Focused Management Audit of
Louisville Gas and Electric's and
Kentucky Utilities'
Earnings Sharing Mechanism

For the
Kentucky Public Service Commission

FINAL REPORT

August 31, 2003

Barrington-Wellesley Group, Inc.

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INTRODUCTION AND EXECUTIVE SUMMARY

A. Introduction

On January 7, 2000, the Kentucky Public Service Commission ("KPSC" or "Commission") issued Orders in Case Nos. 98-426 and 98-474 for LG&E and KU ("the Companies"), respectively. These orders rejected the Companies' proposed Performance Based Ratemaking ("PBR") mechanism and offered a simpler Earnings Sharing Mechanism ("ESM") incentive rate plan in its place. The ESM was to be a pilot program for the three-year operating period 2000-2002, with a focused ESM audit following the end of 2002 operating period. The Companies accepted the offer. Final Orders on rehearing were issued in June 2000.

On February 6, 2003, the KPSC issued a Request for Proposals for a consulting firm to complete the focused ESM audit. The purpose of the audit is to examine and evaluate whether each of the Companies has achieved greater operation efficiencies or processes as a result of the adoption of the pilot ESM mechanism. The Barrington-Wellesley Group, Inc. ("BWG") was awarded the contract for this study, which commenced in late April 2003.

The Commission focused this project on addressing fundamental questions to determine whether LGE/KU's ESM program is achieving, or is capable of achieving, intended benefits. The specific objectives of this audit were to:

1. Identify each Company's efforts and measurable results in achieving greater efficiencies as a result of the adoption of the incentive plan.
2. Identify any effects on service levels resulting from the adoption of the incentive plan.
3. Provide an objective appraisal of whether the incentive plan is an effective alternative to traditional rate of return regulation.
4. Recommend specific changes, or if necessary, an alternative plan for continuation of incentive regulation, if incentive regulation is determined to be an effective form of regulation with respect to each of the companies.

This focused review was not intended as a comprehensive management audit of the two utilities and corporate functions not affected by the ESM were not subject to review. The RFP called for seven primary "areas of inquiry:"

1. Review the Companies' compliance with all applicable Kentucky and SEC requirements for affiliate transactions.
2. Evaluate emerging management practices and policies and the level to which each Company has instituted policy changes in response to the incentive plan.

3. Examine the ESM structure, the ESM monitoring process (including the accuracy and timeliness of filings), and the adequacy of information filed as required by the incentive plan.

4. Examine the incentive plan, the Companies, and the Commission with respect to achievement of the objectives set forth in the final orders pursuant to Case Nos. 98-426 and 98-474.

5. Review the Companies' operating budget procedures, and capital planning and budgeting procedures, to determine the extent to which the Companies have instituted more effective management processes and, therefore, better expenditure control.

6. Examine the Companies' capitalization and deferral policies and practices since the beginning of the ESM plan and verify that the Companies have not recorded certain transactions as Capital Expenditures or Deferred Assets when they should be recorded as operating expenses.

7. Review the Companies' compliance with both the Commission's service-related regulations and their own service objectives, both internal and external, since the incentive plan was instituted.

B. Overall Assessment

BWG believes the existing Kentucky Earnings Sharing Mechanism is an effective alternative to traditional cost of service regulation, although we recommend some modification to the current structure. Within the dead-band, the ESM provides the same incentives as traditional regulation, and outside the dead-band the incentive is reduced by the 40 percent customer share. The ESM operates to stabilize the companies' return on equity, by reducing the return when it exceeds the upper dead-band limit, and by increasing the return when it drops below the lower limit. Therefore the ESM represents a compromise between maximizing incentives and stabilizing return on equity. The ESM could be described as traditional regulation with a shock-absorber. We found the Companies have reasonably complied with ESM filing requirements.

The structure of the Kentucky ESM, in particular the 60/40 sharing of over- or under-earnings, is intended to provide LG&E and KU with incentive to be in an over-earning situation. The deadband, symmetry, and 60/40 split of the existing Kentucky ESM are reasonable. This mechanism equitably shares risks and benefits between shareholders and ratepayers and enables the Companies to delay the need to file rate cases, which also benefits ratepayers. The Commission PBR Order does not specifically provide for the recalibration of the allowed return on equity and a review of the appropriateness of the return on equity was not in the scope of this study.

BWG found LG&E and KU to be well-managed utilities with a strong management team in place. The Companies have sound planning, budgeting and accounting processes and good expenditure control. The Companies have participated in numerous process improvement changes over the past several years including during the trial ESM period (2000-2002). These changes include implementing a shift towards a reliability-centered asset management program, a variable workforce, and an economic/risk-based capital budgeting process. These changes were initiated as part of commitments to best practices following the merger of the two utilities and the acquisition of the Companies by new owners in 2000 and 2002, not necessarily as a result of ESM. The Companies' position is that while these changes have not been driven as a result of ESM, ESM reinforces their existing corporate culture of performance improvement. The Companies have generally maintained, and in some cases improved, already high levels of service reliability and customer satisfaction during the trial period.

While complying with Kentucky and SEC affiliate interest requirements, the Companies have implemented a streamlined organization focused on efficiency and cost control in anticipation of a deregulated utility environment. This does not provide adequate separation of utility operations from other non-regulated businesses in the regulated environment which exists today and for the foreseeable future. We also found that incentive compensation is not adequately aligned with the ESM program and can create conflicts of interest between regulated and non-regulated activities, although our review found no indications of management impropriety or inappropriate accounting practices.

C. Background

LG&E / KU Corporate Structure

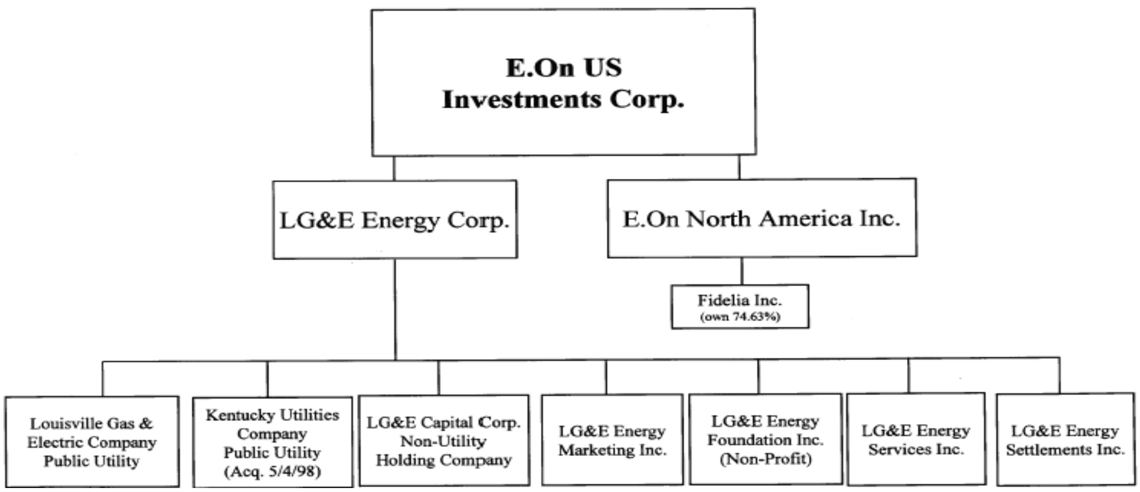
LG&E and KU are each distinct legal entities. They are Kentucky corporations engaged in the production, transmission and distribution of electricity (and gas for LG&E). The Kentucky regulated operations are overseen by the Kentucky Public Service Commission. On May 4, 1998, LG&E and KU merged. LG&E Energy Corp. ("LEC"), originally formed in 1990 as the holding company for LG&E, serves as the holding company for the two operating companies – LG&E and KU. On December 11, 2000, LEC was, in turn, acquired by Powergen plc, a British company. On July 1, 2002, Powergen plc was subsequently acquired by E.ON AG, a German company. Throughout this series of mergers and acquisitions, LG&E and KU have retained their legal identities as Kentucky utility operating companies regulated by the Kentucky Public Service Commission.

As a result of the Powergen acquisition of LEC and the subsequent E.ON acquisition of PowerGen, LG&E and KU are subsidiaries of a registered holding company system under the Public Utility Holding Company Act ("PUHCA"). LG&E, KU and LG&E Energy Services, Inc. ("Servco") are subsidiaries of LEC, which, in turn, is a subsidiary of E.ON US Investments Corp. ("E.ON US"). E.ON US' only other subsidiary is E.ON North America, Inc., which existed prior to E.ON's acquisition of Powergen. E.ON North America, Inc. holds 74.63 percent of Fidelia, Inc. E.ON North America and Fidelia provide financing to E.ON affiliates in the US. The remaining 25.73 percent of Fidelia is held by E.ON US Holding GMBH, which also holds 99.5 percent of E.ON US. The remaining 0.5 percent of E.ON US will be transferred to E.ON US Holding GMBH later this year (2003). E.ON US Holding GMBH is owned by E.ON, AG, the ultimate German parent company.

The corporate structure of LEC and its subsidiaries is complex, although not unlike other large utility holding companies. LEC has four direct subsidiaries in addition to LG&E, KU and Servco. The other four subsidiaries, in turn, own multiple legal entities engaged in various activities not regulated by the KPSC (hereafter referred to as, "non-regulated affiliates"). LEC currently owns a pipeline services company, CRC-Evans, which it is in the process of divesting as part of the Powergen merger agreement with the SEC. LEC's principal non-regulated lines of business are independent power production development and operation, the Western Kentucky Energy ("WKE") generation operation, and Argentine gas distribution. In 2002, these non-regulated businesses accounted for 19 percent of LEC's revenues and 0.8 percent of its income. LEC has been selling off portions of its independent power producer portfolio and other non-regulated subsidiaries in recent years and has been discontinuing the operation of others.

An organizational chart showing the reporting relationships for the primary US companies appears as **Exhibit I-1** below.

Exhibit 1-1
E.ON US Corporate Organization



Kentucky's Earnings Sharing Mechanism

The Kentucky ESM is based upon an 11.5 percent target ROE with a 100 basis point dead band above and below the ROE target. The Companies are required to remit 40 percent of earnings above the dead-band back to customers. Similarly, in the case of under-earning, the Companies are allowed to increase rates to collect 40 percent of any under earnings from customers. Any effects from the Companies' allowed environmental surcharges are to be excluded, as are any effects from the fuel adjustment clauses. The environmental surcharge rate mechanism is excluded because the associated expenses and return on investments are recovered through a separate line item on customer bills. Also, all fuel-related expenses are already being fully recovered through the fuel adjustment clause, also a separate line item on customer bills. The Companies were required to make annual filings on March 1st of 2001, 2002, and 2003 for the operating periods 2000, 2001, and 2002, respectively.

The Companies made their first ESM filing in March of 2001, which was contested by the Attorney General and the Kentucky Industrial Utility Customers ("KIUC"). In addition to the ESM filings, both KU and LG&E had other cases before the Commission. On December 3, 2001 the Commission issued an Order approving a global settlement among all parties. The settlement included some modifications to the Companies' ESM filings. A summary of the issues raised and resolved in the Global Settlement Agreement is presented in **Exhibit I-2.**

Exhibit I-2

Summary of 2001 Global Settlement Agreement

Issue	Settlement Agreement
Case Nos. 2001 – 054 and 2001 – 055	
Should the rate of return on equity earned be determined using year-end capitalization or average capitalization?	Allows the ESM calculations for year 2000 calculations to use year-end capitalization but requires that the ESM calculations for 2001 and 2002 use the monthly average capitalization.
Case Nos. 2001 – 140 and 2001 – 141	
Should KU and LG&E be allowed to use new depreciation rates based on utility plant in service as of December 31, 1999?	Revises the proposed depreciation rates for KU and LG&E resulting in reduced annual depreciation expense. The revised depreciation rates will be used for accounting and ratemaking purposes for all of 2001, with the exception that the revised depreciation rates will only be applied prospectively in the environmental surcharge calculations. KU and LG&E committed to perform a new depreciation study no later than calendar year 2004 based on utility plant in service as of December 31, 2003.
Case No. 2001 – 169	
Should the Companies be allowed to defer the expenses associated with their 2001 workforce reduction and include the amortizations as expenses when determining their net operating incomes for ESM purposes?	Allows the amortization of the workforce reduction expenses and also guarantees that ratepayers will receive a share ($34.5 million) of the expected savings directly. In addition, establishes a value delivery surcredit mechanism in which the estimated savings from the Workforce Reduction are netted against the monthly amortization of the deferred debits with the net savings shared 40 percent to ratepayers and 60 percent to shareholders, which is the same sharing ratio used in the ESM calculations.

In its order approving the October 2001 Settlement Agreement, the Commission noted that the agreement constituted a reasonable resolution of all issues in these cases. The Commission also noted that all customers would benefit from the guaranteed credits totaling $34,500,000 in savings resulting from the Value Delivery Surcredit. For electric customers, it was recognized that there was the potential for additional earnings sharing through the ESM due to the use of average capitalization and lowered depreciation expense. However, the Commission observed that operating expense savings resulting from the workforce reduction would not truly benefit customers if one of the unintended effects was a reduction in the quality of service, and indicated that it would closely monitor LG&E's and KU's service quality, particularly restoration times following storms, and would expect LG&E and KU to address any deterioration or deficiencies in a prompt and comprehensive manner. In addition, if it appeared that LG&E or KU had incurred significantly increased costs for increasing numbers of employees or contractors, the Commission would then consider opening a formal investigation to determine whether such increased costs should be included in the ESM calculations.

In March 2002 the Companies filed their second ESM filing, which was also contested. In October 2002, the Commission issued its Order on the second ESM filing. Both KIUC and the Companies filed for rehearing proposing additional changes to the ESM filings. In November 2002, the Commission granted rehearing on all issues. The parties filed a settlement on December 23, 2002 and the Commission approved the settlement in an order dated February 28, 2003 (Case Nos. 2002-071 and 2002-072). The settlement specified that, as a result of reversing the retroactive booking by the Companies of the Workforce Reduction Adjustment and its related impact on monthly capitalization, LG&E would refund $440,557 to customers. This refund was 75 percent of the ESM collections made by LG&E in the months of April through October 2002. KU would refund $1,023,407 to customers, which is 75 percent of the refund amount determined from the ESM filing in response to the Commission's October 16, 2002 order.

The Companies completed their ESM filings for calendar year 2002 on February 28, 2003, and filed revised filings on May 22, 2003 to correct specific errors in the original filings. The Company has advised that the parties to the proceedings have filed with the Commission statements advising that there are no issues for adjudication and therefore no need for a hearing and requesting the matters be submitted on the record for decision.

Alternative Ratemaking Perspective

The ESM was a product of a proceeding before the Commission referred to as the "PBR Case" (Performance Based Ratemaking), LG&E Case No. 98-426 and KU Case No. 98-474. At the time the Commission approved the LG&E and KU merger, recognizing the changing structure of the electric utility industry the Commission directed the companies to file plans to either continue having rates set under traditional regulation, or to adopt an alternative form of regulation. On October 12, 1998 LG&E and KU filed applications for approval of a Performance Based Ratemaking regulatory structure, and this initiated the PBR case.

The PBR structure proposed by LG&E and KU provided for the measurement of company performance based on three indices, 1) fuel cost, 2) generation performance, and 3) service quality. The companies would receive rewards for performance exceeding the defined indices. Intervenors objected to elements of the structure and one intervenor, the KIUC, presented an alternative proposal. The KIUC had also previously filed a rate complaint against LG&E. The Commission combined the KIUC rate complaint with the PBR proceeding in a consolidated proceeding that addressed both the PBR and rate complaint.

The Commission rejected both the Company and KIUC plans, but offered an optional ESM plan in the PBR case orders issued on January 7, 2000. The companies were ordered to either accept the optional ESM plan, or continue under traditional regulation. The order also stated that if the companies opted for the ESM, they would file draft ESM schedules, based on the findings in the PBR case. Therefore, the ESM structure and the definition and treatment of various cost elements are all defined within the PBR case. The companies accepted the ESM structure, filed draft forms, and made the first filing on March 1, 2001 based on results for the year 2000. The PBR case orders specified the ESM would have a three-year term and that the Commission would conduct a focused management audit to review and reassess the plan.

In explaining its rationale for ordering an earnings sharing mechanism rather than choosing the performance-based ratemaking plan proposed by the Companies, the Commission, in its January 7, 2000 orders, stated that ESM plans are typically and appropriately used when an industry is beginning the transition from a monopolistic to a more competitive structure. The Commission reasoned that earnings sharing mechanisms provide utilities with incentives to operate more efficiently, similar to a competitive market, in the absence of the risk of losing customers to a competitor. ESMs also provide the utility incentives to alter its behavior and take on additional risks by providing a limited safety net in case new efforts result in failure. In addition, ESMs can reduce business and regulatory risk and serve as an automatic means of keeping earnings within acceptable bounds. Sharing revenues allows captive ratepayers, as well as shareholders, to directly benefit from successful company initiatives.

The Commission gained experience in the use of ESMs in the telecommunications industry in Kentucky with BellSouth. The original BellSouth ESM plan was initiated, in part, to obviate the need for frequent rate reviews and to provide incentives for BellSouth to become more efficient by cutting its costs from monopolistic levels to levels more compatible with a competitive market. In the case of BellSouth the alternative ratemaking plan evolved from an earnings sharing mechanisms to a price cap plan. The Commission stated that it believed each form of alternative ratemaking mechanism was appropriate considering the time it was approved and the circumstances under which each company was operating. The Kentucky Commission, as well as many other utility regulatory bodies, have replaced ESMs with price cap plans for many telecommunications utilities. The telecommunications utilities were typically already facing competitive threats for retail services and, as a result, required retail pricing flexibility. In contrast, the Kentucky electric utilities were not, and are not currently facing any retail competition for electric service. At the time of its January 2000 Order, the Commission stated that it believed the ESM plan ordered constitute a reasonable form of regulation and that it would result in fair, just and reasonable rates for Kentucky electric utilities.

A number of other states had also adopted earnings sharing mechanisms as a form of alternative ratemaking in the period when the Kentucky Commission was establishing the earnings sharing mechanism that is the subject of this study. **Exhibit I-3** presents the results of a survey of performance based regulation in the U.S. electric industry appearing in an article published in <u>The Electricity Journal</u> in October 2001. Thus survey identified that utility regulatory commissions in eighteen states were using alternative ratemaking plans to regulate the activities of thirty-one separate electric utilities.

Exhibit 1-3

Summary of Performance-Based Regulation in the US Electric Utility Industry

State	Company	Period	Type of Plan
AL	Alabama Power Co.	1982 to present	Rate case moratorium with an earnings deadband
CA	San Diego Gas & Electric Co.	1994–1998	Revenue cap for base rates, natural gas, and power procurement incentives with earnings sharing
		1999–2002	Price cap (on distribution services) with earnings sharing
	Southern California Edison Co.	1997–1998	Price cap (on transmission and distribution services) with earnings sharing
		1998–2001	Price cap (on distribution services) with earnings sharing
CO	Public Service Co. of Colorado	1997–2001	Rate case moratorium (for base rates) with earnings sharing
		2001–2006	Rate freeze (for base rates) with earnings sharing through 2006; reset base rates in 2002
FL	Tampa Electric Co.	1995–1999	Rate freeze (for base rates) with earnings sharing
IA	Mid-American Energy	1998–2000	Rate case moratorium with earnings sharing
IL	CILCO	1998–2002	Price cap and earnings sharing with rate adjustments based on regional comparison of average retail rates
	Ameren CIPS-UE	1998–2002	Same
	ComEd	1998–2002	Same
	MEC	1998–2002	Same
	IP	1998–2002	Same
LA	Entergy LA	1996–1997	Rate case moratorium with earnings sharing
		1998–2000	Renewed previous plan for 3 years
		2001	Extended plan for an additional year
MA	MECo	1998–2000	Rate freeze (for base rates) with earnings sharing
		2000–2005	Rate freeze for distribution services
		2005–2009	Price cap for distribution services
	NSTAR	1998–2002	Rate freeze for distribution services
ME	Bangor Hydro Electric	1995–1998	Rate case moratorium with rate flexibility
		1998–2000	Price cap with earnings sharing
	Central Maine Power	1991–1993	Revenue-per-customer cap
		1995–2000	Price cap with earnings sharing
		2001–2007	Price cap for distribution service
	Maine Pub. Serv. Co.	1996–2000	Price cap with earnings sharing
MO	AmerenUE	1995–1998	Rate freeze with earnings sharing
		1998–2001	Rate freeze with earnings sharing
MS	Mississippi Power	1995 – present	Rate case moratorium with earnings sharing
MT	Montana Power	1997–1998	Price cap with earnings sharing
ND	Northern States Power	2001–2005	Price cap with earnings sharing
	Otter Tail Power	2001–2005	Price cap with earnings sharing
NY	Consolidated Edison	1995–1997	Revenue-per-customer cap with earnings sharing
		1997–2000	Rate case moratorium with earnings sharing
		2001–2005	Rate freeze (for transmission and distribution services) with earnings sharing
	New York State Electric & Gas	1993–1995	Price cap (for base rates) with earnings sharing
		1995–1998	Price cap with earnings sharing
		1998 to present	Rate freeze with earnings cap
	Niagara Mohawk	1991–1995	Revenue cap
		1998–2002	Rate freeze for three years, followed by a price cap (for distribution and transmission services) for last two years
	Rochester Gas and Electric	1993–1996	Revenue cap with earnings sharing
		1996–1997	Rate case moratorium (for base rates) with earnings sharing
		1998–2002	Rate case moratorium with earnings sharing
OR	PacifiCorp	1994–1995	Price cap
		1998–2001	Revenue cap (for distribution services) with earnings sharing
RI	EUA/Blackstone Valley/ Newport Electric	1997–1998	Price cap with earnings sharing
	Narragansett Electric Company	1997–1998	Price cap with earnings sharing
		2000–2004	Rate freeze (for distribution services) with earnings sharing
SD	Black Hills Power & Light	1995–2000	Rate freeze
		2000–2005	Rate freeze
WA	Puget Sound Energy	1997–2001	Price cap

Source: "The State of Performance-Based Regulation in the Electric Utility Industry" © 2001, Elsevier Science, Inc.

Comparison to Traditional Ratemaking

Because the earnings sharing mechanism offered to the Companies by the Commission is an alternative to traditional regulatory treatment, any assessment must evaluate the structure and operation of the ESM relative to traditional regulation. Traditional regulation, sometimes called Cost of Service Regulation (COSR), is a process that typically involves defining the elements in the following formula to determine the allowed Revenues.

$$\text{Revenues} = \text{Allowed Expenses} + \text{Rate of Return} * \text{Rate Base}$$

These elements are determined for a defined test period, and rates to recover the Revenues are designed and approved based on billing determinants for that same period. The approved rates remain in effect until the utility files another case, or is ordered to file a case to redefine the COSR elements, including revenues.

A common public misconception is that COSR does not provide an incentive to the regulated utility to controls costs or improve efficiency. This misconception usually stems from the incorrect assumption that the utility's revenues are continually adjusted to reflect changes in the COSR revenue formula, as if the utility filed a rate case every year. In fact, most regulated utilities strive to avoid filing frequent rate cases, and there is even a common term for this regulatory strategy, i.e., to "stay out." This strategy is based on the simple fact that between rate cases, the utility (and its shareholders) retains 100 percent of the benefits of additional income and/or cost savings associated with the elements defined in the COSR formula.

For example, if the rate base element is stable (i.e., depreciation is approximately equal to capital additions) and energy sales are increasing, the utility can increase the rate of return (ROR) element by keeping the growth rate of expenses below the rate of increase in Revenues. In recent years, this strategy and similar variations have allowed many regulated utilities to "stay out" for extended periods and either increase the ROR well above the initially approved level, or maintain the ROR at a desirable level. It is important to note that in this example, the utility has a very strong incentive to control expenses, since the benefits of such savings flow directly to the shareholders. COSR also provides incentives, in some cases, to increase energy sales and defer major rate base additions, e.g., base load power stations.

Since COSR provides incentives for the regulated utility to control costs and optimize the utilization of rate base, some of the benefits of such efficiencies eventually flow to the utility's customers. The most obvious example is when rates are lowered to keep the actual rate of return earned within limits. But COSR may also benefit customers even when rates are rising due to inflation or large rate base additions, since programs implemented by the utility to control costs result in minimizing allowed revenues at the time of a rate case. In other words, COSR provides short-term immediate incentives to the utility to control costs between rate cases, but a large share of the benefits of efficiency improvements flow to the customers in the longer term.

To properly evaluate ESM, it is important to recognize that traditional regulation has a number of significant weaknesses. Probably the most widely known and discussed COSR flaw is the lack of long-term incentives to recognize the impact of load growth when incremental capacity costs are greater than embedded cost, as was the case in many jurisdictions in the 1970's and 1980's. Traditional regulation gives the utility a short-term incentive to promote growth and maximize the utilization of existing plant (rate base), but when higher cost plant is built as a result of that growth, rates must rise in order to cover the increase in average cost. Regulators may consider the positive aspects of growth on the local economy when evaluating this issue, i.e., the positive economic aspects of load growth may overshadow the increase in electric rates. In recent years this issue has been minimized by the fact that many utilities have been meeting increased load with combustion turbine units, which may cost less than embedded cost.

Another significant weakness of traditional regulation becomes apparent when a regulated utility is filing rate cases on a frequent basis, e.g., every year. A number of factors may contribute to such a short-cycle filing schedule, including the addition of plant, high inflation, or decreasing sales. In Kentucky, and other jurisdictions that allow CWIP in rate base, the construction of a base load generating plant is likely to result in a number of rate filings in succession. Regardless of the legitimacy of the cause, when a utility is filing on a frequent basis there is very little direct incentive to control costs, because any savings are reflected in the test year results for the next rate filing, and therefore the benefits of the costs savings flow primarily to ratepayers through lower rates rather than to shareholders. COSR certainly provides much better cost control incentives when the regulated utility files rate cases infrequently, and a long-cycle filing schedule is also usually in the utility's best economic interests.

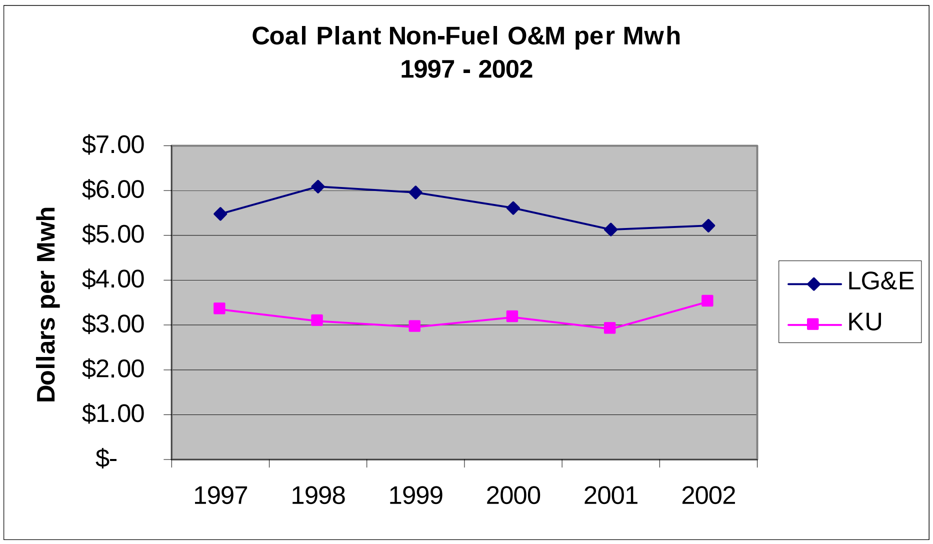
Under traditional regulatory structure, a fuel adjustment clause is usually employed to allow the regulated utility to recover the cost of fuel and certain other variable production costs. The typical fuel adjustment clause provides no direct incentive to minimize fuel costs or improve generating efficiency, since the benefits of such actions flow directly to the customers. However, regulated utilities usually realize it is in their best long-term interests to keep fuel costs low in order to maintain customer satisfaction and be competitive.

LG&E / KU ESM Performance Overview

During the first two years of the ESM period, the Companies were in a slight over-earning recovery position. In 2002, however, the Companies had net earnings significantly below the deadband and, as a result, had significant under-earnings, 40 percent of which are recoverable from ratepayers through the earnings sharing mechanism. Current projections indicate that the Companies will remain in an under-earning position for the next several years.

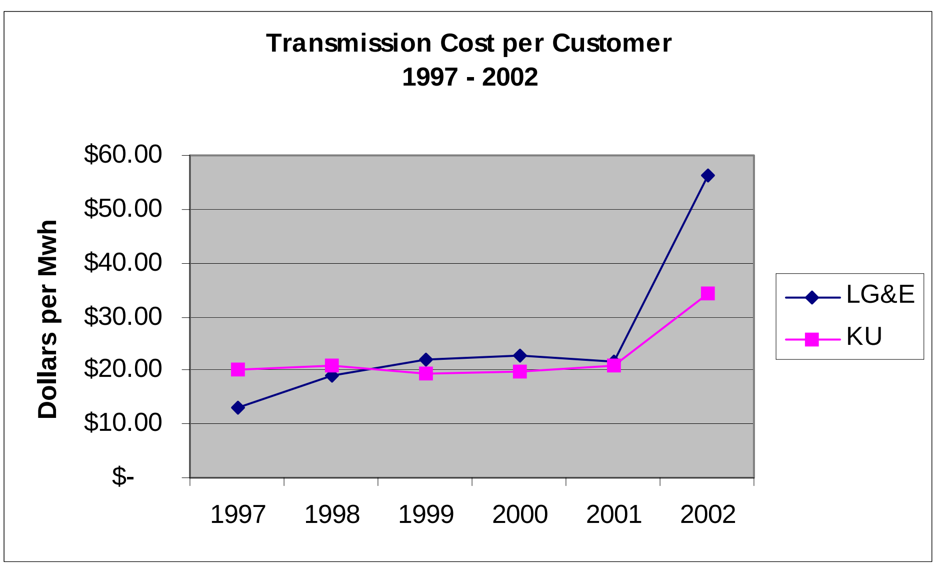
Looking at the three-year ESM period as a whole, overall average O&M expense per customer per year grew 2.8 percent, in line with customer growth and inflation during 2000-2002. And when compared to the immediately preceding three-year period, expenses actually declined in several expense categories: Distribution Expense, Customer Accounts Expense, Customer Service and Informational Expense, and Sales Expense. Many of the reductions in these categories can be directly linked to improvement initiatives. These decreases in expenses were offset, however, by increases in excess of customer growth and inflation in Transmission Expense and Administrative and General Expense. **Exhibits I-4a** through **I-4e** shown below present cost trends in several categories of operations for both LG&E and KU for the period 1997 through 2002.

Exhibit I-4a
Coal Plant Non-Fuel O&M per Mwh Trends



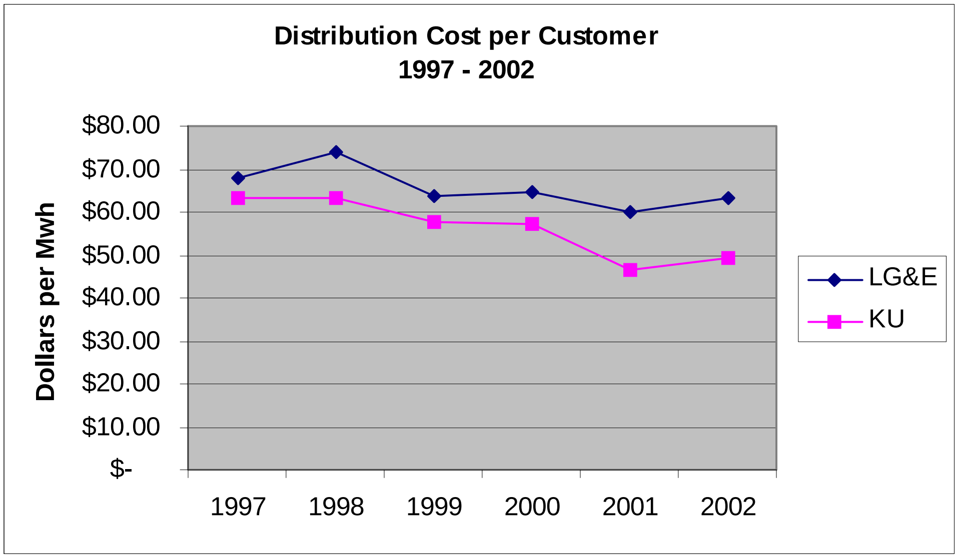
Source: SNL Database – FERC Form 1

Exhibit I-4b
Transmission Cost per Customer Trends



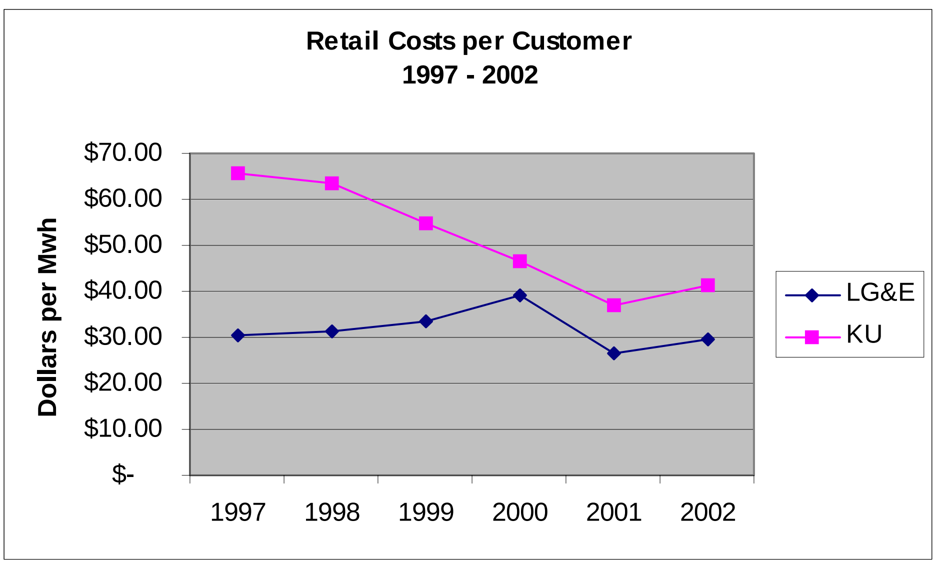
Source: SNL Database – FERC Form 1

Exhibit I-4c
Distribution Cost per Customer Trends



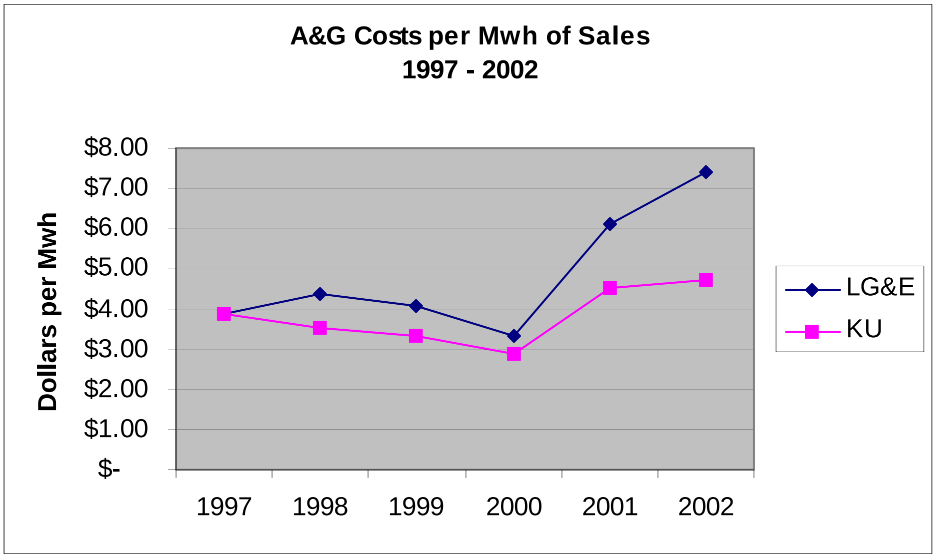
Source: SNL Database – FERC Form 1

Exhibit I-4d
Retail Cost per Customer Trends



Source: SNL Database – FERC Form 1

Exhibit I-4e
A&G Cost per Mwh Sold Trends



Source: SNL Database – FERC Form 1

The most significant O&M increases occurred in 2002, and were related to MISO-related expenses ($18.9 million) and VDT (Value Delivery Team) amortization ($16.5 million), recorded as Transmission Expense and A&G Expense, respectively. These expenses largely contributed to the overall decline in net operating income at the utilities that led to the significant ESM under-recovery in 2002. A&G costs also increased significantly from 2000 to 2001; primarily related to the start of the amortization of VDT costs and significantly higher pension expense.

In total, net operating income (NOI) for the Companies decreased by $33.7 million from 2001 to 2002. See **Exhibit I-5** for the primary reasons for this decrease, on an after-tax basis.

Exhibit I-5

Explanation for Change in NOI – 2001 and 2002

Description	Increase / (Decrease)
Expense Items	(millions)
MISO-Related expenses	($11.3)
VDT Amortization (1)	($9.8)
Steam Operation Expenses	($5.2)
Depreciation	($7.2)
Property Insurance	($3.0)
Employee Benefits	($4.6)
Margin Items	
Off-System Sales (price and volume)	($24.9)
Other Margins (primarily weather-related)	$20.7
Accrued ESM Revenues (2)	$13.7
Other	($2.1)
Total	**($33.7)**

Source: DR 1-21, FERC Form 1, 2002 ESM Filing and BWG Analysis

(1) Represents the amortization of costs associated with the implementation of Value Delivery Team (VDT) initiatives, which largely relate to employee separation costs.

(2) Represents the Companies' accruals for the recovery of the earnings deficit in 2002.

Several adjustments are made to book income to calculate ESM under or over-recoveries in the annual ESM filings made by the utilities. As a result of these adjustments, which totaled $23.4 million in 2002, Kentucky-jurisdictional net operating income decreased by a total of $57.1 million ($33.7 million plus $23.4 million) from 2001 to 2002. The primary reasons for the $23.4 million change are shown in **Exhibit I-6.**

Exhibit I-6

ESM Filing Adjustments – Change from 2001 to 2002

Description	Increase / (Decrease) (millions)
KU – Non-KY Jurisdictional NOI (1)	($4.5)
ESM Revenues (2)	($14.0)
Environmental Surcharge (3)	($2.4)
Other	($2.5)
Total	**($23.4)**

Source: 2002 ESM Filing and BWG Analysis

(1) Reflects the adjustment for growth in non-KY jurisdictional NOI from 2001 to 2002.
(2) Reflects the reversal of book entries recorded in 2002 to recognize the 40% of under-earnings recoverable from ratepayers.
(3) Reflects the elimination of environmental cost recovery-related revenues and expenses.

The earnings sharing mechanism provides for earnings above or below the deadband to be shared between shareholders and ratepayers based on a 60/40 split. The upper and lower limits are determined based on actual return on capital and actual jurisdictional capitalization.

Exhibit I-7 on the following page presents the calculation of the ESM factors to be applied to LG&E and KU customers' bills for calendar year 2002 as reported in Form 1 of the ESM filing. Return on Capital (column B) is the weighted average cost of capital using actual interest rates and 12.5 percent as the return on equity for the upper limit and 10.5 percent for the lower limit. Changes in the weighted average cost of capital can occur as a result of changes in interest rates or capital structure. Electric Capitalization (column D) represents actual Kentucky jurisdictional capitalization adjusted for capital requirements associated with environmental-related expenditures. The Upper and Lower Limits of Net Operating Income (NOI) are calculated by multiplying the Electric Capitalization by the Return on Capital.

Actual NOI represents actual Kentucky jurisdictional net income, as adjusted. Adjustments include the elimination of booked revenue associated with the ESM recovery of 40 percent of estimated under-earnings, the removal of brokered sales, the removal of fuel adjustment clause revenues and expenses, the removal of environmental cost recovery-related revenues and expenses, and an adjustment for shareholder merger savings. These adjustments are reported on Form 2 of the ESM filing.

The Earnings Deficit (line 4) is the difference between NOI (line 2) and the Lower Limit (line 3). In the event of earnings in excess of the upper limit, the Earnings Surplus is the difference between NOI and the Upper Limit (line 1).

The customer portion of the Earnings Deficit or Earnings Surplus (line 5) is calculated by multiplying Line 4 by 40 percent. Since the Earnings Deficit or Earnings Surplus is an after-tax amount, it must be "grossed-up" for income taxes (line 7) that will be paid on revenues received. Finally, the Revenue Adjustment (line 7) is divided by actual electric revenues to determine the percent by which rates must be increased or decreased (line 9).

In 2002, interest rates, which decreased significantly from 2001 to 2002, reduced the amount of the ESM earnings deficit subject to recovery from ratepayers. Ratepayers receive the benefit of lower interest rates because both the upper and lower limits are reduced by the application of a lower return on capital to the electric capitalization, thereby reducing the deficit between actual NOI and the lower limit (in the event of an earnings deficit) or increasing the surplus between actual NOI and the upper limit (in the event of an earnings surplus). Shareholders are equally protected in periods of rising interest rates.

To determine the benefit to ratepayers in 2002 resulting from the lower interest rates, BWG recalculated the Upper and Lower Limits (lines 1 and 3), Earnings Deficit (line 4), Customer Portion of Deficit (line 5), and ESM Revenue Adjustment (line 7) using the same Return on Capital as was used in the 2001 ESM filings. The results of this comparison are summarized in **Exhibit I-8** on the page I-17. As can be seen in Exhibit I-B Column B, the actual Return on Capital in calendar 2002 is less than the Return on Capital in 2001, which reflects lower interest rates. Electric Capitalization and Actual Net Operating Income are not adjusted.

Exhibit I-7
ESM Filing Form 1 -- 2002

Louisville Gas and Electric Company – 2002 ESM Filing Form 1					
A		B	C	D	
		Return on Capital	**Electric Capitalization**	**Revenue Requirement**	
1	Upper Limit of Net Operating Income based on Return on Equity of 12.5%	8.09%	$1,369,067,794	$110,757.585	(1)
2	Actual Electric Net Operating Income			$76,758,796	(2)
3	Lower Limit of Net Operating Income based on Return on Equity of 10.5%	7.09%	$1,369,067,794	$97,066,907	(1)
4	Net Operating Income is Less than the Lower Equity Limit. Earnings Deficit			$20,308,110	(3)
5	Sharing of Earnings Deficit at 40% to the Customer			$8,123,244	(4)
6	Gross Up Revenue Factor			0.595251	(5)
7	Revenue Adjustment			$13,646,758	(6)
8	Actual Electric Revenues for the Current Reporting Period (Excluding ESM Revenues)			$587,386,549	
9	Earnings Sharing Mechanism Factor			2.323%	(7)
Kentucky Utilities – 2002 ESM Filing Form 1					
A		B	C	D	
		Return on Capital	**Electric Capitalization**	**Revenue Requirement**	
1	Upper Limit of Net Operating Income based on Return on Equity of 12.5%	8.90%	$1,111,015,350	$98,880,366	(1)
2	Actual Electric Net Operating Income			$68,391,869	(2)
3	Lower Limit of Net Operating Income based on Return on Equity of 10.5%	7.71%	$1,111,015,350	$85,659,283	(1)
4	Net Operating Income is Less than the Lower Equity Limit. Earnings Deficit			$17,267,415	(3)
5	Sharing of Earnings Deficit at 40% to the Customer			$6,906,966	(4)
6	Gross Up Revenue Factor			0.595251	(5)
7	Revenue Adjustment			$11,603,455	(6)
8	Actual Electric Revenues for the Current Reporting Period (Excluding ESM Revenues)			$667,090,473	
9	Earnings Sharing Mechanism Factor			1.739%	(7)

(1) Column 2 times Column 3, (2) From Form 2, (3) Line 2 minus Line 3, (4) Line 4 times 40%, (5) From Form 1d
(6) Line 5 divided by Line 6, (7) Line 7 divided by Line 8

Exhibit I-8

LG&E – ESM Filing Form 1 – 2002 (Pro Forma)

Louisville Gas and Electric Company – 2002 ESM Filing Form 1 – PRO FORMA					
A		B	C	D	
		Return on Capital (2001)	**Electric Capitalization**	**Revenue Requirement**	
1	Upper Limit of Net Operating Income based on Return on Equity of 12.5%	8.75%	$1,369,067,794	$119,793,432	(1)
2	Actual Electric Net Operating Income			$76,758,796	(2)
3	Lower Limit of Net Operating Income based on Return on Equity of 10.5%	7.76%	$1,369,067,794	$106,239,661	(1)
4	Net Operating Income is Less than the Lower Equity Limit. Earnings Deficit			$29,480,865	(3)
5	Sharing of Earnings Deficit at 40% to the Customer			$11,792,346	(4)
6	Gross Up Revenue Factor			0.595251	(5)
7	Revenue Adjustment			$19,810,712	(6)
8	Actual Electric Revenues for the Current Reporting Period (Excluding ESM Revenues)			$587,386,549	
9	Earnings Sharing Mechanism Factor			3.37%	(7)

KU – ESM Filing Form 1 – 2002 (Pro Forma)

Kentucky Utilities – 2002 ESM Filing Form 1 – PRO FORMA					
A		B	C	D	
		Return on Capital (2001)	**Electric Capitalization**	**Revenue Requirement**	
1	Upper Limit of Net Operating Income based on Return on Equity of 12.5%	9.73%	$1,111,015,350	$108,101,794	(1)
2	Actual Electric Net Operating Income			$68,391,869	(2)
3	Lower Limit of Net Operating Income based on Return on Equity of 10.5%	8.53%	$1,111,015,350	$94,769,609	(1)
4	Net Operating Income is Less than the Lower Equity Limit. Earnings Deficit			$26,377,740	(3)
5	Sharing of Earnings Deficit at 40% to the Customer			$10,551,096	(4)
6	Gross Up Revenue Factor			0.595251	(5)
7	Revenue Adjustment			$17,725,457	(6)
8	Actual Electric Revenues for the Current Reporting Period (Excluding ESM Revenues)			$667,090,473	
9	Earnings Sharing Mechanism Factor			2.66%	(7)
Notes: See previous page (Exhibit I-7)					

As shown in **Exhibit I-9** below, ratepayers received a substantial benefit in 2002 as a result of the lower interest rates. The amount of under-earnings (deficit) was $18.3 million less and the revenue requirement was $12.3 million less than they would have been if financing costs had stayed at the same levels as 2001.

Exhibit I-9
Impact on Earnings Deficit Due to Decreased Interest Rates

	KU	LG&E	Combined
Lower Limit – Deadband, as Filed	$85,659,283	$97,066,907	$182,726,190
Lower Limit – Deadband, Pro Forma	$94,769,609	$106,239,661	$201,009,270
Actual Jurisdictional NOI	$68,391,869	$76,758,796	$145,150,665
Deficit, as Filed	$17,267,414	$20,308,111	$37,575,525
Deficit, as Calculated	$26,377,740	$29,480,865	$55,858,605
Amount of Deficit Reduction	**($9,110,326)**	**($9,172,754)**	**($18,283,080)**
Customer Portion of Earnings Deficit - Actual	$6,906,966	$8,123,244	$15,030,210
Customer Portion of Earnings Deficit – Pro Forma	$10,551,096	$11,792,346	$22,343,442
Revenue Requirement, as Filed	$11,603,455	$13,646,758	$25,250,213
Revenue Requirement, Pro Forma	$17,725,457	$19,810,712	$37,536,169
Amount of Reduced Revenue Requirements	**($6,122,002)**	**($6,163,954)**	**($12,285,956)**

Source: ESM Filings, Form 1 and BWG Analysis

D. Summary of Findings

Specific audit findings are as follows:

Task Area 1 - Affiliate Transactions

1. Contracts or other formal documents are in place that adequately specify the relationship between the regulated and unregulated companies and that adequately protect the regulated companies' interests from a legal and accounting perspective.

2. Adequate organizational separation does not exist between regulated and unregulated affiliates and there are opportunities for conflicts of interest, although no abuses of the LG&E/KU affiliate relationships were found during this study of the ESM.

3. Service Level Agreements are not used as intended because of a lack of organizational separation.

4. Internal Audit has had significant reductions in resource commitments between 2000 and 2002, although the majority of this reduction related to audits of non-regulated operations.

5. The basis for costing and pricing transactions between LG&E/KU and affiliates is appropriate and supported, the affiliate transactions comply with the letter of Kentucky and SEC requirements, and there is no apparent cross-subsidization between regulated and non-regulated affiliates.

Task Area 2 - Management Practices

1. Continuous improvement programs were in place before and during the ESM pilot period (2000–2002) and the Companies have undertaken many initiatives to reduce costs.

2. The improvement initiatives have been successful in containing direct expenses for operating and maintaining the utilities through 2002. However, they have not fully offset cost increases in other areas.

3. The executive short-term incentive compensation program is not adequately in alignment with the ESM program.

Task Areas 3 and 4 - ESM Structure

1. The Companies have complied with filing requirements and the ESM filings have been filed on time, and are complete and reasonably accurately. In a few cases, there were errors in a filing, which were corrected in a timely manner.

2. The existing Kentucky ESM is an effective alternative to traditional cost of service regulation. Within the dead-band, the ESM provides the same incentives as traditional regulation, and outside the dead-band the incentive is reduced by the 40 percent customer share. The ESM operates to stabilize the companies' return on equity, by reducing the return when it exceeds the upper dead-band limit, and by increasing the return when it drops below the lower limit. Therefore the ESM represents a compromise between maximizing incentives and stabilizing return on equity. The ESM could be described as traditional regulation with a shock-absorber.

3. The ESM does accomplish the objectives stated in the PBR case orders.

    - Business and regulatory risk are reduced by the ESM adjustments to rates as the return on equity deviates from the dead-band. The ESM tends to stabilize the return on equity.

    - The ESM provides incentives to increase efficiency, approximately the same incentives as under traditional regulation.

    - Shareholders and customers benefit from successful company initiatives.

4. The ESM has a number of weaknesses, some in common with traditional COS regulation and some unique to Kentucky's form of ESM.

- One weakness of the ESM that is also commonly found in traditional regulation is that the use of a Fuel Adjustment Clause gives no direct incentive to minimize fuel costs or maximize generating efficiency.

- The ESM does not completely address large capital additions.

- The ESM provides no direct control over financing costs or capital structure, although the Commission has other means to exert control over these items.

- The ESM requires an annual filing based on actual booked revenues and expenses, and ESM rate adjustments are required when the results do not fall within the dead-band dollar limits. Under certain circumstances, this structure invites cost shifting between filing years in order to maximize returns. For example, if a utility expected to have three years of performance just above the lower dead-band limit, it would be advantageous to shift costs into one year in order to decrease return below the dead-band level in that year and invoke an ESM factor adjustment.

- The annual ESM filings are based on actual revenues and expenses in each year and only specific adjustments are allowed in the ESM forms, consistent with the Commission Order:

  > *To ensure that the ESM plan does not become cumbersome and the annual reviews do not result in lengthy and costly rate cases, only limited ratemaking adjustments will be required.*

  By limiting adjustments, there could be situations in which actual revenues and expenses incurred during the filing period may be more or less than the amounts included in a traditional rate case. For example, in a rate proceeding, pro forma adjustments are typically made to adjust test year sales to reflect normal weather. No such adjustments are made in the annual ESM filing. By allowing only a limited number of adjustments, the annual ESM filing may reflect earnings at a level that is greater or less than levels that would be reported if the filing period were a general rate case test year subject to a full array of pro forma adjustments.

Task Area 5 – Budgeting

1. Operating and capital budgeting processes have not changed as a result of the earnings sharing mechanism except for the calculation of the budgeted amount of any over or under-earnings. Business unit and cost center targets are not adjusted based on the amount of the over- or under-recovery.

2. Operating and capital budgeting processes are effective and have been enhanced in recent years as a part of VDT emphasis on asset life cycle costs and benefits, for example, and not as a result of ESM.

3. Capital projects are subject to a structured evaluation process, and this process has not changed as a result of ESM. Based on our review of Investment Committee minutes

from 2000 through 2002, there appears to have been a conscious shift to increased economic justification of reliability-related capital investments as a result of Powergen/VDT initiatives. This is consistent with the Commission's goal for the ESM as stated in the enabling Order for this ESM trial program: *"ESMs also provide the utility incentives to alter its behavior and to take additional risks by providing a limited safety net in case new efforts result in failure."*

Task Area 6 – Accounting

1. Capitalization policies and procedures have not changed as a result of ESM and there are no explicit provisions under the earnings sharing mechanism that require the disclosure of changes to capitalization policies an procedures to the Commission.

2. Actual practices are consistent with the Companies' policies and procedures related to the capitalization of expenditures.

3. The system of internal controls related to the appropriate accounting for expenditures as either capital, expense, or deferred is adequate and appears to be operating effectively.

Task Area 7 – Service Levels

1. The Companies have complied with requirements to file reliability reports with the Commission.

2. The Companies place considerable emphasis on service levels, customer satisfaction, and safety as part of the planning, budgeting, capital expenditure, and performance monitoring activities.

3. The Companies have, in most instances, maintained or improved distribution reliability levels over pre-ESM period levels.

4. The Companies have maintained top-quartile performance levels in both reliability and safety as measured by several well-recognized industry benchmarking surveys.

5. Retail business unit performance levels improved in 2002 over the previous year and are tracking at higher levels in early year-to-date reports for 2003.

6. Preliminary review of 2003 storm recovery effort indicates that this storm was out of the ordinary and that the recovery was well managed.

E. Summary of Recommendations

BWG identified 11 recommendations as summarized in the table below:

Recommendation	Priority
<u>Affiliate Transactions</u> • Make a single executive without conflicts of interest responsible for the integrity of the Kentucky regulated companies. He or she should be the executive responsible to assure all affiliate relationships are beneficial and costs and prices are fair. He or she or his or her delegate should sign all service agreements, service level agreements, tax sharing agreements and other affiliate contracts and conscientiously review the performance against them. All non-state regulated activity management responsibility should be removed from his or her charter and he or she should be responsible for state regulatory relationships. He or she should be specifically responsible to assure that all costs, including generation costs, charged to the regulated companies are accurate and fair. This executive should have adequate internal audit assistance. This executive should have specific incentives to achieve all reliability and customer service level targets and the allowed rate of return. The KPSC regulates LG&E and KU, the utility operating companies serving Kentucky. It is the regulated operating companies' responsibility to assure that affiliate transactions are fair and beneficial to the ratepayer. There is no executive free from conflicts of interest to represent LG&E/KU in affiliated transactions today. (Refers to Finding 2)	**A**
• Utilize service level agreements according to the spirit of the concept. The service level agreements should be negotiated and signed by an executive who represents LG&E/KU without a conflict of interest. Performance against the agreements should be monitored and appropriate corrective action taken as cost or service problems arise. (Refers to Finding 3)	**B**
• Assure adequate internal audit resources are available to the executive responsible for the integrity of Kentucky regulated companies. (Refers to Finding 4)	**B**
<u>Management Practices</u> • Directly link the executive short-term incentive program to the ESM. Senior executives responsible for any part of LG&E/KU's operation or administration should have a meaningful portion of their short-term incentive opportunity linked to the two utility operating companies meeting and exceeding their allowed rates of return. The incentive payments would be reduced if the allowed rate of return is not achieved. The allowed rate of return is set by a deliberative process that is intended to provide adequate financing for the operating utilities and a fair return to investors. When the allowed rate of return is not achieved, it jeopardizes the utilities' financing capability and shortchanges the investors, in this case, E.ON. Achievement of reliability and customer service goals should continue to be a major factor in the individual performance portion of the incentive programs. Achievement of allowed rates of return should not be at the expense of reliability and customer service. Executives, managers and employees should continue to be expected, and provided incentives, to achieve both financial and operating performance success.	**A**

Recommendation	Priority
The new goal for the 2003 E.ON Executive Long-Term Incentive Plan is a step in the right direction. Although not specifically linked to achieving utility operating company allowed rates of return, it does relate to an absolute performance level of 9.6 percent, or better, return on total invested capital (debt and equity).[1] As long as interest rates are low, achieving this absolute target in the utility operating companies will keep the rate of return on equity in or above the dead band for the ESM. (Refers to Finding 3)	
<u>ESM Structure</u> • The Commission should implement a multi-year ESM based on the current ESM format. Timing issues represent a significant weakness because they may encourage the companies to shift costs between accounting periods in order to invoke an ESM factor revenue adjustment.	**A**
• The Company should work with the Commission Staff to identify a means for adequately addressing concerns regarding the timely communication of issues related to the current year's ESM filings. This may include narrative explanations, more frequent communications, or other means to be worked out between the Company and Staff.	**B**
• ESM should not preclude the Companies from petitioning for, nor preclude the Commission from allowing, the deferral of costs incurred as a result of extraordinary events. However, since the Companies are operating under the ESM, the Commission may wish to consider increasing the threshold used to base its decisions to allow the Companies to defer costs for recovery in subsequent regulatory proceedings. In these instances, if so ordered by the Commission, SFAS 71 would require the Companies to defer and amortize those costs to properly match revenues and expenses.	**B**
<u>Budgeting</u> • Assure that capital investment criteria continue to include appropriate consideration of reliability issues needed to meet customer service level standards and safety factors that may not have quantifiable economic benefits. (Refers to Finding 3 and Task Area 7, Finding 4).	**B**
<u>Accounting</u> • The KPSC should require as part of the ESM filing process a disclosure from Company management describing any changes in Company policies, procedures or practices that have occurred related to the classification of expenditures (capital, deferred, expense). (Refers to Finding 1)	**B**
<u>Reliability Service Levels</u> • The Companies should continue their on-going efforts to work with the Commission on the accuracy of reliability information provided to the Commission, and on formatting changes to facilitate Staff analysis of this data. (Refers to Finding 1)	**B**
• The Companies should continue to pay close attention to maintaining and improving service reliability and customer satisfaction to remain in compliance with both ESM and E.ON acquisition Commission Orders. (Refers to Finding 4)	**B**

CHAPTER II

AUDIT APPROACH

A. Audit Objectives

The overall objective of this audit is to determine whether the Louisville Gas and Electric and Kentucky Utilities ESM pilot program which covered the years 2000 through 2002 is achieving, or is capable of achieving, its intended benefits. The specific objectives of this audit are to:

1. Identify each Company's efforts and measurable results in achieving greater efficiencies as a result of the adoption of the incentive plan.

2. Identify any effects on service levels resulting from the adoption of the incentive plan.

3. Provide an objective appraisal of whether the incentive plan is an effective alternative to traditional rate of return regulation.

4. Recommend specific changes, or if necessary, an alternative plan for continuation of incentive regulation, if incentive regulation is determined to be an effective form of regulation with respect to each of the companies.

This focused review was not intended as a comprehensive management audit of the two utilities; and corporate functions not affected by the ESM were not subject to review.

B. Auditing Standards

BWG conducted this audit in accordance with generally accepted government auditing standards. These standards are set forth in the booklet entitled *Government Auditing Standards, 1994 Revision* developed by the Comptroller General of the United States and published by the United States General Accounting Office. These standards pertain to auditors' professional qualifications and, among other things, require auditor independence and that the audit be carefully planned and performed in accordance with a written work plan. In addition, audit findings and conclusions are required to be properly documented in working papers and results are to be communicated in a written report.

C. Audit Approach

BWG developed a preliminary work plan and budget to achieve the objectives listed above based on our understanding of the scope of the project as described in the request for proposals. Our audit program followed the seven primary "areas of inquiry" described in the RFP and presented in **Exhibit II-1** on the following page.

Exhibit II-1
Primary Audit Tasks

Task No.	Description
1	Review the Companies' compliance with all applicable Kentucky and SEC requirements for affiliate transactions.
2	Evaluate emerging management practices and policies and the level to which each Company has instituted policy changes in response to the incentive plan.
3	Examine the ESM structure, the ESM monitoring process (including the accuracy and timeliness of filings), and the adequacy of information filed as required by the incentive plan.
4	Examine the incentive plan, the Companies, and the Commission with respect to achievement of the objectives set forth in the final orders pursuant to Case Nos. 98-00426 and 98-00474.
5	Review the Companies' operating budget procedures, and capital planning and budgeting procedures, to determine the extent to which the Companies have instituted more effective management processes and, therefore, better expenditure control.
6	Examine the Companies' capitalization and deferral policies and practices since the beginning of the ESM plan and verify that the Companies have not recorded certain transactions as Capital Expenditures or Deferred Assets when they should be recorded as operating expenses.
7	Review the Companies' compliance with both the Commission's service-related regulations and their own service objectives, both internal and external, since the incentive plan was instituted.

BWG started the focused audit of the ESM plan for LG&E and KU with a planning meeting (teleconference) with Commission Staff in mid-April. This was followed by the three-party, two-day kick-off meeting held on April 24-25, 2003 in Louisville at the LG&E Corporate Office. BWG provided the Companies with an initial data request at this time.

Following the presentations and interviews conducted during the project kick-off meeting, and the review of responses to the initial data request, BWG developed a final, detailed audit program and additional interview and data requests. As part of the final work plan ESM-related tasks 3 and 4 were combined into one work task. See **Exhibit II-2** for additional task-specific, detailed work tasks.

Between April and August 2003, BWG, along with KPSC Staff members, conducted fifty-seven interviews of LG&E, KU and LG&E Energy Services Company employees. A complete list of the individuals interviewed is included as **Appendix A**. In addition, BWG issued ninety-nine data requests for information critical to the audit. BWG greatly appreciates the responsiveness and cooperation of the Companies and employees in responding to these requests and for the guidance received from the KPSC staff that participated in the audit on a daily basis.

Exhibit II-2
Detailed Work Tasks

Work Area	Detailed Work Tasks
Affiliate Transactions	• Identified all relevant KY and SEC requirements covering affiliated transactions. • Inventoried all current affiliate relationships (starting from the tax legal entity organization chart) that have a potential impact on LGE/KU's ESM results. • Reviewed all relevant corporate and subsidiary policies – including the code of conduct, conflict of interests, and procurement and contracting policies, and cost allocation manuals. • Assessed compliance with KY and SEC requirements and develop preliminary findings and conclusions.
Management Practices	• Identified continuous improvement and similar programs for the periods 1997-1999 and 2000-2002. • Reviewed incentive compensation programs. • Determined if the incentive compensation and performance management programs are in alignment with the ESM.
ESM Structure	• Review the ESM structure as defined by the Commission. Review previous case material and other available information to determine appropriate KPSC standards and definitions. • Review the Companies ESM filings made to date, including supporting documentation. Determine the timeliness of filings and compliance with minimum filing requirements and the KPSC standards and definitions. • Identify information filed to address special circumstances or transactions which were not anticipated by the ESM structure and existing standards and definitions. • Determine treatment of off-system sales in the ESM and FAC. • Review jurisdictional split (cost of service) methodology. • Compare results under the ESM to results that would have occurred under traditional regulation.
Budgeting	• Interviewed financial and operating management personnel to determine how management processes, including operating and capital budgeting and expenditure control, have improved as a result of ESM. • Reviewed operating and capital budgets for 1998 through 2002 to identify trends. • Reviewed variance reports for each year to identify trends in managing actual costs compared to amounts budgeted. • Reviewed capital investment prioritization and approval processes.
Accounting	• Interviewed accounting department personnel to identify processes and controls in place to ensure transactions are properly recorded as capital, expense or deferred.

Work Area	Detailed Work Tasks
	• Reviewed charges to the individual clearing accounts by year for each year from 1998 through 2002. Confirmed the consistency of the types of costs flowing through the clearing accounts during this time period. • Reviewed clearings to capital and O&M by individual clearing account for this same time period and the basis for the clearings. Confirmed the consistency of the basis for the clearings during the time period. • Reviewed capitalization policies (both repair vs. replacement and expense vs. capital dollar threshold) for each year from 1998 through 2002. Obtained explanations for any changes in these policies during the period being reviewed. • Evaluated systems of internal controls in place to ensure compliance with policies and procedures related to expenditure capitalization. • Reviewed all related internal audit reports since January 1, 2000. • Asked accounting department management whether general journal entries have been made in 2000, 2001 or 2002 that moved costs from operation and maintenance to capital. • Reviewed charges to deferred asset accounts by account for each year from 1998 through 2002. Obtained explanations for any significant increases in amounts deferred and determined appropriateness.
Service Levels	• Reviewed service quality reports filed with the Commission from 1998 through 2002 for trends in service quality. • Reviewed service quality measures used by the Companies for goal setting and performance measurement from 1998 through 2002 for trends. Obtain explanations for any measures dropped during the ESM pilot period. • Conducted interviews with senior management and responsible managers in Energy Delivery and Energy Services to determine how reliability and customer service levels are monitored and managed.

CHAPTER III

AFFILIATE TRANSACTIONS

Review the Companies' compliance with all applicable Kentucky and Securities and Exchange Commission requirements for affiliate transactions.

A. Background

LG&E and KU are distinct legal entities. They are Kentucky corporations (KU is also a Virginia corporation) engaged in the production, transmission and distribution of electricity (and gas for LG&E). The Kentucky regulated operations are overseen by the Kentucky Public Service Commission. On May 4, 1998, LG&E and KU merged. LG&E Energy Corp., ("LEC"), originally formed in 1990 as the holding company for LG&E, serves as the holding company for the two operating companies – LG&E and KU. On December 11, 2000, LEC was, in turn, acquired by Powergen plc, a British company. On July 1, 2002, Powergen plc was subsequently acquired by E.ON AG, a German company. Throughout this series of mergers and acquisitions, LG&E and KU have retained their legal identities as Kentucky utility operating companies regulated by the Kentucky Public Service Commission.

As a result of the Powergen acquisition of LEC and the subsequent E.ON acquisition of PowerGen, LG&E and KU are subsidiaries of a registered holding company system under the Public Utility Holding Company Act ("PUHCA"). LG&E, KU and LG&E Energy Services, Inc. ("Servco") are subsidiaries of LEC, which, in turn, is a subsidiary of E.ON US Investments Corp. ("E.ON US"). E.ON US' only other subsidiary is E.ON North America, Inc., which existed prior to E.ON's acquisition of Powergen. E.ON North America, Inc. holds 74.63 percent of Fidelia, Inc. E.ON North America and Fidelia provide financing to E.ON affiliates in the US. The remaining 25.73 percent of Fidelia is held by E.ON US Holding GMBH, which also holds 99.5 percent of E.ON US. The remaining 0.5 percent of E.ON US will be transferred to E.ON US Holding GMBH later this year (2003). E.ON US Holding GMBH is owned by E.ON, AG, the ultimate German parent company.[2]

The corporate structure of LEC and its subsidiaries is complex, although not unlike other large utility holding companies. LEC has four direct subsidiaries in addition to LG&E, KU and Servco. The other four subsidiaries, in turn, own multiple legal entities engaged in various activities not regulated by the KPSC (hereafter referred to as "non-regulated affiliates").[3] LEC currently owns a pipeline services company, CRC-Evans, which it is in the process of divesting as part of the Powergen merger agreement with the SEC.[4] LEC's principal non-regulated lines of business are independent power production development and operation, the Western Kentucky Energy ("WKE") generation operation, and Argentine gas distribution. In 2002, these non-regulated businesses accounted for 19 percent of LEC's revenues and 0.8 percent of its income.[5] LEC has been selling off portions of its independent power producer portfolio and other non-regulated subsidiaries in recent years and has been discontinuing the operation of others.[6]

The SEC merger order requires reporting of all service transactions between LEC companies and E.ON and Powergen companies. Only three of these relationships were reported that involved LG&E/KU in 2002, as shown in **Exhibit III-1**.

Exhibit III-1

LG&E/KU Affiliate Transactions with E.ON and Powergen

LG&E/KU Affiliate	Types of Services Provided
Power Technology	Generating station engineering and technical services
E.ON Engineering	Generating station engineering and technical services
Powergen plc	Ex-patriot salaries

Source: Data Request BWG 1-3, 2002 SEC Form U-13-60 Supplemental Schedule

None of the individual transactions exceeded $250,000 and all can be considered incidental to the mergers.

LEC, the LG&E/KU direct parent, owns dozens of legal entities. However, all regulated/non-regulated product and service affiliate transactions with LG&E/KU are processed through its principal affiliate, LG&E Energy Services, Inc. PUHCA requires LEC, the registered holding company, to have a service company subsidiary that provides services to both the regulated LG&E/KU and the other non-regulated LEC subsidiaries. As such, Servco provides services both to LG&E and KU and to other LEC affiliates within the registered holding company system under SEC rules for service companies.

Substantially all product and service transactions among LEC affiliates transactions are processed through Servco. As an SEC regulated PUHCA service company, all charges to Servco are allocated to affiliates at cost. In 2002, Servco processed $335 million of transactions, of which, LGE was allocated $95 million and KU was allocated $75 million. Together, LG&E and KU were billed about 50 percent of Servco's costs.

Servco records and reports all affiliate services transactions under the "Outside Services Employed" category, along with non-affiliated services transactions. **Exhibit III-2** below summarizes the affiliate product and service transactions that involve affiliated companies and Servco.

Exhibit III-2

Servco Outside Services Affiliate Transactions Summary

Affiliate	2002 Total Amount
E.ON Engineering GMBH	$94,884
LG&E Power Operations, Inc.	$107,589
Power Technology	$615,765
Powergen UK plc	$615,765

Source: Data Request BWG 1-3, Servco 2002 SEC Form U-13-60

The only significant departure from the Servco processing of affiliate transactions is that LG&E and KU have an exemption from the SEC for the operating companies to direct bill each other for union labor and incidental supervisory labor provided to each other for convenience or emergency assistance.

Currently, the only employees that are specifically LG&E or KU employees are individuals who are physically present in the LG&E or KU service territories and work predominately for the operating company in that territory. This would include line technicians, generating station workers, and similar physical workers. Any individual employee who works routinely for more than one subsidiary is placed in Servco. As such, virtually all management and administrative services for LG&E and KU are provided by Servco employees. In some cases, the Servco employees just serve the two regulated operating companies. However, many Servco employees, and substantially all of the executive level employees, serve both the regulated operating companies and non-regulated affiliates.[7]

In addition to the affiliate product and service transactions processed by Servco, there are four types of financial transactions that do not flow through Servco: common stock dividend payments, income tax payments, inter-affiliate loans, and insurance premiums. Dividend payments flow up from LG&E and KU to LEC. LEC, in turn, pays dividends to its share owners, who have evolved from individual and institutional investors to Powergen to E.ON. **Exhibit III-3** summarizes the dividend payment flow trends.

Exhibit III-3
Common Stock Dividends
(Millions)

Common Stock Dividends	1999	2000	2001	2002
From LG&E to LEC	$89.0	$73.0	$23.0	$69.0
From KU to LEC	$73.0	$94.5	$30.5	$0
Total from Utilities	$162.0	$167.5	$53.5	$69.0
From LEC to public shareholders	$162.0	$158.0	$0.0	$0.0
From LEC to Powergen	$0.0	$0.0	$69.5	$127.0

Source: DR 5-82

Through 2000, LEC was an investor owned utility and routinely passed through most of the dividends from the operating utilities to the public shareholders. When LEC became a subsidiary of Powergen in 2001, LEC began paying its dividends to Powergen US, the holding company formed to hold LEC stock. From 2001 forward, the payment of dividends became principally a tool for managing the operating companies' capital structures to conform with the Merger Agreement and to maintain financial credit ratings. Because LG&E/KU had substantial capital programs and borrowing in 2001 and 2002, the dividends to LEC were reduced to keep the capital structures of the operating companies in balance. In 2003, E.ON switched LEC from being a subsidiary of Powergen US to E.ON US. Beginning in 2003, LEC pays its dividends to E.ON US.[8]

Income taxes likewise are paid by LG&E and KU to LEC, which, in turn, paid income taxes to the US Treasury in 2000, and to Powergen US in 2001 and 2002. **Exhibit III-4** summarizes the total reported income taxes for 2000 to 2002.

Exhibit III-4
Income Taxes
(Millions)

Entity	2000	2001	2002
LG&E Electric	$55.1	$53.5	$46.9
LG&E Gas	$6.6	$7.9	$6.0
KU Electric	$49.4	$53.9	$50.0
Utilities Subtotal	$111.1	$115.3	$102.9
Non-Utility Operations	($37.3)	($76.8)	($6.8)
LEC Consolidated	$73.8	$38.5	$96.1

Source: Data Request 3-58, LEC 2002 Consolidated Financial Statement, and BWG calculations

During the three year ESM pilot period, LG&E/KU paid $329.3 million in income taxes to LEC. LEC in turn reported $208.4 million in actual income taxes on a consolidated basis. However, on a cash basis, LEC paid the US Treasury $14.3 million and $9.0 million in 2000 and 2001, respectively for federal income taxes, and $22.7 million to Powergen US in 2002 for federal income tax.[9] Tax advantages of the Powergen acquisition of LEC left Powergen with no cash US federal income tax liability for 2001 and 2002.[10]

The third category of financial affiliate transaction is inter-company loans, in which one affiliate loans cash to another, either on a long-term or short-term basis. LEC operates a cash pool for its subsidiaries (currently managed by Servco employees). LG&E has been a net borrower from the pool since November of 2000. From January to October 2000, LG&E loaned the pool between $16 and $48 million. KU has been a net borrower from the pool throughout the 2000-2002 period. A simulation of money market rates is paid by the borrower and to the lender through the pool. These rates declined from a high of 6.84 percent in September of 2000 to 1.3 percent in December of 2002.[11]

E.ON North America, a subsidiary of E.ON US and the parent of Fidelia, lends money to LEC to fund the cash pool. E.ON North America also provides a letter of credit facility for LEC subsidiaries, which LG&E and KU use for state requirements to post letters of credit for liabilities like landfill restoration and workers' comp. Powergen US provides back up LEC cash pool lending when E.ON North America cannot meet the needs. Beginning in 2003, Fidelia has provided ten year financing of $100 million each to LG&E and KU, and three year financing of $150 million to LEC.[12]

The fourth category of affiliate financial transactions is insurance. LG&E and KU buy T&D insurance from Ergon, a captive Powergen insurance company. The insurance was placed by Risk Management Services, a non-affiliated company, with Ergon on behalf of the operating companies. Servco Treasury employees manage the relationship with Risk Management Services. The premium is less than $1 million per year and it has a $2 million deductible. KU received a $13 million payment from Ergon in June 2003 for ice storm damage incurred earlier in the year.[13]

B. Evaluation Criteria

1. Are contracts or other formal documents in place that adequately specify the relationship between the regulated and unregulated companies, and do they adequately protect the regulated company's interests?

2. Is there adequate organizational separation between regulated and unregulated affiliates? Are there any apparent conflicts of interest in representing the regulated affiliate's interests with the unregulated company?

3. Is the basis for the cost of affiliate transactions appropriate and supported?

4. Is pricing of goods and services to the regulated company fair, either fully allocated costs or well-documented market prices?

5. Is there cross-subsidization between the regulated operating companies and their affiliates?

6. Do the affiliated transactions comply with Kentucky and SEC requirements for affiliate transactions as well as with the corporation's policies?

C. Findings

1. Contracts or other formal documents are in place that adequately specify the relationship between the regulated and unregulated companies, and that adequately protect the regulated companies' interests from a legal and accounting perspective.

   - LG&E and KU affiliate transactions are governed by the US Public Utility Holding Company Act of 1935, the related SEC General Rules and Regulations under PUHCA, Kentucky Revised Statues applicable to affiliate relationships, and the KPSC.

   - LG&E and KU's management are aware of the relevant laws, regulations and orders governing affiliate transactions and work to comply with the letter of those requirements.

   - LEC is relatively new to being a PUHCA regulated entity, with 2001 being the first full year for PUHCA compliance. However, the LEC family of companies has made a good faith effort to implement PUHCA requirements and comply with the regulations. The SEC has specific requirements for PUHCA regulated companies. LEC and its affiliates comply with these requirements to the letter.[14]

- LEC and its affiliates have required service agreements, codes of conduct, tax sharing agreements and similar documents in place.[15]

2. Adequate organizational separation does not exist between regulated and unregulated affiliates and there are opportunities for conflicts of interest, although no abuses of the LG&E/KU affiliate relationships were found during this study of the ESM.

   - LG&E/KU are both legal entities with their own books and records and are subject to regulation by the KPSC. They have some exclusive, middle management and physical employees. However, in practice, they are managed jointly as one division of one company. The executive management of both companies is provided by Servco employees who also supervise the parent holding company, LEC, and other, non-regulated legal entities. **Exhibit III-5** is a list of the LG&E and KU senior executives and their other legal entity responsibilities.

Exhibit III-5

LG&E and KU Executives Legal Entity Responsibilities

LG&E/KU Title	Similar LEC Role	Similar Servco Role	Significant Non-Regulated Subsidiary Responsibilities
Chairman of the Board, CEO and President	Yes	Yes	Yes
Chief Financial Officer	Yes	Yes	Yes
Senior Vice President – Finance and Controller	Yes	Yes	Yes
Executive Vice President, General Counsel and Corporate Secretary	Yes	Yes	Yes
Treasurer	Yes	Yes	Yes
Senior Vice President – Distribution Operations	Yes	No	Yes
Senior Vice President – Energy Services	Yes	No	Yes
Senior Vice President – Project Engineering	Yes	No	Yes

Source: Data Request 3-50

   - There are no senior executives solely dedicated to the regulated Kentucky utilities. Therefore, there is no voice representing the utilities interests exclusively in the executive management team and who can speak for the utilities without potential conflicts of interests.

   - All regulated and non-regulated generation and transmission, including LG&E's and KU's, is managed by one executive. All Kentucky regulated and non-Kentucky regulated distribution is managed by one executive. There is inadequate organizational separation between regulated and non-regulated affiliates.

   - One PUHCA requirement for service companies is to have written service agreements in place with each served affiliate. Servco has this required agreement in place with

LG&E/KU. The counter-party signatories to the SEC required service agreements are two different Servco executives, each with multiple regulated and non-regulated business responsibilities. There is no non-conflicted party representing LG&E/KU. Also, Article 10 of this agreement, "Notice" specifies that the exact same Servco employee receive notices under the agreement for all three companies.[16] He could be sending notices to himself under the agreement. The agreement does not provide a clear "buyer" of Servco services in the operating companies.[17]

- The Tax Allocation Agreement between Powergen and LEC and each of the LEC subsidiaries is signed by a single executive for all entities party to the agreement, including LG&E and KU.[18]

- Income tax liabilities are calculated by the Servco Tax Manager for all LEC entities. His work is reviewed and approved by superior Servco executives. There is no independent LG&E/KU review of the calculations to assure that the amounts charged to the regulated utilities are correct and fair. This is a case in which LEC has a clear conflict of interest to maximize the reported tax liability to the operating companies. These calculated tax liabilities are paid in cash to LEC, but LEC and its parent, in fact, pay far less in taxes on a consolidated basis to the government than were collected from LG&E/KU.[19] The Servco calculated tax liabilities for LG&E/KU become a presumed cost of doing business for ratemaking purposes. There is no organizational separation between the LEC/Servco and the regulated operating companies on tax matters. Auditing the LG&E/KU income tax calculations was not within the scope of this study.

- Servco bills to affiliates are prepared by Servco accountants and delivered to other Servco accountants assigned to affiliate accounting, but in the same Servco Finance Department. There is no specific LG&E/KU independent review of the bills, again showing a lack of organizational separation. Some budget analysts and managers exclusively assigned to LG&E/KU operations may also review specific charges resulting from the bills and may challenge them.[20] Again, this shows that there is not a clear "buyer" of Servco services.

- The management organization structure does not match the legal entity structure. A single organization structure of Servco employees manages a highly complex organization structure of legal entities, both regulated and unregulated. Any one executive may have officer roles in dozens of legal entities. Additionally, employees of one legal entity, such as, LG&E or KU, often report to an employee of another legal entity, like Servco. This contributes to the lack of organizational separation between LGE/KU and their affiliates.

- Senior executives' incentive compensation is based significantly on LEC's performance, not LG&E/KU's specific performance alone. This can create conflicts of interest when decisions are made that affect both regulated and non-regulated subsidiaries. Although no instances of improper allocation of costs were found by this study, BWG concludes that senior executives have incentives to place costs in the regulated companies that can recover the costs through rate cases or the ESM, rather than in unregulated companies that must recover costs through competitive prices.[21]

- While Servco state regulatory management employees are focused on state regulatory requirements and relationships, they report to executives who manage regulated and non-regulated operations and are not as focused on regulatory requirements and relationships. This arrangement can result in confusion and delays in state regulatory relationships.

- There is no identifiable executive solely responsible for LG&E's and KU's integrity as legal entities and to represent them in dealing with affiliates at arms length. There are no separate, identifiable executives who just manage LG&E and KU. There is no single executive responsible for LG&E or KU's individual integrity within the LEC system. Other companies similar to LEC often either consolidate non-regulated entities under one executive or put all regulated entities under a single executive, separating regulated and non-regulated responsibilities. LEC does neither, but rather mixes regulated and non-regulated responsibilities for all senior executives. The result is that there is no executive clearly responsible for the interests of the regulated companies *vis-a-vis* the holding company, service company, unregulated affiliates and state regulatory relationships.

3. Service Level Agreements are not used as intended because of a lack of organizational separation.

   - LEC also has service level agreements in place, but they are not used to guide the Servco/regulated operating companies' relationships. The service level agreements were put in place as a good management practice and are not required by PUHCA or the KPSC. They include the following components: scope of services, business requirements, roles and responsibilities of the parties, performance measurements (which often overlap with key performance indicators used for other management purposes), review procedure and accounting.

   - Generally, one Servco executive signed the agreement for Servco and another Servco executive signed for the operating utilities. In some cases, Servco service level agreements signed by the relevant Servco department manager are countersigned by his or her direct supervisor on behalf of the operating company.[22]

   - All Servco executives questioned about the service agreements were unfamiliar with them, even those who had signed them themselves. No instance of the service level agreements actually being used in practice was found.[23]

   - Again, no LG&E/KU "buyer" of Servco services was found to represent their interests.

4. Internal Audit has had significant reductions in resource commitments between 2000 and 2002, although the majority of this reduction related to audits of non-regulated operations.

   - Total internal audit hours were reduced from by 36 percent from 2000 to 2002. Most of this reduction relates to audits of non-regulated operations.

- Utility-focused resources as a percent of total resources increased from 50.3 percent in 2000 to 61.8 percent in 2002.[24]

- BWG understands that E.ON's corporate audit department is scheduled to perform an assessment of LEC's auditing function in August of this year.[25]

5. The basis for costing and pricing transactions between LG&E/KU and affiliates is appropriate and supported, the affiliate transactions comply with the letter of Kentucky and SEC requirements, and there is no apparent cross-subsidization between regulated and non-regulated affiliates.

   - The SEC requires that PUHCA affiliate transactions involving system utilities be at cost, fairly or equitably allocated among the companies.[26]

   - Servco has elaborate Servco costing and management systems that accurately track Servco activities and calculate costs of Servco services. The Servco management system uses several software systems: Cetec for timekeeping, PeopleSoft for human resources, and Oracle for financial reporting.[27]

   - Servco pricing of services to LG&E/KU is cost based.[28]

   - The LEC internal audit group, which later became the Servco internal auditing group on January 1, 2001, began monitoring the planning and development of Servco in 2000. In a November 30, 2000 file memo, this group found that, "… Servco will be in compliance with the PUHCA rules and SEC requirements on January 1, 2001." This finding was based upon review of the plans and implementation activities, including attendance at implementation team meetings and a gap analysis for SEC requirements and guidelines for compliance with PUHCA.

   - The Servco US Audit Services (internal audit) unit followed up with an audit of Shared Services in 2001. The audit report was issued on May 23, 2002 and was circulated to the CEO, the external auditors, and the highest Finance organizational levels. A synopsis was also sent to the Audit Committee. The 2002 internal audit report of 2001 Servco activities found that, "Existing Servco policies, procedures and controls are sufficient to ensure accurate and timely financial reporting, and the Servco shared services functions are appropriately performed and billed. Also, the policies, procedures, and controls in place are sufficient to maintain compliance with the SEC and PSC requirements." Minor problems were discovered with executive time reporting and service level agreements. These problems were corrected.[29]

   - The 2000 to 2002 charges from affiliates other than Servco to LG&E and KU were not significant. The only material charges from PowerGen to LG&E and KU were a total of approximately $1.44 million in the years 2001 and 2002 for salary and expenses of PowerGen employees on assignment at LEC.[30]

D. Recommendations

1. Make a single executive without conflicts of interest responsible for the integrity of the Kentucky regulated companies. He or she should be the executive responsible to assure all affiliate relationships are beneficial and costs and prices are fair. He or she or his or her delegate should sign all service agreements, service level agreements, tax sharing agreements and other affiliate contracts and conscientiously review the performance against them. All non-state regulated activity management responsibility should be removed from his or her charter and he or she should be responsible for state regulatory relationships. He or she should be specifically responsible to assure that all costs, including generation costs, charged to the regulated companies are accurate and fair. This executive should have adequate internal audit assistance. This executive should be provided with specific incentives to achieve all reliability and customer service level targets and the allowed rate of return. The KPSC regulates LG&E and KU, the utility operating companies serving Kentucky. It is the regulated operating companies' responsibility to assure that affiliate transactions are fair and beneficial to the ratepayer. There is no executive free from conflicts of interest to represent LG&E/KU in affiliated transactions today. (Refers to Finding 2)

2. Utilize service level agreements according to the spirit of the concept. The service level agreements should be negotiated and signed by an executive who represents LG&E/KU without a conflict of interest. Performance against the agreements should be monitored and appropriate corrective action taken as cost or service problems arise. (Refers to Finding 3)

3. Assure adequate internal audit resources are available to the executive responsible for the integrity of Kentucky regulated companies. (Refers to Finding 4)

CHAPTER IV

MANAGEMENT PRACTICES

Evaluate emerging management practices and policies and the level to which the companies have instituted policy changes in response to the incentive plan.

A. Background

The ESM incentive plan is intended to motivate management behavior that reduces actual costs and increases earnings. The original intent of this task area was to identify management initiatives made in response to the ESM incentive. However, it is the LG&E/KU management's position that the ESM program did not change management behavior. Management contends that LG&E and KU already had a strong continuous improvement program and that the ESM reinforced this behavior and added a regulatory mechanism for dealing with the ebb and flow of earnings over time.[31] Therefore, this task area was modified to confirm that a continuous improvement program was in place and to assure that the executive and employee incentive programs were in alignment with the ESM program.

LG&E/KU have been through four waves of improvement initiatives since 1997. The first wave was in conjunction with the KU merger. LG&E/KU committed to $760 million of merger savings to be shared with ratepayers over ten years. This initiative to capture the expected merger savings started in the fourth quarter of 1997 and ran through June of 1998. It focused on identifying and achieving the synergies and economies of scale expected from the merger. The program included a severance package/early retirement program in the summer of 1998. Functional organizations were consolidated at a very high level but stopped short of triggering a "doctrine of union accretion" problem that might have resulted in the non-union KU employees being unionized by consolidating union and non-union work groups.

The second improvement program initiative was the "One Utility" program that ran from mid-1999 to mid-2000. It overlapped with the Powergen acquisition of LEC and the beginning of the ESM program. This program further streamlined the business processes. Andersen Consulting/Accenture helped with both of the first two waves.

The third improvement program wave began in 2000 and corresponded to the Powergen acquisition of LEC. It built on Powergen's experience with integrating their East Midlands acquisition. This effort was led by an executive and several core team members from Powergen assigned to LEC, and is referred to as, "Value Delivery." This project's scope included fourteen teams covering regulated operations, shared services and WKE. The program included benchmarking at two Spanish companies and introduced the high level, globally applicable concept of total (O&M and capital) cash cost per customer. This program led to a large severance package/early retirement program and implemented the "variable workforce" (fewer employees in favor of more contractors) business model. It ended in the second quarter of 2002. The semi-annual reporting to the KPSC on the results of this program is still continuing, although most initiatives have been completed.

The fourth improvement program wave is the worldwide benchmarking effort triggered by the E.ON acquisition of Powergen. It started in September of 2002 and included a presentation to the E.ON CEO in Germany in February of 2003. It includes E.ON's US, English, Swedish and German companies. The results so far have validated the LEC Value Delivery program. Each participating company's CEO will report on further improvement progress to E.ON Germany semi-annually, including LEC's CEO.

B. Evaluation Criteria

1. Is a continuous improvement program in place and have the companies taken initiatives since the inception of the ESM that are intended to reduce costs?

2. Have the initiatives been successful in reducing expenses through 2002?

3. Are the incentive compensation programs in alignment with ESM objectives?

C. Findings

1. Continuous improvement programs were in place before and during the ESM pilot period (2000–2002) and the Companies have undertaken many initiatives to reduce costs.

   - Many of the improvement initiatives to date have been driven by the ongoing merger cost savings surcredit to ratepayers negotiated by LG&E/KU with the KPSC. The savings had to be achieved or earnings would fall short. The surcredit is calculated prior to the ESM calculation and therefore affects the ESM.

   - The LEC performance focus now is on LEC earnings/contribution to E.ON, which could come from regulated or unregulated subsidiaries.

   - There were no further merger savings commitments to Kentucky ratepayers for the Powergen and E.ON mergers. The logic is that there is less opportunity for synergies with off-shore parents, although both mergers triggered additional waves of improvement initiatives.[32]

   - Examples of the types of improvements initiated during the ESM pilot period, as taken from the Value Delivery Team Best Practices Progress Report filed with the KPSC on February 14, 2003, include:

     – Standardization of design and construction, material, operating and maintenance standards.

     – Incorporation of Reliability Centered Maintenance Principles into maintenance practices.

     – Investment planning linked to lifecycle optimization of assets.

     – Improved resource planning, scheduling and dispatching technologies.

     – Shift from fixed to variable costs through increased use of contractor resources.

- Transformation of the business into a process organization.
- Devolution of support services (Finance, Human Resources, Procurement and Warehousing) to business units.
- Plant Status Review based on modern condition monitoring.
- Virtual call centers and integrated voice response units.
- Third party pay stations.
- Web enabled customer service.
- Customer Relationship Management system.
- Pay-as-you-go meters.[33]

These improvement programs and improvement initiatives are typical of utilities' efforts during this time period.

2. The improvement initiatives have been successful in containing direct expenses for operating and maintaining the utilities through 2002. However, they have not fully offset cost increases in other areas.

- LG&E and KU expense trends for the periods 1997-1999, the three-year period immediately prior to the ESM pilot period, and 2000-2002, the initial ESM period, are shown in **Exhibit IV-1.**

Exhibit IV-1
LG&E and KU Expense Trends for the Periods 1997-1999 and 2000-2002

(Millions)

Cost Category	LG&E 97-99	KU 97-99	LG&E/KU Total 97-99	LG&E 00-02	KU 00-02	LG&E/KU Total 00-02	97-99 to 00-02 Change in Totals	Average Percent Change per Year
Power Production Expense	$949.6	$1,241.7	$2,191.3	$1,013.9	$1,366.1	$2,380.0	$188.7	8.6%
Transmission Expense	$19.5	$28.6	$48.1	$37.9	$37.4	$75.3	$27.2	56.6%
Distribution Expense	$74.1	$87.0	$161.1	$70.7	$75.9	$146.6	($14.5)	(9.0)%
Customer Accounts Expense	$25.1	$58.5	$83.6	$28.8	$52.6	$81.4	($2.2)	(2.6)%
Customer Service and Informational Expense	$5.1	$11.2	$16.3	$5.3	$5.6	$10.9	($5.4)	(33.1)%
Sales Expense	$4.1	$17.1	$21.2	$1.6	$3.7	$5.3	($15.9)	(75.0)%
A&G Expense	$133.5	$169.2	$302.7	$194.9	$207.4	$402.3	$99.6	32.9%
Total Electric O&M Exp	$1,211.1	$1,613.2	$2,824.3	$1,353.2	$1,748.9	$3,102.1	$277.8	9.8%
Avg. No. of Electric Cust.			862,055			873,952	11,897	1.4%
Average O&M Expense per Customer per Year			$1,092			$1,183	$91	2.8%

Source: BWG Data Request 1-13 (FERC Form 1) and BWG analysis

- Moderate customer growth, 1.4 percent, and moderate inflation occurred from the earlier period to the ESM pilot period. Major categories of expenses changed as follows:

- Overall average O&M expense per customer per year grew 2.8 percent, in line with customer growth and inflation.

- Several expense categories declined: Distribution Expense, Customer Accounts Expense, Customer Service and Informational Expense, and Sales Expense. Many of the reductions in these categories can be linked to improvement initiatives.

- The decreases in expenses were offset by increases in excess of customer growth and inflation in: Transmission Expense (56.6 percent), and Administrative and General Expense (32.9 percent). There was a major change in Transmission Operations in 2002, the Midwest Independent System Operator (MISO) start-up, sending expenses up $18.5 million from 2001 to 2002. Other significant cost increases not particularly susceptible to improvement initiatives were in pension expense, property insurance and medical benefits expenses.

3. The executive short-term incentive compensation program is not adequately in alignment with the ESM program.

   - There are three different incentive programs for LEC and subsidiary employees. The Short-Term and Long-Term Incentive Plans cover key executive employees. The Team Incentive Awards Program (TIA) covers virtually all other employees today. (It was extended to represented workers beginning in 2003.)

   - The Short-Term Incentive Plan is intended to provide a meaningful annual incentive opportunity geared toward the achievement of specific LEC corporate, business unit, line of business, and/or individual goals. Corporate and individual goals and targets are established annually and the incentive is up to 35-75 percent of base pay. 60 percent of the incentive opportunity is tied to budgeted Internal Operating Profit (IOP) for the most relevant business unit. For senior executives, it is the LEC IOP, for more junior executives, such as, a plant manager, the IOP target may be for a specific operating company. The remaining 40 percent of the Short-Term Incentive is tied to the accomplishment of individualized performance goals set by the executive and his or her superior with concurrence by the next level superior. The two components operate independently, that is, the incentive can be paid on one without the other being met.

   - The Long-Term Incentive Plan is intended to link key employee interests to the long-term financial success of LEC and LEC shareholder value growth. Long-term measures and targets are established annually. The measures of long-term financial success have been evolving rapidly through the series of mergers. Prior to the Powergen merger, the LEC Executive Long-Term Incentive Plan was driven by total shareholder return, a common measurement for investor owned companies. During the brief period with Powergen as the LEC parent, the Executive Long-Term Incentive Plan was focused on cash flow. Following the E.ON acquisition of Powergen, the Long-Term program is being revised once again, this time to emphasize value added, or return on total capital employed, a typical measurement for a subsidiary of a larger company. The LTIP award ranges from 30-175 percent of base compensation. Seventy-five percent of the LTIP award is made in LG&E performance units measured by valued added / return on capital employed performance for a three year performance period and is paid in cash based on value added / return on capital employed performance. Twenty-five percent of the LTIP award is made in E.ON phantom stock options which vest after two years and, if performance criterion are met, can be exercised for cash.[34]

- The TIA program is essentially the same as the executives' short-term plan, but for all employees, including represented workers as of 2003, other than senior management. The payouts from the TIA can range from six to 30 percent of base pay.[35]

- The Powergen merger accelerated all earned short-term and long-term incentive payments to the year 2000. There were no incentive payments made in 2001 (the payments for 2000, which normally would have been made in 2001, were accelerated to 2000), as the Powergen program was implemented.

- The E.ON merger agreement contained a provision for a floor of 100 percent of the incentive compensation to be paid to all participants in the LEC incentive compensation programs, in cash, in the year 2002. Payments could exceed 100 percent, if earned, but would not be below that level. The merger was effective July 1, 2002. This provision was known only by senior executives privy to the merger negotiations.[36] In general, the Short-Term plan payouts in 2002 based upon actual results were higher than the guaranteed floor. The calculations for the Long-Term plan were disrupted by the merger and the payments were made at the guaranteed amounts. TIA payments for 2002 were made at the guaranteed levels and were six percent higher than were earned using actual results.[37]

- None of the three incentive programs are directly linked to the ESM. The regulated companies, LG&E and KU, are major factors in LEC's Internal Operating Profit and return on invested capital, and some individual goals may coincidentally relate to the ESM. However, there is no attempt to link the ESM and the incentive programs. Further, even where there is coincidental alignment, the incentive programs may pay out even if the ESM does not benefit the ratepayer. This can happen because the incentive programs are based on performance against goals, not absolute operating company rate of return. For example, in a year in which poor performance is expected because of market conditions or other factors, such as 2002, the goals could be set low and the incentive programs would pay out for meeting the goals even if operating company allowed rates of return were not met. In 2002, incentive payments throughout LEC, Servco and LG&E/KU were at 100 percent or more, even though the LG&E and KU rates of return fell below the dead band, although the

Short-Term and TIA payouts would have been lower without the merger guaranteed floor.

D. Recommendations

1. Directly link the executive short-term incentive program to the ESM. Senior executives responsible for any part of LG&E/KU's operation or administration should have a meaningful portion of their short-term incentive opportunity linked to the two utility operating companies meeting and exceeding their allowed rates of return. The incentive payments would be reduced if the allowed rate of return is not achieved.

   The allowed rate of return is set by a deliberative process that is intended to provide adequate financing for the operating utilities and a fair return to investors. When the allowed rate of return is not achieved, it jeopardizes the utilities' financing capability and shortchanges the investors, in this case, E.ON.

   Achievement of reliability and customer service goals should continue to be a major factor in the individual performance portion of the incentive programs. Achievement of allowed rates of return should not be at the expense of reliability and customer service. Executives, managers and employees should continue to be expected and incented to achieve both financial and operating performance success.

   The new goal for the 2003 E.ON Executive Long-Term Incentive Plan is a step in the right direction. Although not specifically linked to achieving utility operating company allowed rates of return, it does relate to an absolute performance level of 9.6 percent, or better, return on total invested capital (debt and equity).[38] As long as interest rates are low, achieving this absolute target in the utility operating companies will keep the rate of return on equity in or above the dead band for the ESM. (Refers to Finding 3)

CHAPTER V

ESM STRUCTURE

Examine the ESM structure, the ESM monitoring process, including the accuracy and timeliness of filings, and the adequacy of information filed as required by the incentive plan.

Examine the incentive plan, the Companies, and the Commission with respect to achievement of the objectives set forth in the final orders pursuant to Case Nos. 98-00426 and 98-00474.

A. Background

The ESM was a product of a proceeding before the Commission referred to as the "PBR Case" (Performance Based Ratemaking), LG&E Case No. 98-426 and KU Case No. 98-474. At the time the Commission approved the LG&E and KU merger, recognizing the changing structure of the electric utility industry the Commission directed the companies to file plans to either continue having rates set under traditional regulation, or to adopt an alternative form of regulation. On October 12, 1998 LG&E and KU filed applications for approval of a Performance Based Ratemaking regulatory structure, and this initiated the PBR case.

The PBR structure proposed by LG&E and KU provided for measurement of company performance based on three indices, 1) fuel cost, 2) generation performance, and 3) service quality. The companies would receive rewards for performance exceeding the defined indices. Intervenors objected to elements of the structure and one intervenor, the KIUC, presented an alternative proposal.

The Commission rejected both the Company and KIUC plans, but offered an optional ESM plan in the PBR case orders issued on January 7, 2000. The companies were ordered to either accept the optional ESM plan, or continue under traditional regulation. The order also stated that if the companies opted for the ESM, they would file draft ESM schedules, based on the findings in the PBR case. Therefore, the ESM structure and the definition and treatment of various cost elements are all defined within the PBR case. The companies accepted the ESM structure, filed draft forms, and made the first filing on March 1, 2001 based on results for the year 2000. The PBR case orders specified the ESM would have a three-year term and that the Commission would conduct a focused management audit to review and reassess the plan.

The major elements of the ESM are generally defined as follows.

- Rate adjustments are based on the company's Return On Equity (ROE) using actual annual results.
- The ESM rate adjustments are applied as a percentage of the customer bill.
- Only limited ratemaking adjustments are allowed. Major adjustments are as follows.
    - Fuel Adjustment Clause revenues and expenses are excluded.

- Environmental Surcharge revenues, expenses, and capitalization are excluded.
- Brokered sales revenues and expenses are excluded.
- Certain workforce reduction expenses are deferred and amortized.
- Shareholder merger savings are recognized through an adjustment to expenses.

- There is an ROE dead-band of plus or minus 100 basis points around the approved ROE of 11.5 percent. Therefore there are no ESM rate adjustments if the ROE falls within the range of 10.5 percent to 12.5 percent.
- When the ROE is outside the dead-band, earnings over or under the dead-band limits are shared, 60 percent to the company and 40 percent to the customer.

The Commission offered ESM to the Companies as an alternative to traditional regulatory treatment. Therefore any assessment of the ESM should consider the structure and operation of the ESM relative to traditional regulation. Traditional regulation, sometimes called Cost of Service Regulation (COSR), is a process that typically involves defining the elements in the following formula to determine the allowed revenues.

Revenues = Allowed Expenses + Rate of Return * Rate Base

These elements are determined for a defined test period, and rates to recover the Revenues are designed and approved based on billing determinants for that same period. The approved rates remain in effect until the utility files another case, or is ordered to file a case to redefine the COSR elements, including revenues.

A common public misconception is that COSR does not provide the regulated utility any incentive to controls costs or improve efficiency. This misconception usually stems from the incorrect assumption that the utility's revenues are continually adjusted to reflect changes in the COSR revenue formula, as if the utility filed a rate case every year. In fact, most regulated utilities strive to avoid filing frequent rate cases, and there is even a common term for this regulatory strategy, i.e., to "stay out." This strategy is based on the simple fact that between rate cases, the utility (and its shareholders) retains 100 percent of the benefits of additional income and/or cost savings associated with the elements defined in the COSR formula.

For example, if the rate base element is stable (i.e., depreciation is approximately equal to capital additions) and energy sales are increasing, the utility can increase the rate of return (ROR) element by keeping the growth rate of expenses below the rate of increase in revenues. In recent years, this strategy and similar variations have allowed many regulated utilities to "stay out" for extended periods and either increase the ROR well above the initially approved level, or maintain the ROR at a desirable level. It is important to note that in this example, the utility has a very strong incentive to control expenses, since the benefits of such savings flow directly to the shareholders. COSR also provides incentives, in some cases, to increase energy sales and defer major rate base additions, e.g., base load power stations. When the ROR falls below the allowed level, the regulated company has incentives to increase revenues and reduce costs to minimize the gap between actual and allowed ROR.

Since COSR provides incentives for the regulated utility to control costs and optimize the utilization of rate base, some of the benefits of such efficiencies eventually flow to the utility's customers. The most obvious example is when rates are lowered to keep the actual rate of return earned within limits. But COSR may also benefit customers even when rates are rising due to inflation or large rate base additions, since programs implemented by the utility to control costs result in minimizing allowed revenues at the time of a rate case. In other words, COSR provides short-term immediate incentives to the utility to control costs between rate cases, but a large share of the benefits of efficiency improvements flow to the customers in the longer term.

To properly evaluate ESM, it is important to recognize that traditional regulation has a number of significant weaknesses. Probably the most widely known and discussed COSR flaw is the lack of long-term incentives to recognize the impact of load growth when incremental capacity costs are greater than embedded cost, as was the case in many jurisdictions in the 1970's and 1980's. Traditional regulation gives the utility a short-term incentive to promote growth and maximize the utilization of existing plant (rate base), but when higher cost plant is built as a result of that growth, rates must rise in order to cover the increase in average cost. Regulators may consider the positive aspects of growth on the local economy when evaluating this issue, i.e., the positive economic aspects of load growth may overshadow the increase in electric rates. In recent years this issue has been minimized by the fact that many utilities have been meeting increased load with combustion turbine units, which may cost less than embedded cost.

Another significant weakness of traditional regulation becomes apparent when a regulated utility is filing rate cases on a frequent basis, e.g., every year. A number of factors may contribute to such a short-cycle filing schedule, including the addition of plant, high inflation, or decreasing sales. In Kentucky, and other jurisdictions that allow CWIP in rate base treatment as opposed to AFUDC, the construction of a base load generating plant is likely to result in a number of rate filings in succession.[39] Regardless of the legitimacy of the cause, when a utility is filing on a frequent basis there is very little direct incentive to control costs, because any savings are reflected in the test year results for the next rate filing, and therefore the benefits of the costs savings flow primarily to ratepayers through lower rates rather than to shareholders. COSR certainly provides much better cost control incentives when the regulated utility files rate cases infrequently, and a long-cycle filing schedule is also usually in the utility's best economic interests.

Under traditional regulatory structure, a fuel adjustment clause is usually employed to allow the regulated utility to recover the cost of fuel and certain other variable production costs. The typical fuel adjustment clause provides no direct incentive to minimize fuel costs or to improve generating efficiency, since the benefits of such actions flow directly to the customers. However, regulated utilities usually realize that it is in their best long-term interests to keep fuel costs low in order to maintain customer satisfaction and be competitive.

B. Evaluation Criteria

1. Are the ESM filings reasonably accurate, complete, and filed on time?
2. Is the ESM an effective alternative the traditional regulation?
3. Does the ESM accomplish the objectives stated in the PBR case orders?
   - Reduce business and regulatory risk.
   - Provide incentives to increase efficiency.
   - Shareholders and Customers benefit from successful company initiatives.
4. Can the ESM be improved?

C. Findings

1. The Companies have complied with filing requirements and the ESM filings have been filed on time, and are complete and reasonably accurate. In a few cases, there were errors in a filing, which were corrected in a timely manner.

   - Certain expenses were corrected in the LG&E year 2000 ESM filing in order for the filing to agree with previously filed ES Form 2.1 (Environmental Surcharge). The correction was made in response to a Commission data request addressing that issue. The response and corrected filing were filed April 20, 2001, fifteen days after the date of the Commission's data request. The revised filing increased the revenue surplus to be refunded to customers about $182,000.

   - There were minor errors in the LG&E 2002 filing, which were corrected in a revised filing on May 22, 2003. The corrections were so minor that the ESM factor did not change as a result.

   - There were several errors in the Kentucky Utilities 2002 filing, which were corrected in a revised filing on May 22, 2003. These corrections increased the filed 2002 revenue adjustment from 1.573 percent to 1.739 percent, or about $1.1 million.

   - The Commission was not expecting the relatively large rate adjustments in the year 2002 filings for both companies. Because ESM is a relatively new mechanism, communication between the Companies and the Commission is particularly important.

2. The existing Kentucky ESM is an effective alternative to traditional cost of service regulation. Within the dead-band, the ESM provides the same incentives as traditional regulation, and outside the dead-band the incentive is reduced by the 40 percent customer share. The ESM operates to stabilize the companies' return on equity, by reducing the return when it exceeds the upper dead-band limit, and by increasing the return when it drops below the lower limit. Therefore the ESM represents a compromise between maximizing incentives and stabilizing return on equity. The ESM could be described as traditional regulation with a shock-absorber.

The ESM also serves to encourage longer periods between rate cases. Under ESM, when the ROR is above the dead-band, the ESM discount will lower the effective rates used to bill customers, which lessens the need for intervenors to call for a rate case to reduce rates. Likewise, when ROR is below the dead-band, the ESM adder will increase the effective rates used to bill customers, which lessens the Companies' need to file a rate case to increase rates. This structure can work to extend the period between rate cases.

3. The ESM does accomplish the objectives stated in the PBR case orders.

   - Business and regulatory risk are reduced by the ESM adjustments to rates as the return on equity deviates from the dead-band. The ESM tends to stabilize the return on equity.

   - The ESM provides incentives to increase efficiency, although somewhat less than the incentives under traditional regulation.

   - Shareholders and customers benefit from successful company initiatives. This benefit is most obvious when the return exceeds the dead-band and customers receive a rate reduction at the same time that shareholders enjoy relatively high returns. LG&E customers received such a reduction from the filing for the year 2000, and KU customers received a reduction from the year 2001 filing.

     Under the ESM, shareholders and customers may also share immediate benefit from reductions in financing costs. Under traditional regulation, customers do not receive the benefit of company initiatives to reduce the cost of debt until a rate case, and all such benefits would flow, in the interim, to shareholders. If the cost of debt is reduced under the ESM, that reduction will be reflected in a lower overall rate of return, which will reduce the upper and lower dead-band limits. If the results are either above or below the dead-band limits, customers will receive a benefit from the lower debt costs, either from an increased ESM rate credit, or a decreased ESM charge. This benefit is realized as a result of the lower interest rates in the 2002 ESM filings as compared to 2001. For example, the lower limit weighted average cost of capital in the LG&E 2001 filing (filed October 28, 2002) was 7.76 percent, whereas the cost dropped to 7.09 percent in the 2002 filing (filed May 22, 2003) due to lower interest rates. If the rate had remained at the 2001 level, the ESM revenue adjustment would have increased by $6.2 million, or 45 percent. The results are similar for the KU filing.

   - Customers will also benefit from company initiatives at the time that rates are adjusted, since the benefits of such initiatives will be reflected in the new approved rates.

4. The ESM has a number of weaknesses, some in common with traditional regulation and some unique to Kentucky's form of ESM.

   - Fuel Adjustment Clause - One weakness of the ESM that is also commonly found in traditional regulation is that the use of a Fuel Adjustment Clause gives no direct incentive to minimize fuel costs or maximize generating efficiency. However, the LG&E and KU fuel adjustment clauses allow margins from off-system sales to contribute to company returns (margins are not included in fuel adjustment) and this provides some incentive to minimize fuel costs, in order to maximize off-system sales margins. In addition, the companies have other indirect incentives to minimize fuel related costs, e.g., to maintain customer satisfaction and remain competitive.

- Large Capital Additions - The ESM does not completely address large capital additions. The ESM was never expected to yield acceptable results in the event that the company made a large capital addition, such as a base load generating plant that might require an increase in rates to recover the increased fixed costs. Depending on the nature and schedule of the project and other factors, such an addition would likely result in one or more rate filings, and possibly the suspension of the ESM for some period of time. Under these circumstances, traditional regulation provides less incentive to control costs, since increases or decreases in costs are likely to be reflected in rates to be approved in the near future.

- Capital Structure - The ESM provides no direct control over financing costs or capital structure although the Commission has other means to exert some control over these items. If the company's results were within the dead-band, there would be the same incentives to minimize financing costs and optimize the capital structure as under traditional regulation. However, if the results were outside the dead-band, there could be some incentive to increase capitalization, and increase the equity ratio, in order to increase the dead-band dollar limits. **Exhibit V-3** on page V-10 summarizes the upper limit capitalization reported in ESM filings for the years 2000, 2001, and 2002. In these three years, rate base increases in proportion to capitalization, and the equity ratio is stable throughout the period. Therefore, we find no evidence that the company is attempting to take advantage of this ESM weakness.

- Timing Issues - The current ESM requires an annual filing based on actual booked revenues and expenses, and ESM rate adjustments are required when the results do not fall within the dead-band dollar limits. Under certain circumstances, this structure invites cost shifting between filing years in order to maximize returns. For example, if the utility expected to have three years of performance just above the lower dead-band limit, it would be advantageous to shift costs into one year in order to decrease return below the dead-band level in that year and invoke an ESM factor adjustment.

  Regulated utilities commonly move transactions that create costs between accounting periods for normal business reasons, e.g., minimize budget variations, avoid large swings in earnings or keep annual returns within reasonable limits. Therefore it would be reasonable to expect that strategies to shift costs between accounting periods were known and being employed prior to the implementation of an ESM. These strategies are generally within the bounds of normal business practices, and conform with regulatory and generally accepted accounting principles. For example, strategies may involve the scheduling of planned maintenance activities performed by contract labor. Identifying such cost shifting to achieve specific ESM-related goals may be difficult, since it requires judgment of intent.

In our review of the LG&E and KU ESM filings for the three years 2000 through 2002 (see **Exhibits V-1** and **V-2** on page 9), the companies were either within the ROE dead-band or only required minor ESM adjustments in the first two years. However, the filing for 2002 is well below the dead-band for both utilities, requiring ESM factor adjustments of +2.3 percent for LG&E and +1.8 percent for KU. Company representatives attributed the poor results for 2002 to three factors: 1) lower margins from off-system sales; 2) increased transmission (MISO) costs; and 3) increased pension costs related to poor investment performance.[40] Although we have found no indications that suggest the companies have shifted costs into 2002 for ESM recovery purposes, the fact that the ESM encourages such actions is a significant weakness in the structure.

- Adjustments – The annual ESM filings are based on actual revenues and expenses in each year and only specific adjustments are allowed in the ESM forms, such as the removal of brokered sales revenues and expenses, removal of Fuel Adjustment Clause revenues and expenses, and an adjustment for shareholder merger savings. The Commission specified the use of actual results in the January 7, 2000 orders in cases 1998-00426 and 1998-00474 (PBR case). Quoting from those orders:

> *To ensure that the ESM plan does not become cumbersome and the annual reviews do not result in lengthy and costly rate cases, only limited ratemaking adjustments will be required.*

By limiting adjustments, there could be situations in which actual revenues and expenses incurred during the filing period may be more or less than the amounts included in a traditional rate case. For example, in a rate proceeding, pro forma adjustments are typically made to adjust test year sales to reflect normal weather. No such adjustments are made in the annual ESM filing. By allowing only a limited number of adjustments, the annual ESM filing may reflect earnings at a level that is greater or less than levels that would be reported if the filing period were a general rate case test year subject to a full array of pro forma adjustments.

Regulators may order an enterprise to defer and amortize current period costs for which future revenues are intended to provide recovery. In these instances, generally accepted accounting principles (GAAP) would require the costs be charged to income currently by an unregulated enterprise. On the other hand, Statement of Financial Accounting Standards No. 71 (SFAS 71), Accounting for the Effects of Certain Types of Regulation, requires that regulated enterprises account for these costs in the same manner allowed for regulatory purposes if it is probable that future revenue will be provided to permit recovery of these costs. These adjustments are made on the utility's books and are not considered to be adjustments as defined above for ESM purposes.[41]

D. Recommendations

1. The Commission should implement a multi-year ESM based on the current ESM format. Timing issues represent a significant weakness because they may encourage the companies to shift costs between accounting periods in order to invoke an ESM factor revenue adjustment.

   The annual ESM filings for the years 2000 through 2002 are summarized in **Exhibit V-1**, **Exhibit V-2** and **Exhibit V-3** on pages 9 and 10. This summary assumes that the 2002 filings will be approved as filed. The results for all three years are totaled on line 11 and show that LG&E and KU would recover $13.2 million and $10.6 million respectively over the period, with small net rate refunds over the first two years and a large rate recovery in the third year. However, line 12 shows the results if the upper and lower earnings limits are consolidated for the three years and applied on that basis. On a consolidated basis, LG&E would recover $2.1 million and KU would be within the dead-band.

   Although the use of a three-year consolidated ESM would have resulted in lower rate adjustments for customers based on these filings, in other circumstances the use of a longer period could work in the company's favor. In either case, using the longer period would yield more consistent results, a more consistent incentive for the companies to operate efficiently, and reduce the incentive to shift costs between years.

   There are a number of ways that a multi-year ESM could be structured; we will outline one example herein. The example ESM period is three years, but a longer period may also be appropriate. This example three-year method would accumulate results of filings within the three-year period. The ESM factor applied to customers' bills would be based on results to date. Filings would be made each year and the ESM computation for the first year would be the same as under the present ESM. The second annual filing would be on the same basis as the first, except that the earnings limits for the two years would be combined for computing the ESM adjustment. A one-year revenue basis would be used to compute the resulting ESM factor. In like manner, the third annual filing would combine the earnings limits for all three years. A true-up, or balancing adjustment, would be applied in the final year based on the actual ESM revenues for the three-year collection period.

2. The Company should work with the Commission Staff to identify a means for adequately addressing concerns regarding the timely communication of issues related to the current year's ESM filings. This may include narrative explanations, more frequent communications, or other means to be worked out between the Company and Staff.

3. ESM should not preclude the Companies from petitioning for, nor preclude the Commission from allowing, the deferral of costs incurred as a result of extraordinary events. However, since the Companies are operating under the ESM, the Commission may wish to consider increasing the threshold used to base its decisions to allow the Companies to defer costs for recovery in subsequent regulatory proceedings. In these instances, if so ordered by the Commission, SFAS 71 would require the Companies to defer and amortize those costs to properly match revenues and expenses.

Exhibit V-1

Summary of LG&E ESM Filings

Summary of Louisville Gas and Electric ESM Filings for Years Ending December 2000 - 2002

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	ESM YE	Filing Date	note	Capitalization	Upper Income Limit	Net Operating Income	Lower Income Limit	(Surplus) Deficit	Customer 40% share	Gross Up Factor	Gross Revenue	Actual Annual Revenues	Filed ESM Factor
1	2000	March 1, 2001		$1,330,563,593	$121,081,287	$121,729,261	$107,642,595	($647,974)	($259,189)	0.595211	($435,457)	$533,027,206	-0.082%
2	2000	April 20, 2001	(1)	$1,330,563,593	$121,081,287	$122,000,307	$107,642,595	($919,020)	($367,608)	0.595211	($617,609)	$533,027,206	-0.116%
3	2000	Final Approved ESM Revenues for Year									($617,609)		
4	2001	March 1, 2002		$1,368,114,076	$121,351,719	$105,741,400	$107,260,144	$1,518,744	$607,498	0.595243	$1,020,588	$533,335,960	0.191%
5	2001	October 28, 2002	(2)	$1,325,437,378	$115,975,771	$105,744,065	$102,853,941	$0	$0	0.595243	$0	$533,335,960	-0.262%
6	2001	December 23, 2002	(3)								$146,852		-0.174%
7	2001	Final Approved ESM Revenues for Year									$146,852		
8	2002	February 28, 2003		$1,369,067,794	$110,757,585	$76,758,796	$97,066,907	$20,308,110	$8,123,244	0.595251	$13,646,758	$587,386,549	2.323%
9	2002	May 22, 2003	(4)	$1,369,066,903	$110,757,512	$76,758,790	$97,066,843	$20,308,054	$8,123,222	0.595251	$13,646,721	$587,386,549	2.320%
10	2002	Pending Approved ESM Revenues for Year									$13,646,721		
11	Totals for Three Filings (assuming approval of 2002 filing)		(5)		$347,814,570	$312,346,189	$307,563,379				$13,175,964	$1,653,749,715	0.797%
12	Consolidated ESM for 3 Year Period				$347,814,570	$304,503,162	$307,563,379	$3,060,217	$1,224,087	0.595235	$2,056,477	$1,653,749,715	0.124%

(1) Refiled ESM in response to KPSC 1st Data Request in Case 2001-054. Adjusted certain expenses to conform with Environmental Surcharge Form 2.1.

(2) Refiled ESM to comply with October 16, 2002 Order in Case No. 2002-00071. ESM factor reflects 7 months ESM revenues ($567,257) and small balancing adjustment ($16,987) all to be refunded over 5 months.

(3) Filed a balancing adjustment calculation to reflect 12/23/02 settlement agreement and refund 75% of current year ESM revenues for April through October ($587,409 * .75 = $440,557). Net ESM revenues = $146, 852. Factor is determined net of refunds in November and December 2001 at -0.262% factor.

(4) Refiled ESM to correct minor errors. ESM factor did not change.

(5) Net Operating Income here includes ESM Revenues adjusted for taxes (Customer 40% Share or Revenues * Gross Up Factor)

Exhibit V-2

Summary of Kentucky Utilities Filings

Summary of Kentucky Utilities ESM Filings for Years Ending December 2000 - 2002

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	ESM YE	Filing Date	note	Capitalization	Upper Income Limit	Net Operating Income	Lower Income Limit	(Surplus) Deficit	Customer 40% share	Gross Up Factor	Gross Revenue	Actual Annual Revenues	Filed ESM Factor
1	2000	March 1, 2001		$980,633,782	$100,514,963	$95,049,816	$88,845,421	$0	$0	0.595211	$0	$577,972,889	0.000%
2	2000	Final Approved ESM Revenues for Year									$0		
3	2001	March 1, 2002		$1,021,468,484	$99,899,618	$99,542,173	$87,437,702	$0	$0	0.595243	$0	$601,753,736	0.000%
4	2001	October 28, 2002	(1)	$1,002,148,027	$97,509,003	$99,539,590	$85,483,227	($2,030,587)	($812,235)	0.595243	($1,364,543)	$600,282,247	-0.546%
5	2001	December 23, 2002	(2)								($1,023,407)		-0.315%
6	2001	Final Approved ESM Revenues for Year									($1,023,407)		
7	2002	February 28, 2003		$1,111,015,350	$98,880,366	$70,048,720	$85,659,283	$15,610,563	$6,244,225	0.595251	$10,490,074	$667,090,473	1.573%
8	2002	May 22, 2003	(3)	$1,110,930,061	$98,872,775	$68,391,342	$85,652,708	$17,261,365	$6,904,546	0.595251	$11,599,389	$667,090,473	1.771%
9	2002	Pending Approved ESM Revenues for Year									$11,599,389		
10	Totals for Three Filings (assuming approval of 2002 filing)		(4)		$296,896,741	$269,276,118	$259,981,356				$10,575,982	$1,845,345,609	0.573%
11	Consolidated ESM for 3 Year Period				$296,896,741	$262,980,748	$259,981,356	$0	$0	0.595235	$0	$1,845,345,609	0.000%

(1) Refiled ESM to comply with October 16, 2002 Order in Case No. 2002-00072. ESM factor reflects ESM revenues of ($1,364, 543) to be credited over 5 months. Factor computed based on 5 months revenue of $250,117,603

(2) Filed a balancing adjustment calculation to reflect 12/23/02 settlement agreement and credit 75% of ESM revenues as detemined by the October 28, 2002 ESM filing. Factor is determined net of refunds in November and December 2001 at -0.546% factor.

(3) Refiled ESM to correct several errors. ESM factor adjusted to recover adjusted revenues over 10 months.

(4) Net Operating Income here includes ESM Revenues adjusted for taxes (Customer 40% Share or Revenues * Gross Up Factor)

Exhibit V-3

Summary of Upper Limit Jurisdictional Capitalization

Summary of Upper Limit Jurisdictional Capitalization
Reported in ESM Filings for Years Ending December 2000 - 2002

Louisville Gas and Electric Company

	Year 2000 Filing - March 1, 2001				Year 2001 Filing - October 28, 2002				Year 2002 Filing - May 22, 2003			
	Capitalization	Pct	Rate	Weighted	Capitalization	Pct	Rate	Weighted	Capitalization	Pct	Rate	Weighted
Short Term Debt	$98,582,402	7.41%	6.84%	0.51%	$67,548,110	5.10%	4.84%	0.25%	$104,412,203	7.63%	1.73%	0.13%
A/R Securitization	$0	0.00%	0.00%	0.00%	$36,300,032	2.74%	4.11%	0.11%	$38,999,593	2.85%	2.17%	0.06%
Long Term Debt	$479,993,778	36.07%	5.38%	1.94%	$480,453,552	36.25%	5.14%	1.86%	$460,713,521	33.65%	4.06%	1.37%
Preferred Stock	$81,849,882	6.15%	5.75%	0.35%	$81,310,182	6.13%	5.07%	0.31%	$76,904,253	5.62%	4.47%	0.25%
Common Equity	$670,137,530	50.36%	12.50%	6.30%	$659,825,502	49.78%	12.50%	6.22%	$688,037,333	50.26%	12.50%	6.28%
Total Capitalization	$1,330,563,592	100.00%		9.10%	$1,325,437,378	100.00%		8.75%	$1,369,066,903	100.00%		8.09%
Rate Base	$1,370,638,809	103.01%			$1,513,221,918	114.17%			$1,629,166,763	119.00%		

Kentucky Utilities Company

	Year 2000 Filing - March 1, 2001				Year 2001 Filing - October 28, 2002				Year 2002 Filing - May 22, 2003			
	Capitalization	Pct	Rate	Weighted	Capitalization	Pct	Rate	Weighted	Capitalization	Pct	Rate	Weighted
Short Term Debt	$53,401,918	5.45%	6.84%	0.37%	$33,643,196	3.36%	4.82%	0.16%	$63,143,150	5.68%	1.72%	0.10%
A/R Securitization	$0	0.00%	0.00%	0.00%	$28,494,945	2.84%	3.96%	0.11%	$35,908,266	3.23%	2.12%	0.07%
Long Term Debt	$308,949,152	31.51%	7.12%	2.24%	$304,873,396	30.42%	5.81%	1.77%	$315,510,865	28.40%	3.91%	1.11%
Preferred Stock	$34,880,641	3.56%	5.68%	0.20%	$34,611,483	3.45%	5.68%	0.20%	$34,212,584	3.08%	5.68%	0.17%
Common Equity	$583,402,071	59.49%	12.50%	7.44%	$600,525,007	59.92%	12.50%	7.49%	$662,155,195	59.60%	12.50%	7.45%
Total Capitalization	$980,633,782	100.00%		10.25%	$1,002,148,027	100.00%		9.73%	$1,110,930,060	100.00%		8.90%
Rate Base	$1,180,426,245	120.37%			$1,250,007,841	124.73%			$1,388,183,087	124.96%		

CHAPTER VI

BUDGETING

Review the Companies' operating budget procedures, and capital planning and budgeting procedures, to determine the extent to which the Companies have instituted more effective management processes and, therefore, better expenditure control.

A. Background

The planning and budgeting process starts with a strategic overview for the five-year forecast period based on the prior year plan and significant business changes. Targets for O&M, Capital and Other expenditures by Strategic Business Unit result from this overview. Key budget assumptions include wage rates, benefits, inflation and best practices. The LEC Financial Planning group then prepares business plan guidance for the operating business units and shared services groups as these groups develop their business plans and budgets. Business units must submit written plans, including monthly financial information for the first twenty-four months and annual information for the remaining three years of the forecast period. The financial information provided must be accompanied by a financial commentary fully detailing plan assumptions. Once business unit plans are developed, they are presented to senior management for approval. Once approved, these plans serve as the basis for the development of cost center budgets.[42]

ESM-related recoveries / refunds, while recognized when presenting financial plans to the parent company, are based on calculations made at the end of the budget process and are not used to set responsibility budget objectives.

Responsibility for cost center budget performance is driven to the operating manager level. There are more than 200 cost centers within LG&E. In addition, the business units have budget coordinators and an asset management function responsible for ensuring capital and operating budgets support the corporate targets while effectively allocating scarce resources. The budget coordinators report to the business unit heads while reporting indirectly to the corporate planning and budgeting department. The budget coordinators prepare reports monthly summarizing actual and projected results compared to the budget for their business units.[43]

Starting in late 2002, the Companies implemented a monthly process for reviewing actual and projected consolidated financial results. This process now includes eight members of senior management including operating, as well as financial officers.[44] Controlling expenditures is included in incentive compensation plans as part of a manager's effectiveness measure and as part of achieving overall earnings objectives.

In addition to the capital budgeting process mentioned above, formal business cases must be developed and presented to the Investment Committee for each major capital investment. With the exception of emergencies, the Investment Committee will not review capital investment business cases unless the expenditures have been budgeted. However, the inclusion of a project in the capital budget does not ultimately guarantee the Investment Committee will approve the project.

BWG reviewed actual results as well as variances from budget for both capital expenditures and income statement items for the ESM period. The results of this review are presented below.

As shown in **Exhibits VI-1 and VI-2**, there are no discernable trends in electric distribution capital expenditures or the reliability-related portion of these expenditures during the period 2000 through 2002.

Exhibit VI-1

Distribution Capital Expenditures

(in millions)	**2000**	**2001**	**2002**	**Total**
Enhance the Network	$29.7	$19.7		$49.4
Repair the Network	$4.7	$1.1		$5.8
Maintain the Network	$0.8	$4.8		$5.6
Other Enhancements		$10.9		$10.9
Mandatory Relocations			$3.1	$3.1
System Upgrades to Meet Demand			$11.3	$11.3
Repair / Replace Defective Equipment			$11.4	$11.4
Circuit Reliability			$2.5	$2.5
Total	**$35.2**	**$36.5**	**$28.3**	**$100.0**

Source: BWG Analysis and Response to DR 2-43.

Exhibit VI-2

Reliability-Related Distribution Capital Expenditures

(in millions)	**Reliability %**	**2000**	**2001**	**2002**	**Total**
Enhance the Network	33%	$9.8	$6.5		$16.3
Repair the Network	100%	$4.7	$1.1		$5.8
Maintain the Network	33%	$0.3	$1.6		$1.9
Other Enhancements	33%		$3.6		$3.6
Mandatory Relocations	25%			$0.8	$0.8
System Upgrades to Meet Demand	33%			$3.7	$3.7
Repair / Replace Defective Equipment	100%			$11.4	$11.4
Circuit Reliability	100%			$2.5	$2.5
Total		**$14.8**	**$12.8**	**$18.4**	**$46.0**

Source: BWG Analysis and Response to DR 2-43.

In 2002, capital spending in all areas was slightly below budget, with more spending on combustion turbines (CT) and NOx equipment than on all other types of capital expenditures.[45]

Additions to Plant in Service and CWIP ranged from $181.0 million in 1998 to $423.8 million in 2002 based on a review of Louisville Gas and Electric and Kentucky Utilities FERC Form 1 reports for each year during the period 1998 through 2002, as summarized in **Exhibit VI-3** below.

Exhibit VI-3
Additions to Plant-In-Service and CWIP – 1998-2002

Louisville Gas & Electric (Electric Only)		1998	1999	2000	2001	2002
301 - 303	Intangible Plant	$ -	$ -	$ -	$ -	$ -
310 - 316	Steam Production Plant	16,086,552	57,910,420	24,029,060	55,156,053	50,385,517
330 - 336	Hydraulic Production Plant	216,799	-	152,195	-	15,489
340 - 346	Other Production Plant	67,166	45,216,138	2,691,648	58,119,740	34,779,451
350 - 359	Transmission Plant	5,453,552	2,561,086	5,745,713	5,503,220	11,875,999
360 - 373	Distribution Plant	13,558,939	26,561,696	33,756,773	30,429,835	33,257,181
389 - 399	General Plant	1,450,485	1,425,093	646,292	280,755	912,236
		$ 36,833,493	$ 133,674,433	$ 67,021,681	$ 149,489,603	$ 131,225,873
	CWIP Balance at Year End	$ 90,471,522	$ 107,796,865	$ 137,062,687	$ 207,177,011	$ 261,760,776
	Total Additions to Utility Plant - LG&E	$ 90,392,239	$ 150,999,776	$ 96,287,503	$ 219,603,927	$ 185,809,638
Kentucky Utilities						
301 - 303	Intangible Plant	$ 8,729	$ 11,824,547	$ 3,044,648	$ 174,996	$ 2,247,234
310 - 316	Steam Production Plant	2,766,760	16,017,606	3,035,401	15,865,448	15,573,497
330 - 336	Hydraulic Production Plant	-	-	-	-	-
340 - 346	Other Production Plant	6,250,430	76,467,259	14,967,834	58,680,453	83,684,304
350 - 359	Transmission Plant	10,748,396	8,395,610	16,260,930	10,417,830	5,440,661
360 - 373	Distribution Plant	43,740,364	40,361,248	38,821,755	52,074,613	37,758,128
389 - 399	General Plant	2,644,221	4,938,013	24,866,457	8,478,353	5,500,226
		$ 66,158,900	$ 158,004,283	$ 100,997,025	$ 145,691,693	$ 150,204,050
	CWIP Balance at Year End	$ 83,360,613	$ 106,686,218	$ 106,379,912	$ 103,402,029	$ 191,233,222
	Total Additions to Utility Plant - KU	$ 90,580,514	$ 181,329,888	$ 100,690,719	$ 142,713,810	$ 238,035,243

Source: FERC Form 1 (DR BWG 1-26)

BWG observed no discernable income statement trends, either budget or actual, since the implementation of ESM. In 2002, actual O&M labor expenses were less than budget while non-labor O&M expenses were more than budget. This variance reflects the implementation of VDT recommendations to move toward a variable work force coupled with additional non-labor expenses such as MISO 10B administrative expenses.[46] There are also no discernable trends in O&M variances, other than variances attributable to the amortization of VDT / One Utility Costs, during the period 1998 through 2002.[47] See **Exhibit IV-1** and the related discussion on pages IV-3 and IV-4 for an analysis of LG&E and KU expense trends for the periods 1997-1999 and 2000-2002.

Actual retail margins were greater than budget in 2002 due primarily to weather. Off system sales were below budget in 2002 due to pricing (primarily LG&E) and reduced volumes due to unit availability problems and milder winter weather.[48]

B. Evaluation Criteria

1. Has expenditure control improved, as a result of ESM, due to more effective operating budgeting and capital planning and budgeting procedures?

C. Findings

1. Operating and capital budgeting processes have not changed as a result of the earnings sharing mechanism except for the calculation of the budgeted amount of any over or under-earnings. Business unit and cost center targets are not adjusted based on the amount of the over- or under-recovery.[49]

2. Operating and capital budgeting processes are effective and have been enhanced in recent years as a part of VDT emphasis on asset life cycle costs and benefits, for example, not as a result of ESM.[50]

   - Budgeting processes have changed as the result of the merger between LG&E and KU, the acquisitions by Powergen and E.ON, and the formation of the LG&E Energy Services Company.

     – Powergen required the Companies to establish decentralized budget coordinators reporting directly to the business unit heads.[51]

     – As a result of a best practices study, Powergen also established an asset management service provision model. Changes resulting from the formation of an asset management function included:

       - Separated planning (long-term) from business execution.

       - Combined gas and electric engineering.

       - Combined KU and LG&E engineering to develop consistency in material standards, O&M practices, and construction standards.

       - Established Asset Management responsibility for investment strategy. The objective of this strategy is to optimize life cycle costs while at the same time maintain reliability and service levels.[52]

   - The Oracle ERP system was implemented in 1999. At this time, the current, basic responsibility reporting procedures were established.[53] Responsibility budgets are established at the following level of detail:

     – Company (LG&E, KU, Services Company)

     – Cost Center

     – Project Number

     – Task

  - Expenditure Type

- In 2000, the Company reorganized cost centers in connection with its "One Utility" and process initiatives. Certain information from 2000 forward is not directly comparable with prior periods.[54]

- Significant percents of short-term incentive compensation payouts are based on the achievement of budgeted results.[55]

3. Capital projects are subject to a structured evaluation process, and this process has not changed as a result of ESM.[56] Based on our review of Investment Committee minutes from 2000 through 2002, there appears to have been a conscious shift to increased economic/risk-based justification of reliability-related capital investments as a result of Powergen/VDT initiatives. This is consistent with the Commission's goal for the ESM as stated in the enabling Order for this ESM trial program:

   > *"ESMs also provide the utility incentives to alter its behavior and to take additional risks by providing a limited safety net in case new efforts result in failure."*

- The companies have formal, written capital planning, budgeting and approval policies: LG&E Energy Corp.'s Capital Policy and Powergen's Investment Decision Procedure.[57]

- Within the Energy Delivery business unit, approximately 300 capital projects are evaluated annually as part of the capital budgeting process. Evaluation criteria include financial (NPV/IRR), reliability, safety, environmental, and customer demand / load growth. In addition, there are "must do" new business and line reallocation projects.[58]

- Starting with projects included in the fiscal 2003 budget, Energy Delivery began using the Capital Investment Proposal System to record and prioritize projects. This system was developed internally to use the same evaluation criteria as the existing process.

- The Investment Committee requires that business cases be prepared to justify proposed large capital expenditures. However, projects that have not been budgeted and aren't emergencies will not be considered by the Investment Committee.

  - The justification must include financial as well as non-financial factors. Projects with positive net present values (NPV) or above target internal rates of return (IRR), and which have incremental O&M costs that can be offset by incremental O&M savings, are most likely to be approved.[59]

  - All projects over $1 million ($375,000 for IT projects) must be approved by the Investment Committee.[60] [61]

- As an example, the Worthington Substation Investment Proposal provides justification for a project that will ensure adequate and consistent voltage levels in a rapidly growing part of Louisville. The proposal was presented to the Investment Committee on December 18, 2001, with the intention of receiving authorization for investments in 2002 and 2003. According to the director of Distribution Operations, this proposal is typical of the project proposals submitted for approval by the Investment Committee. The approval process has not changed as a result of ESM. The recommended solution was compared to a "do nothing" option and two other alternatives. The evaluation considered engineering design practices, service reliability (short- and long-term) and costs. For this project, the NPV for all alternatives was negative. The approval of this project by the Investment Committee indicates that LG&E continues to consider both economic and non-economic issues when determining whether to make capital investments, and not disapprove all projects with negative NPVs.[62]

- An example of a proposed capital project not approved by the Investment Committee is the enhancement to the CIS to support the Virginia Unbundling Act. Rather than make a large investment that would affect few customers, the company was able to obtain an exemption from the requirements of the Act.[63]

- In 2002, generation service levels did not meet expectations as a result of the unusually high number of forced outages. This contributed to actual off system sales margins falling below budget projections. Investment Committee meeting minutes reflect that high equivalent forced outage (EFOR) rates may have been at least partially impacted by capital budgeting decisions made one or two years prior.[64]

- Hurdle rates have not changed as a result of merger activity during the past few years, and have definitely not changed as a result of ESM.[65]

- The Budget Process flowchart is provided as **Appendix B** and the Capital Investment Approval Process flowchart is provided as **Appendix C** to this report.

D. Recommendation

1. Assure that capital investment criteria continue to include appropriate consideration of reliability issues needed to meet customer service level standards and safety factors that may not have quantifiable economic benefits. (Refers to Finding 3 and Task Area 7, Finding 4)

CHAPTER VII

ACCOUNTING

Examine the Companies' capitalization and deferral policies and practices since the beginning of the ESM plan and verify that the Companies have not recorded certain transactions as Capital Expenditures or Deferred Assets when they should be recorded as operating expenses.

A. Background

As a regulated utility, LG&E and KU account for capital expenditures in accordance with FERC Electric Plant Instructions. These instructions require that electric plant be recorded at cost. In addition, the instructions specify the components of construction cost, a partial list of which includes contract work, labor, materials and supplies, rents, engineering and supervision and general administrative costs capitalized. In addition, the instructions distinguish between repair (expense) and replacement (capital) costs, and provide for the expensing of certain capital expenditures below a threshold dollar amount. Although the electric plant instructions also provide for the capitalization of interest costs (AFUDC) on capital projects, Kentucky regulation provides for the inclusion of CWIP for ratemaking purposes, and as a result, the utilities do not capitalize financing costs.

The Companies' have an Authorization for Investment Proposal (AIP) process that is used to document proposed capital projects and the approvals required. This form also describes the accounting for project costs (that is, distinguishes between capital and O&M). Prior to setting up a project in Oracle, the accounting department ensures that all information has been provided, that all approvals have been obtained, and that budgeted funds are available.

BWG examined the Companies' policies and procedures in these areas focusing on any changes that may have occurred since the implementation of ESM to ensure that work completed is properly accounted for.

B. Evaluation Criteria

1. Have the Companies' policies and procedures related to the capitalization of expenditures, before and after the beginning of the ESM plan, remained unchanged?
2. Are actual practices consistent with these policies and procedures?
3. Are systems of internal control adequate to ensure that policies and procedures are complied with?

C. Findings

1. Capitalization policies and procedures have not changed as a result of ESM and there are no explicit provisions under the earnings sharing mechanism that require the disclosure of changes to capitalization policies and procedures to the Commission.

- The Companies follow FERC capitalization policies, which have not changed during ESM program period.[66]

- Costs are capitalized when over $500 and are consistent with FERC Electric Utility Plant instructions. Accounting personnel have had preliminary, internal discussions regarding raising the $500 threshold for capitalization. The dollar impact of this change is expected to be insignificant.[67]

- Costs are not deferred unless specifically approved by the KPSC.[68]

2. Actual practices are consistent with the Companies' policies and procedures related to the capitalization of expenditures.

   - Capital projects are direct charged as much as possible.[69]

   - Property Accounting ensures that Authorization for Investment Proposals (AIP) have been properly completed and approved. Property Accounting is responsible for all property accounting activities for the two utilities.[70]

   - Based on discussion with accounting department management, there were no general journal entries written in 2002 which moved costs from O&M to Capital or from Capital to O&M other than normal entries associated with capitalized A&G costs consistent with FERC reporting requirements.

   - The methodology used to capitalize A&G costs is consistent for LG&E and KU. The only costs capitalized are A&G Labor (920), A&G Office Expenses (921), and Outside Services (923). Service Company labor allocated to the utilities is recorded in account 923. Non-labor costs associated with Service Company employees are not capitalized. A&G capitalization factors have not changed significantly between years.[71]

   - A&G costs capitalized during the period 1998 through 2002 are presented in **Exhibit VII-1** on the following page. Capitalized administrative and general costs have decreased at LG&E during this period. At Kentucky Utilities, no A&G costs were capitalized prior to 2000. KU had employees directly charge capital (the "local engineering" overhead account) when working on a capital project. After the merger, the Companies adopted a single policy for both Companies with KU adopting LG&E's policy of allocating time worked on capital projects through the A&G percentage.

     In 2001, as a result of the One Utility project and resultant reorganization, the Companies combined certain engineering and administrative functions resulting in a pool of A&G dollars to be subject to capitalization.[72] There has been no significant change in the total amount of A&G costs capitalized from 2000 through 2002, with the amount significantly reduced form 1998 and 1999 levels.

Exhibit VII-1
Analysis of Capitalized A&G

Year	LG&E	KU	Total
2002	$1,230,769	$1,191,415	$2,422,184
2001	$1,446,053	$946,361	$2,392,414
2000	$2,103,246	$0	$2,103,246
1999	$2,831,388	$0	$2,831,388
1998	$3,311,307	$1,027	$3,312,334

Source: FERC Form 1

- BWG reviewed construction overheads for the period 1998 through 2002. These amounts are summarized in **Exhibit VII-2** below. KU was on a different financial system in 1998 and 1999 and individual overhead classifications are not available for those two years. For comparative purposes, amounts cleared to O&M are presented in **Exhibit VII-3** on the following page.

Exhibit VII-2a
Analysis of Construction Overheads – LG&E

Year	Employee Benefits	Stores Expense and Other	Local Eng. and A&G	Total
2002	$5,751,229	$556,065	$6,052,564	$12,359,858
2001	$4,607,625	$2,020,921	$8,155,546	$14,784,092
2000	$5,355,037	$1,638,544	$9,098,364	$16,091,945
1999	$6,436,403	$1,676,555	$10,864,937	$18,977,895
1998	$8,359,891	$1,232,857	$6,951,689	$16,544,437

Source: DR 6-85

Exhibit VII-2b
Analysis of Construction Overheads – KU

Year	Employee Benefits	Stores Expense and Other	Local Eng. and A&G	Total
2002	$10,051,235	$3,212,237	$8,341,505	$21,604,977
2001	$6,530,160	$2,845,993	$6,964,323	$16,340,476
2000	$5,582,976	$4,360,241	$11,905,956	$21,849,173
1999	NA	NA	NA	$16,550,428
1998	NA	NA	NA	$13,390,324

Source: DR 6-85

Exhibit VII-3a
Analysis of O&M Overheads – LG&E

Year	Employee Benefits	Stores Expense and Other	Total
2002	$34,406,575	$597,542	$35,004,117
2001	$26,531,307	$875,633	$27,406,940
2000	$22,620,586	$1,318,499	$23,939,085
1999	$27,377,198	$1,385,260	$28,762,458
1998	$30,921,624	$1,140,389	$32,062,013

Source: DR 6-85

Exhibit VII-3b
Analysis of O&M Overheads – KU

Year	Employee Benefits	Stores Expense and Other	Total
2002	$30,428,141	$852,650	$31,280,791
2001	$25,508,663	$642,869	$26,151,532
2000	$25,790,214	$5,712,148	$31,502,362
1999	NA	NA	$35,848,443
1998	NA	NA	$35,883,724

Source: DR 6-85

- BWG reviewed deferred asset account activity for the period 1998 through 2002 as reported on FERC Form 1 and explanations provided in response to DR 2-38 for significant activity. No unusual items were noted.

3. The system of internal controls related to the appropriate accounting for expenditures as either capital, expense, or deferred is adequate and appears to be operating effectively.

- Based on our review of reports of internal audits completed since January 1, 2000, no instances of non-compliance with policies and procedures related to the capitalization or deferral of expenditures were noted.

  – The Internal Audit department completed a property cycle audit in 2000. The audit found that "transactions affecting property, plant and equipment are authorized in accordance in accordance with Company policy; charges to work orders are properly processed; property transactions are accurately accounted for; and records are maintained in accordance with regulatory requirements."

- The Internal Audit department completed a post-implementation audit of the Virtual Online Time System (VOLTS) in 2002. The audit found that application data control procedures and operations are adequate and effective.

- The Internal Audit department completed a LG&E Energy Services Inc. / Shared Services audit in 2001. The audit concluded that "existing SERVCO policies, procedures, and controls are sufficient to ensure accurate and timely financial reporting, and the SERVCO shared services functions are appropriately performed and billed." The audit included a review of "a sample of payroll expenses for the pay period ending May 27, 2001, to determine whether the expenses were recorded properly and found no exceptions."

- The final step in the capital expenditure approval process is the review of the project plan / authorization for investment proposal (AIP) by the accounting department. The purpose of this review is to ensure all required approvals have been obtained, to verify the project has been budgeted (and if not, that an explanation of funding has been provided so the project will not create a budget variance), and that projected costs have been properly identified as capital or O&M. Once this review has been completed, the project will be set-up in Oracle and can begin accepting charges.

- Since the formation of the Services Company, PCs and office equipment purchased for LEC employees is on the books of the Services Company and not accounted for as utility plant in service.

- There were no adjustments proposed by the external auditors and not booked by the utilities that related to the incorrect classification of expenditures between capital and expense for fiscal years 2000 through 2002.

D. Recommendation

1. The KPSC should require as part of the ESM filing process a disclosure from Company management describing any changes in Company policies, procedures or practices that have occurred related to the classification of expenditures (capital, deferred, expense). (Refers to Finding 1)

CHAPTER VIII

SERVICE LEVELS

Review the Companies' compliance with both the Commission's service-related regulations and their own service objectives, both internal and external, since the incentive plan was instituted.

A. Background

LG&E and KU are subject to a number of service level commitments agreed to as part of the Order authorizing the use of the Earnings Sharing Mechanism (Case No. 98-474) and E.ON Acquisition of PowerGen (2001-104/105). Specifically, the terms of the Commission proposed ESM program included the language that LG&E and KU "will be expected to continue and maintain its superior level of service quality which will be monitored through existing reporting requirements."[73] Among requirements included in the KPSC Order approving the E.ON acquisition are the following related to service-level commitments:[74]

- E.ON, PowerGen, LG&E Energy, LG&E, and KU commit that customers will experience no change in utility service due to the continuing existence of LG&E Energy Services, Inc.
- E.ON, PowerGen, LG&E Energy, LG&E, and KU commit to:
  - Adequately funding and maintaining LG&E's and KU's transmission and distribution systems.
  - Complying with all Commission regulations and statutes.
  - Supplying LG&E and KU customers' service needs.
- When implementing best practices, E.ON, PowerGen, LG&E Energy, LG&E, and KU commit to taking into full consideration the related impacts on the levels of customer service and customer satisfaction, including any negative impacts resulting from workforce reductions.
- E.ON, PowerGen, LG&E Energy, LG&E, and KU commit that they will minimize, to the extent possible, any negative impacts on levels of customer service and customer satisfaction resulting from workforce reductions.
- LG&E and KU commit to periodically filing the various reliability and service quality measurements they currently maintain, to enable the Commission to monitor their commitment that reliability and service quality will not suffer as a result of the acquisition.
- E.ON and PowerGen commit to maintaining LG&E Energy's level of commitment to high quality utility service, and will fully support maintaining the LG&E and KU track record for superior service quality.

- E.ON, PowerGen, LG&E Energy, LG&E, and KU commit that LG&E and KU shall continue to operate through regional offices with local service personnel and field crews.
- E.ON, PowerGen, LG&E Energy, LG&E, and KU commit that local customer service offices will not be closed as a result of the proposed transaction and that, if and when local customer service offices may be closed to achieve world class best practices, the Applicants will take into account the impact of the closures on customer service.

Both LG&E and KU have reputations for being reliable, customer service oriented utilities. In February 2003, the Lexington area was hit by an unprecedented ice storm--thirty-six (36) hours of continuous freezing rain were reported with temperatures at or below freezing. As a result, KU's customers experienced an unusually long outage and KU expended over $22 million in recovery efforts. The Commission has a case open related to whether the ice storm damage, recovery effort, and outage durations were affected by the implementation of the ESM program that is the subject of this focused audit. BWG has included perspective on this issue in this report (see Finding VIII-6), however a detailed audit of distribution-related management practices was not within the scope of this review.

B. Evaluation Criteria

1. Have the Companies complied with all Commission service-related regulations?
2. For those service quality measures not included in Commission regulations, have service levels been maintained at, or improved upon, pre-2000 levels.

C. Findings

1. The Companies have complied with requirements to file reliability reports with the Commission.
    - Quarterly reports submitted to the Commission include information on System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) statistics for KU and LG&E substations and provide a summary of current year and five-year average performance levels and explanations for negative variances greater than ten percent from the five-year average.[75]
    - Although the reports have been submitted as required, the Commission staff has concerns over the accuracy and format of some of the information provided (particularly, the five-year customer count information) and the Company has confirmed that a "data problem" exists, which is being worked on.[76]
    - These reports are prepared solely for the use of Staff and are not used internally. Instead, the Companies rely on more detailed information highlighting "worst circuits" for assessing reliability issues and prioritizing capital investment requirements.[77]
2. The Companies place considerable emphasis on service levels, customer satisfaction, and safety as part of the planning, budgeting, capital expenditure, and performance monitoring activities.

- The Company monitors a number of key performance indicators (KPIs) that reflect on reliability and service levels.[78] These include:

  Distribution Operations

  - Annual Outage Duration (SAIDI)
  - Annual Outages per Customer (SAIFI)

  Retail Business

  - Overall Residential Customer Satisfaction
  - Call Handling Customer Satisfaction

- Forty percent of the Team Incentive Award (TIA) component of incentive compensation for key Energy Delivery management personnel is tied to achieving desired performance levels in these KPIs and other personal goals.[79]
- Management monitors performance against KPI goals on a monthly basis.
- The primary influence on cost structure has been implementation of the Value Delivery Team initiative, approved by the Commission in 2000. This focus of VDT in the Energy Delivery area of the Company was on implementing an asset management approach to investment decisions, reducing fixed costs by shifting to a more variable work force and placing additional emphasis on contactor safety.[80] VDT included a reliability goal to remain in the top quartile of utilities in both SAIFI and SAIDI performance.

3. The Companies have, in most instances, maintained or improved distribution reliability levels over pre-ESM period levels.

- **Exhibit VIII-1** includes information on SAIFI and SAIDI levels for 1998 through 2002 for the combined utilities. Both SAIDI and SAIFI levels improved in 1999 (the year prior to implementation of ESM) above levels the year earlier. Performance declined somewhat in 2000 over 1999 and then improved in 2001. SAIDI declined slightly in 2002, while SAIFI improved slightly during the same period.

Exhibit VIII-1

Combined Utilities SAIFI and SAIDI Statistics - 1998 - 2002

Utilities (Consolidated – Distribution Only)		**1998**	**1999**	**2000**	**2001**	**2002**
Annual Outage Duration (SAIDI)	Minutes	64.46	46.02	56.97	55.40	59.65
Annual Outages per Customer (SAIFI)	Frequency	0.802	0.708	0.777	0.708	0.660

Source DR 2-45

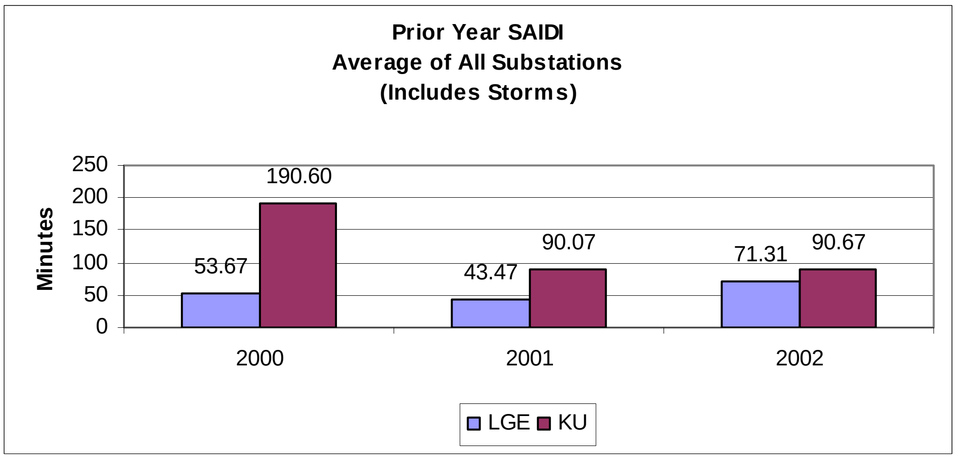
- Analysis of LG&E and KU reliability information filed with the KPSC in response to the E.ON merger requirements identifies similar reliability performance trends, as described below and shown in the charts which follow:

SAIDI

- LG&E performance improved in 2001 over 2000, but minutes of outages experienced by customers increased significantly in 2002 over prior year levels.
- KU performance improved in 2001 over 2000 and remained relatively constant in 2002.

Exhibit VIII-2

SAIDI – Average of All Substations
Twelve months ending March 31



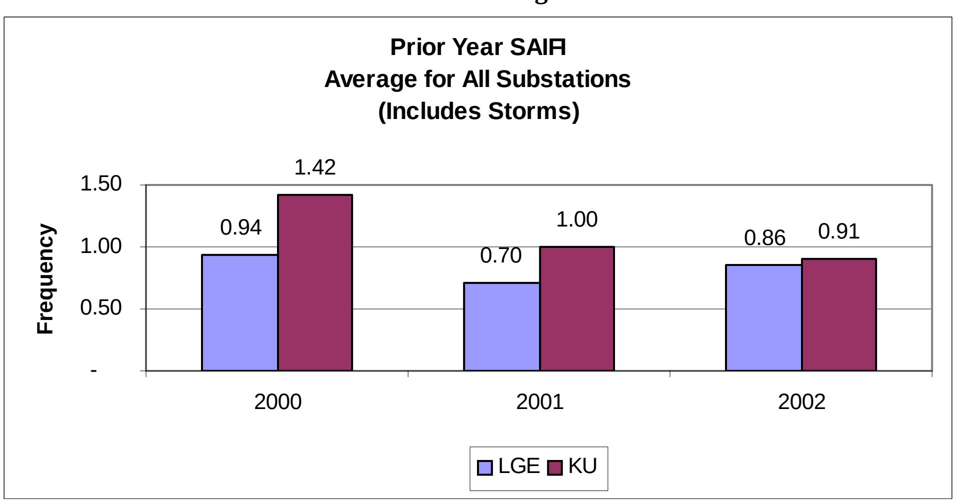
Source: DR 3-48, BWG Analysis

SAIFI

- LG&E outage frequency levels decreased in 2001 over 2000 levels and increased again in 2002, although remaining lower than 2000.
- KU outage frequency levels decreased in each succeeding year.

Exhibit VIII-3

SAIFI – Average of All Substations
Twelve months ending March 31



Source: DR3-48, BWG Analysis

4. The Companies have maintained top-quartile performance levels in both reliability and safety as measured by several well-recognized industry benchmarking surveys.

- LG&E and KU participate in several industry benchmarking studies in order to monitor its performance against industry best practices. In recent years these studies have included:
  - PA Consulting Group 2001 T&D Benchmarking Survey (covering data for LG&E and KU in 2000 – the Companies did not participate in the 2002 survey but are currently participating in the 2003 survey).[81]
  - Edison Electric Institute (EEI) annual Transmission & Distribution Reliability Survey (T& D).
  - Southeast Electric Exchange (SEEE) Distribution Reliability Survey.
- LG&E's overall reliability performance is among the best in the industry based on the results reported in these independent benchmarking surveys.[82]
- The following charts summarize benchmarking results for the EEI T&D surveys for 2001.

Exhibit VIII-4

T & D Survey SAIDI - 2001

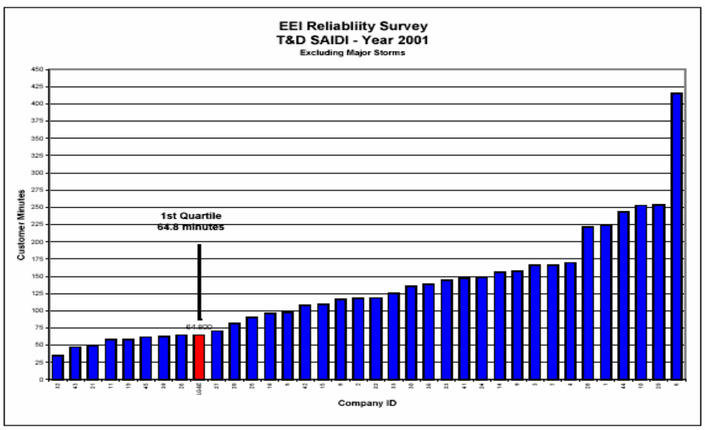
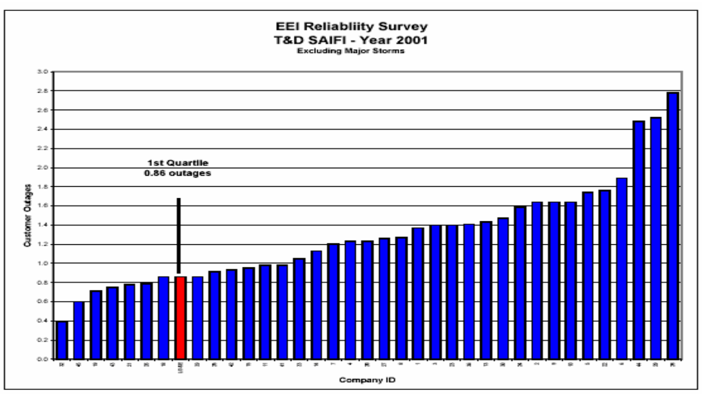


Exhibit VIII-5

T & D Survey SAIFI - 2001



- The following four charts summarize the results for the SEEE Distribution Reliability Survey for 2000 and 2001.

Exhibit VIII-6

Reliability Survey SAIDI - 2000

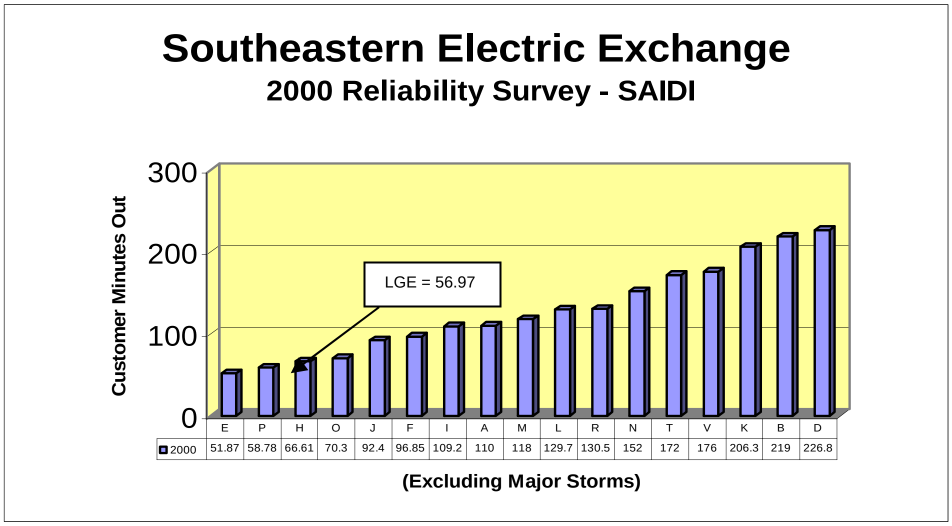


Exhibit VIII-7

Reliability Survey SAIDI - 2001

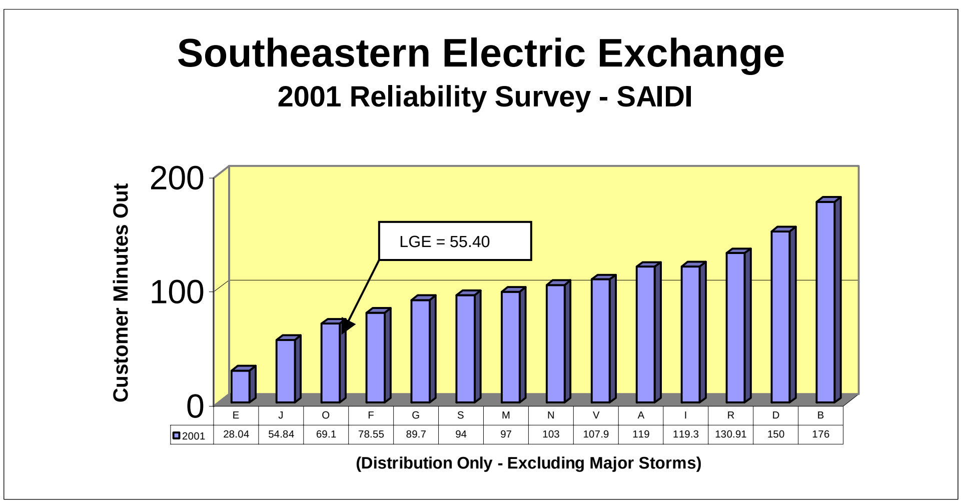


Exhibit VIII-8
Reliability Survey SAIFI – 2000

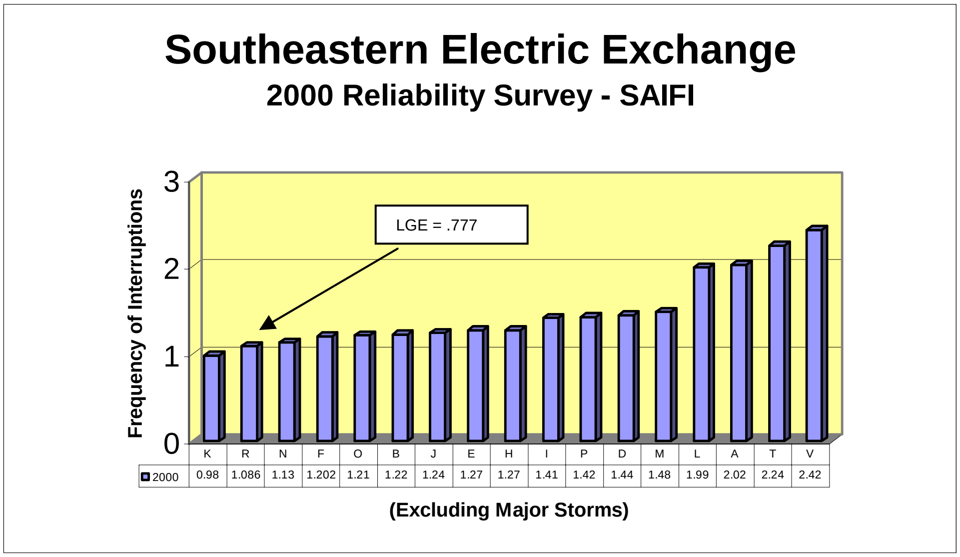
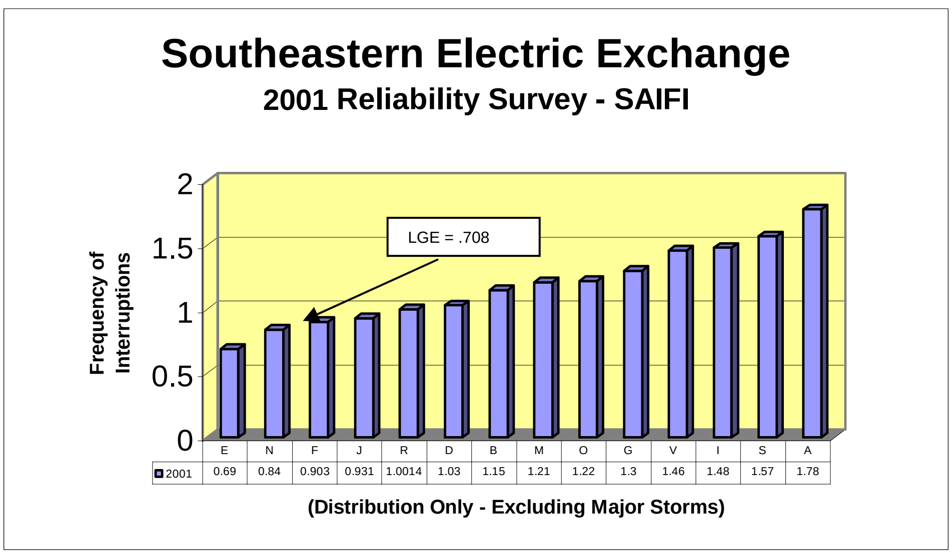


Exhibit VIII-9
Reliability Survey SAIFI – 2001



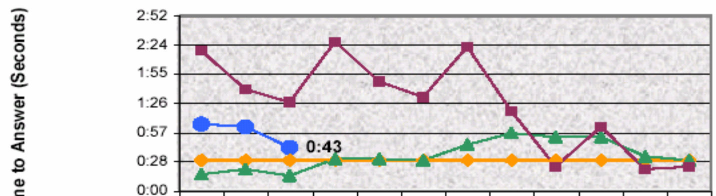
5. Retail business unit performance levels improved in 2002 over the previous year and are tracking at higher levels in early year-to-date reports for 2003.[83]
   - LG&E/KU-performed surveys of both residential and business customer satisfaction levels show increases in 2002 over prior years.
   - Residential and business center call answer times have been reduced significantly over the past two years.

Exhibit VIII-10

Residential Average Speed of Answer

RSC

RESIDENTIAL SERVICE CENTER
AVERAGE SPEED OF ANSWER



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2003 Actual	1:06	1:03	0:43									
2003 Target	0:30	0:30	0:30	0:30	0:30	0:30	0:30	0:30	0:30	0:30	0:30	0:30
2002	0:17	0:21	0:15	0:32	0:32	0:31	0:46	0:57	0:54	0:54	0:34	0:31
2001	2:18	1:40	1:28	2:27	1:48	1:33	2:22	1:19	0:24	1:03	0:22	0:24

Average Speed of Answer (ASA): The average delay of all calls. It is total delay divided by total number of calls.

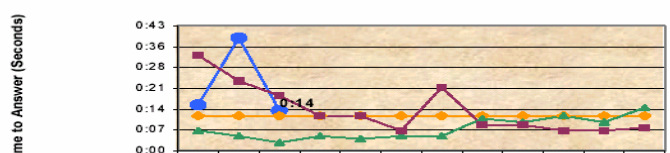
The RSC targeted ASA is :30 seconds or less.

Exhibit VIII-11

Business Average Speed of Answer

BSC

BUSINESS SERVICE CENTER
AVERAGE SPEED OF ANSWER



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2003 Actual	0:16	0:39	0:14									
2003 Target	0:12	0:12	0:12	0:12	0:12	0:12	0:12	0:12	0:12	0:12	0:12	0:12
2002	0:07	0:05	0:03	0:05	0:04	0:05	0:05	0:11	0:10	0:12	0:10	0:15
2001	0:33	0:24	0:19	0:12	0:12	0:07	0:22	0:09	0:09	0:07	0:07	0:08

Average Speed of Answer (ASA): The average delay of all calls. It is total delay divided by total number of calls.

The BSC targeted ASA is :12 or less.

- The Company has been selected as the highest-ranked utility in the country by JD Powers for both residential and midsize business customers. Performance in the JD Powers survey for the past several years is shown in **Exhibit VIII–12.**

Exhibit VIII-12

Residential J.D. Power Awards

1999	1st U.S. (78)	1st Midwest (18)
2000	2nd U.S. (75)	1st Midwest (16)
2001	11th U.S. (70)	3rd Midwest (16)
2002	1st U.S. (74)	1st Midwest (16)
2003	1st U.S. (77)	1st Midwest (16)

Midsize Business J.D. Power Awards

2000	2nd U.S. (44)	1st Midwest (11)
2001	2nd U.S. (38)	1st Midwest (11)
2002	1st U.S. (44)	1st Midwest (11)

Source: Response to DR 1-32 and LG&E Press Release dated July 30, 2003

- In 2002, the Companies installed a GUI front-end to its two legacy customer information systems. This enhancement has significantly reduced the learning curve needed for customer service representatives to become proficient in using both (LG&E / KU) CIS systems, and has contributed to the recent increase improvement in call center performance.[84]

6. Preliminary review of 2003 storm recovery effort indicates that this storm was out of the ordinary and that the recovery was well managed.

    - LG&E/KU utilizes the National Electrical Safety Code (NESC) as a basis for its distribution design standards. The NESC provides guidelines for electrical distribution system design, construction and maintenance including minimum clearances and design parameters. LG&E/KU design their overhead lines to comply at least with the minimum NESC Medium Loading criteria contained in Section 250 that corresponds to the loading district for this area of the United States. The loading criteria provide combined wind and ice loading to be used in calculating loads for overhead lines.[85]
    - Accumulation of more than two inches of ice resulted in loading at least eight times design.
    - **Exhibit VIII-13** on the following page provides a comparison of materials used during the ice storm versus a normal week.

Exhibit VIII-13

Comparison of Distribution Materials Used During 2003 Ice Storm vs. Normal Week

Materials Used	Normal Week	During Storm
Transformers	10	236
Poles	12	547
Service Wire & Overhead Primary Cable (ft.)	14,000	187,000
Cross arms	22	1,000
Wire Connectors	40	102,000
Insulators	29	7,423
Fuses	30	10,508
Guy Wire (ft.)	480	23,500

Source: Response to DR 3-53

- Management concedes that much of the damage to wires and circuits during the 2003 ice storm was caused by falling trees and branches, not wire overloading.[86] While review of tree-trimming practices was outside the scope of this focused audit, LG&E/KU have made tree-trimming process changes over the past several years that warrant comment.
  - Tree trimming process improvements began in the fall of 1998 as an LG&E initiative not related to the KU merger and preceded any Powergen-VDT or E.ON initiatives. While reliability centered maintenance has been in place at LG&E for the past ten years or so, it was only implemented at KU last year. Management believes that this has reduced costs by at least thirty percent from previous levels while maintaining tree trimming cycles and SAIDI and SAIFI goals. LG&E/KU's average tree trimming cycle time is just under four years, with individual circuits ranging from 3.5 to 4.5-5.0 years, which is not an unusual cycle.[87]
  - Management's perspective is that these changes were unrelated to ESM, other than being part of the Company's efforts toward continuous improvement, and that they had no bearing on the ice storm damage levels or the length of the outage recovery effort.[88]

D. Recommendations

1. The Companies should continue their on-going efforts to work with the Commission on the accuracy of reliability information provided the Commission, and on formatting changes to facilitate Staff analysis of this data. (Refers to Finding 1)
2. The Companies should continue to pay close attention to maintaining and improving service reliability and customer satisfaction to remain in compliance with both ESM and E.ON acquisition Commission Orders. (Refers to Finding 4)

Endnotes

[1] Interview with Paula Pottinger, VP-Human Resources, on June 11, 2003.
[2] Interview with Ron Miller, Director, Corporate Tax, on May 12, 2003; response to DR BWG 1-4, and various public documents.
[3] Response to DR BWG 1-4.
[4] Interview with Kent Blake, Business Development, on May 13, 2003.
[5] Response to DR BWG 3-58.
[6] Interview with Kent Blake, Business Development, on May 13, 2003.
[7] Interview with Diana Wacker, Manager, PUHCA Compliance, on June 12, 2003.
[8] Interview with Dan Arbough, Director, Corporate Finance and Treasurer, on May 29, 2003.
[9] Response to DR BWG 5-82.
[10] Interview with Dan Arbough, Director Corporate Finance and Treasurer, on June 30, 2003.
[11] Response to DR BWG 5-83.
[12] Interview with Dan Arbough, Director, Corporate Finance and Treasurer, on June 30, 2003.
[13] Interview with Dan Arbough, Director, Corporate Finance and Treasurer, on June 30, 2003.
[14] Response to DR BWG 1-1 and interview with Diana Wacker, Manager, PUHCA Compliance, on June 12, 2003.
[15] Response to DR BWG 1-7.
[16] Response to DR BWG 1-7.
[17] Response to DR BWG 1-6.
[18] Response to DR BWG 1-6.
[19] Interviews with Ron Miller, Director, Corporate Tax, on May 12, 2003 and Dan Arbough, Director Corporate Finance and Treasurer, on June 30, 2003.
[20] Interview with Diana Wacker, Manager, PUHCA Compliance, on June 12, 2003.
[21] See the Management Practices Chapter for a description of incentive compensation programs.
[22] Response to DR BWG 1-6 (Service Level Agreements – Confidential).
[23] Based on multiple interviews.
[24] Response to DR BWG 3-47 and additional information from Carl Balderson, director of Internal Audit, provided on August 19, 2003.
[25] Interview with Richard Aitken-Davies, EVP and CFO, on June 30, 2003.
[26] Response to DR BWG 1-1.
[27] Response to DR BWG 1-2 (Confidential).
[28] Response to DR BWG 1-8.
[29] Response to DR BWG 1-2 (Confidential).
[30] Response to DR BWG 1-3 (Form U-13-60, Supplement).
[31] Presentation by John McCall, EVP, General Counsel, at the orientation meeting and repeated by others in multiple interviews thereafter.
[32] Interview with Chris Hermann, SVP, Energy Delivery, on May 13, 2003 and interview with John Gallagher on May 14, 2003.
[33] Response to DR BWG 1-10.
[34] Response to DR BWG 1-30 and interview with Paula Pottinger, VP, Human Resources, on May 13, 2003.
[35] Interview with Greg Meiman, Law department, on May 27, 2003.
[36] Response to DR BWG 2-46 (Confidential) and interview with Paula Pottinger, VP, Human Resources, on June 11, 2003.
[37] Response to DR BWG 5-81.
[38] Interview with Paula Pottinger, VP, Human Resources, on June 11, 2003.
[39] Interview with Howard Bush, Manager, Regulatory Compliance, on May 13, 2002.
[40] Interview with Mike Beer, VP, Rates and Regulatory Affairs, on April 25, 2003.
[41] Public Utility Finance & Accounting: A Reader, Second Edition, edited by Joel Berk and published by the Financial Accounting Institute in 1989.
[42] Interviews with Lynda Clark, Manager, Accounting and Financial Reporting, on May 13, 2003, and Glen French, Director, Financial Planning and Accounting, on May 12, 2003, and response to DR BWG 1-23 (Confidential).

[43] Interviews with Pam MacDonald, Energy Delivery Budgeting Team Leader, on May 29, 2003, Lynda Clark, Manager, Accounting and Financial Reporting, on May 13, 2003, and Glen French, Director, Financial Planning and Accounting, on May 12, 2003.
[44] Interview with Glen French, Director, Financial Planning and Accounting, on May 12, 2003.
[45] Response to DR BWG 1-21 (Confidential).
[46] Various interviews and response to DR BWG 1-21 (Confidential)
[47] Response to DR BWG 1-21 (Confidential).
[48] Response to DR BWG 1-21 (Confidential).
[49] Interview with Glen French, Director, Financial Planning and Accounting, on May 12, 2003, and Lynda Clark, Manager, Accounting and Financial Reporting, on May 13, 2003.
[50] Interview with Barry Walker, Gas Operations, on June 23, 2003.
[51] Interview with Glen French, Director, Financial Planning and Accounting, on May 12, 2003.
[52] Interview with Barry Walker, Gas Operations, on June 23, 2003.
[53] Interview with Pam McDonald, Energy Delivery Budgeting Team Leader, on May 29, 2003.
[54] Response to DR BWG 2-43.
[55] Interviews with various LG&E managers.
[56] Interviews with Denise Simon, Director, Asset Management, on June 10, 2003, and Gerald Skaggs, Manager, Property Accounting, on May 13, 2003.
[57] Response to DR BWG 1-22.
[58] Interview with Denise Simon, Director, Asset Management, on June 10, 2003.
[59] Response to DR 2-41 (Confidential).
[60] Capital Investment Approval Process Flowchart provided in response to DR BWG 2-39.
[61] 2000 – 2002 Investment Committee Minutes (DR 2-41 – Confidential).
[62] Interview with Greg Thomas, Director, Energy Delivery, on May 28, 2003, and response to DR BWG 4-71 (Confidential).
[63] Interview with Dave Vogel, VP, Energy Delivery Retail, on June 10, 2003, and response to DR BWG 2-41 (Confidential).
[64] Response to DR BWG 2-41 (Confidential).
[65] Interview with Glen French, Director, Financial Planning and Accounting, on May 12, 2003.
[66] Interview with Gerald Skaggs, Manager of Property Accounting, on May 13, 2003, and response to DR BWG 1-24.
[67] Interview with Gerald Skaggs, Manager of Property Accounting, on May 13, 2003. Confirmed by Brad Rives, SVP – Finance, on July 8, 2003.
[68] Interview with Scott Williams, Manager, Financial Reporting and Control, on May 27, 2003.
[69] Interview with Scott Williams, Manager, Financial Reporting and Control, on May 27, 2003.
[70] Interview with Gerald Skaggs, Manager, Property Accounting, on May 13, 2003.
[71] Interview with Scott Williams, Manager, Financial Reporting and Control, on May 27, 2003.
[72] Discussion with Scott Williams, Manager, Financial Reporting and Control, on July 17, 2003.
[73] Application of Kentucky Utilities Company for Approval of an Alternative Method of Regulation of Its Rates and Service (Case No. 98-474), p. 49.
[74] Joint Application for Transfer of Louisville Gas and Electric Company and Kentucky Utilities Company In Accordance With E.ON AG's Planned Acquisition of Powergen Plc, Case NO. 2001-104, Appendix A, pp. 7-9.
[75] Response to DR BWG 3-48.
[76] Interview with Martha Morton, KPSC Engineering Staff, on July 14, 2003.
[77] Interview with Barry Walker, Gas Operations, on June 23, 2003.
[78] Response to DR BWG 1-29.
[79] Interviews with Greg Thomas, Director, Energy Delivery, on May 28, 2003, and Dave Vogel / Greg Thomas on April 25, 2003.
[80] Interview with Barry Walker, Gas Operations, on June 23, 2003.
[81] Interview with Barry Walker, Gas Operations, on June 23, 2003.
[82] Response to DR BWG 6-88b.
[83] Response to DR BWG 1-29.
[84] Interview with Dave Vogel, VP, Energy Delivery Retail, on June 10, 2003.

85 Response to DR BWG 2-42.

86 Interview with Chris Hermann, SVP, Energy Delivery, on April 25, 2003.

87 Interview with Bill Wheeler, Manager, Forestry Services, on May 28, 2003.

88 Interviews with Bill Wheeler, Manager, Forestry Services, on May 28, 2003, Chris Hermann, SVP, Energy Delivery, on April 25, 2003, and Greg Thomas, Director, Energy Delivery, on May 28, 2003.

APPENDIX A

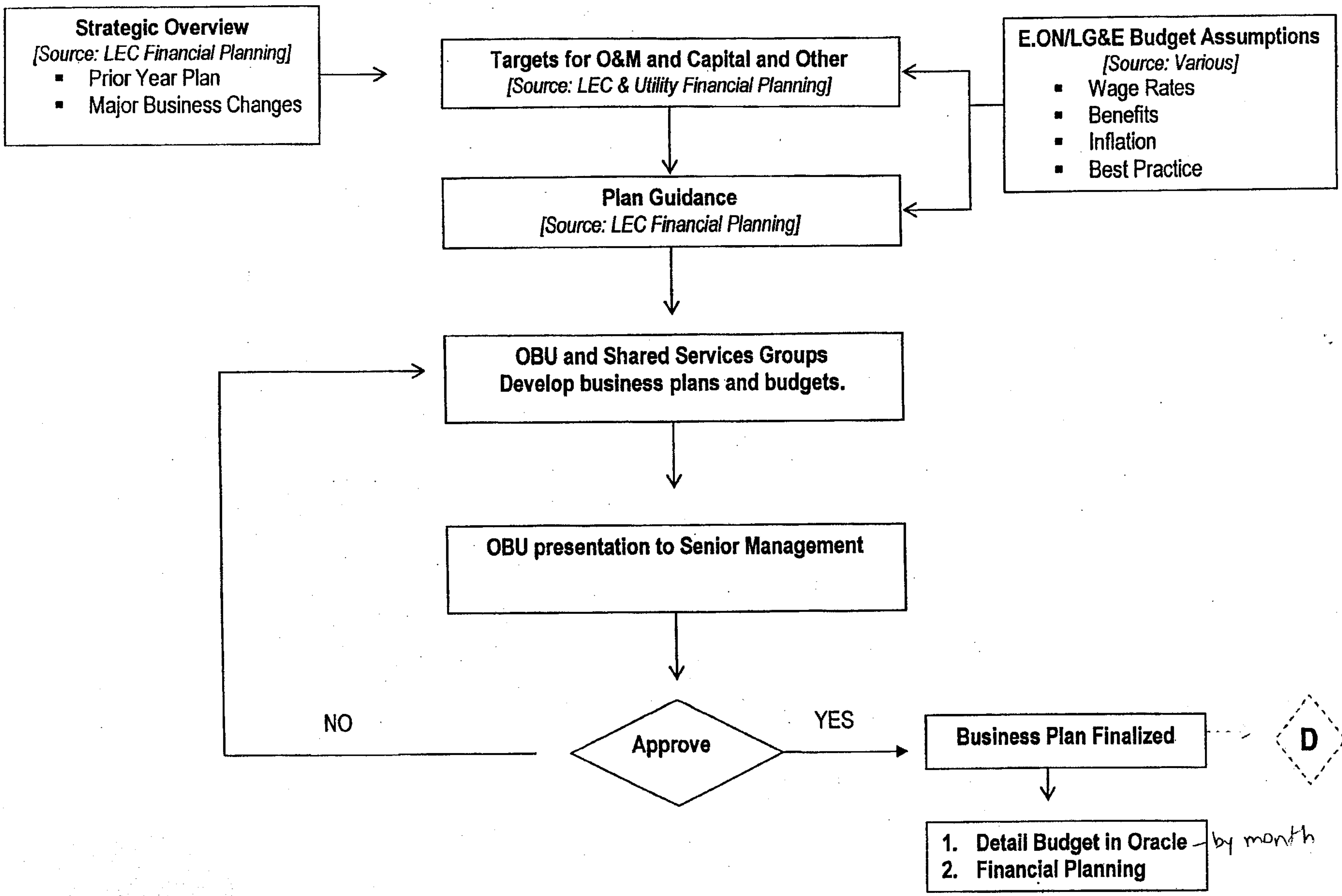
LISTING OF INDIVIDUALS INTERVIEWED

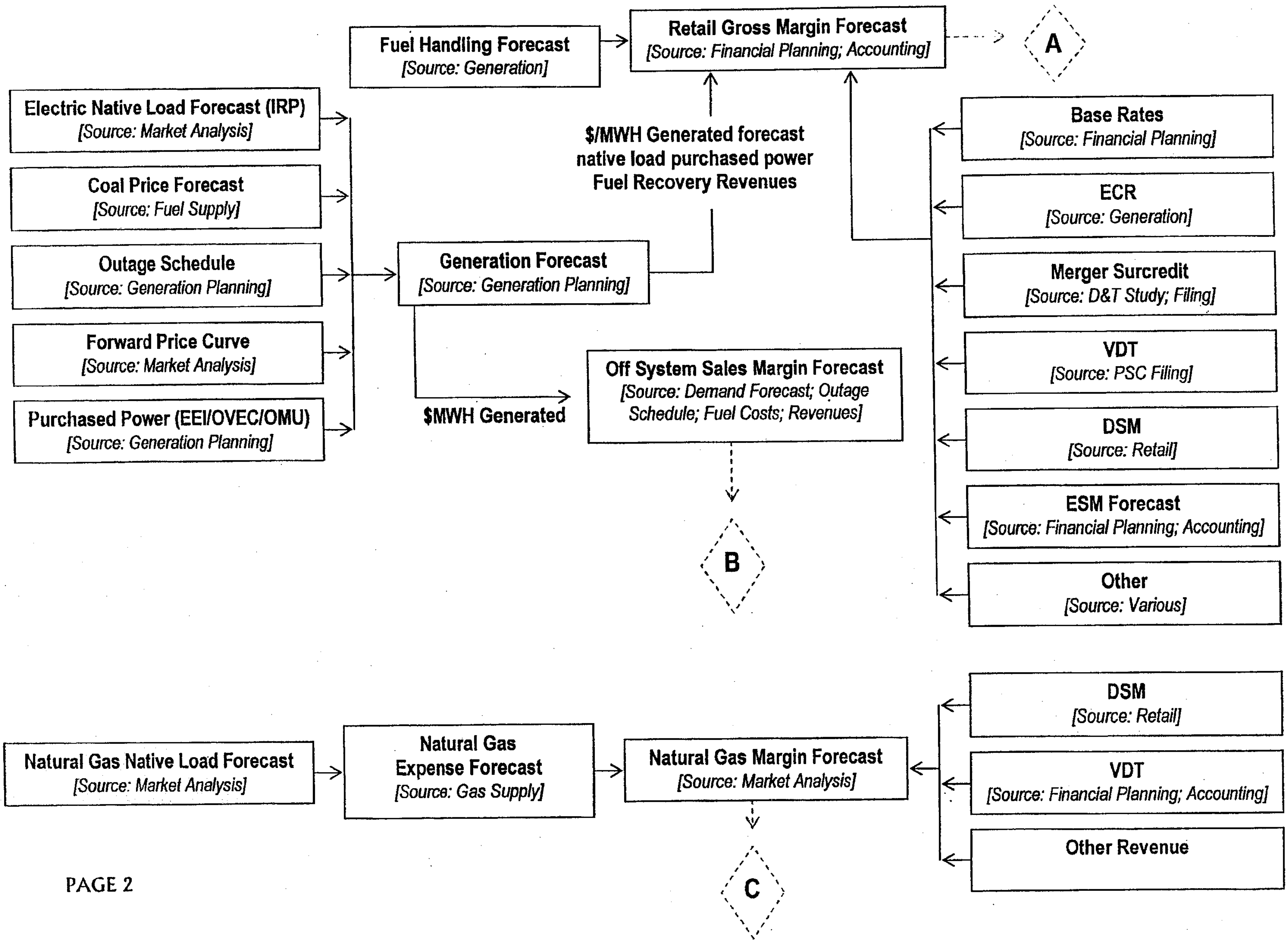
Indvidual Interviewed	Position	Date(s)
Richard Aitken-Davies	CFO	June 30
Dan Arbough	Director Corp. Finance and Treasurer	May 29 June 30 August 7
Carl Balderson	Director - Internal Auditing	May 12
Mike Beer	Vice President - Rates and Regulatory Affairs	April 25 May 28
Kent Blake	Director - Business Development	May 13
Howard Bush	Manager - Regulatory Compliance	May 13
Lynda Clark	Manager - Accounting and Financial Controls	May 13
Robert Conroy	Mgr Generation Planning	May 27
Carol Foxworthy	Sr. Rate Analyst	May 29
Glen French	Director - Financial Planning and Budgeting	May 12
John Gallagher	Director - Value Delivery Implementation	May 14
Robert Henriques	VP - Generation Services	June 25
Chris Hermann	SV - Energy Delivery	April 25 May 13
Roger Hickman	Senior Analyst, Regulatory Policy and Strategy	May 27
Rusty Hudson	Energy Services, Director Financial Planning and Analysis	May 27
Mark Johnson	Director, Transmission	August 6
Doug Leichty	Sr. Rate Analyst	May 15
John McCall	EVP, General Counsel	July 2
Pam McDonald	Team Leader, ED Budget and Financial Control	May 29
Greg Meiman	Senior Counsel	May 27
Ron Miller	Director - Corporate Tax	May 12
Marcelo Paciurek	Manager - Energy Delivery Budget Control	May 14
Caryl Pfeiffer	Director - Corporate Fuels and By-Products	April 25
Paula Pottinger	VP - Human Resources	May 13 June 11

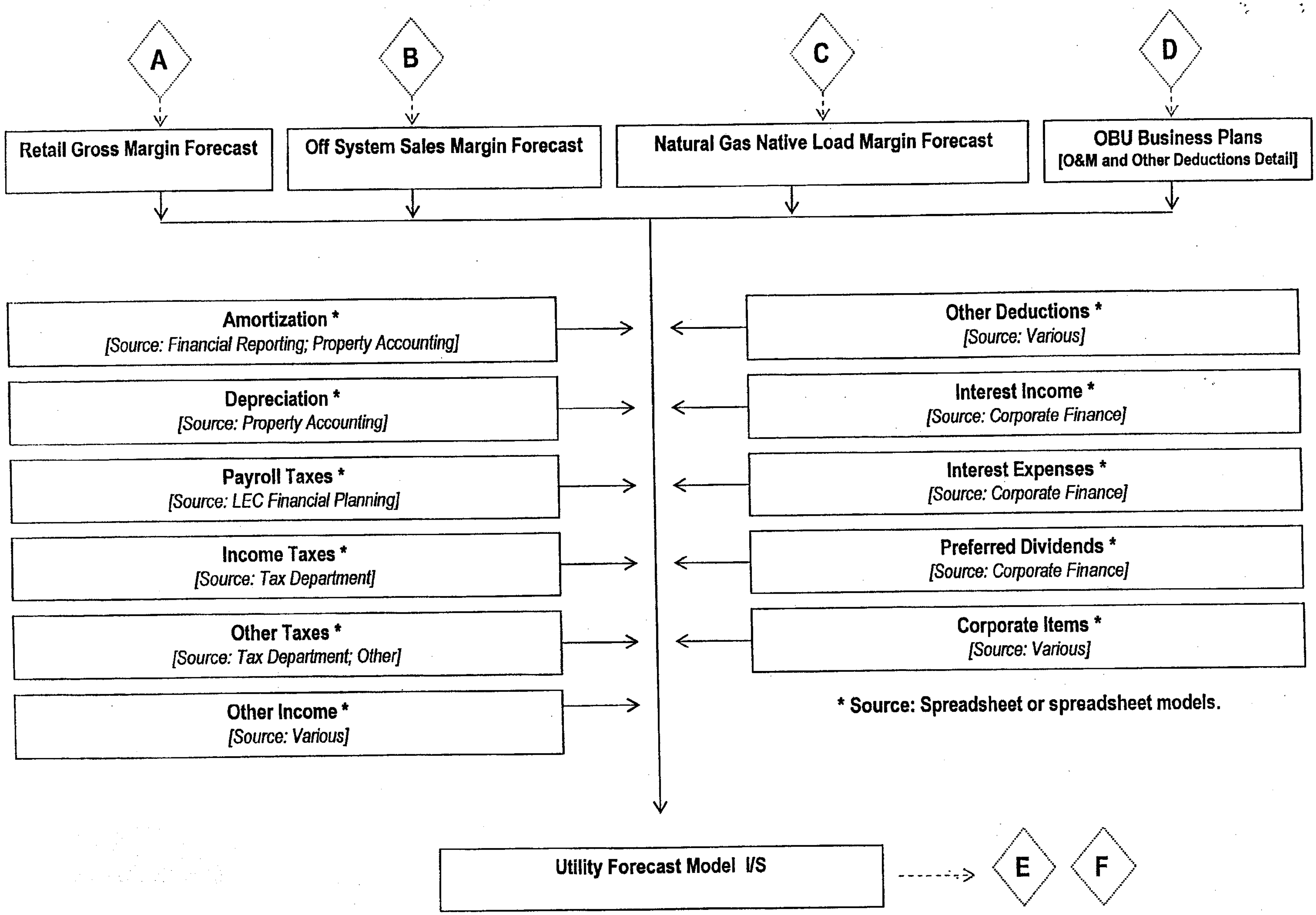
Indvidual Interviewed	Position	Date(s)
Chuck Schram	Manager Strategic Planning	May 14
Valerie Scott	Director - Financial Planning and Accounting (Utility Operations)	April 25 August 6
Denise Simon	Director, Asset Management	June 10 August 11
Gerald Skaggs	Manager - Property Accounting	May 13
Roger Smith	SVP Project Engineering	June 23
Vic Staffieri	CEO and President	June 30
Ed Staton	Mgr, Louisville Electric Operations	May 29
Brad Rives	SVP - Finance	June 25
Greg Thomas	Director, Energy Delivery	April 25 May 28 August 11
Paul Thompson	SVP Energy Services	June 11 June 25
Dave Vogel	VP - Retail Business and Gas Storage Operations	April 25 June 10 August 11
John Voyles	Director/VP, Generation Services	April 25 May 27 August 11
Diana Wacker	Mgr, PUHCA Compliance	June 12
Barry Walker	Gas Operations	June 23
Guntram Werzberg	E.ON Vice President of General Legal Affairs	June 12
Bill Wheeler	Manager, Forestry Services	May 28
Scott Williams	Manager - Financial Reporting and Control	May 15 May 27
John Wolfram	Manager - Regulatory Policy and Strategy	May 13

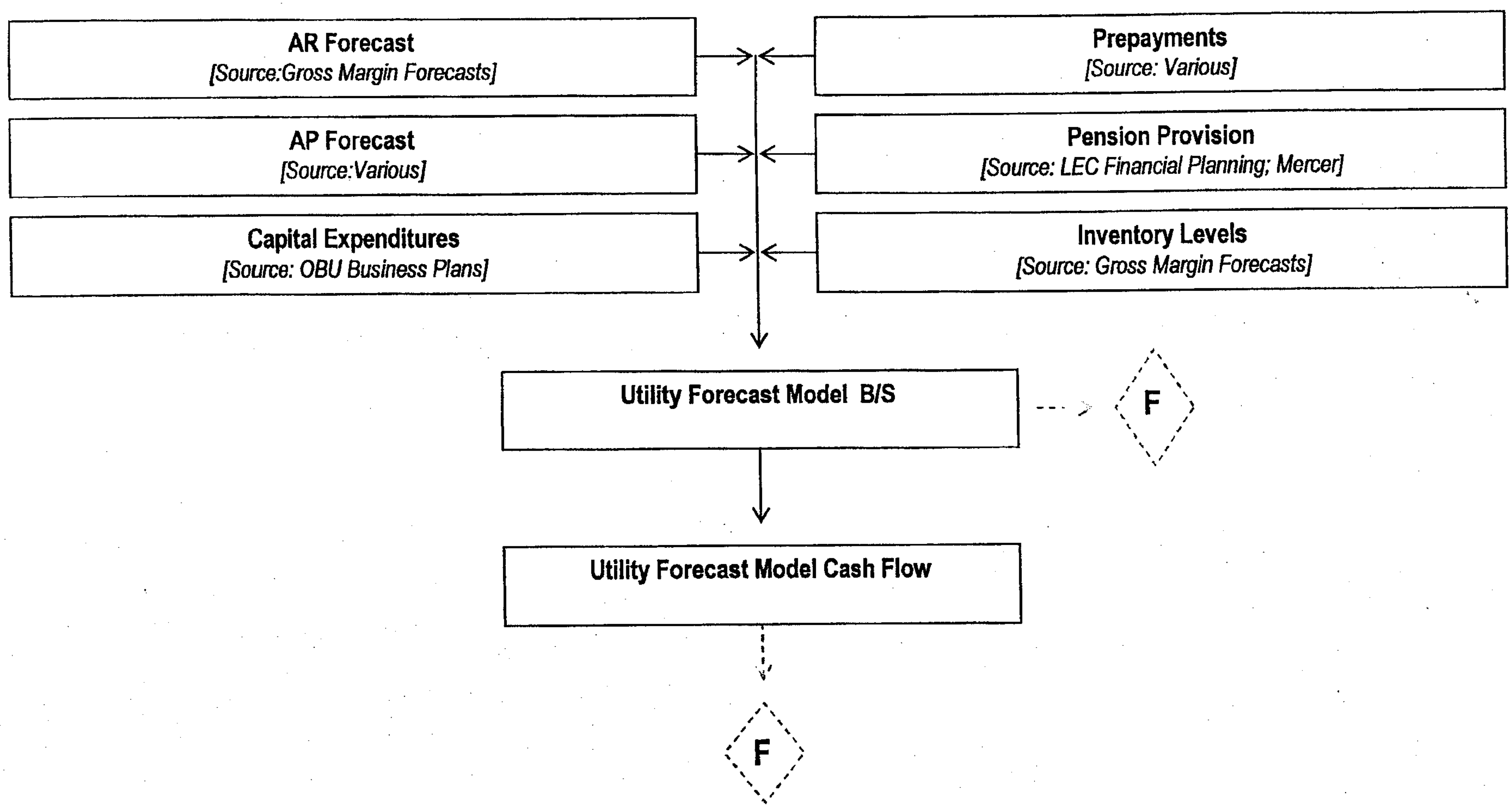
APPENDIX B

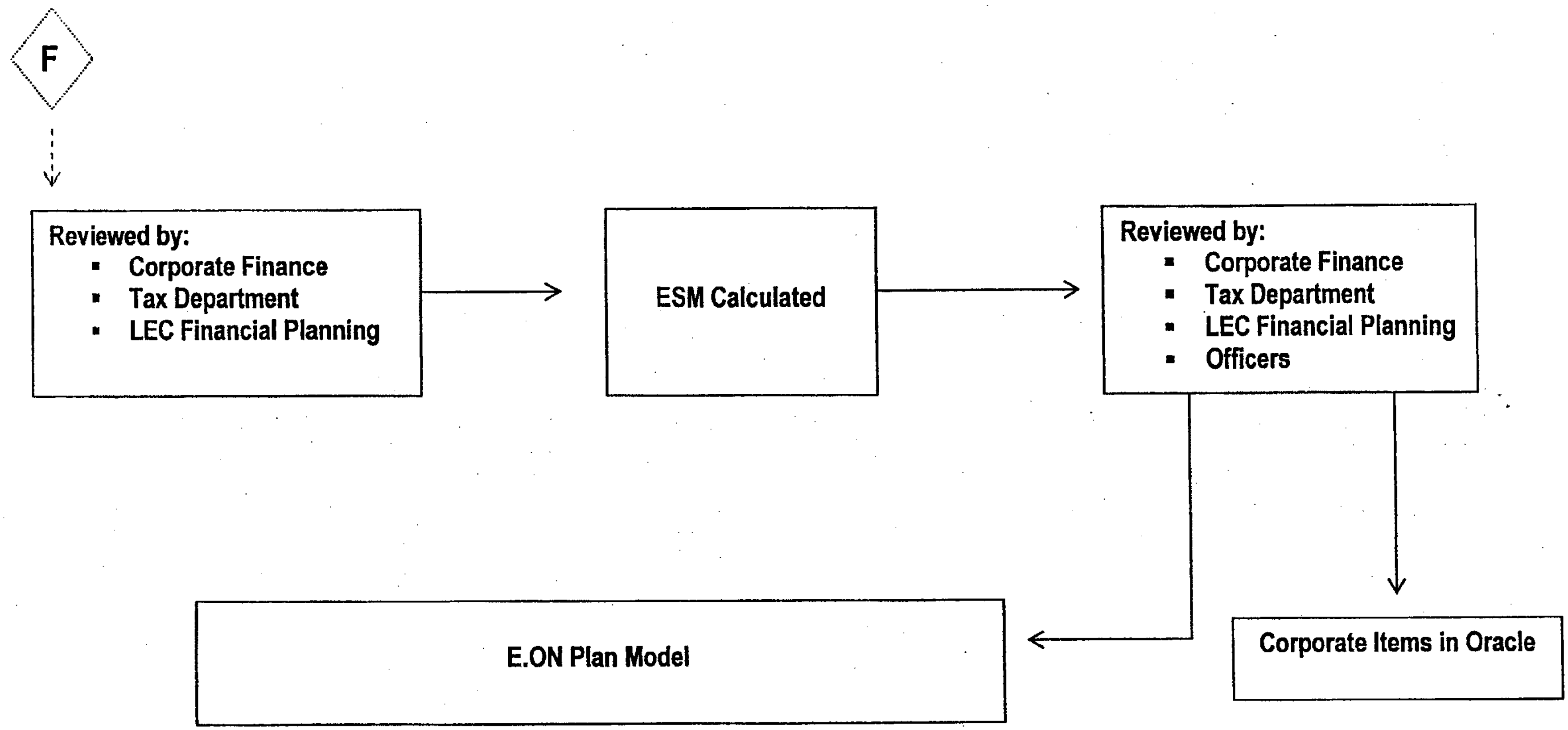
BUDGET PROCESS FLOWCHART


Strategic Overview
[Source: LEC Financial Planning]
Prior Year Plan
Major Business Changes
Targets for O&M and Capital and Other
[Source: LEC & Utility Financial Planning]
E.ON/LG&E Budget Assumptions
[Source: Various]
Wage Rates
Benefits
Inflation
Best Practice
Plan Guidance
[Source: LEC Financial Planning]
OBU and Shared Services Groups
Develop business plans and budgets.
OBU presentation to Senior Management
NO
Approve
YES
Business Plan Finalized
D
1. Detail Budget in Oracle
2. Financial Planning
by month


Fuel Handling Forecast
[Source: Generation]
Retail Gross Margin Forecast
[Source: Financial Planning; Accounting]
A
Electric Native Load Forecast (IRP)
[Source: Market Analysis]
Coal Price Forecast
[Source: Fuel Supply]
Outage Schedule
[Source: Generation Planning]
Forward Price Curve
[Source: Market Analysis]
Purchased Power (EEI/OVEC/OMU)
[Source: Generation Planning]
$/MWH Generated forecast
native load purchased power
Fuel Recovery Revenues
Generation Forecast
[Source: Generation Planning]
$MWH Generated
Off System Sales Margin Forecast
[Source: Demand Forecast; Outage Schedule; Fuel Costs; Revenues]
B
Base Rates
[Source: Financial Planning]
ECR
[Source: Generation]
Merger Surcredit
[Source: D&T Study; Filing]
VDT
[Source: PSC Filing]
DSM
[Source: Retail]
ESM Forecast
[Source: Financial Planning; Accounting]
Other
[Source: Various]
Natural Gas Native Load Forecast
[Source: Market Analysis]
Natural Gas
Expense Forecast
[Source: Gas Supply]
Natural Gas Margin Forecast
[Source: Market Analysis]
C
DSM
[Source: Retail]
VDT
[Source: Financial Planning; Accounting]
Other Revenue


A
B
C
D
Retail Gross Margin Forecast
Off System Sales Margin Forecast
Natural Gas Native Load Margin Forecast
OBU Business Plans
[O&M and Other Deductions Detail]
Amortization *
[Source: Financial Reporting; Property Accounting]
Depreciation *
[Source: Property Accounting]
Payroll Taxes *
[Source: LEC Financial Planning]
Income Taxes *
[Source: Tax Department]
Other Taxes *
[Source: Tax Department; Other]
Other Income *
[Source: Various]
Other Deductions *
[Source: Various]
Interest Income *
[Source: Corporate Finance]
Interest Expenses *
[Source: Corporate Finance]
Preferred Dividends *
[Source: Corporate Finance]
Corporate Items *
[Source: Various]
* Source: Spreadsheet or spreadsheet models.
Utility Forecast Model I/S
E
F

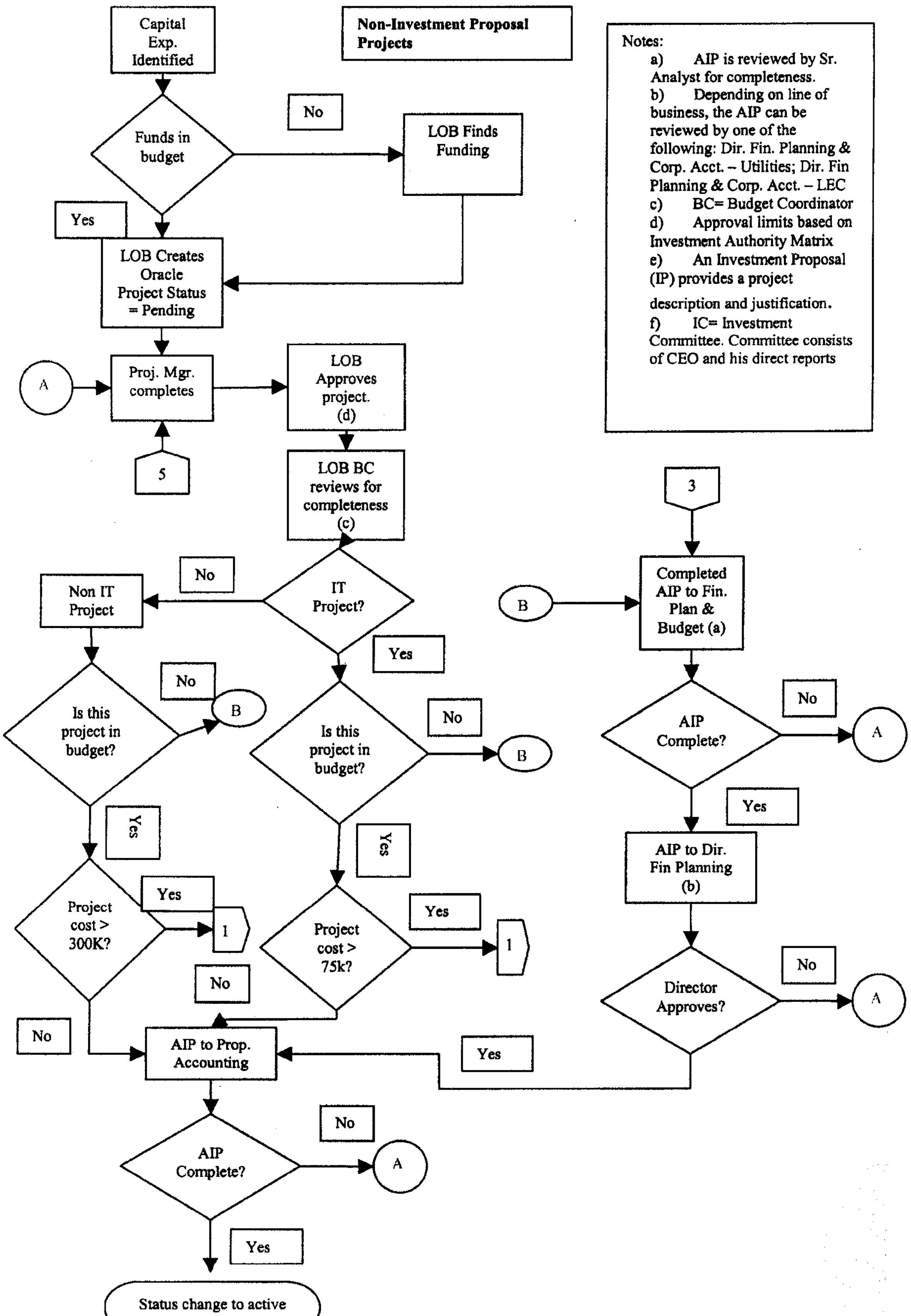

AR Forecast
[Source:Gross Margin Forecasts]
AP Forecast
[Source:Various]
Capital Expenditures
[Source: OBU Business Plans]
Prepayments
[Source: Various]
Pension Provision
[Source: LEC Financial Planning; Mercer]
Inventory Levels
[Source: Gross Margin Forecasts]
Utility Forecast Model B/S
F
Utility Forecast Model Cash Flow
F


F
Reviewed by:
Corporate Finance
Tax Department
LEC Financial Planning
ESM Calculated
Reviewed by:
Corporate Finance
Tax Department
LEC Financial Planning
Officers
E.ON Plan Model
Corporate Items in Oracle

APPENDIX C

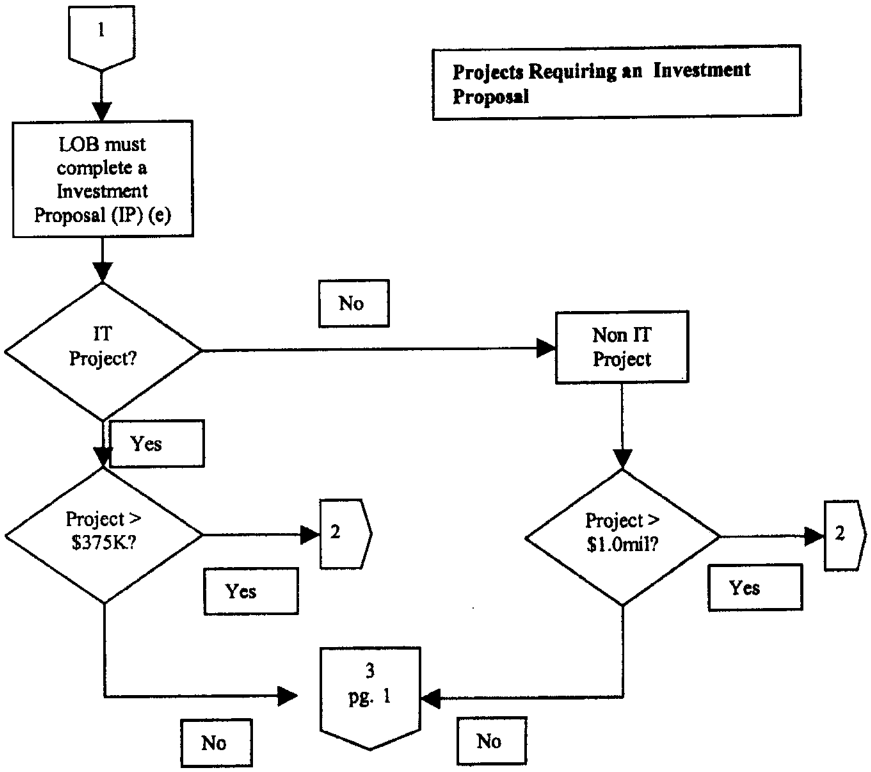
CAPITAL INVESTMENT APPROVAL PROCESS FLOWCHART

Capital Investment Approval Process

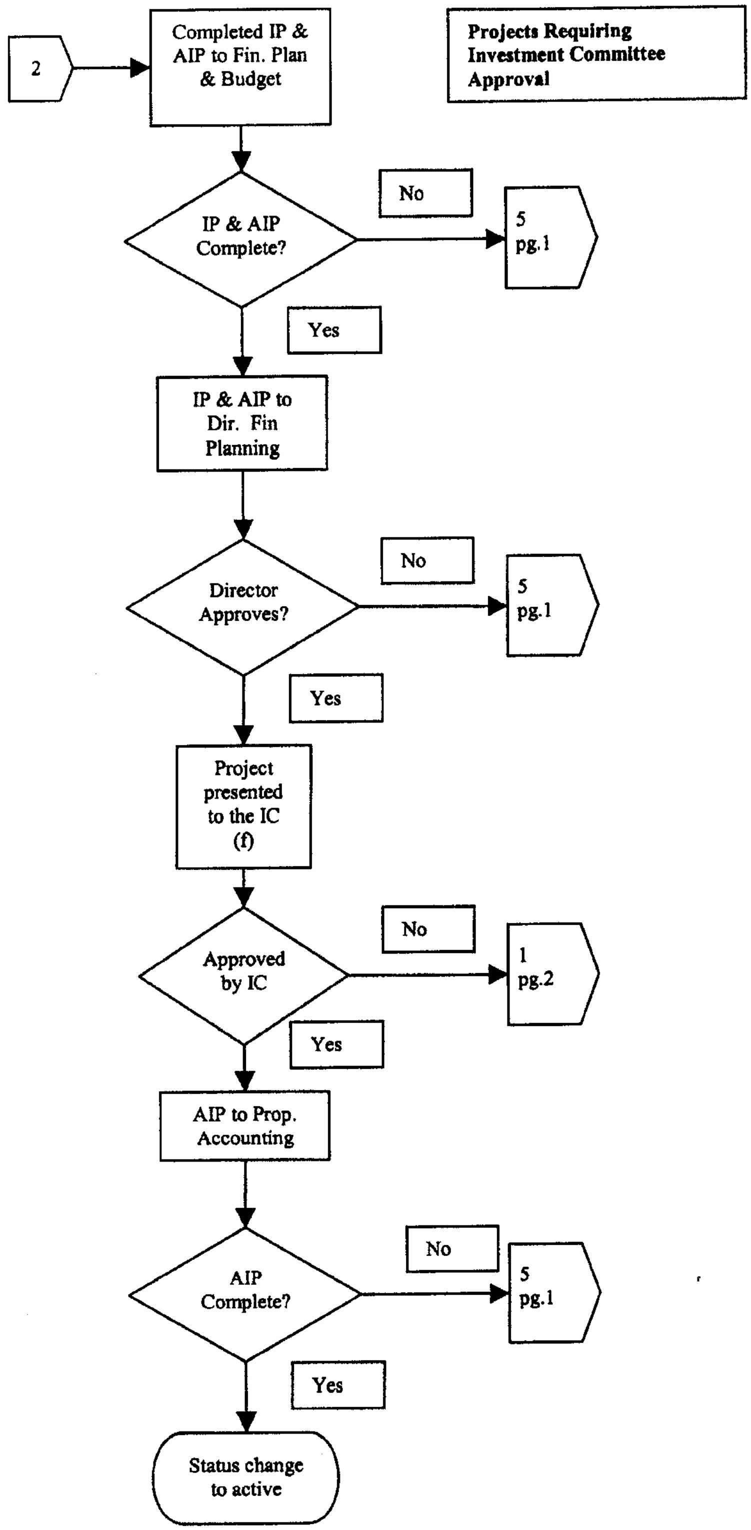


C:\WIN[illegible]4\Temporary Internet Files\OLK101\Utility Capital Expenditure Approval.doc

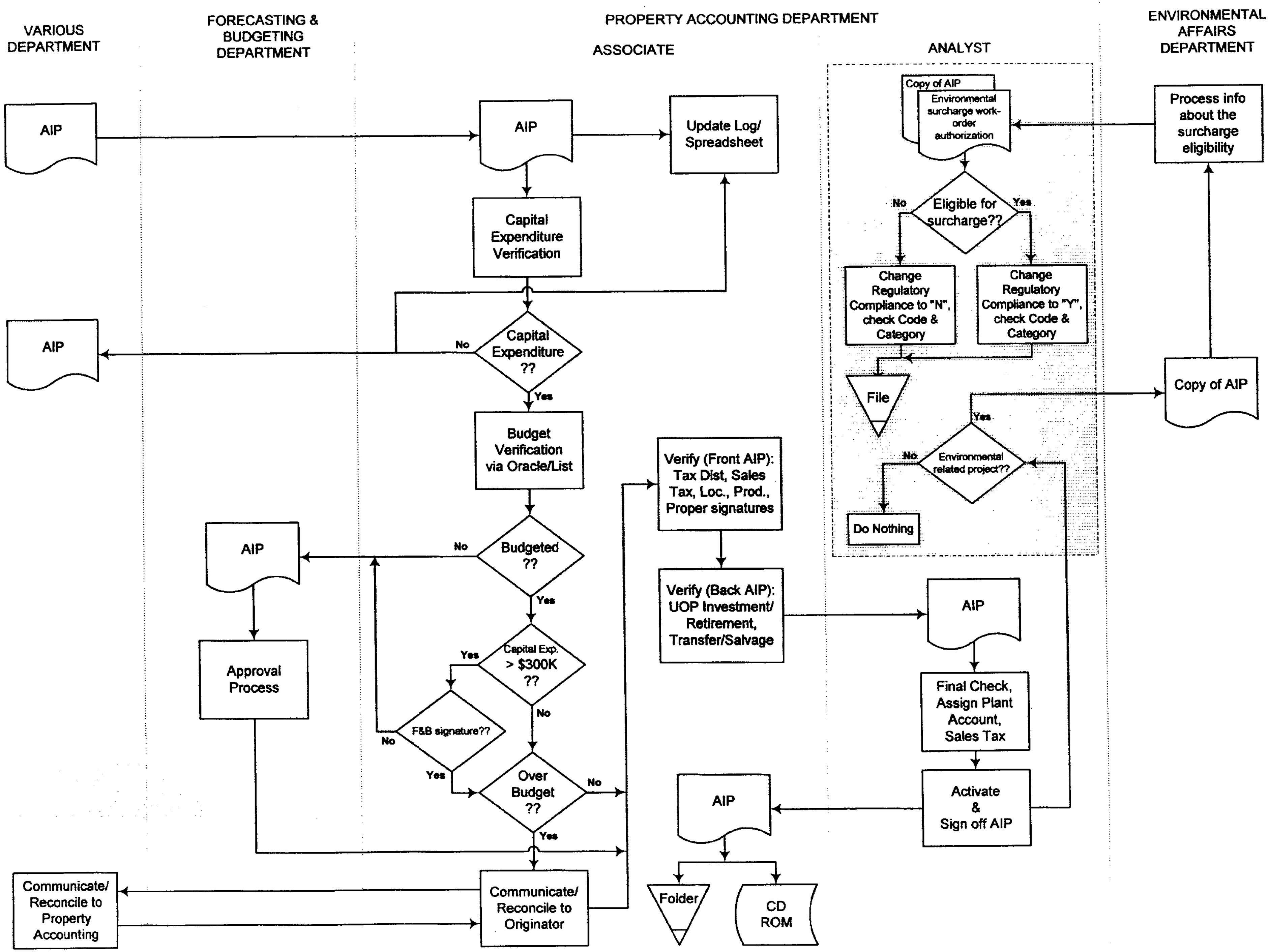
Capital Investment Approval Process



Capital Investment Approval Process



PROPERTY ACCOUNTING DEPARTMENT
AIP ACTIVATION and REVIEW PROCESS FLOW



Capital Asset Construction Process