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Mr. Jeff DeRouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, KY 40602

RECEIVED
JAN 28 2010
PUBLIC SERVICE COMMISSION

January 28, 2010

RE: ***APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR APPROVAL OF PURCHASED POWER AGREEMENTS AND RECOVERY OF ASSOCIATED COSTS***
CASE NO. 2009-00353

Dear Mr. DeRouen:

Please find enclosed and accept for filing the original and ten (10) copies of the Response of Louisville Gas and Electric Company and Kentucky Utilities Company to the Joint Intervenors' Supplemental Requests for Information dated January 15, 2010, in the above-referenced matter.

Also enclosed are an original and ten (10) copies of a Petition for Confidential Protection regarding certain information provided in response to Question No. 3 and Question No. 8.

Should you have any questions concerning the enclosed, please contact me at your convenience.

Sincerely,

Rick E. Lovekamp

Rick E. Lovekamp

Enclosures

cc: Parties of Record

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E. Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of January 2010.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Charles R. Schram**, being duly sworn, deposes and says that he is Director – Energy Planning, Analysis and Forecasting for E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Charles R. Schram

Charles R. Schram

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of January 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 30, 2010

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Douglas Keith Schetzel**, being duly sworn, deposes and says that he is Director of Business Development for E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Douglas Keith Schetzel

Douglas Keith Schetzel

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of January 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND	)	
ELECTRIC COMPANY AND KENTUCKY	)	CASE NO.
UTILITIES COMPANY FOR APPROVAL OF	)	2009-00353
PURCHASED POWER AGREEMENTS AND	)	
RECOVERY OF ASSOCIATED COSTS	)	

RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY
TO SUPPLEMENTAL REQUESTS FOR INFORMATION
OF JOINT INTERVENORS'
DATED JANUARY 15, 2010

FILED: January 28, 2010

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to Supplemental Requests for Information of Joint Intervenors Dated January 15, 2010

Case No. 2009-00353

Question No. 1

Witness: Lonnie E. Bellar / Counsel

Q-1. With regard to your response to JI-3:

a. Provide an explanation of how the costs associated with a 20-year long contract can be "unanticipated."

b. Have the companies not presented data indicating that certain known parameters exist regarding how frequently and at what intensities wind will blow at the generating sites?

c. Will the companies acknowledge that every cost factor in the utility business to one extent or another carries a risk of uncertainty (i.e., no one can predict with certainty what the future holds)?

A-1. a. Proposed expenditures for energy under the 20-year wind power contracts would be "unanticipated" in exactly the same sense that fuel costs are "unanticipated" as the Kentucky Court of Appeals used the term in *Kentucky Public Service Commission and Duke Energy Kentucky Inc., f/k/a The Union Light, Heat and Power Company, v. Commonwealth of Kentucky, ex rel., Greg Stumbo*, Case No. 2007-CA-001635-MR, November 7, 2008 (not to be published). In *Stumbo*, the court described fuel costs recovered through Kentucky utilities' fuel adjustment clause mechanisms:

> So that our opinion is not misunderstood and to address the issues raised in the amici curiae brief, we reiterate that our decision is premised on the nature of the long-term capital

> improvements proposed by Duke **as distinguished from fuel increases that are fluctuating and unanticipated**. The latter have been approved by our Supreme Court and remain the law.[1]

The Companies' fuel costs are "unanticipated" only to the extent that their precise amount cannot be known in advance due to fluctuating market prices (and fluctuating electric production needs). Certainly the Companies anticipate purchasing fuel, and plenty of it, for many decades to come. But because the total fuel cost for a given time period cannot be fully anticipated, it is appropriate for surcharge recovery and is "unanticipated," as the Court of Appeals has used the term. The same is true for the energy and transmission costs of the wind power contracts.

b. The Companies have presented data concerning historical wind patterns at the Grand Ridge site; however, there simply is no set of "certain known parameters ... regarding how frequently and at what intensities wind will blow at the generating sites." The wind will blow whenever, and at whatever intensities, it blows. Though there are historical data that suggest expected bounds for wind intensities at given times, forecasting the weather, which is a complex and uncontrollable system, is uncertain at best.

But the same can be said for coal prices. Certainly there is a range of coal prices the Companies expect based on historical trends and what they can see in the marketplace. Indeed, the Companies employ sophisticated models and trained professionals to do the best they can to forecast what coal and other fuel prices are likely to be in the foreseeable future; among other reasons, they do this so they can hedge against likely cost increases. In that sense, perhaps, coal prices, like wind patterns, have some "certain known parameters."

But none of this changes the fact that coal prices, like wind patterns, are inherently unpredictable. All of the factors that go into coal prices cannot be known by any one person, nor can they be known with certainty. The Court of Appeals recognized this when it described fuel costs as "unanticipated." In the same way, the weather is a complex system that nobody fully understands; indeed, not all of weather's variables are even known, much less predictable. So wind patterns are at least as "unanticipated" as coal costs.

---

[1] *Stumbo* at 19 (emphasis added).

And there is at least one way in which wind patterns are more "unanticipated" than coal prices. Unlike fuel costs, there is no hedging the wind; the Companies can't stockpile it when it's blowing to use when the air stills. In that sense, wind is even more "unanticipated" than coal prices.

c. Agreed: "In this world nothing can be said to be certain, except death and taxes."[2] But the question is not whether there is *any* uncertainty associated with the energy and transmission costs associated with the wind power contracts, but rather whether those costs are "fluctuating and unanticipated." The Companies believe they have shown that these costs are at least as "fluctuating and unanticipated" as the fuel costs Kentucky's courts have repeatedly held are appropriate to recover through surcharge mechanisms.

---

[2] Benjamin Franklin, Letter to Jean-Baptiste Leroy, 1789, re-printed in The Works of Benjamin Franklin, 1817.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to Supplemental Requests for Information
of Joint Intervenors
Dated January 15, 2010

Case No. 2009-00353

Question No. 2

Witness: Lonnie E. Bellar / Charles R. Schram

Q-2. With regard to your response to JI-4:

a. Confirm that the per unit price for wind energy is fixed and certain, and thus does not fluctuate.

b. With regard to the confidential attachment to your response to this request, confirm that knowing [redacted] in advance allows the companies to plan and anticipate certain elements of total cost involved pertaining to the costs.

c. Confirm that the companies can absorb any remaining costs that may or may not be subject to fluctuation in-between rate cases without incurring material impairment to the companies' credit or operations by passing the costs along through base rate cases. If not, why not? In regard to your response, please take into consideration the following responses from the companies: (1) JI-6 in which the companies acknowledge the "small size" of the wind contracts; in which the companies acknowledge the "small size" of the wind contracts; (2) JI-7, that no additional maintenance costs would be incurred to the companies' system; (3) JI-8, that the nominal start up costs identified therein will be recovered through base rates; (4) JI-10, that under the contracts the companies will not pay for volume uncertainty associated with wind power developments, as the companies have structured the contracts in such a manner so that they will pay only for energy delivered, and that holders of transmission reservations within PJM are entitled to Financial Transmission Rights which may provide a partial hedge against fluctuating congestion costs.

A-2. a. Yes, the wind power contracts provide a fixed price per MWh for the wind energy they produce. But several factors that contribute to the total cost of energy from the wind farms cannot be predicted with any real certainty, such as: (1) how much energy the wind farms will produce; (2) whether transmission paths will be available to transport the energy to the Companies; and (3) how much transmission will cost (taking into account congestion pricing). Please see also the Companies' response to Question No. 1 above.

b. If the Companies knew the total amount they would actually pay annually under the wind power contracts, yes, it would eliminate a significant uncertainty associated with the overall wind power costs. But the Companies do not, and cannot, actually have that knowledge. Please see the Companies' response to Question No. 1 above.

c. This sub-question presupposes that the Companies would recover the proposed wind energy costs through their base rates. The Companies are not seeking such recovery, but rather are seeking recovery of all wind-energy-related costs through their proposed surcharge mechanism.

The Companies have elected to pursue surcharge recovery, rather than the base rate recovery, because in this case surcharge recovery is the most equitable way to address the cost of adding wind power to the Companies' energy portfolio. The Companies' desire is not, nor has it ever been, to benefit financially from the proposed wind power contracts; it does not have an equity stake in the wind farms on which the Companies would seek to earn a return, nor is there any other sort of profit margin the Companies are seeking to earn from the wind power contracts. The proposed surcharge ensures that the wind contracts will not provide any direct financial benefit to the Companies.

Also, the Companies have proposed surcharge recovery because the wind energy cost is indistinguishable from the Companies' other fuel and energy costs, which have passed through their Fuel Adjustment Clause ("FAC") mechanisms for decades. Though there is a component of fuel and energy cost embedded in the Companies' base rates, the purpose of the FAC mechanisms is to ensure near-real-time cost recovery of fuel and energy costs in excess of the amount embedded in base rates (or to return the benefits of lower fuel costs to customers). The Companies do not seek, and do not receive, any direct financial benefit from passing their fuel and energy costs directly to customers, just as would be true of the wind energy costs that passed through the proposed surcharge mechanism. There simply is no principled distinction between the proposed wind energy costs and the fuel and energy costs the Companies recover through their FAC mechanisms, so there is no reason to seek to embed the wind energy costs in base rates.

The Companies would also remind the Joint Intervenors that embedding such costs in base rates is not a magic bullet. Though it is certainly possible that the Companies' customers could "win" if the actual wind energy costs exceeded the amounts embedded in base rates, they can also "lose" if the wind doesn't blow or transmission costs are lower than expected. The Companies' surcharge approach keeps customers from having to make that bet.

Finally, the question asks the Companies to confirm that they could "absorb" wind energy cost fluctuations if a base level of such costs were embedded in the Companies' base rates. The answer is yes, the Companies likely could absorb some amount of losses associated with higher-than-forecasted wind energy costs without forcing the Companies into bankruptcy. But that is the wrong frame from which to evaluate the issue. As the Joint Intervenors well know, the Companies' stockholders are constitutionally entitled to earn a fair, just, and reasonable return on their invested capital. What the Joint Intervenors seem to be proposing is that the Companies' shareholders take additional risks with their invested capital with no additional compensation. Notably, the Joint Intervenors do not suggest that if the wind energy costs were embedded in base rates, they would support a higher return on equity for the Companies. But the Joint Intervenors cannot have it both ways; in the pending case, either the wind energy costs should pass through directly to customers with no return to the Companies, or the Companies' return on equity should be increased to compensate for the additional risk of embedding wind energy costs in base rates.

Concerning the other items the question asks the Companies to "take into consideration":

(1) The Companies' response to JI-1-6 described the wind contracts as being of "small size" from a capacity perspective, not a cost perspective: "Given their small size, the wind contracts offer no significant firm capacity to the system, and therefore have no material impact on reserve margin."

(2) As the Companies stated in their response to JI-1-7, it is true that the Companies would incur no additional maintenance costs as a result of entering into the wind power contracts.

(3) As the Joint Intervenors note in this sub-question, the start-up costs the Companies stated in their response to JI-1-8 were indeed "nominal" and capable of being recovered through base rates; however, the energy and transmission costs associated with the wind power contracts are significant and will be most equitably recovered through the Companies' proposed surcharge mechanism.

(4) Concerning the sub-question's assertion about volume uncertainty, please see the Companies' response to Question 10 below. Concerning the use of Financial Transmission Rights ("FTRs") as a partial hedge against congestion costs, please note the Companies' intentional use of the word "partial"; FTRs do not guarantee having no congestion costs, and are not cost-free to obtain.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to Supplemental Requests for Information
of Joint Intervenors
Dated January 15, 2010

Case No. 2009-00353

Question No. 3

Witness: Charles R. Schram

Q-3. With regard to the Companies' response to JI-14, please calculate for at least one year the estimated increase in: (a) off-system sales revenues; and (b) off-system sales margins, that will occur in the event the PSC approves the subject contracts. In making this calculation please use the same PROSYM production cost assumptions used in your response to PSC Staff Question 7. Please provide the workpapers for this calculation.

A-3. Based on the overlay of the wind energy profile with the production cost model assumptions and forecasted market power prices, the model forecasts that an additional [redacted] of energy, or [redacted] of the expected wind energy, will be available for economic off-system sales in 2011. The associated increase in off-system revenue is [redacted] and the increase in off-system sales margin is [redacted].

However, as noted in the response to item JI-14 in the Joint Intervenors' first data request, the inherent uncertainty surrounding the availability of the wind generation at any given hour may preclude the Companies' ability to sell any additional energy off-system. For example, even on an hour-ahead basis, it may not be possible to estimate the available wind energy with a high level of confidence. Therefore, the Companies would not commit to the off-system sale of energy that might be required to serve native load.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to Supplemental Requests for Information
of Joint Intervenors
Dated January 15, 2010

Case No. 2009-00353

Question No. 4

Witness: Lonnie E. Bellar

Q-4. Reference [redacted] June 18, 2009). Explain in detail the following: [redacted]

A-4. The sender of the e-mail was mistaken. The Companies' proposal is to recover all costs associated with the wind power contracts via a surcharge mechanism. Such recovery would render the energy zero-cost for After-the-Fact-Billing ("AFB") purposes, effectively "pushing" wind energy to the "bottom" of the AFB "stack" used to compute the amounts billed through the Companies' Fuel Adjustment Clause mechanisms. In other words, the Companies' native-load customers would pay for and receive the benefits of the wind energy. Therefore, wind energy would not be used directly for off-system sales.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to Supplemental Requests for Information of Joint Intervenors
Dated January 15, 2010

Case No. 2009-00353

Question No. 5

Witness: Lonnie E. Bellar

Q-5. With regard to your response to JI-11, are the companies acknowledging that costs associated with the proposed contracts are minimal, but that they are concerned the companies' shareholders will object unless there is a means to rapidly recover costs? If so, isn't that just the normal cost of doing business in an investor-owned company?

A-5. Please see the Companies' response to Question No. 2.c. above.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to Supplemental Requests for Information of Joint Intervenors Dated January 15, 2010

Case No. 2009-00353

Question No. 6

Witness: Lonnie E. Bellar

Q-6. With regard to the companies response to PSC 1-3, acknowledge that as of the date of your response, the U.S. Senate has yet to vote upon the proposed legislation known as Waxman-Markey (HR 2454), or any other federal laws commonly referred to as "cap and trade."

A-6. Acknowledged.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to Supplemental Requests for Information of Joint Intervenors Dated January 15, 2010

Case No. 2009-00353

Question No. 7

Witness: Lonnie E. Bellar / Counsel

Q-7. With regard to [redacted] DVD attached to the companies' unredacted response to JI-20, the document contains [redacted]

a. With regard to the above-quoted statement, identify any and all meetings, telephonic conferences, or written exchanges (regardless of the media in which they occurred) [redacted] In your response, include the following information: (1) identify who at the KPSC made such inquiries; (2) provide copies of any and all documents associated in any way with such inquiries; (3) provide the context in which such requests were made, including where they were made: (4) identify any other people present when any such inquiries were made; (5) Identify whether in making such inquiries, the [redacted] ever made any mention of the [redacted]; (6) state whether the person(s) [redacted] responsible for making the so-called [redacted] ever stated why they were making such an [redacted].

b. With regard to the statement in the above-referenced document that begins: [redacted]

[redacted] Acknowledge that the wind power contracts at issue do not meet these two conditions.

c. Provide the basis for the claimed confidentiality of the document. Specifically, explain how the document could place the companies in an unfair competitive disadvantage.

A-7. a. The Companies are aware of four such inquiries. All pertinent documents are attached to this response.

1. The Recommendations section of the Commission Staff Report on the Companies' 2005 Integrated Resource Plan ("IRP") states, "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."[3]

2. On January 15, 2009, during the public hearing of the Companies' most recent base rate cases, 2008-00251 and 2008-00252, Commission Chairman David Armstrong stated, "[T]he Commission has a very keen interest in seeing renewables as a part of the portfolio of resources and we were hoping that that would be utilized here, but I understand the fact you've not had the chance to develop it, but, in the future, I think the Commission would welcome that."[4]

3. On February 26, 2009, the Companies' representatives presented information concerning the Companies' analysis of their renewable Request for Proposals. The presentation, handouts, and an e-mail showing that representatives from the Attorney General's Office of Rate Intervention and the Kentucky Industrial Utilities Customers, Inc., were invited to attend. The actual attendees were: Jeff Derouen, Rick Bertelson, Stephanie Bell, Thomas Self, David Samford, Bill Boucher, Vice Chairman James Gardner, Aaron Greenwell, John Rogness, Commissioner John Clay, Allyson Sturgeon, David Sinclair, Lonnie Bellar, and Doug

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[3] *In the Matter of: The 2005 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2005-00162, Commission Staff Report at 24 (Feb. 15, 2006).

[4] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates*, Case No. 2008-00251, *In the Matter of: Application of Kentucky Utilities Company to File Depreciation Study*, Case No. 2007-00565, *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates*, Case No. 2008-00252, *In the Matter of: Application of Louisville Gas and Electric Company to File Depreciation Study*, Case No. 2007-00564; Transcript of Evidence, Vol. II, at 23 ln. 23 – 24 ln. 4 (Jan. 15, 2009).

Schetzel The Companies' representatives do not recall specific inquiries Commission personnel made during the presentation, or even if such inquiries were made.

4. The Recommendations section of the Commission Staff Report on the Companies' 2008 Integrated Resource Plan ("IRP") states, "Also, there is a likelihood of new federal legislation and/or environmental rules regarding the control of greenhouse gas emissions in the foreseeable future. The aggressive pursuit of renewable generation opportunities, including smaller-scale distributed generation all the way down to the residential level, additional DSM programs and greater public awareness is all the more relevant."[5]

b. Please see the Companies' response to Question No. 8 below.

c. The document at issue reveals considerations not made public or part of the Companies' renewable RFP. It shows the review process between the Companies and their parent, E.ON A.G. Disclosing the contents of this review process and the kinds of considerations therein could enable future renewable energy bidders to manipulate their bids to the detriment of the Companies' customers.

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[5] *In the Matter of: The 2008 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2008-00148, Commission Staff Report at 22 (Oct. 13, 2009).

Case No. 2005-00162 – Commission Staff Report

Ernie Fletcher
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LaJuana S. Wilcher, Secretary
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Protection Cabinet

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Teresa J. Hill
Vice Chairman

Gregory Coker
Commissioner

MEMORANDUM

KENTUCKY PUBLIC SERVICE COMMISSION

TO: Main Case File - Case No. 2005-00162

FROM: Jeff Shaw, Division of Financial Analysis

DATE: February15, 2006

SUBJECT: Commission Staff's Report on the 2005 Integrated Resource Plan of Louisville Gas and Electric Company . and Kentucky Utilities Company

Pursuant to 807 KAR 5:058, the Commission Staff has prepared its report on the 2005 Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company. The report, attached to this memorandum, is being filed in the record of this case. Filing this report constitutes final substantive action in the case. The final administrative action in the case will an Order to close the case and remove it from the Commission's docket. Such an Order will be issued in the near future.

Attachment

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.

<u>Key Assumptions in KU's Forecast</u>

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.

<u>The LG&E Forecast</u>

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.

<u>Uncertainty Analysis</u>

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.

Setback Thermostats

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.

Smart Thermostat (TOU rate)

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.

Energy Efficient Indoor Lighting

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.

[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.

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[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

<u>Compliance Planning</u>

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.

Renewable RFP Analysis Presentation – 02/26/2009

E.ON U.S.

KPSC Informal Conference
Renewable RFP Analysis

February 26, 2009

E.ON U.S.

Agenda

- RFP Process and Results
- Typical Renewable Project Attributes
- Wind Energy Details
- Landfill Gas Project Details
- Solar Energy Details
- Regulatory Issues
- Next Steps

E.ON U.S.

RFP Process and Results

- RFP released on July 9, 2007 seeking
  - Up to 30 year supply of capacity / energy from renewable resources
  - Minimum 2 MW capacity, up to 750 MW
- Fifteen responses received
  - 1 Hydro, 4 Wind, 4 Solar (PV), 6 Biomass
- Follow-up interviews held with all respondents
- Focus for shortlisting
  - Status of technologies and projects offered (maturity, stage of development)
  - Energy costs and supply terms
  - Competence, experience and creditworthiness of bidder
- Contract discussions held throughout 2008 with 2 windfarm developers (Indiana) and 1 landfill gas supplier (Kentucky)

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RFP Process and Results (continued)

- All-in unit cost of the least-expensive renewable energy sources (wind & biomass) still exceeds that of the Utilities' conventional thermal generation options
- Indicative pricing (levelized, excluding transmission):

	RFP	2008 IRP
Wind	~$90/MWh	$83/MWh
Biomass	~$90/MWh	$63/MWh
Solar	~$300/MWh	$486/MWh

- Cost of wind does not include cost of back-up capacity
- Tax incentives (included in above estimates) reduce the cost of renewables development

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RFP Process and Results (continued)

			Capital Cost		
Plant type	**Size (MW)**	**Capacity factor**	**2008 IRP ($/kW)**	**RFP responses ($/kW)**	**All-in cost ($/MWh)**
Coal - SCPC	750	92%	$2,500	NA	$57
IGCC (1x1)	290	84%	$3,200	NA	$70
CCGT	475	62%	$900	NA	$79
GT	155	15%	$680	NA	$170
Hydro	30	42%	$4,280	~$3,800	$120
Wind	~2MW	28%	$2,022	~$2,000	$90
Solar PV	~1MW	23%	$7,208	~$5,500	$300
Biomass	Various	85%	$2,692	$2,200 - $11,000	$43 - $273

Fossil data based on 2008 IRP and Cummins & Barnard Generation Technology Options Study, Sep 2007.
Renewable data based on RFP responses.

Typical Renewable Project Attributes

Technology	Wind	Landfill Gas	Solar
Capital Cost in $/KW	2,000 – 2,500	2,500	7,500 – 8,000
Project Size MW	100	< 20	0.25
Fuel Cost in $/MWH	0	18 – 25	0
Capacity Factor	30%	90%	14%
Reliable Capacity	< 10%	Full	Nearly Full Summer Only
Levelized Cost $/MWH	91 – 93 at interconnection point	80 - 90	250 +
Tax Incentives	Full PTC	Half PTC	ITC + Full PTC

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Wind Energy Details – 20 Year Term PPA Opportunities

Owner	A	B	C
Counterparty to contract	Confidential LLC	Confidential LLC	Confidential LLC
Type of Proposal	Unsolicited bid	Response to RFP	Response to RFP
Contract Size MW	99	100	201.3
Location of Resource	Northern Illinois	Northern Indiana	Northern Indiana
Delivery Point	PJM/COMED	PJM/AEP	PJM/AEP
Projected MWh Delivered/year	277,000	295,000	570,500
Levelized Cost $/MWh *	100 – 110 delivered to LG&E/KU	100 – 110 delivered to LG&E/KU	100 – 110 delivered to LG&E/KU
Status	Negotiating	Extensive negotiation – offer was withdrawn	Evaluating

* *Includes $20/KW-Year PJM Transmission cost plus $2/MWH for LMP risk*

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Wind Energy Details

- Energy Contract
  - Wind Energy cost exceeds that of the Utilities' conventional thermal generation options
  - 20 year term – take or pay contract for energy
  - Energy on an as available basis depending on wind
  - Low Capacity Value – less than 10% of Nameplate Capacity

- Transmission Service
  - Utilities at risk for full energy & PTC cost if transmission is curtailed
  - PJM Transmission cost of $20/KW-YR adds $7 to $8/MWH
  - PJM LMP Differential difficult to quantify or hedge
  - PJM and SPP transmission studies for Owner A to be completed in 2009
  - Cost of any system upgrades required by transmission studies unknown

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Landfill Gas Project Details

- Company to sell LFG produced at 3 landfill sites in Kentucky
  - Cost of gas – Indexed to a percentage of Henry Hub with price collar
  - Proposed Term of 20 years with two five year extensions

- Utilities to build and own approximately 20 MW of total generation
  - Capital Cost of approximately $45 million for 2011 commercial operation
  - Cost of generation potentially competitive with the Utilities' conventional thermal generation options
  - Expected levelized cost of generation to be $80 to $90/Mwh with PTC
  - Interconnection to LG&E/KU transmission system (Studies Underway)

Solar Energy Details

- Cost of Energy – expected to be $250 - $300/MWH
- Studied installation of Solar Arrays on E.ON U.S. Facilities
  - Example – production at Simpsonville facility utilizing all available roof space (approx. 44,000 sqft) generates 215 KW
- Small individual project size (250 KW or less)
- Annual degradation in power output of 0.5 – 1 % per year
- Eligible for both ITC and PTC
- Energy Cost is highest of the alternatives studied
- Solar projects can be readily developed to meet RPS requirements

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Regulatory Issues – Cost Recovery to be Addressed

- Wind
  - How will purchase power contracts be approved?
  - How will energy costs be recovered (e.g. through the Fuel Adjustment Clause)?
  - Should an opportunity for a return on purchased power cost be allowed?
  - Should a Renewable Energy Rider be setup to recover costs?

- Landfill Gas
  - Will these facilities pass the traditional cost recovery measures?

- Solar
  - Should a Renewable Energy Rider be setup to recovery costs?
  - Will pre-approval of rate-making treatment for construction costs be provided?

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Next Steps

- Finalize negotiations with suppliers
- Develop contracts dependent on regulatory approval
- File appropriate KPSC applications for each renewable option supporting cost recovery

Case No. 2008-00148 – Commission Staff Report

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Chairman

James W. Gardner
Vice Chairman

Charles R. Borders
Commissioner

October 13, 2009

PARTIES OF RECORD

RE: Case No. 2008-00148
The 2008 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company

Enclosed please find a memorandum announcing the issuance of the Staff Report on October 13, 2009 that has been filed in the record of the above referenced case. Any comments regarding this memorandum's content should be submitted to the Commission within five days of the receipt of this letter. Questions regarding this memorandum should be directed to Rick Bertelson at 502-564-3940, extension 260.

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MEMORANDUM

KENTUCKY PUBLIC SERVICE COMMISSION

TO: Main Case File – Case No. 2008-00148

FROM: Jorge Valladares, Division of Financial Analysis

DATE: October 13, 2009

SUBJECT: Commission Staff's Report on the 2008 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company

Pursuant to 807 KAR 5:058, the Commission Staff has prepared its report on the 2008 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company. The report, attached to this memorandum, is being filed in the record of this case. The filing of this report constitutes the final substantive action in Case No. 2008-00148. The final administrative action in the case will be an Order to close the case and remove it from the Commission's docket. Such an Order will be issued in the near future.

Attachment

Kentucky Public Service Commission

Staff Report On the

2008 Integrated Resource Plan

of Louisville Gas and Electric Company

and Kentucky Utilities Company

Case No. 2008-00148

October 2009

SECTION 1

INTRODUCTION

Administrative Regulation 807 KAR 5:058, promulgated in 1990 and amended in 1995 by the Kentucky Public Service Commission, ("Commission" or "PSC") 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 electricity 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 2008 Joint IRP to the Commission on April 21, 2008. The IRP submitted by LG&E/KU includes their plan for meeting their customers' electricity requirements for the period 2008-2022.

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 U.S., 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.

In PSC Case No. 2003-00266,[1] the Commission found that the customers of LG&E and KU would benefit from the companies' lower incurred costs by discontinuing their membership in the Midwest Independent System Operator ("MISO") a regional transmission organization subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). On May 31, 2006, the Commission approved LG&E's and KU's exit from MISO subject to a withdrawal settlement between the utilities and MISO.

LG&E supplies electricity and natural gas to customers in the Louisville, Kentucky greater metropolitan area. It provides electric service to over 400,000 customers in Louisville and 11 surrounding counties with a total service area covering approximately 700 square miles. LG&E serves over 300,000 natural gas customers.

KU supplies retail electricity in 77 Kentucky counties to over 515,000 customers in a service area covering roughly 6,600 non-contiguous square miles and in five

[1] Case No. 2003-00266, Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc. (Ky. PSC May 31, 2006).

Virginia counties as Old Dominion Power ("ODP"). 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 companies' 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 report includes an incremental component, noting any significant changes from the companies' most recent IRP filed in 2005.

LG&E/KU state that they have an ongoing resource planning process which is fundamental to all corporate planning and that the report submitted in this proceeding represents only one snapshot in time of the process. LG&E/KU examine the economics and practicality of supply-side and demand-side options in order to forecast the least-cost options available to meet forecasted customer needs. According to LG&E/KU, the planning process is dynamic and the assumptions made in the planning decisions are subject to various degrees of risk and uncertainty.[2]

The LG&E/KU resource planning process is comprised of the following:

- establishment of a reserve margin criterion,
- assessment of the adequacy of existing generating units and purchased power agreements,
- assessment of potential purchased power market agreements,
- assessment of demand-side options,
- assessment of supply-side options, and
- development of the optimal economic plan from the available resource options.

Even though the IRP represents LG&E/KU's analysis of the best options to meet customer needs at a given point in time, the resource plan is reviewed and re-evaluated prior to implementation.[3]

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[2] Application, Volume I, Section 5, Plan Summary, at 5-3 to 5-4.

[3] Id., at 5-4.

LG&E/KU have also addressed the suggestions and recommendations regarding their 2005 IRP included in the Staff report issued in Case No. 2005-00162[4].

Based on a forecasted average annual growth rate of 1.3 percent over the 2008-2022 forecast period, LG&E/KU will require resource additions totaling roughly 1,650 megawatts ("MW"). Supply-side resources include a super-critical 732 MW coal-fired base load plant to be located at LG&E's Trimble County Generating Station (of which LG&E/KU's share would be 549 MW) and three "greenfield" combustion turbines ("CTs") with a total capacity of 1,105 MW. Power purchase agreements total 26,089 GigaWatt-hours ("GWh").

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.

[4] Case No. 2005-00162, 2005 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company (Ky. PSC Feb. 24, 2006).

SECTION 2

LOAD FORECASTING

INTRODUCTION

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 provides a tool for decision-making regarding construction of facilities such as power plants, transmission lines, and substations, all of which are necessary for providing reliable service. The forecasting process is designed to yield reasonable estimates of LG&E/KU's future energy and load growth so that the goals of providing adequate and reliable service at the lowest reasonable cost are met.

Generally, LG&E/KU's forecasting approach uses econometric modeling of energy sales by customer class and growth outlook information collected from their largest customers. Econometric modeling illustrates the statistical relationship between energy consumption and one or more independent variables. Energy sales forecasts are then developed from projections of the independent variables. 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's and 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 12 municipally owned 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. Most of the forecasts are based upon at least ten years of historical monthly sales data. Residential sales modeling also incorporates end-use forecasting of base load, heating, and cooling components of energy sales. The extent of this modeling varies by utility and class. Since LG&E and KU sales data is derived from billing records, 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' load characteristics. Due to the strong link between growth forecasts for national and regional economies and estimates of future energy use, national economic forecast data is used. National, state, and county level 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 as of the First Quarter of 2007 in generating its trend (baseline) forecast. The forecast assumes that the economy suffers no major shocks between the first quarter 2007 and 2037. The economy grows smoothly, in the sense that actual output follows potential output relatively closely. The trend projection may be thought of as an average of all possible paths that the economy could follow.

GI's population projection is consistent with the U.S. Census Bureau's "middle" projection for the U.S. population. The projection is based on specific assumptions about immigration, fertility and mortality rates. GI projects that the U.S. population will grow an average of 0.8 percent annually over the 2005-2030 period.

GI's Energy Service expects the average acquisition price of foreign oil to remain above $50 per barrel. The trend projection assumes that oil will hover in the $50-$70 per barrel range. The price of West Texas Intermediate is expected to rise to about $76 per barrel in nominal terms by 2037. In the long run, scarcity of resources tends to elevate prices, 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 $21.50 a barrel in 2001 to approximately $33.40 per barrel in 2037.

In addition to the national macroeconomic drivers, GI provided LG&E/KU with state- and county-level economic and demographic forecasts. LG&E and KU service territory level forecasts are developed as aggregates of county level forecasts.

The Energy Independence and Security Act of 2007 (EISA 2007) was signed into law in December 2007. Generally, the act was designed to increase energy efficiency and encourage the development and availability of renewable energy. For LG&E and KU, the largest impact on sales will come from new energy-efficient lighting and appliances. New building and commercial equipment standards had not been developed at the time of the forecasts and are not incorporated into the IRP results. The full impact of new lighting standards is expected to be phased in gradually between 2012 and 2019. The companies already assume that future appliances are going to become more energy efficient, so the forecasts are not affected significantly as a result of EISA 2007.

Key Assumptions in KU's Forecast

GI provided the following key economic and demographic assumptions which serve as the primary drivers of KU's Energy and Demand Forecast.

KU's service area population is expected to average 0.6 percent annual growth over the next ten years. Households in KU-served counties are predicted to increase at a 0.7 percent annual average rate over the next ten years. The slightly higher growth rate in households reflects a declining trend in the number of people in each household. Normal climate conditions are obtained from the National Climatic Data Center and reflected by the weather values averaged for the 20-year period ending in 2006. Weather data was collected from Louisville and Lexington, Kentucky and from Bristol, Tennessee for ODP forecasts. The 2008 IRP assumes annual normal heating degree days (HDDs) to be 4,525 and cooling degree days (CDDs) to be 1,219 over the forecast period.

KU's sales forecast is generated by 21 separate forecast models, each of which forecasts the number of customers, use-per-customer, or total sales on a monthly basis and is associated with one or more homogeneous rate classes.

KU's Residential Forecast includes all customers on the residential service and volunteer fire department rate schedules. The residential sales forecast is the product of the use-per-customer forecast and the forecast number of customers. The residential customer forecast is a function of the number of service-territory households. The residential use-per-customer forecast is derived using a Statistically Adjusted End Use (SAE) Model. The SAE model defines energy use as a function of energy used by heating equipment, cooling equipment, and other equipment. Key inputs to the sales-per-customer forecast include heating and cooling degree days, personal income, household size, appliance saturations, appliance efficiencies, and electricity prices. Household size, appliance saturation levels and appliance efficiency information is obtained from the Energy Information Administration and company customer survey data. The survey data allows the company to estimate the mix of residential housing types on the KU system and the approximate appliance saturation levels.

The KU Commercial Forecast is comprised of two forecast models: KU general service/LP secondary and KU all-electric schools. The former includes all customers on the KU general service rate schedule and the KU large power service rate schedule taking service at secondary distribution voltage. Monthly usage was forecast as a function of the average cost of electric service, Kentucky's Real Gross State Product, and weather-related binary variables. The all-electric schools forecast includes all customers on the all-electric school rate schedule. Sales were modeled as a function of the number of KU residential customers and all months except May, June-August, October and November.

The industrial class is unique because of the relatively small number of customers that comprise a significant portion of KU's load. For this reason, KU works directly with its largest industrial customers when possible to develop five-year forecasts. Industrial sales are forecast first and then adjusted for exceptional fluctuations based upon individual customer information. The industrial forecast is made up of five models comprised of various customers grouped according to load, rate schedule and voltage. Key variables in these models include the US Industrial Production Index, weather-related variables, and the average cost of electricity.

The KU Mine Power Forecast is comprised of two forecast models: mine power primary and mine power transmission. The former includes all customers taking service at primary distribution voltage and the latter includes all customers taking service at transmission voltage. Sales are modeled as a function of coal production. Coal production forecasts for Western and Eastern Kentucky were obtained from Hill & Associates.

The KU Municipal Forecast is comprised of three forecast models: transmission municipal, primary municipal, and City of Paris. Differences in the first two models lay in the level of service voltage. The City of Paris is modeled separately because it furnishes some of its own generation. Sales are modeled as a function of weather and the number of households in the counties served by each municipal utility.

The KU Lighting Forecast is comprised of two models: KU street lighting and KU private outdoor lighting. Each forecast is produced as the product of the monthly number of lighting hours, monthly energy use-per-fixture-per-hour, and a monthly forecasted number of fixtures. Trending is used to obtain the underlying forecasts.

Key Assumptions in LG&E's Forecast

GI provided the following key economic and demographic assumptions which serve as the primary drivers of LG&E's Energy and Demand Forecast.

LG&E's service territory population will average 0.7 percent annual growth over both the next five years and the 15-year time horizon. LG&E service territory households will average 1.1 percent annual growth over the next five years and increase at a 1.0 percent annual rate over the 15-year forecast horizon.

Normal climate conditions are obtained from the National Climatic Data Center and reflected by the weather values averaged for the 20-year period ending in 2006. Weather data was collected from Louisville, KY. The 2008 IRP assumes annual normal HDDs to be 4,147 and CDDs to be 1,553 over the forecast period. For LG&E's various forecasts, models similar to those used by KU were run.

LG&E's Residential Forecast includes all customers on the residential service and volunteer fire department rate schedules. The residential sales forecast is the product of the use-per-customer forecast and the forecast number of customers. The Residential Customer Forecast is a function of the number of service territory households. The Residential Use-per-Customer forecast is derived using an SAE Model. The SAE model defines energy use as a function of energy used by heating equipment, cooling equipment and other equipment. Key inputs to the sales-per-customer forecast include heating and cooling degree days, personal income, household size, appliance saturations, appliance efficiencies, and electricity prices. Household size, appliance saturation levels and appliance efficiency information is obtained from the Energy Information Administration and company customer survey data. The survey data allows the company to estimate the mix of residential housing types on the LG&E system and the approximate appliance saturation levels.

The LG&E Commercial Forecast is comprised of two commercial forecast models: LG&E small commercial and LG&E large commercial. The former includes all customers on the LG&E general service rate schedule. LG&E small commercial sales is forecast as the product of forecast use-per-customer and forecast number of customers. The historic use per customer has been essentially flat, so LG&E has modeled the variable as a function of weather since 2000 with binary variables to account for seasonality. The monthly number of customers is a function of residential customers and a trend term to account for a flattening of growth. The LG&E large commercial forecast includes all customers on the large commercial and large commercial time-of-day rate schedules. The sales forecast was modeled as the product of forecasted use-per-customer and the number of customers. Use-per-customer has been flat, so the forecast is a function of weather since 1998. The monthly number of customers is a function of residential customers and an autoregressive AR(1) term.

The LG&E Industrial Forecast industrial class is unique because of the relatively small number of customers that comprise a significant portion of LG&E's load. For this reason, LG&E works directly with its largest industrial customers when possible to develop five-year forecasts. Industrial sales are forecast first and then adjusted for exceptional fluctuations based upon individual customer information. The industrial forecast is made up of two models: LP Power and LP-TOD/Special Contract. The LP Power forecast includes all customers on the large power industrial service rate schedule. The LP-TOD/Special Contract forecast includes all customers on the large power time-of-day rate schedule and all special contract customers. Major accounts make up about 70 percent of the total energy usage in this forecast. Key variables in these models include the US Industrial Production Index, weather-related binary variables, and the average cost of electricity. The LP-TOD/Special Contract model also includes an autoregressive AR(1) term to correct for serially correlated errors.

The LG&E Lighting Forecast is comprised of two models: KU street lighting and KU private outdoor lighting. Each forecast is produced as the product of the monthly number of lighting hours, monthly energy use-per-fixture-per-hour, and a monthly forecasted number of fixtures. The use-per-fixture-per-hour forecast was held flat at 2005 levels and trending is used to obtain the number of fixtures.

Both LG&E and KU conducted a residential appliance saturation survey in October 2007. The last such survey was conducted in 2003. The results of the 2007 survey were not included in the 2008 IRP. However, the companies state that the results broadly confirm the assumptions regarding appliance saturations that were incorporated in the residential forecasts. In addition, the companies participate in an Energy Forecaster's Group managed by Itron, where the collaborative efforts with other utilities provide the development of regional end-use saturation and efficiency data for the various classes of service.

The methodology for obtaining the hourly demand forecast is unchanged from the 2005 IRP. The annual forecast of billed energy sales is converted to a calendar year basis by adding an estimate of net unbilled sales to total billed sales for the year. Net unbilled sales represent the difference between gross unbilled sales at the end of the current year and gross unbilled sales at the end of the prior year. The resulting annual calendar year sales are allocated to months using 20-year-average ratios of monthly to total energy requirements. An estimate of losses and company uses is added to calendar monthly energy sales to obtain the final monthly energy requirement forecast. The monthly energy requirements are then converted to an hourly load duration curve reflecting the historical average hourly load pattern for the same month. For the 2008 IRP, the duration curve represents an averaged normalized curve using the last ten years of monthly data. Finally, the monthly load duration curves are converted to a chronological load curve based on patterns in historical reference months. Then the chronological load curves of LG&E and KU are combined to create the total coincident load for the combined system. The hourly load forecast reflects the impact of interruptible loads.

Results

On a combined basis, weather-normalized energy requirements are forecast to grow from 35,758 GWh in 2007 to 39,080 GWh in 20012, an average annual growth rate of 1.5 percent. By 2022, combined energy requirements are expected to reach 44,036 GWh, an average growth rate of 1.3 percent per year over the forecast horizon.

Combined summer peak demand after industrial curtailments is predicted to grow from 7,095 MW in 2008 to 8,591 MW in 2019, a total increase of 1,496 MW, or an average annual growth rate of 1.4 percent. For each summer period, the companies estimate that 105 MW will be curtailed. The combined LG&E/KU winter peak demand is forecast to increase from 6,055 MW in 2007/08 to 7,193 MW in 2021/22 with an average annual growth rate of 1.2 percent. The combined seasonal forecasts reflect the coincident peak demand of both utilities.

LG&E's weather-normalized energy requirement is forecast to grow from 12,590 GWh in 2008 to 14,854 GWh in 2022, averaging 1.2 percent average annual growth.

LG&E's summer peak demand is forecast to grow from 2,789 MW in 2008 to 3,368 MW in 2022 with an average annual growth rate of 1.2 percent. The winter peak demand is forecast to grow from 1,876 MW in 2008/09 to 2,214 MW in 2022/23 with an average annual growth rate of 1.2 percent.

KU's weather-normalized energy requirement is expected to grow from 22,141 GWh in 2008 to 26,623 GWh in 2022, averaging 1.3 percent average annual growth.

KU's summer peak demand is forecast to grow from 4,306 MW in 2008 to 5,223 MW in 2022 with an average annual growth rate of 1.2 percent. The winter peak demand is forecast to grow from 4,188 MW in 2008/09 to 5,005 MW in 2022/23 with an average annual growth rate of 1.2 percent.

Uncertainty Analysis

For the 2008 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.

For LG&E in 2008, the high and low forecast of energy sales range from 13,559 GWh to 13,081 GWh compared to a baseline forecast of 13,321 GWh. In the long term, LG&E's high and low forecast of energy sales range from 16,628 GWh to 14,892 GWh in 2022 compared to a baseline forecast of 15,737 GWh. LG&E's high and low forecasts of peak demand range from 2,839 MW to 2,739 MW in 2008, in contrast to the baseline forecast of 2,789 MW. LG&E's 2022 high and low forecasts of peak demand range from 3,556 MW to 3,190 MW, in contrast to the baseline forecast of 3,368 MW.

For KU in 2008, the high and low forecast of energy sales range from 24,065 GWh to 22,956 GWh with a baseline forecast of 23,514 GWh. The long-term high and low forecast of energy sales range from 30,150 GWh to 26,446 GWh in 2022 compared to a baseline forecast of 28,300 GWh. KU's high and low forecasts of peak demand range from 5,561 MW to 4,884 MW in 2022, in contrast to the baseline forecast of 5,223 MW.

The 2008 IRP Sales and Peak Demand forecasts are lower than those forecast in the 2005 IRP. For 2008-2022 on a combined basis, the average annual growth rate is 1.3 percent in the 2008 IRP, while it was 1.9 percent in the 2005 IRP, and represents an average annual sales reduction of 1,630 GWh. Similarly, for 2008-2022 on a combined basis, peak demand growth in the 2008 IRP averages 1.4 percent compared to 1.9 percent in the 2005 IRP and represents an average annual reduction of 345 MW. The downward revision in the forecasts and growth rates is a function of slower growth in large commercial and industrial sales, residential use per customer, and efficiency gains from the EISA 2007.

Sensitivity Analysis - Aggressive Green Scenario

In part as a response to EISA 2007, LG&E/KU also undertook a sensitivity analysis to its optimal plan called Aggressive Green Scenario. A Renewable Portfolio Standard (RPS) is one provision of the Aggressive Green Scenario that was not included in the final version of EISA 2007. Under an RPS, some minimum amount of the retail electricity sold to customers must be generated from renewable resources or purchased in the form of tradable energy credits representing an equivalent amount of renewable energy production. Another provision of the Aggressive Green Scenario that was not included in EISA 2007 is stricter limits on the emission of CO_2 and other greenhouse gasses. The eventual realization of some form of these provisions could have major impacts on LG&E and KU and their customers. The Aggressive Green Scenario represents the impact of "efficiency at all costs" and a national commitment toward eliminating coal generation in favor of renewables. LG&E/KU state that the demand-side assumptions for this scenario are consistent with the best available technology case in the Energy Information Administration's Annual Energy Outlook 2007. Supply-side assumptions regarding RPS are consistent with provisions in proposed legislation.

There are three key assumptions that affect both the demand side and supply side of operations in this sensitivity analysis. First, as old equipment and appliances wear out, consumers are assumed to purchase the most energy-efficient equipment available regardless of cost. In part, this will occur as a result of federal legislation changing the minimum efficiency standards for new equipment. Compact fluorescent bulbs are to replace incandescent bulbs by 2012. All new homes and buildings are to be built to the most energy-efficient standards available. Solar panels are to be placed on new homes beginning in 2012. Large industrial and commercial customers are assumed to consume 20 percent less energy by 2022. The growth in energy consumption for this group is taken from the EPA low-growth scenario from the Annual Energy Outlook 2007. The resulting impact on LG&E's and KU's energy and demand forecasts is dramatic when compared to the base case.

LG&E's Energy Requirement is expected to grow from 13,321 GWh in 2008 to 15,737 GWh in 2022 under the base case, or at an average annual growth rate of 1.2 percent. Under the Aggressive Green Scenario, LG&E's Energy Requirement is forecast to grow from 13,090 GWh in 2008 to 13,829 GWh in 2022. This represents an average annual growth rate of 0.4 percent. LG&E's growth in peak demand forecast shows similar declines in magnitude and growth rate. In the base case, peak demand grows from 2,789 MW in 2008 to 3,368 MW in 2022 which represents a 1.4 percent average annual growth rate. Under the Aggressive Green Scenario, peak demand grows from 2,738 MW in 2008 to 3,067 MW in 2022, which represents a 0.8 percent average annual growth rate.

KU's Energy Requirement is expected to grow from 23,514 GWh in 2008 to 28,300 GWh in 2022 under the base case, or at an average annual growth rate of 1.4 percent. Under the Aggressive Green Scenario, KU's Energy Requirement is forecast to grow from 23,156 GWh in 2008 to 24,000 GWh in 2022. This represents an average annual growth rate of 0.2 percent. KU's growth in peak demand forecast shows similar declines in magnitude and growth rate. In the base case, peak demand grows from 4,306 MW in 2008 to 5,223 MW in 2022, which represents a 1.4 percent average annual growth rate. Under the Aggressive Green Scenario, peak demand grows from 4,295 MW in 2008 to 4,618 MW in 2022, which represents a 0.5 percent average annual growth rate.

Two other key assumptions largely impacting the supply side of operations include Kentucky's adoption of a mandatory 15 percent RPS standard by 2020 and that all existing coal-fired electric generating units must be retired after a 50-year life span beginning in 2015. The impact of the 15 percent RPS standard is approximately 5,600 GWh by 2020. The mandate to retire coal-fired units would require the companies to retire nearly 1,800 MW of current capacity by 2020. The optimal expansion plan under the Aggressive Green Scenario over the base case expansion plan forecasts prices to be more than 30 percent higher by 2020.

<u>Changes and Updates to the Forecasting Process</u>

Both LG&E and KU continue to refine their forecasting data and methodology. For the 2005 IRP, service territory level economic level forecasts had been developed by an employment driven model (STEM). The STEM model generated forecasts of sector-level, value-added employment, income and population for five regions corresponding to KU's and LG&E's service territories. These sector forecasts incorporated national economic and demographic data provided by Global Insight. In the 2008 IRP, for both LG&E and KU, GI provided national, state and county level economic and demographic data.

Several long-term forecasts had been developed in 2005 by using growth rates from a medium-term forecast and incorporating them into a long-term model. The 2008 IRP has replaced the two-model structure with a single model that is able to track fluctuations in sales and long-term trends.

In the 2008 IRP, KU's commercial and industrial sales forecasts are now made with the same methodology used to generate LG&E's commercial and industrial sales forecasts. Homogenous rate codes are used to segment groups rather than Standard Industrial Classification codes. Also, in the 2005 IRP, KU's residential service ("RS") and full electric residential service rate classes were forecast separately. Since there is now a single residential rate class, the 2008 IRP forecasts the group as a single rate class.

In the 2005 IRP, the Electric Power Research Institute's ("EPRI") Residential Energy End-Use Planning System ("REEPS") model served a supporting role in the development of appliance-saturation forecasts for the residential use-per-customer forecast. For the 2008 IRP, the REEPS model was not used at all. All appliance-saturation forecasts were taken from the EIA.

Discussion of Reasonableness

In general, Staff is satisfied with the forecasting of LG&E/KU. In its report on the 2005 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 (specifically carbon capture and sequestration and other greenhouse gas mitigation requirements) and how these issues are incorporated into future load forecasts.

LG&E and KU have made very good progress in integrating and refining their forecasting processes. To the extent it is appropriate, they should continue to pursue efforts to integrate their forecasting processes and report on these efforts in their next IRP filing. Also, LG&E and KU demonstrated that they are actively considering the potential effects of pending climate change legislation even though there is a lot of uncertainty regarding exact legislative requirements. They should continue to actively model and incorporate the potential effects of climate change legislation into future IRP filings.

Intervenor Comments

The Attorney General intervened in the case, but did not contest the forecasting methodology, the models, or the data.

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 competition and pending environmental requirements and how these issues are incorporated into future load forecasts.

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

SECTION 3

DEMAND SIDE MANAGEMENT

INTRODUCTION

This section summarizes the Demand-Side Management ("DSM") assessment included in LG&E/KU's 2008 IRP. According to LG&E's and KU's IRP, they 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. 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, their respective weightings and description:

- Customer Acceptance (25 percent) measures the degree to which customers are willing to participate to create a successful program.
- Technical Reliability (15 percent) measures the degree to which technology is commercially available along with data necessary to evaluate the measure.
- Cost Effectiveness of Energy Conservation (25 percent) measures the cost of the alternative to reduce kWh relative to the cost of generation in $/kWh.
- Cost Effectiveness of Peak Demand Reduction (35 percent) measures the cost of the alternative to reduce a kW relative to the cost of generation in $/kW.

Using the four criteria and weights, LG&E/KU's Energy Efficiency Operations Department identified a broad list of 80 potential DSM alternatives to be evaluated. There were 44 potential residential alternatives and 36 commercial alternatives. A weighted score of 2.5 on a scale of 4.0 was selected as the cut-off level for alternatives to advance to the quantitative screening process. In the 2005 IRP, a cutoff level of 2.4

was used. Of the 80 original DSM alternatives, 28 passed LG&E/KU's quantitative screening. Of these 28 alternatives, 15 targeted residential customers while 13 targeted commercial customers.

<u>Quantitative Screening Results</u>

Alternatives that passed the qualitative screening analysis were next modeled in more detail using Quantec LLC's DSM Portfolio Pro software package. Portfolio Pro is a screening tool that determines the cost effectiveness of DSM alternatives by modeling their costs and benefits over a period of time. The program uses both the hourly load shapes for the various DSM options and the companies' aggregate hourly load shape. A detailed production-costing model, PROSYM, is utilized to determine the marginal energy costs, which are then used to estimate the change in production costs resulting from the implementation of each DSM option.

EPRI's DSManager program is used to calculate the net present value of the quantifiable costs and benefits assignable to both LG&E and KU and to the customers participating in a DSM program. For each DSM alternative modeled, Portfolio Pro 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. Portfolio Pro calculates changes to the participant's bill, as well as changes to LG&E's and KU's revenue, production costs, and peak demand.

The present value for each DSM alternative is calculated by Portfolio Pro 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 ("RIM") test, total resource cost test ("TRC"), and societal cost test. The participant test includes changes in all costs and benefits to the customer participating in the DSM alternative. The RIM test indicates the cost and benefit impacts to ratepayers not participating in the DSM alternative. The TRC test combines the RIM and participant tests and indicates the overall benefits of the specific DSM alternative to the average customer.

The actual quantitative screening process was conducted in two phases. Phase I was constructed to remove non-cost-effective DSM alternatives. In this phase, the cost to administer the program was not considered and it was assumed that there would only be a single participant per company. If the program is not cost-effective without consideration of administrative costs, then it would only be eliminated when additional customers and administrative costs are also considered. Only the incremental cost of the DSM alternative was included in this phase. Of the 28 programs evaluated in Phase I, 15 passed the participant test and the TRC test. These DSM alternatives were further evaluated in Phase II. In Phase II, program administrative costs are added and all five California tests are calculated.

Of the 15 programs evaluated in Phase II, three residential programs were ultimately eliminated. Those programs were the High Efficiency Heat Pump program designed to replace the existing unit, the Refrigerator Replacement Incentive, which was designed to replace refrigerators with old, inefficient motors and fans, and the Room Air Conditioner Replacement program which was designed to replace older window units with new more energy efficient units. For all of these programs, the achieved peak and energy savings were insufficient to overcome the program costs.

Recommended DSM Programs

The following four residential programs were included in the 12 programs that passed the quantitative screening process.

1. Duct Evaluation and Sealing

Residential duct systems may be poorly constructed or leaky. This program will perform diagnostic testing of residential air duct systems. Where potential savings are identified, assistance and incentives will be provided to customers for corrective action. Based upon energy and demand savings, this program is cost-effective with a TRC score of 1.14 and a Participant test score of 2.5.

2. Window Shading and Films

The solar gain through windows is generally the largest contributor to residential cooling loads. This program will provide incentives for residential customers to install high-performance film to existing windows to reduce solar heat gain and reduce cooling loads. Based upon energy and demand savings, this program is cost-effective with a TRC score of 1.55 and a Participant test score of 1.71.

3. Responsive Pricing / Smart Meters / Energy Use Display

This is a residential Time of Use (TOU) program with a "real time" component. The TOU rate will be a three-tier TOU rate, but with a fourth "real time" component. Customers will receive smart thermostats, energy-use display devices, and water heater/pool pump controllers to automate energy use based upon the price of electricity. The program will be an expansion of the Companies' Responsive Pricing Smart Metering Program. Based upon energy and demand savings, this program is cost-effective with a TRC score of 2.42. Since the participant cost will be zero, the Participant test score is infinity.

4. Removal of Second Refrigerator

This program will provide incentives to remove old inefficient second refrigerators in the home. The companies estimate that 22 to 29 percent of residential homes have multiple refrigerators. Based upon energy and demand savings, this program is cost-effective with a TRC score of 4.38 and, since the participant cost will be zero, the Participant test score is infinity.

The following eight commercial DSM programs passed the quantitative analysis.

1. Duct Evaluation and Sealing

As with residential air conditioning systems, many commercial systems are poorly insulated and leaky. This program will perform diagnostic testing and, where potential savings are identified, will assist and provide incentives for corrective action. Based upon energy and demand savings, this program is cost-effective with a TRC score of 2.31 and a Participant test score of 7.62.

2. Geothermal Heat Pump (new Construction)

Geothermal heat pumps are highly efficient heating and cooling systems. The high up-front installation costs are somewhat mitigated during new construction. This program will provide incentives to install new systems during the construction of new buildings. Based upon energy and demand savings, this program is cost-effective with a TRC score of 1.00 and a Participant test score of 1.99.

3. High Efficiency Motors

This program will encourage customers considering the replacement of worn-out motors to purchase energy-efficient motors. Based upon energy and demand savings, this program is cost-effective with a TRC score of 1.55 and a Participant test score of 5.32.

4. Refrigeration Optimization

This program is designed to help commercial customers with refrigerators and freezers to improve the operational performance with improved controls, defrost cycles, and high-efficiency motors. Based upon energy and demand savings, this program is cost-effective with a TRC score of 1.52 and a Participant test score of 3.34.

5. Energy Management System

For this program, customers would be provided incentives to install a system to monitor and control HVAC, lighting and equipment energy consumption to reduce peak demand and usage. Based upon energy and demand savings, this program is cost-effective with a TRC score of 1.37 and a Participant test score of 2.21.

6. High Efficiency Heat Pump (replacing resistive heat)

Commercial customers currently using resistive heating will be provided incentives to convert and install high-efficiency heat pump system(s). Based upon energy and demand savings, this program is cost-effective with a TRC score of 1.1 and a Participant test score of 2.36.

7. Heat Pump Water Heater—Restaurants and Laundries

This program is designed for restaurants and laundries that have significant hot water usage. These customers will be eligible for incentives to convert from electric resistance water heaters to more energy-efficient heat pump water heater technology. Based upon energy and demand savings, this program is cost-effective with a TRC score of 1.72 and a Participant test score of 4.07.

8. Refrigeration Case Cover

This program will provide incentives for commercial customers to retrofit their refrigerator and freezer units with doors and case covers. Based upon energy and demand savings, this program is cost-effective with a TRC score of 1.1 and a Participant test score of 4.33.

Summary Discussion of DSM

LG&E and KU pointed out that the 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 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 2005 IRP, Staff made the following recommendations relative to DSM for consideration in preparing LG&E/KU's next IRP filing:

- LG&E/KU should use all five "California tests"—the participant test, utility cost test, RIM test, TRC 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.[5] KU and LG&E 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, KU and LG&E should continue to consider and evaluate a variety of DSM technologies, including those applicable to low-income customers, that would be cost-effective.

[5] Administrative Case No. 2005-00090, An Assessment of Kentucky's Electric Generation, Transmission, and Distribution Needs (Ky. PSC Sept. 15, 2005).

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

Staff notes that the IRP application was filed with the Commission on April 21, 2008. On July 19, 2007, the companies filed Case No. 2007-00319.[6] Parties to the case included the Attorney General's Office, the Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties, Inc., the Kentucky Association for Community Action, Inc., and the Kentucky Industrial Utility Customers. The case was settled and the final Order was issued on March 31, 2008. Seven new DSM programs were approved as pilots that will run for a period of seven years. The seven new approved pilot programs include:

Responsive Pricing and Smart Metering Pilot

This program is described above as one of the residential DSM programs that passed the Phase I and Phase II screening tests.

Residential High Efficiency Lighting

The objective of this program is to encourage customers to purchase compact fluorescent light bulbs rather than the less energy-efficient incandescent bulbs. Increasing customer awareness of the environmental and financial benefits and incentives will be part of the program.

Residential New Construction

The goal of this program is to reduce residential energy usage by shifting builders' new home energy-efficient construction practices. The companies will partner with homebuilders associations to adopt and implement the Department of Energy's Energy Star new homes energy-efficiency program. The Association of Home Builders' approved green buildings methods may also be included to further impact the environment and reduce carbon dioxide emissions.

Residential and Commercial HVAC Diagnostics and Tune Up

These two DSM programs are described above as programs that passed the Phase I and Phase II screening tests.

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[6] Case No. 2007-00319, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company Demand-Side Management for the Review, Modification, and Continuation of Energy Efficiency Programs and DSM Cost Recovery Mechanisms (Ky. PSC Mar. 31, 2008).

Customer Education and Public Information

This program will increase public awareness and understanding of the need for more efficient use of energy as well as the environmental and financial impacts from climate change issues. Increasing public awareness of energy-efficient products and services is a part of the program. There is also an educational component for elementary and middle school students.

Dealer Referral Network

The companies plan to establish and maintain a web-based Dealer Referral Network to deliver services to program constituents. The purpose will be to assist customers in finding qualified and reliable personnel to install energy-efficiency improvements recommended by other energy-efficiency programs, identify energy-related subcontractors for contractors seeking to build energy-efficient homes or improve the energy efficiency of existing homes and to fulfill incentives and rebates.

Program Development and Administration

This is a program that captures development costs, administration costs and functions that are common to all energy-efficiency programs. The problem has been determining an exact allocation to individual programs or rate classes. These common costs will be accrued to this program's administrative budget until they are incorporated into pilot or full-scale program offerings and submitted in subsequent DSM filings.

Staff is very encouraged and the companies should be commended for their efforts in pursuing DSM programs, increasing public awareness of programs generally, and increasing awareness of the environmental and financial issues involved. The number of DSM alternatives which KU and LG&E included in the quantitative evaluation was expanded from the 2005 IRP and a larger number of alternatives passed the second phase of that evaluation. The companies also utilized all five California tests in Phase II of the Quantitative analysis.

Recommendations

Staff notes that on March 4, 2008, in Administrative Case No. 2007-00477,[7] Overland Consulting, in conjunction with London Economics International, LLC, filed its final report (Overland Report). In the same case, on July 1, 2008, the Commission filed its Report, "Electric Utility Regulation and Energy Policy in Kentucky, A Report to the Kentucky General Assembly Prepared Pursuant to Section 50 of the 2007 Energy Act" (Commission Report). In both of these reports, issues regarding DSM programs and

[7] Administrative Case No. 2007-00477, An Investigation of the Energy and Regulatory Issues *in Section 50 of* Kentucky's 2007 Energy Act (Ky. PSC July 1, 2008).

policies were addressed. For the purposes of the IRP Staff Report, some of the recommendations contained in those reports are applicable to LG&E and KU. Also, there is a likelihood of new federal legislation and/or environmental rules regarding the control of greenhouse gas emissions in the foreseeable future. The aggressive pursuit of renewable generation opportunities, including smaller-scale distributed generation all the way down to the residential level, additional DSM programs and greater public awareness is all the more relevant.

The Overland Report noted the lack of large commercial and industrial customer participation in DSM programs in Kentucky.[8] The Commission Report also discussed issues surrounding KRS 278.285. As a result of the lack of industrial and large commercial customer participation, there are no current DSM programs targeted for large users of electric power. For the next IRP, Staff encourages LG&E and KU to continue to reach out to industrial and large commercial customers to pursue DSM alternatives. It may be possible for these customers to work with the companies to design additional DSM programs. In some instances, the resulting DSM program may be customer-specific.

DSM programs must be cost-effective in order to be implemented and in a carbon constrained environment more DSM programs, including energy efficiency, will become cost-effective. Staff encourages the companies to continue aggressively seeking opportunities for new and innovative programs. This approach includes working with customers to better understand and monitor their specific energy consumption needs and to design workable cost-effective programs. Working with large electric users who possess multiple metered facilities (e.g. school districts and local governments) may also provide unexplored opportunities for DSM programs that may be cost-effective for the customer as a whole, but not for individual facilities.

While the recently approved DSM pilot programs and other programs that have passed both Phase I and Phase II evaluations appear to be cost-effective, without verifying the actual achieved results, the true worth of the program may not be known. Staff understands that not all programs, such as those oriented toward customer awareness and education, are designed so that reductions in energy usage are verifiable. Devoting resources toward customer awareness of DSM programs and education of the attendant environmental and financial issues may well increase the participation and cost-effectiveness of other DSM programs. For the next IRP filing, LG&E and KU should work to verify (to the extent possible), document and report the actual achieved reduction in energy usage for each of the pilot DSM programs.

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[8] Essentially, most large commercial and industrial customers eligible to take advantage of the Opt-Out provision in KRS 278.285 have done so. Overland Report at pages 54-56. Public comments filed by Geoffrey M. Young on August 29, 2008 touched on a number of issues, including encouraging the companies to explore new ways to work with industrial customers to implement DSM programs.

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 13 generating stations. Most of their capacity is coal-fired steam generation; six stations have combustion turbines ("CTs") and two stations have hydroelectric units. The newest generation is TC2, a coal-fired unit being constructed at LG&E's Trimble County station. The 2007 summer net capacity for LG&E/KU was 7,519 MW. In addition, LG&E/KU have purchase power agreements in place with Ohio Valley Electric Corporation ("OVEC") and Owensboro Municipal Utilities ("OMU"). Table 4-1 shows LG&E/KU's existing electric generating facilities.

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

Plant Name	Unit No.	Location in Kentucky	Status	Operation Date	Facility Type	Net Capability (MW)		Entitlement		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	139	47%	53%	Gas		None
E W Brown ABB GT24	6			1999		168	154	62%	38%	Gas/Oil	2,200,000 Gals	None
	7			1999		168	154					
E W Brown ABB 11N2	8			1995		140	125	100%				None
	9			1994		140	125					
	10			1995		140	125					
	11			1996		140	125					
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		482	480					None
	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					
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 (34/52)			100%	Water	None	Rehab began Fall 2005
Paddy's Run	11	Louisville	Existing	1968	Turbine	13	12		100%	Gas	None	None
Paddy's Run Siem West V84 3a	12			1968		28	23					
	13			2001		175	158	45%	53%			
Tyrone	3	Versailles	Existing	1953	Steam	73	71			Coal (Trk)	30,000 Tons (1.4# SO2)	None
Trimble County Coal (75%)	1	Near Bedford	Existing	1990	Turbine	515 (386)	511 (383)	0%	75%	Coal (Barge)	500,000 Tons (6.0# SO2)	None
	5			2002		180	160	71%	29%	Gas		
	6			2002		180	160					
Trimble County-GE7FA	7			2004		180	160	63%	37%			
	8			2004		180	160					
	9			2004		180	160					
	10			2004		180	160					
Zorn	1	Louisville	Existing	1969	Turbine	16	14		100%	Gas	None	None

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, environmental 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 have retired a number of older units since their 2005 IRP. Waterside Units 7 and 8 were retired in August 2006; Tyrone Units 1 and 2 were retired in February 2007. 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.

Table 4-2 - Aging Units Considered for Retirement

Type of Unit	Plant Name	Unit	Summer Capacity	In Service Year	Age (2008)
Steam	Tyrone	3	71	1953	55
Steam	Green River	3	68	1954	54
Steam	Brown	1	101	1957	51
CT	Cane Run	11	14	1968	40
CT	Paddy's Run	12	23	1968	40
CT	Zorn	1	14	1969	39
CT	Haefling	1,2,3	36	1970	38

Reliability Criteria

A study was completed by LG&E/KU for this IRP to determine an optimal target reserve margin criterion to be used for planning purposes. The study indicates that an optimal target reserve margin in the range of 13 percent to 15 percent would be adequate to meet customer demand. In the development of the optimal Resource Plan, LG&E/KU used a reserve margin target of 14 percent.[9] In the 2005 IRP, the recommended reserve margin range was 12 percent to 14 percent and a reserve margin target of 14 percent was used.[10]

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 purchased 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 follows:

- Reserve Margin Percent = (Total Supply Capability – Peak Load)/Peak Load
- Capacity Margin Percent = (Total Supply Capability – Peak Load)/(Total Supply Capability).

[9] Application, Volume I, Section 5, Plan Summary, at 5-34.

[10] Id., Section 6, Significant Changes, at 6-26.

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.[11]

A planned outage is defined as the removal of a generating unit from service to perform work on specific components and is scheduled well in advance with a predetermined start date and duration. Forced outages require that a unit 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 and include hours when a unit can operate, but is unable to operate at full load. 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 for some limited period but requires that the unit be removed from service before the next planned outage. Like forced outages, MOs may occur at any time and do not have a predetermined duration.[12]

A sensitivity analysis was also performed on purchase power. While the base assumption limited purchase power only to the contracts with OVEC and OMU, this sensitivity included evaluation of spot (or short-term) purchase power from the wholesale power market.[13]

Emergency energy 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 caused by a failure on the transmission or distribution system, or due to capacity shortages. 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.[14]

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[11] Id., Section 8, Resource Assessment, at 8-125.

[12] Application, Volume III, 2008 Analysis of Reserve Margin Planning Criteria, March 2008, at 3 to 5.

[13] Id., at 7.

[14] Id., at 8.

A system load factor that is higher than forecast could also change the optimal mix of supply-side technologies. This change could force LG&E/KU to operate peaking units with low capital cost but high operating expense at capacity factors that would have made base load units (such as combined cycles or coal-fired units) the better choice.[15]

Supply-Side Evaluation

Fifty-five technologies 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 capacity 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.[16]

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[15] Id., at 9.

[16] The renewable resources identified include wind energy, geothermal, solar, hydroelectric, and waste-to-energy sources of generation.

Table 4-3 - Technologies Screened

Tech ID	Technology Description	Category	Sub-Category	Fuel Type
1	Pumped Hydro Energy Storage–500 MW	Storage	Pumped Hydro	Charging Only
2	Lead-Acid Battery Energy Storage–5 MW	Storage	Battery	Charging Only
3	Compressed Air Energy Storage–500 MW	Storage	Compressed Air	Gas and Charging
4	Simple Cycle GE LM6000 CT–Peaking Capacity	Natural Gas	SCCT	Gas
5	Simple Cycle GE 7EA CT-Peaking Capacity	Natural Gas	SCCT	Gas
6	Simple Cycle GE 7FA CT-Peaking Capacity	Natural Gas	SCCT	Gas
7	Combined Cycle GE 7EA CT-Intermediate Load	Natural Gas	CCCT	Gas
8	Combined Cycle GE 7FA CT-Intermediate Load	Natural Gas	CCCT	Gas
9	Combined Cycle 2x1 GE 7FA CT-Intermediate Load	Natural Gas	CCCT	Gas
10	Combined Cycle 3x1 GE 7FB CT-Intermediate Load	Natural Gas	CCCT	Gas
11	Siemens 5000F CC CT-Intermediate Load	Natural Gas	CCCT	Gas
12	Humid Air Turbine Cycle CT-366 MW	Natural Gas	CCCT	Gas
13	Kalina Cycle CC CT-282 MW	Natural Gas	CCCT	Gas
14	Cheng Cycle CT-140 MW	Natural Gas	CCCT	Gas
15	Peaking Microturbine-0.03 MW	Natural Gas	CT	Gas
16	Baseload Microturbine-0.03 MW	Natural Gas	CT	Gas
17	Subcritical Pulverized Coal-250 MW	Coal	Pulverized Coal	Coal
18	Subcritical Pulverized Coal-500 MW	Coal	Pulverized Coal	Coal
19	Subcritical Pulverized Coal, High Sulfur-750 MW	Coal	Pulverized Coal	Coal
20	Circulating Fluidized Bed-250 MW	Coal	Fluidized Bed Combustion	Coal
21	Circulating Fluidized Bed-500 MW	Coal	Fluidized Bed Combustion	Coal
22	Supercritical Pulverized Coal-500 MW	Coal	Pulverized Coal	Coal
23	Supercritical Pulverized Coal, High Sulfur-750 MW	Coal	Pulverized Coal	Coal
24	Supercritical Pulverized Coal-750 MW	Coal	Pulverized Coal	Coal
25	Supercritical Pulverized Coal, High Sulfur-750 MW	Coal	Pulverized Coal	Coal
26	Pressurized Fluidized Bed Combustion	Coal	Fluidized Bed Combustion	Coal
27	1x1 IGCC	Coal	IGCC	Coal Gasification
28	2x1 IGC	Coal	IGCC	Coal Gasification
29	2x1 IGCC, High Sulfur	Coal	IGCC	Coal Gasification
30	Subcritical Pulverized Coal-500 MW-CCS	Coal	Pulverized Coal	Coal
31	Subcritical Pulverized Coal, High Sulfur-500 MW-CCS	Coal	Pulverized Coal	Coal
32	Circulating Fluidized Bed-500 MW-CCS	Coal	Fluidized Bed Combustion	Coal
33	Supercritical Pulverized Coal-500 MW-CCS	Coal	Pulverized Coal	Coal
34	Supercritical Pulverized Coal, High Sulfur-500 MW-CCS	Coal	Pulverized Coal	Coal
35	Supercritical Pulverized Coal-750 MW-CCS	Coal	Pulverized Coal	Coal
36	Supercritical Pulverized Coal, High Sulfur-750 MW-CCS	Coal	Pulverized Coal	Coal
37	1x1 IGCC-CCS	Coal	IGCC	Coal Gasification
38	2x1 IGCC-CCS	Coal	IGCC	Coal Gasification
39	2x1 IGCC, High Sulfur-CCS	Coal	IGCC	Coal Gasification
40	Wind Energy Conversion-50 MW	Renewable	Wind	No Fuel
41	Geothermal-30 MW	Renewable	Geothermal	Renew
42	Solar Photovoltaic-50 kW	Renewable	Solar	No Fuel
43	Solar Thermal, Parabolic Trough-100 MW	Renewable	Solar	No Fuel
44	Solar Thermal, Parabolic Dish-1.2 MW	Renewable	Solar	No Fuel
45	Solar Thermal, Central Receiver-50 MW	Renewable	Solar	No Fuel
46	Solar Thermal, Solar Chimney-50 MW	Renewable	Solar	No Fuel
47	MSW Mass Burn-7MW	Waste to Energy	MSW	MSW
48	RDF Stoker-Fired-7 MW	Waste to Energy	RDF	RDF
49	Landfill Gas IC Engine-5 MW	Waste to Energy	LFG	Landfill Gas
50	TDF Multi-Fuel CFB (10% Co-fire)-50 MW	Waste to Energy	TDF	10% TDF/90% Coal
51	Sewage Sludge & Anaerobic Digestion	Waste to Energy	SS	No Fuel
52	Bio Mass (Co-fire)	Waste to Energy	Bio Mass	10% Renew/90% Coal
53	Molten Carbonate Fuel Cell-300 kW	Natural Gas	Fuel Cell	Gas
54	Spark Ignition Engine-5MW	Natural Gas	Reciprocating Engine	Gas
55	Hydroelectric-New-30 MW	Renewable	Hydro	No Fuel
200	Ohio Falls 9-10	Renewable	Hydro	No Fuel

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 sensitivity analysis considered the following: (1) capital cost; (2) heat rate; (3) fuel cost; and (4) environmental costs pertaining to nitrogen oxide ("NOx"), sulfur dioxide ("SO2"), and carbon dioxide ("CO2") 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:

- Supercritical Pulverized Coal Unit, High Sulfur, 750 MW
- 3x1 GE 7FB Combined Cycle Combustion Turbine
- 2x1 GE 7FA Combined Cycle Combustion Turbine
- Wind Energy Conversion
- GE 7FA CT Simple Cycle Combustion Turbine
- Ohio Falls 9-10 Hydro Units

Table 4-4 shows LG&E/KU's planned electric generation facilities. The TC2 unit, which is to be located at LG&E's Trimble County site and scheduled for operation in 2010, is presently under construction. LG&E/KU received a Certificate of Public Convenience and Necessity ("CPCN") to construct TC2 in Case No. 2004-00507.[17]

Table 4-4 – LG&E/KU's Planned Future Units

Plant Name	Unit No.	Location in Kentucky	Status	Operation Date	Facility Type	Net Capability (MW)		Entitlement LG&E / KU		Fuel Type	Fuel Storage Cap/SO2 Content	Scheduled Upgrades Derates, Retirements
Trimble County Coal (75%)	2	Near Bedford	Construction	2010	Steam	750 (563)	732 (549)	61%	14%	Coal	800,000 Tons (5.5# SO2)	None
Greenfield Combined Cycle	1	Unknown	Proposed	2015	Turbine	551	475	Unknown		Gas	None	None
	2			2019		551	475					
Greenfield CT	1	Unknown	Proposed	2022	Turbine	184	155	Unknown		Gas	None	None

[17] 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 Compatibility Certificate for the Expansion of the Trimble County Generating Station (Ky. PSC Nov. 9, 2005).

Assessment of Non-Utility Generation – Cogeneration, Renewables and Other Sources

Cogeneration

LG&E/KU did not provide any specific discussion of cogeneration. LG&E/KU did, however, indicate that it did not expect to receive any energy from non-utility sources of generation.[18]

Renewables

In response to a recommendation by Staff for offering green power alternatives, in its report on the companies' 2002 IRP, LG&E/KU submitted an application[19] and received authorization to establish a Green Energy Program. The Program allows customers to contribute funds to be used for the purchase of Renewable Energy Certificates ("RECs") or "Green Tags" by LG&E/KU. Under this program, RS or small commercial ("GS") customers may voluntarily contribute funds for green energy, in any whole multiple of $5 each month. Each $5 contribution will allow the companies to acquire 300 kWh of green energy in the form of RECs. Larger customers receiving service under special contract or any standard rate schedule other than RS or GS may contribute any whole multiple of $13 per month toward the purchase of green tags, representing the environmental attributes of 1,000 kWh of generation from a renewable resource.[20]

LG&E/KU's generation sources include renewable energy generated by hydroelectric facilities at Dix Dam and Ohio Falls.[21] The 2005 IRP discussed the planned rehabilitation of the 80 year-old units at Ohio Falls Station for which a new 40-year license was granted by FERC in 2005. Phase 3 of the rehabilitation of all eight units will increase the expected capacity of the facility from the current planned value at the time of summer peak of 48 MW to 64 MW and the energy from the five-year average production of Ohio Falls Station from 250 GWh to 438 GWh. The rehabilitation of Ohio Falls Station Unit 7 was completed in 2006, rehabilitation of Unit 6 was completed in early 2008. Rehabilitation of Unit 8 at a cost of approximately $13 million

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[18] Application, Volume I, Section 8, Resource Assessment, Table 8.(3)(d), at 8-70.

[19] Case No. 2007-00067, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of Their Proposed Green Energy Riders (Ky. PSC May 31, 2007).

[20] Application Volume I, Section 6, Significant Changes, at 6-35 to 6-36.

[21] Id., Section 5, Plan Summary, at 5-3.

began in 2008.[22] Each of the remaining five units at Ohio Falls Station will be reviewed prior to any rehabilitation.[23]

The Dix Dam hydroelectric station has a 24 MW capability[24] and is undergoing a major upgrade to improve availability.[25]

In response to a recommendation in the Staff Report on their 2005 IRP, LG&E/KU have investigated the potential for incorporating renewable energy into their portfolio of supply-side resources. These alternatives were among the various options considered by LG&E/KU as part of their Aggressive Green Scenario. Among the numerous renewable energy technologies considered were options of wind, solar, biomass, geothermal, waste-to-energy, hydroelectric, and energy storage. Renewable energy units which passed the supply-side screening and thus were considered for the optimal plan included expansion of the Ohio Falls 9-10 hydro units and a wind energy conversion of 50 MW.[26]

The wind turbines and Ohio Falls Station expansion alternatives were the only renewable technologies included in the detailed aggressive green analysis since they were identified as the most economical in the report analyzing supply-side alternatives.[27] Neither the Ohio Falls Station expansion nor the wind turbines were included in the optimal expansion plan through 2022 based on present value revenue requirements criteria.

A discussion of the consideration given to specific renewable resource technologies by LG&E/KU is included in the Appendix of this Staff Report.

Other Non-utility Sources

As noted earlier in this report, LG&E/KU maintain firm purchase power agreements with OMU and OVEC.[28] LG&E/KU expect to receive 168 MW from OMU in 2008, decreasing slightly in 2009 and beyond, until the OMU contract expires in May

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[22] Application, Volume I, Section 6, Significant Changes, at 6-31 to 6-32.

[23] Id., Section 8, Resource Assessment, at 8-9.

[24] Id., Table 8(3)(b), at 8-19.

[25] Id., at, 8-8.

[26] Id., Volume III, PSC Recommendations, Load Forecasting, at 4.

[27] Application, Volume III, Aggressive Green Scenario, at 6 to 8.

[28] Id., Volume I, Section 8, Resource Assessment, at 8-2.

2010.[29] LG&E/KU expect to receive 179 MW net from OVEC for planning purposes for summer peak.[30] Otherwise, LG&E/KU utilize a Request for Proposal ("RFP") process to obtain market offers for specific power needs. The RFP is distributed to qualified parties to ensure broad market coverage and to discover least-cost supply options.[31]

In May 2007, LG&E/KU issued an RFP for peaking power for the next several years. A contract for peaking power from Dynegy's Bluegrass facility for peaking power in the summers of 2008 and 2009 was a product of this solicitation (shown as the first item listed for 2008 in Table 8.(5)(c)-4 below). LG&E/KU also issued an RFP in July 2007 seeking renewable sources for power.[32] The RFP allowed respondents to propose a power purchase agreement, renewable energy technology asset acquisition, or an alternative deal structure. LG&E/KU received 15 responses and respondents were interviewed in late 2007. A short list of respondents was compiled and further discussions are taking place.[33] At this time, the responses to that RFP are still being evaluated.[34] LG&E/KU consider wholesale market opportunities to serve native load on a short-term non-firm basis only. These short-term purchases are typically made as economy purchases to avoid running higher cost resources. LG&E/KU are concerned that the current lack of commitment to build new generation capacity in the U.S. in the near future could lead to further price volatility or even challenge the availability of power from the energy commodity market in the future. Also, according to LG&E/KU, the lack of transmission capability to deliver power from surrounding states will also impact price volatility and the availability of power. LG&E/KU believe forward market prices for power will reflect this relationship between supply, demand and deliverability. Therefore, changes in future market prices may initiate a corresponding revision to the optimal plan as presented in this resource assessment.[35]

Although LG&E/KU have considered renewable and other non-utility resources, the optimal plan through 2022, as shown below, includes only one long-term purchased power contract and no other non-utility resources. The rest of the items included in the optimal plan are DSM and construction projects, as reflected below.

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[29] Id., Section 5, Plan Summary, at 5-40 and Section 8, Resource Assessment, at 8-105.

[30] Id., at 5-42 and Section 8, Resource Assessment, at 8-105.

[31] Id., Section 8, Resource Assessment, at 8-16.

[32] Id., Volume, 1, Section 5, Plan Summary, at 5-38 to 5-39.

[33] Id., Section 6, Significant Changes, 6-36 to 6-37.

[34] Id., Section 5, Plan Summary, at 5-39.

[35] Id., at 5-45 to 5-46.

Table 8.(5)(c)-4
2008 Recommended Integrated Resource Plan[36]

Year	Resource
2008	165 MW Purchase Power Contract (June-Sept only) for 2008-2009
	11MW DSM Initiatives (cumulative totals)*
2009	61 MW DSM Initiatives (cumulative totals)*
2010	549 MW (75% of 732 MW) Trimble County Unit 2 Supercritical Coal**
2011	125 MW DSM Initiatives (cumulative totals)*
2012	191 MW DSM Initiatives (cumulative totals)*
	253 MW DSM Initiatives (cumulative totals)*
2013	314 MW DSM Initiatives (cumulative totals)*
2014	371 M W DSM Initiatives (cumulative totals)*
2015	475 MW Combined Cycle Combustion Turbine
	425 MW DSM Initiatives (cumulative totals)*
2016	441 M W DSM Initiatives (cumulative totals)*
2017	None
2018	None
2019	475 MW Combined Cycle Combustion Turbine
2020	None
2021	None
2022	155 MW Simple Cycle Combustion Turbine

* Case No. 2007-00319[37] approved programs and planned programs in 2008 IRP
** Case No. 2004-00507[38] – CPCN granted November 1, 2005

Compliance Planning

Regarding SO^2 compliance options, LG&E/KU indicate that the construction of wet Flue Gas Desulfurization ("FGD") Units on Ghent Units 1, 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 on an as-needed basis remains the most reasonable and least-cost plan for continued environmental compliance. The Ghent 3 FGD was placed into service in 2007. The Ghent 4 FGD was commissioned in late spring 2008. The Ghent 1 FGD was scheduled to be commissioned in spring 2009. The FGD for the Brown units 1, 2, and 3 should be completed in 2010.

In addition to SO^2 regulation, LG&E/KU must comply with regulations involving emissions of NOx and mercury. The EPA has capped NOx emissions from electric

[36] Id., Section 8, Resource Assessment, at 8-124.

[37] Supra.

[38] Supra.

generating units at 0.15 pounds per million BTUs of historic heat input. LG&E/KU achieved the NOx reductions through the installation of Selective Catalytic Reduction Systems ("SCRs") and other NOx control technologies such as advanced low NOx burners and overfire air systems on many generating units. The SCR process is the most aggressive means of post-combustion NOx removal available to coal-fired boilers and provides the greatest degree of control. An SCR is a large, reactive "filter," about the size of a 10-story building, that houses a catalyst used to convert NOx emissions into the components of nitrogen and water. SCR installation was performed on Trimble County unit 1, Mill Creek units 3 and 4, and Ghent units 1, 3, and 4.

On May 18, 2005, the EPA removed electric generating from the list of sources subject to hazardous air pollutant controls under section 112(c) of the Clean Air Act and promulgated the Clean Air Mercury Rule ("CAMR") which established a two-phase "cap and trade" program for reduction of mercury emissions from those units. On February 8, 2008, the U.S. court of appeals for the D.C. Circuit vacated CAMR on the grounds that the EPA failed to follow the correct procedures for delisting electric generating units from regulation under Section 112(c). A motion for rehearing filed by the EPA and other parties was denied, and a subsequent petition for certiorari before the U.S. Supreme Court was also denied in February 2009. The U.S. EPA has stated its intention to move forward with the development of new mercury emission regulations for electric generating units. However, until such time a final regulatory program is in place, there will continue to be substantial uncertainty as to the impact of mercury regulations on the operation of electric generating units.

Efficiency Improvements

Generation

LG&E/KU evaluate economic improvements to the existing generation fleet. In addition to unit-specific activities, system-wide maintenance schedules are coordinated to insure that outages will have the least economic impact.[39]

LG&E/KU have implemented several activities that improved generation efficiencies, such as new control technologies, boiler tube replacements, pulverizer repairs, precipitator rebuilds, and cooling tower rebuilds.

Distributive control systems ("DCS") have been added to or improved on Trimble County Unit 1, Brown Units 1 and 3, Green River Unit 3, and Ghent Unit 3. DCS give much tighter control and provide more operational information, which results in higher efficiency.

Boiler tube failures are the largest cause of forced outages. LG&E/KU conduct boiler tube inspections and continuous boiler tube studies to identify boiler tube sections needing replacement in order to reduce forced outages. All generation units have had

[39] Application, Volume I, Section 5, Plan Summary, at 5-36 to 5-37.

scheduled boiler outages to replace boiler tube sections as part of the LG&E/KU routine maintenance program.

Several precipitators have had control upgrades to provide tighter control and reduce outages. The precipitators on the following units have had control upgrades: Cane Run Units, Mill Creek Units, Brown Unit 2, and Green River Units 3 and 4. These upgrades have reduced incidences of load restriction initiated to maintain opacity emission compliance.

Other efforts by LG&E/KU to increase efficiency and reduce unit derates have been pulverizer repairs, cooling tower refills, byproduct handling, air heater repairs, air compressor replacements, and condenser tube testing and replacement.

Transmission

The primary purpose of the LG&E/KU transmission system is to reliably transmit electrical energy from company-owned generating sources to their native load customers. The transmission system itself is designed to deliver company-owned generator output and emergency generation to meet projected customer demands and to provide contracted long-term firm transmission services. Interconnections have been established with other utilities to increase the reliability of the transmission system and to provide potential access to other economic and emergency generating sources for native load customers. The transmission system is planned to withstand simultaneous forced outages of a generator and a transmission facility during peak conditions. Although there was no specific discussion of the broad efficiency improvement program or of individual projects, LG&E/KU state that they routinely identify transmission construction projects and upgrades required to maintain the adequacy of the transmission system to meet projected customer demands.[40]

Distribution

Distribution planning standards and guidelines are in place for LG&E/KU. In order to meet growing customer load and to improve service reliability and quality, the distribution system has been enhanced over the past three years by the construction of new substations and distribution lines as well as the expansion or improvement of existing substations and distribution lines. Peak substation transformer loads are monitored annually and load forecasts are developed for a ten-year planning period. LG&E/KU use the loading data and other system information to develop a joint 10-year plan for major capacity enhancements necessary to address load growth and improve system performance. In addition to planned major enhancements, on a daily basis, LG&E/KU distribution personnel continue to plan and construct an appropriate level of conductors, distribution transformers and other equipment necessary to satisfy the normal service needs of new and existing customers. LG&E/KU have undertaken projects each year to install, upgrade or replace distribution substation transformers to

[40] Application, Volume I, Section 8, Resource Assessment, at 8-10.

serve new customers, improve service reliability, and/or mitigate the effects on customers due to major equipment failures. Plans for capacity enhancements at 26 distribution substations were targeted for review in 2008 and 2009. LG&E/KU also install capacitors on the distribution system to provide more efficient use of transmission, substation and distribution facilities as studies identify where power factor correction would most benefit the system. In the past three years, LG&E/KU have installed in excess of $2.5 million in capacitors for power factor improvement.[41]

Discussion of Reasonableness

In its report on LG&E/KU's last IRP, Staff recommended that, due to the termination of its purchased power contract with EEI and the timing of the companies' next IRP filing, KU should provide a summary of its longer range capacity plans as part of its annual filing with the Commission in Administrative Case No. 387.[42] KU provided a summary which Staff concludes adequately responded to its recommendation.

Recommendations

In the next IRP, LG&E/KU should specifically discuss the existence of any cogeneration within their service territories and the consideration given to cogeneration in the resource plan.

LG&E/KU should specifically identify and describe the net metering equipment and systems installed on each system. A detailed discussion of the manner in which such resources were considered in the LG&E/KU resource plan should also be provided.

LG&E/KU should provide a detailed discussion of the consideration given to distributed generation in the resource plan.

LG&E/KU should provide a specific discussion of the improvements to and more efficient utilization of transmission and distribution facilities as required by 807 KAR 5:058, Section 8 (2)(a). This information should be provided for the past three years and should address LG&E/KU's plans for the next three years.

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[41] Id., at 8-10 to 8-11.

[42] Administrative Case No. 387, A Review of the Adequacy of Kentucky's Generation Capacity and Transmission System (Ky. PSC Oct. 7, 2005).

SECTION 5

INTEGRATION AND PLAN OPTIMIZATION

The final step in the IRP process is the integration of supply-side and demand-side options to achieve the optimal 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 Present Value Revenue Requirements (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/KU'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 five areas: (1) DSM performance; (2) load forecast; (3) unit retirement; (4) carbon emission regulations; and (5) combined cycle operation. Break-even analyses were performed on gas prices and coal and capital costs.

LG&E/KU's optimal reserve margin study indicates that a target reserve margin from 13 to 15 percent would be optimal and would adequately and reliably meet customers' current and future demand needs. The study recommended that a 14 percent 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 2005 IRP, in which the reserve margin range was 12 to 14 percent and 14 percent, the high end of the range, was the recommended target reserve margin for planning purposes.

LG&E/KU's supply-side analysis screened 55 supply-side technologies to arrive at six options for analysis within STRATEGIST. Those six options are as follows:

- Supercritical Pulverized Coal Unit High Sulfur, 750 MW
- Combined Cycle Combustion Turbine (a 3x1 GE 7FB and a 2x1 GE 7FA)
- Wind Energy Conversion
- Simple Cycle Combustion Turbine
- Ohio Falls 9 and 10 - Run of River Expansion (2 MW each)

The detailed analysis of the supply-side options reflected cost/performance data for the pulverized coal, simple and combined cycle units are based on data provided by Cummins & Barnard. 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 a combined cycle unit to be constructed at a Greenfield site in 2015 and in 2019, and a Greenfield Combustion Turbine in 2022. The base case analysis shows that these supply additions, in conjunction with the DSM programs that passed the quantitative screening, resulted in a base case optimal resource plan PVRR of $17.95 billion.

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 variables for sensitivity analysis in the screening study are capital cost, heat rate, fuel cost, and cost associated with CO_2 emission control.

Results of supply-side alternative screenings yielded four top options that either received first, second, or third least-cost option in at least 100 scenarios. The top technology options were Supercritical Pulverized Coal (High Sulfur), Supercritical Pulverized Coal, and two Combined Cycle Combustion Turbines (Intermediate Load). Four different coal-fired technologies were identified among the 13 least-cost technologies. However, the Supercritical Pulverized Coal (High Sulfur) 750 MW unit was recommended for further analysis because it was the only one that ranked first in least-cost generation alternatives in every sensitivity scenario.

Specifics of the DSM Analysis

LG&E/KU's qualitative DSM analysis screened 80 DSM measures. The results of this qualitative screening suggested that 28 measures should be evaluated further in a quantitative analysis. The present value for each DSM alternative was calculated in this analysis based on the five California Tests which have been employed historically in the evaluation of DSM alternatives. The five 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 12 programs: Duct Evaluation and Sealing (Residential and Commercial); Geothermal Heat Pump (new construction) (Commercial); Window Shading and Films (Residential); High Efficiency Motors (Commercial); Responsive Pricing/Smart Metering/Energy Use Display (Residential); Refrigeration Optimization (Commercial); Removal of Second Refrigerator (Residential); Energy Management System (Commercial); High Efficiency Heat Pump (replacing resistive heat) (Commercial); Heat Pump Water Heater-Restaurant & Laundries (Commercial); Refrigeration Case Cover (Commercial); should be considered in the integrated analysis, where DSM programs are evaluated together with supply-side alternatives.

Overall Plan Integration

LG&E/KU determined that the optimal expansion plan consists of bringing TC2 online in 2010, adding Combined Cycle Units at Greenfield sites in 2015 and in 2019, and adding a CT in 2022.

After developing this optimal expansion plan, LG&E/KU modeled the plan with the DSM programs added to determine whether the addition of the programs affected the PVRR. Based on the 30-year analysis, adding the programs to the optimal expansion plan reduces the PVRR by approximately $222 million. It is recommended that LG&E and KU implement the described supply-side plan "A." LG&E/KU should continue to investigate the economic viability of power purchase options as an alternative to generation construction.

Discussion of Reasonableness

In its report on LG&E/KU's 2005 IRP, Staff made the following recommendations relative to the integration process for consideration in the preparation of LG&E/KU's next scheduled IRP.

Given the future implications of the Clean Air Interstate Rule ("CAIR"),[43] 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,[44] LG&E/KU are encouraged to fully investigate the potential for incorporating renewable energy into their portfolio of supply-side resources.

In the next IRP, a decision to retire any generating unit(s) should be supported by

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[43] In July 2008, the U.S. Court of Appeals for the D.C. Circuit issued an opinion vacating and remanding CAIR and CAIR Federal Implementation Plans, including their provisions establishing the CAIR NOx annual and ozone season and SO^2 trading programs. However, parties to the litigation requested rehearing of aspects of the Court's decision, including the vacatur of the rules. In December 2008, the Court granted rehearing and remanded the rules to EPA without vacating them in order to allow EPA to develop new rules in compliance with the Clean Air Act and the Court's ruling.

[44] Supra.

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 sensitivity covered in the 2008 Optimal Expansion Plan Analysis contained in Volume III, Technical Appendix. In response to the second recommendation, LG&E/KU offered a status report of the activity involved in its litigation with OMU regarding contract disputes. In response to the third recommendation, LG&E/KU cited a report entitled "Analysis of Supply-Side Technology Alternatives (January 2008)" contained in Volume III, Technical Appendix. Also, the Aggressive Green Scenario was considered and discussed in Volume III, Technical Appendix as well. Units which have been retired since the last IRP have been supported by feasibility studies and are discussed in Section 6 of the 2008 IRP. Finally, sensitivity studies were conducted on the optimal plan for CO_2 and low-emission allocations were performed. The studies are contained in "2008 Optimal Expansion Plan Analysis (March 2008)" in Volume III Technical Appendix.

Staff is generally satisfied with LG&E/KU's responses and the information contained therein. It believes these responses adequately address the previous recommendations. All of Staff's recommendations for LG&E/KU's next IRP filing are contained in Sections 2, 3 and 4 of this report.

Appendix

Appendix to the Staff Report in Case No. 2008-00148

A Summary of LG&E/KU's Consideration of
Renewable Resource Technologies and Energy Storage Technologies[45]

Renewable Resource Technologies

Wind Energy

Wind is converted to power by a rotating turbine and generator. Wind power is rated on a scale of Class 1 to Class 7, with Class 7 representing an area with substantial wind speeds. According to LG&E/KU, it is a general rule, to produce wind energy economically, wind turbines are located in a Class 3 or greater region. Most of Kentucky has a wind power class rating of 2 or less, meaning poor wind energy characteristics for wind power generation. Despite this limitation, a 50 MW wind unit was considered by LG&E/KU.

Solar

Solar technology captures the sun's energy and converts it to thermal energy (solar thermal) or electrical energy (solar photovoltaic), which drives a device (turbine, generator, or heat engine) for electrical generation. According to research reported by Cummins & Barnard, the relatively low solar intensity levels experienced in Kentucky result in relatively low capacity factors for solar technologies. Solar options were considered in the evaluation with ratings ranging from 50 kW to 100 MW and capacity factors between 18 and 65 percent.

Biomass

The most efficient options for electrical generation from biomass resources include units co-fired with coal, offsetting a portion of the fossil fuel consumption. Biomass fuels present unique challenges when burned in any boiler, as compared to coal, due to higher moisture, chlorine, and volatile matter content, lower energy content, alkaline ash, and agglomeration of bed ash. The biomass alternative included in this evaluation is the 500 MW supercritical pulverized coal facility, co-fired with ten percent biomass fuel by weight. Emissions controls are unchanged from a coal-only configuration.

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[45] Application, Volume III, Supply Side Analysis, at 13 to 20.

Geothermal

Heat from the Earth's crust is extracted to generate steam to drive turbine generators to produce electricity. Geothermal power is limited to locations where geothermal pressure reserves are found. Most geothermal reserves can be found in the western portion of the United States. Virtually no geothermal resources exist in Kentucky. There are three types of geothermal power conversion systems in common use including dry steam, flash steam, and binary cycle. Binary cycle plants, which utilize a turbine driven by fluid heated through a non-contact heat exchanger connected to the geothermal resource, could theoretically be implemented in Kentucky with very deep wells, but this has not been proven. A 30 MW binary cycle unit is included in this study.

Hydroelectric

Electricity is generated by water passing through turbines in a dam. The costs and implementation schedules for hydroelectric projects, however, can vary significantly based upon site specifics. The hydroelectric installation considered here is a run-of-river based design sized for 30 MW of generation capacity at a Greenfield location. Additionally, expansion at the existing Ohio Falls Station was evaluated.

Waste to Energy

Waste-to-energy technologies can utilize a variety of waste types to produce electricity. The economics associated with waste-to-energy facilities are difficult to determine, as costs are dependent upon waste transportation, processing, and tipping fees for the particular site. Values contained within this analysis are representative of technologies at generic sites. The specific waste-to-energy technologies considered are cited below.

Municipal Solid Waste – Unprocessed waste is fed into a boiler where there is limited processing before burning in furnace. A 7 MW unit with a 75 percent capacity factor requiring 300 to 350 tons waste per day was considered in this evaluation.

Refuse-Derived Fuel – Pellets from waste are used to fuel generators. A 7 MW unit fueled by refuse-derived fuel with a capacity factor of 85 percent was considered in the evaluation.

Landfill Gas – Gas from decomposition within a landfill is gathered, compressed and used to power combustion turbines or internal combustion engines. This evaluation considers a 5 MW unit with a capacity factor of 90 percent.

Sewage Sludge & Anaerobic Digestion – Sludge waste is digested by bacteria in an anaerobic digester to produce methane gas used to fuel bio-methane fueled generators. An 85 kW unit with a 90 percent capacity factor was considered in this analysis.

Tire-Derived Fuel – Chipped tires are co-fired in a fluidized bed boiler. The tire-derived fuel alternative included in this evaluation is a 10 percent tire-derived fuel co-fired fluidized bed system and is rated at 50 MW with a capacity factor of 92 percent.

Energy Storage Technologies

Energy storage systems are utilized for supplying energy during peak load periods. Energy storage technologies typically have very fast startup times making them an ideal source for instantly dispatchable power. Energy storage systems can be dispatched at times of high demand and/or high generation cost. Energy storage devices must be charged or recharged by equipment utilizing electricity generated by another source. Charging is typically performed during periods of low demand from electricity sources with low generation costs. Alternatively, recharging energy can be sourced from renewable energy sources that are intermittent in nature, such as wind or solar. In the evaluation performed by LG&E/KU, it was assumed that the energy storage options were charged using power generated from LG&E/KU's coal-fired units.

Pumped Hydro Energy Storage – Water is pumped from a lower to a higher reservoir during off-peak hours. When energy is required, water in the upper reservoir is converted to electricity as it flows through a turbine to the lower reservoir (similar to conventional hydroelectric facilities). A 500 MW pumped hydro energy storage unit assumed to recover 80 percent of the energy input was considered in this. Pumped hydro energy storage is considered a viable option to serve intermediate load levels but a low capacity factor (20 percent in this evaluation) makes it difficult for this technology to compete with other peaking technologies.

Lead-Acid Battery Storage – Energy is stored in a battery or batteries which can be discharged when electrical power is needed. The lead-acid battery storage unit included in this analysis is rated at 5 MW with a capacity factor of 20 percent and is assumed to recover 87 percent of the energy input.

Compressed Air Energy Storage – Compressed air stored in an underground cavern is passed through a gas turbine expander to produce electrical power. A 500 MW compressed air energy storage unit with a 25 percent capacity factor was used in this evaluation.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to Supplemental Requests for Information
of Joint Intervenors
Dated January 15, 2010

Case No. 2009-00353

Question No. 8

Witness: Douglas Keith Schetzel / Counsel

[redacted] With regard to [redacted] please explain the statement [redacted]

a. Provide the basis for the claimed confidentiality of the document. Specifically, explain how the document could place the companies in an unfair competitive disadvantage.

A-8. The Companies have not argued that the Commission should approve the wind power contracts and surcharge mechanism because the Companies have an immediate need for additional long-term energy purchases or because the wind power contracts provide economical energy compared to conventional resources; indeed, if the contracts were price-competitive with conventional resources, there would be no need to request the creation of a new surcharge mechanism, because recovery through their Fuel Adjustment Clauses would be appropriate. Rather, the Companies believe it is now prudent to secure long-term renewable energy at competitive prices (relative to the renewable energy market). Waiting until the imposition of a state or federal renewable portfolio standard to acquire renewable energy is almost certain to result in higher prices for customers.

a. In JI-1-20, the Joint Intervenors requested "all memos, emails, or other documents in the possession of the Companies which discuss, describe or relate to the wind power contracts." The Companies took the request seriously and conducted a diligent search for responsive documents. To date, the Companies have produced over 95,000 pages of confidential and non-confidential responsive documents.

To expedite the production process, the Companies requested the Commission to grant confidential protection to whole documents rather than specific portions of documents. Line-by-line redactions of confidential information from tens of thousands of pages of responsive documents would have required more time and manpower than was available for the task. For that reason, as well as the limits of the document-reviewing technology available, it was not possible to separately categorize e-mails and their attachments. Therefore, if the content of an e-mail or one or more of its attachments was confidential, the Companies' counsel treated the e-mail and all of its attachments as confidential.

Turning to the particular e-mail at addressed in this Question, attached to it was a document that contained information the Commission had already held to be confidential in this proceeding. [redacted]

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Response to Supplemental Requests for Information of Joint Intervenors Dated January 15, 2010

Case No. 2009-00353

Question No. 9

Witness: Douglas Keith Schetzel

Q-9. With regard to [redacted], in item no. 6 of that document, confirm that under the proposed contracts, [redacted] is fully recoverable from ratepayers.

A-9. The Companies confirm that the wind power contracts obligate the Companies to pay for all energy the wind farms produce, including any energy that cannot be transported to the Companies' transmission and distribution systems due to transmission constraints. The Companies clearly stated this in their Application ¶ 21:

> [T]he wind power contracts require the Companies to take or pay for all energy produced by the wind farm and pay additional compensation if the energy is curtailed due to transmission constraints.

The Testimony of Lonnie E. Bellar at page 6 also addresses the issue:

> The Companies are required to take and pay for all energy produced by the wind farms. Firm point-to-point transmission service from PJM will be used to deliver the energy to the Companies' transmission system. The Companies hold all transmission risk and are required to pay for all energy that would have been produced but for transmission constraints, plus compensation for any production tax credits ("PTCs") Invenergy would have received if the energy had been produced.

The Company is obligated to pay Invenergy for energy not taken due to a transmission curtailment in accordance with Sections 1.01 and 5.01(c) of the Agreement. Because transmission risk after the interconnection point is on the Buyers, such payments would be the Company's cost and as such, would be recoverable from ratepayers.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Question No. 10

Witness: Douglas Keith Schetzel

Q-10. With regard to [redacted], in item no. 11 of that same document, explain in detail the statement " . . . [redacted]

A-10. The document to which the question refers pre-dates the Companies' Application by several weeks. It is clear that the statement does not reflect what the Companies have actually requested, which is recovery of the wind power costs through a separate surcharge mechanism, not through the Companies' Fuel Adjustment Clause mechanisms.

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Question No. 11

Witness: Douglas Keith Schetzel / Lonnie E. Bellar

Q-11. Please indicate whether either KU or LG&E, or any affiliate of the Companies including any E.ON related entity, will receive either directly or indirectly any tax benefit (including production tax credits or investment tax credits) or other financial benefit as a result of the proposed wind power contracts.

A-11. The Companies are not aware of any direct or indirect tax benefit they would receive from entering into the wind power contracts. The wind power contracts explicitly state at Article 6.02(f) that all Production Tax Credits associated with wind energy from the wind farms will go to Invenergy and its affiliates, not the Companies. There are no other tax benefits of which the Companies and related entities are aware that they could receive associated with the contracts.

Any power purchase agreement ("PPA") having additional energy available to the Companies provides a potential opportunity to make more sales into the off-system market. But the wind power contracts will provide less of an off-system sales opportunity than would equivalent PPAs from conventional generating resources. Please see the response to JI-2-3.

Bond rating agencies treat long-term power purchase obligations as debt ("imputed debt") and imputed debt factors into the Companies decision making regarding capital structure.

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Question No. 12

Witness: Lonnie E. Bellar

Q-12. In its recently-filed base rate case Kentucky Power is seeking recovery of the costs of a proposed 100 mw wind power contract in base rates, not through a new surcharge. To the best of your ability please describe why base rate recovery is feasible for Kentucky Power but not KU or LG&E.

A-12. Please see the Companies' response to Question No. 2.c. above.

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Question No. 13

Witness: Lonnie E. Bellar / Douglas Keith Schetzel

Q-13. Please reference [redacted], which contains an [redacted]

a. Did the receipt of this message cause the companies to change their position?

b. Describe the companies' response to the receipt of this e-mail.

c. To the best of the companies' knowledge, has there been any change to Invenergy's position [redacted]

d. Provide the basis for the claimed confidentiality of the document. Specifically, explain how the document could place the companies in an unfair competitive disadvantage.

A-13. a. No. The Companies have proposed the surcharge mechanism because it is the most equitable way to ensure cost recovery—but nothing more—for the Companies. Please see also the Companies' response to Question No. 2.c. above.

b. The Companies did not change their position as a result of this e-mail.

c. The Companies do not possess sufficient information to respond to this question.

d. The Companies did not request, and are not requesting, confidential protection for this document, which was included in the public, redacted version of the response to JI-1-20.