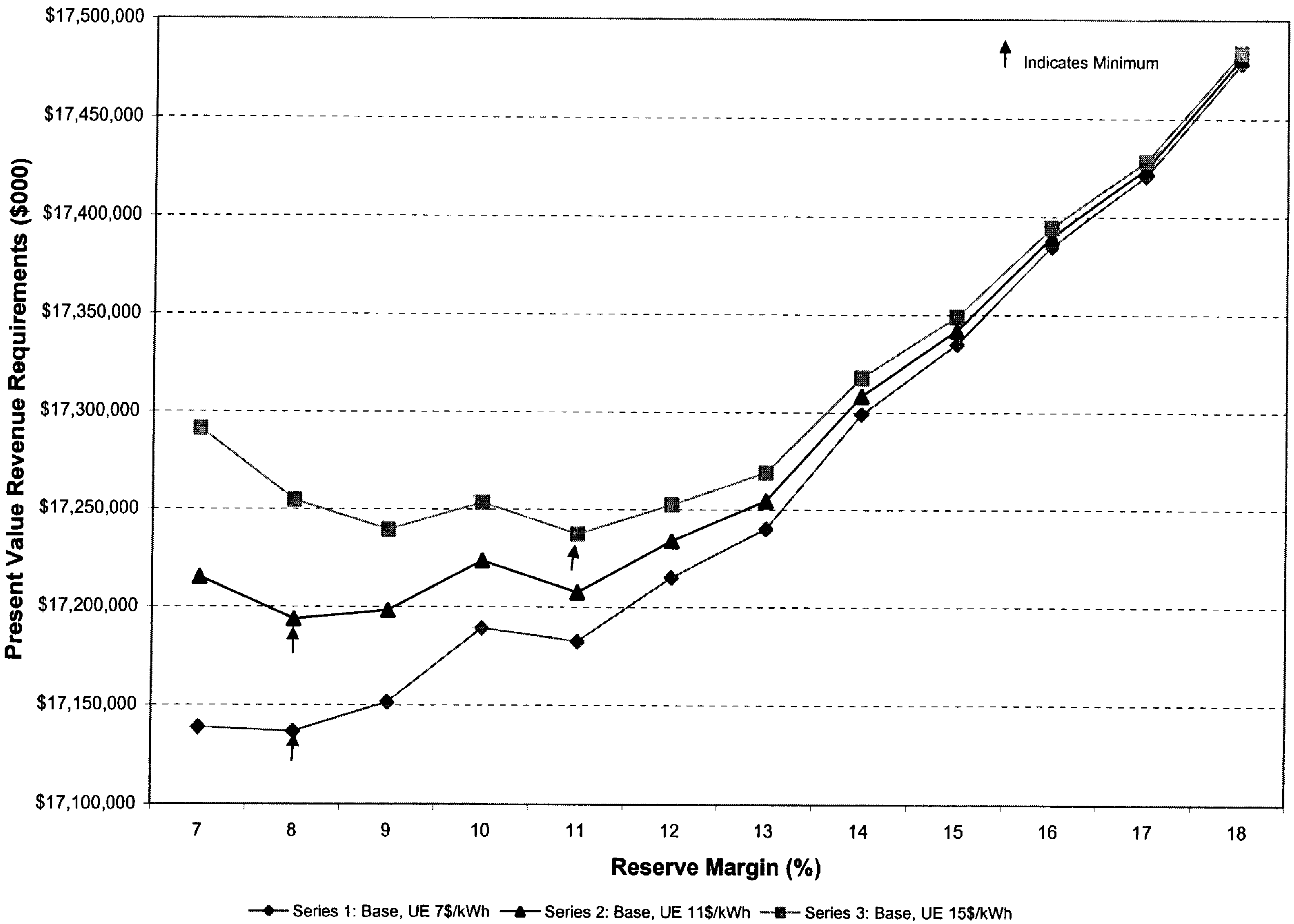

Figure 2

Base Availability; Base Load; No Market Purchase Available

Economically Equivalent PVRR vs Reserve Margin

Margins within 0.50% of Minimum Cost

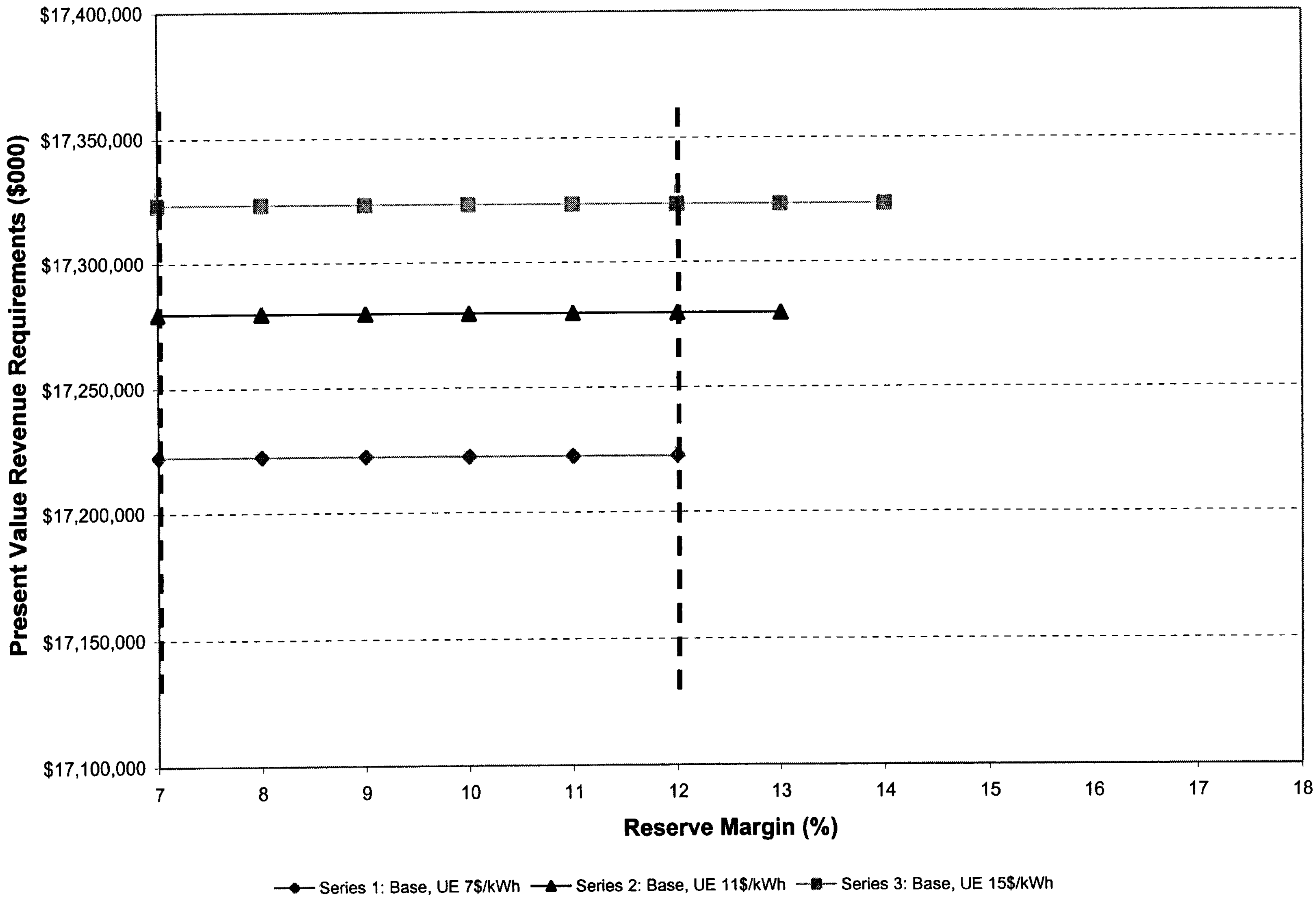

Figure 3

Series 1-12: No Market Purchase Available

Economically Equivalent PVRR vs Reserve Margin

Margins within 0.50% of Minimum Cost

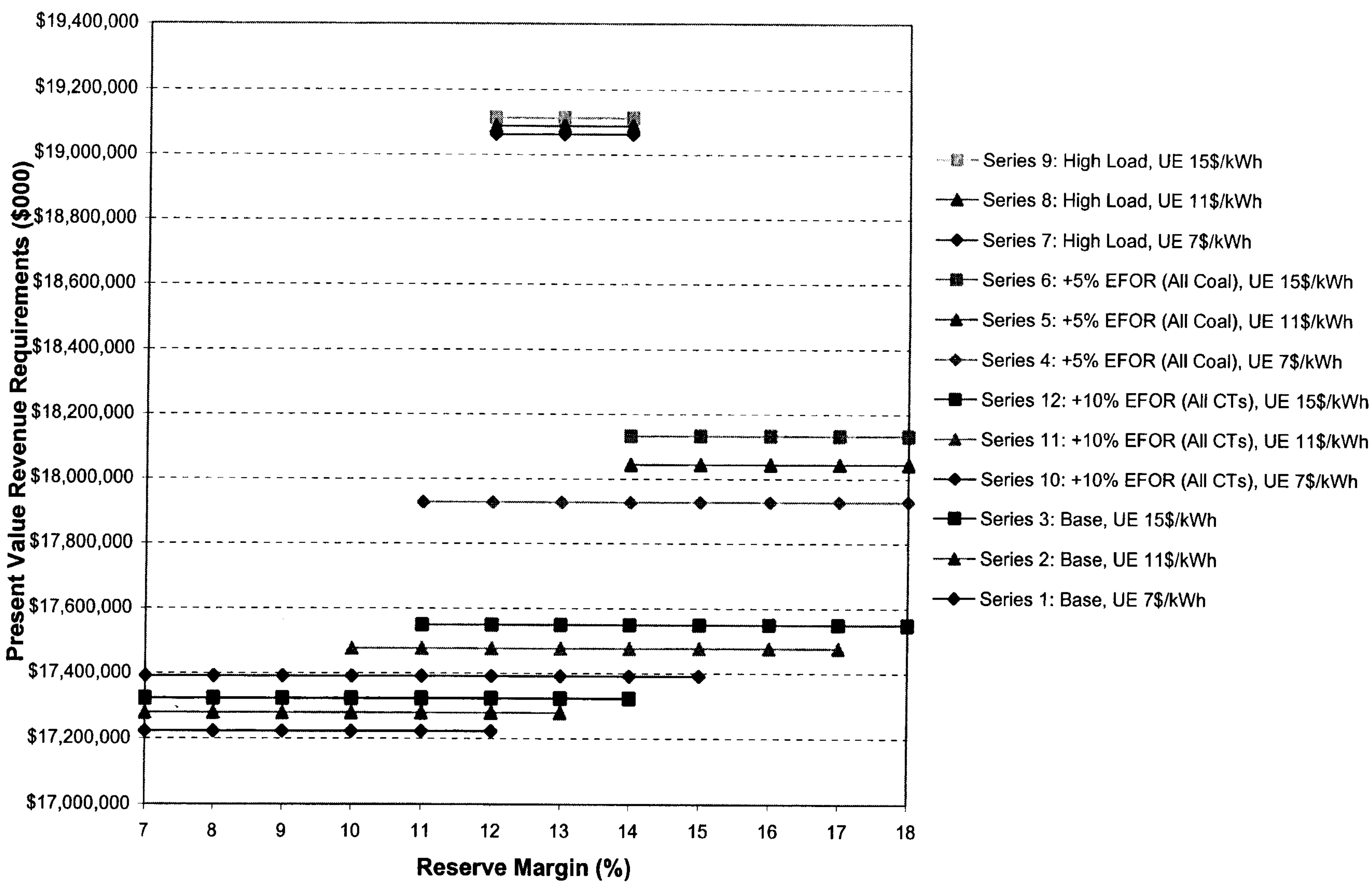

Figure 4

Series 13-24: Market Purchase Available

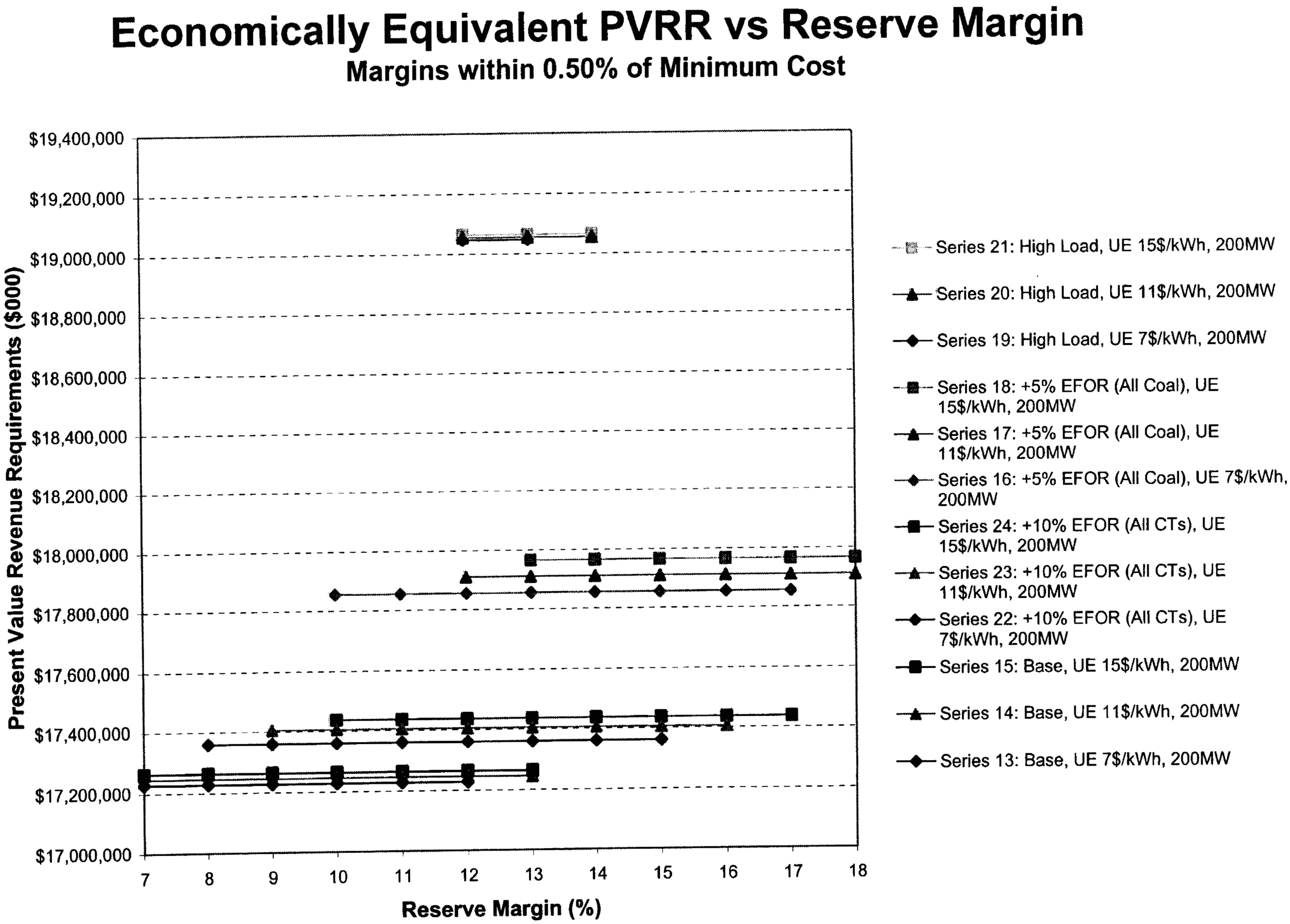

Figure 5

Series 1-12: No Market Purchase Available

Economically Equivalent PVRR vs Reserve Margin

Margins within 0.50% of Minimum Cost

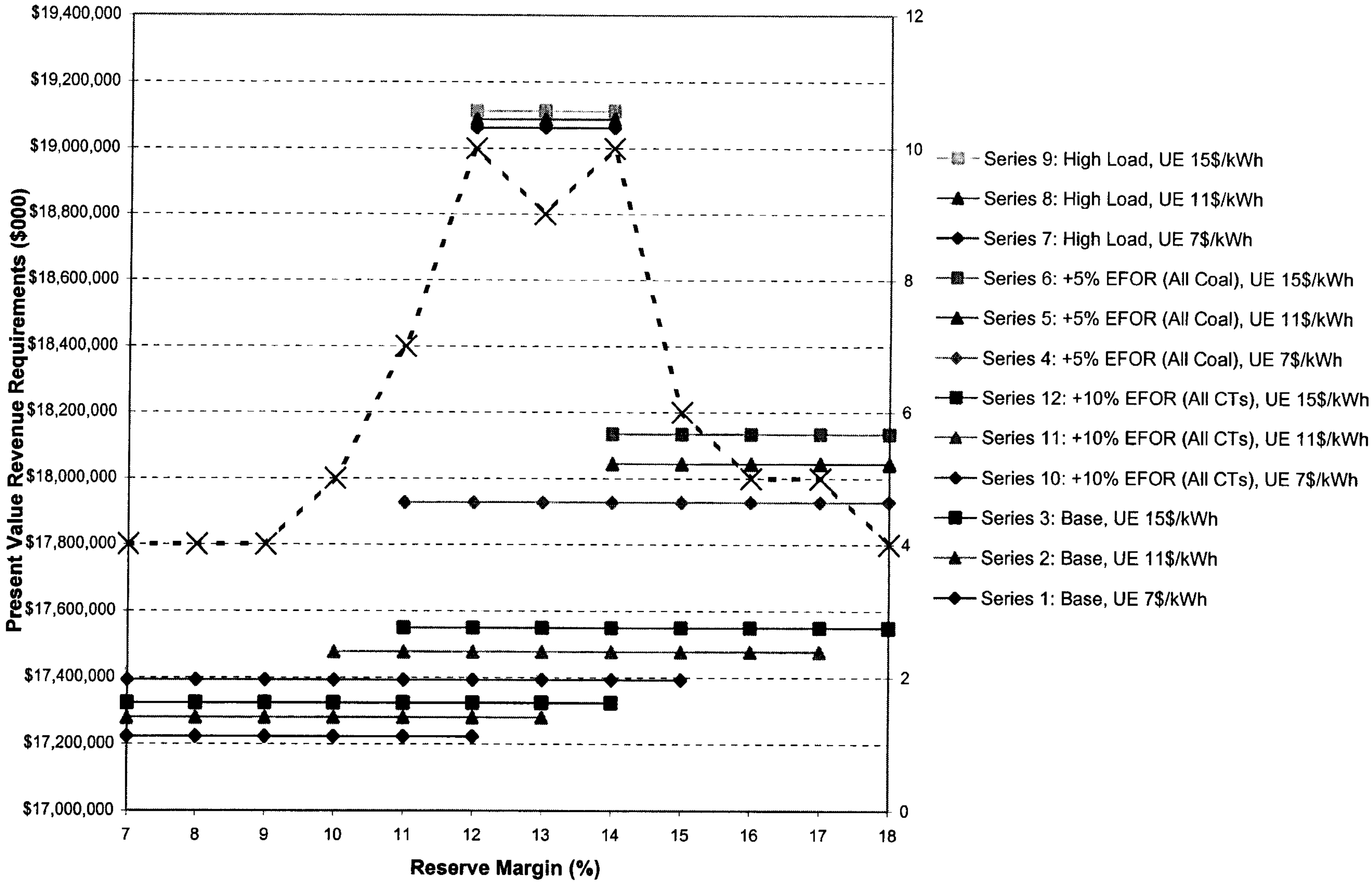

Figure 6

Series 13-24: Market Purchase Available

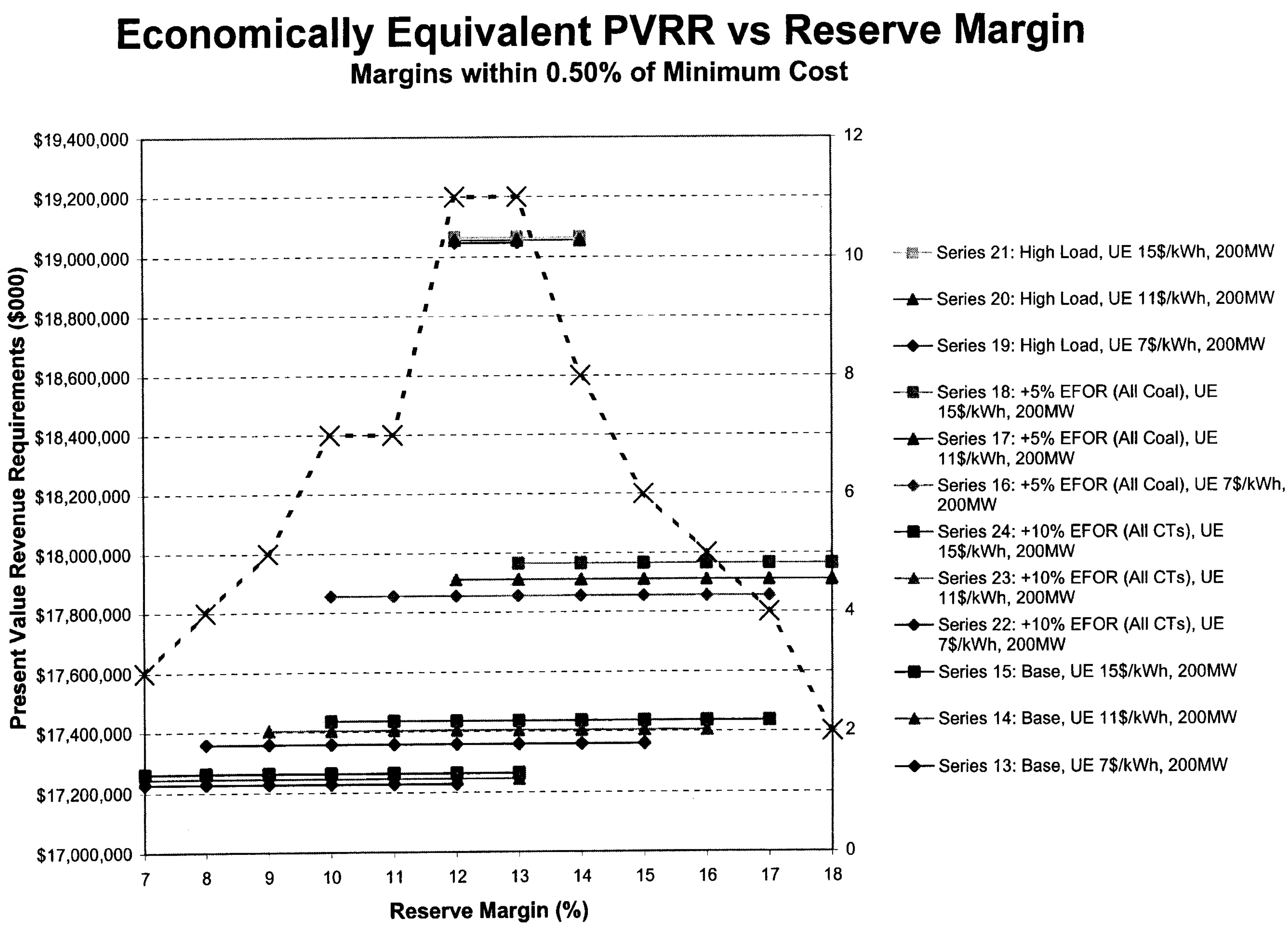

Figure 7
All Series

Economically Equivalent PVRR vs Reserve Margin
Margins within 0.50% of Minimum Cost