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Jeff DeRouen, Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40602

September 23, 2011

RE: ***The Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery by Environmental Surcharge***
Case No. 2011-00161

Dear Mr. DeRouen:

Pursuant to the Commission's Order dated September 16, 2011 in the above-referenced matter, with this letter Kentucky Utilities Company's (KU) is filing one (1) original in paper format of the attachments to KU's response to the Commission Staff's First Information Request, Question Nos. 19(b), 32(h) and 32(i) dated July 12, 2011, previously provided in electronic format on July 25, 2011.

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

Sincerely,

Robert M. Conroy

cc: Parties of Record (w/o attachments)

In the Matter of:

THE APPLICATION OF KENTUCKY UTILITIES	)	CASE NO.
COMPANY FOR CERTIFICATES OF PUBLIC	)	
CONVENIENCE AND NECESSITY AND	)	2011-00161
APPROVAL OF ITS 2011 COMPLIANCE PLAN	)	
FOR RECOVERY BY ENVIRONMENTAL	)	
SURCHARGE	)	

Response to the Commission Staff's First Information Request dated July 12, 2011

One Paper Copy for Question Nos. 19(c) and 32(i)

Filed – September 23, 2011

KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request Dated July 12, 2011

Case No. 2011-00161

Question No. 19

Witness: Lonnie E. Bellar

Q-19. Refer to the Direct Testimony of Lonnie E. Bellar ("Bellar Testimony") at pages 10-12. In the final order in KU's most recent base rate case, at pages 26-31, there is discussion of testimony which supported return on equity ("ROE") estimates over a wide range for KU. The Commission found that KU's "required ROE for electric operations falls within a range of 9.75 to 10.75 percent with a midpoint of 10.25 percent." Pursuant to KRS 278.183(2)(b), the Commission must establish a reasonable return on capital expenditures for projects included in an environmental compliance plan.

a. Notwithstanding that the parties in Case No. 2009-00548, with the exception of the Attorney General, signed settlement agreeing to an ROE of 10.63 percent, explain why a 10.63 percent ROE is appropriate on a going forward basis.

b. Provide all economic analyses performed by or for KU that demonstrate a ROE of 10.63 percent is reasonable based on current economic conditions.

c. If it is appropriate for the Commission to consider the 10.63 percent ROE established in KU's last rate case, and in the absence of any new testimony addressing the derivation of ROE estimates, explain why it would not be appropriate to consider the ROE testimony also.

d. Provide all support for the position that the Commission's decision in KU's last rate case to accept a 10.63 percent ROE for environmental cost recovery obligates the Commission to now adopt that same ROE for a new environmental compliance plan absent a showing that a 10.63 percent ROE is now reasonable.

A-19. a. The 10.63 percent ROE, as agreed to by the eight signatories to the Stipulation in Case No. 2009-00548, is appropriate and reasonable on a going-forward basis. First, the 10.63 percent not only falls within the ROE for electric operations set forth in the Stipulation (10.25% to 10.75%), but likewise falls within the range set forth in the Commission's Order of July 30, 2010 (9.75% to 10.75%). Second, while the Commission issued independent findings that varied from certain terms in the Stipulation, the Commission approved the provisions in the Stipulation containing the 10.63% ROE for ECR purposes "in their entirety." Moreover, KU currently has a pending rate case in Virginia (PUE-2011-00013) in which it has requested a ROE of 11.0 percent, the midpoint of 10.5% and 11.5%. The requested ROE in that

BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA

Application of:

KENTUCKY UTILITIES COMPANY	)	
D/B/A/ OLD DOMINION POWER COMPANY	)	
	)	CASE NO. PUE-2011-00013
For an Adjustment of Electric Base Rates	)	

DIRECT TESTIMONY OF
WILLIAM E. AVERA

FOR KENTUCKY UTILITIES COMPANY
D/B/A OLD DOMINION POWER COMPANY

FINCAP, Inc.
Financial Concepts and Applications, Inc.
3907 Red River
Austin, Texas 78751

Filed: April 1, 2011

COMMONWEALTH OF VIRGINIA
BEFORE THE
STATE CORPORATION COMMISSION

DIRECT TESTIMONY OFWILLIAM E. AVERA

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DIRECT TESTIMONY OF
WILLIAM E. AVERA
FOR KENTUCKY UTILITIES COMPANY
D/B/A OLD DOMINION POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUE-2011-______

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am the President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

A. Overview

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present to the Virginia State Corporation Commission ("SCC" or the "Commission") my assessment of the fair rate of return on common equity ("ROE") for the jurisdictional electric utility operations of Kentucky Utilities Company d/b/a Old Dominion Power Company ("KU/ODP" or the "Company"). In addition, I also examined the reasonableness of the Company's capital structure, considering both the specific risks faced by the Company and other industry guidelines.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Exhibit WEA-1.

Q. PLEASE SUMMARIZE THE INFORMATION AND MATERIALS YOU RELIED ON TO SUPPORT THE OPINIONS AND CONCLUSIONS CONTAINED IN YOUR TESTIMONY.

A. I am familiar with the organization, finances, and operations of the Company from my participation in prior proceedings before the SCC, Kentucky Public Service Commission ("KPSC") and the Federal Energy Regulatory Commission ("FERC"). In connection with the present filing, I considered and relied upon corporate disclosures, publicly available financial reports and filings, and other published information relating to KU/ODP. I also reviewed information relating generally to current capital market conditions and specifically to current investor perceptions, requirements, and expectations for the Company. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required return for KU/ODP, and they form the basis of my analyses and conclusions.

Q. WHAT IS THE PRACTICAL TEST OF THE REASONABLENESS OF THE ROE USED IN SETTING A UTILITY'S RATES?

A. The ROE compensates common equity investors for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield*[1] and *Hope*[2] cases, a utility's allowed ROE should be sufficient to: (1) fairly compensate investors for

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[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

capital invested in the utility, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

Q. **HOW IS YOUR TESTIMONY ORGANIZED?**

A. I first reviewed the operations and finances of KU/ODP and the general conditions in the electric utility industry and the capital markets. With this as a background, I conducted various well-accepted quantitative analyses to estimate the current cost of equity, including alternative applications of the discounted cash flow ("DCF") model and the Capital Asset Pricing Model ("CAPM"), and also made reference to expected earned rates of return for utilities. Based on the cost of equity estimates indicated by my analyses, the Company's ROE was evaluated taking into account the specific risks and potential challenges for its jurisdictional electric utility operations in Virginia, as well as other factors (*e.g.*, flotation costs) that are properly considered in setting a fair rate of return on equity.

B. Summary of Conclusions

Q. **WHAT ARE YOUR FINDINGS REGARDING THE FAIR RATE OF RETURN ON EQUITY FOR KU/ODP?**

A. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital, I recommend an ROE for KU/ODP from the middle of my 10.5 percent to 11.5 percent reasonable range, or 11.0 percent. The bases for my conclusion are summarized below:

- In order to reflect the risks and prospects associated with KU/ODP's jurisdictional utility operations, my analyses focused on a proxy group of other electric utilities with comparable investment risks. Consistent with the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of comparable risk companies in the non-utility sector of the economy;

- Because investors' required return on equity is unobservable and no single method should be viewed in isolation, I applied both the DCF and CAPM methods, as well as the expected earnings approach, to estimate a fair ROE;
- Based on the results of these analyses, and giving less weight to extremes at the high and low ends of the range, I concluded that the cost of equity for the proxy groups of utilities and non-utility companies is in the 10.3 percent to 11.3 percent range, or 10.5 percent to 11.5 percent after incorporating a minimal adjustment to account for the impact of common equity flotation costs;
- The reasonableness of an 11.0 percent ROE for KU/ODP is also supported by the exposures associated with environmental mandates, the need to consider the expected upward trend in capital costs, and the need to support access to capital; and,
- While the Company is exempt from the provisions of the Virginia Electric Restructuring Act, my recommended ROE range encompasses the benchmark earned rate of return threshold produced using the methodology established by the Code of Virginia, and falls well below the 14.1 percent upper bound implied by this guideline.

Q. WHAT OTHER EVIDENCE DID YOU CONSIDER IN EVALUATING YOUR ROE RECOMMENDATION IN THIS CASE?

A. My recommendation was reinforced by the following findings:

- Sensitivity to financial market and regulatory uncertainties has increased dramatically and investors recognize that constructive regulation is a key ingredient in supporting utility credit standing and financial integrity; and,
- Providing KU/ODP with the opportunity to earn a return that reflects these realities is an essential ingredient to support the Company's financial position, which ultimately benefits customers by ensuring reliable service at lower long-run costs.

II. FUNDAMENTAL ANALYSES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. As a predicate to subsequent quantitative analyses, this section briefly reviews the operations and finances of KU/ODP. In addition, it examines the risks and prospects for the electric utility industry and conditions in the capital markets and the general economy. An understanding of the fundamental factors driving the risks and prospects of electric utilities is essential in developing an informed opinion of investors' expectations and requirements that are the basis of a fair rate of return.

A. Operations and Finances of KU/ODP

Q. BRIEFLY DESCRIBE KU/ODP AND ITS ELECTRIC UTILITY OPERATIONS.

A. Along with Louisville Gas and Electric Company ("LGE"), KU/ODP is a wholly owned subsidiary of PPL Corporation ("PPL"), which completed its acquisition of the Company from E.ON AG on November 1, 2010. Headquartered in Lexington, Kentucky, KU/ODP is principally engaged in providing regulated electric utility service. In addition to serving approximately 30,000 Virginia customers in Wise, Lee, Russell, Scott, and Dickinson Counties, KU/ODP provides service to over 514,000 retail customers in central, southeastern, and western Kentucky.[3]

Although KU/ODP and LGE are separate operating subsidiaries, they are operated as a single, fully integrated system. Together, KU/ODP's and LGE's utility facilities include over 7,600 megawatts ("MW") of generating capacity, with coal-fired generating stations accounting for approximately 71 percent of this total and 98 percent of the electricity generated by KU/ODP.[4] In addition to company-owned generation, the Company purchases power under a long-term contract and meets a portion of its energy needs by purchases of additional

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[3] KU/ODP also serves less than ten customers in Tennessee.

[4] KU/ODP's total generating capacity is approximately 4,417 MW. These statistics exclude KU/ODP's and LGE's combined 570 MW interest in Trimble County Unit 2.

supplies in the wholesale electricity markets. KU/ODP's transmission and distribution system includes over 22,000 miles of lines. At year-end 2010, the Company had total assets of $4.9 billion, with total revenues of approximately $1.5 billion. KU/ODP is a member of the Southeastern Electric Reliability Council, Inc. and transmission service is available on the Company's system under its own regional Open Access Transmission Tariff. KU/ODP's retail electric operations are subject to the jurisdiction of the SCC and the KPSC. The FERC regulates the Company's interstate transmission and wholesale operations.

Q. IS KU/ODP SUBJECT TO THE REQUIREMENTS OF THE VIRGINIA ELECTRIC RESTRUCTURING ACT?

A. No. When initially approved in 1999, the Virginia Electric Utility Restructuring Act ("Restructuring Act") gave customers the ability to choose their electric supplier and capped electric rates through December 2010. The Company subsequently received a legislative exemption from the customer choice requirements of this law. The Restructuring Act was subsequently amended to terminate customer choice and re-institute regulation of utility rates. As of January 2009, a hybrid model of regulation is being applied in Virginia, which provides for biennial rate reviews. Because of the Company's original exemption from the requirements of the Restructuring Act, it is not subject to this process. In lieu of submitting an annual information filing, KU/ODP has the option of requesting a change in base rates to recover prudently incurred costs by filing a traditional base rate case, as it has done in this proceeding.

Q. PLEASE DESCRIBE PPL.

A. Headquartered in Allentown, Pennsylvania, PPL owns or controls approximately 19,000 MW of generating capacity in the northeastern, northwestern and southeastern U.S., markets wholesale or retail energy primarily in northeastern and northwestern portions of the U.S., and delivers electricity and natural gas to approximately 5.3 million customers in the U.S. and the United Kingdom. During 2010, PPL's revenues totaled approximately $8.5 billion, with total assets at year-end of $32.8 billion.

Q. WHERE DOES KU/ODP OBTAIN THE CAPITAL USED TO FINANCE ITS INVESTMENT IN ELECTRIC UTILITY PLANT?

A. As a wholly-owned subsidiary, common equity capital provided by investors is obtained solely from the Company's ultimate parent, whose common stock is publicly traded on the New York Stock Exchange. In addition to capital supplied by PPL, KU/ODP also issues debt securities directly under its own name.

Q. WHAT CREDIT RATINGS ARE ASSIGNED TO KU/ODP?

A. Currently, KU/ODP is assigned a corporate credit rating of "BBB" by Standard & Poor's Corporation ("S&P").[5] Moody's Investors Service ("Moody's") has assigned the Company an issuer rating of "Baa1" and Fitch Ratings Ltd. ("Fitch") has assigned KU/ODP a "A-" issuer default rating.

B. Risks for KU/ODP

Q. HOW HAVE INVESTORS' RISK PERCEPTIONS FOR THE UTILITY INDUSTRY EVOLVED?

A. Implementation of structural change, along with other factors impacting the economy and the industry, has caused investors to rethink their assessment of the relative risks associated with utilities. The past decade witnessed steady erosion in credit quality throughout the utility industry, both as a result of revised

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[5] KU/ODP remains on CreditWatch "Negative" by S&P. Standard & Poor's Corporation," Research Update: PPL Corp. Is Lowered To 'BBB' And Placed On CreditWatch Negative After Acquisition Announcement," *RatingsDirect* (Mar. 2, 2011).

perceptions of the risks in the industry and the weakened finances of the utilities themselves. In December 2009, S&P observed with respect to the industry's future that:

> Looming costs associated with environmental compliance, slack demand caused by economic weakness, the potential for permanent demand destruction caused by changes in consumer behavior and closing of manufacturing facilities, and numerous regulatory filings seeking recovery of costs are some of the significant challenges the industry has to deal with.[6]

More recently, Moody's concluded:

> [A] sustained period of sluggish economic growth, characterized by high unemployment, could stress the sector's recovery prospects, financial performance, and credit ratings. The quality of the sector's cash flows are already showing signs of decline, partly because of higher operating costs and investments.[7]

Q. DOES THE COMPANY ANTICIPATE THE NEED FOR ADDITIONAL CAPITAL GOING FORWARD?

A. Yes. KU/ODP will require capital investment to provide for necessary maintenance and replacements of its utility infrastructure, as well as to fund new investment in electric generation, transmission and distribution facilities. Together, construction expenditures at KU/ODP and LGE are anticipated to average approximately $1.0 billion annually over the next three years, with Moody's noting that "[e]volving environmental regulations could substantially increase the level of capital expenditures above the amounts currently expected."[8] In addition, KU/ODP must refinance scheduled maturities of $250 million in

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[6] Standard & Poor's Corporation, "U.S. Regulated Electric Utilities Head Into 2010 With Familiar Concerns," *RatingsDirect* (Dec. 28, 2009).

[7] Moody's Investors Service, "U.S. Electric Utilities: Uncertain Times Ahead; Strengthening Balance Sheets Now Would Protect Credit," *Special Comment* (Oct. 28, 2010).

[8] Moody's Investors Service, "Credit Opinion: Kentucky Utilities Co.," *Global Credit Research* (Nov. 1, 2010).

2015. Support for KU/ODP's financial integrity and flexibility will be instrumental in attracting the capital required to meet these fund needs in an effective manner.

Q. IS THE POTENTIAL FOR ENERGY MARKET VOLATILITY AN ONGOING CONCERN FOR INVESTORS?

A. Yes. In recent years utilities and their customers have had to contend with dramatic fluctuations in fuel costs due to ongoing price volatility in the spot markets, and investors recognize the potential for further turmoil in energy markets. In times of extreme volatility, utilities can quickly find themselves in a significant under-recovery position with respect to power costs, which can severely stress liquidity. Coal has historically provided relative stability with respect to fuel costs, but prices experienced significant volatility over the 2007 – 2009 time period. The power industry and its customers have also had to contend with dramatic fluctuations in gas costs due to ongoing price volatility in the spot markets.

While current expectations for significantly lower power prices reflect weaker fundamentals affecting current load and fuel prices, investors recognize the potential that such trends could quickly reverse. For example, heightened uncertainties in the Middle East have led to sharp increases in petroleum prices, and the potential ramifications of the Japanese nuclear crisis on the future cost and availability of nuclear generation in the U.S. have not been lost on investors. S&P observed that "short-term price volatility from numerous possibilities … is always possible,"[9] while Moody's concluded that utilities remain exposed to fluctuations in energy prices, observing, "This view, that commodity prices

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[9] Standard & Poor's Corporation, "Top 10 Investor Questions: U.S. Regulated Electric Utilities," *RatingsDirect* (Jan. 22, 2010).

remain low, could easily be proved incorrect, due to the evidence of historical volatility."[10]

Q. DON'T THE SCC'S ADJUSTMENT MECHANISMS PROTECT KU/ODP FROM EXPOSURE TO FLUCTUATIONS IN POWER SUPPLY COSTS?

A. To a limited extent, yes. The investment community views KU/ODP's ability to periodically adjust retail rates to accommodate fluctuations in fuel and purchased power as an important source of support for KU/ODP's financial integrity. Nevertheless, investors also recognize that there can be a lag between the time KU/ODP actually incurs the expenditure and when it is recovered from ratepayers. As a result, KU/ODP is not insulated from the need to finance deferred power production and supply costs. Indeed, despite the significant investment of resources to manage fuel procurement, investors are aware that the best that KU/ODP can do is to recover its actual costs. In other words, KU/ODP earns no return on fuel costs and is exposed to disallowances for imprudence in its fuel procurement.

Q. WHAT OTHER FINANCIAL PRESSURES IMPACT INVESTORS' RISK ASSESSMENT OF THE COMPANY?

A. Investors are aware of the financial and regulatory pressures faced by utilities associated with rising costs and the need to undertake significant capital investments. S&P noted that cost increases and capital projects, along with uncertain load growth, were a significant challenge to the utility industry.[11] As Moody's observed:

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[10] Moody's Investors Service, "U.S. Electric Utilities: Uncertain Times Ahead; Strengthening Balance Sheets Now Would Protect Credit," *Special Comment* (Oct. 28, 2010).

[11] Standard & Poor's Corporation, "Industry Economic And Ratings Outlook," *RatingsDirect* (Feb. 2, 2010).

> [W]e also see the sector's overall business risk and operating risks increasing, owing primarily to rising costs associated with upgrading and expanding the nation's trillion dollar electric infrastructure.[12]

As noted earlier, investors anticipate that KU/ODP will undertake significant electric utility capital expenditures. While providing the infrastructure necessary to meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on KU/ODP.

Q. ARE ENVIRONMENTAL CONSIDERATIONS ALSO AFFECTING INVESTORS' EVALUATION OF ELECTRIC UTILITIES, INCLUDING KU/ODP?

A. Yes. Although KU/ODP's exposure is moderated through an environmental cost recovery mechanism ("ECR") in Kentucky, utilities are confronting increased environmental pressures that could impose significant uncertainties and costs.[13] Moody's noted that "the prospect for new environmental emission legislation – particularly concerning carbon dioxide – represents the biggest emerging issue for electric utilities."[14] While the momentum for carbon emissions legislation has slowed, expectations for eventual regulations continue to pose uncertainty. Fitch recently concluded, "Prospects of costly environmental regulations will create uncertainty for investors in the electricity business in 2011."[15] With respect to KU/ODP, Moody's concluded:

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[12] Moody's Investors Service, "Regulation Provides Stability As Risks Mount," *Industry Outlook* (Jan. 19, 2011).

[13] Unlike other utilities operating in Virginia, the Company does not operate under an environmental cost recovery factor.

[14] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities," *Industry Outlook* (Jan. 2009).

[15] Fitch Ratings Ltd., "2011 Outlook: U.S. Utilities, Power, and Gas," *Global Power North America Special Report* (Dec. 20, 2010)

> Coal-fired baseload generation provides a competitive cost structure but exposes KU to potential future regulation or policies aimed at reducing coal based emissions.[16]

C. Impact of Capital Market Conditions

Q. WHAT ARE THE IMPLICATIONS OF RECENT CAPITAL MARKET CONDITIONS?

A. The deep financial and real estate crisis that the country experienced in late 2008, and continuing into 2009 led to unprecedented price fluctuations in the capital markets as investors dramatically revised their risk perceptions and required returns. As a result of investors' trepidation to commit capital, stock prices declined sharply while the yields on corporate bonds experienced a dramatic increase.

With respect to utilities specifically, as of December 2010, the Dow Jones Utility Average stock index remained approximately 25 percent below the previous high reached in May 2008. This prolonged sell-off in common stocks and sharp fluctuations in utility bond yields reflect the fact that the utility industry is not immune to the impact of financial market turmoil and the ongoing economic downturn. As the Edison Electric Institute ("EEI") noted in a letter to congressional representatives in September 2008 as the financial crisis intensified, capital market uncertainties have serious implications for utilities and their customers:

> In the wake of the continuing upheaval on Wall Street, capital markets are all but immobilized, and short-term borrowing costs to utilities have already increased substantially. If the financial crisis is not resolved quickly, financial pressures on utilities will intensify

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[16] Moody's Investors Service, "Credit Opinion: Kentucky Utilities Co.," *Global Credit Research* (Nov. 1, 2010).

> sharply, resulting in higher costs to our customers and, ultimately, could compromise service reliability.[17]

Similarly, an October 1, 2008 *Wall Street Journal* report confirmed that utilities had been forced to delay borrowing or pursue more costly alternatives to raise funds.[18] In December 2008, Fitch confirmed "sharp repricing of and aversion to risk in the investment community," and noted that the disruptions in financial markets and the fundamental shift in investors' risk perceptions had increased the cost of capital for utilities.[19]

While conditions have improved significantly since the depths of the crisis, investors have nonetheless had to confront ongoing fluctuations in share prices and stress in the credit markets. As the Wall Street Journal noted in February 2010:

> Stocks pulled out of a 167-point hole with a late rally Friday, capping a wild week reminiscent of the most volatile days of the credit crisis. ... It was a return to the unusual relationships, or correlations, seen at major flash points over the past two years when investors fled risky assets and jumped into safe havens. This market behavior, which has reasserted itself repeatedly since the financial crisis began, suggests that investment decisions are still being driven more by government support and liquidity concerns than market fundamentals.[20]

In response to renewed capital market uncertainties initiated by unrest in the Middle East, ongoing concerns over the European sovereign debt crisis, and questions over the sustainability of economic growth, investors have repeatedly

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[17] *Letter to House of Representatives*, Thomas R. Kuhn, President, Edison Electric Institute (Sep. 24, 2008).

[18] Smith, Rebecca, "Corporate News: Utilities' Plans Hit by Credit Markets," *Wall Street Journal* at B4 (Oct. 1, 2008).

[19] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22. 2008).

[20] Gongloff, Mark, "Stock Rebound Is a Crisis Flashback – Late Surge Recalls Market's Volatility at Peak of Credit Difficulties; Unusual Correlations," *Wall Street Journal* at B1 (Feb. 6, 2010).

fled to the safety of U.S. Treasury bonds, and stock prices have experienced renewed volatility.[21] The dramatic rise in the price of gold and other commodities also attests to investors' heightened concerns over prospective challenges and risks, including the overhanging threat of inflation and renewed economic turmoil. With respect to electric utilities, Fitch observed that, "the outlook for the sector would be adversely affected by significantly higher inflation and interest rates."[22] Moody's recently concluded:

> Over the past few months, we have been reminded that global financial markets, which are still receiving extraordinary intervention benefits by sovereign governments, are exposed to turmoil. Access to the capital markets could therefore become intermittent, even for safer, more defensive sectors like the power industry.[23]

Uncertainties surrounding economic and capital market conditions heighten the risks faced by electric utilities, which, as described earlier, face a variety of operating and financial challenges.

Q. HOW DO INTEREST RATES ON LONG-TERM BONDS COMPARE WITH THOSE PROJECTED FOR THE NEXT FEW YEARS?

A. Table WEA-1 below compares current interest rates on 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds with near-term projections from the Value Line Investment Survey ("Value Line"), IHS Global Insight, Blue Chip Financial Forecasts ("Blue Chip"), and the Energy Information

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[21] The Wall Street Journal recently reported that the Dow Jones Industrial Average experienced its largest drop since August 2010, which marked the fourth triple-digit move in less than two weeks. Tom Lauricella and Jonathan Cheng, "Dow Below 12000 on Mideast Worries – Troubles in Europe and China Add to Jitters," *Wall Street Journal* C1 (March. 11, 2011).

[22] Fitch Ratings Ltd., "2011 Outlook: U.S. Utilities, Power, and Gas," *Global Power North America Special Report* (Dec. 20, 2010).

[23] Moody's Investors Service, "Regulation Provides Stability As Risks Mount," *Industry Outlook* (Jan. 19, 2011).

Administration ("EIA"), which is a statistical agency of the U.S. Department of Energy ("DOE"):

TABLE WEA-1
INTEREST RATE TRENDS

	Current (a)	2012	2013	2014	2015
30-Yr. Treasury					
Value Line (b)	4.2%	4.9%	5.2%	5.5%	6.0%
IHS Global Insight (c)	4.2%	3.8%	5.0%	5.1%	6.0%
Blue Chip (d)	4.2%	4.8%	5.2%	5.4%	5.5%
AAA Corporate					
Value Line (b)	4.9%	5.6%	6.0%	6.3%	6.5%
IHS Global Insight (c)	4.9%	4.7%	6.0%	6.2%	6.8%
Blue Chip (d)	4.9%	5.4%	5.8%	6.1%	6.3%
S&P (e)	4.9%	6.5%	7.1%	7.2%	--
AA Utility					
IHS Global Insight (c)	5.1%	5.0%	6.2%	6.4%	7.2%
EIA (f)	5.1%	5.5%	6.4%	7.0%	7.4%

(a) Based on monthly average bond yields for the six-month period Sep. 2010 - Feb. 2011 reported at www.credittrends.moodys.com and http://www.federalreserve.gov/releases /h15/data.htm.
(b) The Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 25, 2011).
(c) IHS Global Insight, *U.S. Economic Outlook* at 19 (September 2010).
(d) *Blue Chip Financial Forecasts*, Vol. 29, No. 12 (Dec. 1, 2010).
(e) Standard & Poor's Corporation, "U.S. Economic Forecast: Warming Up Or Frozen Over?," *RatingsDirect* (Feb. 14, 2011).
(f) Energy Information Administration, *Annual Energy Outlook 2011 Early Release* (Dec. 16, 2010).

As evidenced above, there is a clear consensus that the cost of permanent capital will be higher in the 2012-2015 timeframe than it is currently. As a result, current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond.

Q. WHAT DO THESE EVENTS IMPLY WITH RESPECT TO THE ROE FOR KU/ODP?

A. No one knows the future of our complex global economy. We know that the financial crisis had been building for a long time, and few predicted that the economy would fall as rapidly as it has, or that corporate bond yields would fluctuate as dramatically as they did. While conditions in the economy and capital markets appear to have stabilized significantly since 2009, investors continue to react swiftly and negatively to any future signs of trouble in the financial system or economy. The fact remains that the electric utility industry requires significant new capital investment. Given the importance of reliable electric utility service, it would be unwise to ignore investors' increased sensitivity to risk and future capital market trends in evaluating a fair ROE in this case. Similarly, the Company's capital structure must also preserve the financial flexibility necessary to maintain access to capital even during times of unfavorable market conditions.

III. CAPITAL MARKET ESTIMATES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. This section presents capital market estimates of the cost of equity. First, I address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe DCF and CAPM analyses conducted to estimate the cost of common equity for benchmark groups of comparable risk firms and evaluate expected earned rates of return for utilities. Finally, I examine flotation costs, which are properly considered in evaluating a fair rate of return on equity.

A. Economic Standards

Q. WHAT ROLE DOES THE RATE OF RETURN ON COMMON EQUITY PLAY IN A UTILITY'S RATES?

A. The return on common equity is the cost of inducing and retaining investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Investors will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks. Moreover, the return on common equity is integral in achieving the sound regulatory objectives of rates that are sufficient to: 1) fairly compensate capital investment in the utility, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. Meeting these objectives allows the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system expansion.

Q. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THE COST OF EQUITY CONCEPT?

A. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Because all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return, and
RP_i = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with investors demanding correspondingly larger risk premiums for bearing greater risk.

Q. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATES IN THE CAPITAL MARKETS?

A. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. Comparing the observed yields on government securities, which are considered free of default risk, to the yields on bonds of various rating categories demonstrates that the risk-return tradeoff does, in fact, exist.

Q. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A. It is generally accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets – including common stock – required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q. IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. The last investors in line are common shareholders. They receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE COST OF COMMON EQUITY FOR A UTILITY?

A. Although the cost of common equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is not readily observable, the cost of common equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

Q. DID YOU RELY ON A SINGLE METHOD TO ESTIMATE THE COST OF COMMON EQUITY?

A. No. In my opinion, no single method or model should be relied on by itself to determine a utility's cost of common equity because no single approach can be regarded as definitive. Therefore, I applied both the DCF and CAPM methods to estimate the cost of common equity. In addition, I also evaluated a fair ROE using an earnings approach based on investors' current expectations in the capital markets. In my opinion, comparing estimates produced by one method with those produced by other approaches ensures that the estimates of the cost of common equity pass fundamental tests of reasonableness and economic logic.

B. Comparable Risk Proxy Groups

Q. HOW DID YOU IMPLEMENT THESE QUANTITATIVE METHODS TO ESTIMATE THE COST OF COMMON EQUITY FOR KU/ODP?

A. Application of the DCF model and other quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices. Moreover, even for a firm with publicly traded stock, the cost of common equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation error. Thus, the accepted approach to increase confidence in the results is to apply the DCF model and other quantitative methods to a proxy group of publicly traded companies that investors regard as risk-comparable.

Q. WHAT SPECIFIC PROXY GROUP OF UTILITIES DID YOU RELY ON FOR YOUR ANALYSIS?

A. In order to reflect the risks and prospects associated with KU/ODP's jurisdictional utility operations, my DCF analyses focused on a reference group of other utilities composed of those companies classified by Value Line as electric utilities with: (1) S&P corporate credit ratings of "BBB-" to "BBB+", (2) a Value Line Safety Rank of "2" or "3", (3) a Value Line Financial Strength Rating of "B+" to "A", and (4) a market capitalization of $1.6 billion or greater. In addition, I eliminated four utilities (Allegheny Energy, Inc., FirstEnergy Corp., Northeast Utilities, and Progress Energy, Inc.) that otherwise would have been in the proxy group, but are not appropriate for inclusion because they are currently involved in a major merger or acquisition. These criteria resulted in a proxy group composed of 23 companies, which I will refer to as the "Utility Proxy Group."

Q. WHAT OTHER PROXY GROUP DID YOU CONSIDER IN EVALUATING A FAIR ROE?

A. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criterion in establishing a meaningful benchmark to evaluate a fair ROE is relative risk, not the particular business activity or degree of regulation. With regulation taking the place of competitive market forces, required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Consistent with this accepted regulatory standard, I also applied the DCF model to a reference group of comparable risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Proxy Group".

Q. DO UTILITIES HAVE TO COMPETE WITH NON-REGULATED FIRMS FOR CAPITAL?

A. Yes. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Clearly, the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment, and there are a plethora of other enterprises available to investors beyond those in the utility industry. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk.

Q. IS IT CONSISTENT WITH THE *BLUEFIELD* AND *HOPE* CASES TO CONSIDER REQUIRED RETURNS FOR NON-UTILITY COMPANIES?

A. Yes. Returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility. The *Bluefield* case refers to "business undertakings attended with comparable risks and uncertainties."[24] It does not restrict consideration to other utilities. Similarly, the *Hope* case states:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[25]

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Indeed, in teaching regulatory policy I usually observe that in the early applications of the comparable earnings approach, utilities were explicitly eliminated due to a concern about circularity. In other words, soon after the *Hope* decision regulatory commissions did not want to get involved in circular logic by looking to the returns of utilities that were established by the same or similar regulatory commissions in the same geographic region. To avoid circularity, regulators looked only to the returns of non-utility companies.

Q. DOES CONSIDERATION OF THE RESULTS FOR THE NON-UTILITY PROXY GROUP MAKE THE ESTIMATION OF THE COST OF EQUITY USING THE DCF MODEL MORE RELIABLE?

A. Yes. The estimates of growth from the DCF model depend on analysts' forecasts. It is possible for utility growth rates to be distorted by short-term trends in the industry or the industry falling into favor or disfavor by analysts. The result of such distortions would be to bias the DCF estimates for utilities. For example,

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[24] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[25] *Federal Power Comm'n v. Hope Natural Gas Co.* (320 U.S. 391, 1944).

Value Line recently observed that near-term growth rates understate the longer-term expectations for gas utilities:

> Natural Gas Utility stocks have fallen near the bottom of our Industry spectrum for Timeliness. Accordingly, short-term investors would probably do best to find a group with better prospects over the coming six to 12 months. Longer-term, we expect these businesses to rebound. An improved economic environment, coupled with stronger pricing, should boost results across this sector over the coming years.[26]

Because the Non-Utility Proxy Group includes low risk companies from many industries, it diversifies away any distortion that may be caused by the ebb and flow of enthusiasm for a particular sector.

Q. WHAT CRITERIA DID YOU APPLY TO DEVELOP THE NON-UTILITY PROXY GROUP?

A. My comparable risk proxy group of non-utility firms was composed of those U.S. companies followed by Value Line that: (1) pay common dividends; (2) have a Safety Rank of "1"; (3) have a Financial Strength Rating of "B++" or greater; (4) have a beta of 0.85 or less; and, (5) have investment grade credit ratings from S&P.

Q. DO THESE CRITERIA PROVIDE OBJECTIVE EVIDENCE TO EVALUATE INVESTORS' RISK PERCEPTIONS?

A. Yes. Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Ratings generally extend from triple-A (the highest) to D (in default). Other symbols (*e.g.*, "A+") are used to show relative standing within a category. Because the rating agencies' evaluation includes virtually all of the factors

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[26] The Value Line Investment Survey at 445 (Mar. 12, 2010).

normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad, objective measure of overall investment risk that is readily available to investors. Although the credit rating agencies are not immune to criticism, their rankings and analyses are widely cited in the investment community and referenced by investors.[27] Investment restrictions tied to credit ratings continue to influence capital flows, and credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

While credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services also provide relative assessments of risks that are considered by investors in forming their expectations for common stocks. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank provides useful guidance regarding the risk perceptions of investors.

The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. Finally, Value Line's beta measures the volatility of a security's price relative to

[27] While the ratings agencies were faulted during the financial crisis for failing to adequately assess the risk associated with structured finance products, investors continue to regard corporate credit ratings as a reliable guide to investment risks.

the market as a whole. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00.

Q. HOW DO THE OVERALL RISKS OF YOUR PROXY GROUPS COMPARE WITH KU/ODP?

A. Table WEA-2 compares the Utility Proxy Group with the Non-Utility Proxy Group and KU/ODP across four key indicators of investment risk. Because the Company does not have publicly traded common stock, the Value Line risk measures shown reflect those published for KU/ODP's parent, PPL:

TABLE WEA-2
COMPARISON OF RISK INDICATORS

	S&P Credit Rating	Value Line Safety Rank	Value Line Financial Strength	Value Line Beta
Utility Group	BBB	3	B++	0.74
Non-Utility Proxy Group	A	1	A+	0.70
KU/ODP	BBB	3	B++	0.70

Q. DOES THIS COMPARISON INDICATE THAT INVESTORS WOULD VIEW THE FIRMS IN YOUR PROXY GROUPS AS RISK-COMPARABLE TO KU/ODP?

A. Yes. As discussed earlier, KU/ODP, like its parent, PPL, is rated "BBB" by S&P, which is identical to the average corporate credit rating for the utilities in the Utility Proxy Group. Similarly, the average Safety Rank and Financial Strength Rating for the Utility Proxy group is the same as that assigned to PPL, while PPL's beta value is only marginally lower than the average for the proxy group of other utilities. Considered together, a comparison of these objective measures, which consider a broad spectrum of risks, including financial and business position, and exposure to company specific factors, indicates that investors would likely conclude that the overall investment risks for KU/ODP are comparable to those of the firms in the Utility Proxy Group.

With respect to the Non-Utility Proxy Group, its average credit ratings, Safety Rank, and Financial Strength Rating suggest less risk than for KU/ODP, with its 0.70 average beta indicating identical risk. While the impact of differences in regulation is reflected in objective risk measures, my analyses conservatively focus on a lower-risk group of non-utility firms.

C. Discounted Cash Flow Analyses

Q. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF COMMON EQUITY?

A. DCF models attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expectations, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. That is, the cost of equity is the discount rate that equates the current price of a share of stock with the present value of all expected cash flows from the stock. The general form of the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \cdots + \frac{D_t}{(1+k_e)^t} + \frac{P_t}{(1+k_e)^t}$$

where: P_0 = Current price per share;
P_t = Expected future price per share in period t;
D_t = Expected dividend per share in period t;
k_e = Cost of common equity.

Q. WHAT FORM OF THE DCF MODEL IS CUSTOMARILY USED TO ESTIMATE THE COST OF COMMON EQUITY IN RATE CASES?

A. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[28]

$$P_0 = \frac{D_1}{k_e - g}$$

where: g = Investors' long-term growth expectations.

The cost of common equity (k_e) can be isolated by rearranging terms within the equation:

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0); and, 2) growth (g). In other words, investors expect to receive a portion of their total return in the

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[28] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity.

form of current dividends and the remainder through the capital gains associated with price appreciation over the investors' holding period.

Q. WHAT FORM OF THE DCF MODEL DID YOU USE?

A. I applied the constant growth DCF model to estimate the cost of common equity for KU/ODP, which is the form of the model most commonly relied on to establish the cost of common equity for traditional regulated utilities and the method most often referenced by regulators.

Q. HOW IS THE CONSTANT GROWTH FORM OF THE DCF MODEL TYPICALLY USED TO ESTIMATE THE COST OF COMMON EQUITY?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (g) for the firm. The final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of common equity.

Q. HOW WAS THE DIVIDEND YIELD FOR THE UTILITY PROXY GROUP DETERMINED?

A. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by the corresponding stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the utility proxy group are presented on Exhibit WEA-2. As shown there, dividend yields for the firms in the Utility Proxy Group ranged from 3.0 percent to 5.6 percent.

Q. WHAT IS THE NEXT STEP IN APPLYING THE CONSTANT GROWTH DCF MODEL?

A. The next step is to evaluate long-term growth expectations, or "*g*", for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect.

Q. ARE HISTORICAL GROWTH RATES LIKELY TO BE REPRESENTATIVE OF INVESTORS' EXPECTATIONS FOR UTILITIES?

A. No. If past trends in earnings, dividends, and book value are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for utilities, where structural and industry changes have led to declining growth in dividends, earnings pressure, and, in many cases, significant write-offs. While these conditions serve to depress historical growth measures, they are not representative of long-term expectations for the utility industry or the expectations that investors have incorporated into current market prices. As a result, historical growth measures for utilities do not currently meet the requirements of the DCF model.

Q. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A. While the DCF model is technically concerned with growth in dividend cash flows, implementation of this DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry, with the payout ratio for electric utilities falling from approximately 80 percent historically to on the order of 60 percent.[29] As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties.

As payout ratios for firms in the utility industry trended downward, investors' focus has increasingly shifted from dividends to earnings as a measure of long-term growth. Future trends in earnings, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community. As noted in *Finding Reality in Reported Earnings* published by the Association for Investment Management and Research:

> [E]arnings, presumably, are the basis for the investment benefits that we all seek. "Healthy earnings equal healthy investment benefits" seems a logical equation, but earnings are also a scorecard by which we compare companies, a filter through which we assess

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[29] The Value Line Investment Survey (Sep. 15, 1995 at 161, Feb. 4, 2011 at 2237).

> management, and a crystal ball in which we try to foretell future performance.[30]

Value Line's near-term projections and its Timeliness Rank, which is the principal investment rating assigned to each individual stock, are also based primarily on various quantitative analyses of earnings. As Value Line explained:

> The future earnings rank accounts for 65% in the determination of relative price change in the future; the other two variables (current earnings rank and current price rank) explain 35%.[31]

The fact that investment advisory services focus primarily on growth in earnings indicates that the investment community regards this as a superior indicator of future long-term growth. Indeed, "A Study of Financial Analysts: Practice and Theory," published in the *Financial Analysts Journal*, reported the results of a survey conducted to determine what analytical techniques investment analysts actually use.[32] Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securities. Of the 297 analysts that responded, only 3 ranked dividends first while 276 ranked it last. The article concluded:

> Earnings and cash flow are considered far more important than book value and dividends.[33]

In 2007, the *Financial Analysts Journal* reported the results of a study of the relationship between valuations based on alternative multiples and actual market

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[30] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview" at 1 (Dec. 4, 1996).
[31] The Value Line Investment Survey, *Subscriber's Guide* at 53.
[32] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).
[33] *Id.* at 88.

prices, which concluded, "In all cases studied, earnings dominated operating cash flows and dividends."[34]

Q. DO THE GROWTH RATE PROJECTIONS OF SECURITY ANALYSTS CONSIDER HISTORICAL TRENDS?

A. Yes. Professional security analysts study historical trends extensively in developing their projections of future earnings. Hence, to the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts.

Q. WHAT ARE SECURITY ANALYSTS CURRENTLY PROJECTING IN THE WAY OF GROWTH FOR THE FIRMS IN THE UTILITY PROXY GROUP?

A. The earnings growth projections for each of the firms in the Utility Proxy Group reported by Value Line, Thomson Reuters ("IBES"), and Zacks Investment Research ("Zacks") are displayed on Exhibit WEA-2.[35]

Q. SOME ARGUE THAT ANALYSTS' ASSESSMENTS OF GROWTH RATES ARE BIASED. DO YOU BELIEVE THESE PROJECTIONS ARE INAPPROPRIATE FOR ESTIMATING INVESTORS' REQUIRED RETURN USING THE DCF MODEL?

A. No. In applying the DCF model to estimate the cost of common equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out.

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[34] Liu, Jing, Nissim, Doron, & Thomas, Jacob, "Is Cash Flow King in Valuations?," *Financial Analysts Journal*, Vol. 63, No. 2 at 56 (March/April 2007).

[35] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.

They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information.

Any claims that analysts' estimates are not relied upon by investors are illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, then it is irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications (*e.g.*, Value Line) implies that investors use them as a basis for their expectations.

The continued success of investment services such as Thompson Reuters and Value Line, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of

> many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth]. The accuracy of these forecasts in the sense of whether they turn out to be correct is not an issue here, as long as they reflect widely held expectations.[36]

Q. HOW ELSE ARE INVESTORS' EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS OFTEN ESTIMATED WHEN APPLYING THE CONSTANT GROWTH DCF MODEL?

A. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Despite the fact that these conditions are never met in practice, this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

The sustainable growth rate is calculated by the formula, g = br+sv, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate.

Q. WHAT IS THE PURPOSE OF THE "SV" TERM?

A. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. When a company's stock price is greater than its book value per share, the per-share contribution in excess of book value associated with new stock issues will accrue to the current shareholders. This increase to the book value of existing

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[36] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 298 (2006).

shareholders leads to higher expected earnings and dividends, with the "sv" factor incorporating this additional growth component.

Q. WHAT GROWTH RATE DOES THE EARNINGS RETENTION METHOD SUGGEST FOR THE UTILITY PROXY GROUP?

A. The sustainable, "br+sv" growth rates for each firm in the Utility Proxy Group are summarized on Exhibit WEA-2, with the underlying details being presented on Exhibit WEA-3. For each firm, the expected retention ratio (b) was calculated based on Value Line's projected dividends and earnings per share. Likewise, each firm's expected earned rate of return (r) was computed by dividing projected earnings per share by projected net book value. Because Value Line reports end-of-year book values, an adjustment factor was incorporated to compute an average rate of return over the year, consistent with the theory underlying this approach to estimating investors' growth expectations. Meanwhile, the percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio.

Q. WHAT COST OF COMMON EQUITY ESTIMATES WERE IMPLIED FOR THE UTILITY PROXY GROUP USING THE DCF MODEL?

A. After combining the dividend yields and respective growth projections for each utility, the resulting cost of common equity estimates are shown on Exhibit WEA-2.

Q. IN EVALUATING THE RESULTS OF THE CONSTANT GROWTH DCF MODEL, IS IT APPROPRIATE TO ELIMINATE ESTIMATES THAT ARE EXTREME LOW OR HIGH OUTLIERS?

A. Yes. In applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

Q. HOW DID YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE RANGE?

A. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for their risk bearing. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, the DCF results must be adjusted to eliminate estimates that are determined to be extreme low outliers when compared against the yields available to investors from less risky utility bonds.

Q. WHAT DOES THIS TEST OF LOGIC IMPLY WITH RESPECT TO THE DCF RESULTS FOR THE UTILITY PROXY GROUP?

A. As noted earlier, the average S&P corporate credit rating for the Utility proxy Group is "BBB", which is identical to KU/ODP. Companies rated "BBB-", "BBB", and "BBB+" are all considered part of the triple-B rating category, with Moody's monthly yields on triple-B bonds averaging approximately 6.1 percent in February 2011.[37] It is inconceivable that investors are not requiring a

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[37] Moody's Investors Service, www.credittrends.com.

substantially higher rate of return for holding common stock. Consistent with this principle, the DCF results for the Utility Proxy Group must be adjusted to eliminate estimates that are determined to be extreme low outliers when compared against the yields available to investors from less risky utility bonds.

Q. HAVE SIMILAR TESTS BEEN APPLIED BY REGULATORS?

A. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold. In a 2002 opinion establishing its current precedent for determining ROEs for electric utilities, for example, FERC noted:

> An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42 percent, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06 percent, for October 1999. Because investors cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case.[38]

Similarly, in its August 2006 decision in *Kern River Gas Transmission Company*, FERC noted that:

> [T]he 7.31 and 7.32 percent costs of equity for El Paso and Williams found by the ALJ are only 110 and 122 basis points above that average yield for public utility debt.[39]

The Commission upheld the opinion of Staff and the Administrative Law Judge that cost of equity estimates for these two proxy group companies "were too low to be credible."[40]

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[38] *Southern California Edison Company*, 92 FERC ¶ 61,070 at p. 22 (2000).

[39] *Kern River Gas Transmission Company*, Opinion No. 486, 117 FERC ¶ 61,077 at P 140 & n. 227 (2006).

[40] *Id.*

The practice of eliminating low-end outliers has been affirmed in numerous FERC proceedings,[41] and in its April 15, 2010 decision in *SoCal Edison*, FERC affirmed that, "it is reasonable to exclude any company whose low-end ROE fails to exceed the average bond yield by about 100 basis points or more."[42]

Q. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF ESTIMATES AT THE LOW END OF THE RANGE?

A. As indicated earlier, while corporate bond yields have declined substantially as the worst of the financial crisis has abated, it is generally expected that long-term interest rates will rise as the recession ends and the economy returns to a more normal pattern of growth. As shown in Table WEA-3 below, forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of 7.13 percent over the period 2012-2015:

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[41] *See, e.g., Virginia Electric Power Co.*, 123 FERC ¶ 61,098 at P 64 (2008).
[42] *Southern California Edison Co.,* 131 FERC ¶ 61,020 at P 55 (2010) ("*SoCal Edison*").

TABLE WEA-3
IMPLIED BBB BOND YIELD

	2012-15
Projected AA Utility Yield	
IHS Global Insight (a)	6.20%
EIA (b)	6.58%
Average	6.39%
Current BBB - AA Yield Spread (c)	0.74%
Implied Triple-B Utility Yield	**7.13%**

(a) IHS Global Insight, *U.S. Economic Outlook* at 19 (September 2010).

(b) Energy Information Administration, *Annual Energy Outlook 2010* at Table 20 (May 11, 2010).

(c) Based on monthly average bond yields for the six-month period September 2010 - February 2011.

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely-referenced Blue Chip Financial Forecasts, which projects that yields on corporate bonds will climb more than 100 basis points through the period 2012-2016.[43]

Q. WHAT DOES THIS TEST OF LOGIC IMPLY WITH RESPECT TO THE DCF RESULTS FOR THE UTILITY PROXY GROUP?

A. As shown on Exhibit WEA-2, fifteen low-end DCF estimates ranged from 2.5 percent to 6.9 percent. Nine of these values were below current utility bond yields, with cost of equity estimates below 7.0 percent being less than the yield on triple-B utility bonds expected during the period 2012-2015. In light of the risk-return tradeoff principle and the test applied in *SoCal Edison*, it is inconceivable that investors are not requiring a substantially higher rate of return for holding

[43] *Blue Chip Financial Forecasts*, Vol. 29, No. 12 (Dec. 1, 2010) & Vol. 30, No. 3 (Mar. 1, 2011).

common stock, which is the riskiest of a utility's securities. As a result, consistent with the test of economic logic applied by FERC and the upward trend expected for utility bond yields, these values provide little guidance as to the returns investors require from utility common stocks and should be excluded.

Q. IS THERE ANY JUSTIFICATION TO ELIMINATE HIGH-END DCF VALUES FOR THE UTILITY PROXY GROUP?

A. No. As shown on Exhibit WEA-2, the upper end of the cost of equity range produced by the DCF analysis for the firms in the Utility Proxy Group is represented by three values ranging from 15.9 percent to 16.6 percent. While these cost of equity estimates may exceed expectations for most electric utilities, the seven remaining low-end estimates that fall below 8.0 percent are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the DCF estimates, these values provide a reasonable basis on which to evaluate investors' required rate of return. In addition, these high-end values fall below the threshold for high-end outliers repeatedly adopted by FERC, which has determined that DCF cost of equity estimates above 17.7 percent are "extreme," and that including such results would "skew the results."[44]

Q. WHAT COST OF COMMON EQUITY ESTIMATES ARE IMPLIED BY YOUR DCF RESULTS FOR THE UTILITY PROXY GROUP?

A. As shown on Exhibit WEA-2 and summarized in Table WEA-4, below, after eliminating illogical values, application of the constant growth DCF model resulted in average cost of common equity estimates ranging from 9.5 percent to 10.9 percent:

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[44] See, *e.g.*, *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205 (2004). FERC has continued to utilize this benchmark in evaluating DCF estimates at the upper end of the range. *See, e.g.*, *Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 57 (2010).

TABLE WEA-4
DCF RESULTS – UTILITY PROXY GROUP

Growth Rate	Average Cost of Equity
Value Line	10.9%
IBES	10.5%
Zacks	10.8%
br+sv	9.5%

Q. WHAT WERE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY PROXY GROUP?

A. The results of my constant growth DCF analysis for the Non-Utility Proxy Group, which mirror those for the proxy group of utilities, are presented in Exhibit WEA-4, with the br+sv" growth rates for each firm being presented on Exhibit WEA-5. I noted earlier that values that are implausibly low or high should be eliminated when evaluating the results of any quantitative method used to estimate the cost of equity. As highlighted on Exhibit WEA-4, in addition to illogical low-end values, various DCF estimates for the firms in the Non-Utility Proxy Group exceeded 17.0 percent. I determined that, when compared with the balance of the remaining estimates, these values could be considered implausible and should be excluded.

As shown on Exhibit WEA-4 and summarized in Table WEA-5, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in cost of common equity estimates on the order of at least 12 percent:

TABLE WEA-5
DCF RESULTS – NON-UTILITY GROUP

Growth Rate	Average Cost of Equity
Value Line	11.9%
IBES	12.4%
Zacks	12.5%
br+sv	12.1%

As discussed earlier, reference to the Non-Utility Proxy Group is consistent with established regulatory principles. My DCF analyses focused on a select group of 50 low-risk firms in the economy – most of which are household names familiar to investors. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition.

Q. DO THE HIGHER DCF ESTIMATES FOR THE NON-UTILITY PROXY GROUP DEMONSTRATE THAT THE RISKS OF THESE COMPANIES ARE GREATER THAN KU/ODP?

A. No. While we are accustomed to associating higher risk with higher ROE, DCF estimates of investors' required rate of return do not always produce that result. Performing the DCF calculations for the Non-Utility Proxy Group produced ROE estimates that are higher than the DCF estimates for the Utility Proxy Group, even though the risks that investors associate with the group of non-utility firms - as measured by S&P's credit ratings and Value Line's Safety Rank, Financial Strength, and Beta – are lower than the risks investors associate with the Utility Proxy Group. The actual cost of equity is unobservable, and DCF estimates may depart from these values because investors' expectations may not be captured by the inputs to the ROE model, particularly the assumed growth rate. Nevertheless, regulators have relied upon DCF calculations for years in evaluating a fair ROE.

The divergence between the DCF estimates for the Utility and Non-Utility Proxy Groups suggests that both should be considered to ensure a balanced end-result.

D. Capital Asset Pricing Model

Q. PLEASE DESCRIBE THE CAPM.

A. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. The CAPM is mathematically expressed as:

$$Rj = Rf + \beta j(Rm - Rf)$$

where: R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q. HOW DID YOU APPLY THE CAPM TO ESTIMATE THE COST OF COMMON EQUITY?

A. Application of the CAPM to the Utility Proxy Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit WEA-6. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The dividend yield for each firm was calculated based on the annual indicated dividend payment obtained from Value Line, increased by one-years' growth using the rate discussed subsequently (1 + *g*) to convert them to year-ahead dividend yields presumed by the constant growth DCF model. The growth rate was equal to the consensus earnings growth projections for each firm published by IBES, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 354 individual firms, current estimates imply an average growth rate over the next five years of 10.5 percent. Combining this average growth rate with a year-ahead dividend yield of 2.3 percent results in a current cost of common equity estimate for the market as a whole (R_m) of approximately 12.8 percent. Subtracting a 4.7 percent risk-free rate based on the average yield on 30-year Treasury bonds produced a market equity risk premium of 8.1 percent.

Q. WHAT WAS THE SOURCE OF THE BETA VALUES YOU USED TO APPLY THE CAPM?

A. I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings. As noted in *New Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. ... Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[45]

Q. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING THE CAPM?

A. As explained by *Morningstar*:

> One of the most remarkable discoveries of modern finance is that of a relationship between firm size and return. The relationship cuts across the entire size spectrum but is most evident among smaller companies, which have higher returns on average than larger ones.[46]

Because empirical research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size, a modification is required to account for this size effect.

According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, Morningstar has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity.[47] Accordingly, my CAPM analyses incorporated an adjustment to

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[45] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 71 (2006).

[46] *Morningstar*, "Ibbotson SBBI 2010 Valuation Yearbook," at p. 85 (footnote omitted).

[47] *Id.* at Table C-1.

recognize the impact of size distinctions, as measured by the average market capitalization for the respective proxy groups.

Q. WHAT COST OF EQUITY ESTIMATE WAS INDICATED FOR THE UTILITY PROXY GROUP BASED ON THIS FORWARD-LOOKING APPLICATION OF THE CAPM?

A. The average market capitalization of the Utility Proxy Group is $8.5 billion. Based on data from *Morningstar*, this means that the theoretical CAPM cost of equity estimate must be increased by 74 basis points to account for the industry group's relative size. As shown on Exhibit WEA-6, adjusting the theoretical CAPM result to incorporate this size adjustment results in an average indicated cost of common equity of 11.4 percent.

Q. WHAT COST OF COMMON EQUITY WAS INDICATED FOR THE NON-UTILITY PROXY GROUP BASED ON THIS FORWARD-LOOKING APPLICATION OF THE CAPM?

A. As shown on Exhibit WEA-7, applying the forward-looking CAPM approach to the firms in the Non-Utility Proxy Group results in an average implied cost of common equity of 10.0 percent.

Q. SHOULD THE CAPM APPROACH BE APPLIED USING HISTORICAL RATES OF RETURN?

A. No. The CAPM cost of common equity estimate is calibrated from investors' required risk premium between Treasury bonds and common stocks. In response to heightened uncertainties, investors have repeatedly sought a safe haven in U.S. government bonds and this "flight to safety" has pushed Treasury yields significantly lower while yield spreads for corporate debt have widened. This distortion not only impacts the absolute level of the CAPM cost of equity estimate, but it affects estimated risk premiums. Economic logic would suggest that investors' required risk premium for common stocks over Treasury bonds has also increased.

Meanwhile, backward-looking approaches incorrectly assume that investors' assessment of the required risk premium between Treasury bonds and common stocks is constant, and equal to some historical average. At no time in recent history has the fallacy of this assumption been demonstrated more concretely than it is today. This incongruity between investors' current expectations and historical risk premiums is particularly relevant during periods of heightened uncertainty and rapidly changing capital market conditions, such as those experienced recently.[48]

E. Expected Earnings Approach

Q. WHAT OTHER ANALYSES DID YOU CONDUCT TO ESTIMATE THE COST OF COMMON EQUITY?

A. As I noted earlier, I also evaluated the cost of common equity using the expected earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This expected earnings approach is consistent with the economic underpinnings for a fair rate of return established by the U.S. Supreme Court in *Bluefield* and *Hope*. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

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[48] FERC has previously rejected CAPM methodologies based on historical data because whatever historical relationships existed between debt and equity securities may no longer hold. *See Orange & Rockland Utils., Inc., 40 F.E.R.C. P63,053, at pp. 65,208 -09 (1987), aff'd, Opinion No. 314, 44 F.E.R.C. P61,253 at 65,208.*

Q. WHAT ECONOMIC PREMISE UNDERLIES THE EXPECTED EARNINGS APPROACH?

A. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. In this situation the government is effectively taking the value of investors' capital without adequate compensation. The expected earnings approach is consistent with the economic rationale underpinning established regulatory standards and the requirements of the Restructuring Act, which specifies a methodology to determine an ROE benchmark based on earned rates of return for a peer group of other regional utilities.[49]

Q. HOW IS THE COMPARISON OF OPPORTUNITY COSTS TYPICALLY IMPLEMENTED?

A. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line). Because these

[49] Code of Virginia at § 56-585.1.A.2.a. As noted earlier, KU is exempt from the requirements of the Restructuring Act.

returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Moreover, regulators do not set the returns that investors earn in the capital markets – they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q. WHAT RATES OF RETURN ON EQUITY ARE INDICATED FOR ELECTRIC UTILITIES BASED ON THE EXPECTED EARNINGS APPROACH?

A. Value Line reports that its analysts anticipate an average rate of return on common equity for the electric utility industry of 10.5 percent in 2011 and over its 2013-2015 forecast horizon.[50] Meanwhile, for the firms in the Utility Proxy Group specifically, the returns on common equity projected by Value Line over its forecast horizon are shown on Exhibit WEA-8. Consistent with the rationale underlying the development of the br+sv growth rates, these year-end values were

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[50] The Value Line Investment Survey at 139 (Feb. 25, 2011).

converted to average returns using the same adjustment factor discussed earlier and developed on Exhibit WEA-3. As shown on Exhibit WEA-8, Value Line's projections for the Utility Proxy Group suggest an average ROE of 10.9 percent.

F. *Flotation Costs*

Q. WHAT OTHER CONSIDERATIONS ARE RELEVANT IN SETTING THE RETURN ON EQUITY FOR A UTILITY?

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Q. IS THERE AN ESTABLISHED MECHANISM FOR A UTILITY TO RECOGNIZE EQUITY ISSUANCE COSTS?

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. No rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most logical mechanism.

Q. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT TO THE "BARE BONES" COST OF EQUITY TO ACCOUNT FOR ISSUANCE COSTS?

A. There are any number of ways in which a flotation cost adjustment can be calculated, and the adjustment can range from just a few basis points to more than a full percent. One of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, *New Regulatory Finance* concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[51]

Alternatively, a study of data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6%,[52] with PPL incurring issuance costs equal to approximately

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[51] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* at 323 (2006).

[52] *Application of Yankee Gas Services Company for a Rate Increase*, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1. Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6%.

3.02 percent of the gross proceeds from its 2010 public offering of common stock.[53]

Issuance costs are a legitimate consideration in setting the return on equity for a utility, and applying these expense percentages to a representative dividend yield for the Utility Proxy Group of 5 percent implies a flotation cost adjustment on the order of 15 to 50 basis points.

IV. RETURN ON EQUITY FOR KU/ODP

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. In addition to presenting my conclusions regarding a fair ROE for KU/ODP, this section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital. In addition, I evaluate the reasonableness of the Company's requested capital structure.

A. Implications for Financial Integrity

Q. WHY IS IT IMPORTANT TO ALLOW KU/ODP AN ADEQUATE ROE?

A. Given the importance of the utility industry to the economy and society, it is essential to maintain reliable and economical service to all consumers. While KU/ODP remains committed to providing reliable electric service, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal or is unable to earn a return sufficient to attract capital.

As documented earlier, the major rating agencies have warned of exposure to uncertainties associated with ongoing capital expenditure requirements, uncertain economic and financial market conditions, uncertain environmental

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[53] PPL Corporation, *Prospectus Supplement (To Prospectus dated March 25, 2009)* (Jun. 24, 2010). Net proceeds from PPL's sale of 103.5 million shares of common stock raised approximately $2.41 billion of additional equity capital.

compliance costs, and the potential for continued energy price volatility. Investors understand just how swiftly unforeseen circumstances can lead to deterioration in a utility's financial condition, and stakeholders have discovered first hand how difficult and complex it can be to remedy the situation after the fact.

While providing the infrastructure necessary to enhance the power system and meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on the Company and its parent, PPL. For a utility with an obligation to provide reliable service, investors' increased reticence to supply additional capital during times of crisis highlights the necessity of preserving the flexibility necessary to overcome periods of adverse capital market conditions. These considerations heighten the importance of allowing KU/ODP an adequate ROE.

Q. WHAT ROLE DOES REGULATION PLAY IN ENSURING THAT KU/ODP HAS ACCESS TO CAPITAL UNDER REASONABLE TERMS AND ON A SUSTAINABLE BASIS?

A. Considering investors' heightened awareness of the risks associated with the utility industry and the damage that results when a utility's financial flexibility is compromised, the continuation of supportive regulation remains crucial to KU/ODP's access to capital. Investors recognize that regulation has its own risks, and that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions.

Fitch concluded, "[G]iven the lingering rate of unemployment and voter concerns about the economy, there could well be pockets of adverse rate decisions, and those companies with little financial cushion could suffer adverse effects."[54] S&P has also emphasized the need for regulatory support, concluding, "the quality of regulation is at the forefront of our analysis of utility creditworthiness."[55] Similarly, Moody's concluded:

> For the longer term, however, we are becoming increasingly concerned about possible changes to our fundamental assumptions about regulatory risk, particularly the prospect of a more adversarial political (and therefore regulatory) environment. A prolonged recessionary climate with high unemployment, or an intense period of inflation, could make cost recovery more uncertain.[56]

Q. DOES THE FACT THAT KU/ODP OPERATES UNDER CERTAIN RATE ADJUSTMENT MECHANISMS WARRANT ANY ADJUSTMENT IN THE ESTIMATED LEVEL OF A FAIR ROE?

A. No. Investors recognize that KU/ODP is exposed to significant ongoing risks associated with energy price volatility, rising costs, and uncertainty over the impact of future environmental regulations. Rate adjustment mechanisms are a valuable means of mitigating those risks, but they do not eliminate them. For example, despite the fact that KU/ODP is able to recover incremental environmental costs through the ECR mechanism in Kentucky, Moody's cited the potential environmental regulations or policies as a material risk affecting KU/ODP.[57] No such mechanism exists for KU/ODP in Virginia. While adjustment mechanisms may partially attenuate exposure to attrition in an era of rising costs, such mechanisms ultimately serve only to preserve a utility's

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[54] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).

[55] Standard & Poor's Corporation, "Assessing U.S. Utility Regulatory Environments," *RatingsDirect* (Nov. 7, 2008).

[56] Moody's Investors Service, "U.S. Regulated Electric Utilities, Six-Month Update," *Industry Outlook* (July 2009).

[57] Moody's Investors Service, "Credit Opinion: Kentucky Utilities Co.," *Global Credit Research* (Nov. 1, 2010).

opportunity to earn its authorized return, as required by established regulatory standards.

Moreover, adjustment mechanisms and contractual arrangements that enable utilities to implement rate changes to pass-through fluctuations in fuel costs have been widely prevalent in the industry and utilities increasingly benefit from a wide variety of mechanisms designed to mitigate against the risks associated with fluctuations in costs and regulatory lag. While not always directly analogous to the fuel factor mechanism in effect for KU/ODP in Virginia, the objective is similar; namely, to allow the utility an opportunity to earn a fair rate of return and partially attenuate exposure to attrition in an era of rising costs.

Reflective of this industry trend, the companies in the Utility Proxy Group operate under a variety of cost adjustment mechanisms, which range from riders to recover bad debt expense and post-retirement employee benefit costs to revenue decoupling. Moreover, in response to the heightened risk associated with utilities' exposure to the substantial costs associated with new environmental compliance measures, adjustment mechanisms designed to allow for recovery of these costs outside a general rate case have become increasingly prevalent. As a result, the mitigation in risks associated with utilities' ability to attenuate the impact of fluctuations in costs is already reflected in the cost of common equity estimates developed earlier. Similarly, the firms in the Non-Utility Proxy Group also have the ability to alter prices in response to rising production costs, with the added flexibility to withdraw from the market altogether.

Q. DO CUSTOMERS BENEFIT BY ENHANCING THE UTILITY'S FINANCIAL FLEXIBILITY?

A. Yes. Providing a return on fair value that is both commensurate with those available from investments of corresponding risk and sufficient to maintain the ability to attract capital, even under duress, is consistent with the economic requirements embodied in the U.S. Supreme Court's *Bluefield* and *Hope* decisions; but it is also in customers' best interests. Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure a reliable energy supply. By the same token, customers also bear a significant burden of higher capital costs and reduced levels of service when the ability of the utility to attract capital is impaired.

B. Capital Structure

Q. IS AN EVALUATION OF THE CAPITAL STRUCTURE MAINTAINED BY A UTILITY RELEVANT IN ASSESSING ITS RETURN ON EQUITY?

A. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain.

Q. WHAT COMMON EQUITY RATIO IS IMPLICIT IN KU/ODP'S REQUESTED CAPITAL STRUCTURE?

A. The Company's capital structure is presented in the testimony of Dan Arbough. As summarized there, common equity as a percent of the capital sources used to compute the overall rate of return for KU/ODP is approximately 52.9 percent.

Q. HOW CAN THE COMPANY'S REQUESTED CAPITAL STRUCTURE BE EVALUATED?

A. It is generally accepted that the norms established by comparable firms provide one valid benchmark against which to evaluate the reasonableness of a utility's capital structure. The capital structure maintained by other electric utilities should reflect their collective efforts to finance themselves so as to minimize capital costs while preserving their financial integrity and ability to attract capital. Moreover, these industry capital structures should also incorporate the requirements of investors (both debt and equity), as well as the influence of regulators.

Q. WHAT WAS THE AVERAGE CAPITALIZATION MAINTAINED BY THE UTILITY PROXY GROUP?

A. As shown on Exhibit WEA-9, for the firms in the Utility Proxy Group, common equity ratios at December 31, 2010 ranged between 40.1 percent and 63.8 percent and averaged 48.7 percent of long-term capital.

Q. WHAT CAPITALIZATION IS REPRESENTATIVE FOR THE UTILITY PROXY GROUP GOING FORWARD?

A. As shown on Exhibit WEA-10, Value Line expects an average common equity ratio for the Utility Proxy Group of 51.1 percent for its three-to-five year forecast horizon, with the individual common equity ratios ranging from 41.0 percent to 67.0 percent.

Q. WHAT CAPITALIZATION RATIOS ARE MAINTAINED BY OTHER ELECTRIC UTILITY OPERATING COMPANIES?

A. Exhibit WEA-10 displays capital structure data at year-end 2010 for the group of electric utility operating companies owned by the firms in the Utility Proxy Group used to estimate the cost of equity. As shown there, common equity ratios for these electric utilities ranged from 43.1 percent to 61.4 percent, and averaged 51.2 percent.

Q. WHAT IMPLICATION DOES THE INCREASING RISK OF THE UTILITY INDUSTRY HAVE FOR THE CAPITAL STRUCTURE MAINTAINED BY KU/ODP?

A. As discussed earlier, utilities are facing energy market volatility, rising cost structures, the need to finance significant capital investment plans, uncertainties over accommodating economic and financial market uncertainties, and ongoing regulatory risks. Taken together, these considerations warrant a stronger balance sheet to deal with an increasingly uncertain environment. A more conservative financial profile, in the form of a higher common equity ratio, is consistent with increasing uncertainties and the need to maintain the continuous access to capital that is required to fund operations and necessary system investment, including times of adverse capital market conditions.

Moody's has repeatedly warned investors of the risks associated with debt leverage and fixed obligations and advised utilities not to squander the opportunity to strengthen the balance sheet as a buffer against future uncertainties.[58] More recently, Moody's concluded:

> From a credit perspective, we believe a strong balance sheet coupled with abundant sources of liquidity represents one of the best defenses against business and operating risk and potential negative ratings actions.[59]

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[58] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007); "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).
[59] Moody's Investors Service, "U.S. Electric Utilities Face Challenges Beyond Near-Term," *Industry Outlook* (Jan. 2010).

Similarly, S&P noted that, "we generally consider a debt to capital level of 50% or greater to be aggressive or highly leveraged for utilities."[60] Fitch affirmed that it expects regulated utilities "to extend their conservative balance sheet stance in 2010," and employ "a judicious mix of debt and equity to finance high levels of planned investments."[61]

Q. WHAT OTHER FACTORS DO INVESTORS CONSIDER IN THEIR ASSESSMENT OF A COMPANY'S CAPITAL STRUCTURE?

A. Depending on their specific attributes, contractual agreements or other obligations that require the utility to make specified payments may be treated as debt in evaluating KU/ODP's financial risk. Because investors consider the debt impact of such fixed obligations in assessing a utility's financial position, they imply greater risk and reduced financial flexibility. In order to offset the resulting debt equivalent, the utility must rebalance its capital structure by increasing its common equity in order to restore its effective capitalization ratios to previous levels.

These commitments have been repeatedly cited by major bond rating agencies in connection with assessments of utility financial risks,[62] with S&P adjusting KU/ODP's reported debt amounts upward to include debt equivalents associated with leases and power purchase obligations.[63] Unless the Company takes action to offset this additional financial risk by maintaining a higher equity

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[60] Standard & Poor's Corporation, "Ratings Roundup: U.S. Electric Utility Sector Maintained Strong Credit Quality In A Gloomy 2009," *RatingsDirect* (Jan. 26, 2010).

[61] Fitch Ratings Ltd., "U.S. Utilities, Power, and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).

[62] See, *e.g.*, Standard & Poor's Corporation, "Implications Of Operating Leases On Analysis Of U.S. Electric Utilities," *RatingsDirect* (Jan. 15, 2008)

[63] Standard & Poor's Corporation, "Kentucky Utilities Co.," *RatingsDirect* (May 6, 2010).

ratio, the resulting leverage will weaken KU/ODP's creditworthiness and imply greater risk.

Q. WHAT DID YOU CONCLUDE REGARDING THE REASONABLENESS OF KU/ODP'S REQUESTED CAPITAL STRUCTURE?

A. Based on my evaluation, I concluded that the 52.9 percent common equity ratio requested by KU/ODP represents a reasonable mix of capital sources from which to calculate the Company's overall rate of return. Although this common equity ratio is somewhat higher than the historical and projected averages maintained by the Utility Proxy Group, it is well within the range of individual results and consistent with the trend towards lower financial leverage expected for the industry.

While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well as its specific needs to access the capital markets. A public utility with an obligation to serve must maintain ready access to capital under reasonable terms so that it can meet the service requirements of its customers. The need for access becomes even more important when the company has capital requirements over a period of years, and financing must be continuously available, even during unfavorable capital market conditions.

Financial flexibility plays a crucial role in ensuring the wherewithal to meet the needs of customers, and utilities with higher leverage may be foreclosed from additional borrowing, especially during times of stress. KU/ODP's capital structure reflects the Company's ongoing efforts to maintain its credit standing and support access to capital on reasonable terms. The reasonableness of the Company's capital structure is reinforced by the ongoing uncertainties associated with the electric power industry and the importance of supporting continued system investment, even during times of adverse industry or market conditions.

C. Return on Equity Range Recommendation

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSES.

A. Reflecting the fact that investors' required return on equity is unobservable and no single method should be viewed in isolation, I used both the DCF and CAPM methods and referenced expected earned rates of return for utilities. In order to reflect the risks and prospects associated with KU/ODP's utility operations, my analyses focused on a proxy group of other electric utilities. Consistent with the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of low-risk companies in the non-utility sectors of the economy.

The cost of common equity estimates produced by the various capital market oriented analyses described in my testimony are summarized in Table WEA-6, below:

TABLE WEA-6
SUMMARY OF QUANTITATIVE RESULTS

DCF	**Utility**	**Non-Utility**
Earnings Growth		
Value Line	10.9%	11.9%
IBES	10.5%	12.4%
Zacks	10.8%	12.5%
br + sv	9.5%	12.1%
CAPM	11.4%	10.1%
Expected Earnings		
Value Line 2014-16	10.5%	--
Utility Proxy Group	10.9%	--

Q. WHAT THEN IS YOUR CONCLUSION AS TO A FAIR ROE FOR KU/ODP?

A. Considering the specific exposures faced by KU/ODP, the relative strengths and weaknesses inherent in each method, and conservatively giving less emphasis to the upper- and lower-most boundaries of the range of results, I concluded that the cost of common equity for the Company is in the 10.3 percent to 11.3 percent range. After incorporating a minimal adjustment for flotation costs of 20 basis points to my "bare bones" cost of equity range, I concluded that my analyses indicate a fair ROE for KU/ODP in the 10.5 percent to 11.5 percent range. In light of capital market expectations and the economic requirements necessary to maintain financial integrity and support additional capital investment even under adverse circumstances, it is my opinion that the midpoint of this range, or 11.0 percent, represents a fair and reasonable ROE for the Company.

Apart from the results of the quantitative methods summarized above, it is crucial to recognize the importance of supporting KU/ODP's financial position so that the Company remains prepared to respond to unforeseen events that may materialize in the future. Recent challenges in the economic and financial market environment highlight the imperative of maintaining KU/ODP's financial strength in attracting the capital needed to secure reliable service at a lower cost for customers. The reasonableness of my recommended ROE is reinforced by the fact that current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond.

D. Code of Virginia ROE Benchmark

Q. DOES THE CODE OF VIRGINIA ADDRESS SPECIFIC REQUIREMENTS CONCERNING THE DETERMINATION OF A FAIR ROE FOR JURISDICTIONAL ELECTRIC UTILITIES?

A. Yes. Although KU/ODP is exempt from the requirements of the Restructuring Act, in the context of biennial rate proceedings applicable to electric generation, distribution, and transmission services provided by other jurisdictional utilities, the Code of Virginia at § 56-585.1.A.2.a specifies a methodology to determine an ROE benchmark. That methodology provides that the allowed ROE must be no lower than the average historical earned return on book equity for a peer group of regional utilities; nor can it exceed this peer group threshold by more than 300 basis points. The methodology in the Virginia Code is consistent with the economic rationale underpinning established regulatory standards and my expected earnings approach.

Q. WHAT ROE RANGE IS ESTABLISHED BY THE CODE OF VIRGINIA?

A. The results of applying the requirements of § 56-585.1.A are shown in Exhibit WEA-11. Consistent with the Code, the regional peer group consisted of eleven investor-owned utilities with 1) principal operations conducted in the southeastern U.S.,[64] 2) vertically integrated electric utility operations subject to state jurisdiction, and 3) a Moody's credit rating of "Baa" or higher. In addition, companies that do not file financial information with the Securities and Exchange Commission or are affiliated with KU/ODP were excluded. As shown on Exhibit WEA-11, after removing the two utilities with the lowest reported average

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[64] Pursuant to the Code of Virginia, the southeastern U.S. region is defined as those states east of the Mississippi River in either the states of West Virginia or Kentucky or in those states south of Virginia, excluding the state of Tennessee.

returns, as well as the two utilities with the highest returns, the remaining seven companies of the peer group had an average earned rate of return on common equity over the three years 2008-2010 of 11.1 percent. Adding 300 basis points to this ROE floor implies an upper limit of 14.1 percent.

Q. IS YOUR ROE RECOMMENDATION FOR KU/ODP CONSISTENT WITH THIS BENCHMARK?

A. Yes. My recommended ROE of 11.0 percent falls below the average earned ROE for the seven-company regional peer group of 11.1 percent, and well below the implied ceiling of 14.1 percent.

Q. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING THE IMPLICATIONS OF THIS ROE BENCHMARK?

A. While KU/ODP is exempt from the requirements of the Restructuring Act, including those provisions governing the determination of a fair ROE, the Company nevertheless remains exposed to competition from the regional peer group companies in attracting long-term capital. It is a very simple, conceptual principle that when evaluating two investments of comparable risk, investors will choose the alternative with the higher expected return. If KU/ODP's allowed return on the book value of its equity investment falls short of other regional utilities, including Appalachian Power Company and Dominion Virginia Power, the implications are clear –investors will be denied the ability to earn their opportunity cost and KU/ODP's ability to attract capital will be eroded.

Q. PLEASE SUMMARIZE YOUR ROE RECOMMENDATION FOR THE COMPANY IN THIS CASE.

A. Based on my review of the risks specific to KU/ODP and the results of my analyses, I conclude that a fair ROE for KU/ODP falls in the range of 10.5 percent to 11.5 percent. In light of capital market expectations and the economic requirements necessary to maintain financial integrity and support additional capital investment even under adverse circumstances, it is my opinion that the midpoint of this range, or 11.0 percent, represents a fair and reasonable ROE for the Company. My conclusion is supported by the fact that this ROE falls below the 11.1 percent benchmark implied under the Code of Virginia.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

STATE OF TEXAS)
) **SS:**
COUNTY OF TRAVIS)

The undersigned, **William E. Avera**, being duly sworn, deposes and says he is President of FINCAP, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

____
William E. Avera

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 16th day of March 2011.

______________________(SEAL)
Notary Public

My Commission Expires:

1/10/2015

ADRIEN MCKENZIE
Notary Public
STATE OF TEXAS
My Comm. Exp. Jan. 10, 2015

EXHIBIT WEA-1

QUALIFICATIONS OF WILLIAM E. AVERA

Q. WHAT IS THE PURPOSE OF THIS EXHIBIT?

A. This exhibit describes my background and experience and contains the details of my qualifications.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I received a B.A. degree with a major in economics from Emory University. After serving in the U.S. Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas ("PUCT") as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission ("FERC"), as well as the Federal Communications Commission, the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in over 40 states, including the Virginia State Corporation Commission ("SCC" or the "Commission").

In 1995, I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. In addition, I served as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered Financial Analyst (CFA®) designation and have served as Vice President for Membership of the Financial Management

Association. I have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners ("NARUC") Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I have also served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached.

WILLIAM E. AVERA

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

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Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (almost 200 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.
Director, Economic Research Division, Public Utility Commission of Texas (Dec. 1977 to Aug. 1979)	Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.
Manager, Financial Education, International Paper Company New York City (Feb. 1977 to Nov. 1977)	Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance ,
The University of Texas at Austin
(Sep. 1979 to May 1981)
Assistant Professor of Finance,
(Sep. 1975 to May 1977)

Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.

Assistant Professor of Business ,
University of North Carolina at Chapel Hill
(Sep. 1972 to Jul. 1975)

Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance,
University of North Carolina at Chapel Hill
(Jan. 1969 to Aug. 1972)

Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics.

Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*

B.A., Economics,
Emory University, Atlanta, Georgia
(Sep. 1961 to Jun. 1965)

Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts

Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics for evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in over 300 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Missouri, Nevada, New Mexico, Montana, Nebraska, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 42 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (89 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; Appointed by Hays County Commission to Citizens Advisory Committee of Habitat Conservation Plan, Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas;* Appointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Board of Directors, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering (SEAL) Support Unit; Officer-in-Charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

Ethics and the Investment Professional (video, workbook, and instructor's guide) and *Ethics Challenge Today* (video), Association for Investment Management and Research (1995)

"Definition of Industry Ethics and Development of a Code" and "Applying Ethics in the Real World," in *Good Ethics: The Essential Element of a Firm's Success*, Association for Investment Management and Research (1994)

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"Liquidity, Exchange Listing, and Common Stock Performance," with John C. Groth and Kerry Cooper, *Journal of Economics and Business* (Spring 1985); reprinted by National Association of Security Dealers

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"Economic Perspective on Water Marketing in Texas," 2009 Water Law Institute, The University of Texas School of Law, Austin, TX (Dec. 2009).

"Estimating Utility Cost of Equity in Financial Turmoil," SNL EXNET 15th Annual FERC Briefing, Washington, D.C. (Mar. 2009)

"The Who, What, When, How, and Why of Ethics," San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

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"Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston (Nov. 1985).

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""Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)

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"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974) .

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

DCF MODEL

UTILITY PROXY GROUP

		(a)	(a)		(b)	(c)	(d)	(e)	(f)	(f)	(f)	(f)
		Dividend Yield			Growth Rates				Cost of Equity Estimates			
	Company	Price	Dividends	Yield	V Line	IBES	Zacks	br+sv	V Line	IBES	Zacks	br+sv
1	Alliant Energy	$ 38.74	$ 1.70	4.4%	7.0%	8.0%	5.0%	6.1%	11.4%	12.4%	9.4%	10.5%
2	Ameren Corp.	$ 27.67	$ 1.54	5.6%	-2.5%	-1.7%	-2.0%	2.5%	$\boxed{3.1\%}$	$\boxed{3.9\%}$	$\boxed{3.6\%}$	8.1%
3	American Elec Pwr	$ 35.61	$ 1.84	5.2%	3.0%	3.9%	4.0%	4.8%	8.2%	9.1%	9.2%	9.9%
4	Cleco Corp.	$ 31.64	$ 1.08	3.4%	9.5%	3.0%	7.0%	5.5%	12.9%	$\boxed{6.4\%}$	10.4%	8.9%
5	Constellation Energy	$ 31.09	$ 0.96	3.1%	6.0%	9.9%	9.9%	4.7%	9.1%	13.0%	13.0%	7.8%
6	DTE Energy Co.	$ 46.45	$ 2.30	5.0%	6.5%	5.8%	5.0%	3.9%	11.5%	10.8%	10.0%	8.9%
7	Edison International	$ 36.47	$ 1.29	3.5%	-1.0%	4.1%	5.0%	4.7%	$\boxed{2.5\%}$	7.6%	8.5%	8.3%
8	Entergy Corp.	$ 71.46	$ 3.38	4.7%	2.0%	2.0%	1.5%	4.5%	$\boxed{6.7\%}$	$\boxed{6.7\%}$	$\boxed{6.2\%}$	9.2%
9	Exelon Corp.	$ 41.77	$ 2.10	5.0%	-1.5%	-0.8%	-2.5%	5.8%	$\boxed{3.5\%}$	$\boxed{4.2\%}$	$\boxed{2.5\%}$	10.8%
10	Great Plains Energy	$ 19.70	$ 0.87	4.4%	4.5%	8.9%	9.0%	2.4%	8.9%	13.3%	13.4%	$\boxed{6.9\%}$
11	Hawaiian Elec.	$ 24.30	$ 1.24	5.1%	11.5%	7.0%	8.6%	4.2%	16.6%	12.1%	13.7%	9.3%
12	IDACORP, Inc.	$ 37.97	$ 1.20	3.2%	5.5%	4.7%	4.7%	5.0%	8.7%	7.9%	7.9%	8.1%
13	Integrys Energy Group	$ 49.45	$ 2.72	5.5%	11.0%	7.9%	10.4%	3.2%	16.5%	13.4%	15.9%	8.7%
14	OGE Energy Corp.	$ 47.81	$ 1.50	3.1%	6.5%	7.0%	5.5%	7.6%	9.6%	10.1%	8.6%	10.7%
15	PG&E Corp.	$ 45.21	$ 1.92	4.2%	6.0%	6.5%	7.7%	6.7%	10.2%	10.7%	11.9%	10.9%
16	Pinnacle West Capital	$ 41.39	$ 2.10	5.1%	6.0%	6.4%	5.8%	3.7%	11.1%	11.5%	10.9%	8.7%
17	Portland General Elec.	$ 22.80	$ 1.07	4.7%	3.0%	5.0%	5.2%	3.7%	7.7%	9.7%	9.9%	8.4%
18	PPL Corp.	$ 25.02	$ 1.40	5.6%	4.0%	3.6%	NA	7.2%	9.6%	9.2%	NA	12.8%
19	Pub Sv Enterprise Grp	$ 32.23	$ 1.37	4.3%	2.0%	3.3%	0.5%	6.5%	$\boxed{6.3\%}$	7.6%	$\boxed{4.8\%}$	10.8%
20	SCANA Corp.	$ 40.29	$ 1.94	4.8%	3.0%	4.7%	4.6%	5.0%	7.8%	9.5%	9.4%	9.8%
21	Sempra Energy	$ 53.32	$ 1.92	3.6%	1.0%	5.6%	7.0%	5.7%	$\boxed{4.6\%}$	9.2%	10.6%	9.3%
22	Westar Energy	$ 26.29	$ 1.26	4.8%	8.5%	6.1%	5.3%	4.9%	13.3%	10.9%	10.1%	9.7%
23	Wisconsin Energy	$ 29.36	$ 1.05	3.6%	9.5%	8.5%	8.0%	6.5%	13.1%	12.1%	11.6%	10.1%
	Average (g)								**10.9%**	**10.5%**	**10.8%**	**9.5%**

(a) Recent price and estimated dividend for next 12 mos. from The Value Line Investment Survey, *Summary and Index* (Mar. 4, 2011).
(b) The Value Line Investment Survey (Dec. 24, 2010, Feb. 4, & Feb. 25, 2011).
(c) *Thomson ReutersCompany in Context Report* (Mar. 3, 2011).
(d) www.zacks.com (retrieved Mar. 4, 2011).
(e) See Exhibit WEA-3.
(f) Sum of dividend yield and respective growth rate.
(g) Excludes highlighted figures.

BR + SV GROWTH RATE

UTILITY PROXY GROUP

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		2014					Adjustment			"sv" Factor			
	Company	EPS	DPS	BVPS	b	r	Factor	Adjusted r	br	s	v	sv	br + sv
1	Alliant Energy	$3.60	$1.92	$30.60	46.7%	11.8%	1.0246	12.1%	5.6%	0.0147	0.3558	0.52%	**6.1%**
2	Ameren Corp.	$2.50	$1.54	$35.50	38.4%	7.0%	1.0144	7.1%	2.7%	0.0122	(0.1833)	-0.22%	**2.5%**
3	American Elec Pwr	$3.50	$2.00	$34.25	42.9%	10.2%	1.0262	10.5%	4.5%	0.0108	0.2389	0.26%	**4.8%**
4	Cleco Corp.	$2.75	$1.45	$25.75	47.3%	10.7%	1.0412	11.1%	5.3%	0.0178	0.1417	0.25%	**5.5%**
5	Constellation Energy	$3.25	$1.00	$47.75	69.2%	6.8%	1.0250	7.0%	4.8%	0.0083	(0.1938)	-0.16%	**4.7%**
6	DTE Energy Co.	$4.25	$2.60	$45.75	38.8%	9.3%	1.0250	9.5%	3.7%	0.0136	0.1682	0.23%	**3.9%**
7	Edison International	$3.25	$1.40	$40.25	56.9%	8.1%	1.0285	8.3%	4.7%	-	(0.0063)	0.00%	**4.7%**
8	Entergy Corp.	$6.75	$3.60	$59.75	46.7%	11.3%	1.0182	11.5%	5.4%	(0.0266)	0.3361	-0.89%	**4.5%**
9	Exelon Corp.	$3.75	$2.10	$26.00	44.0%	14.4%	1.0204	14.7%	6.5%	(0.0136)	0.5048	-0.69%	**5.8%**
10	Great Plains Energy	$1.75	$1.15	$22.50	34.3%	7.8%	1.0251	8.0%	2.7%	0.0297	(0.0976)	-0.29%	**2.4%**
11	Hawaiian Elec.	$2.00	$1.30	$18.00	35.0%	11.1%	1.0220	11.4%	4.0%	0.0098	0.2653	0.26%	**4.2%**
12	IDACORP, Inc.	$3.10	$1.40	$36.50	54.8%	8.5%	1.0303	8.8%	4.8%	0.0181	0.0875	0.16%	**5.0%**
13	Integrys Energy Group	$4.00	$2.72	$41.75	32.0%	9.6%	1.0134	9.7%	3.1%	0.0074	0.1211	0.09%	**3.2%**
14	OGE Energy Corp.	$3.75	$1.65	$30.00	56.0%	12.5%	1.0386	13.0%	7.3%	0.0081	0.3684	0.30%	**7.6%**
15	PG&E Corp.	$4.25	$2.20	$36.25	48.2%	11.7%	1.0384	12.2%	5.9%	0.0332	0.2368	0.79%	**6.7%**
16	Pinnacle West Capital	$3.50	$2.30	$38.25	34.3%	9.2%	1.0339	9.5%	3.2%	0.0418	0.1000	0.42%	**3.7%**
17	Portland General Elec.	$2.00	$1.20	$23.75	40.0%	8.4%	1.0327	8.7%	3.5%	0.0385	0.0500	0.19%	**3.7%**
18	PPL Corp.	$2.75	$1.60	$23.75	41.8%	11.6%	1.0511	12.2%	5.1%	0.0575	0.3667	2.11%	**7.2%**
19	Pub Sv Enterprise Grp	$3.25	$1.50	$27.75	53.8%	11.7%	1.0375	12.2%	6.5%	-	0.3063	0.00%	**6.5%**
20	SCANA Corp.	$3.50	$2.10	$36.75	40.0%	9.5%	1.0420	9.9%	4.0%	0.0470	0.2263	1.06%	**5.0%**
21	Sempra Energy	$4.75	$2.05	$47.50	56.8%	10.0%	1.0230	10.2%	5.8%	(0.0085)	0.1739	-0.15%	**5.7%**
22	Westar Energy	$2.40	$1.40	$24.20	41.7%	9.9%	1.0281	10.2%	4.2%	0.0322	0.1933	0.62%	**4.9%**
23	Wisconsin Energy	$5.25	$2.70	$40.00	48.6%	13.1%	1.0277	13.5%	6.6%	(0.0000)	0.5000	0.00%	**6.5%**

UTILITY PROXY GROUP

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		2009			2014			Chg	2014 Price				Common Shares		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2009	2014	Growth
1	Alliant Energy	51.2%	$5,423	$2,777	51.5%	$6,895	$3,551	5.0%	$55.00	$40.00	$47.50	1.552	110.66	116.00	0.95%
2	Ameren Corp.	49.1%	$15,991	$7,852	51.5%	$17,600	$9,064	2.9%	$35.00	$25.00	$30.00	0.845	237.40	255.00	1.44%
3	American Elec Pwr	45.4%	$28,958	$13,147	48.0%	$35,600	$17,088	5.4%	$55.00	$35.00	$45.00	1.314	478.05	498.00	0.82%
4	Cleco Corp.	45.8%	$2,436	$1,116	53.5%	$3,150	$1,685	8.6%	$35.00	$25.00	$30.00	1.165	60.26	65.00	1.53%
5	Constellation Energy	62.8%	$12,468	$7,830	67.5%	$14,900	$10,058	5.1%	$50.00	$30.00	$40.00	0.838	199.00	209.00	0.99%
6	DTE Energy Co.	46.0%	$13,648	$6,278	48.0%	$16,800	$8,064	5.1%	$65.00	$45.00	$55.00	1.202	165.40	175.00	1.13%
7	Edison International	46.5%	$21,185	$9,851	45.0%	$29,100	$13,095	5.9%	$50.00	$30.00	$40.00	0.994	325.81	325.81	0.00%
8	Entergy Corp.	43.1%	$19,985	$8,614	41.0%	$25,200	$10,332	3.7%	$105.00	$75.00	$90.00	1.506	189.12	173.00	-1.77%
9	Exelon Corp.	52.9%	$25,651	$13,569	53.5%	$31,100	$16,639	4.2%	$60.00	$45.00	$52.50	2.019	662.00	640.00	-0.67%
10	Great Plains Energy	46.2%	$6,045	$2,793	46.0%	$7,800	$3,588	5.1%	$25.00	$16.00	$20.50	0.911	135.42	159.00	3.26%
11	Hawaiian Elec.	50.7%	$2,841	$1,440	52.0%	$3,450	$1,794	4.5%	$30.00	$19.00	$24.50	1.361	95.52	99.00	0.72%
12	IDACORP, Inc.	49.8%	$2,807	$1,398	50.5%	$3,750	$1,894	6.3%	$50.00	$30.00	$40.00	1.096	47.90	52.00	1.66%
13	Integrys Energy Group	53.9%	$5,304	$2,859	52.5%	$6,225	$3,268	2.7%	$55.00	$40.00	$47.50	1.138	75.98	78.50	0.65%
14	OGE Energy Corp.	49.4%	$4,130	$2,040	49.0%	$6,125	$3,001	8.0%	$55.00	$40.00	$47.50	1.583	97.00	99.50	0.51%
15	PG&E Corp.	47.4%	$21,793	$10,330	54.0%	$28,100	$15,174	8.0%	$55.00	$40.00	$47.50	1.310	370.60	420.00	2.53%
16	Pinnacle West Capital	49.6%	$6,687	$3,317	53.5%	$8,700	$4,655	7.0%	$50.00	$35.00	$42.50	1.111	101.43	122.00	3.76%
17	Portland General Elec.	49.7%	$3,100	$1,541	50.0%	$4,275	$2,138	6.8%	$30.00	$20.00	$25.00	1.053	75.21	90.00	3.66%
18	PPL Corp.	40.0%	$20,620	$8,248	51.5%	$26,700	$13,751	10.8%	$45.00	$30.00	$37.50	1.579	485.00	580.00	3.64%
19	Pub Sv Enterprise Grp	60.5%	$15,950	$9,650	58.5%	$24,000	$14,040	7.8%	$45.00	$35.00	$40.00	1.441	506.00	506.00	0.00%
20	SCANA Corp.	47.1%	$7,854	$3,699	49.5%	$11,375	$5,631	8.8%	$55.00	$40.00	$47.50	1.293	128.00	153.00	3.63%
21	Sempra Energy	54.1%	$16,646	$9,005	51.5%	$22,000	$11,330	4.7%	$65.00	$50.00	$57.50	1.211	246.50	238.00	-0.70%
22	Westar Energy	47.4%	$4,778	$2,265	46.0%	$6,520	$2,999	5.8%	$35.00	$25.00	$30.00	1.240	109.07	124.00	2.60%
23	Wisconsin Energy	47.7%	$7,473	$3,565	49.5%	$9,500	$4,703	5.7%	$90.00	$70.00	$80.00	2.000	116.91	116.90	0.00%

(a) The Value Line Investment Survey (Dec. 24, 2010, Feb. 4, & Feb. 25, 2011).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2014 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2013-15 BVPS.

DCF MODEL

NON-UTILITY PROXY GROUP

		(a)	(a)	(b)	(c)	(d)	(e)	(e)	(e)	(e)
		Dividend	Growth Rates				Cost of Equity Estimates			
	Company	Yield	V Line	IBES	Zacks	br+sv	V Line	IBES	Zacks	br+sv
1	3M Company	2.39%	7.0%	11.9%	11.3%	12.9%	9.4%	14.3%	13.7%	15.3%
2	Abbott Labs.	3.67%	10.0%	8.9%	9.0%	15.0%	13.7%	12.6%	12.7%	18.7%
3	Alberto-Culver	1.02%	15.0%	9.4%	12.5%	8.4%	16.0%	10.4%	13.5%	9.4%
4	AT&T Inc.	6.09%	5.5%	5.7%	7.0%	5.4%	11.6%	11.8%	13.1%	11.5%
5	Automatic Data Proc.	2.93%	8.0%	10.6%	10.8%	9.5%	10.9%	13.5%	13.7%	12.4%
6	Bard (C.R.)	0.77%	9.5%	10.9%	11.8%	18.1%	10.3%	11.7%	12.6%	18.9%
7	Baxter Int'l Inc.	2.45%	10.0%	9.6%	9.3%	15.5%	12.5%	12.1%	11.8%	17.9%
8	Becton, Dickinson	1.97%	9.5%	9.9%	10.8%	9.0%	11.5%	11.9%	12.8%	11.0%
9	Bristol-Myers Squibb	5.11%	8.5%	1.8%	2.0%	5.7%	13.6%	6.9%	7.1%	10.8%
10	Brown-Forman 'B'	1.90%	7.5%	10.9%	13.0%	10.6%	9.4%	12.8%	14.9%	12.5%
11	Chubb Corp.	2.55%	2.5%	8.7%	9.8%	8.0%	5.1%	11.3%	12.4%	10.5%
12	Church & Dwight	0.97%	12.0%	11.8%	12.0%	10.3%	13.0%	12.8%	13.0%	11.3%
13	Coca-Cola	2.80%	9.5%	8.7%	9.0%	9.9%	12.3%	11.5%	11.8%	12.7%
14	Colgate-Palmolive	2.76%	11.0%	9.3%	9.2%	18.1%	13.8%	12.1%	12.0%	20.8%
15	Commerce Bancshs.	2.22%	7.0%	7.0%	7.0%	7.9%	9.2%	9.2%	9.2%	10.1%
16	ConAgra Foods	3.92%	10.5%	7.7%	8.0%	8.1%	14.4%	11.6%	11.9%	12.0%
17	Costco Wholesale	1.24%	7.5%	13.3%	12.9%	8.2%	8.7%	14.5%	14.1%	9.5%
18	Cullen/Frost Bankers	2.96%	4.5%	8.5%	8.0%	5.7%	7.5%	11.5%	11.0%	8.6%
19	CVS Caremark Corp.	1.42%	9.5%	10.1%	12.0%	7.8%	10.9%	11.5%	13.4%	9.2%
20	Ecolab Inc.	1.41%	12.0%	13.2%	13.2%	19.6%	13.4%	14.6%	14.6%	21.0%
21	Exxon Mobil Corp.	2.26%	6.0%	12.1%	8.4%	13.5%	8.3%	14.4%	10.7%	15.7%
22	Gen'l Mills	3.02%	9.5%	7.7%	8.0%	9.3%	12.5%	10.7%	11.0%	12.3%
23	Heinz (H.J.)	3.85%	6.5%	7.0%	8.0%	13.9%	10.4%	10.9%	11.9%	17.8%
24	Hormel Foods	2.01%	10.5%	10.0%	9.3%	10.7%	12.5%	12.0%	11.3%	12.7%
25	Int'l Business Mach.	1.77%	13.0%	11.5%	9.3%	20.4%	14.8%	13.3%	11.1%	22.2%
26	Johnson & Johnson	3.44%	4.5%	6.0%	5.8%	10.8%	7.9%	9.4%	9.2%	14.2%
27	Kellogg	3.14%	9.5%	8.6%	9.0%	9.7%	12.6%	11.7%	12.1%	12.9%
28	Kimberly-Clark	4.09%	6.5%	7.5%	8.7%	18.6%	10.6%	11.6%	12.8%	22.7%
29	Kraft Foods	3.71%	8.0%	8.4%	8.0%	10.7%	11.7%	12.1%	11.7%	14.4%
30	Lilly (Eli)	5.64%	-2.5%	-6.4%	-5.3%	8.4%	3.1%	-0.8%	0.3%	14.0%
31	Lockheed Martin	3.78%	10.0%	8.1%	6.8%	20.3%	13.8%	11.9%	10.6%	24.1%
32	McCormick & Co.	2.24%	8.5%	9.6%	9.5%	13.3%	10.7%	11.8%	11.7%	15.6%
33	McDonald's Corp.	3.25%	9.5%	9.8%	9.3%	10.7%	12.8%	13.1%	12.6%	13.9%
34	McKesson Corp.	0.98%	10.0%	14.2%	11.0%	11.7%	11.0%	15.2%	12.0%	12.7%
35	Medtronic, Inc.	2.47%	7.5%	8.8%	8.4%	11.7%	10.0%	11.3%	10.9%	14.1%
36	Microsoft Corp.	2.26%	12.5%	11.3%	11.7%	15.3%	14.8%	13.6%	14.0%	17.5%
37	NIKE, Inc. 'B'	1.49%	9.5%	10.9%	12.5%	12.2%	11.0%	12.4%	14.0%	13.7%
38	Northrop Grumman	2.82%	12.5%	11.0%	11.1%	7.9%	15.3%	13.8%	13.9%	10.7%
39	PepsiCo, Inc.	2.91%	11.0%	8.9%	9.5%	14.5%	13.9%	11.8%	12.4%	17.4%
40	Pfizer, Inc.	4.50%	5.0%	2.8%	3.5%	7.0%	9.5%	7.3%	8.0%	11.5%
41	Procter & Gamble	3.01%	8.0%	8.9%	9.2%	7.2%	11.0%	11.9%	12.2%	10.3%
42	Raytheon Co.	3.02%	10.0%	8.0%	10.0%	8.6%	13.0%	11.0%	13.0%	11.6%
43	Stryker Corp.	1.26%	12.5%	10.9%	11.4%	13.6%	13.8%	12.2%	12.7%	14.9%
44	Sysco Corp.	3.47%	8.0%	10.0%	9.7%	14.2%	11.5%	13.5%	13.2%	17.6%
45	TJX Companies	1.28%	13.5%	14.5%	14.4%	11.1%	14.8%	15.8%	15.7%	12.4%
46	United Parcel Serv.	2.59%	9.0%	11.7%	11.5%	17.9%	11.6%	14.3%	14.1%	20.5%
47	Verizon Communic.	5.63%	4.0%	6.2%	14.9%	5.7%	9.6%	11.8%	20.5%	11.3%
48	Walgreen Co.	1.68%	11.5%	13.4%	13.0%	8.4%	13.2%	15.1%	14.7%	10.1%
49	Wal-Mart Stores	2.16%	10.0%	10.7%	11.3%	9.9%	12.2%	12.9%	13.5%	12.1%
50	Waste Management	3.52%	5.5%	9.6%	11.0%	5.2%	9.0%	13.1%	14.5%	8.7%
	Average (f)						11.9%	12.4%	12.5%	12.1%

(a) www.valueline.com (retrieved Jan. 28, 2011).
(b) *Thomson Reuters Company in Context Report* (Jan. 28, 2011).
(c) www.zacks.com (retrieved Jan. 31, 2011).
(d) See Exhibit WEA-5.
(e) Sum of dividend yield and respective growth rate.
(f) Excludes highlighted figures.

BR + SV GROWTH RATE

NON-UTILITY PROXY GROUP

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		--------- 2014 --------					Adjust.			--------- "sv" Factor --------			
	Company	EPS	DPS	BVPS	b	r	Factor	Adj. r	br	s	v	sv	br + sv
1	3M Company	$7.60	$3.10	$40.05	59.2%	19.0%	1.0818	20.5%	12.2%	0.0106	0.6731	0.71%	12.9%
2	Abbott Labs.	$5.70	$2.18	$22.05	61.8%	25.9%	1.0384	26.8%	16.6%	(0.0197)	0.7900	-1.56%	15.0%
3	Alberto-Culver	$2.35	$0.55	$17.85	76.6%	13.2%	1.0315	13.6%	10.4%	(0.0330)	0.6033	-1.99%	8.4%
4	AT&T Inc.	$3.25	$2.00	$24.05	38.5%	13.5%	1.0327	14.0%	5.4%	(0.0001)	0.4656	-0.01%	5.4%
5	Automatic Data Proc.	$3.45	$1.60	$22.95	53.6%	15.0%	1.0786	16.2%	8.7%	0.0111	0.7039	0.78%	9.5%
6	Bard (C.R.)	$7.75	$0.85	$31.45	89.0%	24.6%	1.0255	25.3%	22.5%	(0.0564)	0.7754	-4.37%	18.1%
7	Baxter Int'l Inc.	$5.85	$1.50	$22.90	74.4%	25.5%	1.0560	27.0%	20.1%	(0.0633)	0.7224	-4.57%	15.5%
8	Becton, Dickinson	$7.65	$2.20	$34.10	71.2%	22.4%	1.0306	23.1%	16.5%	(0.1030)	0.7216	-7.43%	9.0%
9	Bristol-Myers Squibb	$2.35	$1.54	$11.65	34.5%	20.2%	1.0263	20.7%	7.1%	(0.0212)	0.6671	-1.42%	5.7%
10	Brown-Forman 'B'	$4.50	$1.48	$20.40	67.1%	22.1%	1.0372	22.9%	15.4%	(0.0640)	0.7368	-4.71%	10.6%
11	Chubb Corp.	$7.00	$1.60	$64.85	77.1%	10.8%	1.0184	11.0%	8.5%	(0.0319)	0.1632	-0.52%	8.0%
12	Church & Dwight	$5.80	$1.00	$39.25	82.8%	14.8%	1.0465	15.5%	12.8%	(0.0414)	0.6075	-2.52%	10.3%
13	Coca-Cola	$4.95	$2.48	$18.20	49.9%	27.2%	1.0479	28.5%	14.2%	(0.0526)	0.8267	-4.34%	9.9%
14	Colgate-Palmolive	$7.20	$3.20	$13.25	55.6%	54.3%	1.0671	58.0%	32.2%	(0.1557)	0.9086	-14.15%	18.1%
15	Commerce Bancshs.	$3.35	$1.15	$32.10	65.7%	10.4%	1.0480	10.9%	7.2%	0.0240	0.2867	0.69%	7.9%
16	ConAgra Foods	$2.35	$1.00	$15.00	57.4%	15.7%	1.0288	16.1%	9.3%	(0.0217)	0.5385	-1.17%	8.1%
17	Costco Wholesale	$4.20	$0.95	$33.50	77.4%	12.5%	1.0315	12.9%	10.0%	(0.0301)	0.5939	-1.79%	8.2%
18	Cullen/Frost Bankers	$4.35	$2.10	$44.00	51.7%	9.9%	1.0382	10.3%	5.3%	0.0132	0.2667	0.35%	5.7%
19	CVS Caremark Corp.	$4.00	$0.56	$38.15	86.0%	10.5%	1.0268	10.8%	9.3%	(0.0395)	0.3642	-1.44%	7.8%
20	Ecolab Inc.	$3.60	$0.85	$14.45	76.4%	24.9%	1.0530	26.2%	20.0%	(0.0056)	0.7592	-0.43%	19.6%
21	Exxon Mobil Corp.	$9.35	$2.05	$45.50	78.1%	20.5%	1.0546	21.7%	16.9%	(0.0578)	0.5956	-3.44%	13.5%
22	Gen'l Mills	$3.15	$1.36	$11.95	56.8%	26.4%	1.0318	27.2%	15.5%	(0.0809)	0.7610	-6.16%	9.3%
23	Heinz (H.J.)	$4.10	$2.32	$14.65	43.4%	28.0%	1.0908	30.5%	13.3%	0.0085	0.7830	0.66%	13.9%
24	Hormel Foods	$2.10	$0.70	$13.55	66.7%	15.5%	1.0527	16.3%	10.9%	(0.0025)	0.6387	-0.16%	10.7%
25	Int'l Business Mach.	$18.00	$3.60	$48.75	80.0%	36.9%	1.0856	40.1%	32.1%	(0.1501)	0.7759	-11.65%	20.4%
26	Johnson & Johnson	$5.85	$2.65	$27.60	54.7%	21.2%	1.0378	22.0%	12.0%	(0.0185)	0.6846	-1.26%	10.8%
27	Kellogg	$5.10	$1.88	$9.95	63.1%	51.3%	1.0352	53.1%	33.5%	(0.2690)	0.8829	-23.75%	9.7%
28	Kimberly-Clark	$6.25	$2.75	$15.55	56.0%	40.2%	1.0140	40.8%	22.8%	(0.0506)	0.8363	-4.24%	18.6%
29	Kraft Foods	$3.00	$1.40	$24.00	53.3%	12.5%	1.0480	13.1%	7.0%	0.0716	0.5200	3.72%	10.7%
30	Lilly (Eli)	$3.40	$2.20	$15.60	35.3%	21.8%	1.0636	23.2%	8.2%	0.0032	0.6716	0.21%	8.4%
31	Lockheed Martin	$13.25	$3.50	$31.25	73.6%	42.4%	1.0882	46.1%	34.0%	(0.1663)	0.8188	-13.62%	20.3%
32	McCormick & Co.	$3.50	$1.36	$18.95	61.1%	18.5%	1.0649	19.7%	12.0%	0.0178	0.7293	1.30%	13.3%
33	McDonald's Corp.	$6.05	$3.00	$19.00	50.4%	31.8%	1.0303	32.8%	16.5%	(0.0734)	0.8000	-5.87%	10.7%
34	McKesson Corp.	$6.80	$0.72	$46.65	89.4%	14.6%	1.0421	15.2%	13.6%	(0.0380)	0.4957	-1.88%	11.7%
35	Medtronic, Inc.	$4.50	$1.18	$25.95	73.8%	17.3%	1.0597	18.4%	13.6%	(0.0326)	0.5848	-1.91%	11.7%
36	Microsoft Corp.	$3.35	$0.96	$10.75	71.3%	31.2%	1.0763	33.5%	23.9%	(0.1104)	0.7850	-8.66%	15.3%
37	NIKE, Inc. 'B'	$5.65	$1.50	$34.60	73.5%	16.3%	1.0643	17.4%	12.8%	(0.0085)	0.6358	-0.54%	12.2%
38	Northrop Grumman	$10.25	$2.50	$68.00	75.6%	15.1%	1.0293	15.5%	11.7%	(0.0783)	0.4868	-3.81%	7.9%
39	PepsiCo, Inc.	$6.40	$2.34	$24.00	63.4%	26.7%	1.0724	28.6%	18.1%	(0.0449)	0.8118	-3.64%	14.5%
40	Pfizer, Inc.	$2.05	$1.16	$13.00	43.4%	15.8%	1.0154	16.0%	7.0%	-	0.5273	0.00%	7.0%
41	Procter & Gamble	$5.25	$2.18	$29.45	58.5%	17.8%	1.0230	18.2%	10.7%	(0.0495)	0.6900	-3.41%	7.2%
42	Raytheon Co.	$7.20	$2.00	$38.65	72.2%	18.6%	1.0231	19.1%	13.8%	(0.0870)	0.5932	-5.16%	8.6%
43	Stryker Corp.	$5.35	$0.84	$32.75	84.3%	16.3%	1.0660	17.4%	14.7%	(0.0144)	0.7213	-1.04%	13.6%
44	Sysco Corp.	$2.75	$1.10	$10.10	60.0%	27.2%	1.0502	28.6%	17.2%	(0.0385)	0.7756	-2.98%	14.2%
45	TJX Companies	$4.80	$0.80	$12.75	83.3%	37.6%	1.0374	39.1%	32.5%	(0.2565)	0.8355	-21.43%	11.1%
46	United Parcel Serv.	$5.50	$2.20	$19.30	60.0%	28.5%	1.0912	31.1%	18.7%	(0.0090)	0.8245	-0.75%	17.9%
47	Verizon Communic.	$3.05	$1.96	$18.95	35.7%	16.1%	1.0250	16.5%	5.9%	(0.0032)	0.6555	-0.21%	5.7%
48	Walgreen Co.	$3.65	$1.00	$21.15	72.6%	17.3%	1.0252	17.7%	12.8%	(0.0684)	0.6475	-4.43%	8.4%
49	Wal-Mart Stores	$6.05	$1.75	$23.40	71.1%	25.9%	1.0072	26.0%	18.5%	(0.1157)	0.7400	-8.56%	9.9%
50	Waste Management	$2.90	$1.60	$15.30	44.8%	19.0%	1.0079	19.1%	8.6%	(0.0515)	0.6600	-3.40%	5.2%

BR + SV GROWTH RATE

NON-UTILITY PROXY GROUP

		(a)	(a)	(f)	(a)	(a)		(g)	(a)	(a)	(f)
		---- Common Equity ----			-------- 2014 Price --------				---- Common Shares ----		
	Company	2009	2014	Chg.	High	Low	Avg.	M/B	2009	2014	Growth
1	3M Company	$12,764	$28,975	17.8%	$135.00	$110.00	$122.50	3.059	710.60	723.00	0.35%
2	Abbott Labs.	$22,856	$33,550	8.0%	$115.00	$95.00	$105.00	4.762	1,551.90	1,520.00	-0.41%
3	Alberto-Culver	$1,197	$1,640	6.5%	$50.00	$40.00	$45.00	2.521	98.26	92.00	-1.31%
4	AT&T Inc.	$102,339	$141,895	6.8%	$50.00	$40.00	$45.00	1.871	5,901.90	5,900.00	-0.01%
5	Automatic Data Proc.	$5,323	$11,700	17.1%	$85.00	$70.00	$77.50	3.377	501.70	510.00	0.33%
6	Bard (C.R.)	$2,194	$2,830	5.2%	$155.00	$125.00	$140.00	4.452	95.92	90.00	-1.27%
7	Baxter Int'l Inc.	$7,191	$12,600	11.9%	$90.00	$75.00	$82.50	3.603	600.97	550.00	-1.76%
8	Becton, Dickinson	$5,143	$6,985	6.3%	$135.00	$110.00	$122.50	3.592	237.08	205.00	-2.87%
9	Bristol-Myers Squibb	$14,785	$19,230	5.4%	$40.00	$30.00	$35.00	3.004	1,709.50	1,650.00	-0.71%
10	Brown-Forman 'B'	$1,895	$2,750	7.7%	$85.00	$70.00	$77.50	3.799	146.96	135.00	-1.68%
11	Chubb Corp.	$15,634	$18,800	3.8%	$85.00	$70.00	$77.50	1.195	332.01	290.00	-2.67%
12	Church & Dwight	$1,602	$2,550	9.7%	$110.00	$90.00	$100.00	2.548	70.55	65.00	-1.63%
13	Coca-Cola	$24,799	$40,035	10.1%	$115.00	$95.00	$105.00	5.769	2,303.00	2,200.00	-0.91%
14	Colgate-Palmolive	$3,116	$6,100	14.4%	$160.00	$130.00	$145.00	10.943	494.17	460.00	-1.42%
15	Commerce Bancshs.	$1,886	$3,050	10.1%	$50.00	$40.00	$45.00	1.402	87.26	95.00	1.71%
16	ConAgra Foods	$4,721	$6,300	5.9%	$35.00	$30.00	$32.50	2.167	441.66	420.00	-1.00%
17	Costco Wholesale	$10,018	$13,725	6.5%	$90.00	$75.00	$82.50	2.463	435.97	410.00	-1.22%
18	Cullen/Frost Bankers	$1,894	$2,775	7.9%	$65.00	$55.00	$60.00	1.364	60.04	63.00	0.97%
19	CVS Caremark Corp.	$35,768	$46,750	5.5%	$65.00	$55.00	$60.00	1.573	1,391.00	1,225.00	-2.51%
20	Ecolab Inc.	$2,001	$3,400	11.2%	$65.00	$55.00	$60.00	4.152	236.60	235.00	-0.14%
21	Exxon Mobil Corp.	$110,569	$191,000	11.6%	$125.00	$100.00	$112.50	2.473	4,727.00	4,200.00	-2.34%
22	Gen'l Mills	$5,175	$7,115	6.6%	$55.00	$45.00	$50.00	4.184	656.00	595.00	-1.93%
23	Heinz (H.J.)	$1,891	$4,700	20.0%	$75.00	$60.00	$67.50	4.608	318.06	321.00	0.18%
24	Hormel Foods	$2,124	$3,600	11.1%	$40.00	$35.00	$37.50	2.768	267.19	266.00	-0.09%
25	Int'l Business Mach.	$22,755	$53,650	18.7%	$240.00	$195.00	$217.50	4.462	1,305.30	1,100.00	-3.36%
26	Johnson & Johnson	$50,588	$73,850	7.9%	$95.00	$80.00	$87.50	3.170	2,754.30	2,675.00	-0.58%
27	Kellogg	$2,272	$3,230	7.3%	$95.00	$75.00	$85.00	8.543	381.38	325.00	-3.15%
28	Kimberly-Clark	$5,406	$6,220	2.8%	$105.00	$85.00	$95.00	6.109	417.00	400.00	-0.83%
29	Kraft Foods	$25,972	$42,000	10.1%	$55.00	$45.00	$50.00	2.083	1,477.90	1,750.00	3.44%
30	Lilly (Eli)	$9,524	$18,000	13.6%	$50.00	$45.00	$47.50	3.045	1,149.00	1,155.00	0.10%
31	Lockheed Martin	$4,129	$10,000	19.4%	$190.00	$155.00	$172.50	5.520	372.90	320.00	-3.01%
32	McCormick & Co.	$1,335	$2,555	13.9%	$75.00	$65.00	$70.00	3.694	131.80	135.00	0.48%
33	McDonald's Corp.	$14,034	$19,000	6.2%	$105.00	$85.00	$95.00	5.000	1,076.70	1,000.00	-1.47%
34	McKesson Corp.	$7,532	$11,480	8.8%	$100.00	$85.00	$92.50	1.983	271.00	246.00	-1.92%
35	Medtronic, Inc.	$14,629	$26,600	12.7%	$70.00	$55.00	$62.50	2.408	1,097.30	1,025.00	-1.35%
36	Microsoft Corp.	$39,558	$85,000	16.5%	$55.00	$45.00	$50.00	4.651	8,908.00	7,900.00	-2.37%
37	NIKE, Inc. 'B'	$8,693	$16,550	13.7%	$105.00	$85.00	$95.00	2.746	485.50	478.00	-0.31%
38	Northrop Grumman	$12,687	$17,000	6.0%	$145.00	$120.00	$132.50	1.949	306.87	250.00	-4.02%
39	PepsiCo, Inc.	$17,442	$36,015	15.6%	$140.00	$115.00	$127.50	5.313	1,565.00	1,500.00	-0.84%
40	Pfizer, Inc.	$90,014	$105,000	3.1%	$30.00	$25.00	$27.50	2.115	8,070.00	8,070.00	0.00%
41	Procter & Gamble	$63,099	$79,455	4.7%	$105.00	$85.00	$95.00	3.226	2,917.00	2,700.00	-1.53%
42	Raytheon Co.	$9,827	$12,375	4.7%	$105.00	$85.00	$95.00	2.458	383.20	320.00	-3.54%
43	Stryker Corp.	$6,595	$12,775	14.1%	$130.00	$105.00	$117.50	3.588	397.90	390.00	-0.40%
44	Sysco Corp.	$3,450	$5,700	10.6%	$50.00	$40.00	$45.00	4.455	590.03	565.00	-0.86%
45	TJX Companies	$2,889	$4,200	7.8%	$85.00	$70.00	$77.50	6.078	409.39	330.00	-4.22%
46	United Parcel Serv.	$7,630	$19,035	20.1%	$120.00	$100.00	$110.00	5.699	992.85	985.00	-0.16%
47	Verizon Communic.	$41,600	$53,439	5.1%	$60.00	$50.00	$55.00	2.902	2,835.70	2,820.00	-0.11%
48	Walgreen Co.	$14,376	$18,500	5.2%	$65.00	$55.00	$60.00	2.837	988.56	875.00	-2.41%
49	Wal-Mart Stores	$70,749	$76,025	1.4%	$100.00	$80.00	$90.00	3.846	3,786.00	3,250.00	-3.01%
50	Waste Management	$6,285	$6,800	1.6%	$50.00	$40.00	$45.00	2.941	486.12	445.00	-1.75%

(a) www.valueline.com (retrieved Jan. 28, 2011).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of year-end "r" for 2014 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Five-year rate of change.
(g) Average of High and Low expected market prices divided by 2013-15 BVPS.

CAPITAL ASSET PRICING MODEL

UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.3%	
Growth Rate (b)	10.5%	
Market Return (c)		12.8%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.7%
Market Risk Premium (e)		8.1%
Utility Proxy Group Beta (f)		0.74
Utility Proxy Group Risk Premium (g)		6.0%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.7%
Unadjusted CAPM (h)		10.7%
Size Adjustment (i)		0.7%
Implied Cost of Equity (j)		**11.4%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Jan. 28, 2011).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 (retrieved Feb. 23, 2011).
(c) (a) + (b)
(d) Average yield on 30-year Treasury bonds for February 2011 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) The Value Line Investment Survey (Dec. 24, 2010, Feb. 4 & Feb. 25, 2011).
(g) (e) x (f).
(h) (d) + (g).
(i) *Morningstar*, "Ibbotson SBBI 2010 Valuation Yearbook," at Table C-1 (2010).
(j) (h) + (i).

CAPITAL ASSET PRICING MODEL

NON-UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.3%	
Growth Rate (b)	10.5%	
Market Return (c)		12.8%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.7%
Market Risk Premium (e)		8.1%
Non-Utility Proxy Group Beta (f)		0.71
Utility Proxy Group Risk Premium (g)		5.7%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.7%
Unadjusted CAPM (h)		10.4%
Size Adjustment (i)		-0.4%
Implied Cost of Equity (j)		**10.1%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Jan. 28, 2011).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 (retrieved Feb. 23, 2011).
(c) (a) + (b)
(d) Average yield on 30-year Treasury bonds for February 2011 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) www.valueline.com (retrieved Jan. 28, 2011).
(g) (e) x (f).
(h) (d) + (g).
(i) *Morningstar*, "Ibbotson SBBI 2010 Valuation Yearbook," at Table C-1 (2010).
(j) (h) + (i).

EXPECTED EARNINGS APPROACH

UTILITY PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	Alliant Energy	12.0%	1.0246	12.3%
2	Ameren Corp.	7.0%	1.0144	7.1%
3	American Elec Pwr	10.5%	1.0262	10.8%
4	Cleco Corp.	10.5%	1.0412	10.9%
5	Constellation Energy	7.0%	1.0250	7.2%
6	DTE Energy Co.	9.0%	1.0250	9.2%
7	Edison International	8.5%	1.0285	8.7%
8	Entergy Corp.	11.5%	1.0182	11.7%
9	Exelon Corp.	14.0%	1.0204	14.3%
10	Great Plains Energy	7.5%	1.0251	7.7%
11	Hawaiian Elec.	10.5%	1.0220	10.7%
12	IDACORP, Inc.	8.5%	1.0303	8.8%
13	Integrys Energy Group	10.0%	1.0134	10.1%
14	OGE Energy Corp.	12.5%	1.0386	13.0%
15	PG&E Corp.	12.0%	1.0384	12.5%
16	Pinnacle West Capital	8.5%	1.0339	8.8%
17	Portland General Elec.	8.5%	1.0327	8.8%
18	PPL Corp.	11.5%	1.0511	12.1%
19	Pub Sv Enterprise Grp	12.5%	1.0375	13.0%
20	SCANA Corp.	10.0%	1.0420	10.4%
21	Sempra Energy	10.5%	1.0230	10.7%
22	Westar Energy	10.0%	1.0281	10.3%
23	Wisconsin Energy	13.0%	1.0277	13.4%
	Average (d)			**10.9%**

(a) The Value Line Investment Survey (Dec. 24, 2010, Feb. 4, & Feb. 25, 2011).

(b) Adjustment to convert year-end "r" to an average rate of return from Exhibit WEA-3.

(c) (a) x (b).

(d) Excludes highlighted figures.

CAPITAL STRUCTURE

UTILITY PROXY GROUP

		At Fiscal Year-End 2010 (a)			Value Line Projected (b)		
	Company	Long-term Debt	Preferred	Common Equity	Long-term Debt	Other	Common Equity
1	Alliant Energy	46.3%	4.2%	49.5%	45.0%	3.5%	51.5%
2	Ameren Corp.	47.1%	0.0%	52.9%	47.5%	1.0%	51.5%
3	American Elec Pwr	55.1%	0.2%	44.7%	52.0%	0.0%	48.0%
4	Cleco Corp.	51.7%	0.0%	48.2%	46.5%	0.0%	53.5%
5	Constellation Energy	34.7%	1.5%	63.8%	32.0%	1.0%	67.0%
6	DTE Energy Co.	49.9%	2.1%	48.0%	52.0%	0.0%	48.0%
7	Edison International	51.9%	3.8%	44.3%	52.0%	3.0%	45.0%
8	Entergy Corp.	54.8%	1.6%	43.6%	58.0%	1.0%	41.0%
9	Exelon Corp.	47.2%	0.3%	52.4%	45.0%	0.0%	55.0%
10	Great Plains Energy	54.0%	0.6%	45.4%	53.5%	0.5%	46.0%
11	Hawaiian Elec.	47.3%	1.2%	51.5%	47.0%	1.0%	52.0%
12	IDACORP, Inc.	51.2%	0.0%	48.8%	49.5%	0.0%	50.5%
13	Integrys Energy Group	47.6%	0.0%	52.4%	46.5%	1.0%	52.5%
14	OGE Energy Corp.	49.6%	0.0%	50.4%	51.0%	0.0%	49.0%
15	PG&E Corp.	50.4%	1.1%	48.5%	45.0%	1.0%	54.0%
16	Pinnacle West Capital	49.3%	0.0%	50.7%	46.5%	0.0%	53.5%
17	Portland General Elec.	53.1%	0.0%	46.9%	50.0%	0.0%	50.0%
18	PPL Corp.	59.9%	0.0%	40.1%	45.5%	1.0%	53.5%
19	Pub Sv Enterprise Grp	48.1%	0.0%	51.9%	40.0%	0.0%	60.0%
20	SCANA Corp.	54.8%	0.0%	45.2%	52.5%	0.0%	47.5%
21	Sempra Energy	50.2%	0.5%	49.2%	47.5%	1.0%	51.5%
22	Westar Energy	54.3%	0.4%	45.3%	53.5%	0.5%	46.0%
23	Wisconsin Energy	53.5%	0.4%	46.2%	50.5%	0.0%	49.5%
	Average	**50.5%**	**0.8%**	**48.7%**	**48.2%**	**0.7%**	**51.1%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Dec. 24, 2010, Feb. 4, & Feb. 25, 2011).

CAPITAL STRUCTURE

ELECTRIC UTILITY OPERATING COS.

	Company	Long-term Debt	Preferred Stock	Common Equity
1	Interstate Power & Light	45.4%	6.4%	48.2%
2	Wisconsin Power & Light	43.1%	2.4%	54.5%
3	Ameren Illinois Co.	41.2%	0.0%	58.8%
4	Union Electric Co.	48.8%	0.0%	51.2%
5	AEP Texas Central Co.	55.0%	0.4%	44.6%
6	AEP Texas North Co.	54.6%	0.3%	45.0%
7	Appalachian Power Co.	55.6%	0.3%	44.1%
8	Columbus Southern Power Co.	49.2%	0.0%	50.8%
9	Indiana Michigan Power Co.	54.1%	0.2%	45.7%
10	Kentucky Power Co.	55.8%	0.0%	44.2%
11	Ohio Power Co.	46.1%	0.3%	53.6%
12	Public Service Co. of Oklahoma	53.4%	0.3%	46.3%
13	Southwestern Electric Pwr Co.	51.4%	0.1%	48.4%
14	Cleco Power	53.1%	0.0%	46.9%
	Baltimore Gas & Electric Co.	43.8%	5.7%	50.4%
	Detroit Edison Co.	52.1%	0.0%	47.9%
	Southern California Edison Co.	45.3%	5.5%	49.2%
	Entergy Arkansas Inc.	53.4%	3.6%	43.1%
	Entergy Gulf States Louisiana LLC	51.2%	0.3%	48.5%
	Entergy Louisiana LLC	45.8%	2.5%	51.6%
	Entergy Mississippi Inc.	51.5%	3.1%	45.3%
	Entergy New Orleans Inc.	44.2%	5.2%	50.6%
	Entergy Texas Inc.	50.8%	0.0%	49.2%
	Commonweath Edison Co.	41.3%	1.7%	57.0%
	PECO Energy Co.	41.3%	5.0%	53.6%
	Kansas City Power & Light	47.0%	0.0%	53.0%
	Hawaiian Electric Co.	43.5%	1.4%	55.0%
	Idaho Power Co.	53.4%	0.0%	46.6%
	Upper Penninsula Power Co.	38.6%	0.0%	61.4%
	Wisconsin Public Service Corp.	42.3%	2.5%	55.2%
	Oklahoma Gas & Electric Co.	39.2%	0.0%	60.8%
	Pacific Gas & Electric Co.	49.2%	1.1%	49.7%
15	Arizona Public Service Co.	47.9%	0.0%	52.1%
16	Portland General Elec.	53.1%	0.0%	46.9%
17	PPL Electric Utilities Corp.	43.1%	7.3%	49.6%
18	Louisville Gas & Electric Co.	41.4%	0.0%	58.6%
19	Kentucky Utilities Co.	47.0%	0.0%	53.0%
20	Public Service Electric & Gas Co.	49.7%	0.0%	50.3%
21	South Carolina Electric & Gas	46.3%	0.0%	53.7%
22	San Diego Gas & Electric	51.5%	1.2%	47.4%
23	Kansas Gas & Electric	42.8%	0.0%	57.2%
24	Westar Energy	38.1%	0.6%	61.4%
25	Wisconsin Electric Power Co.	39.2%	0.6%	60.2%
	Average	**47.5%**	**1.4%**	**51.2%**

Source: Company Form 10-K Reports and FERC Form-1 Reports.

VIRGINIA PEER GROUP

RETURN ON EQUITY

3-Year Average Return on Equity

1	Alabama Power Co.	13.29%	Removed - Highest	
2	Mississipi Power Co.	12.79%		
3	Progress Energy Carolinas, Inc.	12.28%	Upper Tier Majority	**11.9%**
4	Gulf Power Co.	12.18%		
5	Georgia Power Co.	12.00%		
6	Progress Energy Florida, Inc.	11.08%	Average	**11.1%**
7	Entergy Mississippi Inc.	10.36%	Lower Tier Majority	**10.3%**
8	Florida Power & Light Co.	10.23%		
9	Tampa Electric Co.	9.64%		
10	Duke Energy Carolinas LLC	9.55%	Removed - Lowest	
11	South Carolina Electric & Gas Co.	9.35%		

VIRGINIA PEER GROUP

RETURN ON EQUITY

	Peer Group Utilities	Return on Average Equity 2010	2009	2008	3-Year Average
1	Alabama Power Co.	13.3%	13.3%	13.3%	13.3%
2	Duke Energy Carolinas LLC	9.8%	9.0%	9.9%	9.6%
3	Entergy Mississippi Inc.	11.4%	11.0%	8.6%	10.4%
4	Florida Power & Light Co.	10.4%	10.1%	10.3%	10.2%
5	Georgia Power Co.	11.4%	11.0%	13.6%	12.0%
6	Gulf Power Co.	11.7%	12.2%	12.7%	12.2%
7	Mississipi Power Co.	11.5%	13.1%	13.8%	12.8%
8	Progress Energy Carolinas, Inc.	12.20%	11.45%	13.19%	12.3%
9	Progress Energy Florida, Inc.	9.6%	11.7%	12.0%	11.1%
10	South Carolina Electric & Gas Co.	8.8%	9.3%	10.0%	9.4%
11	Tampa Electric Co.	11.4%	9.2%	8.4%	9.6%

VIRGINIA PEER GROUP

RETURN ON EQUITY

Company	**2010**	**2009**	**2008**	**2007**
Alabama Power Co.				
Earnings Available to Common	$ 707.0	$ 669.5	$ 616.0	
Common Equity - Year End	$ 5,393.0	$ 5,236.5	$ 4,854.3	$ 4,410.7
Common Equity - Average	$ 5,314.7	$ 5,045.4	$ 4,632.5	
Return on Average Common Equity	13.3%	13.3%	13.3%	
Duke Energy Carolinas LLC				
Earnings Available to Common	$ 838.0	$ 702.0	$ 690.0	
Common Equity - Year End	$ 8,916.0	$ 8,271.0	$ 7,316.0	$ 6,633.0
Common Equity - Average	$ 8,593.5	$ 7,793.5	$ 6,974.5	
Return on Average Common Equity	9.8%	9.0%	9.9%	
Entergy Mississippi Inc.				
Earnings Available to Common	$ 80.9	$ 74.8	$ 56.9	
Common Equity - Year End	$ 726.2	$ 688.8	$ 665.3	$ 656.7
Common Equity - Average	$ 707.5	$ 677.0	$ 661.0	
Return on Average Common Equity	11.4%	11.0%	8.6%	
Florida Power & Light Co,				
Earnings Available to Common	$ 945.0	$ 831.0	$ 789.0	
Common Equity - Year End	$ 9,791.0	$ 8,436.0	$ 8,089.0	$ 7,275.0
Common Equity - Average	$ 9,113.5	$ 8,262.5	$ 7,682.0	
Return on Average Common Equity	10.4%	10.1%	10.3%	
Georgia Power Co.				
Earnings Available to Common	$ 950.0	$ 814.0	$ 902.9	
Common Equity - Year End	$ 8,741.0	$ 7,902.9	$ 6,879.2	$ 6,435.4
Common Equity - Average	$ 8,322.0	$ 7,391.1	$ 6,657.3	
Return on Average Common Equity	11.4%	11.0%	13.6%	

RETURN ON EQUITY

Company	2010	2009	2008	2007
Gulf Power Co.				
Earnings Available to Common	$ 121.5	$ 111.2	$ 98.3	
Common Equity - Year End	$ 1,075.0	$ 1,004.3	$ 822.1	$ 731.3
Common Equity - Average	$ 1,039.7	$ 913.2	$ 776.7	
Return on Average Common Equity	11.7%	12.2%	12.7%	
Mississipi Power Co.				
Earnings Available to Common	$ 80.2	$ 85.0	$ 86.0	
Common Equity - Year End	$ 737.4	$ 658.5	$ 636.5	$ 613.8
Common Equity - Average	$ 697.9	$ 647.5	$ 625.1	
Return on Average Common Equity	11.5%	13.1%	13.8%	
Progress Energy Carolinas, Inc.				
Earnings Available to Common	$ 600.0	$ 513.0	$ 531.0	
Common Equity - Year End	$ 5,180.0	$ 4,657.0	$ 4,301.0	$ 3,752.0
Common Equity - Average	$ 4,918.5	$ 4,479.0	$ 4,026.5	
Return on Average Common Equity	12.2%	11.5%	13.2%	
Progress Energy Florida, Inc.				
Earnings Available to Common	$ 451.0	$ 460.0	$ 383.0	
Common Equity - Year End	$ 4,890.0	$ 4,490.0	$ 3,399.0	$ 3,002.0
Common Equity - Average	$ 4,690.0	$ 3,944.5	$ 3,200.5	
Return on Average Common Equity	9.6%	11.7%	12.0%	
South Carolina Electric & Gas Co.				
Earnings Available to Common	$ 290.0	$ 272.0	$ 266.0	
Common Equity - Year End	$ 3,437.0	$ 3,162.0	$ 2,704.0	$ 2,622.0
Common Equity - Average	$ 3,299.5	$ 2,933.0	$ 2,663.0	
Return on Average Common Equity	8.8%	9.3%	10.0%	
Tampa Electric Co.				
Earnings Available to Common	$ 242.9	$ 192.1	$ 162.7	
Common Equity - Year End	$ 2,158.2	$ 2,103.8	$ 2,090.6	$ 1,801.0
Common Equity - Average	$ 2,131.0	$ 2,097.2	$ 1,945.8	
Return on Average Common Equity	11.4%	9.2%	8.4%	

KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request Dated July 12, 2011

Case No. 2011-00161

Question No. 32

Witness: John N. Voyles, Jr.

Q-32. Refer to Voyles Testimony, Exhibit JNV-2. Provide the following information for each unit proposed for the addition of air quality control ("AQC") equipment:

a. Year placed in service;

b. The number of normal cycles (stops and starts);

c. The number of emergency trips and starts;

d. Heat rate;

e. Capacity Factor;

f. Provide for the last 10 years of major internal and minor outages including the major projects completed during each outage;

g. Provide an outline of the major availability and performance detractors;

h. Provide a condition assessment that includes;

(1) Condition of turbine.

(2) Condition of generator.

(3) Condition of boiler.

(4) Condition of balance of plant equipment.

i. Provide any formal life assessment or extension reports.

A-32. a. The requested information is contained in the table below.

Unit	**In-Service Date**
Brown 1	05/01/57
Brown 2	06/01/63
Brown 3	07/19/71
Ghent 1	02/19/74
Ghent 2	04/20/77
Ghent 3	05/31/81
Ghent 4	08/18/84

b. The requested information is contained in the table below.

Actual Unit Starts

Unit	**2010**
Brown 1	18
Brown 2	14
Brown 3	7
Ghent 1	7
Ghent 2	7
Ghent 3	14
Ghent 4	20

Source: Micro *GADS* NERC data.

c. The requested information is contained in the table below. Please note that emergency starts are not applicable to these coal units.

Actual NERC "U1" *(Immediate)* Forced Outages

Unit	**2010**
Brown 1	10
Brown 2	4
Brown 3	4
Ghent 1	3
Ghent 2	5
Ghent 3	10
Ghent 4	17

Source: Micro *GADS* NERC data.

d. The requested information is contained in the table below.

Actual NERC Net Heat Rate

Unit	2010
Brown 1	11,064
Brown 2	10,293
Brown 3	10,815
Ghent 1	10,342
Ghent 2	10,406
Ghent 3	10,849
Ghent 4	10,911

Source: Micro *GADS* NERC data and station reports.

e. The requested information is contained in the table below.

Actual NERC Net Capacity Factor

Unit	2010
Brown 1	46.26
Brown 2	51.86
Brown 3	49.93
Ghent 1	79.99
Ghent 2	77.16
Ghent 3	81.68
Ghent 4	63.63

Source: Micro *GADS* NERC data.

f. In response, please find attached a list of major capital projects performed during an outage in the last ten years. The Company is providing the requested information under a Petition for Confidential Protection being filed with the Commission.

g. The requested information is contained in the table below.

2010 Events > 20,000 MWh by Unit:

Unit Name	Event Type	Event Start	Event End	Event Hours	MWH Lost	Event Cause
BR2	U2	9/19/10 5:58	9/27/2010 1:40	187.70	31,721	TURBINE MAIN STOP VALVES
BR3	MO	6/30/10 21:41	7/4/10 2:40	76.98	32,025	FIRST REHEATER LEAKS
BR3	MO	10/14/10 20:32	10/17/10 16:20	67.80	29,357	FLUE GAS EXPANSION JOINTS
GH1	U3	5/22/10 22:22	5/26/10 6:55	80.55	38,261	BOILER TUBE WATERWALL (FURNACE WALL) LEAK
GH3	U1	10/5/10 4:25	10/10/10 14:30	130.08	64,391	INDUCED DRAFT FANS
GH3	U2	3/23/10 16:40	3/27/10 22:17	101.62	50,300	CIRCULATING WATER PIPING
GH3	D1	1/7/10 7:36	1/17/10 3:52	236.27	34,529	OTHER FEEDWATER PUMP PROBLEMS
GH3	U3	10/3/10 6:11	10/5/10 4:25	46.23	22,886	BOILER TUBE WATERWALL (FURNACE WALL) LEAK
GH3	U1	12/28/10 21:30	12/30/10 19:30	46.00	22,770	CIRCULATING WATER PIPING
GH3	MO	4/9/10 22:23	4/11/10 21:10	46.78	22,456	FIRST REHEATER LEAKS

h. Please see the attached CD in folder titled Question 32(h).

i. Please see the attached CD in folder titled Question 32(i). Certain redacted information is being filed with the Commission under seal pursuant to a Petition for Confidential Protection.

LU KPSC
32(i)
5docs

An Economic Life Assessment of Generation Assets of KU and LG&E Performed for

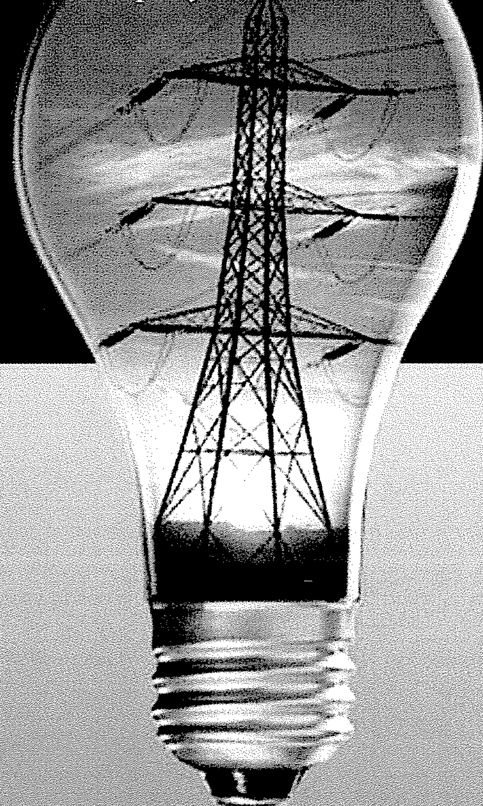
e·on | U.S.

E.ON U.S.

by

NewEnergy Associates, L.L.C.

A Siemens Company



NewEnergy Associates
A Siemens Company

NewEnergy Associates

A Siemens Company

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Table of Contents

A. Introduction:

In order to determine the effective useful economic life of E.ON U.S.'s generating assets, NewEnergy Associates, LLC was retained by E.ON U.S. to perform a Life Assessment of its generating assets. The goal of the analysis was to allow E.ON U.S. to more accurately project when a generating asset will reach the end of its effective useful economic life. With the information supplied by NewEnergy Associates, E.ON U.S. will have a more robust method of determining the depreciation life of an asset. NewEnergy utilized its Strategist strategic planning model, together with E.ON U.S.'s data, to perform this analysis.

B. Methodology:

The analysis was conducted in two phases: an initial phase (Phase 1) to focus on a subset of the generating assets and demonstrate the effectiveness of the proposed methodology, and a second phase (Phase 2) to complete the analysis for the balance of generating assets. The specific tasks for each Phase of the analysis are shown in Appendix A.

For E.ON U.S.'s Life Assessment, units in service for less than 30 years were excluded from the evaluation. None of these units will have been in service for more than 60 years at the end of 2035 and current industry practice indicates that it is both reasonable and cost effective to retain properly operated and maintained units for a life of at least 60 years. The units excluded on the basis of this criterion were the E.W. Brown, Trimble County, Paddys Run 13 combustion turbines, and the Trimble County 1, Ghent 3 & 4, and Mill Creek 3 & 4 coal units.

Figure 1:

Retirement Candidates by Type:

	Net MW	
	Winter 2005	**Summer 2005**
Coal Steam	3,049	3,057
Hydro	56	72
CT	113	99
Total Capacity	**3,218**	**3,228**

Figure 1 shows the total MW of each capacity type of the KU and LG&E assets that were considered for the analysis. Figure 2 shows all KU and LG&E assets and shows the total capacity for those considered in the Life Assessment Analysis. These assets total 3,228 MW (summer). Highlighted assets were not considered in this assessment.

Figure 2:

Kentucky Utilities' Company / Louisville Gas and Electric Company

2006 Generator Ratings (MW)

Plant Name	Owner	In-Service Date	Net Winter 2005	Net Summer 2005	Unit Type	Fuel Type	Age as of December 31, 2006	Age as of December 31, 2035
Brown 1	KU	May 1, 1957	102	101	Steam	Coal	49 67	78 67
Brown 2	KU	June 1, 1963	169	167	Steam	Coal	43 58	72 58
Brown 3	KU	July 1, 1971	433	429	Steam	Coal	35 50	64 50
Total Brown Coal			**704**	**697**				
IAC on 11N2	KU	June 1, 2000		98	Inlet Air Cooling		6 58	35.58
Brown 5	Joint	June 8, 2001	143	117	CT	Natural Gas	5 56	34.56
Brown 6	Joint	August 11, 1999	168	154	CT	Natural Gas/Oil	7 39	36.39
Brown 7	Joint	August 8, 1999	168	154	CT	Natural Gas/Oil	7 40	36.40
Brown 8	KU	February 1, 1995	140	106	CT	Natural Gas/Oil	11 91	40.91
Brown 9	KU	August 1, 1994	140	106	CT	Natural Gas/Oil	12 42	41.42
Brown 10	KU	December 1, 1995	140	106	CT	Natural Gas/Oil	11 08	40.08
Brown 11	KU	May 1, 1996	140	106	CT	Natural Gas/Oil	10 67	39.67
Total Brown CT			**1,039**	**947**				
Cane Run 4	LGE	May 1, 1962	155	155	Steam	Coal	44 67	73 67
Cane Run 5	LGE	May 1, 1966	168	168	Steam	Coal	40 67	69 67
Cane Run 6	LGE	May 1, 1969	240	240	Steam	Coal	37 67	66 67
Total Cane Run			**563**	**563**				
Dix Dam 1	KU	November 1, 1925	8	8	Hydro	Water	81 16	110 16
Dix Dam 2	KU	November 1, 1925	8	8	Hydro	Water	81 16	110 16
Dix Dam 3	KU	November 1, 1925	8	8	Hydro	Water	81 16	110 16
Total Dix Dam			**24**	**24**				
Ghent 1	KU	February 1, 1974	468	475	Steam	Coal	32 91	61 91
Ghent 2	KU	April 1, 1977	466	484	Steam	Coal	29 75	58.75
Ghent 3	KU	May 1, 1981	495	493	Steam	Coal	25 67	54.67
Ghent 4	KU	August 1, 1984	495	493	Steam	Coal	22 41	51.41
Total Ghent			**1,924**	**1,945**				
Green River 3	KU	April 1, 1954	71	68	Steam	Coal	52 75	81 75
Green River 4	KU	July 1, 1959	102	95	Steam	Coal	47.50	76 50
Total Green River			**173**	**163**				
Haefling 1	KU	October 1, 1970	14	12	CT	Natural Gas/Oil	36 25	65 25
Haefling 2	KU	October 1, 1970	14	12	CT	Natural Gas/Oil	36 25	65 25
Haefling 3	KU	October 1, 1970	14	12	CT	Natural Gas/Oil	36 25	65 25
Total Haefling			**42**	**36**				
Mill Creek 1	LGE	August 1, 1972	303	303	Steam	Coal	34 41	63 41
Mill Creek 2	LGE	July 1, 1974	299	301	Steam	Coal	32 50	61.50
Mill Creek 3	LGE	August 1, 1978	397	391	Steam	Coal	28 42	57.42
Mill Creek 4	LGE	September 1, 1982	492	477	Steam	Coal	24 33	53.33
Total Mill Creek			**1,491**	**1,472**				
Ohio Falls 1	LGE	January 1, 1928	4	6	Hydro	Water	79 00	108 00
Ohio Falls 2	LGE	January 1, 1928	4	6	Hydro	Water	79 00	108 00
Ohio Falls 3	LGE	January 1, 1928	4	6	Hydro	Water	79 00	108 00
Ohio Falls 4	LGE	January 1, 1928	4	6	Hydro	Water	79 00	108 00
Ohio Falls 5	LGE	January 1, 1928	4	6	Hydro	Water	79 00	108 00
Ohio Falls 6	LGE	January 1, 1928	4	6	Hydro	Water	79 00	108 00
Ohio Falls 7	LGE	January 1, 1928	4	6	Hydro	Water	79 00	108 00
Ohio Falls 8	LGE	January 1, 1928	4	6	Hydro	Water	79 00	108 00
Total Ohio Falls Hydro			**32**	**48**				
Paddys Run 13	Joint	June 27, 2001	175	158	CT	Natural Gas	5 51	34.51
Total Paddys Run CT			**175**	**158**				
Trimble County 1	LGE	December 23, 1990	386	383	Steam	Coal	16 02	45.02
Total Trimble County			**386**	**383**				
Trimble County 5	Joint	May 14, 2002	180	160	CT	Natural Gas	4 63	33.63
Trimble County 6	Joint	May 14, 2002	180	160	CT	Natural Gas	4 63	33.63
Trimble County 7	Joint	June 1, 2004	180	160	CT	Natural Gas	2 58	31.58
Trimble County 8	Joint	June 1, 2004	180	160	CT	Natural Gas	2 58	31.58
Trimble County 9	Joint	July 1, 2004	180	160	CT	Natural Gas	2 50	31.50
Trimble County 10	Joint	July 1, 2004	180	160	CT	Natural Gas	2 50	31.50
Total Trimble County CT			**1,080**	**960**				
Tyrone 1	KU	October 1, 1947	30	27	CT	Oil	59 25	88.25
Tyrone 2	KU	June 1, 1948	33	31	CT	Oil	58 58	87.58
Tyrone 3	KU	July 1, 1953	73	71	Steam	Coal	53 50	82 50
Total Tyrone			**136**	**129**				
Cane Run 11	LGE	June 1, 1968	14	14	CT	Natural Gas/Oil	38 58	67 58
Paddy's Run 11	LGE	June 1, 1968	13	12	CT	Natural Gas	38 58	67 58
Paddy's Run 12	LGE	July 1, 1968	28	23	CT	Natural Gas	38 50	67.50
Waterside 7	LGE	June 1, 1964	13	11	CT	Natural Gas	42 58	71.58
Waterside 8	LGE	February 1, 1964	13	11	CT	Natural Gas	42 91	71.91
Zorn 1	LGE	May 1, 1969	16	14	CT	Natural Gas	37 67	66 67
Total LG&E CT's			**97**	**85**				
		Total Study Capacity	**3,218**	**3,228**		**Weighted age**	**38**	**67**

	Winter MW	Summer MW
Units that will be less than 60 yrs old in 2035 were not considered in the study	4,559	4,302
Units that were removed from service prior to 2010	89	80

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Phase 1 determined the effective useful economic life of 333 MW (summer net capacity) of the 3,228 MW (summer net capacity) of the life assessment candidates identified in Figure 2. The units designated by E.ON U.S. for evaluation in Phase 1 were: Green River 3 & 4 and Tyrone 3 coal fired steam units, and Haefling, Cane Run 11, Paddy's Run 11 & 12, and Zorn CTs. The CTs were "retired" at the end of 2009 and the coal fired steam units at the end of 2012 for the development of the Phase 1 Life Assessment Reference Plan.

Phase 2 determined the effective useful economic life of the remainder of the 3,228 MW of the life assessment candidates, or 2,895 MW. The effective useful economic lives determined in Phase 1 were incorporated into a newly developed Phase 2 Life Assessment Reference Plan as well as the plans that incorporate each Phase 2 life assessment candidate. All the candidate units included in Phase 2 were either coal fired steam or hydro units, so all of these units were assumed to "retire" at the end of 2012 for the purposes of developing the Phase 2 Life Assessment Reference Plan.

NewEnergy employed a *differential annual revenue requirements* methodology to determine the appropriate effective useful economic life for each unit. The first step involves assuming all the candidate units are "retired" in a specific year. For the life assessment candidates; combustion turbines (CTs) were "retired" at the end of 2009 and the coal and hydro units were "retired" at the end of 2012. These dates were chosen to correspond to the dates when equivalent replacement capacity could be installed. Then, a Reference Plan of replacement capacity was selected by Strategist's PROVIEW resource optimization module. This Reference Plan contains an appropriate mix of peaking, mid-range, and baseload capacity to meet future demand and energy requirements in a least cost method. These capacity types are represented by simple cycle combustion turbines, combined cycle combustion turbines, and coal fired steam generation, respectively.

The alternative resources available for developing the Life Assessment Reference Plans are described briefly in Figure 3. In addition to the annual maximum additions shown for each alternative, these resources were further restricted so that only one large coal unit, of any type, could be added in any one year. This restriction was adopted to limit capital outlay exposure. The only exception to this restriction was for 2013 during the Phase 2 Reference Plan optimization where a large portion of E.ON U.S.'s coal generating assets was "retired" and required more than one coal unit to replace that capacity. In that case, such a limitation would have left the system well below the required minimum reserve margin (see section F; "Results – Phase 2"). Combined Cycle and Simple Cycle Combustion Turbine generators were not limited against the other alternatives. The target minimum reserve margin constraint for the model optimization runs to develop the Life Assessment Reference Plans was set to 2% before 2010, and to 13.71%, 11.75%, and 10.63% for the years 2010, 2011, and 2012 respectively. The minimum target for 2010 through 2012 was adopted to maintain at least the same reserve margin of the base system with no retirements. The low reserve margin target before 2010 reflects an inability to build any new capacity prior to that time. After 2012, the target minimum reserve margin constraint was set to 14%. The 14% reserve margin minimum target from 2013 on reflects the desired long term minimum reserve margin for the system.

Figure 3:

Replacement Capacity Alternatives

Alternative Name	Description	Operating Life	Capacity	Capital Cost	First Year Available	Max per year	Study Period Max
LUSC	Ultra-Super Critical PC	50 years	766 MW	$1,906,270,000	2013	1	10
US_C	Ultra-Super Critical PC with Carbon Sequestration	50 years	613 MW	$2,756,233,000	2013	1	10
IGCC	Integrated Gasification Combined Cycle	50 years	611 MW	$1,758,982,000	2013	1	10
IG_C	Integrated Gasification Combined Cycle with Carbon Sequestration	50 years	488 MW	$2,146,299,000	2013	1	10
LGSC	Super Critical PC	50 years	766 MW	$1,862,896,000	2013	1	10
LG_C	Super Critical PC with Carbon Sequestration	50 years	613 MW	$2,718,858,000	2013	1	10
CCCT	Combined Cycle Combustion Turbine	40 years	552 MW	$465,368,900	2011	1	10
SCCT	Simple Cycle Combustion Turbine	30 years	181 MW	$78,687,500	2010	4	25

Capital Cost Values are shown in 2006$

Once the Reference Plan was developed, the replacement capacity was converted to "deferral capacity". The replacement resources designated as "deferrable" have their capacity adjusted to maintain the same reserve margin as the Reference Plan for all plans with Life Assessment candidate units included. Fixed O&M and capacity costs were also adjusted accordingly. In any year, the last unit added in the Reference Plan is the first one from which capacity is deferred. Due to the relatively high capital costs of the Carbon Sequestration units added in the later years, the Life Assessment candidate units were always less expensive to retain than the replacement carbon sequestration units. Since there were several years of negative PV annual revenue requirements differentials preceding the first of the carbon units, carbon sequestration units were not included in the deferrable capacity.

The basic system modeling was supplemented with specific cost data for each of the candidate units; projecting their O&M costs, capital expenditures (CapEx), property tax and insurance costs, as well as depreciation expenses out to 2035. These are discussed in more detail below. It is widely recognized that operating parameters such as EFOR, maintenance outage requirements, and heat rates increase (degrade) over the lifetime of an asset. Projections of future performance for aging generators would, ideally, be based on such data. However, no reliable source of data to project this performance degradation over the life of an asset currently exists. Thus, NewEnergy instead adopted the assumption that maintenance and capital expenditures would increase over the lifetime of the asset to hold performance at average lifetime levels. Data from OEM sources to support and model this assumption both exists and is readily available.

Fixed O&M costs and total capital costs (represented by the resource's Economic Carrying Charge) of the deferrable resources are also adjusted to reflect their computed capacities. The model is then run to determine the production costs for this adjusted system

The next step develops plans where each of the candidate units is not retired and assumes that each unit will then remain in service for at least 30 years. The Present Value (PV) of the annual revenue requirements is extracted from the model for each plan retaining one of the candidate units. The difference between these PV annual revenue requirements and the PV annual revenue requirements of the Reference Plan is then computed. The first year the difference is negative (the retention costs more than the retirement) is determined and this indicates the earliest potential date for the end of the asset's effective useful economic life. The PV annual revenue requirements differentials are then accumulated from that year forward and the point where the sum turns negative and remains negative is the latest potential date for the end of the asset's effective useful economic life. This is shown in the example in Figure 4; the earliest year that the example unit would reach the end of its effective useful economic life in this case is 2014, with the latest economic retirement in 2018.

A possible situation, which does arise with some Phase 2 units, is that the first negative year for PV annual revenue requirements occurs relatively early, and then several years with positive PV annual revenue requirements follow before the annual PV differential values become negative again. This results in pushing the end of the asset's effective useful economic life out by several years while an accumulated positive differential sum is eliminated by the subsequent accumulation of negative differentials. It is not reasonable to wait until all the benefits accumulated during the intervening positive differential years are eliminated by retaining the unit for several years of negatives. In these cases, it is sensible to ignore the first occurrence of a negative differential, and to wait for the differential series to show stable negatives before beginning the summation.

It is possible for the methodology to indicate *no* end of effective useful economic life for a particular unit in the time frame of the study; in this case through 2035. This means that, based upon the assumptions used, the actual end of the asset's effective useful economic life is beyond 2035.

Figure 4:

Illustration of the Determination of the Effective Useful Economic Life For a Life Assessment Candidate Unit

Year	Differential Annual Revenue Requirements	Cumulative NPV of Differential Annual Revenue Requirements (2014 and beyond)
2010	$1.00	
2011	$1.50	
2012	$0.80	
2013	$0.60	
2014	($0.03)	($0.03)
2015	($0.50)	($0.53)
2016	$0.40	($0.13)
2017	$0.30	$0.17
2018	($0.50)	($0.33)
2019	($0.70)	($1.03)
2020	($1.00)	($2.03)
2021	($0.60)	($2.63)
2022	($0.20)	($2.83)
2023	$0.20	($2.63)
2024	$0.50	($2.13)
2025	($0.80)	($2.93)
2026	($0.10)	($3.03)
2027	$0.05	($2.98)
2028	$0.01	($2.97)
2029	($0.40)	($3.37)
2030	($0.10)	($3.47)
2031	($0.50)	($3.97)
2032	$0.30	($3.67)
2033	$0.50	($3.17)
2034	($0.30)	($3.47)
2035	($0.10)	($3.57)

C. Model Data and Assumptions:

E.ON U.S. provided NewEnergy with their latest Strategist database, translated from a PowerBase database. This basic data included all operating parameters and costs for the existing generation units in the KU and LG&E system. This includes EFOR, scheduled outage requirements, heat rates, variable and fixed operating and maintenance costs for all the generating assets, as well as load and fuel cost forecasts over the study horizon (2006 to 2035). A loads and resources summary report from the Strategist model reflecting only the existing system for selected years over the study horizon is shown in Figure 5.

Figure 5:

Loads and Resources 2006 - 2035

	2006	2010	2015	2020	2025	2030	2035
LOADS							
=====							
PEAK BEFORE DSM	6948.3	7434	8023	8597	9142	9735	10313
+ DSM ADJUSTMENTS	-112.3	-162.5	-167.4	-165.4	-141.9	-138.7	-138.7
-----------------	-----------	-----------	-----------	-----------	-----------	-----------	-----------
FINAL PEAK	6836	7271.5	7855.6	8431.6	9000.1	9596.3	10174.3
RESOURCES							
=========							
TOTAL HYDRO	59.6	75.5	94.9	94.9	94.9	94.9	94.9
TOTAL THERMAL	7724.9	8099.2	8099.2	8099.2	8099.2	8099.2	8099.2
TOTAL CAPACITY	7784.5	8174.7	8194.1	8194.1	8194.1	8194.1	8194.1
RESERVES							
========							
RESERVE (MW)	948.6	903.2	338.5	-237.5	-806	-1402.2	-1980.2
RESERVE MARGIN PERCENT	13.88	12.42	4.31	-2.82	-8.96	-14.61	-19.46
CAPACITY MARGIN PERCENT	12.19	11.05	4.13	-2.9	-9.84	-17.11	-24.17

Historical O&M costs and capital expenditure streams for individual units are significantly volatile with large expenditures in some years and very little expenditures in others. This creates problems in projecting the forward trajectory for these costs. Furthermore, Capital Expenditures should be amortized over the remaining life of the asset. Some of these Capital Expenditure (CapEx) outlays would also be expected to extend the life of the asset, requiring a rolling realignment of capital depreciation for every year of the asset's remaining life. Strategist is, unfortunately, unable to handle this internally so a complex spreadsheet calculation would be required to determine the proper annual revenue requirements impacts associated with CapEx. This procedure is both unwieldy and error prone; so a simplifying assumption to treat the CapEx outlays as if they were expenses for the "extended" life of the retained assets was made.

Projections of the depreciation streams were also needed. It was assumed that since the candidate resources all are retired at specific times (the end of 2009 for CTs, the end of 2012 for Hydro and Coal Steam units), that any net plant balance at that time would have to be reallocated over the assumed additional 30 year life of the resource if it is retained. The depreciation was calculated using straight line depreciation. The calculation of property tax and insurance costs were determined by E.ON U.S. experts in those areas.

All five of these cost streams (O&M, capital expenditures, depreciation, property taxes, and insurance) were then added together for each year of the "extended life" of the asset and overlaid on the Fixed O&M Cost within the Strategist model's database for each candidate unit.

Finally, the candidate units were overlaid on the Reference Plan one at a time and the Present

Value of each year's revenue requirements (equivalent to the PV Utility Cost model output from PROVIEW) was extracted from the model and the differentials with the Reference Plan calculated.

D. Results – Reference Plan

The Life Assessment Reference Plans developed for Phase 1 and Phase 2 are shown below in Figure 6. Please note that the large number of units added in 2013 for the Phase 2 Reference Plan is the result of "replacing" the large amount of capacity that the candidate units represent. For Phase 2, two units were again needed in 2018 due to capacity that had reached the end of its effective useful economic life as projected from Phase 1. These "retirements" were included in the underlying base data for Phase 2.

Figure 6:

Life Assessment Reference Plans

	Phase 1 Reference Plan		Phase 2 Reference Plan
2006			
2007			
2008			
2009			
2010	SCCT(1)		
2011			SCCT(1)
2012			
2013	LGSC(1)		LGSC(7)
2014	SCCT(1)		
2015	SCCT(1)		SCCT(1)
2016	SCCT(1)		SCCT(1)
2017			SCCT(1)
2018	LG_C(1)		SCCT(2)
2019			SCCT(1)
2020			SCCT(1)
2021			SCCT(1)
2022	LG_C(1)		LG_C(1)
2023			
2024			
2025			
2026	IG_C(1)		IG_C(1)
2027			
2028			
2029	LGSC(1)		
2030			SCCT(1)
2031			IG_C(1)
2032			
2033			
2034			SCCT(1)
2035	LG_C(1)		SCCT(1)
2036			IG_C(1)
P.V. UTILITY COST:			
PLANNING PERIOD	$ 18,235,858		$ 23,785,290
END EFFECTS PERIOD	$ 9,224,502		$ 10,936,946
STUDY PERIOD	$ 27,460,360		$ 34,722,236

E. Results – Phase 1:

The numeric results of Phase 1 are presented in Figures 7 and 8. The end of effective useful economic lives for the coal fired steam generation in Phase 1, Green River 3 & 4 and Tyrone 3, are all 2018. Note that the first year with a negative value for Green River 3 is 2016, but the positive value in 2017 offsets this, as well as the negatives in the next several years, delaying the next accumulated negative until 2021. For this reason the negative value in 2016 is ignored, resulting in a projected end of effective useful economic life for Green River 3 in 2018. None of the peaking turbines show a projected end of effective useful economic life. This is due to the fact that once sufficient new peaking capacity is added, these units generate at very low capacity factors and the overall cost of retaining this capacity is relatively low.

Figure 7:

Phase 1

Present Value Utility Cost Differentials vs. All New Build Plan

(PVUC New Build - PVUC Existing Unit)

	Coal Steam Green River 3	Coal Steam Green River 4	Coal Steam Tyrone 3	Gas CT Cane Run 11	Gas CT Haefling	Gas CT Paddy's Run 11	Gas CT Paddy's Run 12	Gas CT Zorn	All New Build
2006	$0	$0	$0	$0	$0	$0	$0	$0	$0
2007	$0	$0	$0	$0	$0	$0	$0	$0	$0
2008	$0	$0	$0	$0	$0	$0	$0	$0	$0
2009	$0	$0	$0	$0	$0	$0	$0	$0	$0
2010	$0	$0	$0	$270	$2	$290	($146)	$430	$0
2011	$0	$0	$0	$618	$1,607	$517	$1,080	$628	$0
2012	$0	$0	$0	$611	$1,542	$518	$1,042	$622	$0
2013	$2,556	$3,583	$2,728	$980	$2,472	$838	$1,615	$992	$0
2014	$711	$1,089	$782	$542	$1,367	$463	$925	$555	$0
2015	$738	$961	$853	$480	$1,275	$434	$841	$525	$0
2016	($159)	$802	$619	$480	$1,234	$414	$824	$494	$0
2017	$624	$930	$132	$454	$1,137	$391	$780	$468	$0
2018	($2)	($38)	($49)	$436	$1,078	$379	$741	$451	$0
2019	($60)	($504)	($68)	$392	$980	$339	$662	$406	$0
2020	($322)	($162)	($169)	$347	$934	$322	$619	$386	$0
2021	($265)	($181)	($140)	$344	$869	$300	$602	$359	$0
2022	($460)	($548)	($452)	$325	$819	$283	$565	$339	$0
2023	($889)	($561)	($604)	$305	$779	$266	$531	$319	$0
2024	($485)	($701)	($949)	$281	$726	$244	$495	$295	$0
2025	($511)	($725)	($651)	$244	$652	$229	$446	$276	$0
2026	($491)	($1,081)	($635)	$249	$625	$218	$437	$262	$0
2027	($507)	($767)	($649)	$227	$572	$200	$401	$240	$0
2028	($549)	($827)	($667)	$228	$545	$204	$385	$240	$0
2029	$744	$983	$658	$453	$1,159	$393	$773	$466	$0
2030	$426	$908	$606	$405	$1,083	$363	$707	$431	$0
2031	$535	$689	$221	$383	$971	$333	$652	$394	$0
2032	$459	$590	$377	$346	$891	$301	$597	$357	$0
2033	$262	$85	$174	$300	$755	$262	$513	$310	$0
2034	$237	$287	$151	$277	$706	$242	$478	$287	$0
2035	$616	$813	$550	$336	$881	$302	$579	$357	$0

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Figure 8:

Phase 1

Accumulated PV Utility Cost from First Year with a Negative Differential

	Coal Steam Green River 3	Coal Steam Green River 4	Coal Steam Tyrone 3	Gas CT Cane Run 11	Gas CT Haefling	Gas CT Paddy's Run 11	Gas CT Paddy's Run 12	Gas CT Zorn	All New Build
2006									$0
2007									$0
2008									$0
2009									$0
2010							($146)		$0
2011							$933		$0
2012							$1,975		$0
2013							$3,590		$0
2014							$4,515		$0
2015							$5,357		$0
2016							$6,181		$0
2017							$6,961		$0
2018	($2)	($38)	($49)				$7,702		$0
2019	($62)	($542)	($117)				$8,364		$0
2020	($385)	($704)	($286)				$8,983		$0
2021	($650)	($885)	($426)				$9,584		$0
2022	($1,110)	($1,433)	($879)				$10,149		$0
2023	($1,999)	($1,994)	($1,483)				$10,680		$0
2024	($2,483)	($2,695)	($2,431)				$11,175		$0
2025	($2,994)	($3,420)	($3,083)				$11,622		$0
2026	($3,485)	($4,500)	($3,717)				$12,058		$0
2027	($3,992)	($5,267)	($4,366)				$12,460		$0
2028	($4,541)	($6,094)	($5,033)				$12,845		$0
2029	($3,797)	($5,111)	($4,375)				$13,618		$0
2030	($3,371)	($4,203)	($3,769)				$14,325		$0
2031	($2,836)	($3,514)	($3,548)				$14,978		$0
2032	($2,378)	($2,924)	($3,172)				$15,574		$0
2033	($2,116)	($2,839)	($2,998)				$16,087		$0
2034	($1,879)	($2,552)	($2,847)				$16,565		$0
2035	($1,263)	($1,739)	($2,297)				$17,144		$0

F. Results – Phase 2:

Phase 2, utilized the demonstrated methodology from Phase 1. In developing the Reference Plan for Phase 2, a significant capacity shortfall occurs in 2013, primarily due to the large amount of candidate unit capacity "retiring" for the Reference Plan but also due to demand growth. Multiple coal fired technology units were required to overcome this shortfall. The numbers of each alternative unit required to cover the shortfall is shown in Figure 9.

Figure 9:

Capacity Additions to Cover 2013 Shortfall

Capacity Needed	
5190 MW	Includes Ghent 3 & 4, and Mill Creek 3 & 4
2895 MW	Excludes Ghent 3 & 4, and Mill Creek 3 & 4

	Max Capacity	Deration %	Summer Rating	Number to meet 5290 MW need	Number to meet 2895 MW need
LUSC	766	3.66%	737.9644	7.033	3.923
LGSC	766	3.50%	739.19	7.021	3.916
IGCC	611	10.97%	543.9733	9.541	5.322
LG_C	612.8	3.50%	591.352	8.777	4.896
CCCT	552	13.88%	475.3824	10.918	6.090
SCCT	181	18.23%	148.0037	35.068	19.560
IG_C	488.8	10.97%	435.17864	11.927	6.652
US_C	612.8	3.66%	590.37152	8.791	4.904

Note: Ghent 3 & 4, and Mill Creek 3 & 4 were initially considered as candidate units when the Phase 2 Reference Plan was developed. The Reference Plan shown for Phase 2 in Figure 2 was developed using the 5190 MW need in 2013. A Reference Plan using the 2895 MW need would have only required 4 LUSC units in 2013 to cover the reserve shortfall from "retiring" the Phase 2 candidate assets.

The final results for Phase 2 are presented in Figures 10 and 11. Most of the projected end of effective useful economic life schedules for this group of units fall in the 2026 to 2028 time frame: Ghent 1 in 2026, Ghent 2 in 2027, Mill Creek 1 and 2 in 2026, and all three Brown units in 2026. Brown 2 shows an early negative in 2015, but this should be ignored. Cane Run 4 retires in 2018, Cane Run 5 retires in 2022, and Cane Run 6 retires in 2023. Both of the hydro plants, Dix Dam and Ohio Falls, show an effective useful economic life throughout the study period.

Figure 10:
Phase 2
Present Value Utility Cost Differentials vs. All New Build Plan
(PVUC New Build - PVUC Existing Unit)

	Brown 1	Brown 2	Brown 3	Cane Run 4	Cane Run 5	Cane Run 6	Dix Dam	Ghent 1	Ghent 2	Mill Creek 1	Mill Creek 2	Ohio Falls	All New Build
2006	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2007	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2008	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2009	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2010	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2011	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2012	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2013	$6,166	$10,801	$33,006	$6,925	$9,499	$13,584	$3,066	$36,183	$40,630	$18,860	$19,578	$10,853	$0
2014	$4,981	$6,603	$30,791	$6,200	$8,619	$12,549	$2,971	$32,362	$37,562	$9,539	$18,224	$14,727	$0
2015	$2,668	($517)	$26,483	$2,979	$3,006	$9,212	$1,995	$29,656	$33,305	$13,778	$14,381	$11,769	$0
2016	$1,886	$3,517	$19,576	$66	$2,101	$1,036	$1,937	$22,755	$26,103	$7,816	$8,526	$11,618	$0
2017	$1,906	$3,527	$14,333	$65	$2,448	$3,453	$1,940	$16,888	$20,404	$5,457	$4,111	$11,611	$0
2018	$2,097	$3,893	$12,675	($1,838)	$2,878	$3,914	$1,942	$13,697	$17,454	$4,569	$6,633	$11,670	$0
2019	$2,063	$3,939	$11,906	$325	$2,800	$4,072	$1,910	$13,625	$16,298	$6,290	$6,559	$11,710	$0
2020	$2,036	$3,370	$12,128	$157	$2,585	$3,808	$1,910	$12,596	$15,884	$5,500	$6,097	$11,706	$0
2021	$1,478	$3,407	$12,156	$216	$2,696	$3,850	$1,921	$11,708	$15,528	$6,182	$6,085	$11,725	$0
2022	$840	$742	$5,231	($1,704)	($1,560)	$992	$1,753	$4,953	$8,190	$2,180	$2,425	$10,709	$0
2023	$735	$1,244	$4,634	($1,837)	$337	($1,187)	$1,786	$4,249	$7,412	$1,992	$2,130	$10,836	$0
2024	$518	$892	$3,623	($2,062)	$116	$187	$1,820	$3,195	$5,972	$1,392	$1,575	$10,892	$0
2025	$443	$804	$2,936	($3,979)	$14	$61	$1,801	$2,465	$5,416	$1,292	$72	$11,016	$0
2026	($202)	($32)	($1,187)	($2,709)	($750)	($1,067)	$1,682	($2,155)	$1,069	($1,226)	($166)	$10,469	$0
2027	($353)	($327)	($1,754)	($2,951)	($1,035)	($1,474)	$1,687	($3,070)	($73)	($740)	($599)	$10,574	$0
2028	($972)	($921)	($3,226)	($3,495)	($1,587)	($2,149)	$1,675	($4,410)	($1,680)	($1,469)	($1,446)	$10,698	$0
2029	($688)	($1,481)	($3,940)	($3,510)	($3,154)	($2,423)	$1,686	($5,255)	($2,529)	($1,850)	($1,746)	$10,674	$0
2030	($686)	($1,133)	($4,210)	($3,534)	($1,842)	($3,874)	$1,651	($5,706)	($3,007)	($1,988)	($1,939)	$10,457	$0
2031	($615)	($1,101)	($5,476)	($3,414)	($1,752)	($2,438)	$1,508	($6,844)	($4,038)	($1,955)	($1,795)	$9,508	$0
2032	($606)	($1,056)	($5,126)	($4,621)	($1,676)	($2,360)	$1,433	($6,321)	($3,695)	($1,845)	($1,801)	$9,090	$0
2033	($602)	($1,002)	($4,026)	($3,225)	($1,636)	($2,266)	$1,375	($5,346)	($2,598)	($1,690)	($2,300)	$8,723	$0
2034	($570)	($950)	($3,684)	($3,121)	($1,572)	($2,229)	$1,313	($4,729)	($2,568)	($2,115)	($1,593)	$8,316	$0
2035	($771)	($841)	($2,904)	($2,964)	($1,469)	($2,147)	$1,260	($3,645)	($1,940)	($1,347)	($1,449)	$7,968	$0

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Figure 11:
Phase 2
Accumulated PV Utility Cost from First Year with a Negative Differential

	Brown 1	Brown 2	Brown 3	Cane Run 4	Cane Run 5	Cane Run 6	Dix Dam	Ghent 1	Ghent 2	Mill Creek 1	Mill Creek 2	Ohio Falls	All New Build
2006													
2007													
2008													
2009													
2010													
2011													
2012													
2013													
2014													
2015													
2016													
2017													
2018				($1,838)									
2019				($1,513)									
2020				($1,356)									
2021				($1,140)									
2022				($2,843)	($1,560)								
2023				($4,680)	($1,223)	($1,187)							
2024				($6,743)	($1,107)	($1,000)							
2025				($10,722)	($1,093)	($939)							
2026	($202)	($32)	($1,187)	($13,431)	($1,843)	($2,006)		($2,155)		($1,226)	($166)		
2027	($554)	($359)	($2,941)	($16,382)	($2,878)	($3,480)		($5,224)	($73)	($1,966)	($765)		
2028	($1,527)	($1,280)	($6,167)	($19,877)	($4,465)	($5,629)		($9,635)	($1,753)	($3,435)	($2,211)		
2029	($2,215)	($2,760)	($10,106)	($23,386)	($7,618)	($8,052)		($14,890)	($4,282)	($5,285)	($3,958)		
2030	($2,900)	($3,894)	($14,316)	($26,921)	($9,460)	($11,925)		($20,596)	($7,289)	($7,273)	($5,897)		
2031	($3,515)	($4,994)	($19,792)	($30,335)	($11,211)	($14,364)		($27,440)	($11,327)	($9,228)	($7,692)		
2032	($4,121)	($6,050)	($24,918)	($34,956)	($12,888)	($16,724)		($33,761)	($15,022)	($11,073)	($9,492)		
2033	($4,723)	($7,052)	($28,944)	($38,181)	($14,523)	($18,989)		($39,107)	($17,620)	($12,763)	($11,792)		
2034	($5,293)	($8,002)	($32,627)	($41,302)	($16,096)	($21,219)		($43,835)	($20,188)	($14,878)	($13,385)		
2035	($6,064)	($8,844)	($35,531)	($44,266)	($17,565)	($23,365)		($47,481)	($22,128)	($16,225)	($14,833)		

G. Summary

NewEnergy Associates, LLC performed a Life Assessment of E.ON U.S.'s generating assets to determine the effective useful economic lives of these assets. Figure 12 summarizes the results of this Life Assessment study and shows the projected end of useful economic life for E.ON U.S.'s coal fired steam assets. The assessment of the economics of continuing to operate E.ON U.S.'s combustion turbine assets; the Haefling units, Cane Run 11, Paddy's Run 11 & 12 and Zorn 1, indicates that these assets should continue to be economic throughout the time horizon of the study (through 2035).

Figure 12:

End of Economic Life

Unit Name	Projected End of Economic Life
Brown 1	2026
Brown 2	2026
Brown 3	2026
Cane Run 4	2018
Cane Run 5	2022
Cane Run 6	2023
Ghent 1	2026
Ghent 2	2027
Green River 3	2018
Green River 4	2018
Mill Creek 1	2026
Mill Creek 2	2026
Tyrone 3	2018

H. Appendices

Appendix A
Project Tasks by Phase

Task No. / Phase No.	Task Description	Lead	Support	Comments
Task1, Phase 1	Develop a Strategist expansion plan with 600 MW of life assessment candidate units (out of a potential of 2.995 MW of life assessment candidate units) "retired in 2010 (CTs) and 2012 (coal). This plan will be the Phase 1 Life Assessment Reference Plan For the purposes of this study the E ON system will be modeled as an isolated system (i e - market sales and purchases will not be modeled).	NewEnergy	E ON	NewEnergy will rely on E ON data for this analysis, including all existing and new unit parameters, fuel costs, emission allowance costs, etc The cost of retiring units along with any unrecovered book costs will be incorporated into the revenue requirements of the Phase 1 Life Assessment Reference Plan New Energy will work with E ON to develop these costs in Task 2
Task 2, Phase 1	For each retirement candidate unit (or combination of units) develop cost data for (a) retiring the unit and (b) maintaining the unit in operation For units that remain in operation develop forecasted operating parameters (EFOR, Scheduled outage requirements) if this will change as the unit continues operation	E ON	NewEnergy	NewEnergy will assist E.ON in developing the cost framework and will review the results to ensure completeness Forecasted operating parameters will be E ON's responsibility
Task 3, Phase 1	Employing the "deferral capacity" logic in Strategist to keep installed reserves constant, add each retirement unit (or combination of units) back into the system and recalculate the expansion plan's costs Using the economic carrying charge to model the impacts of deferring investment costs, construct an economic ranking of all retirement candidates (or combination), showing the NPV of each candidate's impact vs the Life Assessment Reference Plan and the Year-by-year cumulative NPV Identify each life assessment candidate's retirement date using the approach described in this proposal.	NewEnergy	E ON	The deferral capacity logic in Strategist will permit the retirement candidate to be evaluated by keeping reserves or reliability (or a combination thereof) constant It defers a rolling "slice" of new capacity, thereby incorporating the net capital and operating revenue requirements and dispatch impacts of the adjusted new capacity and the retirement candidate into the analysis
Task 4, Phase 1	Develop a draft PowerPoint presentation of results for E ON review and incorporate E ON comments to finalize it Present the results at E ON's offices in Louisville Prepare and transfer Strategist data files and other data used for the study to E.ON.	NewEnergy	E ON	
Task1, Phase 2	Develop a Strategist expansion plan for the remainder of the 2,995 MW of life assessment candidate units **not evaluated in Phase 1.** Incorporate any Phase 1 retirements into Phase 2 and develop a Phase 2 Life Assessment Reference Plan For purposes of this study. the E ON system will be modeled as it was modeled in Phase 1 (i.e : as an isolated system, without any market sales and purchases).	NewEnergy	E ON	NewEnergy will rely on E ON data for this analysis, including all existing and new unit parameters, fuel costs, emission allowance costs, etc The cost of retiring units along with any unrecovered book costs will be incorporated into the revenue requirements of the Phase 1 Life Assessment Reference Plan New Energy will work with E ON to develop these costs in Task 2
Task 2, Phase 2	For each retirement candidate unit (or combination of units) develop cost data for (a) retiring the unit and (b) maintaining the unit in operation For units that remain in operation develop forecasted operating parameters (EFOR, Scheduled outage requirements) if this will change as the unit continues operation.	E ON	NewEnergy	NewEnergy will assist E ON in developing the cost framework and will review the results to ensure completeness Forecasted operating parameters will be E ON's responsibility
Task 3, Phase 2	Same as Task 3, Phase 1	NewEnergy	E ON	Same as Task 3, Phase 1
Task 4, Phase 2	Same as Task 4, Phase 1 with the addition of a written report covering all assumptions, modeling and results from both Phase 1 and Phase 2.	NewEnergy	E ON	

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Kentucky Utilities Company

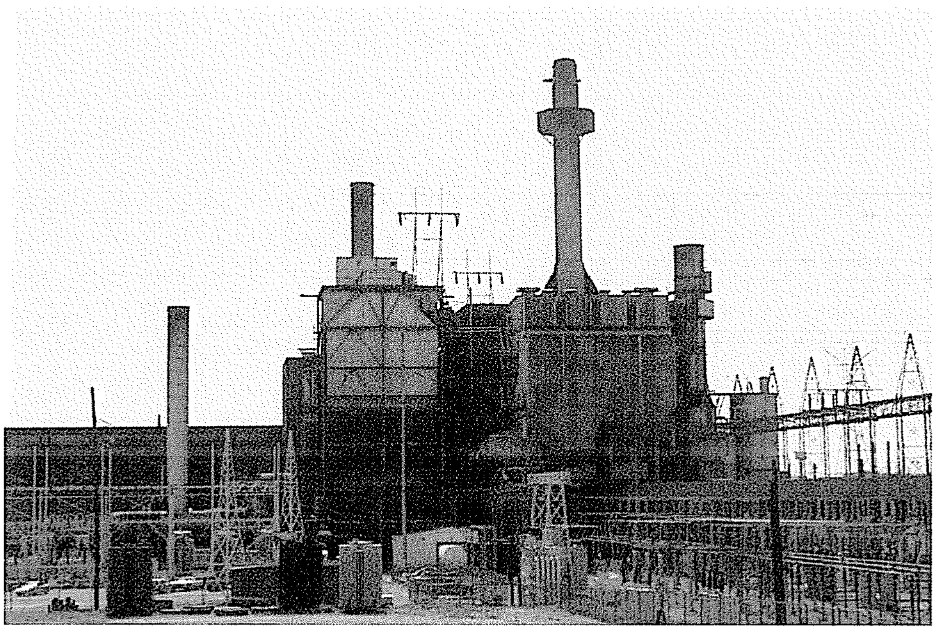
And

Louisville Gas and Electric Company

Phase II

Evaluation of the Economic Viability of

Green River Units 1 and 2



Prepared by: Generation Services

October 2003

Evaluation of the Economic Viability of Green River Units 1 and 2 (Phase II)

-Table of Contents

Executive Summary

This is the second of a two-phase evaluation of the economics associated with the continued operation of select KU/LG&E units. This evaluation focuses on Green River Units 1-2. Green River Units 1-2 are KU owned and operated coal-fired units constructed in 1950 with a combined summer capability of 44MW. The Units are currently operating with a full time staff consisting of eight unit operators and four scrubber operators, each represented by the United Steel Workers Association. The high heat rate of the units combined with the operational costs of the scrubber continues to suppress the annual generation as other less costly sources of generation are often available. Since 1990 there has been only one year that the annual capacity factor of Units 1 or 2 exceeded 20%. The approaching NO_x reduction requirements associated with the 2004 ozone season further exacerbate the economics of the units making them much less cost effective to operate.

Recently the units have experienced boiler tube failures and forced outages that indicate significant plant investment is needed to maintain an appropriate margin of safety. Significant portions of the units are creating a continually decreasing safety margin associated with unit operation. A minimum of $8+ million maintenance expenses alone (exclusive of labor costs) is required if continued safe and reliable operation of the facilities is to be achieved.

This evaluation compared the incremental costs associated with the retirement of both generating units and the scrubber to the costs of their continued operation through a ten year period ending 2012. The evaluation was conducted from three perspectives. Each perspective evaluated both a base set of assumptions and set of sensitivity assumptions. The three perspectives were (1) a regulated company perspective using present value revenue requirements, (2) a regulated company using present value cash flow and finally (3) a merchant/unregulated company using a present value cash flow. Savings were realized under all but one scenario evaluated (see table below). Savings occur in predominantly three areas: company labor ($5+ million NPV), environmental emissions costs ($5+ million NPV) and avoided non-labor maintenance and capital expenses ($10+ million NPV). All of these savings occur with only a modest increase in system production costs (less than $200,000 assuming a $100/MWh purchase or only $1.8 million if a $1,000/MWh purchase market is used).

Based on this evaluation it is recommended that Green River Units 1-2 and the scrubber be retired from service. Furthermore, since there are safety concerns regarding the operation of Green River Units 1-2 that can only be addressed with significant investment and since a significant portion of savings is labor-related, it is recommended that the units no longer be committed to serve load and that retirement occur as soon as possible.

Benefit of Retiring Green River Units 1-2 and the Scrubber in 2003
(2003 Present Value)

Scenario	**Case 1** Regulated Environment Net Present Value Revenue Requirements	**Case 2** Regulated Environment Net Present Value Cash Flow Analysis	**Case 3** Merchant Environment Net Present Value Cash Flow Analysis
Base	$23,432,000	$15,388,000	$12,272,000
Scenario 1	$956,000	$6,544,000	[redacted]
Scenario 2	$21,800,000	$14,415,000	[redacted]
Scenario 3	($676,000)	$5,570,000	[redacted]

Background

The Green River Power Station is located off of US Highway 431 on the Green River in Muhlenberg County, Kentucky and is wholly owned and operated by Kentucky Utilities Company (KU), a subsidiary of LG&E Energy Corp. The plant was constructed during the late 1940's–1950's and houses four coal-fired generating units totaling 212MW (summer). The Green River supplies water to the plant.

Units 1-2 began commercial operation on March 1, 1950 and January 5, 1950 respectively. Generating Units 1-2 are supplied steam from three interconnected B&W front wall-fired, non-reheat boilers rated at 215,000 lbs/hr steam capacity each, 875 psig, 910° F. Boilers 1-3 are medium sulfur coal-fired boilers and supply steam to two Westinghouse steam turbines (generators 1-2), summer rated at 22MW each and operating at 850 psig and 900° F (boiler 4 supplies generator 3 and boiler 5 supplies generator 4). The cooling water system is a once-through type. In the 1970's a Flue Gas Desulfurization system (FGD or "scrubber") was constructed to service both Units 1-2 and is currently operating with an approximately 80% SO_2 removal efficiency. Coal is delivered to the station by truck. The units have Continuous Emission Monitoring (CEM) systems to monitor stack emissions and are normally operated with a capacity factor below 20%. There is a full time operations staff dedicated to these units and the scrubber.

In early 2003, Green River Units 1-2 were identified as potential candidates for retirement in the first of a two phase report entitled *Evaluation of Economic Viability of Group 3 Generating Units*. Phase I of this evaluation quantified the incremental costs and savings associated with the simultaneous retirement of Green River Units 1-2. The major cost assumptions for the Base Scenario of that study are summarized in the next section of this document, Phase I Assumptions: Summary. To briefly review, the analysis considered how the various assumptions for capacity replacement cost, purchase power market prices and any necessary capital investment would affect the decision to retire Green River Units 1-2. The financial evaluation was then conducted from both a regulated and non-regulated company perspective using present value revenue requirements and present value cash flows decision criterion. Results of the Phase I evaluation indicated that the retirement of Green River Units 1-2 could be of economic benefit to the Company and as such, it was recommended that the retirement of Green River Units 1-2 be further evaluated in Phase II. Thus, this evaluation takes a closer look at the following issues and their associated costs as they pertain to the continued economic operation of the two units: safety, environmental compliance and scrubber re-use, maintenance, production cost, staffing issues, reserve margin impacts and fuel contract issues.

Phase I Study Assumptions: Summary

Phase I of this evaluation quantified the incremental costs and savings associated with the simultaneous retirement of Green River Units 1-2. Below are the base assumptions used in the Phase I analysis for reference. These values represent the starting point for this analysis. Note that negative values should be interpreted as cost savings in the event that Green River Units 1-2 are retired.

Table 1
Green River 1-2
Phase I: Base Financial Assumptions
Cost Savings assoc w/ retirement shown as (-)
(Nominal Years Dollars x $1,000)

Variable	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV ($000)
Production	$249	$16	$0	$0	$0	$0	$60	$0	$0	$0	$300
SO_2/NO_x	$52	($632)	($1,015)	($1,199)	($936)	($846)	($848)	($1,387)	($946)	($1,046)	($5,806)
Insurance	($66)	($66)	($66)	($66)	($66)	($66)	($66)	($66)	($66)	($66)	($467)
Air & Water Permit/Usage Fees	($20)	($20)	($20)	($20)	($20)	($20)	($20)	($20)	($20)	($20)	($141)
Labor O&M	($451)	($460)	($469)	($479)	($488)	($498)	($508)	($518)	($528)	($539)	($3,439)
Non-Labor O&M	($75)	($300)	($300)	($150)	($153)	($156)	($159)	($162)	($166)	($169)	($1,284)
Levelized Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Asset Retire Cost	$24	$0	$0	$0	$0	$0	$0	$0	$0	$0	$24
Capacity Benefit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Write Off/ Depreciation	$2,365	($335)	($335)	($335)	($335)	($335)	($335)	($335)	($335)	($335)	$332
Severance	$92	$0	$0	$0	$0	$0	$0	$0	$0	$0	$92
Phase I Estimated Retirement Savings ($000)-Base Scenario											**($10,389)**

Note: NPV in Phase I analysis used a discount rate = 8.74%

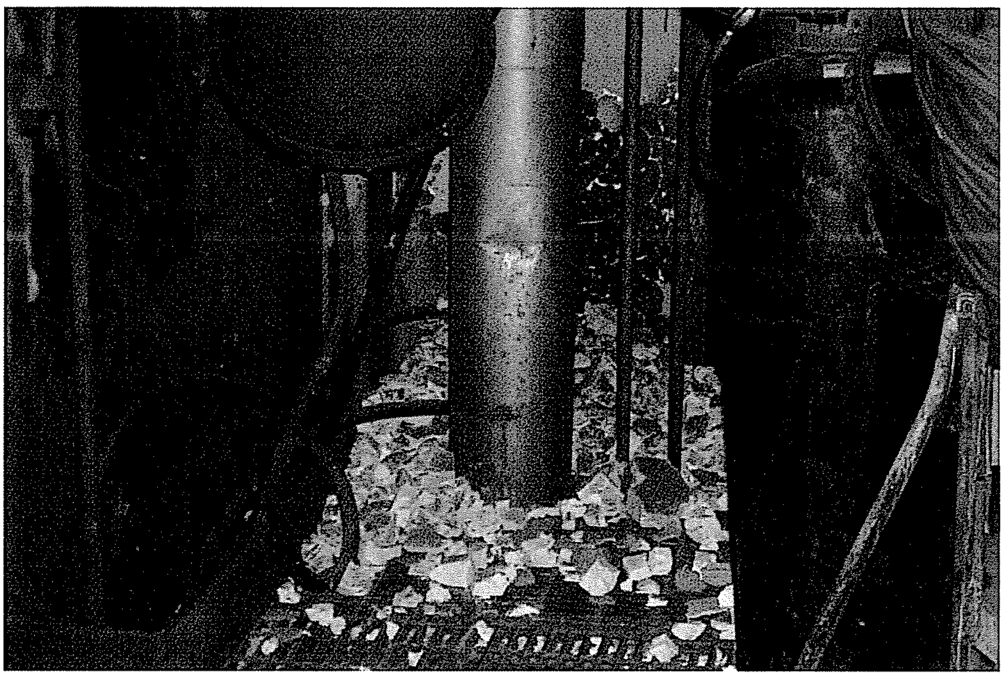
Safety Issues

The primary risk to safe operation of the units in the near term is the increasing occurrence of boiler tube leaks on both units. On January 21, 2003 at 12:50 p.m. a "boiler puff" occurred on boiler number 1 producing an explosion of magnitude strong enough to dislodge a significant amount of refractory and cause additional boiler tube damage resulting in additional unit outage time.

While operating at or around full load a generator tube failed. (Generator tubes connect the steam drum and the mud drum of relatively low pressure boilers like Green River boilers 1, 2 and 3). The tube failure immediately quenched the fireball. Manual observation of the boiler fire is the only way to detect flame out on these boilers since individual burner flame detection controls or closed circuit TV monitoring of the furnaces do not exist. Because manual observation is required, a period of time exists in which the boilers continue to receive pulverized coal from the fuel delivery system. Boilers 1-3 burn pulverized coal supplied by six B&W ball mills, two mills per boiler. Each mill is capable of supplying 9.15 tons of pulverized coal per hour to a boiler. This is equivalent in total to approximately 610 pounds of coal per minute being supplied to each boiler at full capacity. If one assumes a unit operator was physically at the observation window of boiler 1 when the generating tube failure and subsequent flame out occurred and could return to the control room to close all the necessary dampers and shut down all six coal mills 30 seconds after flame out, the boiler would have over 300 pounds of combustible fuel delivered to the hot boiler creating a potentially explosive situation. On January 21, 2003, conditions were such that the fuel ignited and produced an explosion of magnitude strong enough to cause additional tube and refractory damage resulting in additional unit outage time. This explosion is commonly referred to in the industry as "puffing the boiler". By Monday, February 24, 2003 the boiler repairs were completed and Generating Units 1–2 were again available for operation at full load.

Refractory and brick insulation after being damaged by a boiler "puff" of Green River Boiler #1

(January 2003)



Refractory and brick insulation after being damaged by a boiler "puff" of Green River Boiler #1

(January 2003)

To date, the primary location of the boiler leaks has been in the generating tubes of the boilers. Plant personnel plugged the failed generating tube from the steam drum and mud drum sides and removing this tube would have entailed cutting out a number of tubes to reach it. A waterwall tube sample was obtained and analyzed in March 2003 by GE Betz Metallurgy Services. Deposit levels were high, as expected (the full GE Betz report is attached as Appendix A). This does not, however provide evidence that the ongoing tube leaks are due to deposits and can be controlled via a chemical clean. A chemical clean of the boiler will help reduce the risk of waterwall tube leaks and may help reduce the number of generator tube leaks, but tube thinning in the generator tube region of the boiler is suspected by plant management, to be a contributing factor and would not be addressed by cleaning. Confirmation of this cannot be done without extraction of a sample of generator tubes and this is recommended if serious consideration is being given toward replacement of the generating tubes. If tube thinning is found, as expected, then replacement of the generator tubes would be necessary to address the safety issues discussed above. Budget estimates for replacement of the generator tubes are approximately $300,000 per boiler, but would need to be increased by 25%-40% to allow parts to be manufactured, delivered and possibly installed during a 4-6 week outage.

There are several reasons why events (boiler puffs) of this magnitude are notable. Besides the obvious physical dangers associated with the explosion itself, there is the potential for a significant amount of asbestos to be released. While boiler 1 is in most part an asbestos-free boiler, boilers 2 and 3 are not and a similar event on either of these boilers most likely would have resulted in asbestos release.

Had the January 2003 incident occurred on boiler 2 or 3 instead of boiler 1, the associated cost could have been much greater. First is the obvious cost of the asbestos related work (not relevant to any puff on boiler 1). The plant would hire a contractor to perform in-plant air monitoring, testing and all asbestos cleanup if airborne asbestos is detected. The presence of asbestos materials on boilers 2 and 3 does not mean that asbestos will become airborne, but contractors are always retained by the plant to insure no airborne asbestos is present, therefore there will always be some environmental cost with such an event on boilers 2 and 3. This cost is only increased if free asbestos is detected. The cost associated with air monitoring and cleanup alone after an event in which airborne asbestos was detected could easily exceed $100,000. Obviously, it is dependent on the scale of the release. No costs associated with air monitoring or asbestos cleanup have been included in this analysis.

A second reason that costs associated with an asbestos related event could be significant is the possibility of a second OSHA fine. In 2002, OSHA levied fines after an asbestos release event originating from a waterwall tube failing to the outside of boiler 5 (generator 4). A second citation from OSHA would bring "stiffer" financial penalties. While the necessary safety training has continued to be conducted, and proper procedures for just such an event have been continually reiterated to insure another violation does not occur, it is nevertheless, a possibility and should not be discounted.

The third reason costs could be greater is that following an event in which the potential exists for asbestos to be airborne, the plant is forced to shutdown until an "all clear" is issued. In February 1989, asbestos was released when an extraction turbine pipe failed. This failure forced a total plant shutdown for over four weeks. Shutting down the entire plant would obviously be a costly consequence. The cost of replacement power could easily be the most costly component of an asbestos release event.

The safety margin associated with boilers 1-3 is beginning to erode to an uncomfortable level and considerable investment is required to continue the safe operation of these units. This perception is now beginning to be quantitatively supported through increased outage events and more frequent derates on the units as exemplified by the boiler "puff" of January 2003. Significant portions of the plant are beyond their useful life. Because of the noted safety concerns and the recent events on boiler 1, generating tube replacement is recommended, at a minimum, if Green River Units 1-2 are to continue to be operated in a safe and reliable manner. More will be said regarding the maintenance needs of the units and the associated costs in the section entitled Required Maintenance Investment: Short and Long Term.

The Economic Challenges of NO_x Compliance

Although equipped with a 1970's era scrubber operating with approximately an 80% SO_2 removal efficiency, Green River Units 1-2 will be greatly challenged by the upcoming mandatory reduction imposed on NO_x emissions. It is anticipated that inclusion of NO_x costs in the dispatch price of Green River Units 1 and 2 will almost double the dispatch cost of the units from the high $20s to the low $50s (excluding any adders for maintenance expenses). The table below details the impacts to the units' dispatch cost assuming a $4,000 per ton NO_x allowance purchase price. Although the NO_x allowance price is likely to fluctuate, continued economic operation of Green River Units 1-2 beyond the onset of the 2004 is difficult to economically justify given today's projection of wholesale market prices (See Appendix C for the firm market prices used within this evaluation).

Table 2
Green River 1-2 Dispatch Cost
(With and Without NO_x Adder)

Without NOx Adder (Before May 31, 2004)			With NOx Adder (After May 30, 2004)		
Inputs			**Inputs**		
Heat rate	16.807	(Mbtu/MWh)	Heat rate	16.807	(Mbtu/MWh)
Fuel Cost	1.3385	($/Mbtu)	Fuel Cost	1.3385	($/Mbtu)
FGD Consumables	3.18	($/MWh)	FGD Consumables	3.18	($/MWh)
Stack SO_2 Content	0.7321	(lbs/Mbtu)	Stack SO_2 Content	0.7321	(lbs/Mbtu)
SO_2 Allowance Cost	204	($/ton SO2)	SO_2 Allowance Cost	204	($/ton SO2)
NOx Emission Rate	0	(lbs/Mbtu)	NOx Emission Rate	0.69	(lbs/Mbtu)
NOx Allowance Cost	4,000	($/ton NOx)	NOx Allowance Cost	4,000	($/ton NOx)
Dispatch Cost Component			**Dispatch Cost Component**		
Fuel Cost ($/Mbtu)	1.3385		Fuel Cost ($/Mbtu)	1.3385	
X Heat rate (Mbtu/MWh)	16.807		X Heat rate (Mbtu/MWh)	16.807	
Fuel Cost $/MWh	22.50		Fuel Cost $/MWh	22.50	
FGD Consumables $/MWh	3.18		FGD Consumables $/MWh	3.18	
Heat rate (Mbtu/MWh)	16.807		Heat rate (Mbtu/MWh)	16.807	
X SO2 Allowance Cost ($/ton SO2)	204		X SO2 Allowance Cost ($/ton SO2)	204	
X Constant	0.0005		X Constant	0.0005	
X Stack SO2 Content (lbs/Mbtu)	0.7321		X Stack SO2 Content (lbs/Mbtu)	0.7321	
SO_2 Emissions Adder ($/MWh)	1.26		SO_2 Emissions Adder ($/MWh)	1.26	
NOx Emission Rate (lbs/Mbtu)	0		NOx Emission Rate (lbs/Mbtu)	0.69	
X Heat rate (Mbtu/MWh)	16.807		X Heat rate (Mbtu/MWh)	16.807	
X NOx Allowance Cost ($/ton NOx)	4,000		X NOx Allowance Cost ($/ton NOx)	4,000	
X 1 ton/2,000 lbs (tons/lb)	0.0005		X 1 ton/2,000 lbs (tons/lb)	0.0005	
NO_x Emissions Adder ($/MWh)	0.00		NO_x Emissions Adder ($/MWh)	23.19	
Total Dispatch Cost ($/MWh)	**26.93**		Total Dispatch Cost ($/MWh)	**50.12**	

Note: Green River Units 1-2 are assumed to have the same heat rate and emission rates so the table above is applicable to either unit

Computer simulations estimate that $5.1-$5.8 million (2003 net present value – NPV) would be saved in NO_x/SO_2 allowance expenses alone if Green River Units 1-2 were retired (See Tables 1 and 12). Furthermore, the savings are achieved with only a small increase ($300,000 NPV in Phase I or $192,000 in Phase II for the Base set of assumptions) in system production cost. In summary, the operation of Green River Units 1-2 beyond the start of the 2004 ozone season, which begins May 31 of 2004, is not economically prudent, primarily due to the large increase in cost NO_x compliance adds to these units. Furthermore, operation beyond 2004 would require a considerable amount of investment in maintenance as discussed below.

Required Maintenance Investment: Short and Long Term

Maintenance costs are a function of, among other things, the level of availability desired of the station and the scope of work required to allow the unit to operate at that desired level of availability until the next scheduled outage. Maintenance needs (both scope and expected costs) have been presented by the Green River plant management for both the long and short term. The required maintenance and associated costs to continue to operate Green River Units 1-2 can be identified for three time periods: (1) near term operation, (2) operate through the start of the 2004 ozone season and (3) continued operation during 2004 and beyond. We will now discuss each of these in turn.

<u>Short Term Maintenance</u>

Table 3 identifies the maintenance work, cost, operational impact and the estimated time required to complete said work on Green River Units 1-2 to allow for continued safe and reliable in the near term and up to the start of the 2004 ozone season (May 31, 2004). As shown in Table 3, over $3.3 million (which includes $1.1 million associated with replacing the generating tubes) of capital and O&M costs are projected by plant management to be needed to continue safe and reliable operation through the start of the 2004 ozone season. Note that much attention and effort was put into the development of Table 3 to insure it represented true and immediate maintenance concerns of plant management regarding the continued safe and dependable operation of Green River Units 1-2. Some projects address safety, while other projects are expected to improve reliability, performance and/or in the case of the scrubber bleed line, avoid potential violations or environmental cleanup expenses.

Table 3

Green River 1-2 Short Term Maintenance Needs (2003- May 31, 2004)

* indicates required projects for 2003 summer

Equipment	Work Description	Non-Labor O&M or Capital	Estimated Cost	Operational Impact Safety/Reliability Performance Environmental	Long/ Short Term Impact	Outage Length Required
Scrubber*	Bleedline Replacement	Capital	$50,000	Reliability/Environ	Short	< one day
Scrubber*	Replace Scrubber Fan	NL O&M	$120,000	Reliability	Short	6 days
Boiler	Replace Superheater	Capital	$1,000,000	Reliability	Short	4-6 weeks
Boiler	Replace Economizer	Capital	$937,500	Reliability/Perf	Short	4-6 weeks
Boiler*	Replace Generator Tubes	Capital	$1,125,000	Safety/Performance	Short	4-6 weeks
Fuel Supply*	Six feeder overhauls	NL O&M	$80,000	Reliability	Short	6-10 days
		Total	**$3,312,500**			

	Short Term (Inc Summer)	Summer Only
NL O&M	$200,000	$200,000
Capital	$3,112,500	$1,175,000
Total	**$3,312,500**	**$1,375,000**

Equipment descriptions in Table 3 that include an asterisk (*) denote projects that plant management, at a minimum, would strongly suggest be completed if the decision was made to only operate the units through the end of the 2003 summer. The total capital and non-labor maintenance cost of planning to operate only through the 2003 summer is $1.4 million.

Scrubber Fan and Bleed Line

Scrubber reliability issues include fan and bleed line degradation. The scrubber booster fan underwent temporary repair over a year ago when the blade surfaces were hardened. This repair has out lived its usefulness. The fan blades now have holes worn through them and the fan housing has a hole in it. Replacement is required to assure reliable operation of the scrubber and is expected to cost $120,000. Additionally, the scrubber bleed line is in critical need of replacement. The line is on the verge of failure, and a leak would allow scrubber sludge to flow into the ground. This would create a reportable spill and environmental cleanup would be expensive. There is also a risk that the sludge could reach the river. The estimated cost to replace the scrubber bleed line is $50,000.

Economizer and Superheater

The boilers have been experiencing an increase in the number of economizer and superheater tube leaks. Recently, the unit was being shutdown every weekend and maintenance crews were working the entire weekend plugging tubes. Through April 2003, the units had experienced over 40 tube leaks. The economizer plugs are reaching a level that will impact boiler efficiency. The only solution to this issue is replacement of the tube sections. Estimates for economizer/superheater replacement exceed $1.9 million. Included in this cost is a 25%-45% premium for accelerated work to allow completion as soon as possible to achieve reliable operation of the Units. Because this is not a safety related item, we will assume that the current level of reliability associated with the economizer and superheater would be acceptable compared to the expense of repairing them for near term operation. In other words the cost associated with economizer and superheater work should not be included in the cost to have Green River Units 1-2 available in the near term only, but would be needed if operated beyond that period of time.

Generator Tubes

The importance of generator tube replacement has already been discussed in the section labeled Safety Issues. Because this is a safety issue, its importance can not be over-stated. The expected cost is $1.1 million.

Coal Feeders

The coal feeders are in need of an overhaul to continue to provide coal to the boilers in a reliable manner. This has been identified as a critical reliability issue for near term operation and should be completed at an estimated cost of $80,000.

Boiler Chemical Clean

The decision not to list a boiler chemical clean in Table 3 was a difficult one to quantify and is based on unit operating experience. Steam generating equipment is chemically cleaned to prevent boiler tube failures and to minimize efficiency losses caused by water-side and steam-side deposits. If deposits are not removed, eventually they impede heat transfer and cause failures of the boiler tubes due to overheating. In addition to impeding heat transfer, they also serve as a concentrating mechanism for dissolved constituents in the boiler water, and as such are responsible for some corrosion failures. The last time a chemical clean was performed on any of boilers 1-3 was boiler 1 in May of 1972. While the Electric Power Research Institute (EPRI) does not have an industry standard for chemically cleaning units below 1500 psi, it has been an industry standard that for 900 psi units chemical cleaning should be performed when the deposit weight densities (DWD) are between 30-40 g/ft^2. Tube samples taken in 1988 and in 1998 indicate that boiler 3 had the highest DWD of the three boilers (27 and 39.2 g/ft^2 respectively). As the metallurgy report from GE Betz shows (Betz report 2003-0169 included as Appendix A) the DWD on boiler 3 currently exceeds that industry standard and it is the recommendation of Environmental Compliance and System Lab that boilers 1-3 be scheduled for cleaning.

While not generally perceived as a safety issue, the forced outage time associated with a series of boiler tube failures would be unpredictable and difficult to quantify. These outages could occur during the peak summer load period at which point there may be a need to replace the lost capacity (44 MW if both generating units must be taken offline) with potentially high cost market purchases or forego a possible high priced hourly sale the Company was making at the time of the failure. On the other hand, a chemical clean of boilers 1-3 is expected to produce “hundreds of” tube leaks after the clean which, depending on their severity, would also result in a forced outage and cost to repair. Due to the uncertainty associated with boiler tube failures and the potential market exposure, and recognizing the fact that the boilers are in need of a clean, it is recommended that a chemical clean be performed only in the event long term (beyond 2004) operation of Green River Units 1-2 is expected. Therefore, the cost to chemical clean boilers 1-3 ($207,000) will not be included in the short-term maintenance expenses, but will be classified as a long term maintenance expenses.

Short Term Maintenance Investment Summary

The maintenance related costs of operating Green River Units 1-2 through the start of the 2004 ozone season would require over $3.3 million dollars in maintenance related expenses: $200,000 in non-labor O&M (FGD fan, coal feeders) and $3.1 million in capital (FGD bleedline, superheater, economizer, and generator tubes). The maintenance related costs of operating in the near term only would be $1.4 million and would only exclude the superheater and economizer work. Even though the boilers are in need of a chemical clean now, that work introduces uncertainty and therefore it is recommended that the chemical clean only be performed if a decision is made to operate Green River Units 1-2 beyond the start of the 2004 ozone season.

Long Term Maintenance

Table 4 identifies the maintenance work and cost associated with the larger maintenance projects required on Green River Units 1-2 to allow for continued operation beyond the start of the 2004 ozone season (May 31, 2004). As with the items enumerated in Table 3, this list represents a very conservative approach to the plant's budget maintenance in the 2004-2006 time frame. Actual expenses over the period may exceed those shown here. Note the expected need for a turbine generator overhaul on Unit 1 and the inclusion of the chemical clean previously discussed. Unlike what was done for the items listed as short-term maintenance needs (in Table 3) and because of the low probability associated with operating the unit after 2004, detailed discussions pertaining to each of the projects in Table 4 will not be provided here.

Table 4

Green River 1-2 Long Term Maintenance Needs
(June 1, 2004- and beyond)

Equipment	Work Description	Non-Labor O&M or Capital	Estimated Cost
Boiler	Chemical Clean	NL O&M	$207,000
Boiler	Tube repairs post clean	NL O&M	$300,000
Fuel Supply	Four mill overhauls	NL O&M	$300,000
Scrubber	Repairs to the mobile bed	NL O&M	$100,000
Feedwater	Retube HP feedwater heater	Capital	$200,000
Feedwater	Economizer non-return valves	Capital	$120,000
Feedwater	Feedwater Control Valves	Capital	$60,000
Electrical	Motor Control Center replacement	Capital	$115,000
Electrical	Underground cable replacement	Capital	$270,000
Turbine Generator Overhaul (U1)	Blades, Nozzle block, Rewedge and Controls	Capital	$3,000,000
Scrubber	Motor Control Center replacement	Capital	$30,000
		NL O&M	$907,000
		Capital	$3,795,000
		Total	**$4,702,000**

Retirement Costs

It is anticipated that the retirement of Green River Units 1-2 will bring with it some cost to implement. Presently these costs are expected to present themselves in the eight different areas shown in Table 5. Phase I of this evaluation did not attempt to quantify any retirement related costs and estimated only $24,000 in total retirement expenses (associated with the disposal of approximately 100 mercury switches and other miscellaneous on-site mercury sources). The Phase I estimate was based solely on FASB 143 (Financial Accounting Standards Board standard No. 143-Accounting for Asset Retirement Obligations) which includes only legal obligations that require the owner to remove the asset or dispose of some component at retirement. Furthermore, it was assumed in Phase I that the scrubber associated with Green River Units 1-2 could be utilized on Green River Unit 3 or Unit 4 at some point in the near future. Therefore, scrubber related retirement costs (and any labor savings) associated with the retirement of Green River Units 1-2 were not considered.

Table 5
Green River 1-2 Retirement Related Costs

- KU/LG&E System Production Cost
- Scrubber Sludge/Lagoon Closure
- Employee Severance
- Accounting for Net Book Value Remaining
- Cost to Maintain 14% Reserve Margin
- Fuel Contract Issues
- Loss of Black Start Capability
- Transmission System Upgrades

Increase in KU/LG&E System Production Cost

For discussion within this evaluation, system production costs are defined as the sum of KU's/Louisville Gas and Electric (LG&E's) generating units fuel and O&M cost, purchased power costs and market sales net revenues. System production costs are estimated with the assistance of a computer model that dispatches and runs each KU/LG&E generation asset such that the total operating costs of the KU/LG&E generating system are minimized. The removal of a generation asset from this model should only increase the resulting production costs since, if a lower cost supply existed, it would already be operating. Phase I used the results of two computer simulations and assumed that the total production cost increase resulting from the retirement of both Green River Units 1-2 was equal to the sum of the increased production cost associated with the retirement of Green River Unit 1 and the increased production cost associated with the retirement of Green River Unit 2. For this analysis, and in contrast to what was done in Phase I, both units were simultaneously retired in the same production computer simulation thereby eliminating the need to sum the production cost increases of two separate simulations while also more accurately reflecting any cost impacts. The KU/LG&E system production cost increase associated with the base case retirement of Green River Units 1-2 is minimal (10 year NPV of $192,000 when a $100/MWh purchase market is assumed and $1.8 million when a $1,000/MWh purchase market is assumed). The increase in the KU/LG&E system production cost associated with the simultaneous retirement of Green River Units 1-2 by year is shown in Table 6. The two scenarios differ only in that the first scenario assumes any purchased power needs that originate from the retirement of Green River Units 1-2 can be purchased in 2003 for \$100/MWh (escalated at 2% in each subsequent year) while the second scenario quantifies the cost of retirement assuming the market price of purchased power is \$1,000/MWh (again escalated at 2% thereafter).

Table 6
System Production Cost Increase Associated with Green River 1-2 Retirement Prior to Summer 2003
(Includes fuel, O&M, purchased power and the effects of off-system sales)
(Nominal Years Dollars x \$1,000)

Variable	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV
\$100/MWh Purchase Market	\$170	\$0	\$0	\$0	\$30	\$0	\$0	\$0	\$0	\$0	\$192
\$1,000/MWh Purchase Market	\$1386	\$441	\$0	\$0	\$33	\$0	\$0	\$0	\$0	\$0	\$1,819

Net Present Value (NPV) uses a discount rate of 7.91%

The increase in system production costs does not reflect the obligation to maintain spinning reserve and is based on an expansion plan consisting of four simple-cycle combustion turbines installed in 2004 and no base-load unit additions to the KU/LG&E system. The exclusion of a coal unit was a conservative assumption as the presence of a base-load resource would tend to further reduce Green River Units 1-2 energy production and associated benefit. Due to their relatively small capability, the retirement of Green River Unit's 1-2 capacity was assumed to have no affect on the firm sales volumes established with the units in-service. Finally, consistent with historical operation, the units were not available during the period November through April of the following year during which time they are normally winterized.

Scrubber Reuse Evaluation

Before an accurate estimate of total retirement costs (or savings) can be made, it is necessary to determine whether or not the existing FGD operating on Green River Units 1-2 could be used on Green River Units 3 or 4. In addition to a severance expense, the decision to discontinue scrubber operation would also produce a labor cost savings as there are four full-time positions devoted to scrubber operation. If the scrubber could be used on a remaining unit at Green River then there would be no scrubber lagoon retirement costs nor scrubber operations related severance pay.

Based on discussions with plant management, it was determined that the best alternative for potential reuse of the scrubber would be to re-route the ductwork to Unit 3. Unit 3 is rated at 68MW (summer) and is run with annual capacity factors typically above 40%. The scrubber is currently in need of work for continued operation on the smaller Green River Units 1-2, however, operating at capacity factor levels as high as 40% would not only require the scrubber related work of Table 3 (bleedline and fan), but some additional maintenance as well. Table 7 details the minimum investment required to prepare the scrubber for operation on Unit 3 exclusive of the cost to relocate the ductwork from Units 1-2 to Unit 3 (obviously required) and any annual scrubber related maintenance expenses. If, even without these expenses added, the project appears only marginally favorable, the recommendation would be that the re-use of the scrubber no longer be considered.

Table 7

Cost of Green River 1-2 FGD Maintenance
Required to Allow Reliable Operation on Green River 3

Maintenance Project	**Estimated Cost**
Scrubber bleed line	$50,000
Scrubber mobile bed repairs	$100,000
Scrubber fan motor (replacement)	$120,000
Scrubber Motor Control Center Replacement (MCC)	$30,000
Scrubber agitator replacement	$25,000
Scrubber demister drain line replacement	$20,000
Scrubber fan redesign project	$175,000
Install VFDs on scrubber	$50,000
Re-Route FGD Ductwork	???
Total	$570,000

Relocating and operating the scrubber on Unit 3 would only be justified if there were economic benefits to doing so, or if the following equation were true:

NPV Costs < NPV Benefits

NPV Initial NPV NPV Savings

Maintenance Cost (Table 7)	+	Scrubber O&M Costs	<	in SO_2 Allowance Cost

if we assume that:

1. The scrubber operates with a removal efficiency of 80% when relocated to Green River Unit 3.
2. After the scrubber is installed, Green River 3 would dispatch and generate in the near term (2003-2007) at the levels forecasted in the 2003 5-year budget (a conservative assumption since the dispatch cost of Unit 3 would increase and lower the expected generation levels).
3. The cost of operating the scrubber is $3.37/MWh and escalates at 3% annually.
4. The value of an SO2 allowance is $204 per ton and escalates at 2% annually.
5. The expenses in Table 7 would all be incurred in 2003
6. The discount rate is 7.91%

Scrubber Reuse Assumptions	2003	2004	2005	2006	2007	NPV
Green River 3 Generation (MWh).	262,156	259,736	258,243	275,988	274,361	
Cost of SO2 Allowance ($/ton).	204	208	212	216	221	
SO2 Tons Emitted without FGD:	6,504	6,394	6,350	6,799	6,761	
SO2 Tons Emitted with FGD @ 80%:	1,301	1,279	1,270	1,360	1,352	
Tons of SO2 Allowances Saved:	5,203	5,115	5,080	5,439	5,409	
Value of Allowances Saved ($)	$ 1,061,453	$ 1,064,371	$ 1,078,187	$ 1,177,513	$ 1,194,350	**$4,791,622**
Operating Cost of FGD on GR 3 ($)	$ 884,435	$ 902,583	$ 924,292	$ 1,017,440	$ 1,041,784	**$4,092,586**

Using the data in Table 7 and the assumptions above, we find that the NPV of the benefits exceed those of the costs by only $129,000 without including the cost of ductwork relocation and ongoing scrubber maintenance.

Maintenance + Operating Cost < SO_2 Allowance Savings

$570,000 + $4,092,586 is < $4,791,622

$4,662,586 is < $4,791,622 but by only $129,036

Based on the preceding analysis it can be concluded that the relocation of the Green River Units 1-2 scrubber and subsequent operation on Green River Unit 3 is not economic and it would be correct to include the retirement costs associated with the scrubber sludge lagoon in any retirement evaluation of Green River Units 1-2.

Scrubber Sludge/Fly Ash Lagoon Closure Costs

Appendix B of this document contains a preliminary report prepared by LG&E Energy's Environmental Affairs Department entitled Preliminary Evaluation of Closure Alternatives Scrubber Sludge/Fly Ash Lagoon and an email correspondence regarding the issue. The report discusses the closure process, closure alternatives, beneficial reuse considerations and a limited action alternative while the email serves to further document the position of LG&E's Environmental Affairs Department on closure costs. The limited action alternative is the most economically attractive alternative, and the Environmental Affairs Department believes this to be a viable option. Should retirement of the Units occur, this limited action alternative would allow the pond to remain in nearly its current condition without substantial alteration or associated costs. The limited action alternative will allow deferral of the costs of pond closure but will not prevent the costs from being incurred at a later date (i.e. facility closure). Table 8 (below) is based on the aforementioned report and includes the cost associated with the ultimate closure of the scrubber sludge/fly ash lagoon.

Table 8
Cost Estimates for Anticipated Closure Activities
Scrubber Sludge/Fly Ash Lagoon

(All cost in 2003 year dollars)

Activity	Specialization	Entity	Required Time	Estimated Cost
TASK #1 - Preparation of Permit Application	Engineering	Contractor	3 to 6 months	$ 120,000.00
	Subtasks	**Description**		**Subtask Cost**
	A	Installation of Groundwater Monitoring Wells		$ 20,000.00
	B	Hydrogeologic Report		$ 25,000.00
	C	Construction Drawings & Specifications		$ 45,000.00
	D	Permit Application Document Preparation		$ 30,000.00
TASK #2 – Construction	Construction	Contractor	2 to 4 months	$ 307,000.00
	Subtasks	**Description**		**Subtask Cost**
	A	Grading & Drainage		$ 170,000.00
	B	Topsoil Placement & Preparation		$ 70,000.00
	C	Establishment of Vegetative Cover		$ 17,000.00
	D	Construction Monitoring (Engineering Specialization)		$ 50,000.00
TASK #3 - Post-Closure Care	Engineering	Contractor/Internal	5 years	$ 95,000.00
	Subtasks	**Description**		**Subtask Cost**
	A	Groundwater Sample Collection, Analysis, & Reporting		$ 40,000.00
	B	Inspection		$ 20,000.00
	C	Maintenance		$ 35,000.00
TASK #4A - Geotextile Liner	Construction	Contractor	1 to 2 months	$ 150,000.00

Total Estimated Costs for Closure and Post Closure Care (including Task 4A)

Retirement Year Cost (Task 1+Task 2+ Task 4a +1 yr of Task 3)	**$ 596,000.00**
Annual Cost (valid for each of 4 years following retirement only)	**$ 19,000.00**

Employee Severance Costs

With the decision made to no longer operate the scrubber and the estimated closure cost in hand, we can address the second retirement related cost--employee severance. Phase I of this analysis assumed the FGD would continue to operate and nine positions would be affected by the closure of Green River Units 1-2. Based on a basic severance plan a one-time total severance cost of $92,000 was estimated. However, with the completion of the scrubber reuse evaluation (above), the number of positions affected by the retirement of Green River Units 1-2 and the FGD is now known to be 12 (eight associated with the operation of the coal units and four associated with the FGD). For this evaluation the initial estimate used in Phase I was revised after numerous discussions with the Human Resources Department and plant management. Based on an enhanced severance package, a conservative (high) estimate for the severance and outplacement costs (including one year of medical expenses) for 12 individuals is now estimated to be $384,062.

Accounting for Net Book Value Remaining at Retirement/ARO Issues

The net book value (as of July 31, 2003) of Green River 1-2 exclusive of Asset Retirement Obligations (ARO) settlement is $647,000. Should Green River Units 1-2 be retired, this amount would be moved to the accounting books of the remaining plant and made available for depreciation beginning with the year the plant was closed. A loss on ARO settlement of $190k is also assumed.

Cost to Maintain Reserve Margin

In August 2002, KU and LG&E (the Companies) documented an evaluation (*2002 Analysis of Reserve Margin Planning Criterion)* subsequently filed in the October 2002 Integrated Resource Plan (IRP) with the Kentucky Public Service Commission, that established a reserve margin range of 13%-15% to be the most economical for the 15-year study period of the IRP. Based on this evaluation the Companies utilized a reserve margin target of 14% in the development of the expansion plan contained in the 2002 IRP. This value was subject to revisions within the range as conditions vary.

Using the unit ratings and the load forecast data contained in the 2002 IRP, the Companies would not expect the retirement of Green River Units 1-2 to introduce any issues in regard to maintaining adequate reserve. This is especially true if retirement occurs after the 2003 summer when additional peaking capacity is planned to be in-service. For the summer of 2003, assuming that Green River Units 1-2 are in-service (not retired), the Company is expected to have a reserve margin of 13.7% (a need of 21MW to maintain 14%). Should Green River Units 1-2 be retired prior to July 2003, the expected summer reserve margin would drop to 13.0% (representing a need of only 65MW if measured against a 14% reserve margin) but would still be within the economical range of 13-15%. Therefore, based on forecasted loads for the summer of 2003, the retirement of Green River Units 1-2 will not drop the Companies' reserve margin below 13% and no reserve margin related costs for purchased power should be included in the retirement cost.

Fuel Contract Issues

Two coal contracts are currently in place for Green River. The first is with American Mining and Manufacturing Corporation (AMMC) and the second is with Dodge Hill Mining Company, LLC. The AMMC contract is for 300,000 tons of coal annually through 2006, while the Dodge Hill contract is for 100,000 tons annually through 2006. These two contracts comprise Green River Station's total coal purchasing obligation of 400,000 tons annually. It is anticipated that Green River Units 3-4 alone will be able to satisfy these contractual obligations. However, if needed, up to 100,000 tons can be barged to Ghent without financial penalty. Therefore, the retirement of Green River Units 1-2 is not expected to have any fuel contract ramifications, penalties or cost.

Cost Associated with Loss of Black Start Capability

Green River Units 1-2 are not black-start capable, therefore no real or perceived costs would be incurred relative to black-start capacity.

Cost Associated with Transmission Upgrades

Upon retirement of Green River Units 1-2 a capacitor would be required to maintain adequate voltage support during certain system conditions. Per discussions with Transmission planning this cost could range from $100,000 to $250,000 depending on whether a new capacitor would need to be purchased or if a current spare would fit the requirements. For this analysis, the worst-case estimate of $250,000 to purchase and install a new capacitor was used.

Retirement Cost Summary

The retirement related costs of Green River Units 1-2 include energy production impacts that vary annually depending on the assumed purchase price of power, severance pay associated with 12 positions ($384,000), transmission system upgrades ($250,000) and ARO settlement issues ($190,000). No immediate and appreciable scrubber sludge/fly ash lagoon closure expenses were found to be justified. Furthermore, the possibilities of cost being incurred associated with maintaining a reserve margin range, inability to fulfill coal contract obligations and loss of black-start capability were also investigated, but proved to be of no financial consequence. The total retirement costs of Green River Units 1-2 are summarized in Table 9.

Table 9
Green River 1-2 Retirement Related Costs
(Excludes Production Cost impacts)

Task	One Time Cost	Annual Cost
• KU/LG&E Production Cost	Not Applicable	Varies
• Scrubber Sludge/Lagoon Closure Expenses	$596,000*	$19,000*
• Employee Severance	$384,000	Not Applicable
• Loss on ARO settlement	$ 190,000	Not Applicable
• Cost to Maintain 14% Reserve Margin	$ 0	$ 0
• Fuel Contract Issues	$ 0	$ 0
• Loss of Black Start Capability	$ 0	$ 0
• Transmission Upgrades	$250,000	$ 0
	=======	========
	$1,420,000	$19,000*

*Costs would be incurred at time of Station closure

Retirement Savings

There are six areas in which retirement of Green River Units 1-2 would bring savings to the Company. They are shown in Table 10. We have already discussed in detail the short and long term cost savings associated with avoided non-labor maintenance expenses should Units 1-2 be retired. A discussion of the remaining areas follows.

Table 10
Green River 1-2 Retirement Related Savings

- Maintenance (Non-Labor)
- Labor
- SO_2/ NO_x Allowances
- Insurance
- Permitting/ Usage Fees
- Avoided Depreciation

Labor

The operation of Green River Units 1-2 and the scrubber is made possible through the efforts of twelve full time KU employees, eight unit operators and four scrubber operators. Plant management projects that while twelve full time employees are affected by any potential retirement of Green River Units 1-2 and the scrubber, four of those individuals could potentially fill positions currently held by contractors resulting in a loss of eight full time employees and four contractor positions. For the year 2003, Company burdened labor savings (excluding contractor labor) that would be realized upon retirement of Green River Units 1-2 (and the FGD) would amount to $666,000, while the contractor related savings would be $345,000 for a total labor/contractor savings associated with the retirement of the units/FGD of over $1.0 million. Note contractor savings will be considered non-Company labor and will be included in Non-Labor O&M in the financial analysis. Table 11 summarizes the 2003 labor savings. Since the savings in Table 11 are annual savings, one half of these amounts will be used in 2003 assuming a mid-year retirement while in 2004 (and beyond) savings estimates will be based on the 2003 full year savings escalated at 3% annually.

Table 11
Company and Contractor Labor Savings
(Data is for full year 2003)

Number Positions	Company or Contractor Labor	2003 Savings	Accounted for as…
8	Company	$666,452	Labor
4	Contractor	$345,280	Non-Labor
12		$1,011,732	

Note: The annual savings associated with the 8 Company positions included a burdened rate of 68.0%. Estimates assume 2,080 hours /year and no overtime and are in 2003-year dollars.

SO_2/NO_x Allowances

Like production costs, the quantity of SO_2 and NO_x emissions associated with the operation of Green River Units 1-2 are estimated with a computer model. KU or LG&E must surrender an SO_2 or NO_x allowance for each ton of SO_2 or NO_x emitted. All SO_2 or NO_x emissions released are therefore priced out and added to the fuel and O&M cost. The model takes the SO_2 or NO_x emission rates into consideration when calculating the commitment order of each asset. Those units with higher emission rates will be penalized accordingly (See Table 2 as an example of the impact for Green River). In Phase I of this analysis an estimated 2003 price of $150/ton for SO_2 and $4,000/ton for NO_x (escalated at 2% thereafter) was used. Phase II of this study revised the 2003 price of SO_2 and NO_x to $204/ton and $4,000/ton respectively. The SO_2 price continues to be escalated 2% annually starting in 2004 while the NO_x price is held constant until 2007 when it is escalated at 2% annually. Table 12 summarizes the reduced SO_2 and NO_x annual cost associated with the simultaneous retirement of Green River Units 1-2 in 2003. As with the production costs impact summary table (Table 6), SO_2 and NO_x costs impacts vary based on the assumed price for purchased power.

Table 12
Emissions Cost Savings Associated with Green River 1-2 Retirement in 2003

Variable	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV ($000)
$100/MWh Purchase Market											
SO_2 Cost Savings ($)	67,871	32,252	41,557	51,545	54,475	31,600	52,357	46,093	47,087	31,523	
NOx Cost Savings ($)	0	616,000	695,600	972,000	765,408	649,626	786,567	967,694	764,466	722,546	
Total ($)	67,871	648,252	737,157	1,023,545	819,883	681,226	838,924	1,013,787	811,552	754,069	5,134
$1,000/MWh Purchase Market											
SO_2 Cost Savings ($)	68,524	32,252	41,684	51,545	54,475	31,600	52,357	46,093	47,087	31,523	
NOx Cost Savings ($)	0	611,600	694,400	972,000	765,000	650,042	786,567	967,694	764,466	721,194	
Total ($)	68,524	643,852	736,084	1,023,545	819,475	681,642	838,924	1,013,787	811,552	752,718	5,129

Net Present Values (NPV) use a discount rate = 7.91%.

It is evident that the emissions related cost savings associated with Green River Units 1-2 are significant. Using a 7.91% discount rate the NPV is estimated to be over $5.1 million under both assumptions for purchased power. It should be noted here that Green River Units 1-2 are currently allocated 107 base NO_X allowances associated with emissions over the 1998-2000 time period. These allowances would not be available to the Company in about 2010 and every year thereafter if the units were retired in 2003. There would be some NO_X allowances available to the Company in 2007-2009 based on operation during 2001-2003. This could be considered a retirement related environmental expense, but was not included in this analysis because it is most likely that the run times on these units, if not retired, would be greatly reduced in 2004 and beyond anyway.

Insurance

Cost of annual insurance premiums for Green River Units 1-2 equipment has been estimated at $66,000 dollars.

Permitting and Usage Fees

The only applicable cost savings here would be the annual air emissions fee paid to the Kentucky Department for Air Quality. This amount is $20,000 per year and is the total air emissions fee for both Green River Units 1-2.

Depreciation

An estimated an annual depreciation savings of $295,000 would result from the retirement of Green River Units 1-2 over the 2004-2012 time frame.

Case Setup and Descriptions

As in Phase I, a financial analysis was performed from three different perspectives: Regulated Company Revenue Requirements, Regulated Company Cash Flow, and finally, a non-regulated (Merchant) Company Cash Flow perspective.

- Regulated Company using a Revenue Requirements perspective:
  Economic decisions regarding the regulated side of the business are normally conducted and communicated to the Kentucky Public Service Commission and/or the Virginia State Corporation Commission using a revenue requirements analysis, hence this was the primary evaluation technique used.
- Regulated Company using a Cash Flow perspective:
  The determinant quantifies the retirement decision from the vantage point of the regulated company's shareholder.
- Non-Regulated (Merchant) Company perspective:
  Represents how the decision would be viewed in a completely deregulated environment--from the perspective of an Independent Power Producer or Merchant entity. Merchant analyses are based on the option value (profit) each unit would have in the wholesale power market. Note that this analysis will remove the Production and SO_2/NO_x cost items as the impacts of these are reflected in the option value profit. The monthly firm prices used in the Merchant evaluation can be found in Appendix C of this report.

Each scenario will be evaluated using each of these three techniques. Table 13 associates a case number with an evaluation perspective/environment and an evaluation methodology.

Table 13
Case Number, Evaluation Perspective and Financial Evaluation Methodology

- **Case 1**- Regulated Environment, Present Value Revenue Requirements
- **Case 2**- Regulated Environment, Present Value Cash Flow
- **Case 3**- Merchant Environment, Present Value Cash Flow

The annual cost streams resulting from each approach represent incremental costs and savings resulting from the retirement of Green River Units 1-2 and the FGD. It is important to keep in mind which Case is being evaluated when interpreting the revenue requirements or cash flow present values (PV) summaries. For example in Case 1, where a present value revenue requirements evaluation (PVRR) is being performed, a negative PVRR implies that the Company should collect less money from the ratepayers if the Units were to be retired. On the contrary, a positive PVRR, suggests the Company should collect more monies from the ratepayers to cover the increased cost of generation, purchased power, emissions expenses and so on. Stated another way, the presence of a negative PVRR indicates that in present value, the cost savings obtained from retiring a unit outweighs the benefits of continued operation of said facility. The more negative a PVRR becomes, the stronger the argument for retiring that facility, whereas the more positive a PVRR becomes the less economic justification that exists for retiring the unit. Conversely, the Cash Flow values in Cases 2 and 3 work just the opposite. The more positive the Present Value of Cash Flow, the better the indication that retirement should occur. Hence, a negative PV Cash Flow would indicate a worse scenario results from retiring the unit, and thereby would support continued operation of the unit.

Base Assumptions for Long Term Operation

The following is a list of base assumptions that allow for operation of Green River Units 1-2 over the long term. The base assumptions will be evaluated in each of the three Cases discussed above.

Table 14

Base Assumptions for Long Term Operation

- 10-year evaluation period (2003-2012) with no catastrophic equipment failures (i.e. generator step-up transformer, turbine failure etc) through end of period.

- Firm off-system sales volumes unchanged from 2002-2006 Corporate Business Plan. No firm sales beginning in 2007, however, hourly peak period opportunity sales exist through the end of the evaluation period.

- Production cost impacts do not reflect obligation to maintain spinning reserve and are based on an expansion plan consisting of four simple-cycle combustion turbines installed in 2004 and no coal unit in the 2008-2010 time frame. Exclusion of any additional base-load capacity was a conservative assumption from the plant's perspective as its presence would tend to further reduce the runtime and benefit of having these smaller Units, making retirement a more attractive option.

- Retirement in place of both Green River Units 1-2 and the FGD can occur without any immediate cost applicable to remaining physical plant, including notably the scrubber sludge/fly ash lagoon.

- In determination of production cost impacts, the simultaneous retirement of Green River 1-2 and the FGD occur on January 1, 2003. However, consistent with the history of operating the units, the units were assumed in Cases 1 and 2 to be winterized during the period November through April of the following year so any production cost impacts are for the May-October period.

- Earnings Sharing Mechanism (ESM) impacts of retirement are negligible.

- Environmental Cost Recovery (ECR) impact of retirement are negligible since the only environmental assets in the ECR associated with Green River Units 1-2 are the continuous emissions monitoring system (CEMS).

- Assume that 100% of the increased production costs are excluded from FAC (essentially assuming that any increased production related expenses impact OSS margins) - applicable to Regulated Environment only.

- Safe and reliable operation of the units occurs in 2003 and 2004 with minimal capital and non-labor O&M investment as shown in Table 3 and Table 4. Cash flows assume that a majority of equipment is delivered and installed during the 2003-2004 winter. Only exceptions are work required to be performed prior to 2003 summer. Remaining capital and non-labor O&M is split evenly between the last quarter of 2003 and first quarter of 2004.

Non-Labor

	Capital $		O&M $
Prior to 2003 summer:	$1,175,000		$200,000
Fall 2003:	$2,866,250		$453,500
Spring 2004:	$2,866,250		$453,500
	$6,907,500	+	$1,107,000 = $8,014,500

- Beginning in 2005, both units will continue to operate reliably through the end of evaluation period with no other significant capital or non-labor investments.

- Severance package offered to 12 employees at total cost of $384,062.

- Purchased power is available in 2003 around-the-clock at $100/MWh, escalating at 2%.

- No capacity benefit is assigned to the units; therefore, no capacity related costs incurred are to replace retired capability.

Sensitivity Assumptions for Long Term Operation

In addition to evaluating the base set of assumptions, several additional scenarios were evaluated. The first increased the 2003 market purchase price from $100/MWh to $1,000/MWh (escalated at 2% annually thereafter) while the second assigned a capacity replacement cost to the units of $400/kw (estimate for cost of combustion turbine).

- Purchased power available in 2003 around-the-clock at $1,000/MWh, escalating at 2%.

- Treatment of Capacity Replacement Cost
  - In Revenue Requirements Analysis (Case 1), capacity replacement costs were an adder to the first years cost of replacement.
  - In Regulated Cash Flow Analysis (Case 2), capacity replacement costs are is levelized using a fixed charge rate for a CT.
  - In Merchant Cash Flow Analysis (Case 3), no Capacity ($/kW) value is associated with the retired unit since a Merchant plant is under no obligation to maintain any specific reliability, whether measured by reserve or capacity margin, or loss of load probability.

Results of Financial Analysis

The retirement of Green River Units 1-2 and the associated scrubber is supported by all but one scenario evaluated in this analysis. Table 15 quantifies the savings associated with retirement on the base and sensitivity assumptions. A present value revenue requirements evaluation of the Base Scenario (Case 1) estimates a $23 million savings over the ten-year period. The Case 1 Scenario that most favors continued operation of the facility is Scenario 3, which assumes both a very high purchase market price and assigns a capacity value to Green River Units 1-2 summer capability. It is interesting to note that in Case 1 the breakeven capacity value is $417/kW when the 2003 market purchase price is assumed to be $100/MWh and $388/kW when the price is $1,000/MWh. Appendix D contains the present value revenue requirements evaluation for each Case 1 Scenario.

The Base Regulated Environment Cash Flow evaluation (Case 2 Base Scenario) suggests retirement with a net present value savings of over $15 million over the period. As with Case 1, it is the cumulative effect of the conservative assumptions for the price of market purchases and the value placed on the units' capability that make Case 2 Scenario 3 the most favorable Scenario for continued operation. However, even this scenario suggests there is over $5.5 million in value associated with the immediate retirement of Green River Units 1-2. The breakeven capacity value of Case 2 is $696/kW when the 2003 market purchase price is assumed to be $100/MWh and $652/kW when the price is $1,000/MWh.

The unregulated perspective of Case 3 further validates that the characteristics of the plant make continued economic operation difficult. It estimates a merchant power producer would realize over $12.2 million in savings by after retiring Green River Units 1-2.

Table 15
Incremental Cost Impact of Retiring Green River Generators 1-2 and Scrubber

	Assumptions		Case 1	Case 2	Case 3
Scenario	2003 Purchase Market ($/MWh)	Capacity Replacement Cost ($/kW)	Regulated Environment Net Present Value Revenue Requirements	Regulated Environment Net Present Value Cash Flow Analysis	Merchant Environment Net Present Value Cash Flow Analysis
Base	100	0	($23,432,000)-R	$15,388,000-R	$12,272,000-R
Scenario 1	100	400	($956,000)-R	$6,544,000-R	[redacted]
Scenario 2	1,000	0	($21,800,000)-R	$14,415,000-R	[redacted]
Scenario 3	1,000	400	$676,000-0	$5,570,000-R	[redacted]

-"R" implies "suggest retirement" to be economically favorable
-"O" implies "continued operation" to be economically favorable

Summary and Recommendation

An evaluation of the economics associated with the retirement of Green River Units 1-2 and the scrubber servicing the two units was conducted using conservative assumptions, (when assumptions were necessary they favored the continued operation of the facilities, see Table 16) and sensitivities to the price of market purchased power and the value placed on the units generating capability. The evaluation supported the preliminary results of the Phase I analysis and concluded that significant cost savings could be incurred by the immediate retirement of both Green River Units 1-2 and the scrubber. Significant portions of the units are due for replacement or refurbishment creating a continually decreasing safety margin associated with continued unit operation.

Table 16
Summary of Conservative Assumptions
Favoring Continued Operation of Green River Units 1-2 and FGD

1. No cost adjustment made for continued operation at decreasing safety margin.
2. Market purchase price is $100/MWh or greater in every year.
3. Minimum possible maintenance budgeted with no annual outage costs budgeted in 2005 and beyond.
4. No new base-load coal capacity assumed to be installed on KU/LG&E system within the study period.
5. Severance pay based on 12 positions when it is likely some Company labor may displace contractor labor with no severance pay.
6. Scrubber retirement evaluation excluded cost of ductwork relocation and assumed that Green River Unit 3 would generate at "pre-scrubber" levels.
7. The merchant evaluation assumes 100% unit availability on both Green River Units 1-2 (i.e. does not assume the units will be "winterized", derated or forced out).

Significant savings are realized in predominantly three areas: company labor ($5+ million NPV), environmental emissions cost ($5+ million NPV) and avoided non-labor and capital expenses ($10+ million NPV). All of these savings occur with only a modest increase in system production cost (less than $200,000 assuming a $100/MWh purchase market increasing to only $1.8 million with a $1,000/MWh purchase market). Based on this evaluation and the conservative assumptions used, it is recommended that Green River Units 1-2 and the Green River scrubber be retired from service.

Furthermore, because there are safety concerns regarding the operation of Green River Units 1-2 that can only be addressed with significant investment, and since a significant portion of the savings is labor related, it is recommended that retirement occur as soon as possible. This would be after the required meetings with the United Steel Workers Association (USWA) AFL-CIO-CLC union representative(s) have taken place and ample time for affected individuals to consider the severance package. The following are key steps in moving forward to implement closure of the facilities.

Table 17

Key Steps for Closure of Green River Generating Units 1-2 and the Scrubber

Now-Retirement	(1) Due to potential safety issues being present, remove Units 1-2 from the generation commitment pool, effectively placing the units in reserve shutdown. This is the current status of the Units.
Now- May 30, '03	(2) Circulate Phase II retirement study internally soliciting for comments and correcting any material issues affecting the recommendation to retire said facilities.
June-July, '03	(3) Submit Green River Phase II study to senior management for review.
June-July, '03	(4) Human Resources should finalize severance package details.
June-July, '03	(5) Environmental Affairs should continue to pursue Company's environmental obligations/responsibilities at closure.
June-July, '03	(6) Corporate Legal Department should review closure document and assist other departments as needed.
June-July, '03	(7) Receive senior management feedback/comments.
June-July, '03	(8) Incorporate senior management feedback/comments and any material Human Resource, Environmental Affairs or Legal Department item into Phase II evaluation.
June-July, '03	(9) Submit Green River Phase II evaluation to Investment Committee.
June-July, '03	(10) Present to Investment Committee.
June-July, '03	(11) Rates Department communicates with the Kentucky Public Service Commission and Virginia State Corporation Commission informing them of our intentions.
June-July, '03	(12) Human Resources meet with USWA representatives.
July, '03	(13) Begin implementation of closure tasks at station.

Appendix A:

GE Betz Metallurgy Services

Metallurgical Lab Report on Green River Generating Station Boiler 3

Waterwall Tube Sample

GE Betz

Metallurgy Services
9669 Grogan's Mill Road
The Woodlands, Texas 77380
281-367-6201
281-363-7794 Fax

METALLURGICAL LAB REPORT

Representative: Jeff Forshee **Plant:** Kentucky Utilities Company
Location: Green River Generating Station
Unit: Boiler #3
B&W, 900 psig
Report No.: 2003-0169
Date: March 18, 2003

BACKGROUND

A carbon steel waterwall tube section from Boiler #3 at the subject account was submitted for determination of the internal deposit-weight density (DWD) values and internal deposit analysis. The sample was identified as "B3-3/10/03, Sidewall, 10 ft. from the front burner wall, 4 ft. above the top burner level". The time in service for the tubing was reported to be greater than 50 years.

RESULTS

Figure 1 is a photograph showing the tube sample, as received. The fireside surface was coated with dark brown deposit. Only shallow fireside corrosion was observed. There was no visual indication of overheating damage. The internal surface was covered with brown deposit and scattered deposit mounds (Figures 2 and 3).

Test sections were removed from the hot and cold sides to determine the DWD values using a mechanical, glass bead blasting method. The deposit thickness was estimated using a point micrometer. The following results were obtained.

Test Section	DWD g/ft^2	Deposit Thickness (in.)
Hot	41.1	0.001 - 0.005
Cold	21.6	0.001 - 0.004

A sample of the internal deposit was scraped from the hot side and analyzed for inorganic constituents using X-ray Fluorescence Spectroscopy (XRF). The results are listed in Table 1. The brown deposit contained major amounts of iron, phosphorus, calcium, and copper compounds. Lesser amounts of magnesium, silicon, and aluminum species were also detected, among others. The Loss On Ignition (LOI) value for the deposit was 1%, which indicates there was no organic material.

Areas of the tube were mechanically cleaned using glass bead blasting to examine the contour of the underlying metal surface. Internal pitting was observed (Figures 4 and 5). The majority of pits exhibited a rounded, hemispherical morphology that is consistent with dissolved oxygen corrosion occurring in conjunction with boiler outage periods. The maximum internal pit depth was 0.041 inches, which represents a 21% penetration of the wall thickness. The typical wall thickness in unaffected areas was 0.190 inches on the hot side, and 0.200 inches on the cold side.

Bob Hargrave, P.E.
Metallurgist

GE Betz

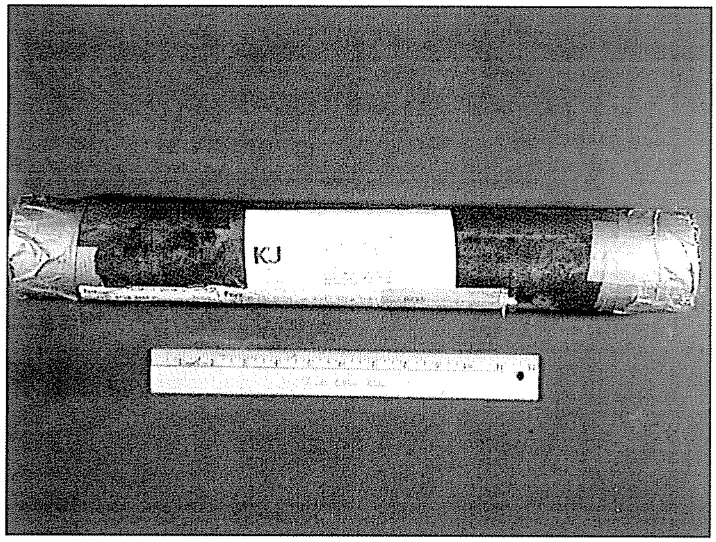


Figure 1.

Photograph showing the waterwall tube, as received. 0.2x.

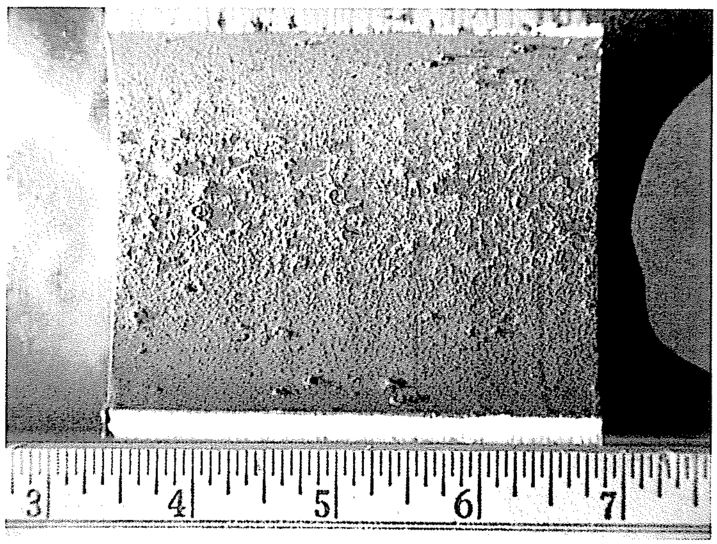


Figure 2.

Photograph showing the internal surface on the hot side. 0.8x.

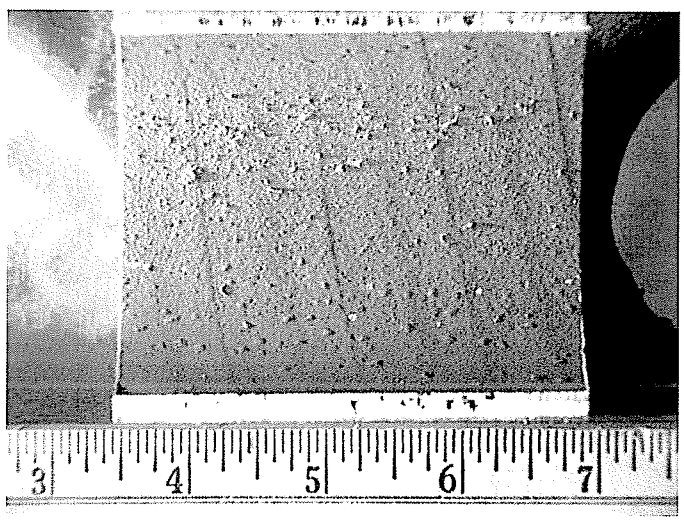


Figure 3.

Photograph showing the internal surface on the cold side. 0.8x.

GE Betz

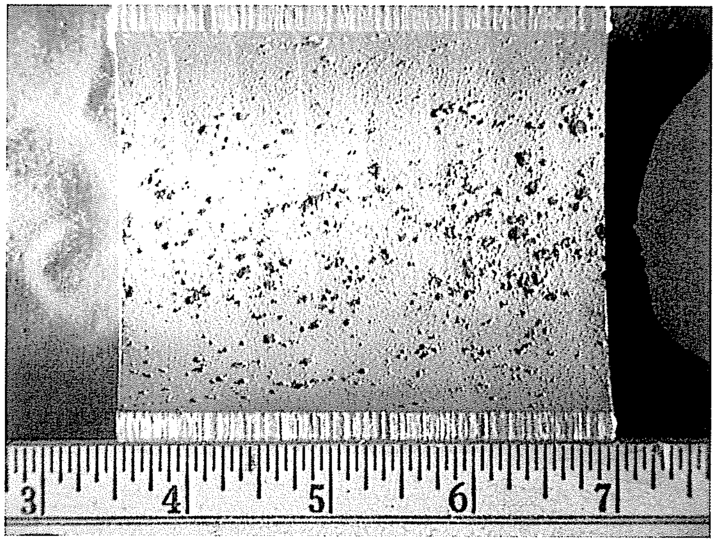


Figure 4.

Photograph showing the internal surface on the hot side, after cleaning. 0.8x.

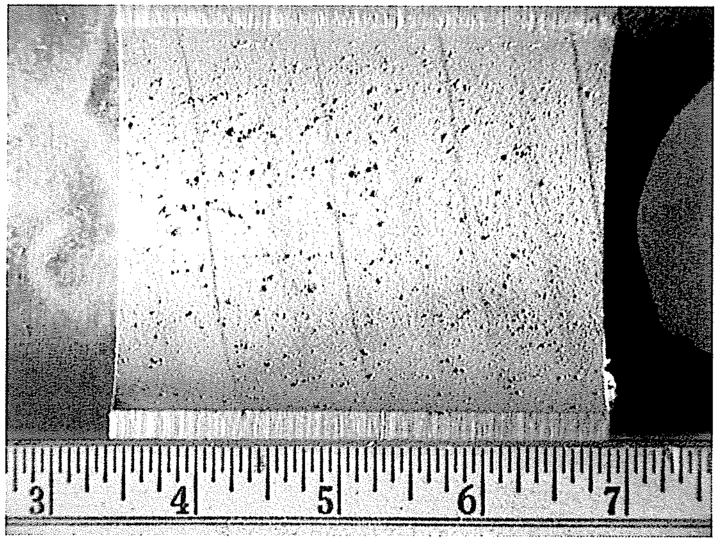


Figure 5.

Photograph showing the internal surface on the cold side, after cleaning. 0.8x.

Element	**Weight Percent**
Iron, as Fe_3O_4	36
Phosphorus, as P_2O_5	19
Calcium, as CaO	18
Copper, as CuO	11
Magnesium, as MgO	7
Silicon, as SiO_2	4
Aluminum, as Al_2O_3	2
Sulfur, as SO_3	1
Zinc, as ZnO	1
Loss On Ignition	1

TABLE 1. XRF INORGANIC ANALYSIS OF INTERNAL DEPOSIT, REPORTED AS OXIDES

Appendix B:

Preliminary Evaluation of Closure Alternatives

Scrubber Sludge/Fly Ash Lagoon

Preliminary Evaluation of Closure Alternatives
Scrubber Sludge/Fly Ash Lagoon

Green River Generating Station
Central City, Muhlenberg County, Kentucky
Kentucky Utilities Company

Prepared by:
Paul Puckett
LG&E Energy's Environmental Affairs Department

March 2003

Preliminary Evaluation of Closure Alternatives
Scrubber Sludge/Fly Ash Lagoon
Green River Generating Station - Kentucky Utilities Company

March 2003

Table of Contents

1. Introduction

Kentucky Utilities (KU) operates the Green River Generating Station on U.S. Highway 431 north of Central City in Muhlenberg County, Kentucky. The facility has been operational since 1949 and currently has four operational units and a generating capacity of about 250 megawatts.

The Green River Generating Station is located on the Green River near river mile 82. It is within the coal fields of western Kentucky (Illinois Basin) in a region that has been and continues to be actively mined. There are no current mining operations at the site or in the immediate vicinity.

The facility has operated a venture throat scrubber for Units 1 & 2 since the mid 1970s that uses a lime solution to remove sulfur dioxide and particulates from stack emissions. The resulting scrubber slurry is sent to an on-site pond where the solids (including calcium salts and fly ash particulates) are allowed to settle and the decant waters are recycled into the scrubbing process. The pond is referred to as the Scrubber Sludge/Fly Ash Lagoon.

Although operation of the lagoon was initially administered as a solid waste disposal facility (Permit Number 089-0010) under the Kentucky Division of Waste Management (KY DWM), regulation of the facility was transferred to the Kentucky Division of Water (KY DOW) in 1992. According to information contained in an internal report[1], the lagoon covers approximately 8.5 acres and its discharge is currently monitored as part of the facility's KPDES permit (Permit Number KY0002011). The elevation at the top of the pond's berms is 405 feet NGVD which exceeds the 100-year flood elevation of 398 feet NGVD.

KU is currently evaluating its obligations if it were to interrupt or terminate the use of Units 1 & 2 at the Green River Generating Station. In the event the units (and associated scrubber) were shut down, there would no longer be a need to operate the Scrubber Sludge/Fly Ash Lagoon. If the discharge stream to the lagoon were removed, the facility may be required to transition between divisions within the Department for Natural Resources and Environmental Protection Cabinet (DNREPC). The transition process would occur through a permit application that would provide information about the basin and what measures would be taken to close the basin down in a manner that was protective of the environment. The transition of a regulated facility between divisions within the DNREPC is unusual and there is not much recent precedent of this nature to reference. As a result, there is uncertainty associated with identifying the procedures and otherwise evaluating the basin closure process.

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[1] *Information in Support of a Permit Application to Construct and Operate a Solid Waste Retention Facility at Green River Generating Station near South Carrollton, Kentucky*

2. Evaluation of Closure Alternatives

A. Overview of the Anticipated Closure Process

The closure process would be initiated by gathering and evaluating information to develop an approach to the basin's closure. The information to be gathered would include details about the nature of the waste (including its environmental character, mobility, and stability), the plan to isolate the waste from the environment, installation of a monitoring system to evaluate the effectiveness of the closure approach, and engineering details describing how the proposed approach would be accomplished.

The application would be submitted to KY DWM for review, comment, and modification. If all of the information is correct and the application is considered complete, the KY DWM has 6 months to determine whether to issue a permit. The regulation allows the KY DWM to issue a "draft" permit for new facilities after the review process.

If placed in "draft" permit status, KY DWM may require KU to take out a public notice in the newspaper and hold a public meeting to describe the activity. The draft permit process also requires KY DWM to solicit input from other regulatory agencies and would obligate KY DWM to respond to all received comments. This approach could significantly extend the amount of time and effort needed to transition the facility to "closed" status.

B. Likely Closure Requirements

Because KY DWM will likely rely on requirements for special waste landfills when considering the minimum measures necessary to close the scrubber sludge lagoon, it is EAD's expectation that an acceptable closure plan will include: solidification of the ponded materials, placement of two feet of cover soil, establishment of low-profile vegetation across the cover, and installation of and sample collection from a groundwater monitoring network.

The placement of cover soil is intended to isolate the ponded materials from exposure to surface waters, precipitation, air born transport, and human & ecologic receptors. The placement of the cover soils would require compaction and grading to ensure stability, control runoff, and eliminate standing water from the surface.

The establishment of vegetation on the cover will stabilize the soils to prevent differential settlement and erosion and to promote slope stability. Establishment of vegetation does not generally include woody vegetation and generally closure plans specifically call for periodic removal of trees, shrubs, and other similar plants.

The groundwater monitoring system will include the installation of at least three monitoring wells that will be required to be sampled on a quarterly basis for a 5-year period. Sample analysis will likely consist of selected metals (i.e. arsenic, barium, cadmium, chromium, lead, mercury, nickel, selenium, and silver) and indicator parameters (i.e. calcium, conductance, chloride, pH, sodium, sulfates, and total dissolved solids) and the results will have to be reported to KY DWM.

Additionally, KY DWM may require that a geomembrane or low-permeability layer be placed between the vegetative cover and solidified scrubber sludge. Although preliminary EPRI studies (*Evaluation and Modeling of Cap Alternatives at Three Unlined Coal Ash Impoundments*, TR 1005165) have indicated that specially-designed covers do not result in a higher level of environmental performance, the lack of precedent may cause the KY DWM require the conservative approach and inclusion of a liner or low-permeability layer.

Costs associated with each portion of the closure process have been estimated and are included in Table 1.

3. Beneficial Reuse Considerations

Kentucky's Special Waste Regulations (401 KAR 45) specify that coal combustion byproducts (including scrubber sludge) may be beneficially reused as ingredients in many products including structural fill and mine stabilization and reclamation materials. Additional uses have also been approved for coal combustion byproducts that are high in lime. One such use is for agricultural augmentation.

A. Mine Reclamation/Acid Neutralization

Because of its inherently high pH, scrubber sludge has been used many times to increase low pH levels to improve runoff quality or to augment soils that have a low pH. Acidic soils and runoff are a common problem in areas of where coal mining has occurred. Since the area has been used for coal mining and there are active and inactive mines in the area, it is expected that there could be situations where low pH issues in need of correction exist. As a result, there would seem to be some opportunity to use dredged slurry to stabilize areas with low pH values.

B. Agricultural Augmentation

Although much less commonplace than most traditional beneficial reuses for coal combustion byproducts, the use of this material as an agricultural amendment is becoming more acceptable. The scrubber sludge offers many of the same benefits as traditional lime treatments in agricultural applications. However, the potential use of the scrubber sludge in agriculture would be a function of the pH of soil and availability of a user. It would also be necessary to evaluate the effect of the scrubber material on the crop and other crops that may be rotated into the area. Finally, due to the unusual (infrequent) nature of this reuse and the lack of its specific mention in the regulations

(401 KAR 45:060, Section 7), it may be necessary to receive specific approval for this reuse from KY DWM.

In either of the reuse scenarios outlined previously, the scrubber sludge would be removed from the basin, but the basin would still be open. Because of its past status and available storage, KY DWM may require a simplified closure procedure for the emptied basin.

4. The Limited Action Alternative

The scrubber sludge lagoon may be able to continue its existence in nearly its current condition if it can retain its status as a facility regulated by the KY DOW. The advantage of this approach is that the basin can continue in its present form with little, if any, modification. However, the key to this approach is maintaining some type of regulated process or establishment of a future process flow to the basin. By maintaining a regulated flow process to the basin, the KY DOW would be required to consider and account for the process in its administration of the KPDES permit. The basin use transformation is likely to require some negotiation with KY DOW and some up-front data gathering and evaluation to allow for the modification of the KPDES permit. The permit modification process may also result in changes to the required monitoring but the change in cost would not be likely to be considered significant.

The drawback to this approach is that it could be difficult to make an adequate case for routing one of these regulated flow streams across numerous closer and similar receiving basins, thereby effectively bypassing them, in order to use the scrubber sludge basin. Additionally, the limited size and volume of the scrubber basin is not likely to offer the long-term use potential necessary for a waste stream of significant and continuous volume, such as is associated with ash.

If a legitimate situation can be identified, this option is expected to be the least expensive immediate alternative and most actions associated with this approach could likely be handled by internal resources.

Table 1
Cost Estimates for Anticipated Closure Activities
Scrubber Sludge/Fly Ash Lagoon
Green River Generating Station
Kentucky Utilities Company

Activity	Specialization	Entity	Required Time	Estimated Cost
TASK #1 - Preparation of Permit Application	Engineering	Contractor	3 to 6 months	$ 120,000.00
	Subtasks	**Description**		**Subtask Cost**
	A	Installation of Groundwater Monitoring Wells		$ 20,000.00
	B	Hydrogeologic Report		$ 25,000.00
	C	Construction Drawings & Specifications		$ 45,000.00
	D	Permit Application Document Preparation		$ 30,000.00
TASK #2 - Construction	Construction	Contractor	2 to 4 months	$ 307,000.00
	Subtasks	**Description**		**Subtask Cost**
	A	Grading & Drainage		$ 170,000.00
	B	Topsoil Placement & Preparation		$ 70,000.00
	C	Establishment of Vegetative Cover		$ 17,000.00
	D	Construction Monitoring (Engineering Specialization)		$ 50,000.00
TASK #3 - Post-Closure Care	Engineering	Contractor/Internal	5 years	$ 95,000.00
	Subtasks	**Description**		**Subtask Cost**
	A	Groundwater Sample Collection, Analysis, & Reporting		$ 40,000.00
	B	Inspection		$ 20,000.00
	C	Maintenance		$ 35,000.00
Additional Activity (consider only one)				
TASK #4A - Geotextile Liner	Construction	Contractor	1 to 2 months	$ 150,000.00
TASK #4B - Low Permeability Layer	Construction	Contractor	2 to 4 weeks	$ 40,000.00
Total Estimated Costs for Closure and Post Closure Care (not including Tasks 4A or 4B)				**$ 522,000.00**

From: **Puckett, Paul**
Sent: Tuesday, September 02, 2003 10:47 AM
To: Isaac, Brian
Cc: Pfeiffer, Caryl; Voyles, John; Conroy, Robert; Skaggs, Gerald; Portasik, Linda; Foxworthy, Carol; Charnas, Shannon; Winkler, Michael
Subject: RE: GR12 Env

Brian,
EAD continues to believe that the "limited action" alternative is a viable option for dealing with the scrubber sludge/fly ash lagoon at the Green River Generating Station The viability of this option is not contingent upon, but would be more secure, if a realistic use were planned for its future (the next few years) Based on our recent experiences with the ash pond at the former Pineville Generating Station and conversations with personnel at the Division of Water (DOW), EAD believes that the SS/FA Lagoon can continue to exist without change, provided it continues as a DOW-regulated facility This option is preferable and recommend because:
1) it minimizes the regulatory difficulties associated with transferring a regulated facility between two regulating agencies with different environmental missions and concerns;
2) it maintains DOW jurisdiction over the facility which requires little, if any modifications for monitoring, evaluation, monitoring, or other regulatory oversight
3) it is the lowest cost alternative identified during the evaluation process It will likely require only administrative efforts to attend to any details related to changes in pond operations If the use of the pond changes drastically or if the DOW requires the pond be incorporated into the stations operations, it may be necessary to account for use changes or operational delays with studies or other consultant-supported justifications requiring funding

This option is not without drawbacks, but EAD would not consider the potential shortcomings to be high-risk or to be worth avoiding the "limited action" alternative Specific considerations are noted below.
1) to limited action alternative does not allow for closure costs to be avoided, only delayed until the station is closed or the SS/FA Lagoon can no longer be regulated by DOW The delay in transitioning the SS/FA Lagoon between administering agencies could allow the closure requirements to change and become more onerous
2) the "limited action" alternative is viable because of experience and discussion with the current DOW representatives Changes in administrations (at the agency or higher government levels) may require that we change this approach to one that requires a greater expenditure of effort and resources

The "limited action" alternative should require virtually no immediate physical changes to the current FA/SS Lagoon It may require minor modifications to the station's existing KPDES permit (and some associated fees, likely $1,000 or less) and some administrative negotiations by EAD, but those should not be significant nor should they require any expenditures (other than permit modification fees)

In the longer term, some expenditure may be required to maintain the SS/FA Lagoon as a legitimate part of the facilities water management program In general such expenditures should be minimal in comparison to closure costs and may be incorporated into the budget of a capital project, rather than requiring an unplanned expenditure

As a result of the known benefits, EAD would continue to recommend that the company pursue the "limited action" alternative at this time

-----Original Message-----
From: Isaac, Brian
Sent: Tuesday, September 02, 2003 8:49 AM
To: Puckett, Paul
Cc: Pfeiffer, Caryl; Voyles, John; Conroy, Robert; Skaggs, Gerald; Portasik, Linda; Foxworthy, Carol; Charnas, Shannon
Subject: GR12 Env

Paul-
John Voyles met with Rates, Legal, Generation Planning, Finance and Budgeting and Property Accounting last week regarding the retirement of Green River 1-2 The meeting can best be summarized as one trying to identify and bring closure to all outstanding items and formulate a Rates and Regulatory action plan John asked that I cycle back to environmental and see if our view of the environmental requirements associate with retirement of GR12 has changed A preliminary report of March 2003 enumerated several closure alternatives, one being a limited action alternative, relating to the scrubber sludge lagoon At the time that report was prepared it was somewhat uncertain as to which plan would fulfill minimum closure requirements etc More recently however, an Executive Brief of the GR12 retirement evaluation was prepared (I've attached the Exec Brief for reference) and by this time, more work had been done on the closure issue to suggest that the limited action alternative was not only still an option but would be implemented should the Units be retired With all of that being said, could you confirm that the limited action alternative would be the alternative pursued by the Company at the retirement of Green River 1-2? Also, could you explain exactly what actions would be done under the limited action alternative (i e periodic ground water monitoring etc?) Thanks for you time Paul

<< File: Executive Brief GR12-(081803).doc >>

Regards,
Brian Isaac
(502-627-2226)

Appendix C:

Market Prices Used in Case 3-Merchant Evaluation

Regional Market Prices Assumed in Merchant Evaluation

(Case 3)

Firm 5x16 Market Price ($/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2003		36.85	35.00	34.00	34.50	44.50	57.20	57.20	40.10	39.25	39.25	39.25
2004	45.75	45.75	42.00	42.00	40.00	42.00	51.45	51.45	37.75	34.75	34.75	34.75
2005	38.91	38.06	38.65	38.59	36.69	36.65	46.56	44.96	35.46	34.39	34.71	33.21
2006	38.77	37.77	38.97	37.97	36.49	37.07	48.73	45.99	36.57	35.90	35.95	34.27
2007	37.69	39.20	39.02	38.38	38.67	39.09	51.46	49.20	36.42	36.37	34.56	36.12
2008	38.62	39.92	40.29	40.93	39.69	40.55	54.55	52.76	38.09	37.86	37.34	38.07
2009	41.56	40.75	41.87	41.33	41.97	42.51	57.38	55.98	39.08	39.89	39.58	38.42

Firm 7x8 Market Price ($/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2003		23.00	15.48	15.98	14.96	18.00	20.00	20.00	17.00	17.00	17.00	17.00
2004	20.00	20.00	17.00	17.00	17.00	17.00	19.00	19.00	16.00	16.00	16.00	16.00
2005	16.46	16.40	16.91	18.82	20.04	20.61	24.15	22.65	16.99	15.80	15.54	16.00
2006	17.44	17.36	18.26	19.09	20.32	21.48	25.18	23.89	17.49	16.53	16.03	17.04
2007	18.34	17.95	19.36	20.68	21.41	22.89	26.00	23.85	19.06	16.93	16.51	17.30
2008	19.53	19.03	20.45	22.48	22.52	23.24	26.91	25.10	19.76	17.82	17.05	17.88
2009	20.32	20.08	21.76	22.58	23.36	23.97	28.14	26.16	20.41	19.11	18.08	18.93

Firm 2x16 Market Price ($/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2003		25.00	16.71	16.42	15.47	29.00	33.00	33.00	28.00	27.50	27.50	27.50
2004	26.00	26.00	25.00	25.00	26.00	28.00	32.00	32.00	27.00	26.50	26.50	26.50
2005	20.96	19.17	19.80	21.89	24.84	26.36	34.11	30.77	23.85	17.09	16.23	20.75
2006	22.65	21.33	22.19	22.95	25.68	27.39	34.80	32.18	24.51	18.69	17.11	22.96
2007	25.37	20.94	24.13	24.22	25.02	27.08	36.47	34.43	24.78	19.76	20.49	23.32
2008	27.42	23.28	25.38	26.60	26.23	28.35	36.33	36.46	25.74	21.51	18.69	23.78
2009	25.83	27.03	27.95	26.77	28.23	29.73	39.51	38.54	26.66	23.67	20.64	26.49

Note: Prices are projections as of May 2003.

Appendix D:

Case 1- All Scenarios

Present Value Revenue Requirements Analysis

Appendix D
Case 1, Base Scenario

Incremental Value of Retiring Green River 1-2 and FGD Prior to 2003 Summer
Present Value Revenue Requirements Analysis

(All dollars are in $000s)

Base Scenario: 0 $/kw Capacity Replacement Cost, 100 $/MWh Purchase Power

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPVRR @ 7.91% ($000)
Retirement Costs											
Production[1,2,3,4]	$ 170	$ -	$ -	$ -	$ 30	$ -	$ -	$ -	$ -	$ -	$ 192
Capacity Replacement PVRR[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Severance[6]	$ 384	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 384
Transmission Issues											
Trans Capital (Cash Flow)[7]	$ -	$ 250	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Transmission PVRR[8]	$ 124	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 124
Total Retirement Cost NPV											$ 700
Retirement Savings											
SO_2/NO_x[9]	$ (68)	$ (648)	$ (737)	$ (1,024)	$ (820)	$ (681)	$ (839)	$ (1,014)	$ (812)	$ (754)	$ (5,134)
Insurance Premium[10]	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (481)
Air/Water Fees[11]	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (145)
Company Labor (Burdened)[12]	$ (333)	$ (686)	$ (707)	$ (728)	$ (750)	$ (773)	$ (796)	$ (820)	$ (844)	$ (870)	$ (5,120)
Depreciation Avoided[13]	$ 190	$ (295)	$ (295)	$ (295)	$ (295)	$ (295)	$ (295)	$ (295)	$ (295)	$ (295)	$ (1,660)
Non-Labor O&M											
Contractor Personel[14]	$ (173)	$ (356)	$ (366)	$ (377)	$ (389)	$ (400)	$ (412)	$ (425)	$ (437)	$ (451)	
Pre-2003 Summer	$ (200)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Short Term	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Long Term	$ (454)	$ (454)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Non-Labor O&M Savings	$ (826)	$ (809)	$ (366)	$ (377)	$ (389)	$ (400)	$ (412)	$ (425)	$ (437)	$ (451)	$ (3,726)
Maintenance Capital											
Pre-Summer '03 (Cash Flow)	$ (1,175)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Short Term(Cash Flow)	$ (969)	$ (969)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Long Term(Cash Flow)[15]	$ (1,898)	$ (1,898)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Maint Capital (Cash Flow)	$ (4,041)	$ (2,866)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Maint Capital PVRR[16]	$ (7,865)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,865)
Total Retirement Savings NPV											$ (24,132)
NPV Savings of Retirement ($000)											$ (23,432)

Notes:

1 System Spinning Reserve requirement was removed from base and subsequent cases because the model was using these units to meet spinning and (1) in reality they are, in general, only rarely used for such purposes and (2) if spinning requirement was left in case the removal of a single unit would cause the costs to decrease
2 Purchase power market is $100 /MWh (all hours) in 2003 escalated at 2% annually
3 No Firm Off-System Sales starting in 2007 Hourly sales continue through end of study period
4 "Production" includes Fuel, Scrubber O&M, Purchased Power and effects of OSS Revenues
5 No capacity replacement costs were assumed
6 Conservative (high) estimate for 12 positions
7 Installation of capacitor bank in 2004 ($250k-Capital expense) is required to prevent voltage problems during a contingency situation should GR12 be retired Capacity bank assumed to still be needed if GR12 were to operate only thru 2012
8 This is the increase in PVRR associated with accelerating the capacity installation and its associated capital costs, from sometime after the study period (assumed 2013) to 2004 PVRR account for Companies' allowed taxes and return on debt and equity
9 SO2 priced out at $204/ton in 2003 and escalated at 2% annually NOx priced out at $4000/ton in 2003-2006 and escalated at 2% annually starting in 2007
10 Based on a Green River 1-2 contribution to 2003 insurance premium with a $2 5 million deductible No escalation applied to future years
11 No escalation applied to future years
12 2003 labor savings reflect retirement mid-year and elimination of 8 company positions Future years based on 3% escalation of 2003 full year company labor costs. All company labor costs include a 68 0% burden rate
13 The Net Book Value of Green River 1-2 as of 7/31/03 is $647,000 This amount would be rolled into Units 3-4 upon retirement and depreciated to a Net Book Value of $0 In 2003, there is a loss (expense) on Asset Retirement Obligation (ARO) of $190,000
14 Estimate for 4 contractor positions
15 Note that a conservative estimate of no annual cost for parts is assumed in 2005 and beyond
16 Various maintenance projects with potentially various book/tax lives are addressed with the capital monies PVRR was calculated based on a 10 year book/tax life

Appendix D
Case 1, Scenario 1

Incremental Value of Retiring Green River 1-2 and FGD Prior to 2003 Summer
Present Value Revenue Requirements Analysis

(All dollars are in $000s)

Scenario 1: 400 $/kw Capacity Replacement Cost, 100 $/MWh Purchase Power

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPVRR @ 7.91% ($000)
Retirement Costs											
Production[1,2,3,4]	$ 170	$ -	$ -	$ -	$ 30	$ -	$ -	$ -	$ -	$ -	$ 192
Capacity Replacement PVRR[5]	$ 22,476	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,476
Severance[6]	$ 384	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 384
Transmission Issues											
Trans Capital (Cash Flow)[7]	$ -	$ 250	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Transmission PVRR[8]	$ 124	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 124
										Total Retirement Cost NPV	$ 23,176
Retirement Savings											
SO_2/NO_x[9]	$ (68)	$ (648)	$ (737)	$ (1,024)	$ (820)	$ (681)	$ (839)	$ (1,014)	$ (812)	$ (754)	$ (5,134)
Insurance Premium[10]	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (481)
Air/Water Fees[11]	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (145)
Company Labor (Burdened)[12]	$ (333)	$ (686)	$ (707)	$ (728)	$ (750)	$ (773)	$ (796)	$ (820)	$ (844)	$ (870)	$ (5,120)
Depreciation Avoided[13]	$ 190	$ (295)	$ (295)	$ (295)	$ (295)	$ (295)	$ (295)	$ (295)	$ (295)	$ (295)	$ (1,660)
Non-Labor O&M											
Contractor Personel[14]	$ (173)	$ (356)	$ (366)	$ (377)	$ (389)	$ (400)	$ (412)	$ (425)	$ (437)	$ (451)	
Pre-2003 Summer	$ (200)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Short Term	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Long Term	$ (454)	$ (454)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Non-Labor O&M Savings	$ (826)	$ (809)	$ (366)	$ (377)	$ (389)	$ (400)	$ (412)	$ (425)	$ (437)	$ (451)	$ (3,726)
Maintenance Capital											
Pre-Summer '03 (Cash Flow)	$ (1,175)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Short Term(Cash Flow)	$ (969)	$ (969)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Long Term(Cash Flow)[15]	$ (1,898)	$ (1,898)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Maint Capital (Cash Flow)	$ (4,041)	$ (2,866)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Maint Capital PVRR[16]	$ (7,865)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,865)
										Total Retirement Savings NPV	$ (24,132)
										NPV Savings of Retirement ($000)	$ (956)

Notes:

1. System Spinning Reserve requirement was removed from base and subsequent cases because the model was using these units to meet spinning and (1) in reality they are, in general, only rarely used for such purposes and (2) if spinning requirement was left in case the removal of a single unit would cause the costs to decrease
2. Purchase power market is $100 /MWh (all hours) in 2003 escalated at 2% annually
3. No Firm Off-System Sales starting in 2007. Hourly sales continue through end of study period.
4. "Production" includes Fuel, Scrubber O&M, Purchased Power and effects of OSS Revenues.
5. PVRR of a 400 $/kW CT installed in 2003 equal in capacity to the retired capability of GR12
6. Conservative (high) estimate for 12 positions
7. Installation of capacitor bank in 2004 ($250k-Capital expense) is required to prevent voltage problems during a contingency situation should GR12 be retired. Capacity bank assumed to still be needed if GR12 were to operate only thru 2012
8. This is the increase in PVRR associated with accelerating the capacity installation and its associated capital costs, from sometime after the study period (assumed 2013) to 2004. PVRR account for Companies' allowed taxes and return on debt and equity
9. SO2 priced out at $204/ton in 2003 and escalated at 2% annually. NOx priced out at $4000/ton in 2003-2006 and escalated at 2% annually starting in 2007
10. Based on a Green River 1-2 contribution to 2003 insurance premium with a $2.5 million deductible. No escalation applied to future years
11. No escalation applied to future years.
12. 2003 labor savings reflect retirement mid-year and elimination of 8 company positions. Future years based on 3% escalation of 2003 full year company labor costs. All company labor costs include a 68.0% burden rate
13. The Net Book Value of Green River 1-2 as of 7/31/03 is $647,000. This amount would be rolled into Units 3-4 upon retirement and depreciated to a Net Book Value of $0. In 2003, there is a loss (expense) on Asset Retirement Obligation (ARO) of $190,000
14. Estimate for 4 contractor positions
15. Note that a conservative estimate of no annual cost for parts is assumed in 2005 and beyond
16. Various maintenance projects with potentially various book/tax lives are addressed with the capital monies. PVRR was calculated based on a 10 year book/tax life

Appendix D

Case 1, Scenario 2

Incremental Value of Retiring Green River 1-2 and FGD Prior to 2003 Summer

Present Value Revenue Requirements Analysis

(All dollars are in $000s)

Scenario 2: 0 $/kw Capacity Replacement Cost, 1000 $/MWh Purchase Power

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPVRR @ 7.91% ($000)
Retirement Costs											
Production[1,2,3,4]	$ 1,386	$ 441	$ -	$ -	$ 33	$ -	$ -	$ -	$ -	$ -	$ 1,819
Capacity Replacement PVRR[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Severance[6]	$ 384	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 384
Transmission Issues											
Trans Capital (Cash Flow)[7]	$ -	$ 250	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Transmission PVRR[8]	$ 124	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 124
										Total Retirement Cost NPV	$ 2,327
Retirement Savings											
SO_2/NO_x[9]	$ (69)	$ (644)	$ (736)	$ (1,024)	$ (819)	$ (682)	$ (839)	$ (1,014)	$ (812)	$ (753)	$ (5,129)
Insurance Premium[10]	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (481)
Air/Water Fees[11]	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (145)
Company Labor (Burdened)[12]	$ (333)	$ (686)	$ (707)	$ (728)	$ (750)	$ (773)	$ (796)	$ (820)	$ (844)	$ (870)	$ (5,120)
Depreciation Avoided[13]	$ 190	$ (295)	$ (295)	$ (295)	$ (295)	$ (295)	$ (295)	$ (295)	$ (295)	$ (295)	$ (1,660)
Non-Labor O&M											
Contractor Personel[14]	$ (173)	$ (356)	$ (366)	$ (377)	$ (389)	$ (400)	$ (412)	$ (425)	$ (437)	$ (451)	
Pre-2003 Summer	$ (200)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Short Term	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Long Term	$ (454)	$ (454)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Non-Labor O&M Savings	$ (826)	$ (809)	$ (366)	$ (377)	$ (389)	$ (400)	$ (412)	$ (425)	$ (437)	$ (451)	$ (3,726)
Maintenance Capital											
Pre-Summer '03 (Cash Flow)	$ (1,175)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Short Term(Cash Flow)	$ (969)	$ (969)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Long Term(Cash Flow)[15]	$ (1,898)	$ (1,898)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Maint Capital (Cash Flow)	$ (4,041)	$ (2,866)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Maint Capital PVRR[16]	$ (7,865)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,865)
										Total Retirement Savings NPV	$ (24,127)
										NPV Savings of Retirement ($000)	$ (21,800)

Notes:

1 System Spinning Reserve requirement was removed from base and subsequent cases because the model was using these units to meet spinning and (1) in reality they are, in general, only rarely used for such purposes and (2) if spinning requirement was left in case the removal of a single unit would cause the costs to decrease

2 Purchase power market is $1,000 /MWh (all hours) in 2003 escalated at 2% annually

3 No Firm Off-System Sales starting in 2007 Hourly sales continue through end of study period

4 "Production" includes Fuel, Scrubber O&M, Purchased Power and effects of OSS Revenues

5 No capacity replacement costs were assumed

6 Conservative (high) estimate for 12 positions

7 Installation of capacitor bank in 2004 ($250k-Capital expense) is required to prevent voltage problems during a contingency situation should GR12 be retired Capacity bank assumed to still be needed if GR12 were to operate only thru 2012

8 This is the increase in PVRR associated with accelerating the capacity installation and its associated capital costs, from sometime after the study period (assumed 2013) to 2004 PVRR account for Companies' allowed taxes and return on debt and equity

9 SO2 priced out at $204/ton in 2003 and escalated at 2% annually
NOx priced out at $4000/ton in 2003-2006 and escalated at 2% annually starting in 2007

10 Based on a Green River 1-2 contribution to 2003 insurance premium with a $2 5 million deductible No escalation applied to future years

11 No escalation applied to future years

12 2003 labor savings reflect retirement mid-year and elimination of 8 company positions Future years based on 3% escalation of 2003 full year company labor costs
All company labor costs include a 68 0% burden rate

13 The Net Book Value of Green River 1-2 as of 7/31/03 is $647,000 This amount would be rolled into Units 3-4 upon retirement and depreciated to a Net Book Value of $0 In 2003, there is a loss (expense) on Asset Retirement Obligation (ARO) of $190,000

14 Estimate for 4 contractor positions

15 Note that a conservative estimate of no annual cost for parts is assumed in 2005 and beyond

16 Various maintenance projects with potentially various book/tax lives are addressed with the capital monies PVRR was calculated based on a 10 year book/tax life

Appendix D

Case 1, Scenario 3

Incremental Value of Retiring Green River 1-2 and FGD Prior to 2003 Summer

Present Value Revenue Requirements Analysis

(All dollars are in $000s)

Scenario 3: 400 $/kw Capacity Replacement Cost, 1000 $/MWh Purchase Power

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPVRR @ 7.91% ($000)
Retirement Costs											
Production[1,2,3,4]	$ 1,386	$ 441	$ -	$ -	$ 33	$ -	$ -	$ -	$ -	$ -	$ 1,819
Capacity Replacement PVRR[5]	$ 22,476	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,476
Severance[6]	$ 384	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 384
Transmission Issues											
Trans Capital (Cash Flow)[7]	$ -	$ 250	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Transmission PVRR[8]	$ 124	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 124
Total Retirement Cost NPV											$ 24,803
Retirement Savings											
SO_2/NO_x[9]	$ (69)	$ (644)	$ (736)	$ (1,024)	$ (819)	$ (682)	$ (839)	$ (1,014)	$ (812)	$ (753)	$ (5,129)
Insurance Premium[10]	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (481)
Air/Water Fees[11]	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (145)
Company Labor (Burdened)[12]	$ (333)	$ (686)	$ (707)	$ (728)	$ (750)	$ (773)	$ (796)	$ (820)	$ (844)	$ (870)	$ (5,120)
Depreciation Avoided[13]	$ 190	$ (295)	$ (295)	$ (295)	$ (295)	$ (295)	$ (295)	$ (295)	$ (295)	$ (295)	$ (1,660)
Non-Labor O&M											
Contractor Personel[14]	$ (173)	$ (356)	$ (366)	$ (377)	$ (389)	$ (400)	$ (412)	$ (425)	$ (437)	$ (451)	
Pre-2003 Summer	$ (200)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Short Term	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Long Term	$ (454)	$ (454)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Non-Labor O&M Savings	$ (826)	$ (809)	$ (366)	$ (377)	$ (389)	$ (400)	$ (412)	$ (425)	$ (437)	$ (451)	$ (3,726)
Maintenance Capital											
Pre-Summer '03 (Cash Flow)	$ (1,175)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Short Term(Cash Flow)	$ (969)	$ (969)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Long Term(Cash Flow)[15]	$ (1,898)	$ (1,898)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Maint Capital (Cash Flow)	$ (4,041)	$ (2,866)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Maint Capital PVRR[16]	$ (7,865)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,865)
Total Retirement Savings NPV											$ (24,127)
NPV Cost of Retirement ($000)											$ 676

Notes:

1 System Spinning Reserve requirement was removed from base and subsequent cases because the model was using these units to meet spinning and (1) in reality they are, in general, only rarely used for such purposes and (2) if spinning requirement was left in case the removal of a single unit would cause the costs to decrease.
2 Purchase power market is $1,000 /MWh (all hours) in 2003 escalated at 2% annually
3 No Firm Off-System Sales starting in 2007 Hourly sales continue through end of study period
4 "Production" includes Fuel, Scrubber O&M, Purchased Power and effects of OSS Revenues
5 PVRR of a 400 $/kW CT installed in 2003 equal in capacity to the retired capability of GR12
6 Conservative (high) estimate for 12 positions
7 Installation of capacitor bank in 2004 ($250k-Capital expense) is required to prevent voltage problems during a contingency situation should GR12 be retired Capacity bank assumed to still be needed if GR12 were to operate only thru 2012.
8 This is the increase in PVRR associated with accelerating the capacity installation and its associated capital costs, from sometime after the study period (assumed 2013) to 2004 PVRR account for Companies' allowed taxes and return on debt and equity
9 SO2 priced out at $204/ton in 2003 and escalated at 2% annually NOx priced out at $4000/ton in 2003-2006 and escalated at 2% annually starting in 2007
10 Based on a Green River 1-2 contribution to 2003 insurance premium with a $2 5 million deductible No escalation applied to future years
11 No escalation applied to future years
12 2003 labor savings reflect retirement mid-year and elimination of 8 company positions Future years based on 3% escalation of 2003 full year company labor costs All company labor costs include a 68 0% burden rate
13 The Net Book Value of Green River 1-2 as of 7/31/03 is $647,000 This amount would be rolled into Units 3-4 upon retirement and depreciated to a Net Book Value of $0 In 2003, there is a loss (expense) on Asset Retirement Obligation (ARO) of $190,000
14 Estimate for 4 contractor positions
15 Note that a conservative estimate of no annual cost for parts is assumed in 2005 and beyond
16 Various maintenance projects with potentially various book/tax lives are addressed with the capital monies PVRR was calculated based on a 10 year book/tax life

Appendix E:

Case 2 All Scenarios

Regulated Environment Present Value Cash Flow Analysis

CONFIDENTIAL INFORMATION REDACTED

Appendix F:

Case 3

Merchant Environment Present Value Cash Flow Analysis

CONFIDENTIAL INFORMATION REDACTED

Evaluation of Economic Viability of Group 3 Generating Units (Phase I)

Kentucky Utilities Company

And

Louisville Gas and Electric Company

Prepared by: Generation Services

March 24, 2003

Evaluation of Economic Viability of Group 3 Units
(Phase I)

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Executive Summary

The age of the Companies' generation fleet together with increasing environmental compliance costs, depressed wholesale market conditions and increased maintenance costs suggest that improved corporate financials can be realized through retirement of some of the older, less efficient electric plant. The Companies have completed the first phase of a two phase study evaluating the economic feasibility of continuing to operate the older units on the KU and LG&E systems. Phase I identifies the units within the KU/LG&E system that should be evaluated in Phase II by making a high-level review of the incremental economic impacts associated with retirement of each unit. Included are the cost impacts associated with fuel, O&M, SO_2 and NO_x emissions, insurance, depreciation and unit capacity. Phase II will commence with the units identified by this study and will evaluate in detail each of the options available to the unit so as to insure the future challenges associated with operating these units are met in the most economically possible way.

The Companies generating units have been categorized into three separate groups: Group 1 includes 31 units comprised of the lowest cost base-load units, the larger CTs and the hydro units, Group 2 includes 8 units each currently operating well but with generally higher operating costs and Group 3 includes 13 of the older, less efficient, more costly units that are expected to face significant economic challenges within the next ten years. This analysis focuses solely on the 13 units in Group 3 totaling approximately 220MW of KU/LG&E capacity.

An incremental financial evaluation was performed that quantified the additional costs or savings resulting from retirement of each unit in Group 3. The evaluation was performed from three perspectives: a Regulated Environment using a Revenue Requirements Analysis, a Regulated Environment using a Cash Flow Analysis, and a Merchant Environment again using a Cash Flow Analysis. In addition to the Base Assumptions, sensitivities around the value of capacity and the price of purchased power were conducted.

Generation Services recommends, based on the results of the financial evaluation, that all 13 units in Group 3 and shown in the table below be evaluated in Phase II of this study. Furthermore, it is recommended that if a simultaneous evaluation of these units can not be performed in Phase II, then Green River 1-2 be the first units evaluated since, based on this evaluation, the economics of these two units support retiring in the most scenarios, thereby potentially offering the most substantial and immediate cost savings.

Generators Recommended for
Phase II of Economic Unit Viability Study

- Green River 1 and 2
- Tyrone 1 and 2
- Haefling 1, 2 and 3
- Waterside 7 and 8
- Paddy's Run 11 and 12
- Cane Run 11
- Zorn 1

Background

Periodically the economics surrounding the continued operation of the units on the Kentucky Utilities Company (KU) and Louisville Gas and Electric Company (LG&E) generating systems are reviewed to ensure the efficiency of the overall system. The generating units across the Companies' fleet continue to age and thus require evaluation to review the economic operation of the units. Some of these units have operated past their design lives and thereby run a greater risk of a catastrophic failure than other units. An example of such occurred in November of 2001 when KU's Pineville Unit #3 (circa: 1951) experienced a generator failure. The failure was such that a subsequent evaluation recommended the most economic decision was to retire the unit and close the facility rather than to repair the damage and continue operation. In addition, the relatively high production costs of some units combined with the recent decline in wholesale market prices and increasingly stringent environmental restrictions, most recently the Clean Air Act Amendments (CAAA) of 1990, will only worsen the economics of continued operation of some units. The upcoming NO_x environmental restrictions will allow for the totaling of NO_x emissions over the Companies' entire system during the ozone season and do not require reduction at the unit level. Given the ability to comply on a system-wide basis the Companies will be reducing NO_x emissions more than required on some of the generating units in order to emit below the combined system tonnage cap of 12,447 tons. For example, the Companies are installing Selective Catalytic Reduction systems (SCRs) on at least six generating units and additional NO_x control technologies are underway on nearly every generating unit in the system. Furthermore, the questions surrounding the economics of more frequent and often costly maintenance on older units are becoming more difficult to address.

Table 1
Reasons for Currently Evaluating Economic Viability of Generating Units

1.	Unit Age
2.	Relatively High Production Cost
3.	Recent Decline in Wholesale Market Prices
4.	Increasingly Stringent Environmental Restrictions (i.e. Clean Air Act of 1990) which target SO2 and NO_x reduction
5.	Increasing cost/frequency of maintenance related work combined with difficulty obtaining spare/replacement maintenance equipment
6.	Future Environmental Compliance Costs (carbon tax, mercury reduction)

For the reasons shown in Table 1 above, the Companies initiated a two-part study in November 2002 to address the economics of continued operation of the older units on the KU and LG&E system. This is the first phase of a multi-phase evaluation to identify those units most likely to be affected. Subsequent evaluations will begin with the units identified by this study and will evaluate in detail each of the options available to the unit so as to insure the future challenges associated with operating these units are met in the most economical way possible.

Discussion of Unit Groupings

The Companies' generating units have been categorized into three basic groupings. Group 1 includes the lowest cost, most efficient base-load units expected to be operational for 20 or more years without any significant issues. Most of these are also the newest units on the KU/LG&E system, with the exception of the hydro units. Group 2 includes units that operate well, but have somewhat higher operating costs. These units are currently not expected to have significant economic challenges during the next ten years but may have issues surface beyond ten years. Group 3 consists of mostly peaking units with individual unit capacities of 30MW or less. These units are older and more costly to operate and maintain.

This analysis focuses on the Companies' Group 3 units. Group 3 units are expected to face significant economic challenges in the near term (less than ten years out). Challenges include complying with new environmental requirements in an economic manner, maintaining a unit in reliable working condition despite its age, and the risk of obsolete replacement parts. Thirteen different units are identified as Group 3 units at seven different plant locations totaling approximately 220MW of KU/LG&E summer capacity. The nine CTs in this group operated for a combined total of 40 hours in 2002, while Tyrone 1-2 have no service hours for two of the last three years. The remaining two units in Group 3 (Green River Units 1 and 2) operated just over 10 weeks (~1,700 service hours) each in 2002. Table 2 follows, which shows the KU/LG&E units and their corresponding Group as well as other relevant data. Ten years of service hours for units in each of the three groups (excluding the hydro units of Group 1) are shown in Appendix A at the end of this report.

Table 2
KU/LG&E Generators in Group 1, 2 and 3

Type of Unit	Plant Name	Unit	Summer Capacity (MW)	In Service Year	Age (2002)
Group 1					
Steam	Brown	3	429	1971	31
Steam	Ghent	1	509	1974	28
Steam	Ghent	2	494	1977	25
Steam	Ghent	3	496	1981	21
Steam	Ghent	4	467	1984	18
Steam	Mill Creek	1	308	1972	30
Steam	Mill Creek	2	306	1974	28
Steam	Mill Creek	3	391	1978	24
Steam	Mill Creek	4	480	1982	20
Steam	Trimble Co	1	386	1990	12
CT	Brown	5	134	2001	1
CT	Brown	6-7	154 each	1999	3
CT	Brown	8, 10	130 each	1995	7
CT	Brown	9	130	1994	8
CT	Brown	11	130	1996	6
CT	Paddy's Run	13	158	2001	1
CT	Trimble Co	5-6	155 each	2002	0
Hydro	Ohio Falls	1-8	6 each	1928	74
Hydro	Dix Dam	1-3	8 each	1925	77
Group 2					
Steam	Brown	1	104	1957	45
Steam	Brown	2	168	1963	39
Steam	Cane Run	4	155	1965	37
Steam	Cane Run	5	168	1966	36
Steam	Cane Run	6	240	1969	33
Steam	Green River	3	68	1954	48
Steam	Green River	4	100	1959	43
Steam	Tyrone	3	71	1953	49
Group 3					
Steam	Tyrone	1	27	1947	55
Steam	Tyrone	2	31	1948	54
Steam	Green River	1-2	22 each	1950	52
CT	Waterside	7-8	11 each	1964	38
CT	Cane Run	11	14	1968	34
CT	Paddy's Run	11	12	1968	34
CT	Paddy's Run	12	23	1968	34
CT	Zorn	1	14	1969	33
CT	Haefling	1,2,3	12 each	1970	32

Evaluation Scope

The evaluation of the Group 3 units has been broken up into a multi-phase approach due to the significant effort necessary to fully evaluate the economic viability of the Group 3 units. A detailed list of items and issues, the product of "brainstorming" exercises and the experiences gained from the Pineville 3 retirement, that should be considered when evaluating the economic viability of units was initially developed (see Appendix B-General Evaluation Outline for Phase II of Unit Viability Study). From this list the scope of Phase I was developed.

Phase I consists of a high level evaluation as a screening to identify the issues surrounding economic operation of the units. From this phase of the analysis, a determination will be made concerning the potential retirement of any or all of the units. The scope of the Phase I evaluation consists of the following:

1. Quantify and communicate the production cost impact (fuel cost, scrubber consumables cost, purchase power cost and SO_2/NO_x allowance cost) of retiring each unit in Group 3.
2. Quantify and communicate the capital cost impacts of the simultaneous retirement of all Group 3 units.
3. Identify fixed costs (environmental permitting/water usage costs, insurance premium impacts, depreciation expense etc) for each unit regardless of unit utilization.
4. Identify and discuss black-start units and the Companies' black-start obligations.
5. Discuss the unique contractual relationship LG&E has with the Louisville Water Company thru the Zorn combustion turbine.

Phase II of the Group 3 evaluation will follow upon completion of Phase I. The Phase II evaluation will consist of a detailed set of evaluations for each of the units identified in Phase I as being a potential for retirement. The initial scope of the Phase II evaluation will consist of the following:

1. Human Resource issues (severance pay, job reclassification, relocation).
2. Environmental issues (lead paint/asbestos abatement).
3. Intermediate-run options. (i.e. Evaluate costs of scenarios somewhere between current operations and retirement, utilization of Green River 1-2 FGD on another unit at Green River).
4. Unit "Re-powering" options (i.e. Tyrone 1-2).
5. Retirement Costs (stack demolition, scrubber/ash pond reclamation, etc.).

Financial Perspectives and Cases Evaluated

A financial analysis was performed from three different perspectives, a Regulated Company using a Revenue Requirements perspective, a Regulated Company using a Cash Flow determinant and finally, a Non-Regulated (or Merchant) Company evaluating each scenario via a Cash Flow perspective. Economic decisions regarding the regulated side of the business are normally conducted using a revenue requirements analysis, hence this was the primary evaluation technique used. A revenue requirements evaluation is based on the amount of money that must be collected by the Companies from the ratepayer to compensate the Companies for all capital and O&M expenditures (plus an allowed return on the Companies' capital investment) and taxes. The Regulated Company Cash Flow technique quantifies the decision from the vantage point of the regulated company shareholder. The final methodology represents how each decision would be viewed in a completely deregulated environment--from the perspective of an Independent Power Producer or Merchant entity. Merchant analyses are based on the option value (profit) each unit would have in the wholesale power market. Each scenario will be evaluated using each one of these three techniques.

Case Setup and Definition

- **Case 1**- Regulated Environment, Present Value Revenue Requirements
- **Case 2**- Regulated Environment, Present Value Cash Flow
- **Case 3**- Merchant Environment, Present Value Cash Flow

The annual cost streams resulting from each approach represent incremental costs or savings resulting from the retirement of the unit/units in question. It is important to keep in mind which Case is being evaluated when interpreting the revenue requirements or cash flow present values (PV) summaries. For example in Case 1, where a present value revenue requirements evaluation (PVRR) is being performed, a negative PVRR implies that the Company should collect less money from the ratepayers if the unit were to be retired. On the contrary, a positive PVRR, suggests the Company should collect more monies from the ratepayers to cover the increased cost of generation, purchase power, emissions expenses and so on. Stated another way, the presence of a negative

PVRR indicates that in present value, the cost savings obtained from retiring a unit outweighs the benefits of continued operation of said facility. The more negative a PVRR becomes, the stronger the argument for retiring that facility whereas the more positive a PVRR becomes the less economic justification that exists for retiring the unit.

Conversely, the Cash Flow values in Cases 2 and 3 work just the opposite. The more positive the Present Value of Cash Flow, the better the indication that retirement should occur. Hence, a negative PV Cash Flow would indicate a worse scenario results from retiring the unit, and thereby would support continued operation of the unit.

Global Base Assumptions

The following is a list of base assumptions applicable to all units evaluated in this study. Each unit may have additional issues that should be considered, and if so, those issues and a discussion of how they are addressed can be found in the appropriate section.

Global Assumptions

- 10 year evaluation period (2003-2012).
- Firm off-system sales volumes unchanged from 2002-2006 Corporate Business Plan. No firm sales beginning in 2007, however, hourly peak period opportunity sales exist thru end of evaluation period.
- Production cost impacts do not reflect obligation to maintain spinning reserve and are based on an expansion plan consisting of four simple-cycle CTs installed in 2004 and no coal unit in the 2008-2010 time frame. This was a conservative assumption from the plants perspective as the presence of a base-load coal unit would tend to further reduce the runtime and benefit of having these smaller units.
- Retirement in place can occur without any significant cost applicable to remaining physical plant unless otherwise noted.
- Retirement occurs January 1, 2003.
- Earnings Sharing Mechanism (ESM) impacts of retirement are negligible.
- Assume that 100% of the increased production costs are excluded from FAC (essentially assuming that any increased production related

expenses impact OSS margins) - applicable to Regulated Environment only.

- Purchase power available in 2003 around-the-clock at $100/MWh, escalating at 2%.

- Treatment of Capacity "Benefit" Dollars
  - In Revenue Requirements Analysis (Case 1), Capacity ($/kW) was an adder to the first years cost of replacement.
  - In Regulated Cash Flow Analysis (Case 2), Capacity ($/kW) is levelized.
  - In Merchant Cash Flow Analysis (Case 3), no Capacity ($/kW) benefit is given the retired unit since a Merchant plant is under no obligation to maintain any specific reliability, whether measured by reserve or capacity margin, or loss of load probability.

- Treatment of Capital Costs
  - In Revenue Requirements Analysis (Case 1), Capital dollars are levelized.
  - In Cash Flow Analysis (Case 2 and Case 3), Capital dollars are modeled as annual expenditures.

Black-Start Capability

This study has been performed exclusive of the cost of black-start capability on any of the units. Currently, the following units have black-start capability for the Companies: Haefling, Cane Run 11, Paddy's Run 11, Zorn 1, and the hydro units located at Dix Dam and Ohio Falls (however, the hydro stations are not considered part of the Group 3 units in this study). There is no current cost or value given to these units for having black-start capability. The issue of ECAR or NERC requirements regarding black-start is not being addressed in this Phase of the evaluation. Likewise, the Companies' needs/desires as they relate to black-start capability throughout the system are not being addressed here. Therefore, this study has only identified units with black-start capability and the economic evaluations have been performed exclusive of the appropriate units having a black-start monetary benefit.

Green River Units 1-2

The Green River Power Station is located off of US Highway 431 on the Green River in Muhlenberg County, Kentucky and is owned and operated by Kentucky Utilities Company, a subsidiary of LG&E Energy Corp. The plant was constructed during the late 1940s –1950s and houses four coal-fired generating units totaling 212MW (summer). The Green River supplies water to the plant.

Units 1 and 2 began commercial operation on March 1, 1950 and January 5, 1950 respectively. Units 1 and 2 consist of three interconnected B&W front wall-fired, non-reheat boilers rated at 215,000 lbs/hr steam capacity each, 875 psig, 910° F. These medium sulfur coal-fired boilers supply steam to two Westinghouse steam turbines summer rated at 22MW each and operating at 850 psig and 900° F. The cooling water system is a once-through type. In the 1970's a "scrubber" (FGD), currently operating with approximately 80% SO_2 removal efficiency, was constructed to service both Unit 1 and Unit 2. Coal is delivered to the station by truck. The units have Continuous Emission Monitoring (CEM) systems to monitor stack emissions. These units are operated with a capacity factor typically below 20%. There is an operations staff dedicated to these units. This evaluation estimates a staffing level of 9 employees for Units 1-2.

Green River Power Station
(Owned by Kentucky Utilities Company)

Green River 1-2 Base Assumptions

- Global Assumptions

- 2003-2006 Capital investment reflective of current Business Plan.

- Beginning in 2007, units will continue to reliably operate thru end of evaluation period with no significant capital investment.

- Non-Labor O&M cost thru 2006 as per plant management escalating at 2% in 2007 through the end of the period.

- No capacity benefit assigned therefore, no capacity-related cost incurred to replace retired unit's capability.

- Beneficial re-use of Unit's 1 and 2 FGD on Units 3 and 4 not evaluated.

- Units were assumed to be winterized during the period November thru April of the following year.

- Severance offered to 9 personnel at a total cost of under $100,000 due to the short tenure of the majority of personnel impacted personnel.

- Simultaneous retirement of Units 1-2 occur in 2003.

- Merchant Environment removes Production and SO_2/NO_x cost impacts as the effects of these are reflected in the option value profit.

In addition to a Base Scenario using the above assumptions, several additional scenarios were evaluated relative to Green River 1 and 2.

GR 1, 2 Scenario 1- Capacity benefit of $221/kW assigned (i.e. Capacity related cost incurred to replace retired unit's capability).

GR 1, 2 Scenario 2- Purchase power available at $1000/MWh in 2003 escalating at 2%.

GR 1, 2 Scenario 3- Assume that some capital investment must be invested to insure reliable operation thru the end of evaluation period.

GR 1, 2 Scenario 4- Scenario 1 and Scenario 2 occur.

GR 1, 2 Scenario 5- Scenario 1 and Scenario 3 occur.

Table 3
Incremental Cost Impact of Retiring Green River Units 1, 2

Retire Green River Units 1 and 2	Case 1	Case 2	Case 3
	Regulated Environment Present Value Revenue Requirements	Regulated Environment Net Present Value Cash Flow Analysis	Merchant Environment Net Present Value Cash Flow Analysis
Base Scenario	($10,389,000)-R	$5,982,000-R	$3,010,000-R
Scenario 1- $221/kW Benefit	($680,000)-R	$775,000-R	Not Evaluated
Scenario 2- $1000/MWh Purch	($8,908,000)-R	$5,412,000-R	Not Evaluated
Scenario 3- Invest Capital $	($14,412,000)-R	$9,603,000-R	Not Evaluated
Scenario 4- Sce 1 & Sce 2	$802,000-O	$3,826,000-R	Not Evaluated
Scenario 5- Sce 1 & Sce 3	($4,702,000)-R	$4,396,000-R	Not Evaluated

-R implies "suggest retirement" to be economically favorable
-O implies "continued operation" to be economically favorable

All but one Scenario evaluated for Green River 1-2 suggests the units be retired. The Regulated Environment-Revenue Requirements analysis indicates that revenue requirements would be reduced in all but the most optimistic scenario by the retirement of Units 1 and 2 at Green River. The Revenue Requirements scenario that most strongly suggests retirement of these two facilities is Scenario 3 where capital expenditures equal to those originally proposed by plant management for the current budget period are deemed necessary expenses should the plant continue to operate and no capacity benefit is assigned to the units existing capacity. The Base Scenario also suggests that the two units should be retired even when the assumption is made that no capital expenses will be incurred thru the study period. The most beneficial Scenario, from the plant's perspective is Scenario 4 in which a $221/kW benefit is applied to replacement capacity in order to maintain the Company's 14% reserve margin and any market purchases resulting from the retirement of the Units cost $1000/MWh. This Scenario indicates that the revenue requirements of the Company would be increased by $802,000 (in present value) over the period if Green River Units 1-2 were to be retired.

The Regulated Environment-Cash Flow evaluation supports the retirement of Green River 1-2 as well. Each of the scenarios examined increases the Companies' cash flow. The Base Scenario, which assumes retirement occurs in 2003, indicates an increase in the Companies NPV cash flow of $5.9 million should no capacity value be assigned or $775,000 (Scenario 1) if the cost to replace Green River 1-2 capability is assumed to be $221/kW.

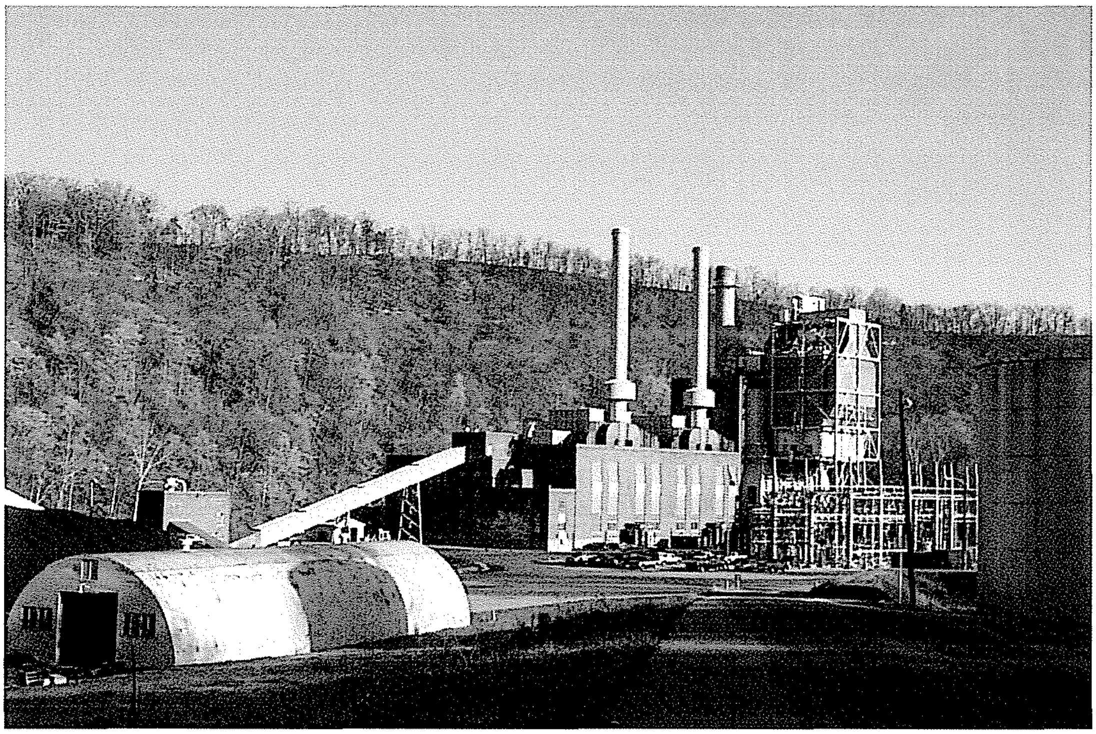
The Merchant Environment-Cash Flow perspective suggested retirement of Green River 1-2 as well. Very little option value can be justified for a steam unit with a high production cost and requiring a relatively long time-to-start. In addition depressed wholesale market prices and the reduced price volatility that often accompanies a soft market further exacerbate the economics of Green River 1-2 operation.

The dominating factors affecting the economics of Green River 1-2 are twofold. First there is the environmental cost impact of operation. While, the presence of a SO_2 scrubber on the units does reduce the SO_2 allowance cost impact, the units' high NO_x emission levels greatly detract from the economics of continued unit operation starting in 2004. With NO_x allowances on the order of $4000/ton and SO_2 allowances $150/ton it is estimated that retirement of Green River 1-2 will save over $5.8 million in NOx/SO2 allowance expenses. Second is the dedicated labor costs associated with operating and maintaining the units. While the $400,000 annual (loaded) labor cost estimates used has not been scrutinized for detailed accuracy it does reflect, within reason, the annual KU labor related cost associated with operation of Units 1 and 2.

In light of the cost associated with complying with NO_x environmental regulations and the potential O&M savings, Generation Services recommends that Green River Units 1 and 2 be in evaluated in Phase 2 of this study which will evaluate in detail costs associated with retirement of Green River Units 1 and 2.

Tyrone Units 1-2

The Tyrone Power Station is located on US Highway 62 at the Kentucky River in Woodford County, Kentucky and is owned and operated by Kentucky Utilities Company, a subsidiary of LG&E Energy Corp. The plant was constructed during the 1940s and houses three steam turbine generators totaling 129MW. The Kentucky River supplies water to the plant. Units 1 and 2 began commercial operation on October 12, 1947 and June 14, 1948 respectively. Presently contributing 27 and 31MW (summer ratings) to the KU/LG&E system, Units 1 and 2 have four interconnected B&W front wall fired, non-reheat boilers rated at 150,000 lbs/hr steam capacity each, 900 psig, 910° F. Originally coal fired, these boilers were converted to #2 fuel oil in 1971. Oil is delivered by truck and stored in an above ground tank. Unit 3, which burns low sulfur coal, uses the same oil for startup fuel and flame stabilization. These four boilers supply steam to two Westinghouse steam turbines rated at 25MW each operating at 850 psig and 900° F. The cooling water system is a once-through type. The units have CEM systems to monitor stack emissions and are primarily operated for peaking power during high system load periods. There are no employees solely dedicated to the operation and maintenance of these units. Employees primarily assigned to the operation of Unit 3 perform labor on these units through overtime.



Tyrone Power Station
(Owned by Kentucky Utilities Company)

Tyrone 1-2 Base Assumptions

- Global Assumptions

- No capacity benefit assigned therefore, no capacity-related cost incurred to replace retired unit's capability.
- Simultaneous retirement of Units 1-2 occur in 2003.
- Capital and O&M costs are not budgeted but reflect plant cost expectations to operate the units simultaneously for 1 full week in each of the summer months June, July and August.
- No staff impacts as a result of closing either Tyrone 1 or 2.
- Labor savings, if applicable, are in areas not currently budgeted.
- Labor O&M estimates represent overtime required by plant staff based on simultaneous runtimes (i.e. units 1 and 2 will always be operated together) for one full calendar week during each month of June, July and August.
- Capital costs reflect a runtime as assumed in Labor O&M for duration of evaluation period.
- Some retirement related costs for Tyrone 1-2 have been estimated by plant management and are included (Stack Dismantlement-$50,000; Mercury Removal-$20,000 and an annual Asbestos Containment expense -$5,000).
- Merchant Environment removes Production and SO_2/NO_X cost impacts as the effects of these are reflected in the option value profit.

In addition to a Base Scenario using the above assumptions, several additional scenarios were also evaluated.

TY 1, 2 Scenario 1- Capacity benefit of $221/kW assigned (i.e. Capacity related cost incurred to replace retired unit's capability).

TY 1, 2 Scenario 2- Purchase power available at $1000/MWh in 2003 escalating at 2%.

TY 1, 2 Scenario 3- Scenario 1 and Scenario 2 occur.

Table 4
Incremental Cost Impact of Retiring Tyrone Units 1, 2

Retire Tyrone Units 1 and 2	**Case 1** Regulated Environment Present Value Revenue Requirements	**Case 2** Regulated Environment Net Present Value Cash Flow Analysis	**Case 3** Merchant Environment Net Present Value Cash Flow Analysis
Base Scenario	($1,430,000)-R	$872,000-R	$872,000-R
Scenario 1- $221/kW Benefit	$11,370,000-O	($5,982,000)-O	Not Evaluated
Scenario 2- $1000/MWh Purch	$1,512,000-O	($883,000)-O	Not Evaluated
Scenario 3- Sce 1 & Sce 2	$14,311,000-O	($7,737,000)-O	Not Evaluated

-R implies "suggest retirement" to be economically favorable
-O implies "continued operation" to be economically favorable

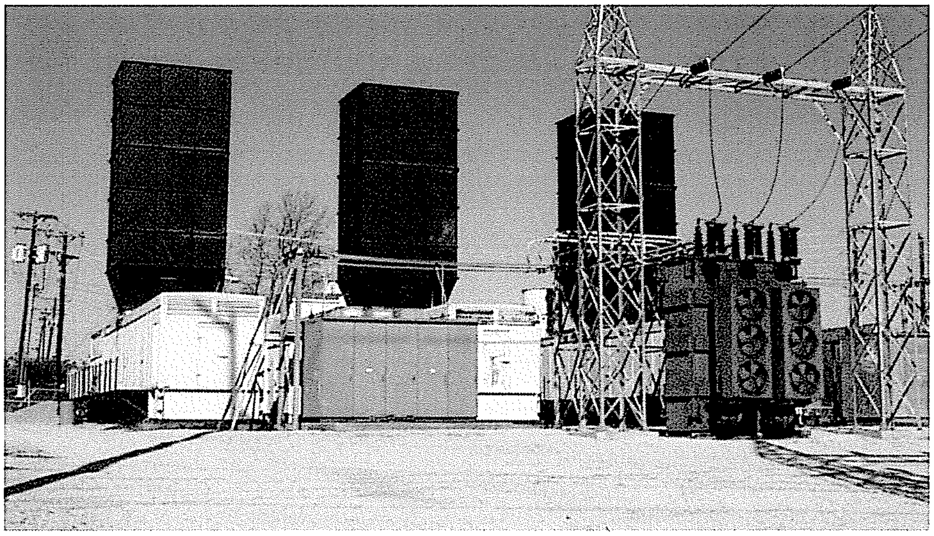
Each of the Base Scenarios in all three Cases suggests that retirement of Tyrone 1-2 would be economically sound. Retirement of the Units in the Base Scenario has the potential to reduce revenue requirements by a NPV of $1.4 million over the 10 year period. Revenue Requirements would increase (indicating that the economics favor continued operation) in all but the Base Scenario- where no capacity value is placed on the capability of Tyrone Units 1 and 2. It is of interest to note that the Case 1-Base Scenario break-even $/kW capacity benefit value for Tyrone 1-2 is approximately $25/kW. Therefore, if the assumed replacement cost of Tyrone 1-2 capacity is above $25/kW, then none of the Regulated Environment Scenarios evaluated would suggest retirement for Tyrone Units 1 and 2.

Evaluations of the Regulated and Merchant Cash Flow Base Scenarios arrive at the same conclusions as the Revenue Requirements analysis. Note that the Base Scenario of Case 2 and Case 3 yield the same dollar savings when the unit is retired. This is due to the fact that Tyrone 1-2 have no generation in any of the Base Scenarios. In the regulated environment Tyrone 1-2 are not utilized because their production costs exceed that of other units or purchase power and in the Merchant case it is out of the money based on current estimates of future market prices/volatility and the large lead-time (> 4 hours) associated with bringing a unit on line. Note however, that when either (or both) a $221/kW capacity value is assigned or high wholesale purchase power prices exist, the cash flow of the Company would be negatively impacted should the units be retired.

The economic evaluations of units such as Tyrone 1-2 are relatively straightforward. Given today's view that the depressed prices within the wholesale power market will not increase substantially in the near term and the fact that the units are not projected to run for native load or off-system sales (and hence have little or no opportunity to produce revenue) yet still incur fixed costs such as Insurance and Air/Water fees one should expect that the economics would favor unit retirement. That is exactly what the Base Scenarios indicate for Tyrone 1-2. Only when a $/kW capacity value (over $25/kW) is placed on Tyrone 1-2's capacity (regardless of whether the units are generating or not) or when purchase power must be bought from a $1000/MWh priced market do the economics favor the continued operation of these two units. Therefore, Generation Services recommends that the retirement of Tyrone Units 1 and 2 be evaluated in Phase 2 of this study.

Haefling Units 1, 2, 3

The Haefling Generating units are located off Baumann Drive in Lexington, Kentucky. There are three GE Frame 5 combustion turbines located within the Haefling Substation. These units burn natural gas or #2 fuel oil and are started by diesel engines. Each has a summer rated capacity of 12MW and is capable of providing black-start power for the E.W. Brown or Ghent Stations. All three units have undergone combustion chamber overhauls in the late 1990s; however, the control system is aging and reliability is decreasing. The inlet and exhaust plenums and silencers have been replaced allowing these units to continue to serve their peaking role. The site is not manned necessitating that Generation Dispatch notify Tyrone plant personnel when the Haefling Units are anticipated being dispatched. Tyrone plant personnel travel to Lexington (~45 minutes) to oversee the startup and operation of the units.



Haefling Power Station
(Owned by Kentucky Utilities Company)

Haefling 1-3 Base Assumptions

- Global Assumptions
- No capacity benefit assigned therefore, no capacity-related cost incurred to replace retired unit's capability.
- Simultaneous retirement of Units 1, 2 and 3 occur in 2003.
- Labor O&M estimates represent overtime required by 2 plant personnel for simultaneous runtimes on Unit 1-3 (i.e. units 1, 2 and 3 will always be operated together) for one full calendar week during each month of June, July and August.
- Capital costs reflect a runtime as assumed in Labor O&M for the duration of evaluation period.
- Capital expenditures consist of a $185,000 expenditure in 2004.
- No economic benefit for being a proven system black-start capable unit.
- Merchant Environment removes Production and SO2/NOx cost impacts as the effects of these are reflected in the option value profit.

In addition to a Base Scenario using the above assumptions, several additional Regulated Environment scenarios were also evaluated.

HF 1, 2, 3 Scenario 1- Capacity benefit of $221/kW assigned (i.e. Capacity related cost incurred to replace retired unit's capability).

HF 1, 2, 3 Scenario 2- Purchase power available at $1000/MWh in 2003 escalating at 2%.

HF 1, 2, 3 Scenario 3 -Scenario 1 and Scenario 2 occur.

Table 5
Incremental Cost Impact of Retiring Haefling Units 1, 2, 3

Retire Haefling Units 1, 2 and 3	**Case 1** Regulated Environment Present Value Revenue Requirements	**Case 2** Regulated Environment Net Present Value Cash Flow Analysis	**Case 3** Merchant Environment Net Present Value Cash Flow Analysis
Base Scenario	($293,000)-R	$217,000-R	($97,000)-O
Scenario 1- $221/kW Benefit	$7,651,000-O	($4,043,000)-O	Not Evaluated
Scenario 2- $1000/MWh Purch	$2,381,000-O	($1,377,000)-O	Not Evaluated
Scenario 3- Sce 1 & Sce 2	$10,325,000-O	($5,638,000)-O	Not Evaluated

-R implies "suggest retirement" to be economically favorable
-O implies "continued operation" to be economically favorable

From the Regulated-Revenue Requirements perspective the retirement of Haefling 1-3 would increase the Companies' revenue requirements (suggesting the facility not be retired) in all but the Base Scenario- where no replacement cost is placed on the capability of Haefling station. It is of interest to note that the break-even point for Case 1-Base Scenario is approximately $8/kW. Therefore, if the assumed value of Haefling 1-3 capacity is above $8/kW, then none of the Regulated Environment Scenarios evaluated would suggest retirement.

The Regulated Environment Cash Flow Analysis arrives at the same conclusions as the Regulated Environment Revenue Requirements. When either a $221/kW capacity value is assigned and/or high wholesale power prices exist, the cash flow of the Company would be negatively impacted.

In contrast to the Revenue Requirements analysis and the Regulated Environment Cash Flow analysis, the Merchant Environment Cash Flow Analysis does not suggest that closure of the Haefling station. Given the current wholesale market volatility and prices, the closure of Haefling would negatively impact, although modestly, the cash flows of the Company ($97,000 in present value of the ten year period). One significant factor impacting the economics is that more than $1 million presently estimated to be on the books would have to be written off if Haefling were to be retired.

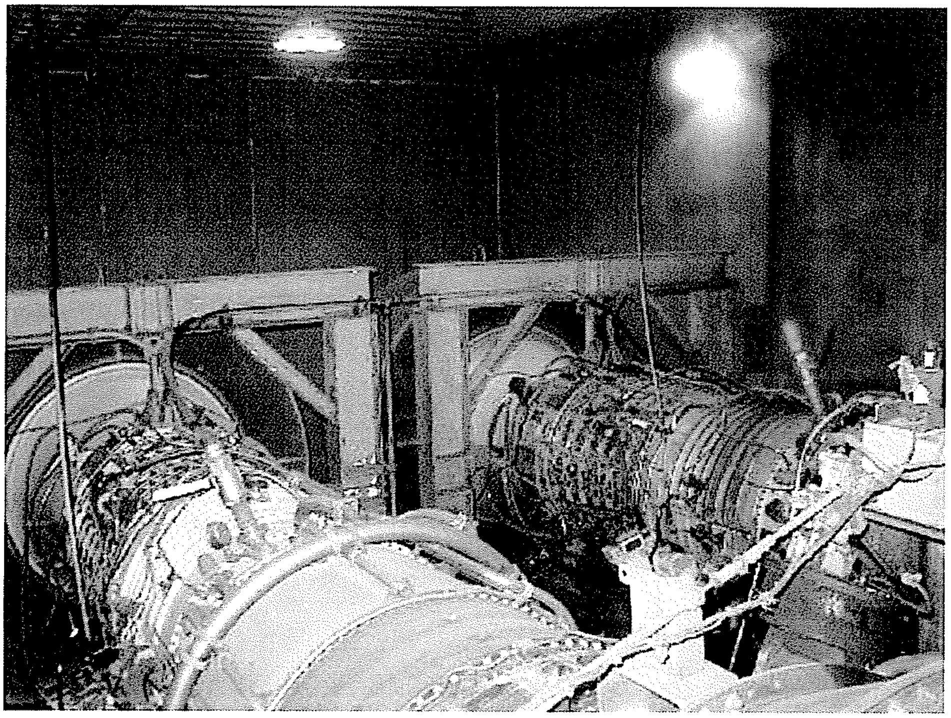
There appears to be some reasonable scenarios in which the retirement of Haefling is warranted and as such, it is recommended that the retirement of Haefling be evaluated in Phase 2 of this study.

Waterside Units 7-8

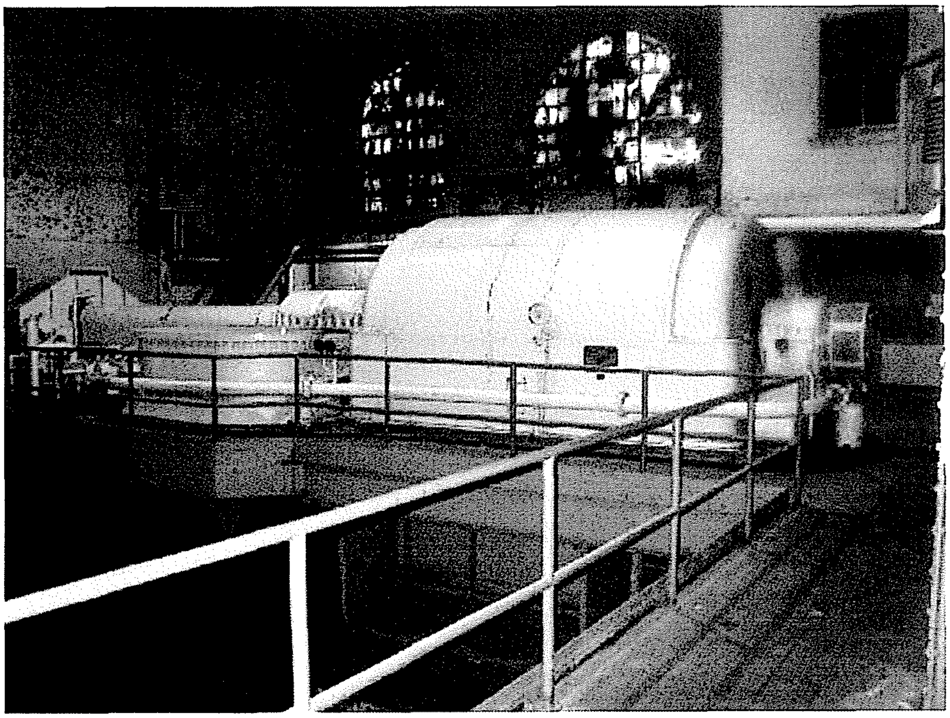
The site is located in a former coal-fired power station in downtown Louisville, Kentucky. Each generating unit consists of two GE 7LM1500-PD101 industrial aero derivative gas turbines, which operate at 5523 rpm. Both units drive through a common load gear to the original 1920's 20MW generators, which run at 1800 rpm. A fuel gas compressor is located outside the main building in a dedicated enclosure. The units do not provide a black-start capability and were commissioned in 1964. The summer rated net capability of each is 11MW. The units are started locally and the site is manned during operation, typically during peak load periods.

Unit 8 had both gas generators, replaced in 1999 following the failure of a turbine blade that damaged both the gas generator and power turbine (8B). The original gas generators (CJ805) were obsolete and were replaced with a later refurbished model (J79).

Other than to replace unit 8's gas generators there have been no other major overhauls, inspections or repairs to either turbine generating set. The gas compressor was overhauled in 1996 and is working reliably; however, it is now obsolete and parts are difficult to obtain. There are a number of issues and concerns with both units, which would require significant investment to rectify and as a result it is difficult to justify the full capacity benefit used previously in this evaluation of $221/kW without a substantial amount of work/inspection being conducted on the machines. Evaluation of these units with the full $221/kW value is only justified if the machines were to undergo a Control System upgrade and a Hot Gas Path Inspection (HGPI) and part replacement. A scenario was evaluated that regards the units as having the necessary capital and O&M expenditures to justify the full $221/kW capacity benefit.



Waterside Station-Units 7 & 8
(Owned by Louisville Gas and Electric Company)



Waterside Station-Generators 7 & 8
(Owned by Louisville Gas and Electric Company)

Waterside 7-8 Base Assumptions

- Global Assumptions
- No capacity benefit assigned therefore, no capacity-related cost incurred to replace retired unit's capability.
- No Capital expenditures and no significant non-labor O&M is required through the study period to maintain "status-quo" operational characteristics (start reliability, availability etc).
- Waterside 7 and 8 are not black-start capable.

In addition to a Base Scenario using the above assumptions, several additional Regulated Environment scenarios were also evaluated.

WS 7, 8 Scenario 1- Capacity benefit increased to $221/kW thru a needed $1.25 million (per unit) maintenance expense consisting of a control system upgrade and a Hot Gas Path Inspection (HGPI) and part replacement (as needed) occurring in 2006.

WS 7, 8 Scenario 2- Purchase power available at $1000/MWh in 2003 escalating at 2%.

WS 7, 8 Scenario 3- Scenario 1 and Scenario 2 occur.

Table 6
Incremental Cost Impact of Retiring Waterside Units 7, 8

Retire Waterside Units 7 and 8	Case 1	Case 2	Case 3
	Regulated Environment Present Value Revenue Requirements	Regulated Environment Net Present Value Cash Flow Analysis	Merchant Environment Net Present Value Cash Flow Analysis
Base Scenario	($58,000)-R	$134,000-R	($342,000)-O
Scenario 1- $221/kW Benefit + Increased Maintenance Costs	$2,409,000-O	($5,290,000)-O	Not Evaluated
Scenario 2- $1000/MWh Purch	$48,000-O	$71,000-R	Not Evaluated
Scenario 3- Sce 1 & Sce 2	$2,515,000-O	$2,102,000-R	Not Evaluated

-R implies "suggest retirement" to be economically favorable
-O implies "continued operation" to be economically favorable

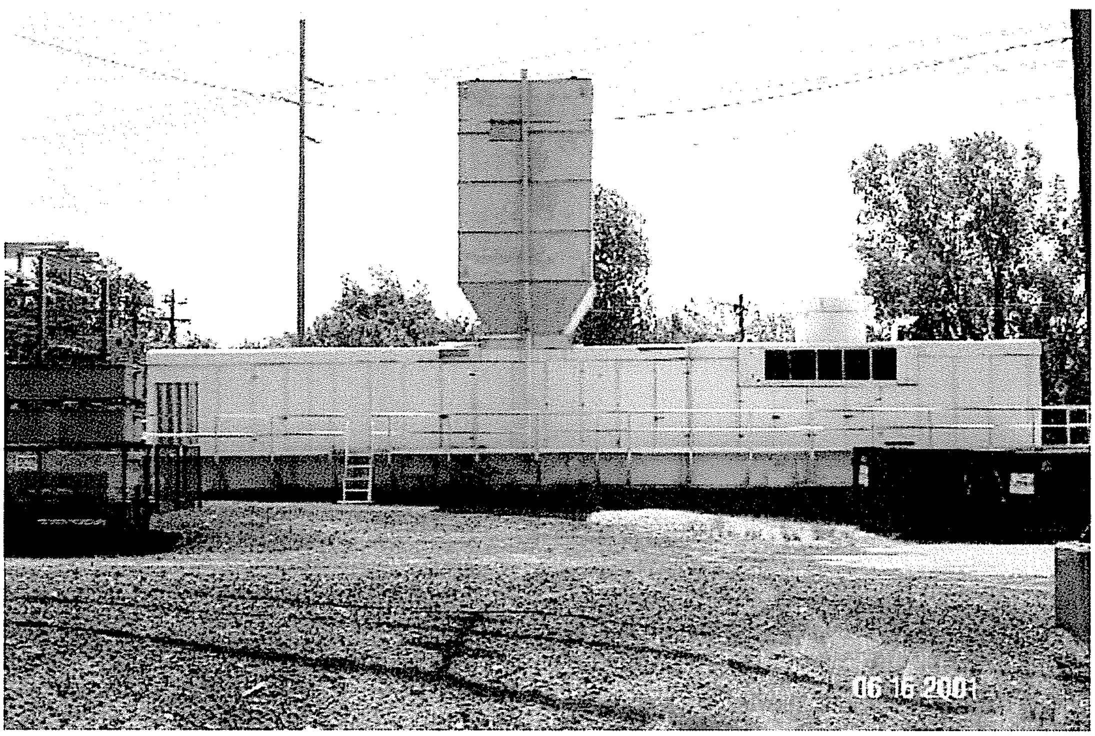
The Base Scenarios for two of the three Cases indicate retirement of Waterside 7-8 would be prudent. Waterside Units 7-8, like Tyrone Units 1-2 do not generate in the Regulated environment Base Scenarios (Case 1 and Case 2). The units fixed costs of operation (Insurance, Non-Labor O&M etc) therefore are not able to be offset by any revenues except a capacity benefit. When a capacity benefit is applied, the economics suggest continued operation to be marginally economically favorable. One point of interest is that the break-even $/kW capacity benefit for Case 1- Scenario 1 is $111/kW (Note: It would be incorrect to calculate a breakeven $/kW cost on Case 1- Base Scenario because the units should be subject to a HGPI, the costs of which are included only in Scenarios 1 and 3).

In light of the economic evaluation performed above, Generation Services recommends that the retirement of Waterside Units 7-8 be further evaluated in Phase II of this study.

Paddy's Run 11-12

Unit 11 is a 12MW (net summer rating) GE Frame 5001LA gas turbine located in a close fitting acoustic enclosure adjacent the switchyard of the retired Paddy's Run coal-fired power station in Louisville, Kentucky. Although the coal-fired power station is closed the switchyard and substations remain active. The unit is normally started locally although remote starting is possible from the LG&E load dispatch office in downtown Louisville. The unit operates on gas fuel only and commenced operation on June 10, 1968.

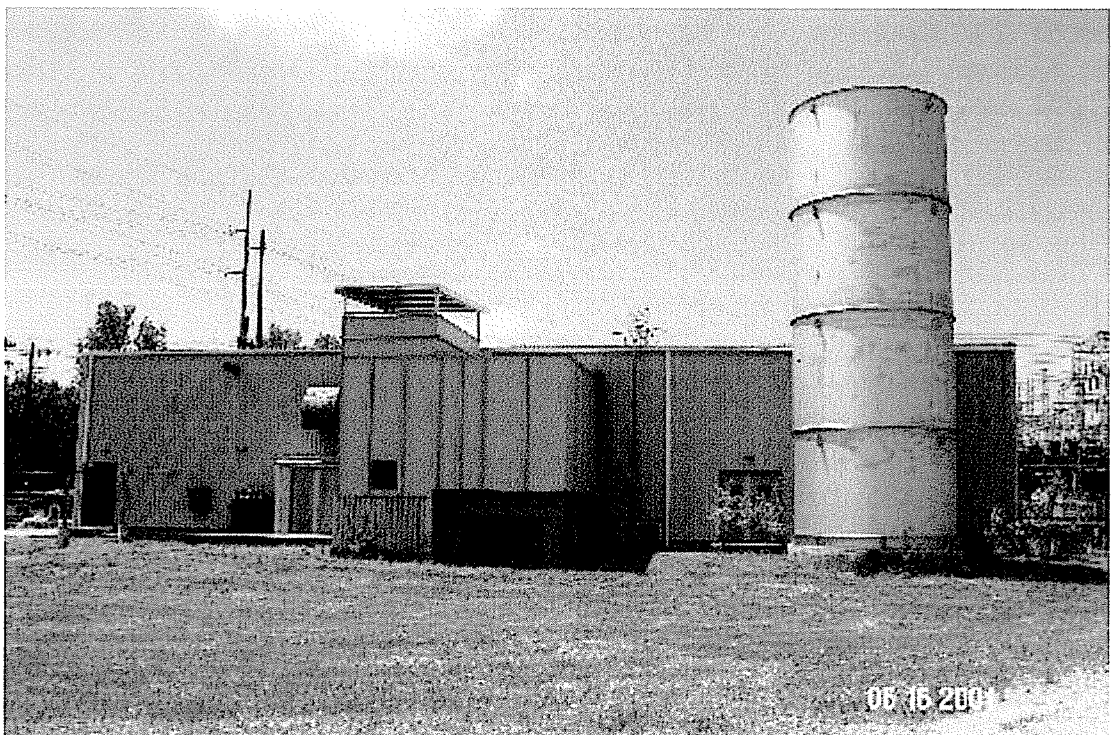
Unit 11 is generally in good and serviceable condition with the gas turbine and load gear being overhauled in 1996, although the generator was not inspected. The unit has started reliably and provides black-start capability. The main risk to the continued good reliability is that the control system is now obsolete and there is increasing difficulty finding support and spare parts.



Paddy's Run Unit 11
(Owned by Louisville Gas and Electric Company)

Unit 12 is located within a single, portal frame metal clad building adjacent the switchyard of the closed Paddy's Run coal-fired power station in Louisville, Kentucky. Unit 12 is a Westinghouse 301G gas turbine generator. This is a long, heavy-duty industrial gas turbine featuring cold end drive, two-bearing configuration, can-annular combustion and a hydrogen-cooled generator. The gas turbine operates at 3600 rpm and therefore requires no load gear. First operated on July 16, 1968, Paddy's Run 12 operates on gas fuel only and has a net summer rating of 23MW.

Unit 12 is currently started locally, although remote starting has been installed but is not fully implemented. The unit requires significant investment to overhaul the gas turbine and generator and to upgrade its control. As a result, starting reliability is poor. Two to three days annually is normally spent testing systems and preparing the unit for operation and even then the unit often fails to achieve load. The unit does not contribute any black-start capability to the system.



Paddy's Run Unit 12
(Owned by Louisville Gas and Electric Company)

Paddy's Run 11-12 Base Assumptions

- Global Assumptions
- No capacity benefit assigned therefore, no capacity-related cost incurred to replace retired unit's capability.
- Base Capital expenditures are $250,000 in 2004 for Unit 11 and $350,000 ($100,000 in 2003, $250,000 in 2005) for Unit 12.
- No economic benefit for Unit 11 being a proven system black-start capable unit.

In addition to a Base Scenario using the above assumptions, several additional Regulated Environment scenarios were also evaluated.

PR 11, 12 Scenario 1- Capacity benefit increased to $221/kW as a result of additional capital expenses of $1 million for a Hot Gas Path Inspection (HGPI) and part replacement on Unit 11 (in 2004), and $1 million HGPI/part replacement on Unit 12 in 2005.

PR 11, 12 Scenario 2- Purchase power available at $1000/MWh in 2003 escalating at 2%.

PR 11, 12 Scenario 3- Scenario 1 and Scenario 2 occur.

Table 7
Incremental Cost Impact of Retiring Paddy's Run Units 11, 12

Retire Paddy's Run 11-12	Case 1	Case 2	Case 3
	Regulated Environment Present Value Revenue Requirements	Regulated Environment Net Present Value Cash Flow Analysis	Merchant Environment Net Present Value Cash Flow Analysis
Base Scenario	($979,000)-R	$742,000-R	$101,000-R
Scenario 1- $221/kW Benefit + Increased Maintenance Cost	$4,182,000-O	($1,385,000)-O	Not Evaluated
Scenario 2- $1000/MWh Purch	$63,000-O	$120,000-R	Not Evaluated
Scenario 3- Sce 1 & Sce 2	$5,224,000-O	($2,007,000)-O	Not Evaluated

-R implies "suggest retirement" to be economically favorable
-O implies "continued operation" to be economically favorable

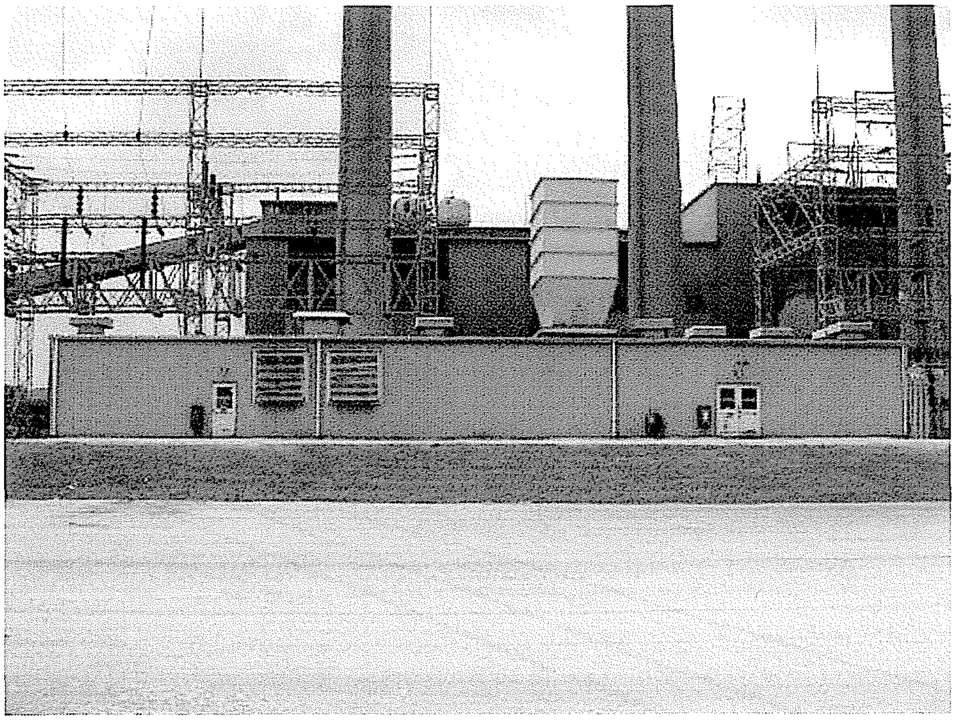
Results of all Base Scenarios for Paddy's Run 11 and 12 imply that the units should be retired. The economics of Paddy's Run 11 and 12, like the Waterside Units, justify continued operation in only one of the two scenarios when the purchase power price is $1000/MWh (Case 1 Scenario 2). With a capacity benefit of $221/kW in spite of the $2 million costs to perform a HGPI, the economics suggest continued operation to be economically favorable. One point of interest is that the break-even $/kW capacity benefit for Case 1- Scenario 1 is $101/kW (Note: It would be incorrect to calculate a breakeven $/kW cost on Case 1- Base Scenario because the units should be subject to a HGPI, the costs of which are included only in Scenarios 1 and 3).

In light of the economic evaluation performed above, Generation Services recommends that the retirement of Paddy's Run Units 11, 12 be further evaluated in Phase II of this study.

Cane Run 11

Cane Run 11 is located on the site of the Cane Run coal-fired station in Louisville, Kentucky. The unit is a Westinghouse W191G gas turbine installed inside a portal frame clad building. The unit is a heavy-duty industrial gas turbine featuring cold end drive, two-bearing configuration, can-annular combustion and an air-cooled generator. With a net summer capability of 14MW it is the only LG&E peaking unit that has dual fuel capability. The unit commenced operation on April 29, 1968.

The gas turbine is in good and serviceable condition having been overhauled in the spring of 2000. The load gear and generator were inspected and found to be in good condition. The main risk to the continued good reliability is that the control system is now obsolete and there is increasing difficulty finding support and spare parts. The unit is normally started locally although remote control is available in a nearby switchyard control room. The unit has black-start capabilities.



Cane Run Unit 11
(Owned by Louisville Gas and Electric Company)

Cane Run 11 Base Assumptions

- Global Assumptions
- No capacity benefit assigned therefore, no capacity related cost incurred to replace retired unit's capability.
- Base Capital expenditures are $250,000 in 2003 associated with a controls upgrade.
- No economic benefit for being proven system black-start capable.

In addition to a Base Scenario using the above assumptions, several additional Regulated Environment scenarios were also evaluated.

CR11 Scenario 1- Capacity benefit increased to $221/kW. This unit had an overhaul performed in the spring of 2000.

CR11 Scenario 2- Purchase power available at $1000/MWh in 2003 escalating at 2%.

CR11 Scenario 3- Scenario 1 and Scenario 2 occur.

Table 8
Incremental Cost Impact of Retiring Cane Run Unit 11

Retire Cane Run 11	Case 1 Regulated Environment Present Value Revenue Requirements	Case 2 Regulated Environment Net Present Value Cash Flow Analysis	Case 3 Merchant Environment Net Present Value Cash Flow Analysis
Base Scenario	($208,000)-R	$214,000-R	$27,000-R
Scenario 1- $221/kW Benefit	$2,881,000-O	($1,442,000)-O	Not Evaluated
Scenario 2- $1000/MWh Purch	($48,000)-R	$119,000-R	Not Evaluated
Scenario 3- Sce 1 & Sce 2	$3,042,000-O	($1,538,000)-O	Not Evaluated

-R implies "suggest retirement" to be economically favorable
-O implies "continued operation" to be economically favorable

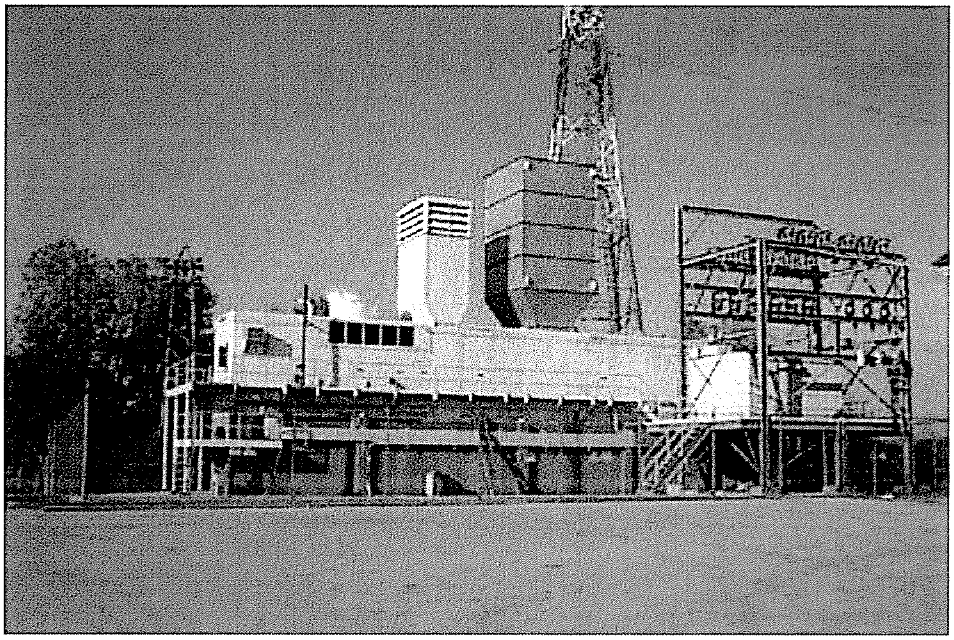
Results of all Base Scenarios for Cane Run 11 once again indicate that the units should be retired. The economics of continued operation are unfavorable to the units even when the purchase power price is $1000/MWh . When a capacity benefit of $221/kW is factored in, the economics suggest continued operation to be economically favorable. One point of interest is that the break-even $/kW capacity benefit for Case 1- Base Scenario is $15/kW.

In light of the economic evaluation performed above, Generation Services recommends that the retirement of Cane Run Unit 11 be further evaluated in Phase II of this study.

Zorn 1

The Zorn gas turbine generating unit is a GE Frame 5001 LA installed in a close-fitting acoustic enclosure. The unit is located in a small fenced enclosure adjacent to the Louisville Water Companies' (Water Company) river water pumping station and sits on a tall concrete base to protect it against flooding. The unit was installed primarily to supply emergency power for the nearby Riverside pumping station. A contract exists between the Water Company and LG&E. More information on the LG&E/Water Company contract can be found in the section titled LG&E, Louisville Water Company and Zorn CT. The Water Company makes annual payments of $10,000 to LG&E associated with that contract. The unit operates on gas fuel only and has a net summer rating of 14MW. The unit commenced operation on the May 23, 1969.

The unit is in good and serviceable condition. The gas turbine and load gear (but not the generator) had a major inspection and overhaul in 1995. Remote starting, although possible, is problematic; therefore the unit is normally started locally. The unit has started reliably and has black-start capability. The main risk to the continued good reliability is that the control system is now obsolete and there is increasing difficulty finding support and maintenance spare parts.



Zorn Unit 1
(Owned by Louisville Gas and Electric Company)

Zorn 1 Base Assumptions

- Global Assumptions
- No capacity benefit assigned therefore, no capacity related cost incurred to replace retired unit's capability.
- Base Capital expenditures expected to be $250,000 in 2004 associated with a controls upgrade.

- While this unit is a proven system black-start unit, it is under contract to service the Louisville Water Company during a black-start emergency. No economic benefit is assumed.

In addition to a Base Scenario using the above assumptions, several additional Regulated Environment scenarios were also evaluated.

ZN 1 Scenario 1- Capacity benefit increased to $221/kW as a result of additional capital expenditure of $1 million for a Hot Gas Path Inspection (HGPI) and part replacement in 2004.

ZN 1 Scenario 2- Purchase power available at $1000/MWh in 2003 escalating at 2%.

ZN 1 Scenario 3- Scenario 1 and Scenario 2 occur.

Table 9
Incremental Cost Impact of Retiring Zorn Unit 1

Retire Zorn 1	**Case 1**	**Case 2**	**Case 3**
	Regulated Environment Present Value Revenue Requirements	Regulated Environment Net Present Value Cash Flow Analysis	Merchant Environment Net Present Value Cash Flow Analysis
Base Scenario	($327,000)-R	$295,000-R	$4,000-R
Scenario 1- $221/kW Benefit + Increased Maintenance Cost	$1,394,000-O	($317,000)-O	Not Evaluated
Scenario 2- $1000/MWh Purch	$123,000-O	$26,000-R	Not Evaluated
Scenario 3- Sce 1 & Sce 2	$1,843,000-O	($585,000)-O	Not Evaluated

-R implies "suggest retirement" to be economically favorable
-O implies "continued operation" to be economically favorable

Retirement of Zorn Unit 1 is the suggested course of actions based on the results of all three Base Scenarios. The unit is also uneconomical to continue to operate under one of the two Cases of Scenario 2, where the price of purchase power is $1000/MWh. The production cost of this unit are generally the highest of any LG&E unit and the resulting limited run time the unit normally is experiences is not sufficient, in this analysis, to produce enough benefits to cover the annual expenses of depreciation, insurance etc. As with the other Group 3 units, addition of a capacity adder suggests the unit should continue to operate. One point of interest is that the break-even $/kW capacity benefit for Case 1- Base Scenario is $121/kW.

Based on the results of this evaluation, Generation Services recommends that retirement of the Zorn CT be evaluated in Phase II of this analysis.

LG&E, Louisville Water Company and Zorn CT

LG&E has a special contract with the Louisville Water Company for emergency power from the Zorn CT. The contract was entered into on November 25, 1968 and renews annually unless cancelled by either party. The contract requires the parties give 2 year notice to terminate. The Water Company has paid LG&E $40,000 per year from 1969-1993 to maintain the unit and for capital recovery. From 1994 until the contract is cancelled, the Water Company will pay $10,000 per year for maintenance and for capital recovery. Other than showing the $10,000 annual payment stream that would go away if Zorn would be retired, this evaluation only recognizes that contractual obligations exist and does not factor any other costs stemming from the contract into the financial analysis.

Conclusion and Recommendation

KU and LG&E have several units currently in service that warrant close examination of the costs associated with keeping them in service compared to the costs of retiring the facility. The age and operational cost of the thirteen units identified in Group 3 suggest that it may be the best economic decision to retire these units. This Phase I evaluation took a high-level view of each unit and evaluated the 10 year cost streams incurred from both operating that unit and the costs incurred if the unit were to be retired. Present value revenue requirements and present value cash flow techniques were performed for a base scenario and various sensitivity scenarios. The base scenario for all units under all financial techniques utilized indicated that possible cost savings could be realized if the units were to be retired in place. The analysis was highly sensitive to the value put on the capacity benefit of the units in contributing to the Companies' reserve margin obligation. Sensitivities were performed around this capacity value with Green

River 1-2 being the only units that continued to suggest the retirement of the units would be the best economic option. It is therefore recommended that all 13 units continue to be evaluated in Phase II for possible retirement.

Appendix A
Service Hours by Unit
(1993-2002)

Service Hours by Unit

GROUP	UNIT	Service Hours (Run-Times) 1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Group 1	BR3	5,791	7,428	4,845	7,750	6,636	7,324	7,986	8,265	7,519	7,105
	GH1	7,847	5,984	7,838	8,046	7,392	7,479	7,820	6,884	7,957	7,199
	GH2	7,554	8,078	8,302	7,402	8,082	7,917	7,906	7,263	7,679	7,533
	GH3	7,858	7,928	7,277	8,545	7,934	7,576	7,847	8,137	7,882	8,112
	GH4	6,233	8,107	8,488	7,526	7,869	8,255	7,810	8,413	8,337	5,922
	MC1	6,523	6,788	7,024	6,650	7,317	6,742	7,769	7,483	7,281	7,112
	MC2	6,591	6,975	6,376	7,253	6,807	6,301	7,913	8,029	7,219	7,671
	MC3	6,880	7,769	6,041	7,370	7,715	7,392	6,747	7,447	7,929	7,022
	MC4	7,273	5,678	7,352	8,018	6,193	7,075	5,911	7,189	6,282	7,170
	TC1	7,608	7,713	7,618	6,962	8,213	7,547	8,372	7,483	7,108	7,883
	BR5									491	809
	BR6								269	74	814
	BR7								260	457	665
	BR8				57	137	670	508	581	609	474
	BR9				40	39	702	433	443	380	277
	BR10				36	199	676	417	395	238	287
	BR11				17	74	399	435	254	153	177
	PR13									333	794
	TC5										737
	TC6										719
Group 2	BR1	6,555	6,065	4,953	6,502	6,747	7,046	6,587	7,984	8,077	8,128
	BR2	6,831	5,419	6,158	6,859	7,511	7,867	7,796	7,130	6,426	6,969
	CR4	5,373	7,023	7,124	5,563	8,022	7,407	6,862	7,877	7,460	8,082
	CR5	6,559	5,919	6,080	6,416	6,751	6,839	7,766	6,747	6,982	7,593
	CR6	6,654	5,026	5,290	6,738	6,681	6,852	6,234	7,250	7,188	5,134
	GR3	4,353	5,554	6,328	5,495	3,830	6,598	7,382	7,165	6,797	4,133
	GR4	6,896	6,641	4,594	4,540	6,785	7,700	6,805	7,281	7,055	6,657
	TY3	2,324	2,161	2,791	2,492	2,818	4,300	4,504	5,956	5,831	5,586
Group 3	CR11	29	64	78	135	185	176	119	29	31	14
	GR1	425	46	550	176	197	2,091	1,368	2,980	1,991	1,692
	GR2	452	130	610	124	254	2,268	1,416	3,130	1,995	1,674
	HF1	1	1	36	17	1	205	126	33	5	2
	HF2	1	1	36	26	2	169	138	29	1	2
	HF3	1	1	31	16	2	208	134	26	6	2
	PR11	4	0	0	36	236	258	194	69	18	5
	PR12	13	45	140	111	201	267	184	63	16	7
	TY1	162	7	373	4	40	115	76	0	18	0
	TY2	45	105	372	58	24	131	181	0	17	0
	WS7	27	31	75	8	133	245	138	57	6	2
	WS8	27	31	0	6	42	15	19	41	5	2
	Z1	9	0	96	117	210	194	160	57	23	4

Note:

The data for Group 1 excludes the service hours associated with Dix Dam and Ohio Falls hydro units.

Appendix B
General Evaluation Outline for Phase II of Unit Viability Study

General Evaluation Outline for Phase II of Unit Viability Study

I) **General Unit Data** (Generation Planning, Generation Engineering, Plant Staff)
   a) Unit Name
   b) In-Service Year
   c) Boiler Data
   d) Turbine Data
   e) Generator Data
   f) GSU Data

II) **Operating Data** (Generation Planning, Generation Engineering, Plant Staff)
   a) Annual Net Generation
      i) Seasonal Generation
   b) Annual Net Summer/Winter Capacity
   c) Annual GADS Data
      i) EFOR
      ii) MOH
      iii) FOR
   d) Maintenance
      i) Historical/Scheduled Turbine/Generator Overhaul
      ii) Historical/Scheduled Annual Maintenance Weeks

III) **Plant/Unit Assessment** (Generation Engineering)
   a) Risks of continued operation
   b) Impact on other units at the site
   c) Impact on the system

IV) **O&M costs** (Plant Staff, Generation Planning, Generation Engineering)
   a) Operational costs
   b) Maintenance costs
      i) Routine maintenance
      ii) Overhauls
   c) Capital Projects

V) **Layup Vs Retire** (Generation Planning, Operations Analysis, Generation Engineering)
   a) Operational costs
   b) Maintenance costs
   c) Staffing

VI) **Capacity and Energy Value** (Generation Planning, Market Valuation)
   a) Impact on expansion plan or reserve margin
   b) Market value of capacity and energy

VII) **Environmental** (Environmental Affairs, Generation Planning, Generation Engineering)

a) Ash Pond
b) SO_2 Emissions
   i) Rate (#/mmbtu)
   ii) Annual Tons
c) NO_x Emissions
   i) Ozone Season
      (1) Rate (#/mmbtu)
      (2) Annual/Monthly Tons
d) Mercury Emissions
e) Asbestos
f) Lead based paint
g) PCB
h) Coal yard reclamation
i) Chemical disposal
j) UST closure
k) Permit modification(s)/notification(s)(DOW, DWM, DAQ, State Boiler Inspector)

VIII) **Scrap/Salvage/Re-Use Potential** (Plant Staff, Generation Engineering, Generation Planning)

a) Scrap Value – raw material value
b) Salvage Value – equipment with potential resale value
c) Identify location of identical turbines still in operation for possible purchase of balance of plant equipment or strategic spares
d) Opportunities exist to use GSU or BOP equipment on other units within KU/LG&E or at another company.

IX) **KY Public Service Commission** (Regulatory Management, Generation Planning)

a) Any required filings
b) Effect on ECR
c) Effect on ESM

X) **Financial** (Operations Analysis, Property Accounting)

a) Current Book Cost
b) Depreciation related expenses
c) Are stranded costs an issue

XI) **Community Issues** (Corporate Communications, External Affairs)

a) Public Comments/Affected Community Meetings
b) Relationship with the Louisville Water Company (Zorn unit)

XII) **Transmission System Issues** (Transmission Planning & Substations)

a) Voltage Support: Affect of unit retirements on area voltage support.
b) Substation reliability (remote operation of equipment)

XIII) **Fuel** (Fuels Management)
  a) Contract termination issues
  b) For Haefling, what would happen to gas line.

XIV) **Employees** (Human Resources)
  a) Number of Union Employees
  b) Number of Non-Union Employees
  c) Options for redeployment/ retirement

Appendix C
Revenue Requirements Financial Analysis
(Case 1)

Retire Green River Units 1-2
Case 1: Present Value Revenue Requirements Analysis

Negative Numbers Imply Cost Savings from Retiring Unit

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPV @ 8.74% ($000)	
Base Scenario (0$/kW Capacity Benefit, 100$/MWh Purch Market, No Capital Budget)												
Production	249	16	-	-	-	-	60	-	-	-	300	
SO2/NOx	52	(632)	(1,015)	(1,199)	(936)	(846)	(848)	(1,387)	(946)	(1,046)	(5,806)	
Insurance	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(467)	
Air/Water Fees	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(141)	
Labor O&M	(451)	(460)	(469)	(479)	(488)	(498)	(508)	(518)	(528)	(539)	(3,439)	
Non-Labor O&M	(75)	(300)	(300)	(150)	(153)	(156)	(159)	(162)	(166)	(169)	(1,284)	
Levelized Capital	-	-	-	-	-	-	-	-	-	-	-	
Asset Retire Cost	24	-	-	-	-	-	-	-	-	-	24	
Capacity Benefit	-	-	-	-	-	-	-	-	-	-	-	
Write off/Depreciation	2,365	(335)	(335)	(335)	(335)	(335)	(335)	(335)	(335)	(335)	332	
Severance	92	-	-	-	-	-	-	-	-	-	92	
Total	2,169	(1,797)	(2,206)	(2,249)	(1,999)	(1,921)	(1,877)	(2,489)	(2,062)	(2,175)	(10,389)	Retire
Scenario 1 (221 $/kw Capacity Benefit)												
Production	249	16	-	-	-	-	60	-	-	-	300	
SO2/NOx	52	(632)	(1,015)	(1,199)	(936)	(846)	(848)	(1,387)	(946)	(1,046)	(5,806)	
Insurance	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(467)	
Air/Water Fees	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(141)	
Labor O&M	(451)	(460)	(469)	(479)	(488)	(498)	(508)	(518)	(528)	(539)	(3,439)	
Non-Labor O&M	(75)	(300)	(300)	(150)	(153)	(156)	(159)	(162)	(166)	(169)	(1,284)	
Levelized Capital	-	-	-	-	-	-	-	-	-	-	-	
Asset Retire Cost	24	-	-	-	-	-	-	-	-	-	24	
Capacity Benefit	9,710	-	-	-	-	-	-	-	-	-	9,710	
Write off/Depreciation	2,365	(335)	(335)	(335)	(335)	(335)	(335)	(335)	(335)	(335)	332	
Severance	92	-	-	-	-	-	-	-	-	-	92	
Total	11,879	(1,797)	(2,206)	(2,249)	(1,999)	(1,921)	(1,877)	(2,489)	(2,062)	(2,175)	(680)	Retire
Scenario 2 (1000 $/MWh Purchase Market Price)												
Production	1,281	459	-	-	-	-	60	-	-	-	1,739	
SO2/NOx	56	(623)	(1,010)	(1,199)	(929)	(847)	(848)	(1,387)	(946)	(1,000)	(5,763)	
Insurance	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(467)	
Air/Water Fees	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(141)	
Labor O&M	(451)	(460)	(469)	(479)	(488)	(498)	(508)	(518)	(528)	(539)	(3,439)	
Non-Labor O&M	(75)	(300)	(300)	(150)	(153)	(156)	(159)	(162)	(166)	(169)	(1,284)	
Levelized Capital	-	-	-	-	-	-	-	-	-	-	-	
Asset Retire Cost	24	-	-	-	-	-	-	-	-	-	24	
Capacity Benefit	-	-	-	-	-	-	-	-	-	-	-	
Write off/Depreciation	2,365	(335)	(335)	(335)	(335)	(335)	(335)	(335)	(335)	(335)	332	
Severance	92	-	-	-	-	-	-	-	-	-	92	
Total	3,205	(1,346)	(2,201)	(2,249)	(1,991)	(1,923)	(1,877)	(2,489)	(2,062)	(2,130)	(8,908)	Retire
Scenario 3 (Assume Capital $ Investment for Reliable Operation)												
Production	249	16	-	-	-	-	60	-	-	-	300	
SO2/NOx	52	(632)	(1,015)	(1,199)	(936)	(846)	(848)	(1,387)	(946)	(1,046)	(5,806)	
Insurance	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(467)	
Air/Water Fees	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(141)	
Labor O&M	(451)	(460)	(469)	(479)	(488)	(498)	(508)	(518)	(528)	(539)	(3,439)	
Non-Labor O&M	(75)	(300)	(300)	(150)	(153)	(156)	(159)	(162)	(166)	(169)	(1,284)	
Levelized Capital	(142)	(265)	(648)	(720)	(720)	(720)	(720)	(720)	(720)	(720)	(4,023)	
Asset Retire Cost	24	-	-	-	-	-	-	-	-	-	24	
Capacity Benefit	-	-	-	-	-	-	-	-	-	-	-	
Write off/Depreciation	2,365	(335)	(335)	(335)	(335)	(335)	(335)	(335)	(335)	(335)	332	
Severance	92	-	-	-	-	-	-	-	-	-	92	
Total	2,027	(2,062)	(2,854)	(2,968)	(2,718)	(2,641)	(2,597)	(3,209)	(2,781)	(2,895)	(14,412)	Retire

Retire Green River Units 1-2
Case 1: Present Value Revenue Requirements Analysis

Negative Numbers Imply Cost Savings from Retiring Unit

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPV @ 8.74% ($000)	
Scenario 4 (Scenario 1 and Scenario 2 Occur)												
Production	$ 1,281	$ 459	$ -	$ -	$ -	$ -	$ 60	$ -	$ -	$ -	$ 1,739	
SO2/NOx	$ 56	$ (623)	$ (1,010)	$ (1,199)	$ (929)	$ (847)	$ (848)	$ (1,387)	$ (946)	$ (1,000)	$ (5,763)	
Insurance	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (467)	
Air/Water Fees	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (141)	
Labor O&M	$ (451)	$ (460)	$ (469)	$ (479)	$ (488)	$ (498)	$ (508)	$ (518)	$ (528)	$ (539)	$ (3,439)	
Non-Labor O&M	$ (75)	$ (300)	$ (300)	$ (150)	$ (153)	$ (156)	$ (159)	$ (162)	$ (166)	$ (169)	$ (1,284)	
Levelized Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Asset Retire Cost	$ 24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24	
Capacity Benefit	$ 9,710	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,710	
Write off/Depreciation	$ 2,365	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ 332	
Severance	$ 92	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92	
Total	$ 12,915	$ (1,346)	$ (2,201)	$ (2,249)	$ (1,991)	$ (1,923)	$ (1,877)	$ (2,489)	$ (2,062)	$ (2,130)	$ 802	Operate
Scenario 5 (Scenario 1 and Scenario 3 Occur)												
Production	$ 249	$ 16	$ -	$ -	$ -	$ -	$ 60	$ -	$ -	$ -	$ 300	
SO2/NOx	$ 52	$ (632)	$ (1,015)	$ (1,199)	$ (936)	$ (846)	$ (848)	$ (1,387)	$ (946)	$ (1,046)	$ (5,806)	
Insurance	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (66)	$ (467)	
Air/Water Fees	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (20)	$ (141)	
Labor O&M	$ (451)	$ (460)	$ (469)	$ (479)	$ (488)	$ (498)	$ (508)	$ (518)	$ (528)	$ (539)	$ (3,439)	
Non-Labor O&M	$ (75)	$ (300)	$ (300)	$ (150)	$ (153)	$ (156)	$ (159)	$ (162)	$ (166)	$ (169)	$ (1,284)	
Levelized Capital	$ (142)	$ (265)	$ (648)	$ (720)	$ (720)	$ (720)	$ (720)	$ (720)	$ (720)	$ (720)	$ (4,023)	
Asset Retire Cost	$ 24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24	
Capacity Benefit	$ 9,710	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,710	
Write off/Depreciation	$ 2,365	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ (335)	$ 332	
Severance	$ 92	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92	
Total	$ 11,737	$ (2,062)	$ (2,854)	$ (2,968)	$ (2,718)	$ (2,641)	$ (2,597)	$ (3,209)	$ (2,781)	$ (2,895)	$ (4,702)	Retire

Retire Tyrone Units 1-2
Case 1: Present Value Revenue Requirements Analysis

Negative Numbers Imply Cost Savings from Retiring Unit

Base Scenario (0$/kW Capacity Benefit, 100$/MWh Purch Market)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPV @ 8.74% ($000)	
Production	$ 0	$ -	$ 0	$ -	$ 0	$ -	$ -	$ 0	$ 0	$ -	$ 0	
SO2/NOx	$ (0)	$ (0)	$ -	$ (0)	$ -	$ -	$ (0)	$ -	$ -	$ (0)	$ (0)	
Insurance	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (279)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (4)	
Labor O&M	$ (125)	$ (125)	$ (125)	$ (127)	$ (130)	$ (133)	$ (135)	$ (138)	$ (141)	$ (143)	$ (922)	
Non-Labor O&M	$ (40)	$ (40)	$ (40)	$ (40)	$ (40)	$ (40)	$ (41)	$ (42)	$ (42)	$ (43)	$ (287)	
Levelized Capital	$ -	$ -	$ -	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (43)	
Asset Retire Cost	$ 75	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 105	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ (130)	$ (200)	$ (200)	$ (213)	$ (215)	$ (218)	$ (221)	$ (225)	$ (228)	$ (232)	$ (1,430)	Retire

Scenario 1 (221 $/kw Capacity Benefit)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPV @ 8.74% ($000)	
Production	$ 0	$ -	$ 0	$ -	$ 0	$ -	$ -	$ 0	$ 0	$ -	$ 0	
SO2/NOx	$ (0)	$ (0)	$ -	$ (0)	$ -	$ -	$ (0)	$ -	$ -	$ (0)	$ (0)	
Insurance	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (279)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (4)	
Labor O&M	$ (125)	$ (125)	$ (125)	$ (127)	$ (130)	$ (133)	$ (135)	$ (138)	$ (141)	$ (143)	$ (922)	
Non-Labor O&M	$ (40)	$ (40)	$ (40)	$ (40)	$ (40)	$ (40)	$ (41)	$ (42)	$ (42)	$ (43)	$ (287)	
Levelized Capital	$ -	$ -	$ -	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (43)	
Asset Retire Cost	$ 75	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 105	
Capacity Benefit	$ 12,799	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,799	
Write off/Depreciation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 12,669	$ (200)	$ (200)	$ (213)	$ (215)	$ (218)	$ (221)	$ (225)	$ (228)	$ (232)	$ 11,370	Operate

Scenario 2 (1000 $/MWh Purchase Market Price)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPV @ 8.74% ($000)	
Production	$ 2,135	$ 812	$ 78	$ -	$ 0	$ -	$ -	$ 0	$ 0	$ -	$ 2,948	
SO2/NOx	$ (0)	$ (4)	$ (4)	$ (0)	$ -	$ -	$ (0)	$ -	$ -	$ (0)	$ (7)	
Insurance	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (279)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (4)	
Labor O&M	$ (125)	$ (125)	$ (125)	$ (127)	$ (130)	$ (133)	$ (135)	$ (138)	$ (141)	$ (143)	$ (922)	
Non-Labor O&M	$ (40)	$ (40)	$ (40)	$ (40)	$ (40)	$ (40)	$ (41)	$ (42)	$ (42)	$ (43)	$ (287)	
Levelized Capital	$ -	$ -	$ -	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (43)	
Asset Retire Cost	$ 75	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 105	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 2,005	$ 608	$ (126)	$ (213)	$ (215)	$ (218)	$ (221)	$ (225)	$ (228)	$ (232)	$ 1,512	Operate

Scenario 3 (Scenario 1 and Scenario 2 Occur)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPV @ 8.74% ($000)	
Production	$ 2,135	$ 812	$ 78	$ -	$ 0	$ -	$ -	$ 0	$ 0	$ -	$ 2,948	
SO2/NOx	$ (0)	$ (4)	$ (4)	$ (0)	$ -	$ -	$ (0)	$ -	$ -	$ (0)	$ (7)	
Insurance	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (39)	$ (279)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (4)	
Labor O&M	$ (125)	$ (125)	$ (125)	$ (127)	$ (130)	$ (133)	$ (135)	$ (138)	$ (141)	$ (143)	$ (922)	
Non-Labor O&M	$ (40)	$ (40)	$ (40)	$ (40)	$ (40)	$ (40)	$ (41)	$ (42)	$ (42)	$ (43)	$ (287)	
Levelized Capital	$ -	$ -	$ -	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (43)	
Asset Retire Cost	$ 75	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5	$ 105	
Capacity Benefit	$ 12,799	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,799	
Write off/Depreciation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 14,805	$ 608	$ (126)	$ (213)	$ (215)	$ (218)	$ (221)	$ (225)	$ (228)	$ (232)	$ 14,311	Operate

Retire Haefling Units 1, 2 and 3
Case 1: Present Value Revenue Requirements Analysis

Negative Numbers Imply Cost Savings from Retiring Unit

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPV @ 8.74% ($000)	
Base Scenario (0$/kW Capacity Benefit, 100$/MWh Purch Market)												
Production	$ 13	$ 21	$ 0	$ 0	$ 0	$ 0	$ -	$ 0	$ 0	$ 0	$ 32	
SO2/NOx	$ (0)	$ (9)	$ -	$ -	$ -	$ -	$ (0)	$ -	$ -	$ -	$ (8)	
Insurance	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (175)	
Air/Water Fees	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (1)	
Labor O&M	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (8)	$ (8)	$ (50)	
Non-Labor O&M	$ (30)	$ (30)	$ (30)	$ (31)	$ (31)	$ (32)	$ (32)	$ (33)	$ (34)	$ (34)	$ (222)	
Levelized Capital	$ -	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (168)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 911	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ 298	
Other											$ -	
	======	======	======	======	======	======	======	======	======	======	======	
Total	$ 863	$ (178)	$ (191)	$ (191)	$ (192)	$ (193)	$ (194)	$ (194)	$ (195)	$ (196)	$ (293)	Retire
Scenario 1 (221 $/kw Capacity Benefit)												
Production	$ 13	$ 21	$ 0	$ 0	$ 0	$ 0	$ -	$ 0	$ 0	$ 0	$ 32	
SO2/NOx	$ (0)	$ (9)	$ -	$ -	$ -	$ -	$ (0)	$ -	$ -	$ -	$ (8)	
Insurance	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (175)	
Air/Water Fees	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (1)	
Labor O&M	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (8)	$ (8)	$ (50)	
Non-Labor O&M	$ (30)	$ (30)	$ (30)	$ (31)	$ (31)	$ (32)	$ (32)	$ (33)	$ (34)	$ (34)	$ (222)	
Levelized Capital	$ -	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (168)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ 7,944	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,944	
Write off/Depreciation	$ 911	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ 298	
Other											$ -	
	======	======	======	======	======	======	======	======	======	======	======	
Total	$ 8,807	$ (178)	$ (191)	$ (191)	$ (192)	$ (193)	$ (194)	$ (194)	$ (195)	$ (196)	$ 7,651	Operate
Scenario 2 (1000 $/MWh Purchase Market Price)												
Production	$ 1,685	$ 980	$ 117	$ 0	$ 0	$ 30	$ -	$ 0	$ 0	$ 0	$ 2,705	
SO2/NOx	$ 1	$ (7)	$ (3)	$ -	$ -	$ 1	$ (0)	$ -	$ -	$ -	$ (7)	
Insurance	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (175)	
Air/Water Fees	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (1)	
Labor O&M	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (8)	$ (8)	$ (50)	
Non-Labor O&M	$ (30)	$ (30)	$ (30)	$ (31)	$ (31)	$ (32)	$ (32)	$ (33)	$ (34)	$ (34)	$ (222)	
Levelized Capital	$ -	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (168)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 911	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ 298	
Other											$ -	
	======	======	======	======	======	======	======	======	======	======	======	
Total	$ 2,535	$ 783	$ (76)	$ (191)	$ (192)	$ (161)	$ (194)	$ (194)	$ (195)	$ (196)	$ 2,381	Operate
Scenario 3 (Scenario 1 and Scenario 2 Occur)												
Production	$ 1,685	$ 980	$ 117	$ 0	$ 0	$ 30	$ -	$ 0	$ 0	$ 0	$ 2,705	
SO2/NOx	$ 1	$ (7)	$ (3)	$ -	$ -	$ 1	$ (0)	$ -	$ -	$ -	$ (7)	
Insurance	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (25)	$ (175)	
Air/Water Fees	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (1)	
Labor O&M	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (7)	$ (8)	$ (8)	$ (50)	
Non-Labor O&M	$ (30)	$ (30)	$ (30)	$ (31)	$ (31)	$ (32)	$ (32)	$ (33)	$ (34)	$ (34)	$ (222)	
Levelized Capital	$ -	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (168)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ 7,944	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,944	
Write off/Depreciation	$ 911	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ (101)	$ 298	
Other											$ -	
	======	======	======	======	======	======	======	======	======	======	======	
Total	$ 10,480	$ 783	$ (76)	$ (191)	$ (192)	$ (161)	$ (194)	$ (194)	$ (195)	$ (196)	$ 10,325	Operate

Retire Waterside Units 7-8
Case 1: Present Value Revenue Requirements Analysis

Negative Numbers Imply Cost Savings from Retiring Unit

Base Scenario (0$/kW Capacity Benefit, 100$/MWh Purch Market)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPV @ 8.74% ($000)	
Production	$ 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3	
SO2/NOx	$ (0)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0)	
Insurance	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (195)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (9)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (12)	$ (12)	$ (13)	$ (13)	$ (13)	$ (13)	$ (14)	$ (14)	$ (14)	$ (14)	$ (92)	
Levelized Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 717	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ 234	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 679	$ (120)	$ (121)	$ (122)	$ (122)	$ (122)	$ (122)	$ (122)	$ (123)	$ (123)	$ (58)	Retire

Scenario 1 (221 $/kw Capacity Benefit resulting from Capital/O&M expenses associated w/ HGPI)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV	
Production	$ 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3	
SO2/NOx	$ (0)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0)	
Insurance	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (195)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (9)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (12)	$ (12)	$ (13)	$ (1,013)	$ (13)	$ (13)	$ (14)	$ (14)	$ (14)	$ (14)	$ (869)	
Levelized Capital	$ -	$ -	$ -	$ (375)	$ (375)	$ (375)	$ (375)	$ (375)	$ (375)	$ (375)	$ (1,610)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ 4,855	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,855	
Write off/Depreciation	$ 717	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ 234	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 5,534	$ (120)	$ (121)	$ (1,497)	$ (497)	$ (497)	$ (497)	$ (497)	$ (498)	$ (498)	$ 2,409	Operate

Scenario 2 (1000 $/MWh Purchase Market Price)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV	
Production	$ 100	$ 13	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ -	$ 113	
SO2/NOx	$ (2)	$ (0)	$ (1)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2)	$ (4)	
Insurance	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (195)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (9)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (12)	$ (12)	$ (13)	$ (13)	$ (13)	$ (13)	$ (14)	$ (14)	$ (14)	$ (14)	$ (92)	
Levelized Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 717	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ 234	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 775	$ (107)	$ (122)	$ (122)	$ (122)	$ (122)	$ (122)	$ (122)	$ (123)	$ (125)	$ 48	Operate

Scenario 3 (Scenario 1 and Scenario 2 Occur)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV	
Production	$ 100	$ 13	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ -	$ 113	
SO2/NOx	$ (2)	$ (0)	$ (1)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2)	$ (4)	
Insurance	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (28)	$ (195)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (9)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (12)	$ (12)	$ (13)	$ (1,013)	$ (13)	$ (13)	$ (14)	$ (14)	$ (14)	$ (14)	$ (869)	
Levelized Capital	$ -	$ -	$ -	$ (375)	$ (375)	$ (375)	$ (375)	$ (375)	$ (375)	$ (375)	$ (1,610)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ 4,855	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,855	
Write off/Depreciation	$ 717	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ (80)	$ 234	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 5,630	$ (107)	$ (122)	$ (1,497)	$ (497)	$ (497)	$ (497)	$ (497)	$ (498)	$ (500)	$ 2,515	Operate

Retire Paddy's Run Units 11-12
Case 1: Present Value Revenue Requirements Analysis

Negative Numbers Imply Cost Savings from Retiring Unit

Base Scenario (0$/kW Capacity Benefit, 100$/MWh Purch Market)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPV @ 8.74% ($000)	
Production	$ 18	$ 15	$ -	$ -	$ -	$ -	$ -	$ 0	$ -	$ -	$ 32	
SO2/NOx	$ (4)	$ (6)	$ -	$ -	$ -	$ -	$ -	$ (0)	$ -	$ (0)	$ (10)	
Insurance	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (127)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (9)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (51)	$ (52)	$ (55)	$ (58)	$ (59)	$ (60)	$ (61)	$ (62)	$ (63)	$ (65)	$ (406)	
Levelized Capital	$ (15)	$ (53)	$ (90)	$ (90)	$ (90)	$ (90)	$ (90)	$ (90)	$ (90)	$ (90)	$ (526)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 202	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ 66	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 131	$ (137)	$ (187)	$ (189)	$ (190)	$ (192)	$ (193)	$ (194)	$ (195)	$ (196)	$ (979)	Retire

Scenario 1 (221 $/kw Capacity Benefit resulting from Capital/O&M expenses associated w/ HGPI)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV	
Production	$ 18	$ 15	$ -	$ -	$ -	$ -	$ -	$ 0	$ -	$ -	$ 32	
SO2/NOx	$ (4)	$ (6)	$ -	$ -	$ -	$ -	$ -	$ (0)	$ -	$ (0)	$ (10)	
Insurance	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (127)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (9)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (51)	$ (552)	$ (555)	$ (58)	$ (59)	$ (60)	$ (61)	$ (62)	$ (63)	$ (65)	$ (1,288)	
Levelized Capital	$ (15)	$ (203)	$ (390)	$ (390)	$ (390)	$ (390)	$ (390)	$ (390)	$ (390)	$ (390)	$ (2,206)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ 7,724	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,724	
Write off/Depreciation	$ 202	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ 66	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 7,855	$ (787)	$ (987)	$ (489)	$ (490)	$ (492)	$ (493)	$ (494)	$ (495)	$ (496)	$ 4,182	Operate

Scenario 2 (1000 $/MWh Purchase Market Price)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV	
Production	$ 734	$ 365	$ 2	$ -	$ 1	$ 20	$ -	$ 0	$ -	$ -	$ 1,084	
SO2/NOx	$ (11)	$ (4)	$ (2)	$ -	$ -	$ (1)	$ -	$ (0)	$ -	$ (4)	$ (20)	
Insurance	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (127)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (9)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (51)	$ (52)	$ (55)	$ (58)	$ (59)	$ (60)	$ (61)	$ (62)	$ (63)	$ (65)	$ (406)	
Levelized Capital	$ (15)	$ (53)	$ (90)	$ (90)	$ (90)	$ (90)	$ (90)	$ (90)	$ (90)	$ (90)	$ (526)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 202	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ 66	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 840	$ 214	$ (187)	$ (189)	$ (190)	$ (173)	$ (193)	$ (194)	$ (195)	$ (201)	$ 63	Operate

Scenario 3 (Scenario 1 and Scenario 2 Occur)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV	
Production	$ 734	$ 365	$ 2	$ -	$ 1	$ 20	$ -	$ 0	$ -	$ -	$ 1,084	
SO2/NOx	$ (11)	$ (4)	$ (2)	$ -	$ -	$ (1)	$ -	$ (0)	$ -	$ (4)	$ (20)	
Insurance	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (127)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (9)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (51)	$ (552)	$ (555)	$ (58)	$ (59)	$ (60)	$ (61)	$ (62)	$ (63)	$ (65)	$ (1,288)	
Levelized Capital	$ (15)	$ (203)	$ (390)	$ (390)	$ (390)	$ (390)	$ (390)	$ (390)	$ (390)	$ (390)	$ (2,206)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ 7,724	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,724	
Write off/Depreciation	$ 202	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ (22)	$ 66	
Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total	$ 8,564	$ (436)	$ (987)	$ (489)	$ (490)	$ (473)	$ (493)	$ (494)	$ (495)	$ (501)	$ 5,224	Operate

Retire Cane Run Unit 11
Case 1: Present Value Revenue Requirements Analysis

Negative Numbers Imply Cost Savings from Retiring Unit

Base Scenario (0$/kW Capacity Benefit, 100$/MWh Purch Market)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPV @ 8.74% ($000)	
Production	$ 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7	
SO2/NOx	$ (1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1)	
Insurance	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (67)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (5)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (20)	$ (21)	$ (22)	$ (23)	$ (23)	$ (24)	$ (24)	$ (25)	$ (25)	$ (26)	$ (162)	
Levelized Capital	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (265)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 869	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ 284	
Other											$ -	
Total	$ 807	$ (165)	$ (166)	$ (167)	$ (168)	$ (168)	$ (169)	$ (169)	$ (170)	$ (170)	$ (208)	Retire

Scenario 1 (221 $/kw Capacity Benefit)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV	
Production	$ 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7	
SO2/NOx	$ (1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1)	
Insurance	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (67)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (5)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (20)	$ (21)	$ (22)	$ (23)	$ (23)	$ (24)	$ (24)	$ (25)	$ (25)	$ (26)	$ (162)	
Levelized Capital	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (265)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ 3,089	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,089	
Write off/Depreciation	$ 869	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ 284	
Other											$ -	
Total	$ 3,896	$ (165)	$ (166)	$ (167)	$ (168)	$ (168)	$ (169)	$ (169)	$ (170)	$ (170)	$ 2,881	Operate

Scenario 2 (1000 $/MWh Purchase Market Price)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV	
Production	$ 155	$ -	$ 1	$ -	$ 1	$ 20	$ -	$ -	$ -	$ -	$ 168	
SO2/NOx	$ (0)	$ -	$ -	$ -	$ -	$ (2)	$ -	$ -	$ -	$ -	$ (2)	
Insurance	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (67)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (5)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (20)	$ (21)	$ (22)	$ (23)	$ (23)	$ (24)	$ (24)	$ (25)	$ (25)	$ (26)	$ (162)	
Levelized Capital	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (265)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Write off/Depreciation	$ 869	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ 284	
Other											$ -	
Total	$ 955	$ (165)	$ (166)	$ (167)	$ (167)	$ (150)	$ (169)	$ (169)	$ (170)	$ (170)	$ (48)	Retire

Scenario 3 (Scenario 1 and Scenario 2 Occur)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	NPV	
Production	$ 155	$ -	$ 1	$ -	$ 1	$ 20	$ -	$ -	$ -	$ -	$ 168	
SO2/NOx	$ (0)	$ -	$ -	$ -	$ -	$ (2)	$ -	$ -	$ -	$ -	$ (2)	
Insurance	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (67)	
Air/Water Fees	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (5)	
Labor O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Non-Labor O&M	$ (20)	$ (21)	$ (22)	$ (23)	$ (23)	$ (24)	$ (24)	$ (25)	$ (25)	$ (26)	$ (162)	
Levelized Capital	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (38)	$ (265)	
Asset Retire Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Benefit	$ 3,089	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,089	
Write off/Depreciation	$ 869	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ (97)	$ 284	
Other											$ -	
Total	$ 4,045	$ (165)	$ (166)	$ (167)	$ (167)	$ (150)	$ (169)	$ (169)	$ (170)	$ (170)	$ 3,042	Operate

Retire Zorn Unit 1
Case 1: Present Value Revenue Requirements Analysis

Negative Numbers Imply Cost Savings from Retiring Unit

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2003-2012 10 Yr NPV @ 8.74% ($000)	
Base Scenario (0$/kW Capacity Benefit, 100$/MWh Purch Market)												
Production	5	4	-	-	-	-	-	0	-	-	8	
SO2/NOx	(1)	(2)	-	-	-	-	-	(0)	-	(0)	(3)	
Insurance	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(61)	
Air/Water Fees	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(5)	
Labor O&M	-	-	-	-	-	-	-	-	-	-	-	
Non-Labor O&M	(19)	(19)	(20)	(21)	(22)	(22)	(23)	(23)	(24)	(24)	(151)	
Levelized Capital	-	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(227)	
Asset Retire Cost	-	-	-	-	-	-	-	-	-	-	-	
Capacity Benefit	-	-	-	-	-	-	-	-	-	-	-	
Write off/Depreciation	126	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	41	
Loisville Water Com	10	10	10	10	10	10	10	10	10	10	71	
Total	111	(69)	(71)	(72)	(73)	(73)	(73)	(74)	(74)	(75)	$\boxed{(327)}$	Retire
Scenario 1 (221 $/kw Capacity Benefit resulting from Capital/O&M expenses associated w/ HGPI)												
Production	5	4	-	-	-	-	-	0	-	-	8	
SO2/NOx	(1)	(2)	-	-	-	-	-	(0)	-	(0)	(3)	
Insurance	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(61)	
Air/Water Fees	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(5)	
Labor O&M	-	-	-	-	-	-	-	-	-	-	-	
Non-Labor O&M	(19)	(519)	(20)	(21)	(22)	(22)	(23)	(23)	(24)	(24)	(611)	
Levelized Capital	-	(188)	(188)	(188)	(188)	(188)	(188)	(188)	(188)	(188)	(1,136)	
Asset Retire Cost	-	-	-	-	-	-	-	-	-	-	-	
Capacity Benefit	3,089	-	-	-	-	-	-	-	-	-	3,089	
Write off/Depreciation	126	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	41	
Loisville Water Com	10	10	10	10	10	10	10	10	10	10	71	
Total	3,200	(719)	(221)	(222)	(223)	(223)	(223)	(224)	(224)	(225)	$\boxed{1,394}$	Operate
Scenario 2 (1000 $/MWh Purchase Market Price)												
Production	322	138	-	-	1	20	-	0	-	-	462	
SO2/NOx	(4)	(2)	-	-	-	(2)	-	(0)	-	(0)	(7)	
Insurance	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(61)	
Air/Water Fees	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(5)	
Labor O&M	-	-	-	-	-	-	-	-	-	-	-	
Non-Labor O&M	(19)	(19)	(20)	(21)	(22)	(22)	(23)	(23)	(24)	(24)	(151)	
Levelized Capital	-	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(227)	
Asset Retire Cost	-	-	-	-	-	-	-	-	-	-	-	
Capacity Benefit	-	-	-	-	-	-	-	-	-	-	-	
Write off/Depreciation	126	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	41	
Loisville Water Com	10	10	10	10	10	10	10	10	10	10	71	
Total	425	65	(71)	(72)	(72)	(55)	(73)	(74)	(74)	(75)	$\boxed{123}$	Operate
Scenario 3 (Scenario 1 and Scenario 2 Occur)												
Production	322	138	-	-	1	20	-	0	-	-	462	
SO2/NOx	(4)	(2)	-	-	-	(2)	-	(0)	-	(0)	(7)	
Insurance	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(61)	
Air/Water Fees	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(5)	
Labor O&M	-	-	-	-	-	-	-	-	-	-	-	
Non-Labor O&M	(19)	(519)	(20)	(21)	(22)	(22)	(23)	(23)	(24)	(24)	(611)	
Levelized Capital	-	(188)	(188)	(188)	(188)	(188)	(188)	(188)	(188)	(188)	(1,136)	
Asset Retire Cost	-	-	-	-	-	-	-	-	-	-	-	
Capacity Benefit	3,089	-	-	-	-	-	-	-	-	-	3,089	
Write off/Depreciation	126	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	41	
Loisville Water Com	10	10	10	10	10	10	10	10	10	10	71	
Total	3,515	(585)	(221)	(222)	(222)	(205)	(223)	(224)	(224)	(225)	$\boxed{1,843}$	Operate

Appendix D
Total Cash Flows from a Regulated and Merchant Perspective
(Cases 2 and 3)

Total Cash Flows Associated with Group 3 Units
Regulated and Merchant Environment

Note: A postive NPV suggests retirement while a negative NPV suggests continued operation.

Units	Market Environment	Case	Assumptions	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	10 Year NPV Cash Flow ($000s) @ 8.74%	Retire or Operate
				Total Cash Flow ($000)											
Green River 1-2	Regulated	Case 2	Base Assumptions	($1,194)	$1,072	$1,207	$1,285	$1,155	$1,068	$1,119	$1,386	$1,224	$1,206	$5,982	Retire
		Case 2	Scenario 1	($1,931)	$334	$470	$547	$417	$331	$382	$648	$486	$468	$775	Retire
		Case 2	Scenario 2	($1,812)	$802	$1,313	$1,341	$1,187	$1,146	$1,119	$1,484	$1,229	$1,270	$5,412	Retire
		Case 2	Scenario 3	($349)	$1,878	$3,690	$1,656	$1,047	$968	$1,027	$1,300	$1,144	$1,131	$9,603	Retire
		Case 2	Scenario 4	($1,704)	$871	$3,058	$975	$342	$309	$289	$661	$412	$457	$3,826	Retire
		Case 2	Scenario 5	($1,086)	$1,141	$2,953	$919	$309	$231	$289	$562	$406	$393	$4,396	Retire
	Merchant	Case 3	Base Assumptions	($1,016)	$705	$710	$626	$634	$641	$649	$657	$665	$674	$3,010	Retire
Tyrone 1-2	Regulated	Case 2	Base Assumptions	$78	$119	$119	$187	$120	$122	$124	$126	$129	$131	$872	Retire
		Case 2	Scenario 1	($893)	($852)	($852)	($784)	($851)	($849)	($847)	($845)	($842)	($840)	($5,982)	Operate
		Case 2	Scenario 2	($1,196)	($363)	$75	$187	$120	$122	$124	$126	$129	$131	($883)	Operate
		Case 2	Scenario 3	($2,167)	($1,334)	($896)	($784)	($851)	($849)	($847)	($845)	($842)	($840)	($7,737)	Operate
	Merchant	Case 3	Base Assumptions	$78	$119	$119	$187	$120	$122	$124	$126	$129	$131	$872	Retire
Haefling 1-3	Regulated	Case 2	Base Assumptions	($514)	$272	$92	$92	$93	$94	$95	$96	$96	$97	$217	Retire
		Case 2	Scenario 1	($1,118)	($332)	($512)	($511)	($510)	($510)	($509)	($508)	($507)	($507)	($4,043)	Operate
		Case 2	Scenario 2	($1,512)	($301)	$23	$92	$93	$75	$95	$96	$96	$97	($1,377)	Operate
		Case 2	Scenario 3	($2,116)	($905)	($580)	($511)	($510)	($528)	($509)	($508)	($507)	($507)	($5,638)	Operate
	Merchant	Case 3	Base Assumptions	($538)	$238	$65	$56	$54	$45	$32	$28	$24	$20	($97)	Operate
Waterside 7-8	Regulated	Case 2	Base Assumptions	($305)	$72	$72	$72	$72	$73	$73	$73	$73	$73	$134	Retire
		Case 2	Scenario 1	($1,461)	($984)	($984)	$2,072	($1,059)	($1,053)	($1,048)	($1,043)	($1,039)	($1,034)	($5,290)	Operate
		Case 2	Scenario 2	($362)	$64	$73	$72	$72	$73	$73	$73	$73	$75	$71	Retire
		Case 2	Scenario 3	($462)	$64	$73	$3,128	($3)	$3	$8	$13	$18	$23	$2,102	Retire
	Merchant	Case 3	Base Assumptions	($347)	$11	$30	$17	$12	$1	($16)	($22)	($28)	($35)	($342)	Operate
Paddy's 11-12	Regulated	Case 2	Base Assumptions	$13	$296	$296	$45	$46	$48	$50	$51	$53	$54	$742	Retire
		Case 2	Scenario 1	($574)	$992	$961	($600)	($594)	($589)	($583)	($578)	($574)	($571)	($1,385)	Operate
		Case 2	Scenario 2	($410)	$87	$296	$45	$46	$37	$50	$51	$53	$57	$120	Retire
		Case 2	Scenario 3	($997)	$782	$961	($600)	($595)	($600)	($583)	($578)	($574)	($568)	($2,007)	Operate
	Merchant	Case 3	Base Assumptions	($36)	$221	$240	($31)	($36)	($50)	($74)	($82)	($90)	($98)	$101	Retire
Cane Run 11	Regulated	Case 2	Base Assumptions	($254)	$76	$76	$77	$77	$78	$78	$78	$78	$79	$214	Retire
		Case 2	Scenario 1	($489)	($159)	($158)	($158)	($157)	($157)	($157)	($157)	($156)	($156)	($1,442)	Operate
		Case 2	Scenario 2	($342)	$76	$76	$77	$77	$67	$78	$78	$78	$79	$119	Retire
		Case 2	Scenario 3	($577)	($159)	($159)	($158)	($158)	($168)	($157)	($157)	($156)	($156)	($1,538)	Operate
	Merchant	Case 3	Base Assumptions	($267)	$51	$60	$55	$53	$49	$42	$40	$37	$35	$27	Retire
Zorn 1	Regulated	Case 2	Base Assumptions	($60)	$271	$19	$20	$20	$21	$22	$22	$23	$24	$295	Retire
		Case 2	Scenario 1	($295)	$1,318	($246)	($243)	($240)	($238)	($235)	($233)	($231)	($230)	($317)	Operate
		Case 2	Scenario 2	($248)	$191	$19	$20	$20	$11	$22	$22	$23	$24	$26	Retire
		Case 2	Scenario 3	($482)	$1,238	($246)	($243)	($241)	($248)	($235)	($233)	($231)	($230)	($585)	Operate
	Merchant	Case 3	Base Assumptions	($84)	$234	($7)	($15)	($17)	($23)	($33)	($36)	($40)	($43)	$4	Retire

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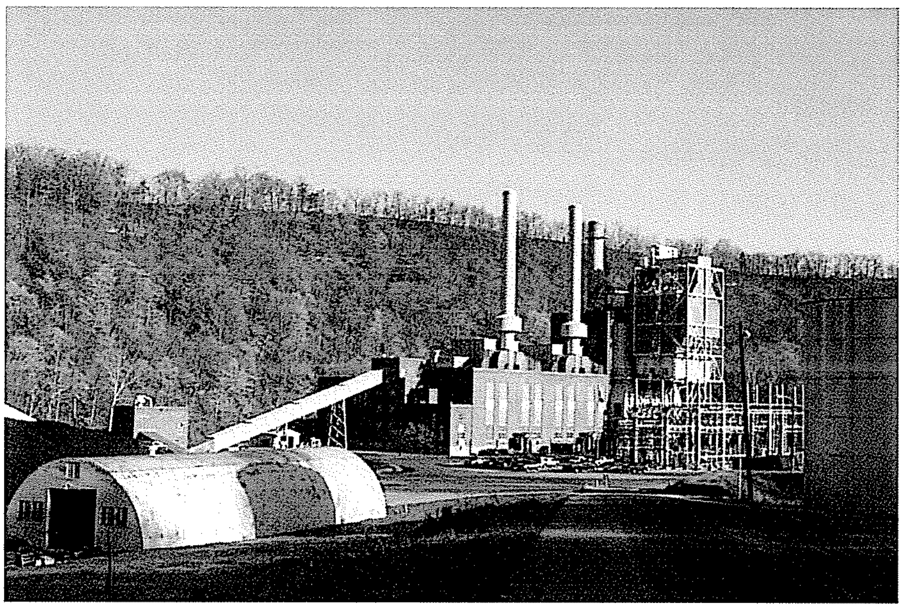
Life Assessment Study: Kentucky Utilities Tyrone Units 1 and 2



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Life Assessment Study: Kentucky Utilities Tyrone Units 1 and 2

Executive Summary

Tyrone 1 & 2 were reported on forced outage on July 26, 2006, and were placed in "mothball" status on September 26, 2006. Event and performance data are submitted to the North American Electric Reliability Council (NERC) quarterly and updated continuously in the MicroGads Database on each Kentucky Utilities and Louisville Gas and Electric unit. It is optional, according to NERC and MicroGads standards, to place a unit that has been on forced outage for more than 60 days in mothball status while it is determined if the unit will be repaired for a return to service or retired. Placing a unit in mothball status eliminates the effect of the unit being out of service on a company's forced outage rate.

An engineering life assessment study was initiated, following Tyrone 1 & 2 being placed in mothball status, to determine if it was cost beneficial to return the units to service. Sargent & Lundy (S&L) was contracted to assess the condition of the units and provide technical comments and costs to return the units to service. Generation Services used the costs identified by S&L to analyze the effects of retiring verses returning the units to service on the net present value revenue requirements over a ten year study period. Revenue Requirements are the amount of money that must be paid or collected from customers to compensate a utility for all expenditures in capital, goods, and services. Therefore, this analysis determines the direct impact to the ratepayers if Tyrone 1 & 2 are returned to service or retired.

The major cost associated with retiring the units are reserve margin purchases required in the absence of the capacity of Tyrone 1 & 2. Reserve margin purchases will need to be made to comply with the 14% reserve margin capacity target listed in the latest Integrated Resource Plan (IRP) filing in 2005. A 14% reserve margin implies that our combined companies have access to capacity 14% above the peak load in order to assure reliability. This can either be met by building extra capacity or purchasing reserve margin purchases. The major savings associated with retiring the units include the avoided cost to refurbish the units to a reliable status as identified by S&L, annual depreciation expense, labor expense to operate and maintain the units, operation and maintenance expenses to keep the units at a reliable state, air and water fees, and an annual insurance premium.

In an analysis that included the required, highly probable, and potential costs identified by S&L, there was a benefit to the net present value revenue requirements of $7.3 million when the units are retired compared to being refurbished. Multiple sensitivities were evaluated to determine the validity of the initial result. These sensitivities included looking at the generation levels and associated costs and savings with an oil price decrease, a market price increase, and a combination of the oil price decrease and market price increase. Also evaluated were cases which included only the required and highly probable expenses identified by S&L and a reserve margin cost of $6/kilowatt-month figure instead of the $4/kilowatt-month used in the latest business plan. Each of these sensitivities showed that there was still a benefit to the net present value requirements if the units were retired.

A 30 year analysis, included in the appendix, was also evaluated to determine if there were any long term effects to the expansion plan if the units were retired. The retirement of Tyrone 1 & 2 resulted in units being installed at earlier dates than in the case with Tyrone 1 & 2 in service. The accelerated units in the expansion plan resulted in capital costs being experienced earlier, but also resulted in revenues from off-system sales and benefits from the fleet of units being more efficient from those units being in place earlier. Over the 30 year period, the retirement of Tyrone 1 & 2 led to an expansion plan that was more expensive inclusive of capital and operation and maintenance costs. However, even with this cost included in the analysis, over a 30 year period, it is still beneficial to retire Tyrone 1 & 2. The benefit to the 30 year net present value revenue requirements from retirement is $800,000. Therefore, it is the recommendation of Generation Services that Tyrone 1 & 2 be retired, effective immediately.

1.0 Background

Tyrone 1 & 2 were reported on forced outage on July 26, 2006, and were placed in mothball status on September 26, 2006, consistent with NERC and MicroGads policies. An engineering life assessment study was initiated to determine if it was cost beneficial to return the units to service. Sargent & Lundy (S&L) was contracted to assess the condition of the units and provide technical comments and costs to return the units to service. Generation Services used the costs identified by S&L to analyze the effects on the net present value revenue requirements over a ten year study period to determine the impact the decision would have on the ratepayer.

1.1 Tyrone Units 1-2

Tyrone Generating Station is nearly 60 years old, built in 1947 on the Woodford County side of the Kentucky River between Versailles and Lawrenceburg. Groundbreaking occurred on December 12, 1945. Unit 1, a 30-megawatt generator, began operation in 1947. Unit 2, also a 30 megawatt generator, began operation in 1948. Units 1 and 2 were converted to No. 2 fuel oil in the 1970s, and they are currently used only when demand for electricity is unusually high.

Tyrone Units 1 and 2 consist of four Babcock & Wilcox, balanced draft, non-reheat, oil fired boilers supplying steam to a common header. Steam at 910 F, 850 psig, is supplied to two 30 MW Westinghouse steam turbines.

2.0 Economic Impact Evaluation

The major costs associated with retiring the units are reserve margin purchases required in the absence of the capacity of Tyrone 1 & 2 and the lost production from the units. The optimal target reserve margin, a certain level or guaranteed capacity above peak load levels, from the 2005 Integrated Resource Plan ("IRP") for the combined companies, KU and LG&E, is 12% to 14%, with the companies using a reserve margin target of 14%. This reserve margin target can be met by either building capacity or making reserve margin purchases. The value of the lost production is calculated by charging a fee of $100 per megawatt-hour to replace the expected generation with market purchases. The major savings associated with retiring the units include the avoided cost to refurbish the units to a reliable status as identified by S&L[1], annual depreciation expense, labor expense to operate and maintain the units, operation and maintenance expenses to keep the units at a reliable state, air and water fees, and an annual insurance premium. The effect of these items on the net present value revenue requirements were analyzed over a ten year study period to determine the direct impact on the ratepayer.

[1] "Engineering Assessment and Analysis of Tyrone 1 & 2", Sargent & Lundy, Table 1-2, page 11

Listed below are some key assumptions that were made in this analysis.

Base Key Assumptions:

- Off-System sales values in accordance with the current Generation/Off-System Sales forecast
- Forward Price Curve as in the 2006 Operating Plan
- Fuel forecast as in the 2006 Operating Plan
- No capacity value assigned to replace the loss of the units in the ten year analysis
- No employee severance cost or employee salary expenses avoided if unit not returned to service
- Retirement in-place can occur with no significant physical asset related cost
- SO_2 and NOx allowance pricing as in the 2006 Operating Plan
- Total cost of $4,360,000[2], as identified by third party contractor Sargent & Lundy, for required activities needing completion before returning the unit to service
- Total cost of $7,750,000[3], as identified by third party contractor Sargent & Lundy, for high probability activities needing completion before returning the unit to service
- Total cost of $4,035,000[4], as identified by third party contractor Sargent & Lundy, for potential activities needing completion before returning the unit to service

Table -1

Cases	Description	Benefit of Retirement to Net Present Value Revenue Requirements ($000s)
Case A	$16.1M* Cost Applied to Returning the Units to Service and Reserve Margin Price of $4/kw-month	$7,331
Case B	$12.1M** Cost Applied to Returning the Units to Service and Reserve Margin Price of $4/kw-month	$3,278
Case C	$16.1M* Cost Applied to Returning the Units to Service and Reserve Margin Price of $6/kw-month	$2,678

*$16.1M is inclusive of all required, highly probable, and potential costs identified by S&L to return the units to reliable status
**$12.1M is inclusive of all required and highly probable costs identified by S&L to return the units to reliable status

The effect on the net present value revenue requirements for case A is included in Appendix A. In this analysis, there was no capacity replacement associated with the retirement of the units. However, there was a $100 per MWh cost associated with purchasing power to replace the lost production. The only costs associated with retiring Tyrone 1 & 2 were the value of the lost

[2] "Engineering Assessment and Analysis of Tyrone 1 & 2", Sargent & Lundy, Table 6-1, page 51
[3] "Engineering Assessment and Analysis of Tyrone 1 & 2", Sargent & Lundy, Table 6-2, page 52
[4] "Engineering Assessment and Analysis of Tyrone 1 & 2", Sargent & Lundy, Table 6-3, page 52

production from the units and reserve margin purchases due to the capacity loss. Savings associated with retirement included: avoided cost to repair, depreciation expense avoided, operation and maintenance expenses avoided, air and water fees avoided, and an annual insurance premium for the newly added assets purchased to return the unit to service. The cost to repair the units is inclusive of all required, high probability, and potential activities identified by S&L. The benefit to the net present value revenue requirements from retiring the units in Case A is $7.3 million.

Tyrone 1 & 2 are oil fired units. Price sensitivities of lowering the cost of oil and raising market prices were evaluated to test the effect on the net present value revenue requirements from retiring Tyrone 1 & 2. These changes made no effect to the generation levels of Tyrone 1 & 2 and therefore did not change the result of the benefit to the net present value revenue requirements from retiring the units as identified in the base case of assumptions, or Case A.

The analysis performed in Case A assumes that all required, highly probable, and potential costs identified by S&L must be incurred for the units to operate reliably. However, if only the required and highly probable costs are incurred, there is still a benefit to the net present value revenue requirements associated with retiring Tyrone 1 & 2. This benefit is $3.3 million, as shown in the appendix as "Case B".

The last analysis evaluated was a scenario where all costs identified by S&L are incurred in returning the units to service and the cost for reserve margin purchases is increased to $6/kilowatt-month. This scenario, identified as "Case C", yielded a benefit to the net present value revenue requirements from retiring the units of $2.7 million. The reserve margin purchases would need to exceed $7.80/kilowatt-month to make it cost beneficial to retire Tyrone 1 & 2.

2.1 Expansion Plan Impact

Retiring Tyrone 1 & 2 will have an impact to the combined companies' current expansion plan. The retirement of the units would cause some of the current expansion units to be accelerated to cover for the lost capacity. Please see Table – 2 below for a comparison of the expansion plans. Over the course of the 10 year study period, this causes no effect to the net present value revenue requirements because no units are altered from the base case throughout the 2007-2016 time frame. Over a 30 year period, the accelerated units in the expansion plan resulted in capital costs being experienced earlier, but also resulted in revenues from off-system sales and benefits from the fleet of units being more efficient from those units being in place earlier. However, even with this cost included in the analysis, it is still beneficial to retire Tyrone 1 & 2. The benefit of retirement to the 30 year net present value revenue requirements is $800,000.

Table – 2

	Base Case	No Tyrone 1&2
2007		
2008		
2009		
2010		
2011		
2012		
2013	LGSC	LGSC
2014		
2015		
2016	SCCT	SCCT
2017	SCCT	SCCT
2018		CCCT
2019	CCCT	
2020		
2021		
2022	CCCT	CCCT
2023		
2024		
2025		LGSC
2026	LGSC	
2027		
2028		
2029		
2030		
2031	SCCT	SCCT
2032	LGSC	LGSC
2033		
2034		
2035		
2036		

SCCT is a 148 MW CT
CCCT is a 484 MW combined cycle
LGSC is a 739 MW coal unit

2.2 Reserve Margin Impact

The optimal target reserve margin from the 2005 Integrated Resource Plan ("IRP") for the combined companies, KU and LG&E, is 12% to 14%, with the companies using a reserve margin target of 14%. System reserve margin is expected to fall below 14% in the years of 2008-2012 without the retirement of Tyrone 1 & 2. This case is referred to as the "Base" in the following table. Based on 2006 unit ratings information and 2006 load forecast data, the system reserve margin is expected to be 15.4% in 2007, 12.6% in 2008, 10.0% in 2009, 13.8% in 2010, 11.9% in 2011, and 10.7% in 2012 with Tyrone 1 & 2 in service. If Tyrone 1 & 2 are retired at the end of this year, the 2007 reserve margin will be 14.6%. But load is expected to increase and the reserve margin will fall to 11.8% in 2008, to 9.2% in 2009, 13.0% in 2010, 11.1% in 2011, and 9.9% in 2012. The reserve margin increases to above 14% in 2013 with a new coal unit.

Additional reserve margin purchases will be needed in 2008-2012 if Tyrone 1 & 2 are retired. Despite the need for reserve margin purchases, the economic analysis results in an overall benefit to the net present value revenue requirement if the units are retired.

Table – 3

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Base	15.4%	12.6%	10.0%	13.8%	11.9%	10.7%	18.5%	17.0%	15.0%	15.4%
Tyrone 1&2 Retired	14.6%	11.8%	9.2%	13.0%	11.1%	9.9%	17.7%	16.3%	14.3%	14.7%

Purchases are budgeted to cover the amount of capacity needed to reach a 14% reserve margin. In order to maintain a 14% reserve margin, additional capacity must be purchased in 2008-2012 if Tyrone 1 & 2 are retired. These purchases would be required in the months of June through September when load reaches its peak for the combined companies. Upper limit projections estimate a capacity cost of $6 per kilowatt-month. In the latest budget plan, a cost of $4 per kilowatt-month is applied to reserve margin purchases. Therefore, the $4 per kilowatt-month is used in this study and an analysis showing the effects of a $6 per kilowatt-month is used to evaluate the effect on the net present value revenue requirements from retiring Tyrone 1 & 2 as well. The cost associated with these purchases is defined as Reserve Margin Purchases in the tables in the appendix.

2.3 Fuel Adjustment Clause Impact

Tyrone 1 & 2 are the highest cost units among the KU/LG&E fleet. The dispatch cost for Tyrone 1 & 2 has ranged from $200 per megawatt-hour to over $250 per megawatt-hour during 2006. The Fuel Adjustment Clause ("FAC") requirement on recoverable purchase power cost is that the cost has to be less than the highest cost unit. However, Tyrone 1 & 2 cannot be used as the highest cost unit since they are currently not available. [Note: These units had a forced outage that began on July 28, 2006. In alignment with NERC requirements, after 60 days the units were placed into mothball status. They will remain in mothball status until they are either place into active operation or are retired.

If Tyrone 1 & 2 are returned to service, there would be virtually no impact to the Fuel Adjustment Clause. Existing units, Haefling 1-3 are close to the cost of the Tyrone 1 & 2 units. The only way for the FAC to benefit from the return to service of Tyrone 1 & 2 is for the cost of the purchases to exceed the cost of the Haefling units. This is not likely to happen and therefore there would be minimal impact to the FAC filing if the units were returned to service.

2.4 Business Plan Impact

The current draft of the Business Plan excludes capital expenditures and O&M costs for Tyrone 1 & 2. Therefore, none of the costs identified by S&L are included in the current Business Plan. Incurring any of these costs would be in addition to our current plan. The projected cost, inclusive of all required, highly probable, and potential costs identified by S&L, to return the units to service is $16.1 million. The additional cost of yearly maintenance is projected to be around $20,000 per unit per year. In addition, if the units are projected to run, operational costs will need to be applied to the units. Based on projected generation, the operation dollars that will be spent on the units is projected to be approximately $11,000.

2.5 Off System Sales Impact

Tyrone 1 & 2 have not operated since 2001. Therefore, in the past five years the units have made no contribution to the Companies' off-systems sales levels. In the latest 30 year budget run, Tyrone 1 and Tyrone 2's generation is applied only to native load and is not allocated to off-system sales. From 2009 and beyond, the units are not forecast to run and are not expected to make any contribution to off-system sales.

2.6 Environmental/Emission Allowance Impact

Tyrone 1 & 2 are oil fired units. Therefore, they do not emit a significant amount of SO_2 as a part of the combustion process. They do emit a small amount of NOx when in operation.

Units that are retired retain future SO_2 allowances allocated to them. However, since Tyrone 1 & 2 did not receive SO_2 allowance allocations, the combined companies SO_2 allowances will not change if Tyrone 1 & 2 are retired.

Units that are retired retain the NOx allowances previously allocated to them, but generally do not receive future allocations. Tyrone 1 & 2 were not allocated any allowances for 2007-2008 due to lack of heat input. For 2009 and beyond, they are expected to receive no ozone-season allowances and no annual allowances under Kentucky's proposed regulations to implement CAIR due to their lack of heat input in recent years. Therefore, if Tyrone 1 & 2 are retired, there will be no effect on the amount of NOx allowances for the combined companies.

Since Tyrone 1 & 2 are not projected to run during the ozone season when they generate in 2007 and 2008, there would be no NOx emission cost savings from retiring the units.

2.7 Water Permit Impact

The USEPA granted Kentucky primacy to issue and enforce NPDES permits within the state; the existing Kentucky Pollution Discharge Elimination System (KPDES) permit for the Tyrone plant is required to describe water management processes including an estimate of daily flows. If Tyrone Units 1 & 2 are retired, there would be changes to the water intake system.

Assumed Relevant Physical Changes if Tyrone 1 & 2 are retired

- Continued (but decreased) use of the Units 1-2 service water pumps with intake through the existing Units 1-2 river intake/traveling screen structure;
- Unit 3 service and circulating pumps would continue to operate and be supplied from the Unit 3 river intake/traveling screen structure;

- Discontinued use of the Units 1-2 Circulating Water pumps.

The above mentioned changes would likely require a minor modification of the permit which would consist of a technical package submission describing any reconfigured flows and adjustments of the service and circulating water intake and discharge flow estimates. It is not expected that these changes would change existing KPDES permitted conditions or outfall limits.

Although the KPDES permit must describe if one or both river intakes are used, it will not significantly affect the permit conditions or limits if the plant continues to use one or both intakes. Future operations flexibility, or additional water intake needs, may be enhanced by continued use and maintenance of the Unit 1-2 river intake structure.

2.8 Insurance Impact

Currently there is not insurance coverage for Tyrone 1 & 2. If the units are returned to service, the insurance premium would be $.06 per $100 of the insured assets value. Typically, the full replacement cost of the asset is insured. Therefore, for the net present value revenue requirements analysis, the assumed insurance premium is 0.06% of the projected cost for repairs.

2.9 Depreciation and Net Book Value Remaining at Retirement Impact

Based on the past practices of the utilities, if Tyrone 1 & 2 are retired, the net book value of -$783,850 as of June 30, 2006 would remain unchanged unless there were removal costs associated with retiring the unit. If so, the net book value for the unit would move closer to zero. However, it is suspected that there will be no removal costs associated with Tyrone 1 & 2 if the units are retired in the near future. The units and their assets are expected to be abandoned in place. The land at the Tyrone station is a common asset between all three units and has a net book value, $52,070 as of June 30, 2006. This value would remain unchanged by the retirement of Tyrone 1 & 2. Depreciation is not calculated on assets that are retired. Therefore, if Tyrone 1 & 2 are retired, the yearly depreciation expense of $12,000 will be avoided.

2.10 Human Resources Impact

Currently there are no employees dedicated to the operation of Tyrone 1 & 2. All of the employees at the Tyrone Station work under a budget for Tyrone 3. Retirement of Tyrone 1 & 2 would result in no headcount reduction therefore no severance pay expense or savings associated with headcount at the Tyrone Station would be expected.

If Tyrone 1 & 2 were returned to service, employees would need to be trained on how to operate the units. This cost is estimated by S&L to be $300,000[5]. Also, existing staff would need to work 8 hours per week on preventative maintenance for the units on overtime or double-time

[5] "Engineering Assessment and Analysis of Tyrone 1 & 2", Sargent & Lundy, Table 5-1, page 50

hours depending on the day of the week when the units are in operation. The labor expense associated with Tyrone 1 & 2's return to service is included in the net present value revenue requirements analysis.

3.0 Regulatory Assessment

In the review of the Companies' 2005 IRP, the Kentucky Public Service Commission ("KPSC") has recommended that decisions to retire any generating unit(s) should be supported by a feasibility study regarding the decision to retire the unit(s) and that those studies should be included in the next IRP (which will be filed in 2008). Generation Planning full accepts the KPSC's recommendation and will include the appropriate documents with the 2008 IRP. However, approval from the KPSC is not needed to retire the units. Any aspect of retirement that might impact rates and the accounting for the retirement will be addressed in the next rate case.

3.1 SPCC Impacts

The Federal Oil Pollution Act requires that facilities storing more than 1320 gallons of oil maintain a Spill Prevention Control and Countermeasures Plan. In July of 2002, the USEPA revised the SPCC Federal Amendments to require compliance for both oil storage and oil-containing equipment. Retirement of the Units 1 and 2 does not significantly affect costs for site compliance except that significantly less oil must be stored on-site because only Unit 3 startup oil must be supplied. Without retirement of the units, improvements to berm of the existing 500,000 gallon tank, overfill protection equipment, and replacement of the underground lines from the tank to the building would be required. The tank may require repairs. With retirement of the units, the tank may be removed and replaced with a much smaller tank adjacent to the building. A new, smaller tank would reduce the company's environmental exposure.

3.2 316(b) Impacts

Revisions of Section 316(b) of the Clean Water Act require the company to demonstrate reductions of the impact of river water intake structures regarding fish impingement mortality. The retirement of Units 1-2 and reduction in water intake from discontinued use of the circulating water pumps reduces the total impact to fish impingement mortality of the Tyrone plant. Environmental Affairs has the responsibility to report the required reductions necessary for the facility through a reduction in flow; or alternatively, we must propose to install alternative technologies to reduce the impingement impacts. Retirement of the units will greatly contribute to meeting the regulatory reduction criteria and thus reduce (but not eliminate) additional capital investments required.

4.0 Safety Issues

Currently there is asbestos insulation on the turbines, boilers, and piping on Tyrone 1 & 2. In the event of a boiler tube leak or boiler 'puff' asbestos insulation on the boiler could be damaged and released into the building, exposing employees. The age of the boiler increases the risk of boiler tube leaks that could damage asbestos insulation. If the units are re-powered, boiler repair work and replacement of boiler controls will reduce, but not eliminate the risk of asbestos release. If the unit is retired there will be no risk of boiler pressurization or steam release to destroy the asbestos and transport it throughout the building. The asbestos insulation will remain encapsulated.

Mercury is present in some of the boiler controls, adjacent to live steam lines. In the event of a rupture of the steam line within the controls, mercury would be vaporized and into the atmosphere in the plant. Staff would be exposed and mercury cleanup procedures would be required. This risk would be eliminated by retiring the units, or replacing the controls if the units are re-powered.

Due to the vintage of the units it is expected that some if not all paint used for the units is lead based. For Tyrone Units 1 & 2 to continue safe operation, minimizing the abovementioned safety risks, the equipment maintenance describe in the S&L Life Assessment report would be required.

5.0 Conclusions and Recommendations

The economic analysis performed in this study, supported by the S&L Life Assessment Study, concludes it is in the best interest of the Companies and the ratepayers to retire Tyrone Units 1 and 2 from service. The primary factors influencing this decision were the significant investment required for continued operation and the units' high cost of production.

Appendix
Case A
Incremental Value of Retiring Tyrone 1 & 2
Net Present Value Revenue Requirements Analysis

(All dollars are in $000s)

Base Scenario - Purchase Market at $100 per MWh

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	10 Yr NPVRR @ 7.61%
Retirement Costs											
Lost Production*	$74	$11	$0	$0	$0	$0	$0	$0	$0	$0	$85
Reserve Margin Purchases	$0	$2,601	$2,601	$1,121	$2,601	$2,601	$0	$0	$0	$0	$9,306
Total NPV Revenue Requirements Costs from Retirement											$9,391
Retirement Savings											
Total Cost to Repair	$16,145	$0	$0	$0	$0	$0	$0	$0	$0	$0	$16,145
Depreciation Avoided	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$88
Labor Expense	$11	$11	$11	$11	$12	$12	$12	$12	$13	$13	$86
Operation and Maintenance	$49	$42	$42	$42	$43	$44	$45	$46	$47	$47	$327
Air/Water Fees	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$4
Insurance Premium	$10	$10	$10	$10	$10	$10	$10	$10	$10	$10	$71
Total NPV Revenue Requirements Savings from Retirement											$16,722
NPV Revenue Requirement Benefit of Retirement ($000)											$ 7,331

*Note: Tyrone 1 & 2 would not be dispatched during these hours in reality. This lost generation is representative of hours the units are forced to run in our generation model due to the constraints placed on the market purchase units and the time of dispatch being during maintenance season. In reality, these megawatt-hours would have been purchased from the market.

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Case B - Required and Highly Probably Costs Only
Incremental Value of Retiring Tyrone 1 & 2
Net Present Value Revenue Requirements Analysis

(All dollars are in $000s)

Base Scenario - Purchase Market at $100 per MWh

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	10 Yr NPVRR @ 7.61%
Retirement Costs											
Lost Production*	$74	$11	$0	$0	$0	$0	$0	$0	$0	$0	$85
Reserve Margin Purchases	$0	$2,601	$2,601	$1,121	$2,601	$2,601	$0	$0	$0	$0	$9,306
Total NPV Revenue Requirements Costs from Retirement											$9,391
Retirement Savings											
Total Cost to Repair	$12,110	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,110
Depreciation Avoided	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$88
Labor Expense	$11	$11	$11	$11	$12	$12	$12	$12	$13	$13	$86
Operation and Maintenance	$49	$42	$42	$42	$43	$44	$45	$46	$47	$47	$327
Air/Water Fees	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$4
Insurance Premium	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7	$53
Total NPV Revenue Requirements Savings from Retirement											$12,669
NPV Revenue Requirement Benefit of Retirement ($000)											$ 3,278

*Note: Tyrone 1 & 2 would not be dispatched during these hours in reality. This lost generation is representative of hours the units are forced to run in our generation model due to the constraints placed on the market purchase units and the time of dispatch being during maintenance season. In reality, these megawatt-hours would have been purchased from the market.

E.ON U.S.

Generation Services

Case C - All Costs and Reserve Margin Prices at $6/kw-month
Incremental Value of Retiring Tyrone 1 & 2
Net Present Value Revenue Requirements Analysis

(All dollars are in $000s)

Base Scenario - Purchase Market at $100 per MWh

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	10 Yr NPVRR @ 7.61%
Retirement Costs											
Lost Production*	$74	$11	$0	$0	$0	$0	$0	$0	$0	$0	$85
Reserve Margin Purchases	$0	$3,902	$3,902	$1,682	$3,902	$3,902	$0	$0	$0	$0	$13,960
Total NPV Revenue Requirements Costs from Retirement											$14,044
Retirement Savings											
Total Cost to Repair	$16,145	$0	$0	$0	$0	$0	$0	$0	$0	$0	$16,145
Depreciation Avoided	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$88
Labor Expense	$11	$11	$11	$11	$12	$12	$12	$12	$13	$13	$86
Operation and Maintenance	$49	$42	$42	$42	$43	$44	$45	$46	$47	$47	$327
Air/Water Fees	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$4
Insurance Premium	$10	$10	$10	$10	$10	$10	$10	$10	$10	$10	$71
Total NPV Revenue Requirements Savings from Retirement											$16,722

NPV Revenue Requirement Benefit of Retirement ($000) $\boxed{\$ \quad 2,678}$

*Note: Tyrone 1 & 2 would not be dispatched during these hours in reality. This lost generation is representative of hours the units are forced to run in our generation model due to the constraints placed on the market purchase units and the time of dispatch being during maintenance season. In reality, these megawatt-hours would have been purchased from the market.

E.ON U.S.
Generation Services

Expansion Plan Analysis
Incremental Value of Retiring Tyrone 1 & 2
Net Present Value Revenue Requirements Analysis

(All dollars are in $000s)

		30 Yr NPVRR @ 7.61%
NPV Revenue Requirements Costs from Retirement		
	Reserve Margin Purchases	$9,306
	Expansion Plan Impact (Capital, O&M, OSS, Lost Production*)	$7,663
	Total	$16,969
NPV Revenue Requirements Savings from Retirement		
	Total Cost to Repair	$16,188
	Depreciation Avoided	$151
	Labor Expense	$164
	Operation and Maintenance	$617
	Emission Costs (SO2 and NOx)	$499
	Air/Water Fees	$8
	Insurance Premium	$122
	Total	$17,749
NPV Revenue Requirement Benefit of Retirement ($000)		$ 779

*Note: Tyrone 1 & 2 would not be dispatched during these hours in reality. This lost generation is representative of hours the units are forced to run in our generation model due to the constraints placed on the market purchase units and the time of dispatch being during maintenance season. In reality, these megawatt-hours would have been purchased from the market.

Tyrone 1 & 2

Engineering Assessment and Analysis

Prepared for
E.ON U.S. Services Inc.

Report SL-008956

e·on | U.S.

Project 12084-001
January 2007

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Final Report

Tyrone 1 & 2
Engineering Assessment and Analysis

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LEGAL NOTICE

ENGINEERING ASSESSMENT AND ANALYSIS OF TYRONE 1 & 2

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TABLES

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FIGURES

ACRONYMS AND ABBREVIATIONS

Term	Description or Clarification
CPU	Central processing unit
ECT	Eddy current testing
ELCID	Electromagnetic core imperfection detection
EMAT	Electromagnetic acoustic transducer based testing
FAC	Flow assisted corrosion
GADS	Generating Availability Data System
I&C	Instrumentation and control
ID	Induced draft
MCC	Motor control center
MPI	Magnetic particle inspection
MPT	Magnetic particle testing
NDE	Non-destructive examination
NERC	North American Electric Reliability Council
NFPA	National Fire Protection Association
OEM	Original equipment manufacturer
pf	Power factor
PLC	Programmable logic controller
psi	Pound(s) per square inch
UT	Ultrasonic testing

1. EXECUTIVE SUMMARY

Sargent & Lundy, L.L.C. (S&L) was retained by E.ON U.S. Services, Inc. (E.ON US) to perform an engineering life assessment of Tyrone Units 1 and 2 to determine the capability of achieving the following levels of performance and reliability (Performance Targets) specified by E.ON US:

Table 1-1 — Performance Targets

Parameter	Unit 1	Unit 2
Capacity - Summer Net MW	31	31
- Winter Net MW	33	33
Heat Rate, Btu/kWh	18,000	18,000
Forced Outage rate, %	6%	6%
Availability, %	94%	94%
Cold Start Duration, minutes	300	300

Tyrone Generating Station is located on the east side of the Kentucky River in Woodford County between the cities of Versailles and Lawrenceburg. Unit 1 and Unit 2 are each 30-MW electric generating units that began commercial operation in 1947 and 1948, respectively. Each unit has two steam boilers that supply steam to a Westinghouse steam turbine-generator. Units 1 and 2 share a common building with Unit 3, which is a 75-MW coal-fired unit that began commercial operation in 1953.

The four Unit 1 and 2 boilers were originally designed to burn coal and were converted to burn No. 2 fuel oil in the 1970s. The higher fuel costs and lower thermal performance of Units 1 and 2 relative to the E.ON US and the regional generation fleet have resulted in these units being seldom dispatched for operations. The units have operated an average of about 40 hours per year since 1985 and neither unit has been operated since 2001.

S&L conducted visual inspections of Tyrone Units 1 and 2 on October 30, 2006, with document reviews and plant staff interviews completed on October 31. The inspections consisted of walk-downs throughout both units and the common facilities in the company of E.ON US engineering and plant staff. The scope of this study did not include internal visual inspections of any of the equipment.

The minimal levels of unit operation over the past 30 years have resulted in only a few overhauls of some of the major equipment. Preventive maintenance has been focused on health and safety and facility integrity issues and the common service water and auxiliary electrical systems used by Unit 3. The other mechanical and electrical equipment and instrumentation and control (I&C) systems on Unit 1 and 2 have not been operated and have had little or no maintenance performed on them since 2001.

S&L's evaluation of the condition of the equipment and the required upgrade and replacement costs were based on the following:

- S&L's extensive experience in assessing the condition of power plant equipment including steam units of similar vintage and design,
- Available plant equipment and design documents and operating and maintenance records,
- Observations from the unit inspection walk downs, and
- Interviews and discussion with E.ON US engineering and plant maintenance and operations staff.

The available information does not indicate that any of the plant equipment is inoperable. However, given the age of the equipment, the minimal levels of preventative maintenance, and the long period of time since these units were last operated, an attempt to restart these units without prior inspections and maintenance could result in component malfunctions and failures that may result in a long, protracted startup period with the potential for damage to major equipment.

S&L recommends that a restart program be developed and implemented in order to provide for safe and reliable operations. A restart program would be similar to the process used in starting and commissioning a new unit. The restart program would include inspection and routine preventive maintenance for all the mechanical, electrical, and I&C equipment and systems on Units 1 and 2. It would also include overhauls and upgrades necessary for safe operations and to provide the level of reliability and performance specified in the Performance Targets. This report provides an engineering assessment and estimates of expected and potential costs for completing the inspections and necessary maintenance work.

Table 1-2 summarizes the estimated costs for inspections, maintenance, overhauls, and equipment upgrades and replacements needed to support the restart efforts and the subsequent safe and reliable operation of the units.

Table 1-2 — Cost Summary by Category

Cost Category	Cost ($Million)
Required Activities	$4.36
High Probability Activities	$7.75
Potential Activities	$4.04
Total Potential Restart Cost	$16.15

These cost categories are defined as follow:

- **Required Activities.** Required to provide for safe operations and to achieve the Performance Targets.
- **High Probability Activities.** Probably will be required, subject to inspections and testing.
- **Potential Activities.** Possibly required, given the age and condition of the unit equipment.

The cost estimates were developed using cost information available to S&L from previous project capital cost estimates and other work experience of the S&L project team. These estimates are intended to provide high-level estimates of the aggregate costs that would likely be required to restart the units for purposes of resource planning evaluations. If E.ON US's economic analyses using these preliminary cost estimates indicate that restart of these units could be a cost-effective resource option, S&L recommends that more extensive condition assessment and upgrade planning be performed in order to support detailed cost analysis with vendor-supplied budgetary estimates for the identified work.

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2. INTRODUCTION

2.1 STUDY PURPOSE AND OBJECTIVES

Sargent & Lundy, L.L.C. (S&L) was retained by E.ON U.S. Services, Inc. (E.ON US) to perform an engineering life assessment of Tyrone Units 1 and 2 to determine the capability of achieving the levels of performance and reliability specified by E.ON US for these units.

The scope of work consisted of visual inspections, staff interviews, and document reviews to evaluate the overall condition of the oil-fired generating units and to assess the general condition of the following major equipment and systems:

- Oil-fired boilers and appurtenances, including burners, headers and piping.
- Steam turbine and appurtenances including lube oil and turbine oil systems.
- Water supply systems including pumps, motors, and piping.
- Electrical systems including power distribution, relay protection, transformers, control systems, and instrumentation.
- Turbine, boiler, and balance-of-plant control systems.

The assessment also considered unit equipment and system safety issues, including the cost impacts of asbestos and lead paint remediation.

This report is the deliverable for this study. It includes a description of the evaluations and findings, along with recommendations and cost estimates for repairs, upgrades, and equipment replacement required to achieve the Performance Targets identified in Table 1-1.

2.2 FACILITY DESCRIPTION AND HISTORY

Tyrone Generating Station is located on the east side of the Kentucky River in Woodford County, Kentucky between Versailles and Lawrenceburg. Unit 1 and Unit 2 are each 30-MW electric generating units that began commercial operation in 1947 and 1948, respectively. Each unit has two steam boilers that supply steam to a Westinghouse steam turbine-generator. Table 2-1 summarizes the design gross unit and net unit power outputs and the manufacturer's design ratings for the steam turbine and generator on both Units 1 and 2. The boilers were originally designed to burn coal and were converted to burn No. 2 fuel oil in the 1970s. Units 1 and 2 share a common building with Unit 3, which is a 75-MW coal-fired unit that began commercial operation in 1953.

Table 2-1 — Units 1 and 2 Design Electrical Output and Turbine-Generator Ratings

Gross Unit Power Output	31.3 MW*
Net Unit Power Output	29.5 kW*
Nominal Steam Turbine Rating	25 MW**
Nominal Generator Rating	39.1 MVA**

* Performance Diagram, 1945 Forecast, Sargent & Lundy.

** "Steam Turbine Instructions", Westinghouse Instruction Book SO SA-5516.

The exhaust steam from the steam turbine is condensed in a surface condenser with once-through cooling water from the Kentucky River. The intake structure for Units 1 and 2 has two bays of traveling screens that supply the circulating water to Units 1 and 2 as well as service water to all three units.

The higher relative fuel costs and thermal performance of Units 1 and 2 has resulted in these units being seldom dispatched for operations. Information pertaining to the hours of operation of these units for the period January 1985 – December 2006 is summarized below. Neither unit has operated since 2001.

Table 2-2 — Summary of 1985–2006 Operations

1985-2006 Operations	Unit 1	Unit 2
Cumulative Hours	921	979
Average Annual Hours	42	45
Years with Zero Hours of Operation	9	10

Last page of Section 2

3. FACILITY ASSESSMENT

3.1 PERFORMANCE TARGETS

The engineering assessment was based on achieving the following Performance Target values specified by E.ON US:

Table 3-1 — Performance Targets

Parameter	Unit 1	Unit 2
Capacity - Summer Net MW	31	31
- Winter Net MW	33	33
Net Heat Rate (Btu/kWh)	18,000	18,000
Forced Outage Rate	6%	6%
Equivalent Availability Factor	94%	94%
Cold Startup Duration (minutes)	300	300

S&L reviewed the available historical operating data and concluded that the targets for capacity and heat rate were consistent with the actual values from the limited operations since 1985. The level of maintenance and upgrade work outlined in this study would maintain and may even improve on these historical levels, as well as provide a high level of certainty in meeting the specified availability criteria and startup times.

3.2 TYRONE 1 & 2 INSPECTION AND REVIEWS

S&L conducted visual inspections of Tyrone Units 1 and 2 on October 30, 2006, with follow-on document reviews and plant staff interviews completed on October 31. The inspections consisted of walk-downs throughout both units and the common facilities in the company of E.ON US engineering and plant staff. The scope of this study did not include internal visual inspections of any of the equipment.

Overhauls of the major equipment have been infrequent over the past 30 years due to the minimal level of unit operations. Preventive maintenance has been focused on health and safety and facility integrity issues and the common service water and auxiliary electrical systems used by Unit 3. The low level of operations and associated required maintenance has not necessitated removal of the original asbestos insulation, lead paint, or the mercury-containing instruments and switches from the units. Most of the boiler and steam piping insulation is the original asbestos-based material. It appears that this insulation has been properly maintained. S&L did not find any areas of exposed or frayed insulation. E.ON US stated that there has also been no program to replace the original lead-painted surfaces throughout the units. Pealing paint was observed on some of the piping and structural steel members, but there was no observed accumulation of paint chips on the floors or other horizontal surfaces.

Units 1 and 2 are enclosed in a common building with the Unit 3 coal-fired unit. The building has been maintained so that the boiler and turbine equipment have been protected from weathering. The boilers were drained and a dehumidification system was installed in 2001 and kept in service on all four boilers through 2005. The feedwater, condensate, and service water systems were laid-up wet. The mechanical and electrical equipment and the instrumentation and control (I&C) systems have not been operated since 2001, with the exception of Unit 1 and 2 service water and coal handling systems used for operations of Unit 3. The steam turbine-generators have not been run on turning gear for over 3 years.

S&L's evaluation of the condition of the equipment and the required maintenance, upgrade and replacement costs were based on the following:

- S&L's extensive experience in assessing the condition of power plant equipment, including steam units of similar vintage and design,
- Available plant equipment and design documents and operating and maintenance records,
- Observations from the unit inspection walk downs, and
- Interviews and discussion with E.ON US engineering and plant maintenance and operations staff.

The available information does not indicate that any of the plant equipment is inoperable. However, given the age of the equipment, the minimal levels of preventive maintenance, and the long period of time since these units were last operated, an attempt to restart these units without prior inspections and maintenance could result in component malfunctions and failures that may result in a long, protracted startup period with the potential for damage to major equipment.

S&L recommends that a restart program be developed and implemented in order to provide for safe and reliable operations in an economically viable manner. A restart program would be similar to the process used in starting and commissioning a new unit. The restart program would include inspection and routine preventive maintenance for all the mechanical, electrical, and I&C equipment and systems on Units 1 and 2. It would also include overhauls and upgrades necessary for safe operations and to provide the level of reliability and performance specified in the Performance Targets. This report provides an engineering assessment and estimates of expected and potential costs for completing the inspections and necessary maintenance work.

Last page of Section 3.

4. RESTART PROGRAM SCOPE AND COSTS

This section describes the specific equipment and system inspection, overhaul, and replacement work that will likely be required to successfully complete a restart effort and to achieve the Performance Targets. Inspections, overhauls, and equipment replacement work and their associated estimated costs were divided into the following three categories:

- **Required Activities.** Required to provide for safe operations and to achieve the Performance Targets.
- **High Probability Activities.** Probably will be required, subject to inspections and testing.
- **Potential Activities.** Possibly required, given the age and condition of the unit equipment.

S&L developed cost estimates for each identified work task using available information from previous S&L capital cost estimates and other work experiences of the S&L project team. These cost estimates include equipment, material, and labor in current 2006 dollars. Costs include allowances for asbestos and lead removal and disposal for the inspection, repair, and replacement work.

The cost estimates were developed using cost information available to S&L from previous project capital cost estimates and other work experience of the S&L project team. These estimates are intended to provide high-level estimates of the aggregate costs that would likely be required to restart the units for purposes of resource planning evaluations. If E.ON US's economic analyses using these preliminary cost estimates indicate that restart of these units could be a cost-effective resource option, S&L recommends that more extensive condition assessment and upgrade planning be performed in order to support detailed cost analysis with vendor-supplied budgetary estimates for the identified work.

4.1 BOILER AND APPURTENANCES

4.1.1 Background

The Unit 1 and Unit 2 Babcock & Wilcox (B&W) non-reheat boilers are each rated at 150,000 lb/hr, 1,000 psig, and 910°F.[1] There are two boilers providing steam to a single steam turbine for each unit. The boilers were

[1] "Tyrone Power Station, Equipment Data, Units 1&2", Sargent & Lundy, SL-1226, December 23, 1953.

originally designed to fire coal and were converted to oil firing in the early 1970s. The boiler drums are a rolled-tube design. The superheater header does not have tube stubs; the tubes are rolled and flared in the header. Overhaul records were not available.

Availability statistics from the North American Electric Reliability Council–Generating Availability Data System (NERC-GADS) database indicates that the boiler accounts for 50% of the occurrences of the top 25 component outage/derating causes for plants in the 1-MW to 99-MW size range. Accordingly, the condition of the boiler and associated auxiliary equipment is a critical element in developing a plan to achieve the Performance Targets.

4.1.2 Return to Service

Before returning the boilers to service, the following are recommended:

- Internal visual inspection
- Non-destructive examination (NDE) that focuses on boiler components whose failure would affect the reliability and availability of the boiler. Components that comprise the pressure parts of the boiler are the main focus for NDE since the failure of one of these components would have the highest impact on the reliability and availability of the boiler. The following areas and type of NDE are recommended:
  - Drum fluorescent magnetic particle testing (MPT) of major welds, selected attachment welds, and at least 20% of the ligaments
  - Tube ultrasonic thickness testing (UT) where external erosion or corrosion are observed
  - UT of the leading-edge tube row of the superheater
  - Electromagnetic acoustic transducer based testing (EMAT) of approximately 20% of the riser tubes to evaluate under deposit corrosion, pitting, or hydrogen damage
  - UT of the first economizer tube row
  - Critical piping NDE
- Safety valves testing and recertification
- Hydrostatic test of boiler at 1.5 times the design pressure

There is no universally recognized definition of critical piping. However, systems that represent a potential hazard to personnel or have a major impact on unit operation, because of their function or because of their operating conditions, are often referred to as "critical" piping systems. Table 4-1 lists the critical systems considered and the recommended NDE.

Table 4-1 — Critical Piping Evaluation Matrix

Piping & Header Systems	System Critical to Unit Operation	System Critical to Unit Efficiency	Probable Failure Mechanisms	Typical Examination Specified	Primary Areas for Examination *
Main Steam	Yes	Yes	Creep, Fatigue	MT, Replica, UT	H, F, E, V, N, IWA
Feedwater	Yes	Yes	Fatigue, FAC	MT, UT	H, F, E, V, N,
Extraction Steam	No	Yes	Fatigue, FAC	MT, UT	H, F, E, V, N,
Heater Drains	No	Yes	Fatigue, FAC	MT, UT	F, E, V
High-Energy Drains	No	Yes	Fatigue, FAC	MT, UT	H, F, E, V, N,
Auxiliary Steam Systems	No	Yes	Fatigue	MT, UT	H, F, E, V, N

* H = High stress areas of system from stress analysis, F = fittings, E = elbows, V = valves, N = nozzle connections, IWA = Integral Welded Attachments.

The costs for the activities listed above are estimated to be at least $150,000 per unit.

4.1.3 Major Concerns

4.1.3.1 Steam Drum

The steam drum is the most expensive boiler component. The carbon steel drum is rarely subject to significant creep damage due to the relatively low operating temperature. Component wear is primarily due to internal metal loss due to corrosion, which can occur during extended outages and from acid attack, oxygen pitting, and chelant attack. Damage can also occur from mechanical and thermal stresses on the drum, which concentrate at nozzle and attachment welds. These stresses, most often associated with boilers that are cycled on and off, can result in crack development. Cyclic operation can lead to drum distortion, resulting in concentrated stresses at the major support welds, seam welds, and girth welds. Since inlet feedwater temperature is significantly lower than the drum temperature, the feedwater penetration area has the greatest stress potential. Unit 1 and Unit 2 boilers are rolled-tube design. A problem unique to steam drums with rolled tube seats is tube seat water seepage. Caustic embrittlement of the joint can occur if a leak is not repaired. In addition, the act of eliminating the tube seat leak by repeated tube rolling can overstress the drum shell between tube seats and lead to ligament cracking. Information provided by E.ON US indicated that oxygen pitting in the drums has been observed on both Units 1 and Unit 2.

Based on the vintage of the equipment, the existing oxygen pitting, and the historical caustic embrittlement susceptibility, there is a high probability that major repairs will be necessary. A cost of $100,000 is allocated for these repairs.

4.1.3.2 Tubes

Boiler tube failures are the industry-wide primary cause for forced outages. Water-cooled tubes include the economizer, boiler bank, and furnace. The convection pass sidewall and screen tubes may also be water-cooled. These tubes operate at or below saturation temperature and are not subject to significant creep. Damage to these tubes can occur from excessive deposition that leads to corrosion and hydrogen damage. Waterside corrosion fatigue is a serious boiler tube failure mechanism. The failures usually occur close to attachments such as buckstay welds or windbox attachment welds. The combination of thermal fatigue stresses and corrosion leads to cracking initiated on the inside diameter that is oriented along the tube axis. Corrosion-fatigue has been identified on older units, those with greater than 30 years operation, as the root cause mechanism of riser tube failure. Whether caused by chelant attack or corrosion fatigue, the failures tended to be catastrophic with a large piece of tube rupturing. Based on the vintage of the equipment, a cost of $100,000 was allocated for replacement of 25% of the riser tubes for each of the four boilers.

4.1.3.3 Superheater

A portion of superheater tubes were replaced on Unit 1 in 1996. The superheater header does not have tube stubs; the tubes are rolled and flared in the header. Spacing of the tubes was noted to be very close, which makes repairs difficult. Based on the vintage of the equipment, there is a high probability that major superheater repairs will be necessary. The estimated capital cost for superheater tube repairs is $75,000 per unit.

4.1.3.4 Chemical Cleaning

Considering the period of idleness, tube oxidation will most likely be excessive. After repairs and tube replacements, a chemical cleaning of each boiler will be required. The estimated expense of cleaning is $100,000 per boiler.

4.1.3.5 Air Preheater

Each unit has a tubular air heater. Based on the vintage of the equipment, there is a high probability that sections of tube replacement will be necessary. An estimated capital cost for replacement of 25% of the air preheater tubes is $50,000 per unit, including minor repairs of ductwork damage.

4.1.3.6 Feedwater Piping

Depending on the operating parameters of the feedwater system, the flow rates, and the piping geometry, the pipe may be prone to corrosion or flow-assisted corrosion (FAC). This is also referred to as erosion-corrosion. If susceptible, the pipe may lose material from internal surfaces near bends, pumps, injection points, and flow transitions. Ingress of air into the system can lead to corrosion and pitting. Out-of-service corrosion can occur if the boiler is idle for long periods. Based on the vintage of the equipment and the idle time, there is a high probability that sections of the feedwater piping will need to be replaced. The estimated capital cost for replacement of 200 feet and 20 elbows in the feedwater piping system is $50,000 per unit.

4.1.3.7 Attemperator

The attemperator is subject to failures associated with thermal fatigue cracking of its components and welds. Since it is in a closed loop of the boiler, failures may go undetected until overspray or pieces of the attemperator lead to other damage, such as superheater tube failures due to pluggage or tube metal overheating from nucleate boiling on the tube surfaces. Based on the age of the equipment and the length of time with no operation, there is a high probability that the attemperators will need to be replaced. The estimated capital cost for attemperator replacement is $25,000 per unit.

4.1.4 Summary

The potential costs for returning the boilers to service, including recommended and high probability items, are summarized in the table that follows. The estimated costs were increased by 10% to account for asbestos removal and disposal where indicated in the table below.

Table 4-2 — Estimated Costs for Returning the Boilers to Service

Activity	Action	Estimated Cost
Internal Visual Inspection; Non-Destructive Examination; Safety Valves Testing and Recertification; Hydrostatic Test of Boiler *	Required	Unit 1 $165,000 Unit 2 $165,000 Total $330,000
Steam Drum Repairs*	High Probability repairs required	Unit 1 $110,000 Unit 2 $110,000 Total $220,000

Activity	Action	Estimated Cost
Tube Replacements	High Probability replacements required	Unit 1 $110,000 Unit 2 $110,000 Total $220,000
Superheater Tube Repairs	High Probability repairs required	Unit 1 $75,000 Unit 2 $75,000 Total $150,000
Chemical Cleaning	Required	Unit 1 $100,000 Unit 2 $100,000 Total $200,000
Air Preheater Tube Replacement*	High Probability replacements required	Unit 1 $55,000 Unit 2 $55,000 Total $110,000
Feedwater Piping Replacements*	High Probability replacements required	Unit 1 $55,000 Unit 2 $55,000 Total $110,000
Attemperator Replacement*	High Probability replacements required	Unit 1 $30,000 Unit 2 $30,000 Total $60,000
Total of All Required and High Probably Items		Unit 1 $700,000 Unit 2 $700,000 $1,400,000

* Includes 10% cost adder for asbestos removal and disposal.

4.2 STEAM TURBINE AND APPURTENANCES

4.2.1 Background

The Unit 1 and 2 Westinghouse steam turbines are each nominally rated at 25 MW. The steam turbines are non-reheat with inlet steam conditions of 850 psig / 900°F and have one Curtis stage impulse row and 25 reaction rows of blading. The last rows of blades are attached to a separate disc, which is shrunk fit onto the rotor.

Available information indicates the last inspection for the steam turbines was conducted in 1977–1978. The steam turbines were last operated in 2001

4.2.2 Return to Service

Before returning the steam turbines to service, the following activities are recommended:

- Internal inspection
- Non-destructive examinations
  - Visual and fluorescent MPI of the rotor surface and UT/MPI/ECT of the rotor bore for surface and forging defects
  - Visual and MPI of cylinder casing and shell
  - Visual and MPI of throttle valve body
  - Visual of the blades
  - ECT of blade root fixings
- Remaining life assessment based on the NDE data. Calculations based on fracture mechanics predicts crack initiation and growth rates under cyclic loading (fatigue) and enables a prediction if a crack of a given size, as determined by NDE, will fail under a particular load and if flaws will propagate to failure within known time and operational factors.

The rotors of steam turbines are subject to life limitations due to creep and thermal fatigue. Creep occurs during steady-state operation due to the centrifugal stresses sustained at high temperature while thermal fatigue arises from cyclic thermal stresses set up during startup and shutdown. The most serious threat to the rotor arises from the possibility that, near the bore, creep cracks may initiate and grow to a size that could result in a brittle fracture of the rotor during a cold start. Initiation may be assisted by any pre-existing forging defects in the near-bore region, and growth may be assisted by fatigue due to the thermal and mechanical stresses applied during starting.

Creep cracking can also occur at blade root fixings leading eventually to the loss of blades and possibly substantial consequential damage to the turbine. Creep, thermal fatigue, and stress corrosion cracking can occur at other stress-concentrating features, such as balance holes and changes of section; the effect of any cracking at such features depends on the local stress levels.

The turbine lube oil and control oil systems will require inspection, cleaning, and repair. Recommended activities include mechanical cleaning of the turbine oil tank and cleaning of the turbine oil coolers on both the shell side and tube side. The coolers should be tested for tube leaks. The turbine oil reservoir of about 2,500 gallons must be tested and will likely need to be reconditioned or replaced.

Turbine lube oil piping should be examined internally to determine the extent of corrosion. Chemical or mechanical cleaning may be required, but at a minimum, the entire oil system will require a high-velocity flush.

Inspection and cleaning of the generator seal oil piping and detraining tanks is recommended. The hydrogen dryer desiccant should be replaced, and the hydrogen and carbon dioxide inventories must be replenished. A generator hydrogen leakage rate test (air test) should be performed before generator operation.

If the NDE data and remaining life assessment determine that the steam turbines are suitable for continued operation, it is recommended that, at a minimum, the labyrinth seals and inner gland seals be replaced. Seal replacement is recommended to reduce steam leakage and improve the heat rate.

The costs for the recommended activities before returning the steam turbines to service are listed in the following table.

Table 4-3 — Recommended Activity Costs for Returning the Steam Turbines to Service

	Estimated Cost	
Activity	**Unit 1**	**Unit 2**
Disassemble and Reassemble for Inspection	$180,000	$180,000
Non-Destructive Examination	$150,000	$150,000
Remaining Life Assessment	$50,000	$50,000
Seal Replacements	$40,000	$40,000
Reconditioning of the Lube Oil System	$40,000	$40,000
Replenish Inventory of Turbine Oil and Operating Gases	$40,000	$40,000
Subtotal	$500,000	$500,000
Total	$1,000,000	

4.2.3 Major Concerns

4.2.3.1 Rotor

Older rotor forgings suffered from 'segregation' problems, whereby inclusions and impurities in the steel clustered at the center. The center of the forging was machined out to remove these impurities leaving the rotor bore. The combination of thermal and centrifugal stresses during startup, and creep strain during relaxation at temperature and under steady-state operation, makes the rotor bore the most highly stressed area of a rotor.

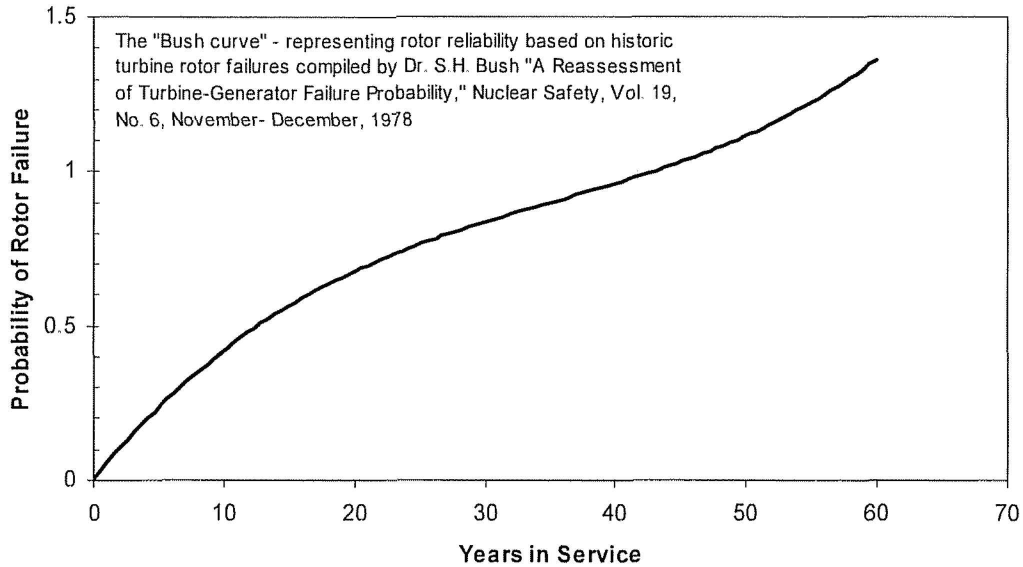
During a rapid cold start, the combination of high-periphery and low-bore temperature causes tensile thermal hoop stress at the bore. If the combined effect of thermal and centrifugal stresses during startup is sufficient, yielding occurs at the bore. As the rotor warms through, thermal stresses decrease, and the residual compressive stress (due to previous tensile yielding) reduces bore stress to less than the normal centrifugal stress. This reduction is compensated by increased stresses at larger radii in the rotor, which are redistributed by creep during operation. With sufficient operating duration, bore stress increases to the steady-state value with attendant accumulation of bore creep strain. Subsequent starts severe enough to cause bore yielding repeat the cycle, with each cycle increasing creep rate in the rotor body slightly until the equilibrium stress distribution is restored.

The most serious threat to a rotor from the bore region arises from the possibility that, near the bore, creep cracks may initiate and grow to a size that could result in a brittle fracture of the rotor during a cold start. Initiation may be assisted by any pre-existing forging defects in the near bore region, and growth may be assisted by fatigue due to the thermal and mechanical stresses mentioned above applied during startup and shutdown cycles.

In assessing critical crack size, it is assumed that an initial defect will be propagated by cyclic thermal and centrifugal stresses to a final size, beyond which catastrophic brittle fracture would occur. The critical size depends on stress level, the material's fracture appearance transition temperature (brittle-to-ductile transition), and temperature in the defect region. Again, for bore defects, the most arduous combination of these, as mentioned above, occurs during a cold start or overspeed test when thermal and centrifugal bore stresses are at their maximum, while the rotor bore temperature (and material toughness and resistance to brittle fracture) is low.

Regardless of the degree of sophistication employed in calculating or measuring stresses (or strains); there remains a considerable amount of uncertainty about their actual magnitude in service under different operating conditions. Similarly, one cannot assume a single value of strength (or strain capability). Heat-to-heat variations and even variations within a single large component, such as a rotor forging or turbine shell, introduce unavoidable uncertainties in material capability. Thus, it has become necessary to treat the problem statistically. The "permissible" probability of failure, or failure rate, depends on many factors, including the consequences of failure. While there is no definitive rotor end-of-life based on the number of service hours, the probability of rotor failure begins to increase significantly at 40 years of service, as depicted below. The graph in Figure 4-1 shows the probability of failure, expressed as percentage, as a function of years of operation. This curve was based on historic turbine rotor failures compiled by Dr. S. Bush. The Bush curve represents the cumulative hazard or probability of failure in percent versus operating time. The curve indicates that at 40 years in service the risk of rotor failure is 10 times greater than during the first couple of years in service.

Figure 4-1 — Probability of Turbine Rotor Failure versus Time



Since the rotor is the most expensive component of the steam turbine, failure will effectively be the end-of-life for the steam turbine. The installed replacement cost for a new rotor is estimated at $1,500,000. The risk of rotor failure estimated by NDE testing and remaining life assessment is as previously discussed.

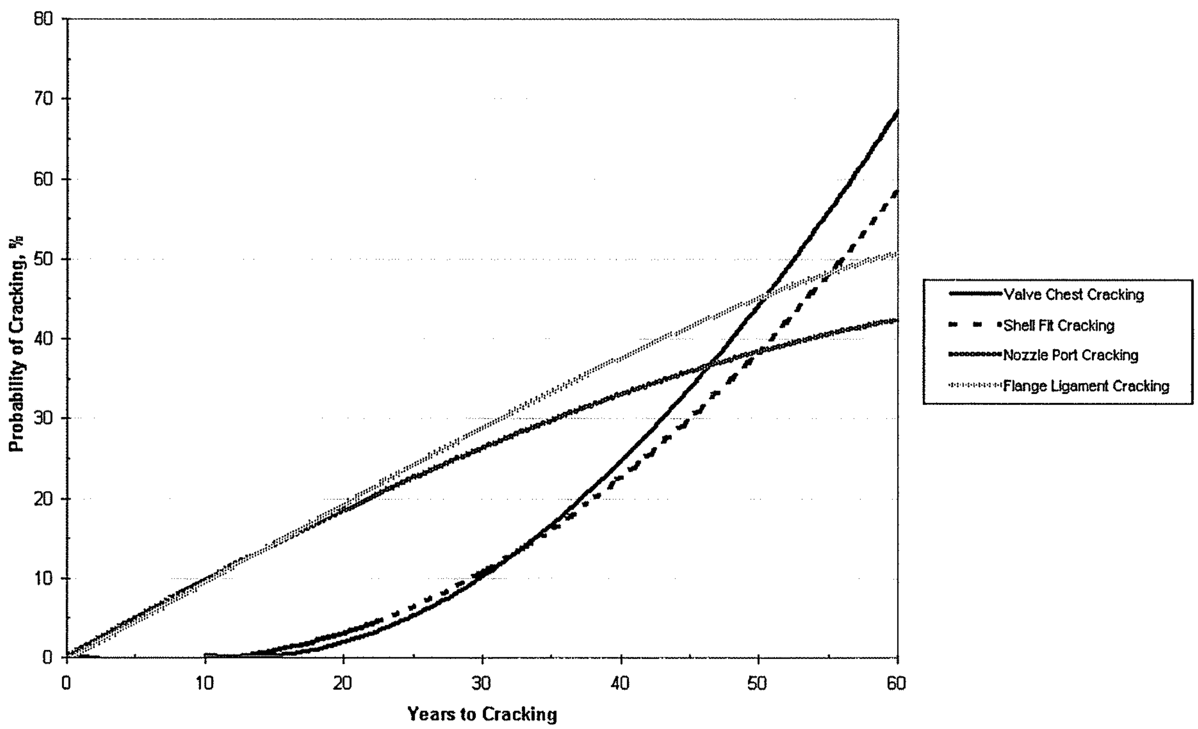
4.2.3.2 Shrunk on Disc

The last rows of blades are attached to a separate disc, which is shrunk fit onto the rotor. The keyways of the shrunk-on-disc design have high-stress concentrations and are susceptible to stress corrosion cracking. The tangential stresses are greatest at the keyways and steam has a tendency to condense in this area. Based on the vintage of the equipment, the inspection intervals, and the stress corrosion cracking susceptibility of the shrunk-on-disc design, there is a high probability that stress corrosion exists and major repairs will be necessary. For each steam turbine, the estimated cost of repairs is $200,000. Since the last rows of blades are attached to a separate disc, which is shrunk fit onto the rotor, the repairs would still be required if the rotor is replaced.

4.2.3.3 Steam Turbine Body

Valve chest, shell, nozzle ports, and flange ligament cracking can be expected as the units age, as depicted in Figure 4-2. The Unit 1 1961 inspection report indicated cracks were found in the high-pressure base and cover cylinders.

Figure 4-2 — Steam Turbine Body Cracking Probability



Based on the vintage of the equipment, the length of inspection intervals, and the historical cracking susceptibility, there is a high probability that stress corrosion exists and major repairs will be necessary. For each steam turbine, the estimated cost of repairs is $125,000.

4.2.3.4 Throttle Valve Body

Records indicate the Unit 1 throttle valve body was replaced in 1979. Radiographic tests revealed the valve body was honeycombed with stress and metal fatigue cracks, which made it unsafe to operate and unable to be repaired by welding. There is a high probability, based on the Unit 1 history, that the Unit 2 throttle valve body has stress and metal fatigue cracks that will necessitate replacement. The estimated cost for the Unit 2 throttle valve body replacement is $150,000.

4.2.3.5 Blades

There is no record of any blade replacements for the steam turbines. Due to the higher moisture content steam at the low-pressure section, trailing edge erosion is a high probability for at least the last three rows of blading. Replacement cost for the last three rows of blades for each steam turbine is estimated to be $200,000 per unit.

4.2.4 Summary

The potential costs for returning the steam turbines to service, including recommended and high probability items, are summarized below.

Table 4-4 — Estimated Costs for Returning the Steam Turbines to Service

Activity	Action	Estimated Cost
Disassemble and Reassemble for Inspection Non-Destructive Examination Remaining Life Assessment Reconditioning of the Lube Oil System Replenish Inventory of Turbine Oil and Operating Gases	Required	Unit 1 $460,000 Unit 2 $460,000 Total $920,000
Seal Replacements	Required if adequate remaining life remains	Unit 1 $40,000 Unit 2 $40,000 Total $70,000

Activity	Action	Estimated Cost
Rotor Replacement	Potential Activities - As determined by Remaining Life Assessment	Unit 1 $1,500,000 Unit 2 $1,500,000 Total $3,000,000
Shrunk-on-Disc Repairs	High Probability repairs required	Unit 1 $200,000 Unit 2 $200,000 Total $400,000
Steam Turbine Body Repairs	High Probability repairs required	Unit 1 $125,000 Unit 2 $125,000 Total $250,000
Throttle Valve Body Replacement*	High Probability Unit 2 replacement required	Unit 2 $165,000 Total $165,000
Blade Replacements	High Probability last 3 rows replacement required	Unit 1 $200,000 Unit 2 $200,000 Total $800,000
Total of All Required and High Probably Items		Unit 1 $1,025,000 Unit 2 $1,190,000 $2,215,000
Total if New Rotor Required		Unit 1 $2,525,000 Unit 2 $2,690,000 $5,215,000

* Includes 10% cost adder for asbestos removal and disposal.

4.3 WATER SYSTEMS

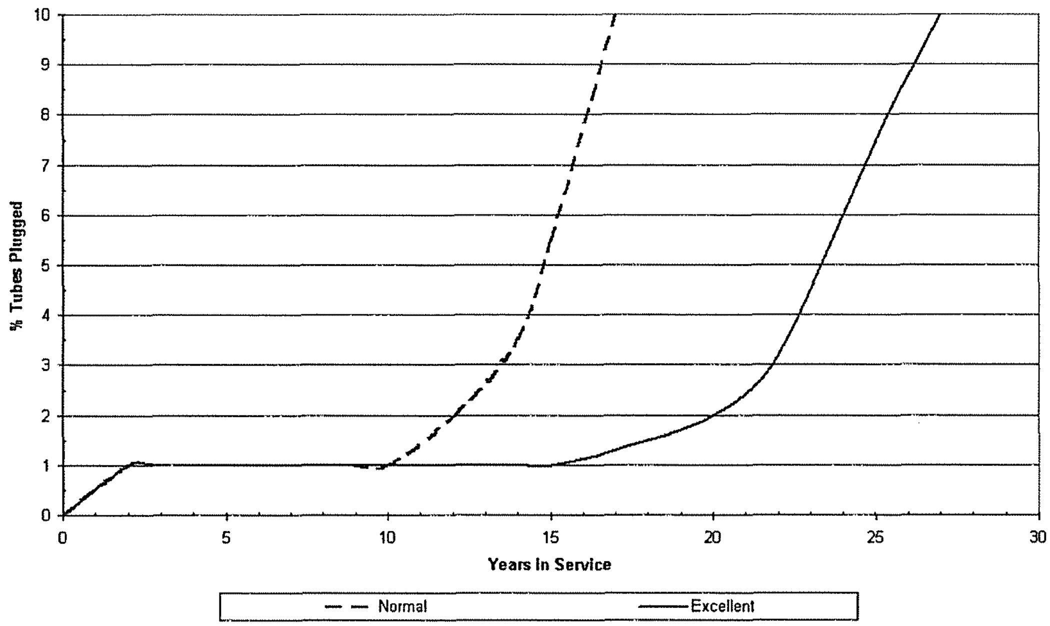
4.3.1 Feedwater Heaters

Each unit has two low-pressure and two high-pressure feedwater heaters, all manufactured by the American Locomotive Company. Low-pressure heater No. 1 has 600 Admiralty tubes, and No. 2 has 479 Admiralty tubes. High-pressure heaters No. 3 and No. 4 each have 384 copper nickel tubes. A detailed survey was conducted (*High-Reliability Feedwater Heater Study*, Palo Alto, California: Electric Power Research Institute, June 1988. CS-5856) to rate the problem areas in the feedwater heaters. The top problem areas are listed below:

- Normal and abnormal operating conditions — highest
- Tube plugging (leaks)
- Drain cooler zone level control
- Steam impingement desuperheat zone
- Tube vibration
- Steam impingement condensing zone
- Inlet end erosion
- Loss of impingement plates

Typically, plugged tubes do not become a concern with respect to thermal performance until the pluggage rate approaches 10%. This typically occurs after 15 to 25 years in service, as depicted in the following life cycle curve.

Figure 4-3 — Life Cycle of Heat Exchanger Tubing



Source: R. J. Bell and S. D. Strauss, "Advancing Heat Exchanger Reliability," *Power*, July 1991.

There is no record of any heater or heater tube replacements. Based on the vintage of the equipment, there is a high probability that feedwater heater tube replacements will be necessary to maintain the thermal efficiency of the units. E.ON US stated that the steam-side baffle plates have been damaged in all the heaters, which will require the replacement of these baffles. This work will require the entire tube bundles to be removed from the heater shell. With the heater bundles removed from the heater shells, the incremental cost of replacing all of the tubes is relatively low compared to selective tube replacements. The estimated cost of complete feedwater heater retubing and baffle replacements is $40,000 for each heater, for a total of $160,000 per unit.

Feedwater heater shell pressure relief valves should be replaced with factory-certified valves.

4.3.2 Feedwater Regulator Valves

The feedwater regulator (Bailey) valves are critical to drum level control. The valve trim may seize after extended idleness. The valves should be disassembled and inspected and then repaired and repacked. The estimated cost for valve refurbishment is $10,000 each.

4.3.3 Condenser

Each unit has a steam surface condenser containing 4,776 Admiralty tubes. There is no record of any tube replacements. As depicted in the preceding life cycle curve (Figure 4-3), tube pluggage rate affecting thermal performance typically occurs after 15 to 25 years in service. Based on the vintage of the equipment, there is a high probability that condenser tube replacements will be necessary to maintain thermal efficiency of the units. Typically, the condenser pressure is not significantly affected until the number of plugged tubes exceeds about 10% of the total. It appears that there is sufficient space between the condensers to allow for individual tube replacements. For each unit, S&L assumed that 25% of the tubes would be replaced at an estimated cost of $50,000 per unit.

If the tubes are not replaced, a condenser tube plug cleaning is recommended, followed by a steam space flooding to find tube leaks and plug defective tubes. The water box priming jets and the condenser steam space startup air ejector should be inspected and cleaned.

4.3.4 Circulating Water Intake and Piping

According the Tyrone Plant staff, the silt build-up at the river water intake has reduced the water withdrawal capacity by at least 50%. For Unit 1 and 2 to operate at full load, the intake area will need to be dredged. The estimated cost for the dredging and disposal of the spoils is $100,000. This assumes the Toxicity Characteristic Leachate Procedure determines that the spoils can be deposited on site.

The circulating water intake is a 72-inch pipe from the Kentucky River to the plant. There is no record of an inspection. Before return to service, an inspection of the intake piping is recommended. The estimated cost for inspection, excluding any necessary repairs, is $20,000.

Traveling screens at the circulating water intakes will require lubrication, and the backwash jets should be inspected and cleaned. Repair costs for these activities are estimated to be $10,000.

4.3.5 Service Water

The service water system piping, in particular the piping to supply bearing cooling water (filtered water) to the various plant rotating equipment, has reportedly been having plugging problems. Before return to service, an inspection of the service water system piping and strainers is recommended. The estimated cost for inspection and miscellaneous replacements is $25,000 per unit.

4.3.6 Summary

The potential costs for returning the water systems to service, including recommended and high probability items, are summarized below.

Table 4-5 —Estimated Costs for Returning the Water Systems to Service

Activity	Action	Estimated Cost
Circulating Water System	Required	$130,000
Service Water Piping	Required	Unit 1 $25,000 Unit 2 $25,000 Total $50,000
Feedwater Regulating Valve Reconditioning*	Required	Unit 1 $10,000 Unit 2 $10,000 Total $20,000
Feedwater Heater Tube Replacements*	High Probability	Unit 1 $175,000 Unit 2 $175,000 Total $350,000

Activity	Action	Estimated Cost
Condenser Tube Replacements	High Probability	Unit 1 $50,000 Unit 2 $50,000 Total $100,000
Total		$650,000

* Includes 10% cost adder for asbestos removal and disposal.

4.4 ELECTRICAL SYSTEMS

The main electrical power train of Tyrone consists of the 39,063-kVA generator delivering 13.8-kV power to generator step-up transformers in the open-air switchyard, where the voltage is increased to 69 kV for delivery to the grid. The switchyard has a 2,500-kVA reserve auxiliary transformer that is used for startup and as a backup to the 2,500-kVA main auxiliary transformers that are powered from the generator bus and used to supply the plant's 480-volt auxiliary motors and other 480-volt equipment. Underground cable connects the generator to the transformers in the switchyard.

4.4.1 Transformers and High-Voltage Circuit Breakers

4.4.1.1 Background

The original main generator step-up transformers were single phase with each phase sized for 12,500 kVA. In the early 1950s, a failure of one of the Unit 1 transformers resulted in its replacement by a three-phase transformer, which came from another plant. The "A" phase and "C" phase transformers were removed, but the "B" phase transformer was kept in place as a spare for Unit 2. The current arrangement of the transformers in the switchyard has the Unit 1, three-phase transformer at the north end of the yard. Next to it is the original Unit 1 "B" phase that is now an available spare for Unit 2 followed by the three-phase reserve transformer and the three single-phase main generator step-up transformers of Unit 2.

A 69-kV oil-filled circuit breaker is used to connect the main step-up transformers and the reserve auxiliary transformer to the 69-kV transmission system. The two auxiliary transformers are sitting just outside the boiler room with no fire walls or fire suppression system protecting the building adjacent to them.

Only the reserve auxiliary transformer is currently energized. It is being used to carry lighting services and some of the plant's other housekeeping loads in the buildings. The two de-energized unit auxiliaries are interconnected with the still-active Unit 3 through several 480-volt switchgear and motor control center (MCC) busses. This makes the reserve transformer a requirement for the still active unit.

Each of these main transformers is 60 years old, with the possible exception of the replacement transformer for Unit 1. This generator step-up transformer was not new when it was installed on Unit 1 and its exact age is not known, but it is likely that it is as old as or older than the other original transformers. Sixty years is well beyond the expected life of a power transformer, even with the light duty they were given over the past several years. In spite of the advanced age of the transformers, they could continue to be operated if they could be refurbished and tested out successfully.

4.4.1.2 Return to Service

The fact that the transformers have been de-energized and dormant for at least five years will require them to be completely checked out before they can be energized with any degree of confidence. The transformer oil will likely need to be reconditioned or replaced, as will the high-voltage circuit breaker oil. Bushing, gauges, and cabling on the equipment may also require replacement. Cabling, fans, and pumps will all likely require maintenance to get them into operating condition.

The transformers will also require a battery of insulation tests, starting with a basic megger test, as a prerequisite to other testing and to ensure there are no weak points that would cause the transformer to fail when energized. Other Doble or power factor testing, turns ratio testing, etc. will be needed to prove the transformer is in operable condition and can be energized safely.

4.4.1.3 Major Concerns

Each of the principal transformers and high-voltage circuit breakers identified above is critical to the operation of the unit to which it serves. A transformer or 69-kV breaker failure would result in a unit trip, which makes each of these transformers or oil-filled circuit breakers a critical item. The insulation systems deteriorate with age and the type of usage or loading the transformer has over its time in service.

From the testing of these transformers or breakers to bring them back into service, one could expect to find weak points in the insulation, the need to replace fans and coolers due to rusting and leakage at flanges, inter-turn shorts in the windings, and general deterioration of the transformer or breaker due to the effects of aging.

4.4.1.4 Summary

To put these transformers back into reliable service, the cost noted below may be incurred.

Table 4-6 — Estimated Costs for the Main and Auxiliary Transformers and High-Voltage Circuit Breakers

Activity	Action	Estimated Cost
Testing: Complete testing for power factor (pf), insulation resistance of windings and core, check bushings for pf and capacitance	Required	Unit 1 $25,000 Unit 2 $25,000
Oil Replacement: Replace or recondition oil in all transformers and oil filled breakers	Required	Unit 1 $25,000 Unit 2 $25,000
Equipment Replacement: New temperature devices, new bushings and fans on some transformers, new conservator tank for Unit 1 main power transformers	High Probability	Unit 1 $50,000 Unit 2 $30,000
Replace Unit 1 main power transformers and Unit 2 auxiliary transformer (Incremental of oil and equipment replacement costs)	High Probability	Unit 1 $370,000 Unit 2 $35,000
Replace Unit 2 main power transformer and Unit 1 auxiliary transformer (Incremental of oil and equipment replacement costs)	Potential	Unit 1 $35,000 Unit 2 $250,000
Total		$870,000

4.4.2 Generators

4.4.2.1 Background

Each unit has an identical hydrogen-cooled generator rated for 39,063 kVA at 30 psi of hydrogen. These generators have not been synchronized to the transmission system for several years, and they have not been inspected with the rotors out since the late 1970s. These old Westinghouse generators were quite hardy with a very simple excitation system that consisted of a small 2.5-kW dc pilot exciter feeding the field of a larger 125-kW dc main exciter. The main exciter's output to the generator's rotor windings is adjusted by a rheostat in its field circuit, which is controlled by a voltage regulator looking at generator output voltage. There is a spare exciter available on the turbine deck that can be used by any of the machines at the site.

4.4.2.2 Return to Service

The Rototrol Westinghouse excitation system will probably still be usable due to the simplicity of its design and equipment. Nevertheless, the insulation on the 60-year-old generator has lasted far beyond its expected life, which means the generator would not be considered reliable unless it were inspected and tested to show that it did not need to be rewound. Inspection and testing would have to be done to confirm this or to prove that the machine's condition is satisfactory enough to bring it back on line.

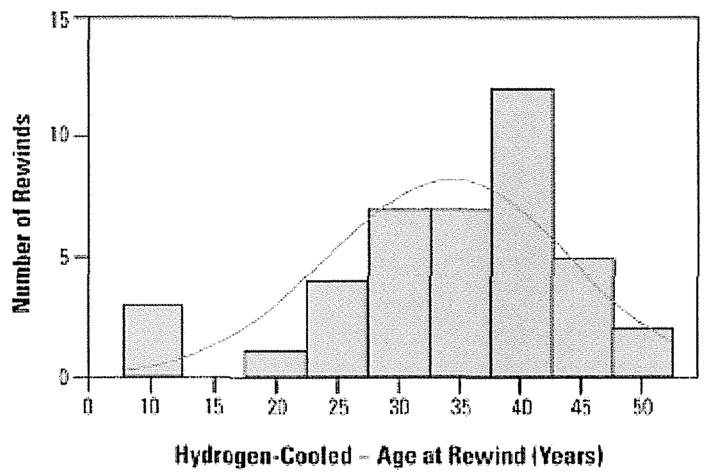
Older generators have other problems besides the aging of the insulation. Core distortion causing the laminated steel plates of the core to short and produce hot spots is also a likely possibility. Hydrogen seals at the generator bearings will need to be inspected and most likely repaired unless the generator is to be de-rated by eliminating the hydrogen and cooling the generator with air. This change would de-rate the unit by approximately 20%.

There is high probability that a generator of this age that has not been operated for five years could have a major failure if it is started-up without being inspected and overhauled. Before using this machine, the generator should be dismantled, the rotor pulled, overall inspections done, and a full battery of insulation testing performed, including a reduced-voltage hi pot, electromagnetic core imperfection detection (ELCID), rotor winding imbalance, and other dielectric tests.

4.4.2.3 Major Concerns

The biggest cost item that could result from the testing of the generator would be the rewinding of the rotor and stator. Stator rewinds for hydrogen-cooled generators are usually required between the 30- and 40-year age of the machine. Rotor rewinds usually occur several years sooner.

Figure 4-4 — Stator Rewinds



Source: GE Energy, GER – 4223, January 2004.

Without testing the machines, the integrity of the insulation is not known; however, given the age and time of the last inspection, it is reasonable to expect insulation deterioration to the point that a rewind would be required.

Cracks in the rotor are often found in older machines. Surface cracking on the rotor near the ends where it most often occurs requires machining and possibly longer retaining rings.

4.4.2.4 Summary

To put these generators back into service in a reliable condition, the following costs would likely be incurred.

Table 4-7 — Estimated Costs for the Generators

Activity (includes both units)	Action	Estimated Cost
Disassembly & Testing: Insulation resistance and PI on both rotor & stator, pf tip-up, ELCID, reduced hi-pot, boroscopic, dye penetrant	Required	Unit 1 $50,000 Unit 2 $50,000 Total $100,000
Hydrogen Seals: Replace or repair H_2 seals	Required	Unit 1 $25,000 Unit 2 $25,000 Total $50,000
Rotor Repair: Tooth cracking, retaining rings, rewind	High Probability	Unit 1 $750,000 Unit 2 $750,000 Total $1,500,000
Stator Repair: Rewedge and rewind stator windings	High Probability	Unit 1 $1,250,000 Unit 2 $1,250,000 Total $2,500,000
Coolers: Clean and retube	High Probability	Unit 1 $25,000 Unit 2 $25,000 Total $50,000
Miscellaneous: Replace seal oil vacuum pumps Replace eroded valves	Required	Unit 1 $25,000 Unit 2 $25,000 Total $50,000
Total		$4,250,000

4.4.3 Switchgear and Motor Control Centers

4.4.3.1 Background

The voltage system for the motors and other auxiliaries in the plant is 480 volts, which is fed from the two General Electric 13.8–0.480-kV auxiliary transformers with a backup from the GE, 69–0.480-kV reserve auxiliary transformer. The 480-volt switchgear is indoor, metal-clad, and rated at 4,000 amperes at 600 volts. It was manufactured by the ITE Corporation, which is no longer in business, but replacements parts are still available from third-party suppliers.

Some of the original ITE switchgear on Unit 3 has had its breakers replaced with a Square D design. Switchgear lineups in Units 1 and 2 are still energized because they have feeder breakers that are still associated with equipment in Unit 3.

The Unit 1 and 2 motor control centers (MCCs) do not have disconnects that would allow them to be individually isolated, as is currently required by E.ON US engineering standards. The coal handling system that currently supplies Unit 3 was originally designed for Unit 1and 2 and was expanded when Unit 3 was later built. As a result, some of the coal handling system for Unit 3 is controlled through MCCs located on Units 1 and 2. Lighting and other common systems that are used throughout the plant are also partially powered from the Unit 1 and 2 MCCs. E.ON US engineering personnel told S&L that these MCCs that are common to Unit 3 will be eventually replaced with new MCCs that meet current engineering standards.

4.4.3.2 Return to Service

Based on the age of the switchgear that will have to be used in the operation of Units 1 and 2 if they are restarted, cleaning and refurbishment will be required for the switchgear to have it operate up to its specified level.

Since all of the MCCs will need to be replaced to meet current E.ON US engineering standards, the cost estimate is based on replacing all of the Unit 1 and 2 MCCs.

4.4.3.3 Major Concerns

There is a concern for spare and replacement parts for some of the equipment. That has not been a major problem in the past, but parts could become more of a problem due to lack of OEM or alternative suppliers.

4.4.3.4 Summary

The estimated cost of switchgear and MCCs replacement and overhauls are listed below.

Table 4-8 — Estimated Costs for Switchgear and MCCs

Activity (includes both units)	Action	Estimated Cost
Cleaning and refurbishment of the 480 volt switchgear	High probability	Unit 1 $20,000 Unit 2 $20,000 Total $40,000
Replace and reinstall the four condenser pit MCCs	Required	Unit 1 $75,000 Unit 2 $70,000 Total $145,000
Replace and reinstall the twelve boiler MCCs	Required	Unit 1 $30,000 Unit 2 $20,000 Total $50,000
Replace and reinstall the four turbine MCCs	Required	Unit 1 $20,000 Unit 2 $15,000 Total $35,000
Total		$270,000

4.4.4 Cable and Raceways

4.4.4.1 Background

Okonite provided the majority of the cables for Unit 1, and General Cable was the cable supplier for Unit 2.

4.4.4.2 Return to Service

Since the majority of the cables at Tyrone have not been in use for several years, they should be inspected and tested for loose connections and deteriorated insulation.

Insulation resistance should be measured using a megger, and the cables should receive a reduced hi-pot test at the rated voltage for each cable. The insulation shield on the underground cables connecting the generators to the main and auxiliary transformers should be checked for continuity and for proper grounding. During the unit startup program, thermographic surveys should be done to detect hot areas caused by connections that have become loosened over time.

Meggering and hi-potting the cables for both units would cost anywhere from $50,000 to $100,000, depending on the results.

4.4.4.3 Major Concerns

A cable failure on major equipment could bring the unit down. Failure of large cables that are routed underground between the generator and the main transformers in the switchyard would create one of the most serious consequences.

4.4.4.4 Summary

The estimated costs for cable and raceways are listed below.

Table 4-9 — Estimated Costs for Cables and Raceways

Activity (includes both units)	Action	Estimated Cost
Megger and hi-pot cables. Clean and tighten connections. Do thermographic survey	Required	Unit 1 $50,000 Unit 2 $50,000 Total $100,000
Replace and reinstall 1800 feet of single conductor, 15 kV cable	High probability	Unit 1 $20,000 Unit 2 $20,000 Total $40,000
Replace 3 phase, 1 kV power cable	High probability	Unit 1 $100,000 Unit 2 $100,000 Total $200,000
Replace control and instrument cable	High probability	Unit 1 $50,000 Unit 2 $50,000 Total $100,000
Total		$440,000

4.4.5 Motors

The major motors for the two units have not been operated for at least five years, so they will require cleaning and meggering before they are put back into service. The majority of these motors are open drip proof, so moisture accumulation in them could be a problem. If all the motors were inspected and checked out as usable, the cost of the inspection and cleaning would range between $50,000 and $100,000.

4.4.5.1 Summary

The estimated costs for motor inspections and overhauls are as follows.

Table 4-10 — Estimated Costs for Motor Inspections and Overhauls

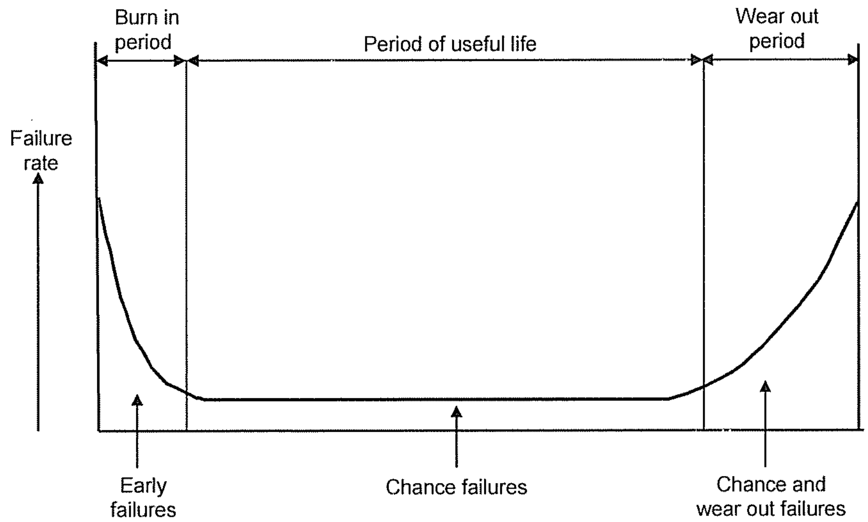
Activity (includes both units)	Action	Estimated Cost
Send out twenty two large, 460 volt motors on Unit 1for testing and cleaning Send out twenty large, 460 volt motors on Unit 2 for testing and cleaning	Required	Unit 1 $25,000 Unit 2 $20,000 Total $45,000
Inspect, megger and clean small 460 volt motors and dc motors	Required	Unit 1 $10,000 Unit 2 $10,000 Total $20,000
Total		$65,000

4.5 INSTRUMENTATION AND CONTROL SYSTEMS

4.5.1 Background

During the last 50 years, the instrumentation and control (I&C) systems evolved from the pneumatic in the 1950s, to analog in the 1960s, and finally to microprocessor-based and programmable logic controller (PLC) based systems beginning in the 1970s. The use of microprocessor-based or PLC-based depended on the type and scope of the application. Whenever a new generation of I&C systems is produced, spare parts of the preceding generations have limited availability and are expensive, if available. As such, many utilities have opted to replace I&C systems when they become obsolete. Another factor that affects the utility's decision is the life of the I&C systems. The typical mortality curve (Figure 4-5) for I&C system hardware indicates that their useful life is between 15 and 20 years. After that time, the hardware starts having high failure rates, which result in poor availability and high maintenance cost.

Figure 4-5 — Typical Mortality Curve for I&C System Hardware



4.5.2 Return to Service

The existing pneumatic systems for the boiler controls and monitoring are obsolete and have not been in service for a long time. It is likely that the many of the seals will need replacing and that internal controller parts will also need to be replaced. In many cases, these parts are not available from suppliers and must be manufactured in-house or through contracting to local machine shops. Therefore, to achieve the objective of returning the units to reliable service, the additions and/or upgrades discussed in the following subsections are recommended.

4.5.2.1 Boilers and Station Common Pneumatic Control System

The existing pneumatic systems for the boilers and station common should be replaced with PLC-based control systems. A total of three PLCs are recommended: one for Unit 1 boilers, one for Unit 2 boilers, and one for the station common (e.g., service water) systems. Each PLC would be provided with two central processing units (CPUs) and two power supply systems. Failure of any CPU and or power supply system would not cause the loss of the boilers and station common services control that are configured in the related PLC.

4.5.2.2 Field-Mounted Instruments

All field-mounted instruments used to provide the necessary indication for the units and station common services control and monitoring are recommended to be replaced. The new instruments would be electronic-type and would provide the 4-20 mA signals to the PLCs. Furthermore, because of the existing equipment age, it is recommended that all instrument tubing and valves between the instrument tap points and the instruments also be replaced.

4.5.2.3 Pump and Fan Motors and Motor-Operated Valves

The relay logic currently used for the control of pumps, fans, and the associated motors and for the motor-operated valves will be retained. However, the testing of the relay logic and the corresponding control switches and stations in the control room should be included in the commissioning and restart program.

4.5.2.4 Control Valves

The output signal from the PLCs to the control valves will be 4-to-20 mA dc. Therefore, electronic-to-pneumatic converters will be required for the interface with the PLCs.

4.5.2.5 FD Fan Inlet Vans

The pneumatic controller for the inlet vans of the four FD fan will be changed out to electric drives at a cost of $10,000 per fan.

4.5.2.6 Operator Interface

Three CRT-based operator stations are recommended for the boilers and station common services whose control logic is configured in the PLCs. The three stations would be configured such that each of them would have access to control any of the four boilers and the station common services. This configuration provides the necessary redundancy so that no one single failure would cause loss of access to the control of boilers and station common services.

4.5.3 Summary

The potential costs for returning the I&C systems to service are summarized in Table 4-11. These costs include the estimated installation costs.

Table 4-11 — Estimated Costs for Returning the I&C Systems to Service

Activity	Action	Estimated Cost
PLCs (Including the CRT-based Operator Stations)	Required	Unit 1 Boilers $120,000 Unit 2 Boilers $120,000 Station Common $80,000 Total $320,000
Field-Mounted Instruments (Based on 10 transmitters for each of the Unit 1 & 2 boilers and 15 transmitters for station common services)	Required	Unit 1 $40,000 Unit 2 $40,000 Station Common $60,000 Total $140,000
Control Valves Electric-to-Pneumatic Converters (Based on 6 control valves for each of the Unit 1 & 2 boilers and 10 control valves for station common services)	Required	Unit 1 $10,000 Unit 2 $10,000 Station Common $20,000 Total $40,000
FD Fan Control Drives	Required	Unit1 $10,000 Unit 2 $10,000 Total $20,000
Total		Unit 1 $180,000 Unit 2 $180,000 Station Common $160,000 Total $520,000

4.6 SAFETY EQUIPMENT

4.6.1 Fire Protection

To comply with National Fire Protection Association (NFPA) standards, it is recommended that fixed water-based fire protection be added to the following areas in the plant:

- Burner front for each boiler
- Turbine lube oil tank on each steam turbine
- Clean/dirty lube oil tanks

The estimated cost for a fire protection system is $250,000. The cost includes two new independent fire protection water supply pumps, as required by NFPA, and a fire protection control panel. Since the plant water supply system is not adequate for fire protection, a 250,000-gallon fire protection water storage tank (based on 2,000 gpm demand for two hours) will be required. The cost for the storage tank and interconnecting piping is estimated to be $500,000.

4.6.2 Burner Management Supervisory System

The Cohen Fyr-Monitor Supervisory Panel provides NFPA-code compliance for flame monitoring and burner operations that prevent furnace explosions. The pilot igniter proof-of-flame and the main fire flame scanner must be serviced and proven. Code-mandated trips and interlocks must be proven operational by exercising the related plant sensors to test the installed logic and wiring. In addition, OEM services may be required. The estimated expense for these activities is $80,000.

4.6.3 Summary

The estimated costs for safety equipment are summarized in Table 4-12.

Table 4-12 — Potential Costs for Safety Systems

Activity	Action	Estimated Cost
Install Fire Protection System per NFPA Standards	Potential	$750,000
Burner Management Maintenance	Required	$80,000
Total		$830,000

4.7 BALANCE-OF-PLANT SYSTEMS

4.7.1 Fuel Oil System

The existing fuel oil storage tank and underground piping is unlined and likely is not serviceable. The existing tank should be abandoned in place and replaced with a lined 500,000-gallon tank and above-ground piping. Replacing the tank and piping will require an $850,000 capital investment.

Oil guns and burner tips should be inspected and cleaned. Atomizing steam piping should be inspected and blown down with compressed air. Fuel oil and steam pressure regulating valves should be exercised and calibrated. Fuel oil pump mechanical seals should be inspected and reconditioned. The propane tank for the pilot igniters and the associated piping should be inspected for soundness.

Restoring the fuel oil system will require $20,000 per unit in expense.

4.7.2 Flue Gas System

Forced draft and induced draft fan rotors are prone to cracking at weld root lines. Sandblasting and NDE inspection for cracks should be performed. Cracks can usually be ground out and weld repaired. Testing and repair of the fans will cost $20,000 per unit.

Ductwork, expansion joints, the tubular air heaters including the internal expansion joints, and the abandoned hoppers associated with coal fly ash should be inspected for integrity and leakage. The estimated cost for inspection is $10,000 per unit. Based on the vintage of the units, there is a high probability a portion of the ductwork bracing and expansion joints will have to be replaced. An allocation of $70,000 per unit is included for the replacements.

Control and isolation vanes and dampers should be exercised and repaired as needed. An allocation of $5,000 per unit is included for minor repairs.

If the units are retired, the stack will have to have periodic inspections to verify structural integrity. In lieu of inspections, the stack can be removed. The estimated removal cost is $400,000, but the cost is dependent on the salvage value in effect at the time of removal. This cost is not included in the restart cost estimate.

4.7.3 Boiler Feed Pumps

Each unit has a motor-driven and a steam-turbine-driven boiler feed pump. Feed pumps have tight clearances at the impeller hub rings, and there is a danger that rust particles could accumulate in these tight spaces during extended shutdown. The pump casing should be opened, and the clearances measured and flushed if necessary. The shaft gear couplings must be cleaned and regreased to prevent seizure. If possible, suction strainers should be installed during initial startup.

Inspection and cleaning of the pumps will cost $10,000 per pump. Based on the vintage of the pumps, there is a high probability the pumps will need to be overhauled, at an estimated cost of $30,000 per pump.

The steam turbine drive must be opened for inspection at an estimated $20,000 expense. Based on the vintage of the steam turbine drive, there is a high probability that blade repairs and seal replacement are required, at an estimated cost of $50,000.

4.7.4 Other Rotating Equipment

Condensate, heater drain, and other low-pressure water pumps need to be drained and flushed, then repacked before operation.

The oil should be replaced in all equipment having bearing oil reservoirs, and all roller bearings should be greased before operation.

A sum of $30,000 should be allowed for inspection, repair, and lubrication of rotating equipment.

4.7.5 General

Before returning the plant to service, other activities associated with the plant equipment not previously discussed within this report will be required, the extent and cost of which will have to be evaluated. Based on the vintage of the units and the period of inactivity, certain equipment and components are suspect but, depending on the existing condition, will have to be evaluated case by case. Such equipment and components include the following

- Equipment gaskets and seals
- Instrument sensing lines
- Underground piping
- Stack and Liner

4.7.6 Summary

The estimated costs for balance-of-plant equipment are summarized in the following table.

Table 4-13 — Estimated Costs for Balance-of-Plant Systems

Activity	Action	Estimated Cost
Replace 500,000-gallon Storage Tank and Piping	Required	$850,000
Service Fuel Oil Firing Equipment	Required	Unit 1 $20,000 Unit 2 $20,000 $40,000
Flue Gas System Inspection*	Required	$25,000
Ductwork repairs and expansion joint replacements*	High Probability	Unit 1 $75,000 Unit 2 $75,000 $150,000
Control and isolation vanes and dampers repairs	High Probability	$10,000
FD and ID Fan Repairs	Required	Unit 1 $20,000 Unit 2 $20,000 $40,000
Boiler Feed Pump Inspections (3 pumps)	Required	$30,000
Turbine Drive Inspection	Required	$20,000
Miscellaneous Equipment Inspections	Required	$30,000
Boiler Feed Pumps Overhaul (3 pumps)	High Probability	$90,000
Turbine Drive Overhaul	High Probability	$50,000
Total Required and High Probability Items		$1,335,000

* Includes 10% cost adder for asbestos removal and disposal.

4.8 FACILITY AND EQUIPMENT SPARE PARTS

The infrequent operations of these units and the resulting long periods between major maintenance overhauls generally does not support a large inventory of spare parts beyond normal consumables and frequent maintenance items such as lubricants, chemicals, filters, and gaskets. A spare parts plan should be developed for these units if they are to remain in service. The plan should consider the use of available spare part inventories for Unit 3 and from other E.ON US generating units, as well as vendor supply programs. The I&C upgrades to PLC and digital field instrumentation will require some inventories of spare parts. The estimated costs for spare parts would be about $100,000.

Last page of Section 4

5. OPERATIONS AND TRAINING

The full-time plant staff at Tyrone has been significantly decreased from staffing levels of the 1970s when all three units were operated regularly. The current operating and maintenance staff is currently sized to meet the needs for operation of only Unit 3 and the common facilities required for operation of Unit 3. It is likely that additional operations and maintenance staff would be required to support operations of Units 1 and 2. In our discussions during the site visits, S&L was told that E.ON US would develop the staffing plans for Units 1 and 2. In developing the staffing plan, S&L recommends that E.ON US consider the potential reduction from previous staffing requirements for Units 1 and 2 if the I&C modifications described in Section 4.5 are implemented.

S&L was also told by E.ON US that many of the operators who had experience in the operations of Unit 1 and 2 have retired; therefore, a training program for the current operating staff would need to be conducted as part of the restart effort. As is generally done for startups of new generating units, the restart training program should begin with formal training sessions for the maintenance and operations staff. The objectives of this training would be to understand the purpose and function of each system and to understand proper operational and maintenance requirements of the equipment. Vendor support of this training will be required. In addition, adequate training of the new operators with the controls and instrumentation is essential. The operations staff would then provide operations support to the startup engineering team by operating the systems as they started-up and then operating the entire units through the startup testing. The startup team should include an operations supervisor with experience in operating units similar to Tyrone Units 1 and 2.

The restart of Units 1 and 2 should be managed similar to the startup of a new unit due to the many modifications and major maintenance activities. A formal startup plan should be developed that tests components individually and systems as a whole before first unit start. A startup team would consist of the plant staff that will operate and maintain the units along with experienced startup engineers. A process to turn over equipment from the control of the repair personnel to the control of operations would be established. Safety precautions are essential at all times during this turnover and startup of the systems. At some point of the startup timeline, it will be necessary to have the startup team working around the clock. Mechanical and electrical maintenance along with instrument technicians should be available with the operators on each shift during the startup to resolve problems.

The existing station startup procedures would be reviewed and revised by the startup team. The major changes to the procedures would be due to any I&C changes implemented. The sequence of events of the unit startup should be the same as before the renovation. In general terms, these steps would include the following:

- Establish and verify proper operation of auxiliary systems (i.e., compressed air, cooling water, fire protection, etc.)
- Establish and verify proper operation of feedwater / condensate/ circulating water systems
- Establish and verify proper operation of flue gas system
- Light off boiler and establish proper steam pressure and temperature
- Warm up and roll turbine
- Synchronize generator

The expense of the startup engineers would be an addition to the plant payroll costs. During the startup, it is expected that this shift will require two mechanics, two electricians, and one instrument mechanic. If the E.ON US staffing plan does not require this many permanent employees, additional costs will be incurred for contracted personnel during startup. The summary of costs for restart operations and training are listed in Table 5-1.

Table 5-1 — Estimated Costs for Restart Operations and Training

Activity	Estimated Cost
Startup Engineers (Planning, Training and Oversight)	$200,000
Vendor Training Support	$100,000
Total	$300,000

Last page of Section 5

6. RETURN-TO-SERVICE ACTIVITIES

The following tables summarize the estimated costs for inspections, maintenance, overhauls, upgrades, replacements, and other costs as developed in Sections 4 and 5 of this report. The costs are delineated into the following categories:

- **Required Activities.** Required to provide for safe operations and to achieve the Performance Targets.
- **High Probability Activities.** Probably will be required, subject to inspections and testing.
- **Potential Activities.** Possibly required, given the age and condition of the unit equipment.

Table 6-1 — Required Return-to-Service Activities

Plant Systems	Unit 1	Unit 2	Common	Total
Boilers and Appurtenances	$265,000	$265,000	$0	$530,000
Steam Turbine and Appurtenances	$500,000	$500,000	$0	$1,000,000
Water Systems	$35,000	$35,000	$130,000	$200,000
Transformers and Breakers	$50,000	$50,000	$0	$100,000
Generators	$100,000	$100,000	$0	$200,000
Switchgear and MCCs	$125,000	$105,000	$0	$230,000
Cables and Raceways	$50,000	$50,000	$0	$100,000
Motors	$35,000	$30,000	$0	$65,000
Instrumentation and Controls	$180,000	$180,000	$160,000	$520,000
Safety Systems	$0	$0	$80,000	$80,000
Balance of Plant	$40,000	$40,000	$955,000	$1,035,000
Restart Operations and Training	$0	$0	$300,000	$300,000
Totals	$1,380,000	$1,355,000	$1,625,000	$4,360,000

Table 6-2 — High-Probability Return-to-Service Activities

Plant Systems	Unit 1	Unit 2	Common	Total
Boilers and Appurtenances	$435,000	$435,000	$0	$870,000
Steam Turbine and Appurtenances	$525,000	$690,000	$0	$1,215,000
Water Systems	$225,000	$225,000	$0	$450,000
Transformers and Breakers	$420,000	$65,000	$0	$485,000
Generators	$2,025,000	$2,025,000	$0	$4,050,000
Switchgear and MCCs	$20,000	$20,000	$0	$40,000
Cables and Raceways	$170,000	$170,000	$0	$340,000
Motors	$0	$0	$0	$0
Instrumentation and Controls	$0	$0	$0	$0
Safety Systems	$0	$0	$0	$0
Balance of Plant	$75,000	$75,000	$150,000	$300,000
Restart Operations and Training	$0	$0	$0	$0
Totals	$3,895,000	$3,705,000	$150,000	$7,750,000

Table 6-3 — Potential Return-to-Service Activities

Plant Systems	Unit 1	Unit 2	Common	Total
Boilers and Appurtenances	$0	$0	$0	$0
Steam Turbine and Appurtenances	$1,500,000	$1,500,000	$0	$3,000,000
Water Systems	$0	$0	$0	$0
Transformers and Breakers	$35,000	$250,000	$0	$285,000
Generators	$0	$0	$0	$0
Switchgear and MCCs	$0	$0	$0	$0
Cables and Raceways	$0	$0	$0	$0
Motors	$0	$0	$0	$0
Instrumentation and Controls	$0	$0	$0	$0
Safety Systems	$0	$0	$750,000	$750,000
Balance of Plant	$0	$0	$0	$0
Restart Operations and Training	$0	$0	$0	$0
Totals	$1,535,000	$1,750,000	$750,000	$4,035,000

A projected schedule to return the units to service is shown in Table 6-4. The Phase II schedule is dependent on the findings of the Phase I NDE testing and the extent of work required. Equipment delivery lead times will also affect the Phase II duration. The subsequent unit startup and testing will require an additional 4 to 6 weeks per unit.

Table 6-4 — Return to Service Schedule

Task	Start Week	End Week
Phase I – NDE Testing	1	17
Phase II – Overhauls, Repairs, Replacements	17	35
Phase III – Startup	34	44

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7. MARKET VALUE OF EQUIPMENT

The resale value of the equipment at Tyrone is limited due to its age; nevertheless, there are sometimes buyers interested in vintage equipment if it meets a particular need they may have. Certain items such as the laminated steel core plates or copper windings of the generators and transformers have salvage value due to the high quality of the commodity. In addition, pulp mills and sugar refiners in South and Central America have been known to use older power plant equipment to operate their mills.

The integral arrangement of the three units as far as lighting and internal power distribution prevents the removal of some of the switchgear, MCCs, and housekeeping equipment. Steel contained in the stacks, boilers, and building structure will most likely have less value than its removal cost. For a power plant as old as Tyrone, large transformers and generators would have the best market value of equipment and commodities should the plant be retired. The following asset recovery estimate table was prepared for Tyrone:

Table 7-1 — Tyrone Asset Recovery Estimate

Equipment	Description	Estimated net tons	Scrap	Salvage	Re-use
Generator with exciter	Westinghouse 39,063 kVA, 30# H2, 13.8 kV, 3600 rpm	110	$22,000	$44,000	$77,000
Generator with exciter	Westinghouse 39,063 kVA, 30# H2, 13.8 kV, 3600 rpm	110	$22,000	$44,000	$77,000
Transformer, Main Power	3-phase, 13.8kV – 69 kV ≈ 30 MVA	40	$7,600	$19,000	$30,400
Transformer, Main Power	1-phase, 13.2 kV – 39.83 kV, 12.5 MVA	15	$3,000	$6,000	$10,000
Transformer, Main Power	1-phase, 13.2 kV – 39.83 kV, 12.5 MVA	15	$3,000	$6,000	$10,000
Transformer, Main Power	1-phase, 13.2 kV – 39.83 kV, 12.5 MVA	15	$3,000	$6,000	$10,000
Transformer, Main Power	1-phase, 13.2 kV – 39.83 kV, 12.5 MVA	15	$3,000	$6,000	$10,000
Transformer, Aux Power	3-phase, 13.2 kV – 0.48 kV, 2.5 MVA	5	$1,000	$2,000	$3,500
Transformer, Aux Power	3-phase, 13.2 kV – 0.48 kV, 2.5 MVA	5	$1,000	$2,000	$3,500
Total		330	$65,600	$135,000	$233,400

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