Kentucky Public Service Commission

Staff Report On the 2005 Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utilities Company

Case No. 2005-00162

February 2006

SECTION 1

INTRODUCTION

Administrative Regulation 807 KAR 5:058, promulgated in 1990 by the Kentucky Public Service Commission, ("Commission") established an integrated resource planning ("IRP") process that provides for regular review by the Commission Staff of the long-range resource plans of the six major electric utilities under its jurisdiction. The goal of the Commission in establishing the IRP process was to ensure that all reasonable options for the future supply of electrity were being examined and pursued, and that ratepayers were being provided a reliable supply of electricity at the lowest possible cost.

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (jointly "LG&E/KU") submitted their 2005 Joint IRP to the Commission on April 21, 2005. The IRP submitted by LG&E/KU includes the plan for meeting their customers' electricity requirements for the period 2005-2019.

LG&E and KU are investor-owned public utilities that supply electricity and natural gas to customers primarily located in Kentucky. Both are subsidiaries of E.ON US, formerly LG&E Energy LLC. As owners and operators of interconnected electric generation, transmission, and distribution facilities, LG&E/KU achieve economic benefits through the operation of an interconnected and centrally dispatched system and through coordinated planning, construction, operation and maintenance of their facilities.

LG&E and KU are members of the Midwest Independent System Operator ("MISO") a regional transmission organization subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Since the issuance of the Staff Report on LG&E's and KU's Joint 2002 IRP, LG&E and KU have announced their intention to terminate their membership in MISO. LG&E/KU's request to exit MISO is presently pending in cases before both the Commission and FERC.

LG&E supplies electricity and natural gas to customers in the Louisville, Kentucky greater metropolitan area. It provides electric service to more nearly 400,000 customers in Louisville and 11 surrounding counties with a total service area covering approximately 700 square miles.

KU supplies retail electricity in 77 Kentucky counties to over 515,000 customers in a service area covering roughly 6,500 non-contiguous square miles and in 5 Virginia counties. It sells wholesale electricity to 12 Kentucky municipalities and the municipal system serving Pitcairn, Pennsylvania.

The purpose of this report is to review and evaluate the Joint IRP in accordance with the requirements of 807 KAR 5:058, Section 12(3), which requires the Commission

Staff to issue a report summarizing its review of each IRP filing made with the Commission and make suggestions and recommendations to be considered in future IRP filings. The Staff recognizes that resource planning is a dynamic ongoing process. Thus, this review is designed to offer suggestions and recommendations to LG&E/KU on how to improve their resource plan in the future. Specifically, the Staff's goals are to ensure that:

- All resource options are adequately and fairly evaluated;
- Critical data, assumptions and methodologies for all aspects of the plan are adequately documented and are reasonable; and
- The selected plan represents the leas-cost, least risk plan for the ultimate customers served by LG&E/KU, recognizing the need to achieve a balance between the interests of ratepayers and shareholders.

The report also includes an incremental component, noting any significant changes from the Companies' most recent IRP filed in 2002.

Based on a forecasted average annual growth rate of 2.0% over the 2005-2019 forecast period, LG&E/KU will require resource additions of roughly 2,400 megawatts ("MW"). Supply-side resources included in the plan include a supercritical 732 MW (the LG&E/KU share would be 549 MW) coal-fired base load plant to be located at LG&E's Trimble County Generating Station and 6 "greenfield" combustion turbines ("CTs") with a total capacity of 888 MW. The resources also include 28 MW through greater demand-side management ("DSM") savings, a hydro power purchase agreement with an average summer capacity of 181 MW, and a 750 MW supercritical coal unit for which a site was not designated.

The remainder of this report is organized as follows:

- Section 2, Load Forecasting, reviews LG&E/KU's projected load growth and load forecasting methodology.

- Section 3, Demand-Side Management, summarizes LG&E/KU's evaluation of DSM opportunities.

- Section 4, Supply-Side Resource Assessment, focuses on supply resources available to meet LG&E/KU's load requirements.

- Section 5, Integration and Plan Optimization, discusses LG&E/KU's overall assessment of supply-side and demand-side options and their integration into an overall resource plan.

SECTION 2

LOAD FORECASTING

This section reviews LG&E/KU's projected load growth and load forecasting methodology. Although much progress has been made in standardizing the forecasting processes for LG&E/KU, some differences remain, especially in how data is segmented. The value gained from this distinction will be analyzed in the near future, according to the IRP. Therefore, this IRP presents separate forecasts for LG&E and KU.

Forecasting Methodology

Forecasting energy and demand is important for both the planning and control of LG&E/KU's operations. The forecast is a tool for decisions regarding construction of facilities such as power plants, transmission lines, and substations, all of which are necessary for providing reliable service. The desired outcome of the forecasting process are reasonable estimates of LG&E/KU's future energy and load growth so that their goals of providing adequate and reliable service to their customers at the lowest reasonable cost can be attained.

LG&E/KU's energy forecasting uses econometric modeling and growth outlook information collected from their largest customers. Econometric modeling satisfies two critical forecasting requirements. First, it combines economic and demographic factors that determine sales in a rational manner. This means that national economic conditions affect regional and local economic and demographic conditions. Local economic and demographic conditions contribute their own unique characteristic trends to the outlook. Together, these provide a reasoned outlook for demographic and economic growth in LG&E/KU's service territories. This widely accepted approach establishes the basis for a base case analysis and for optimistic and pessimistic growth scenarios for sensitivity analyses of the various resource acquisition plans studied.

Second, this approach quantifies cause and effect relationships between electric sales and the national, regional, and local factors that influence their growth. The relationships will vary depending upon the jurisdiction being modeled and the class of service. For LG&E, only one jurisdiction is modeled, Kentucky-retail. KU's forecast includes three jurisdictional groups: Kentucky-retail, Virginia-retail, and wholesale sales to 11 municipal utilities in Kentucky. Typical classes modeled include Residential, Commercial, and Industrial.

According to the IRP, the models were proven theoretically and empirically robust to explain the behavior of LG&E/KU's customer and sales data. Once econometric relationships were established, the forecast was produced using standard procedures. For both LG&E and KU, the forecast incorporates both short and long term models with the specification and length of historic data varying by customer class.

The modeling processes incorporate various elements of end-use forecasting, such as base load, heating and cooling components. The extent of this modeling varies by utility and class. Energy forecasts are converted from a billed to calendar basis and inflated for company use and losses. The resulting estimate of monthly energy requirements is then associated with a typical load profile and load factor to generate annual, seasonal, and monthly peak demand forecasts for each utility and on a combined utility basis.

The first step in the forecasting process is to gather national, state and service territory economic and demographic data in order to specify models that describe customers' usage characteristics. Due to the strong link between growth forecasts for national and regional economies and estimates of future energy use, national economic forecast data are used. The national forecast data for both LG&E and KU was prepared by Global Insight ("GI"), an economic consulting firm used by many utilities.

Key Macroeconomic Assumptions in GI's forecast

Following is a brief review of GI's key assumptions in generating its trend forecast.

- After the first five years of the forecast, the national economy suffers no exogenous shocks. Economics output grows smoothly, in the sense that actual output follows potential output relatively closely.

- GI's population projection is consistent with the U.S. Census Bureau's "middle" projection for the U.S. population. The projection, based on numerous assumptions about immigration, fertility and mortality rates, projects that the US population will grow an average of 0.8% annually over the fifteen year period from 2002 to 2028.

- Except for temporary spikes, the average price of foreign crude oil is expected to remain below $30 per barrel until 2010. Between 2011 and 2020, the price of oil is projected to average $36 and then climbing steadily toward $62 per barrel by 2028. In the long run, scarcity of resources tends to bid prices up, while new technologies tend to hold them down. In the end, scarcity will have the greater effect, with the real price of imported oil expected to increase from around $21 a barrel in 2001 to approximately $27 a barrel in 2028.

- Annual real US Gross Domestic Product is expected to average 3.0 percent growth over the 2002 to 2028 period.

- Inflation over the forecast period will remain moderate. Inflation as measured by the CPI will average 3.2% over the forecast period.

The KU Forecast

For KU, GI generated national forecast data is fed into the University of Kentucky Center for Business and Economic Research's ("UK/CBER") State Econometric Model, which then generates value-added forecasts for over 30 industries and employment forecasts for nearly 70 sectors, as well as an income forecast. State forecasted data from the State Econometric Model are fed into the Service Territory Economic Model ("STEM") that UK/CBER produces to create service territory level class forecast drivers.

Demographic trends are an important part of the forecasting process. Population and number of persons per household forecasts work together in the STEM model to create a household forecast, which is a key driver in the development of a total Kentucky retail residential customer forecast. Kentucky retail residential customers are then used to explain growth in commercial customers. Virginia residential customers are forecast similarly using Virginia data from the STEM model.

KU's forecast of long term residential sales is a function of customers by class and sales per customer by class. Total residential customers are split between Full-Electric Residential Services ("FERS") customers and Residential Service ("RS") using EPRI's Residential End-Use Energy Planning System ("REEPS") model. For both FERS and RS customers, personal income from the STEM model is used as an explanatory variable to generate long term forecasts of residential customers.

Assumptions regarding electricity and competing fuel prices are an important component in the forecast of customers by class. KU develops internal forecasts of electricity price and obtains a forecast of regional gas and oil prices from GI.

Industrial sales in KU's service territory are forecast as a function of Real Gross State Product, which is an output of the STEM Model for specific industries. Commercial sales forecasts are driven by the residential customer forecast and by estimates of commercial employment. Coal mining continues to be an important industry in KU's service territory. KU forecasts mining sales using data from Hill & Associates.

Since retail price is important in forecasting for all customer classes, the model must make assumptions about the future retail price of electricity. The model assumes there will be no potential future rate increases for KU. There are adjustments made for fuel expenses and environmental cost recovery.

Finally, weather data is also an important aspect of forecasting electricity usage. A twenty year rolling average for both cooling and heating degree days from the National Climatic Data Center ("NCDC") is used in the modeling.

In addition to data gathered from other sources, KU also relies upon company collected reports and survey data to supplement the analysis. Such data allow KU to forecast the percentage of new Residential customers choosing the FERS rate by type of housing, the availability of gas at new hook-ups, the mix of residential housing type, the approximate level of various appliance saturation levels, and sales history by key industrial SIC codes.

Key Assumptions in KU's Forecast

The following key economic and demographic assumptions are the primary drivers of KU's Energy and Demand Forecast.

- KU's service area population will average 0.8% annual growth over the next five years, and 0.8% annual growth over the next fifteen years.

- Annual US Real Gross Domestic Product growth will average 3.4% over the next five years and 3.1% over the next fifteen years.

- Households in KU-served counties are predicted to increase at a 1.3% annual average rate over the next five years, and 1.1% over the next fifteen years.

- Future climate, reflected by the weather values averaged for the most recent twenty-year period, is expected to be normal over the forecast period, 2005-2019.

- In the next five years, industrial output is predicted to increase at a 4.3 % annual rate and at a 3.4% rate over the next fifteen years.

- KU service territory commercial employment is predicted to increase at an average annual rate of 2.4% for the next five years and 2.1% over the next fifteen years.

- West Kentucky coal production is predicted to decline at an average annual rate of 3.0% for the next five years and decline at an average annual rate of 2.3% for the next fifteen years.

The LG&E Forecast

For LG&E's forecast, methodologies similar to those used in the KU forecast were used. Regional economic data and forecasts were provided by GI the University of Louisville Center for Urban Economic Research ("UL/CUER"), and UK/CBER. The UL/CUER forecasts focused on the Louisville Metropolitan Area and cover each of the seven counties included in the Louisville Metropolitan Statistical Area ("MSA") and the six Kentucky counties surrounding the Louisville MSA. Customer projections were made on the basis of the regional demographic forecasts developed by UK/CBER using the STEM model. In both the UL/CUER and UK/CBER studies, GI's 20-year long term forecasts were used as inputs for national economic and demographic variables.

Weather data, utilizing NCDC data for a twenty-year rolling average for the Louisville, Kentucky weather station, were used in the forecasts. As was the case with KU, no general retail rate increase was assumed.

Key Assumptions in LG&E's Forecast

The following key economic and demographic assumptions were made for the primary drivers of LG&E's Energy and Demand Forecast:

- LG&E's service territory population will average 0.5% annual growth over the next five years and average 0.6% annual growth over the next fifteen years.

- LG&E service territory households will average 0.8% annual growth over the next five years and increase at a 0.8% annual rate over the fifteen-year forecast horizon.

- Real per capita personal income in the Louisville MSA will increase at an average annual growth rate of 3.5% through 2019.

- The forecast does not reflect any potential future rate actions, including but not limited to those associated with home energy assistance programs, demand side management programs, corporate actions, new federal or state regulations, or unforeseeable surcharges or surcredits.

- Commercial industry employment in the Louisville MSA will grow at an annual average rate of 2.3%.

- Future climate as reflected by the weather values averaged for the most recent twenty-year period is forecast to be normal over the 2005-2019 forecast period.

Results

On a combined basis, weather normalized energy requirements are forecast to grow from 34,368 GigaWatt-hours ("GWh") in 2005 to 37,462 GWh in 2009, an average annual growth rate of 2.1 percent. By 2019, combined energy requirements are expected to reach 45,306 GWh, an average growth rate of 2.0 percent per year over the forecast horizon.

Combined summer peak demand is predicted to grow from 6,696 MW in 2005 to 8,794 MW in 2019, an average increase of 150 MW per year or an average annual growth rate of 2.0 percent. The combined LG&E/KU winter peak demand is forecast to increase from 5,647 MW in 2004/05 to 7,355 MW in 2018/19 with an average annual growth rate of 1.9 percent or about 122 MW per year.

KU's weather normalized energy requirement is expected to grow from 21,812 GWh in 2005 to 23,983 GWh in 2009, averaging 2.4 percent average annual growth. Between 2009 and 2019, energy requirements are forecast to reach 28,933 GWh, with growth averaging 1.9 percent per year.

KU's summer peak demand is forecast to grow from 4,076 MW in 2005 to 5,393 MW in 2019 with an average annual growth rate of 1.9 percent. The winter peak demand is forecast to grow from 3,842 MW in 2004/05 to 5,097 MW in 2018/19 with an average annual growth rate of 2.0 percent.

LG&E's weather normalized energy requirement is forecast to grow from 12,657 GWh in 2005 to 13,478 GWh in 2009, averaging 1.6 percent average annual growth. Between 2009 and 2019, energy requirements are forecast to grow from 13,478 GWh to 16,374 GWh with growth averaging 1.9 percent per year.

LG&E's summer peak demand is forecast to grow from 2,629 MW in 2005 to 3,401 MW in 2019 with an average annual growth rate of 1.9 percent. The winter peak demand is forecast to grow from 1,805 MW in 2004/05 to 2,335 MW in 2018/19 with an average annual growth rate of 1.9 percent.

Uncertainty Analysis

For the 2005 IRP, high and low scenarios were prepared based on probabilistic simulation of the historical volatility which is exhibited by both companies' weather normalized year over year sales trends. Specifically, a probabilistic simulation is run on the historic year over year growth for each utility's as-billed, weather normalized energy sales. A lower and an upper bound is identified based upon the 33rd and 67th percentile values, respectively. For the "low growth" sales scenario, the year over year growth in the base case forecast is decreased by the percent difference between the 33rd and 50th percentile values of the historical growth rate distribution. For the "high growth" sales scenario, the bas case year over year growth rate is increased by the percent difference between the 67th and 50th percentile values. These high and low growth rates are then applied to the 2003 weather normalized actual energy sales to produce the "high" and "low" energy sales forecst cases. The distribution of the monthly sales in the low ansd high scenarios is the same as in the base case forecast.

For KU, the long-term high and low forecast of energy sales range from 28,842 GWh to 25,344 GWh in 2019 compared to a baseline forecast of 27,198 GWh. KU's high and low forecasts of peak demand range from 5,708 MW to 5,0014 MW in 2019, in contrast to the baseline forecast of 5,393 MW. In the near term period, KU's 2009 high and low forecasts of peak demand range from 4,586 MW to 4,321 MW, in contrast of the baseline forecast of 4,472 MW.

For LG&E, the long-term high and low forecast of energy sales range from 16,825 GWh to 14,285 GWh in 2019 compared to a baseline forecast of 15,488 GWh. LG&E's high and low forecasts of peak demand range from 3,694 MW to 3,135 MW in

2019, in contrast to the baseline forecast of 3,401 MW. In the near term, KU's 2009 high and low forecasts of peak demand range from 2,885 MW to 2,723 MW, in contrast of the baseline forecast of 2,800 MW.

Changes and Updates to the Forecasting Process

The forecasting process for both KU and LG&E is essentially the same. Most differences are due to data issues. For future KU forecasts, sales will no longer be segmented by SIC code. A historical data series for the Commercial and Industrial sectors that is more closely aligned to data reported on a bill code basis has been adopted. For LG&E, a Residential SAE model has been developed; in addition to the models already in use for KU. In the present IRP forecast, the REEPS end-use model served a supporting role, rather than as a direct model of Residential use-per-customer.

The 2005-2019 Demand Forecast is based upon LG&E/KU's forecasted energy requirements and the 10 year average monthly load shapes. Peak demand is derived from the hourly demand forecast. An innovation over the 2002 IRP is in the conversion of monthly energy forecasts to hourly load curves. The 2005 load forecast is an "average" normalized load duration curve based on ten years of history, which is used to distribute monthly energy across individual hours in the month. LG&E/KU report that using representative load duration curves removes the risk of replicating an anomalous pattern over the forecast period and results in a more consistent relationship between monthly peak demands. Also, the use of average values over the last ten years also captures the impact of existing trends in the system load factors.

Discussion of Reasonableness

In general, Staff is satisfied with the forecasting of LG&E/KU. In its report on the 2002 IRP of LG&E/KU, Staff made the following recommendations relative to load forecasting for consideration by LG&E/KU in preparing their next IRP:

- LG&E/KU should continue to examine and report on the potential impact of increasing competition and future environmental requirements and how these issues are incorporated into future load forecasts.

- To the extent it is appropriate, LG&E/KU should continue to pursue efforts to integrate their forecasting processes and report on these efforts in their next IRP filing.

Staff is generally pleased with LG&E/KU's response to past recommendations. Given the lack of retail competition, there is not a large impact on retail customers from wholesale competition. We urge LG&E/KU to continue monitoring this area, as well as future costs of environmental compliance. Staff is satisfied with LG&E/KU's progress in integrating their forecasts.

Intervenor Comments

The Attorney General ("AG") referred to his comments and testimony filed in LG&E/KU's certificate case for the Trimble County Unit No. 2 ("TC2") generator.[1] In that case, the AG argued that TC2 was not needed before 2012; a two year delay from the proposed TC2 implementation date. The AG argued that the historical experience and the forecasts of peak demand growth as well as a 30.7% reserve margin demonstrated that the certificate application was premature. However, the AG did not contest the forecasting methodology, the models, or the data in the 2005 IRP. The AG only criticized how the IRP results were being applied by LG&E/KU.[2]

The Staff is satisfied with the load forecasting model and its results, as well as LG&E/KU's response to questions and comments regarding the forecasts.

Recommendations

- LG&E/KU should continue to examine and report on the potential impact of increasing competition and future environmental requirements and how these issues are incorporated into future load forecasts.

- LG&E/KU should continue its efforts to further integrate the load forecasting processes and report on these efforts in their next IRP filing.

- LG&E/KU should continue to refine their load forecasting models.

- In light of the financial impacts related to the construction of TC2, LG&E/KU should consider reflecting potential future rate actions in future forecasts or explain why they should not be so reflected.

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[1] Case No. 2004-00507, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity, and a Site Compability Certificate, for the Expansion of the Trimble County Generating Station.

[2] For example, see Case No. 2005-00507 Post Hearing Brief of the Attorney General filed August 10, 2005.

SECTION 3

DEMAND SIDE MANAGEMENT

Introduction

This section summarizes the Demand-Side Management ("DSM") assessment included in LG&E/KU's 2005 IRP. According to their IRP, LG&E/KU evaluate the future electric requirements of their customers with a balanced consideration of demand-side and supply-side resource options. LG&E/KU formed an interdepartmental team, which worked to identify a broad range of DSM alternatives. Each alternative was evaluated using a two-step screening process. The first step was qualitative in nature, and consisted of evaluating each alternative based upon four criteria. The alternatives that passed the first step underwent a second step of screening that was quantitative in nature. That quantitative process was broken down into two separate phases, and the programs that passed this process were then evaluated with supply-side alternatives. The remainder of this section describes LG&E/KU's process and the results thereof.

Qualitative Screening Process

A set of criteria was defined to facilitate an objective evaluation of the broad range of DSM alternatives. Four criteria were selected, reflecting LG&E/KU's objective of providing low cost, reliable energy to their customers. LG&E/KU also considered the comments from the Staff's report on their previous IRP and input from the Air Pollution Control District of Jefferson County and the Kentucky Department of Energy. Weights or values were assigned to each of the criteria. The highest weights were assigned to the criteria judged to be the most important to develop a successful DSM program. The most important criterion for LG&E/KU was the cost effectiveness of peak demand reduction. Each potential DSM alternative was evaluated based on a scale of 1 to 4, with 4 being the best score, using the following criteria and their respective weightings: (1) Customer Acceptance - 25 percent; (2) Technical Reliability - 15 percent, (3) Cost Effectiveness of Energy Conservation - 25 percent, and (4) Cost Effectiveness of Peak Demand Reduction - 35 percent.

The DSM team identified a broad list of DSM alternatives to be evaluated, which are summarized by revenue classification in the following table.

Alternatives by Revenue Classification	KU and LG&E
Residential	36
Commercial	34
Industrial	0
Total	70

LG&E/KU's DSM Department selected 2.4, on a scale of 4.0, as the cut-off level for alternatives analyzed in the qualitative screening process. Of the 70 original DSM alternatives, 27 passed LG&E/KU's qualitative screening. Of these 27 alternatives, 17 targeted residential customers while 10 targeted commercial customers.

Quantitative Screening Results

Alternatives that passed the qualitative screening analysis were next modeled in more detail using EPRI's DSManager software package, which was developed by EPS Solutions under contract with EPRI. A screening tool determines the cost effectiveness of DSM alternatives by modeling their costs and benefits over a period of time. The program simplifies the "real world" by using 48 typical days to represent a year. There are four daily load shapes per month: (1) high weekday; (2) medium weekday; (3) low weekday; and (4) weekend. DSManager uses LG&E/KU's aggregate system load shape. It also utilizes marginal energy costs to estimate the change in production costs resulting from the implementation of each DSM option. A detailed production-costing model, PROSYM™, is utilized to determine the marginal energy costs used by DSManager.

DSManager calculates the net present value of the quantifiable costs and benefits assignable to both LG&E/KU and to customers participating in a DSM program. For each DSM initiative modeled, DSManager requires the following: administrative costs, participant's costs, life span of the technology, expected level of participation, expected level of free-riders, and rate schedules. DSManager calculates changes to the participant's bill, LG&E/KU's revenue, production costs, and the peak demand. The present value for each DSM alternative is calculated by DSManager and reported as the costs and benefits using the five generally recognized DSM tests known as the "California Tests." These include the participant test, utility cost test, ratepayer impact measure test ("RIM"), total resource cost test ("TRC"), and societal cost test. LG&E/KU used only the participant and TRC tests to screen DSM options. The participant test includes changes in all costs and benefits to the customer participating in the program. The TRC test combines the RIM and participant tests and indicates overall benefits of the DSM option to the average customer, where the RIM test considers all impacts to the non-participants. A score of 1.0 or greater indicates that a program is cost effective.

15 DSM programs passed the first phase of the quantitative screening analysis, in which administrative costs are not considered and it is assumed that the program has only 1 participant per each company (LG&E and KU). This phase is performed to remove non-cost effective programs. Of these 15 programs, 4 ultimately passed the second phase of the quantitative screening analysis in which administrative costs and the expected levels of penetration for each company are added as inputs.

Recommended DSM Programs

Of the 4 programs that passed the quantitative screening process, two are load management programs: Setback Thermostats and Smart Thermostats (special rate).

These programs are similar in some respects to LG&E/KU's existing load management program, Demand Conservation. LG&E/KU note that these programs could have a detrimental effect on the existing Demand Conservation Program; however, they believe the programs would provide customers additional choices and bring new customers into load management that would not otherwise participate. The other programs are Energy Efficient Indoor Lighting and A/C Tune-up. Descriptions of the 4 programs follows.

<u>Setback Thermostats</u>

As mentioned earlier, this program is similar to the existing load management program, Demand Conservation. The most significant difference between this program and the existing program is the incentive mechanism. The Demand Conservation Program credits customers' bills as an incentive whereas this program would provide the customer with a programmable set back thermostat as an incentive. The Setback Thermostat program can either change the set point on the thermostat or duty cycle the air conditioner, as does the Demand Conservation Program device. An advantage of the Setback Thermostat program is that a utility could pre-cool a home before going into a cycling or control session, and allow the customer to reduce heating and cooling costs year-round. Customers would be provided the thermostat at no cost, but would not receive the bill credit as do customers in the existing Demand Conservation Program. Based upon the estimated energy and demand savings this program is cost effective with a TRC result of 2.09 and a Participant test result of infinity.

<u>Smart Thermostat (TOU rate)</u>

This is a sophisticated load management and Time of Use ("TOU") rate program. The TOU rate would have three-tiers similar to other utilities, but with a fourth rate – a real-time component. The real-time component would be the highest cost period and would be invoked during system peaks (at the times that existing Demand Conservation Program switches are controlled). A Smart Thermostat would incorporate a radio receiver to react when the real-time component of the rate is invoked. Customers would set heating and cooling temperatures and turn large loads off or on, based on the price of electricity. Pilot programs and full-scale deployment of such programs at other utilities indicate that significantly larger demand savings can occur than is seen in the Demand Conservation Program. Based upon the projected energy and demand savings, the Smart Thermostat program is cost effective with a TRC result of 1.24 and a Participant test result of 2.84. LG&E/KU plan to implement a pilot of this program sometime in the near future as stated in the DSM Program Plan filed with the Commission in September of 2000 and approved in May of 2001 in Case No. 2000-00459. This pilot program has not been implemented previously because of costs; however, equipment availability has increased and costs have decreased.

<u>Energy Efficient Indoor Lighting</u>

Compact fluorescent lighting is a technology that has been available for over 15 years, but due to costs and availability of product for limited applications, has not proven viable. Today, costs have been significantly reduced while the product is more readily available in a great number of sizes and shapes, with higher lighting levels, and better color rendition. This program would piggyback on the existing Residential Conservation programs and provide customers with a wide selection of compact products. Based upon the estimated energy and demand savings this program is cost effective with a TRC result of 1.14 and a Participant test result of 6.91.

A/C Tune-up (Commercial)

This program would take advantage of the fact that information indicates that 50 percent or more of existing air conditioning systems operate at or below manufacturers' specified efficiency, due to over or under refrigerant charge, and/or air flow problems in the evaporator coil. This program would provide customers an analysis of existing commercial A/C systems and discounted corrective action when necessary. Based upon the estimated energy and demand savings this program is cost effective with a TRC result of 1.20 and a Participant test result of 5.53.

Another commercial program, Polarized Refrigerant Oxidant Agent, also passed the second phase of the quantitative screening analysis with a TRC result of 1.13 and a Participant test result of 2.59. This product increases the efficiency of heat transfer in refrigerant systems such as heat pumps and air conditioners. LG&E/KU would offer this technology to customers through the existing Commercial Conservation Program.

Summary Discussion of DSM

LG&E/KU pointed out that DSM alternatives that are ultimately selected through this evaluation process may not necessarily be implemented as they are described in the IRP. The DSM alternatives that are ultimately proposed will, according to LG&E/KU, be subjected to a much more rigorous program design cycle, which could result in program concepts and program details being changed significantly or in some programs not being implemented at all.

Discussion of Reasonableness

In its report on LG&E/KU's 2002 IRP, Staff made the following recommendations relative to DSM for consideration in preparing LG&E/KU's next IRP filing:

- The Companies next IRP filing should use all five of the California DSM tests. The five tests include the participant, utility cost, ratepayer impact measure (RIM), total resource cost (TRC), and societal cost tests.

- In their next IRP filing, the Companies should reasonably expand the number of DSM technologies that receive a complete evaluation to determine if they would be cost effective.

- In their next IRP filing, the Companies should report on their efforts to evaluate and support Local Integrated Resource Planning, cogeneration and distributed generation, and statewide and regional market transformation initiatives of the type advocated by Kentucky Department of Energy.

Staff is encouraged by LG&E/KU's efforts in pursuing DSM programs. The number of DSM alternatives which LG&E/KU included in the quantitative evaluation was expanded from the 2002 IRP and a larger number of alternatives passed the second phase of that evaluation. However, Staff continues to believe that LG&E/KU should use all 5 California tests in the next IRP. Staff also continues to believe that LG&E/KU should include for quantitative evaluation a limited number of DSM alternatives that, by a small margin (i.e. 10%), fail to pass the qualitative screening process.

Recommendations

Relative to the DSM efforts of LG&E/KU as reflected in the 2005 IRP, Staff makes the following recommendations:

- LG&E/KU should use all five "California tests", the participant test, utility cost test, ratepayer impact measure test, total resource cost test, and societal cost test, to review DSM alternatives in the next IRP filing.

- In the next IRP filing, consistent with the Commission's findings in Administrative Case No. 2005-00090,[3] LG&E/KU should place a greater emphasis on DSM and attempt to expand the number of DSM technologies that receive a complete evaluation to determine if they would be cost effective.

- In their next IRP filing, LG&E/KU should continue to consider and evaluate a variety of DSM technologies, including those applicable to low income customers, that would be cost effective.

- If any DSM technology applicable to commercial customers passes the qualitative and quantitative screening, LG&E/KU should approach those customers to determine if there is an interest in pursuing the programs. It may be beneficial for LG&E/KU to contact commercial customers engaged in new construction rather than those involved in renovations or retrofits of existing structures.

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[3] Administrative Case No. 2005-00090, An Assessment of Kentucky's Electric Generation, Transmission and Distribution Needs, Order dated September 15, 2005.

SECTION 4

SUPPLY-SIDE RESOURCE ASSESSMENT

Introduction

This section summarizes, reviews, and comments on LG&E/KU's evaluation of existing and future supply-side resources, and includes a discussion of environmental compliance planning.

Existing Capacity

LG&E/KU have generating units at 14 generating stations. Most of their capacity is coal-fired steam generation; 7 stations have CTs; and 2 stations have hydroelectric units.[4] The newest generation is TC2, a coal-fired unit being constructed at LG&E's Trimble County station. The 2004 summer net capacity for LG&E/KU was 7,610 MW. In addition, LG&E/KU have purchase power agreements in place with Ohio Valley Electric Corporation and Owensboro Municipal Utilities ("OMU"). Table 4-1 shows LG&E/KU's existing electric generating facilities.

Several of LG&E/KU's CTs have been in operation for over 30 years. Some of the coal-fired units are over 50 years old. These generating units could become uneconomical due to their high production costs, future nitrogen oxide ("NO_x") restrictions, or the risk of their failure due to age. LG&E/KU indicate that retiring some units might be economical even without a significant mechanical failure. LG&E/KU review the economic value of aging units periodically to determine when, or if, they should be retired. Table 4-2 shows the LG&E/KU units that might be considered for retirement due to their age.

Reliability Criteria

LG&E/KU indicate that a target reserve margin in the range of 12-14% will be adequate to meet their customers' future demand in a reliable manner. LG&E/KU's reserve margin of 14% is being used for the purpose of developing an optimal integrated resource plan. A reserve margin is needed to have sufficient capacity available to allow for (1) unexpected loss of generation, (2) reduced generation capacity due to equipment problems, (3) unanticipated load growth, (4) variances in load due to extreme weather conditions, and (5) disruptions in contracted purchase power. A utility's required reserve capacity can be supplied via its own generation, purchased power, or a combination thereof. "Reserve margin" and "capacity margin" are derived as shown immediately after Table 4-2.

[4] At the time this IRP was filed, LG&E/KU had 3 hydro facilities. Since that filing, KU was authorized to transfer its interest in the Lock 7 hydro facility on the Kentucky River to a non-regulated entity (See Case No. 2005-00405).

Table 4-1
KU and LG&E Combined Existing Generating Facilities

1	2	3	4	5	6	7		8		9	10	11
Plant Name	Unit No.	Location in Kentucky	Status	Operation Date	Facility Type	Net Capability (MW) Winter	Summer	Entitlement KU	LGE	Fuel Type	Fuel Storage Cap/SO2 Content	Scheduled Upgrades Derates, Retirements
Cane Run	4	Louisville	Existing	1962	Steam	155	155		100%	Coal (Rail)	250,000 Tons (6.0# SO2)	None
	5			1966		168	168					
	6			1969		240	240					
	11			1968	Turbine	14	14			Gas/Oil	100,000 Gals	
Dix Dam	1-3	Burgin	Existing	1925	Hydro	24	24	100%		Water	None	None
E. W. Brown Coal	1	Burgin	Existing	1957	Steam	102	101	100%		Coal (Rail)	360,000 Tons (~2.2# SO2)	FGD Derate - 2009
	2			1963		169	167					
	3			1971		433	429					
E.W. Brown-ABB 11N2	5			2001	Turbine	143	135	47%	53%	Gas	2,200,000 Gals	None
E.W. Brown-ABB GT24	6			1999		168	154	62%	38%	Gas/Oil		None
	7			1999		168	154					
E.W. Brown-ABB 11N2	8			1995		140	126	100%				None
	9			1994		140	126					
	10			1995		140	126					
	11			1996		140	126					
Ghent	1	Ghent	Existing	1974	Steam	468	475	100%		Coal (Barge)	310,000 Tons (6# SO2)	None
	2			1977		466	484				1,000,000 Tons (1.1# SO2 & PRB)	FGD Derate - 2008
	3			1981		495	493					FGD Derate - 2007
	4			1984		495	493					FGD Derate - 2009
Green River	3	Central City	Existing	1954	Steam	71	68	100%		Coal	170,000 Tons	None
	4			1959		102	95					
Haefling	1	Lexington	Existing	1970	Turbine	14	12	100%		Gas/Oil	630,000 Gals	None
	2			1970		14	12					
	3			1970		14	12					
Lock 7	1-3	Burgin	Existing	1927	Hydro	Run of River Plant		Lease		Water	None	None
Mill Creek	1	Louisville	Existing	1972	Steam	303	303		100%	Coal (Barge & Rail)	750,000 Tons	None
	2			1974		299	301					
	3			1978		397	391					
	4			1982		492	477					
Ohio Falls	1-8	Louisville	Existing	1928	Hydro	Run of River Plant (32/48)			100%	Water	None	Rehab begins Fall 2005
Paddy's Run	11	Louisville	Existing	1968	Turbine	13	12		100%	Gas	None	None
	12			1968		28	23					
Paddys Run-Siem/West V84.3a	13			2001		175	158	47%	53%		Unknown at this time	
Tyrone	1	Versailles	Existing	1947	Steam	30	27	100%		Oil (Truck)	514,000 Gals	None
	2			1948		33	31					
	3			1953		73	71			Coal (Trk)	30,000 Tons (1.4# SO2)	
Trimble County Coal (75%)	1	Near Bedford	Existing	1990	Steam	514 (386)	511 (383)	0%	75%	Coal (Barge)	500,000 Tons (6.0# SO2)	None
Trimble County-GE7FA	5			2002	Turbine	180	160	71%	29%	Gas		
	6			2002		180	160					
	7			2004		180	160	63%	37%			
	8			2004		180	160					
	9			2004		180	160					
	10			2004		180	160					
Waterside	7	Louisville	Existing	1964	Turbine	13	11		100%	Gas	None	None
	8			1964		13	11					
Zorn	1	Louisville	Existing	1969	Turbine	16	14		100%	Gas	None	None

Table 4-2: Aging Units Considered For Retirement

TYPE OF UNIT	PLANT NAME	UNIT	SUMMER CAPACITY	IN SERVICE YEAR	AGE (2005)
Steam	Tyrone	1	27	1947	58
Steam	Tyrone	3	31	1948	57
CT	Waterside	7	11	1964	41
CT	Waterside	8	11	1964	41
CT	Cane Run	11	14	1968	37
CT	Paddy's Run	11	12	1968	37
CT	Paddy's Run	12	23	1968	37
CT	Zorn	1	14	1969	36
CT	Haefling	1, 2, 3	36	1970	35

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

Capacity Margin % = (Total Supply Capability – Peak Load)/ (Total Supply Capability).

Key variables incorporated into the reserve margin analysis are: (1) number and length of planned generating unit outages and maintenance outages; (2) generating unit forced/equivalent outage rates; (3) the availability of purchased power; (4) customers' perceived cost of unserved/emergency energy; and (5) expected system load and load factor. Forced outages require that a unit to be removed from service unexpectedly and immediately. Forced outage rates are the total number of forced outage hours/(total forced outage hours + total number of service hours). Equivalent forced outage rates are similar to forced outage rates but include hours when a unit can operate but unable to operate at full load. The Strategist computer model was used in the evaluation, and the minimizing present value of revenue requirements ("PVRR") was the decision factor.

Supply-Side Evaluation

Black & Veatch supplied LG&E/KU with the majority of data used to evaluate 47 technologies. Alternatives were screened through a levelized analysis in which total costs were calculated for each alternative, at various levels of utilization, over a 30-year period and levelized to reflect uniform payment streams in each year. Levelized costs of each alternative at varying factors were then compared and the least-cost technologies for each capacity factor increment throughout the planning period were developed. Table 4-3 shows the technologies included in the screening analysis.

Table 4-3: Technologies Screened

Tech. ID	Technology Description	Category	Sub-Category
6.1	Pumped Hydro Energy Storage - 500 MW	Storage	Hydro
6.2	Lead-Acid Battery Energy Storage - 5 MW	Storage	Battery
6.3	Compressed Air Energy Storage - 500 MW	Storage	Compressed Air
2.1.1	Simple Cycle GE LM6000 CT - 31 MW	Natural Gas	SCCT
2.1.2	Simple Cycle GE 7EA CT - 73 MW	Natural Gas	SCCT
2.1.3	Simple Cycle GE 7FA CT - 148 MW	Natural Gas	SCCT
2.2.1	Combined Cycle GE 7EA CT - 119 MW	Natural Gas	CCCT
2.2.2	Combined Cycle GE 7FA CT - 235 MW	Natural Gas	CCCT
2.2.3	Combined Cycle 2x1 GE 7FA CT - 484 MW	Natural Gas	CCCT
2.1.4	W 501F CC CT - 258 MW	Natural Gas	CCCT
2.5.1	Spark Ignition Engine - 5 MW	Natural Gas	Reciprocating Engine
2.5.2	Compression Ignition Engine - 10 MW	Natural Gas	Reciprocating Engine
3.1.1	Wind Energy Conversion - 50 MW	Renewable	Wind
3.2.1	Solar Thermal, Parabolic Trough - 100 MW	Renewable	Solar
3.2.2	Solar Thermal, Parabolic Dish - 1.2 MW	Renewable	Solar
3.2.3	Solar Thermal, Central Receiver - 50 MW	Renewable	Solar
3.2.4	Solar Thermal, Solar Chimney - 200 MW	Renewable	Solar
3.3	Solar Photovoltaic - 50 kW	Renewable	Solar
3.4.1	Biomass (Co-Fire) - 27.5MW	Renewable	BioMass
3.5	Geothermal - 30 MW	Renewable	Geotherm
3.6	Hydroelectric - New - 30 MW	Renewable	Hydro
102	WV Hydro	Renewable	Hydro
4.1	MSW Mass Burn - 7 MW	Waste To Energy	MSW
4.2	RDF Stoker-Fired - 7 MW	Waste To Energy	RDF
4.3	Landfill Gas IC Engine - 5 MW	Waste To Energy	LFG
4.4	TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	Waste To Energy	TDF
4.5	Sewage Sludge & Anaerobic Digestion - .085 MW	Waste To Energy	SS
5.1.1	Humid Air Turbine Cycle CT - 450 MW	Natural Gas	CT
5.1.2	Kalina Cycle CC CT - 275 MW	Natural Gas	CCCT
5.1.3	Cheng Cycle CT - 140 MW	Natural Gas	CCCT
5.2.1	Pressurized Fluidized Bed Combustion - 250 MW	Coal	Fluidized Bed Combustion
5.3.1	IGCC - 267 MW	Coal Gasification	IGCC
5.3.2	IGCC - 534 MW	Coal Gasification	IGCC
5.4	Fuel Cell - 0.2 MW	Storage	Fuel Cell
5.5.1	Peaking Microturbine - 0.03 MW	Natural Gas	CT
5.5.2	Baseload Microturbine - 0.03 MW	Natural Gas	CT
2.3.1	Supercritical Pulverized Coal - 500 MW	Coal	Pulverized Coal
2.3.2	Supercritical Pulverized Coal, High Sulfur - 500 MW	Coal	Pulverized Coal
2.3.3	Supercritical Pulverized Coal - 750 MW	Coal	Pulverized Coal
2.3.4	Subcritical Pulverized Coal - 250 MW	Coal	Pulverized Coal
2.3.5	Subcritical Pulverized Coal - 500 MW	Coal	Pulverized Coal
2.3.6	Subcritical Pulverized Coal, High Sulfur - 500 MW	Coal	Pulverized Coal
2.3.7	Supercritical Pulverized Coal, High Sulfur - 750 MW	Coal	Pulverized Coal
2.4.1	Circulating Fluidized Bed - 250 MW	Coal	Fluidized Bed Combustion
2.4.2	Circulating Fluidized Bed - 500 MW	Coal	Fluidized Bed Combustion
100	Ohio Falls 9 and 10	Renewable	Hydro
101	TC2 732 MW Supercritical Pulverized Coal	Coal	Pulverized Coal

In order to quantify the impact of uncertainties on their estimates of supply-side costs, LG&E/KU conducted a sensitivity analysis as part of the screening process. The screening analysis considered the following: (1) capital cost; (2) heat rate; (3) fuel cost; and (4) environmental costs pertaining to NO_x, sulfur dioxide (SO_2), and carbon dioxide (CO_2) as uncertainties.

Based on the results of the screening analysis, the following supply-side technologies were recommended for further evaluation in the integrated resource optimization analysis:

- Trimble County 2 Supercritical Pulverized Coal Unit
- Supercritical Pulverized Coal, High Sulfur 750 MW Unit
- WV Hydro – Purchase Power Agreement
- GE 2x1 7FA Combined Cycle Combustion Turbine
- Ohio Falls Units 9 and 10
- GE 7FA Simple Cycle Combustion Turbine

Table 4-4 shows LG&E/KU's planned electric generation facilities. The TC2 unit, to be located at LG&E's Trimble County site and scheduled for operation in 2010, is presently under construction. Subsequent to filing their IRP, LG&E/KU received a Certificate of Public Convenience and Necessity ("CPCN") to construct TC2 in Case No. 2004-00507.

Table 4-4: Future Units

Future Units												
Trimble County Coal (75%)	2	Near Bedford	Proposed	2010	Steam	750 (563)	732 (549)	61%	14%	Coal	Unknown at this time	None
Greenfield CT	1	Unknown	Planned	2013	Turbine	181	148	Unknown		Gas	None	None
	2			2015		181	148					
	3			2015		181	148					
	4			2016		181	148					
	5			2017		181	148					
	6			2018		181	148					
W.V. Hydro (PPA)		Smithland/Cannelton	Proposed	2014	Hydro	99	181	Unknown		Water	None	None
Greenfield Coal Unit	1	Unknown	Proposed	2019	Steam	750	750	Unknown		Coal	Unknown at this time	None

Compliance Planning

LG&E/KU performed a study in January 2005 of various NO_x compliance options to determine whether their previously recommended plan is still the most effective plan. Some of the changes since the last study include the addition of early reduction credits ("ERC"), retirement of Green River 1-2 and the update of NO_x emission rates for existing units. LG&E/KU indicate that they will have sufficient NO_x allowances through the end of 2009 and would be dependent on purchasing 152,000 NO_x allowances over the 2010-2025 timeframe to comply. The construction of an SCR at KU's Ghent Unit 2 will mitigate the dependency on purchasing allowances. LG&E/KU are keeping a close watch on legislative activities, technology enhancements, regulatory rulings and judicial actions in order to meet the emissions reduction requirements in a prudent and least-cost manner.

Regarding SO_2 compliance options, LG&E/KU will have sufficient allowances through 2007. More than 2.7 million tons of allowances will be needed over the 2008-2025 timeframe. The construction of wet Flue Gas Desulfurization Units on Ghent Units 2, 3, and 4 and E.W. Brown Units 1, 2, and 3, the simultaneous switching of the units to high sulfur coal, and purchase of SO_2 allowances is offred by LG&E/KU as the most reasonable and least cost plan for continued environmental compliance.

Intervenor Comments.

The AG questioned the need for TC2 in 2010 and argued that new generation would not be needed until 2012. This is the same position that the AG advanced in Case No. 2004-00507. The AG also suggested that the purchase of 240 MW from WV Hydro Inc. should be pursued prior to TC2 but no earlier than 2012 as well. Due to its smaller size, in a period of uncertainty about future load growth, the AG stated that purchased power is less risky to ratepayers if load growth fails to materialize. The AG did not comment on any aspect of the IRP except the proposed addition of generating capacity.

On November 1, 2005 the Commission granted LG&E/KU a CPCN to construct a 750 MW super-critical pulverized-coal based load unit, TC2, at LG&E's Trimble County Generating Station in Trimble County, Kentucky, subject to LG&E/KU monitoring the accuracy of their forecasts and advising the Commission immediately if they notice any material divergence between their energy and peak forecasts and actual usage that could call into question the advisability of further pursuit of construction of TC2. This decision, by the Commission, renders moot the need for Staff comments on the issue of the need for, and timing of, TC2.

Recommendation

LG&E/KU's December 22, 2005 letter regarding the termination of KU's purchase power contract with EEI stated that the loss of the 200 MW available under this contract would have no near term (2006-2007) impact on KU's capacity plans. As LG&E/KU's next IRP is not scheduled to be filed with the Commission until 2008, Staff recommends that KU provide a summary of its longer range capacity plans as part of the annual filings it makes pursuant to Commission Orders in Administrative Case No. 387, A Review of the Adequacy of Kentucky's Generation Capacity and Transmission System.

SECTION 5

INTEGRATION AND PLAN OPTIMIZATION

The final step in the IRP process is the integration of supply-side and demand-side options to arrive at the optimal integrated resource plan. This section will discuss the integration process and the resulting LG&E/KU plan.

The Integration Process

LG&E/KU developed their ultimate resource assessment and acquisition plan based on minimizing expected PVRR over a 30-year planning horizon. Differences were evaluated by changing assumptions and calculating the total PVRR based on the changes with a smaller PVRR as the objective.

LG&E/LU's planning analysis was performed using modules of the STRATEGIST computer model. The plan includes analyses of reserve margin requirements, supply-side resources and demand-side resources. It includes sensitivities of 6 areas: (1) first year available for base load addition; (2) load; (3) fuel cost; (4) unit retirements; (5) capital cost of the coal units; and (6) gas transportation for CTs and combined cycle units.

LG&E/KU's optimal target reserve margin study indicates that a target reserve margin from 11 to 14% would be optimal and adequately and reliably meet customers' current and future demand needs. The study recommended that a 14% target reserve margin be used in LG&E/KU's long-range planning studies, which is the reserve margin used in the development of the optimal long-range resource plan. This represents a slight change from LG&E/KU's 2002 IRP, in which the reserve margin range was 13 to 15% and 14% was recommended as the target reserve margin for planning purposes.

LG&E/KU's supply-side analysis screened 47 supply-side technologies to arrive at 6 options for analysis within STRATEGIST. Those 6 options are as follows:

Simple cycle combustion turbines (CTs - 148 MW each)

Trimble County 2 – Supercritical pulverized Coal (549 MW – 75% of total)

Ohio Falls 9 and 10 - Run of River Expansion (2 MW each)

Supercritical pulverized Coal unit at a Greenfield Site (750 MW)

WV Hydro – Power purchase agreement (potential 240 MW)

Combined cycle combustion turbines (CC – 484 MW)

The detailed analysis of the supply-side options reflected cost/performance data for the CTs and combined cycle units based on data provided by Black & Veatch.

Cost/performance data for the Trimble County coal unit was based on data provided by Burns & McDonnell. Cost/performance data for the Ohio Falls option is based on data provided by Voith-Siemens Hydro. The first year available for each of the options is based on LG&E/KU's experience with permitting and constructing similar projects.

Summary of Results

Iterations of the "base case" analysis show a need for the TC2 coal unit in 2010, six CTs and the WV Hydro option in the middle and later years of the forecast period, and the Greenfield coal unit in 2019, the last year of the forecast period. The base case analysis shows that this plan for adding supply-side resources, in conjunction with the DSM programs that passed the quantitative screening, produces the lowest PVRR ($17.635 billion over 30 years).

Specifics of the Supply-Side Analyses

LG&E/KU performed several sensitivity analyses to determine how other factors might influence the selection of an optimal resource plan. The first sensitivity analysis, using low and high load forecasts has (1) the WV Hydro capacity being added in 2011, (2) TC2 pushed back to 2013 and (3) several of the CTs and the Greenfield coal unit being eliminated in the low load forecast scenario; in the high load forecast scenario (1) 2 of the CTs are moved up to 2009, (2) TC2 remains at 2010 and (3) the Greenfield coal unit is moved up to 2015. A second sensitivity analysis using low and high coal prices was performed to evaluate how different coal prices would impact the plan. This analysis did not impact the timing of adding TC2, but did substitute 2 Ohio Falls hydro units for CTs and moved the Greenfield coal unit up to 2017.

LG&E/KU have no current plans to retire any existing generating units; however, they have a number of older units, i.e. 35 years-plus. These units' relatively high production costs and the stricter emissions limits forthcoming under the Clean Air Interstate Rule ("CAIR") in 2010 will negatively impact the economics of operating these units. Hence, there is some potential that retiring some of these older units might become economical, depending on future events. For this reason, a sensitivity analysis was performed based on retiring approximately 180 MW in 2010. Compared to the base case, the results of this analysis call for adding an additional CT, which would come on line earlier than in the base case, and adding 1 Ohio Falls unit in the later years of the forecast period.

A sensitivity analysis was also conducted based on a 5% increase in the capital cost of TC2. Cost estimates provided by the firm of Cummins & Barnard reflected a cost of $1,314 per Kw of capacity. An increase of 5% increased the PVRR by $105 million, but did not impact the in-service date compared to the results in the base case.

A final sensitivity analysis, based on eliminating firm natural gas transportation costs for the CT and CC options, reduces the PVRR compared to the base case by

$180 million, but does not alter the in-service dates of any of the generation facilities included in the base case.

Specifics of the DSM Analysis

LG&E/KU's qualitative DSM analysis screened 70 DSM measures. The results of this qualitative screening suggested that 27 measures should be evaluated further in a quantitative analysis. The present value for each DSM alternative was calculated in this analysis based on the 5 "California Tests" which have been employed historically in the evaluation of DSM alternatives. The 5 tests are the participant test, the utility cost test, the ratepayer impact measure, the total resource cost test, and the societal cost test. The results of this quantitative analysis indicated that 5 programs, Setback Thermostats, Smart Thermostat, A/C Tune-Up, Energy Efficient Indoor Lighting, and Polarized Refrigerant Oxidant Agent, should be considered in the integrated analysis, where DSM programs are evaluated together with supply-side alternatives.

Overall Plan Integration

Based on its analyses, LG&E/KU determined that the optimal expansion plan consists of TC2 in 2010, 1 CT in 2013, the WV Hydro purchase in 2014, 2 CTs added in 2015, single CTs added in each year from 2016 through 2018, and the Greenfield coal unit in 2019.

After developing this optimal expansion plan, LG&E/KU modeled the plan with the DSM programs added to determine whether the addition of the program affected the PVRR. Based on the 30-year analysis, adding the programs to the optimal expansion plan reduces the PVRR by over $23 million. Based on that result, LG&E/KU modified the plan described above to add the DSM programs over the first 7 years of the forecast period. The estimated cumulative effect of the DSM programs is a demand reduction of 28.8 MW. While this reduces the PVRR to $17.611 billion, it does not alter the timing of any of the supply-side resource additions.

Discussion of Reasonableness

In its report on LG&E/KU's 2002 IRP, Staff made the following recommendations relative to the integration process for consideration in the preparation of LG&E/KU's next scheduled IRP.

- In the next IRP, a decision to retire any generating unit(s) should be supported by a feasibility study regarding the decision to retire the unit(s).

- In the next IRP, LG&E/KU should ensure that their planning adequately reflects the impact of future CO_2 emission restrictions.

In response to the first of these recommendations, LG&E/KU cited the report on the "Phase II Evaluation of the Economic Viability of Green River Units 1 and 2" which supported the decision to retire those units and which was filed with the Commission in Case No. 2004-00434. In response to the second recommendation, LG&E/KU offered the analysis of CO_2 issues included in the section of the IRP headed "Analysis of Supply-Side Technology Alternatives."

Staff is generally satisfied with LG&E/KU's responses and the information contained therein. It believes these responses adequately address the previous recommendations. Staff has the following recommendations which it believes should be addressed in the next LG&E/KU IRP filing.

Recommendations

This report includes Staff's observations on both LG&E/KU's aging generating units and their existing purchase power agreements. Staff's recommendations on those issues for LG&E/KU's next IRP are as follows:

- Given the future implications of the CAIR, LG&E/KU should include a sensitivity analysis in the next IRP based on the possible retirement of a level of capacity much larger than the 180 MW included in the sensitivity analysis performed for this IRP.

- Since the filing of this IRP, LG&E/KU have provided information in other proceedings concerning the status of KU's purchase power agreement with OMU. In the next IRP, LG&E/KU should include a detailed report on the status of this purchase power agreement.

- In the next IRP filing, consistent with the Commission's findings in Administrative Case No. 2005-00090, LG&E/KU are encouraged to fully investigate the potential for incorporating renewable energy into their portfolio of supply-side resources.

Staff will also repeat its recommendations from the prior report, as follows:

- In the next IRP, a decision to retire any generating unit(s) should be supported by a feasibility study regarding the decision to retire the unit(s).

- In the next IRP, LG&E/KU should ensure that their planning adequately reflects the impact of future CO_2 emission restrictions.