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Exhibit WEA-1

WILLIAM E. AVERA

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Financial Concepts and Applications
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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, 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 (88 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)

"On the Use of Security Analysts' Growth Projections in the DCF Model," with Bruce H. Fairchild in *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds. Institute for Study of Regulation (1982)

An Examination of the Concept of Using Relative Customer Class Risk to Set Target Rates of Return in Electric Cost-of-Service Studies, with Bruce H. Fairchild, Electricity Consumers Resource Council (ELCON) (1981); portions reprinted in *Public Utilities Fortnightly* (Nov. 11, 1982)

"Usefulness of Current Values to Investors and Creditors," *Research Study on Current-Value Accounting Measurements and Utility*, George M. Scott, ed., Touche Ross Foundation (1978)

"The Geometric Mean Strategy and Common Stock Investment Management," with Henry A. Latané in *Life Insurance Investment Policies*, David Cummins, ed. (1977)

Investment Companies: Analysis of Current Operations and Future Prospects, with J. Finley Lee and Glenn L. Wood, American College of Life Underwriters (1975)

Articles

"Should Analysts Own the Stocks they Cover?" *The Financial Journalist*, (March 2002)

"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)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

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

"Asymmetric Discounting of Information and Relative Liquidity: Some Empirical Evidence for Common Stocks" (with John Groth and Kerry Cooper), Southern Finance Association, New Orleans (Nov. 1982)

"Used and Useful Planning Models," Planning Executive Institute, 27th Corporate Planning Conference, Los Angeles (Nov. 1979)

"Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York (Oct. 1979)

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

"The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta (Nov. 1977)

"An ANOVA Representation of Common Stock Returns as a Framework for the Allocation of Portfolio Management Effort," with Charles G. Martin, Financial Management Association, Montreal (Oct. 1976)

"A Growth-Optimal Portfolio Selection Model with Finite Horizon," with Henry A. Latané, American Finance Association, San Francisco (Dec. 1974)

"An Optimal Approach to the Finance Decision," with Henry A. Latané, Southern Finance Association, Atlanta (Nov. 1974)

"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)	(b)	(g)	(g)	(g)	(g)	(g)	(g)
		Dividend Yield			Growth Rates						Cost of Equity Estimates					
	Company	Price	Dividends	Yield	V Line	IBES	First Call	Zacks	br+sv	Price	V Line	IBES	First Call	Zacks	br+sv	Price
1	ALLETE	$ 34.01	$ 1.78	5.2%	-1.0%	4.0%	4.0%	4.0%	5.3%	4.1%	4.2%	9.2%	9.2%	9.2%	10.5%	9.4%
2	Alliant Energy	$ 30.49	$ 1.60	5.2%	4.0%	4.3%	4.0%	3.0%	4.2%	7.0%	9.2%	9.5%	9.2%	8.2%	9.4%	12.3%
3	Consolidated Edison	$ 45.03	$ 2.36	5.2%	3.0%	3.4%	4.0%	3.6%	3.7%	2.7%	8.2%	8.6%	9.2%	8.8%	8.9%	7.9%
4	Dominion Resources	$ 39.25	$ 1.87	4.8%	8.0%	5.2%	4.0%	5.0%	8.7%	8.8%	12.8%	10.0%	8.8%	9.8%	13.5%	13.6%
5	Duke Energy Corp.	$ 17.65	$ 0.98	5.6%	5.0%	3.6%	4.0%	4.3%	1.9%	5.1%	10.6%	9.2%	9.6%	9.9%	7.5%	10.6%
6	Entergy Corp.	$ 83.00	$ 3.00	3.6%	6.0%	6.8%	5.0%	4.7%	6.9%	7.3%	9.6%	10.4%	8.6%	8.3%	10.5%	10.9%
7	Exelon Corp.	$ 51.05	$ 2.10	4.1%	4.5%	2.2%	1.0%	2.0%	9.2%	7.2%	8.6%	6.3%	5.1%	6.1%	13.3%	11.3%
8	PG&E Corp.	$ 45.14	$ 1.77	3.9%	6.5%	7.3%	7.6%	7.7%	6.7%	1.3%	10.4%	11.2%	11.5%	11.6%	10.6%	5.2%
9	Progress Energy	$ 41.51	$ 2.48	6.0%	6.0%	4.5%	4.5%	4.5%	3.2%	0.6%	12.0%	10.5%	10.5%	10.5%	9.1%	6.6%
10	SCANA Corp.	$ 37.49	$ 1.92	5.1%	4.0%	5.8%	5.5%	5.0%	5.9%	6.1%	9.1%	10.9%	10.6%	10.1%	11.1%	11.2%
11	Sempra Energy	$ 55.47	$ 1.68	3.0%	5.5%	7.0%	7.0%	7.0%	8.3%	10.4%	8.5%	10.0%	10.0%	10.0%	11.3%	13.5%
12	Vectren Corp.	$ 24.81	$ 1.36	5.5%	5.0%	6.3%	6.0%	7.5%	3.7%	4.9%	10.5%	11.8%	11.5%	13.0%	9.2%	10.3%
13	Wisconsin Energy	$ 47.87	$ 1.55	3.2%	8.0%	9.9%	10.0%	8.3%	6.4%	7.9%	11.2%	13.1%	13.2%	11.5%	9.6%	11.2%
14	Xcel Energy, Inc.	$ 21.48	$ 1.00	4.7%	6.5%	7.3%	7.1%	5.7%	4.9%	0.6%	11.2%	12.0%	11.8%	10.4%	9.6%	5.3%
	Average (h)										**10.2%**	**10.5%**	**10.3%**	**10.1%**	**10.5%**	**11.4%**

(a) Recent price and estimated dividend for next 12 mos. from The Value Line Investment Survey, *Summary and Index* (Nov. 6, 2009).
(b) The Value Line Investment Survey (Nov. 6, Nov. 27, & Dec. 25, 2009).
(c) *Thomson ReutersCompany Report* (Dec. 21, 2009).
(d) *First Call Earnings Valuation Report* (Dec. 22, 2009).
(e) www.zacks.com (retrieved Dec. 22, 2009).
(f) See Exhibit WEA-3.
(g) Sum of dividend yield and respective growth rate.
(h) Excludes highlighted figures.

UTILITY PROXY GROUP

	Company	High (a)	Low (a)	Avg. (b)	EPS (a)	DPS (a)	BVPS (a)	b (c)	r (d)
		2012-14 Market Price			2012-14 Projections				
1	ALLETE	45.00	35.00	$40.00	$2.75	$1.90	$28.25	30.9%	9.7%
2	Alliant Energy	45.00	35.00	$40.00	$3.10	$1.92	$31.05	38.1%	10.0%
3	Consolidated Edison	55.00	45.00	$50.00	$3.85	$2.44	$41.05	36.6%	9.4%
4	Dominion Resources	65.00	45.00	$55.00	$4.00	$2.20	$26.00	45.0%	15.4%
5	Duke Energy Corp.	25.00	18.00	$21.50	$1.40	$1.10	$17.25	21.4%	8.1%
6	Entergy Corp.	125.00	95.00	$110.00	$8.00	$3.60	$57.50	55.0%	13.9%
7	Exelon Corp.	75.00	60.00	$67.50	$5.00	$2.40	$26.25	52.0%	19.0%
8	PG&E Corp.	55.00	40.00	$47.50	$4.25	$2.20	$35.75	48.2%	11.9%
9	Progress Energy	50.00	35.00	$42.50	$3.60	$2.56	$36.80	28.9%	9.8%
10	SCANA Corp.	55.00	40.00	$47.50	$3.50	$2.10	$33.25	40.0%	10.5%
11	Sempra Energy	95.00	70.00	$82.50	$6.00	$2.10	$51.25	65.0%	11.7%
12	Vectren Corp.	35.00	25.00	$30.00	$2.20	$1.50	$20.50	31.8%	10.7%
13	Wisconsin Energy	75.00	55.00	$65.00	$4.50	$2.15	$38.00	52.2%	11.8%
14	Xcel Energy, Inc.	25.00	19.00	$22.00	$2.00	$1.10	$19.00	45.0%	10.5%

SUSTAINABLE GROWTH RATE

UTILITY PROXY GROUP

		(a)	(a)	(e)	(a)	(a)	(e)	(f)	(g)	(h)
		2008			2012-14			Adjusted "r"		
	Company	BVPS	No. Shares	Common Equity	BVPS	No. Shares	Common Equity	Chg in Equity	Adj. Factor	Adj. r
1	ALLETE	$25.37	32.60	$827	$28.25	42.00	$1,187	7.5%	1.0361	10.1%
2	Alliant Energy	$25.56	110.45	$2,823	$31.05	116.00	$3,602	5.0%	1.0244	10.2%
3	Consolidated Edison	$35.43	273.72	$9,698	$41.05	285.00	$11,699	3.8%	1.0188	9.6%
4	Dominion Resources	$17.28	583.20	$10,078	$26.00	623.00	$16,198	10.0%	1.0474	16.1%
5	Duke Energy Corp.	$16.50	1,272.00	$20,988	$17.25	1315.00	$22,684	1.6%	1.0078	8.2%
6	Entergy Corp.	$42.07	189.36	$7,966	$57.50	180.00	$10,350	5.4%	1.0262	14.3%
7	Exelon Corp.	$16.79	658.00	$11,048	$26.25	635.00	$16,669	8.6%	1.0411	19.8%
8	PG&E Corp.	$25.97	361.06	$9,377	$35.75	400.00	$14,300	8.8%	1.0422	12.4%
9	Progress Energy	$32.55	264.00	$8,593	$36.80	288.00	$10,598	4.3%	1.0210	10.0%
10	SCANA Corp.	$25.81	118.00	$3,046	$33.25	141.00	$4,688	9.0%	1.0431	11.0%
11	Sempra Energy	$32.75	243.32	$7,969	$51.25	250.00	$12,813	10.0%	1.0475	12.3%
12	Vectren Corp.	$16.68	81.03	$1,352	$20.50	83.00	$1,702	4.7%	1.0230	11.0%
13	Wisconsin Energy	$28.54	116.92	$3,337	$38.00	117.00	$4,446	5.9%	1.0287	12.2%
14	Xcel Energy, Inc.	$15.35	453.79	$6,966	$19.00	464.00	$8,816	4.8%	1.0236	10.8%

UTILITY PROXY GROUP

	Company	(a) 2008	(a) 2012-14	(f) Change	(i) M/B Ratio	(j) s	(k) v	(l) sv	(m) br + sv
		Common Shares Outstanding				"sv" Factor			
1	ALLETE	32.6	42.0	5.20%	1.42	0.0736	0.2938	2.16%	5.3%
2	Alliant Energy	110.5	116.0	0.99%	1.29	0.0127	0.2238	0.28%	4.2%
3	Consolidated Edison	273.7	285.0	0.81%	1.22	0.0099	0.1790	0.18%	3.7%
4	Dominion Resources	583.2	623.0	1.33%	2.12	0.0281	0.5273	1.48%	8.7%
5	Duke Energy Corp.	1,272.0	1,315.0	0.67%	1.25	0.0083	0.1977	0.16%	1.9%
6	Entergy Corp.	189.4	180.0	-1.01%	1.91	(0.0193)	0.4773	-0.92%	6.9%
7	Exelon Corp.	658.0	635.0	-0.71%	2.57	(0.0182)	0.6111	-1.11%	9.2%
8	PG&E Corp.	361.1	400.0	2.07%	1.33	0.0275	0.2474	0.68%	6.7%
9	Progress Energy	264.0	288.0	1.76%	1.15	0.0203	0.1341	0.27%	3.2%
10	SCANA Corp.	118.0	141.0	3.63%	1.43	0.0518	0.3000	1.55%	5.9%
11	Sempra Energy	243.3	250.0	0.54%	1.61	0.0087	0.3788	0.33%	8.3%
12	Vectren Corp.	81.0	83.0	0.48%	1.46	0.0070	0.3167	0.22%	3.7%
13	Wisconsin Energy	116.9	117.0	0.01%	1.71	0.0002	0.4154	0.01%	6.4%
14	Xcel Energy, Inc.	453.8	464.0	0.45%	1.16	0.0052	0.1364	0.07%	4.9%

(a) The Value Line Investment Survey (Nov. 6, Nov. 27, & Dec. 25, 2009).
(b) Average of High and Low expected market prices.
(c) Computed at (EPS - DPS) / EPS.
(d) Computed as EPS / BVPS.
(e) Product of BVPS and No. Shares Outstanding.
(f) Five-year rate of change.
(g) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(h) Product of year-end "r" for 2012-14 and Adjustment Factor.
(i) Average of High and Low expected market prices divided by 2012-14 BVPS.
(j) Product of change in common shares outstanding and M/B Ratio.
(k) Computed as 1 - B/M Ratio.
(l) Product of "s" and "v".
(m) Product of average "b" and adjusted "r", plus "sv".

NON-UTILITY PROXY GROUP

		(a)	(b)	(c)	(d)	(e)	(a)	(f)	(f)	(f)	(f)	(f)	(f)
		Growth Rates						Cost of Equity Estimates					
	Company	V Line	IBES	First Call	Zacks	br+sv	Price	V Line	IBES	First Call	Zacks	br+sv	Price
1	3M Company	5.0%	12.1%	12.5%	11.6%	15.8%	10.4%	7.5%	14.6%	15.0%	14.1%	18.4%	12.9%
2	Abbott Labs.	10.0%	11.5%	12.0%	10.8%	13.6%	15.7%	13.0%	14.5%	15.0%	13.8%	16.6%	18.7%
3	Alberto-Culver	14.5%	11.7%	12.5%	12.5%	8.0%	7.6%	15.7%	12.9%	13.7%	13.7%	9.2%	8.8%
4	Allergan, Inc.	14.0%	13.0%	13.3%	15.2%	19.2%	15.6%	14.3%	13.3%	13.6%	15.5%	19.5%	16.0%
5	AT&T Inc.	5.0%	5.9%	5.0%	5.9%	5.9%	13.0%	11.2%	12.1%	11.2%	12.1%	12.0%	19.2%
6	Automatic Data Proc.	10.0%	11.8%	12.0%	11.4%	9.8%	15.8%	13.2%	15.0%	15.2%	14.6%	13.1%	19.0%
7	Bard (C.R.)	12.5%	13.6%	13.9%	13.4%	13.4%	14.4%	13.3%	14.4%	14.7%	14.2%	14.3%	15.2%
8	Baxter Int'l Inc.	14.0%	11.5%	11.5%	11.5%	15.1%	15.4%	16.0%	13.5%	13.5%	13.5%	17.1%	17.4%
9	Becton, Dickinson	11.5%	11.3%	11.0%	11.4%	12.1%	12.3%	13.5%	13.3%	13.0%	13.4%	14.0%	14.3%
10	Bemis Co.	4.5%	7.0%	7.0%	8.0%	9.3%	8.9%	7.5%	10.0%	10.0%	11.0%	12.3%	11.9%
11	Bristol-Myers Squibb	9.0%	2.5%	3.0%	7.1%	5.5%	11.7%	13.8%	7.3%	7.8%	11.9%	10.3%	16.5%
12	Brown-Forman 'B'	7.0%	13.0%	13.0%	NA	12.2%	9.2%	9.3%	15.3%	15.3%	NA	14.5%	11.4%
13	Cardinal Health	-2.5%	6.6%	10.0%	10.1%	7.6%	10.8%	-0.2%	8.9%	12.3%	12.4%	9.8%	13.1%
14	Chevron Corp.	5.0%	NA	NA	9.0%	17.5%	12.1%	8.5%	NA	NA	12.5%	21.0%	15.7%
15	Chubb Corp.	3.0%	8.0%	8.5%	7.7%	9.1%	12.4%	5.9%	10.9%	11.4%	10.6%	12.0%	15.3%
16	Coca-Cola	6.5%	9.0%	9.0%	8.9%	11.1%	11.1%	9.6%	12.1%	12.1%	12.0%	14.2%	14.2%
17	Colgate-Palmolive	11.5%	9.0%	10.0%	9.8%	19.5%	13.9%	13.7%	11.2%	12.2%	12.0%	21.7%	16.2%
18	Commerce Bancshs.	5.0%	6.5%	6.5%	6.5%	8.2%	3.5%	7.4%	8.9%	8.9%	8.9%	10.5%	5.9%
19	ConAgra Foods	11.5%	8.6%	9.0%	9.0%	5.9%	12.2%	15.1%	12.2%	12.6%	12.6%	9.5%	15.8%
20	ConocoPhillips	3.0%	-8.8%	-5.6%	3.1%	17.4%	21.1%	7.0%	-4.8%	-1.6%	7.1%	21.3%	25.1%
21	Costco Wholesale	6.0%	13.2%	13.0%	13.5%	8.8%	6.1%	7.3%	14.5%	14.3%	14.8%	10.1%	7.4%
22	CVS Caremark Corp.	10.5%	11.8%	14.0%	13.1%	7.7%	19.6%	11.5%	12.8%	15.0%	14.1%	8.7%	20.6%
23	Disney (Walt)	12.0%	6.3%	6.5%	9.0%	9.6%	20.1%	13.2%	7.5%	7.7%	10.2%	10.8%	21.3%
24	Du Pont	0.0%	5.5%	5.5%	9.3%	4.7%	14.6%	5.2%	10.7%	10.7%	14.5%	9.9%	19.8%
25	Eaton Corp.	-1.5%	10.1%	11.3%	9.7%	7.6%	11.1%	1.6%	13.2%	14.4%	12.8%	10.7%	14.2%
26	Ecolab Inc.	11.5%	13.2%	13.0%	13.3%	22.9%	7.2%	12.9%	14.6%	14.4%	14.7%	24.2%	8.6%
27	Emerson Electric	4.5%	11.5%	10.0%	10.8%	7.8%	10.6%	7.8%	14.8%	13.3%	14.1%	11.1%	13.9%
28	Everest Re Group Ltd.	5.0%	7.5%	7.5%	10.0%	10.7%	13.1%	7.3%	9.8%	9.8%	12.3%	13.0%	15.4%
29	Exxon Mobil Corp.	3.5%	2.8%	3.5%	6.7%	14.6%	10.3%	6.0%	5.3%	6.0%	9.2%	17.1%	12.8%
30	Gen'l Dynamics	11.0%	7.8%	8.0%	10.1%	12.9%	18.2%	13.4%	10.2%	10.4%	12.5%	15.2%	20.6%
31	Gen'l Mills	9.0%	9.1%	8.5%	7.7%	6.2%	9.4%	11.8%	11.9%	11.3%	10.5%	9.0%	12.2%
32	Grainger (W.W.)	6.5%	11.0%	12.0%	11.0%	6.9%	9.2%	8.5%	13.0%	14.0%	13.0%	8.9%	11.2%
33	Heinz (H.J.)	6.5%	6.9%	8.0%	8.0%	15.9%	12.2%	10.6%	11.0%	12.1%	12.1%	20.0%	16.3%
34	Hewlett-Packard	9.0%	10.0%	10.0%	15.5%	10.6%	11.2%	9.6%	10.6%	10.6%	16.1%	11.2%	11.8%
35	Home Depot	1.5%	9.6%	9.5%	11.2%	9.9%	9.7%	4.6%	12.7%	12.6%	14.3%	13.0%	12.8%
36	Honeywell Int'l	4.0%	8.9%	10.0%	9.2%	11.6%	13.0%	7.1%	12.0%	13.1%	12.3%	14.7%	16.0%
37	Hormel Foods	10.5%	10.0%	10.0%	9.3%	10.1%	16.5%	12.7%	12.2%	12.2%	11.5%	12.4%	18.8%
38	Illinois Tool Works	3.0%	3.3%	2.6%	9.0%	9.9%	7.1%	5.6%	5.9%	5.2%	11.6%	12.5%	9.7%
39	Int'l Business Mach.	10.5%	9.4%	10.0%	13.6%	10.6%	13.9%	12.3%	11.2%	11.8%	15.4%	12.4%	15.7%
40	Intel Corp.	10.0%	11.1%	10.0%	11.2%	15.1%	15.8%	13.3%	14.4%	13.3%	14.5%	18.4%	19.1%

NON-UTILITY PROXY GROUP

		(a)	(b)	(c)	(d)	(e)	(a)	(f)	(f)	(f)	(f)	(f)	(f)
		Growth Rates						Cost of Equity Estimates					
	Company	V Line	IBES	First Call	Zacks	br+sv	Price	V Line	IBES	First Call	Zacks	br+sv	Price
41	ITT Corp.	7.5%	6.8%	5.0%	10.0%	13.4%	12.5%	9.2%	8.5%	6.7%	11.7%	15.1%	14.2%
42	Johnson & Johnson	7.5%	7.4%	7.0%	7.4%	10.8%	12.6%	10.6%	10.5%	10.1%	10.5%	13.9%	15.7%
43	Kellogg	9.0%	10.4%	9.0%	9.1%	21.3%	11.2%	11.9%	13.3%	11.9%	12.0%	24.2%	14.1%
44	Kimberly-Clark	6.0%	11.0%	11.0%	9.5%	23.2%	11.0%	9.8%	14.8%	14.8%	13.3%	26.9%	14.8%
45	Kraft Foods	6.5%	9.1%	9.1%	14.1%	4.7%	13.4%	10.8%	13.4%	13.4%	18.4%	9.0%	17.7%
46	Lilly (Eli)	5.0%	1.3%	2.2%	3.8%	17.6%	19.6%	10.7%	7.0%	7.9%	9.5%	23.3%	25.3%
47	Lockheed Martin	11.5%	9.1%	9.5%	9.1%	19.8%	25.9%	14.8%	12.4%	12.8%	12.4%	23.1%	29.2%
48	McCormick & Co.	8.5%	10.0%	20.0%	10.0%	13.2%	11.9%	11.4%	12.9%	22.9%	12.9%	16.1%	14.8%
49	McDonald's Corp.	10.0%	9.4%	9.0%	9.1%	6.2%	8.9%	13.6%	13.0%	12.6%	12.7%	9.8%	12.5%
50	McKesson Corp.	9.0%	11.3%	13.0%	12.0%	12.2%	5.8%	9.8%	12.1%	13.8%	12.8%	12.9%	6.6%
51	Medtronic, Inc.	10.5%	11.0%	11.0%	11.2%	11.7%	22.3%	12.4%	12.9%	12.9%	13.1%	13.7%	24.3%
52	Microsoft Corp.	10.0%	11.0%	11.0%	11.2%	5.0%	13.1%	12.0%	13.0%	13.0%	13.2%	6.9%	15.1%
53	NIKE, Inc. 'B'	9.5%	12.6%	15.0%	11.9%	11.8%	9.6%	11.2%	14.3%	16.7%	13.6%	13.6%	11.3%
54	Northrop Grumman	9.5%	9.2%	10.0%	9.2%	9.6%	21.5%	12.8%	12.5%	13.3%	12.5%	12.9%	24.8%
55	Oracle Corp.	11.5%	12.8%	12.5%	13.1%	8.8%	18.2%	12.4%	13.7%	13.4%	14.0%	9.7%	19.0%
56	PepsiCo, Inc.	8.5%	10.8%	10.8%	10.0%	14.0%	14.3%	11.5%	13.8%	13.8%	13.0%	17.0%	17.3%
57	Pfizer, Inc.	-4.0%	1.5%	1.9%	-0.7%	5.9%	1.8%	-0.1%	5.5%	5.9%	3.3%	9.8%	5.7%
58	Procter & Gamble	7.0%	9.3%	10.0%	8.0%	8.5%	13.5%	9.9%	12.2%	12.9%	10.9%	11.4%	16.4%
59	Raytheon Co.	13.0%	9.0%	9.0%	9.3%	9.3%	17.6%	15.5%	11.5%	11.5%	11.8%	11.8%	20.1%
60	Sigma-Aldrich	10.0%	9.0%	9.0%	8.0%	18.1%	8.7%	11.1%	10.1%	10.1%	9.1%	19.2%	9.8%
61	Stryker Corp.	12.0%	10.7%	10.4%	11.7%	13.7%	20.8%	13.2%	11.9%	11.6%	12.9%	14.9%	22.0%
62	Sysco Corp.	7.0%	15.0%	15.0%	15.0%	9.4%	9.9%	10.8%	18.8%	18.8%	18.8%	13.1%	13.7%
63	TJX Companies	13.5%	12.4%	12.0%	12.5%	14.3%	11.4%	14.8%	13.7%	13.3%	13.8%	15.6%	12.7%
64	United Parcel Serv.	1.5%	7.9%	12.0%	11.7%	16.2%	12.3%	4.6%	11.0%	15.1%	14.8%	19.3%	15.4%
65	United Technologies	8.0%	10.2%	10.0%	8.7%	14.5%	14.8%	10.2%	12.4%	12.2%	10.9%	16.7%	17.0%
66	Verizon Communic.	4.0%	4.6%	4.0%	5.3%	5.9%	13.6%	9.8%	10.4%	9.8%	11.1%	11.7%	19.4%
67	Wal-Mart Stores	9.5%	11.8%	11.0%	11.5%	8.6%	14.3%	11.7%	14.0%	13.2%	13.7%	10.8%	16.4%
68	Walgreen Co.	10.0%	14.2%	15.0%	14.3%	10.9%	12.2%	11.5%	15.7%	16.5%	15.8%	12.3%	13.7%
69	Waste Management	5.5%	9.8%	10.1%	11.0%	6.4%	6.3%	9.2%	13.5%	13.8%	14.7%	10.1%	10.0%
	Average (g)							**12.0%**	**12.6%**	**12.8%**	**12.7%**	**12.2%**	**13.7%**

(a) www.valueline.com (retrieved Dec. 24, 2009).
(b) Thomson Reuters, *Company in Context Report* (Dec. 23, 2009).
(c) *First Call Earnings Valuation Report* (Dec. 24, 2009).
(d) www.zacks.com (retrieved Dec. 24, 2009).
(e) See Exhibit WEA-5.
(f) Sum of dividend yield and respective growth rate.
(g) Excludes highlighted figures.

SUSTAINABLE GROWTH RATE

NON-UTILITY PROXY GROUP

		(a)	(a)	(b)	(a)	(a)	(a)	(c)	(d)
		2012-14 Market Price			2012-14 Projections				
	Company	High	Low	Avg.	EPS	DPS	BVPS	b	r
1	3M Company	$120.00	$100.00	$110.00	$6.90	$2.26	$29.35	67.2%	23.5%
2	Abbott Labs	$100.00	$80.00	$90.00	$5.00	$2.18	$21.95	56.4%	22.8%
3	Alberto-Culver	$45.00	$35.00	$40.00	$2.00	$0.45	$16.30	77.5%	12.3%
4	Allergan, Inc.	$110.00	$90.00	$100.00	$4.35	$0.25	$24.20	94.3%	18.0%
5	AT&T Inc.	$50.00	$40.00	$45.00	$3.25	$2.00	$22.05	38.5%	14.7%
6	Automatic Data Proc	$85.00	$70.00	$77.50	$3.30	$1.60	$20.75	51.5%	15.9%
7	Bard (C.R.)	$155.00	$125.00	$140.00	$7.80	$0.94	$39.25	87.9%	19.9%
8	Baxter Int'l Inc.	$105.00	$90.00	$97.50	$6.10	$1.60	$20.00	73.8%	30.5%
9	Becton, Dickinson	$130.00	$105.00	$117.50	$7.35	$1.90	$38.85	74.1%	18.9%
10	Bemis Co.	$40.00	$35.00	$37.50	$2.25	$1.04	$16.90	53.8%	13.3%
11	Bristol-Myers Squibb	$40.00	$30.00	$35.00	$1.95	$1.40	$10.25	28.2%	19.0%
12	Brown-Forman 'B'	$75.00	$65.00	$70.00	$4.10	$1.24	$22.05	69.8%	18.6%
13	Cardinal Health	$50.00	$45.00	$47.50	$2.80	$1.00	$23.65	64.3%	11.8%
14	Chevron Corp	$140.00	$110.00	$125.00	$12.50	$3.00	$53.15	76.0%	23.5%
15	Chubb Corp.	$85.00	$70.00	$77.50	$7.00	$1.60	$57.85	77.1%	12.1%
16	Coca-Cola	$90.00	$75.00	$82.50	$3.85	$2.12	$16.40	44.9%	23.5%
17	Colgate-Palmolive	$140.00	$115.00	$127.50	$6.30	$2.50	$17.70	60.3%	35.6%
18	Commerce Bancshs.	$50.00	$40.00	$45.00	$3.40	$1.10	$31.75	67.6%	10.7%
19	ConAgra Foods	$40.00	$30.00	$35.00	$2.25	$0.88	$14.95	60.9%	15.1%
20	ConocoPhillips	$125.00	$100.00	$112.50	$11.85	$2.20	$59.05	81.4%	20.1%
21	Costco Wholesale	$80.00	$65.00	$72.50	$3.75	$0.80	$29.00	78.7%	12.9%
22	CVS Caremark Corp	$70.00	$60.00	$65.00	$3.60	$0.48	$35.45	86.7%	10.2%
23	Disney (Walt)	$65.00	$50.00	$57.50	$3.85	$0.60	$27.05	84.4%	14.2%
24	Du Pont	$60.00	$50.00	$55.00	$3.00	$1.92	$13.55	36.0%	22.1%
25	Eaton Corp.	$110.00	$90.00	$100.00	$6.15	$2.50	$53.55	59.3%	11.5%
26	Ecolab Inc.	$65.00	$55.00	$60.00	$3.15	$0.85	$12.25	73.0%	25.7%
27	Emerson Electric	$65.00	$55.00	$60.00	$3.50	$1.55	$13.65	55.7%	25.6%
28	Everest Re Group Ltd.	$165.00	$135.00	$150.00	$15.00	$2.35	$116.65	84.3%	12.9%
29	Exxon Mobil Corp	$125.00	$100.00	$112.50	$9.35	$1.85	$38.70	80.2%	24.2%
30	Gen'l Dynamics	$145.00	$120.00	$132.50	$9.50	$2.50	$50.25	73.7%	18.9%
31	Gen'l Mills	$105.00	$85.00	$95.00	$5.50	$2.45	$22.60	55.5%	24.3%
32	Grainger (W.W.)	$140.00	$115.00	$127.50	$7.40	$2.26	$42.30	69.5%	17.5%
33	Heinz (H.J.)	$70.00	$60.00	$65.00	$3.90	$2.20	$10.65	43.6%	36.6%
34	Hewlett-Packard	$80.00	$65.00	$72.50	$4.50	$0.45	$28.55	90.0%	15.8%
35	Home Depot	$45.00	$35.00	$40.00	$2.50	$1.05	$14.85	58.0%	16.8%
36	Honeywell Int'l	$65.00	$55.00	$60.00	$3.95	$1.75	$18.15	55.7%	21.8%
37	Hormel Foods	$75.00	$60.00	$67.50	$3.80	$1.20	$23.85	68.4%	15.9%
38	Illinois Tool Works	$70.00	$55.00	$62.50	$3.80	$1.36	$21.30	64.2%	17.8%
39	Int'l Business Mach.	$220.00	$180.00	$200.00	$13.25	$3.00	$23.90	77.4%	55.4%
40	Intel Corp	$40.00	$30.00	$35.00	$1.75	$0.80	$9.15	54.3%	19.1%
41	ITT Corp.	$95.00	$75.00	$85.00	$5.30	$1.24	$33.80	76.6%	15.7%
42	Johnson & Johnson	$110.00	$90.00	$100.00	$6.50	$2.50	$25.85	61.5%	25.1%
43	Kellogg	$85.00	$70.00	$77.50	$4.60	$1.80	$13.70	60.9%	33.6%
44	Kimberly-Clark	$95.00	$80.00	$87.50	$5.85	$2.55	$15.15	56.4%	38.6%
45	Kraft Foods	$50.00	$40.00	$45.00	$2.75	$1.40	$26.20	49.1%	10.5%
46	Lilly (Eli)	$75.00	$60.00	$67.50	$4.75	$2.30	$16.05	51.6%	29.6%
47	Lockheed Martin	$215.00	$175.00	$195.00	$13.00	$3.50	$22.75	73.1%	57.1%
48	McCormick & Co.	$60.00	$50.00	$55.00	$3.15	$1.28	$17.40	59.4%	18.1%
49	McDonald's Corp.	$100.00	$80.00	$90.00	$5.25	$2.85	$18.25	45.7%	28.8%
50	McKesson Corp.	$90.00	$70.00	$80.00	$5.90	$0.48	$43.25	91.9%	13.6%
51	Medtronic, Inc.	$100.00	$80.00	$90.00	$4.80	$0.98	$20.15	79.6%	23.8%
52	Microsoft Corp.	$50.00	$45.00	$47.50	$2.65	$0.80	$7.70	69.8%	34.4%
53	NIKE, Inc. 'B'	$100.00	$85.00	$92.50	$5.10	$1.50	$23.90	70.6%	21.3%
54	Northrop Grumman	$130.00	$110.00	$120.00	$8.60	$2.25	$57.35	73.8%	15.0%
55	Oracle Corp.	$45.00	$40.00	$42.50	$2.15	$0.30	$7.90	86.0%	27.2%
56	PepsiCo, Inc.	$115.00	$95.00	$105.00	$5.15	$2.10	$19.45	59.2%	26.5%
57	Pfizer, Inc.	$20.00	$16.00	$18.00	$1.40	$0.64	$13.45	54.3%	10.4%
58	Procter & Gamble	$105.00	$85.00	$95.00	$4.75	$1.95	$26.00	58.9%	18.3%
59	Raytheon Co.	$110.00	$90.00	$100.00	$6.80	$1.75	$39.60	74.3%	17.2%
60	Sigma-Aldrich	$85.00	$65.00	$75.00	$4.15	$0.70	$18.95	83.1%	21.9%
61	Stryker Corp.	$115.00	$95.00	$105.00	$4.75	$0.72	$27.10	84.8%	17.5%
62	Sysco Corp.	$45.00	$35.00	$40.00	$2.40	$1.20	$8.50	50.0%	28.2%
63	TJX Companies	$65.00	$55.00	$60.00	$4.00	$0.75	$10.90	81.3%	36.7%
64	United Parcel Serv.	$100.00	$85.00	$92.50	$4.20	$2.30	$11.85	45.2%	35.4%
65	United Technologies	$120.00	$95.00	$107.50	$6.75	$2.20	$27.75	67.4%	24.3%
66	Verizon Communic.	$60.00	$50.00	$55.00	$3.10	$1.96	$18.85	36.8%	16.4%
67	Wal-Mart Stores	$95.00	$75.00	$85.00	$5.45	$1.55	$31.90	71.6%	17.1%
68	Walgreen Co.	$65.00	$55.00	$60.00	$3.35	$0.76	$22.20	77.3%	15.1%
69	Waste Management	$45.00	$40.00	$42.50	$2.80	$1.50	$16.55	46.4%	16.9%

NON-UTILITY PROXY GROUP

		(a)	(a)	(e)	(a)	(a)	(e)	(f)	(g)	(h)
		2008			2012-14			Adjusted "r"		
	Company	BVPS	No. Shares	Common Equity	BVPS	No. Shares	Common Equity	Chg in Equity	Adj. Factor	Adj. r
1	3M Company	$14.24	693.54	$9,876	$29.35	680.00	$19,958	15.1%	1.0702	25.2%
2	Abbott Labs.	$11.48	1522.40	$17,477	$21.95	1520.00	$33,364	13.8%	1.0646	24.2%
3	Alberto-Culver	$11.35	97.86	$1,111	$16.30	92.00	$1,500	6.2%	1.0300	12.6%
4	Allergan, Inc.	$13.19	304.09	$4,011	$24.20	310.00	$7,502	13.3%	1.0625	19.1%
5	AT&T Inc	$16.35	5893.00	$96,351	$22.05	5900.00	$130,095	6.2%	1.0300	15.2%
6	*Automatic Data Proc*	*$9.97*	*510.30*	*$5,088*	$20.75	520.00	$10,790	16.2%	1.0750	17.1%
7	Bard (C R.)	$19.89	99.39	$1,977	$39.25	90.00	$3,533	12.3%	1.0580	21.0%
8	Baxter Int'l Inc	$10.11	615.99	$6,228	$20.00	550.00	$11,000	12.1%	1.0568	32.2%
9	Becton, Dickinson	$20.30	243.08	$4,935	$38.85	227.00	$8,819	12.3%	1.0580	20.0%
10	Bemis Co.	$13.50	99.71	$1,346	$16.90	108.00	$1,825	6.3%	1.0304	13.7%
11	Bristol-Myers Squibb	$6.20	1974.30	$12,241	$10.25	1970.00	$20,193	10.5%	1.0500	20.0%
12	Brown-Forman 'B'	$12.10	150.13	$1,817	$22.05	145.00	$3,197	12.0%	1.0565	19.6%
13	Cardinal Health	$21.70	357.10	$7,749	$23.65	355.00	$8,396	1.6%	1.0080	11.9%
14	Chevron Corp.	$43.23	2004.20	$86,642	$53.15	1950.00	$103,643	3.6%	1.0179	23.9%
15	*Chubb Corp.*	*$38.13*	*352.30*	*$13,433*	$57.85	325.00	$18,801	7.0%	1.0336	12.5%
16	Coca-Cola	$8.85	2312.00	$20,461	$16.40	2310.00	$37,884	13.1%	1.0615	24.9%
17	Colgate-Palmolive	$3.47	501.41	$1,740	$17.70	480.00	$8,496	37.3%	1.1573	41.2%
18	Commerce Bancshs.	$19.79	79.68	$1,577	$31.75	85.00	$2,699	11.3%	1.0537	11.3%
19	ConAgra Foods	$11.02	484.37	$5,338	$14.95	425.00	$6,354	3.5%	1.0174	15.3%
20	ConocoPhillips	$37.27	1480.20	$55,167	$59.05	1500.00	$88,575	9.9%	1.0473	21.0%
21	Costco Wholesale	$21.25	432.51	$9,191	$29.00	410.00	$11,890	5.3%	1.0257	13.3%
22	CVS Caremark Corp.	$23.90	1438.80	$34,387	$35.45	1325.00	$46,971	6.4%	1.0312	10.5%
23	Disney (Walt)	$17.73	1822.90	$32,320	$27.05	1610.00	$43,551	6.1%	1.0298	14.7%
24	*Du Pont*	*$7.63*	*902.37*	*$6,885*	$13.55	850.00	$11,518	10.8%	1.0514	23.3%
25	Eaton Corp.	$38.28	165.00	$6,316	$53.55	170.00	$9,104	7.6%	1.0365	11.9%
26	Ecolab Inc.	$6.65	236.20	$1,571	$12.25	245.00	$3,001	13.8%	1.0647	27.4%
27	Emerson Electric	$11.82	771.22	$9,116	$13.65	700.00	$9,555	0.9%	1.0047	25.8%
28	Everest Re Group Ltd.	$75.62	65.60	$4,961	$116.65	60.00	$6,999	7.1%	1.0344	13.3%
29	Exxon Mobil Corp.	$22.70	4976.00	$112,955	$38.70	4300.00	$166,410	8.1%	1.0387	25.1%
30	Gen'l Dynamics	$26.00	386.71	$10,054	$50.25	365.00	$18,341	12.8%	1.0600	20.0%
31	Gen'l Mills	$18.42	337.50	$6,217	$22.60	300.00	$6,780	1.7%	1.0087	24.5%
32	Grainger (W W.)	$27.20	74.78	$2,034	$42.30	65.00	$2,750	6.2%	1.0301	18.0%
33	*Heinz (H.J.)*	*$3.87*	*315.04*	*$1,219*	$10.65	310.00	$3,302	22.0%	1.0993	40.3%
34	Hewlett-Packard	$16.13	2415.00	$38,954	$28.55	2100.00	$59,955	9.0%	1.0431	16.4%
35	Home Depot	$10.48	1696.00	$17,774	$14.85	1685.00	$25,022	7.1%	1.0342	17.4%
36	Honeywell Int'l	$9.78	734.59	$7,184	$18.15	715.00	$12,977	12.6%	1.0591	23.0%
37	Hormel Foods	$14.92	134.52	$2,007	$23.85	130.00	$3,101	9.1%	1.0435	16.6%
38	Illinois Tool Works	$14.41	499.12	$7,192	$21.30	475.00	$10,118	7.1%	1.0341	18.4%
39	Int'l Business Mach.	$10.06	1339.10	$13,471	$23.90	1050.00	$25,095	13.2%	1.0621	58.9%
40	Intel Corp.	$7.03	5562.00	$39,101	$9.15	6000.00	$54,900	7.0%	1.0339	19.8%
41	ITT Corp.	$16.83	181.80	$3,060	$33.80	185.00	$6,253	15.4%	1.0714	16.8%
42	*Johnson & Johnson*	*$15.35*	*2769.20*	*$42,507*	$25.85	2520.00	$65,142	8.9%	1.0427	26.2%
43	Kellogg	$3.79	381.86	$1,447	$13.70	375.00	$5,138	28.8%	1.1260	37.8%
44	Kimberly-Clark	$9.38	413.60	$3,880	$15.15	415.00	$6,287	10.1%	1.0482	40.5%
45	Kraft Foods	$15.11	1469.30	$22,201	$26.20	1400.00	$36,680	10.6%	1.0502	11.0%
46	Lilly (Eli)	$5.93	1136.10	$6,737	$16.05	1150.00	$18,458	22.3%	1.1004	32.6%
47	Lockheed Martin	$7.29	393.00	$2,865	$22.75	330.00	$7,508	21.2%	1.0960	62.6%
48	McCormick & Co.	$8.11	130.10	$1,055	$17.40	135.00	$2,349	17.4%	1.0799	19.5%
49	McDonald's Corp.	$12.00	1115.30	$13,384	$18.25	1015.00	$18,524	6.7%	1.0325	29.7%
50	McKesson Corp.	$22.85	271.00	$6,192	$43.25	254.00	$10,986	12.1%	1.0573	14.4%
51	*Medtronic, Inc*	*$11.42*	*1124.90*	*$12,846*	$20.15	1000.00	$20,150	9.4%	1.0450	24.9%
52	Microsoft Corp.	$3.97	9151.00	$36,329	$7.70	7500.00	$57,750	9.7%	1.0463	36.0%
53	NIKE, Inc. 'B'	$15.93	491.10	$7,823	$23.90	460.00	$10,994	7.0%	1.0340	22.1%
54	Northrop Grumman	$36.45	327.01	$11,920	$57.35	300.00	$17,205	7.6%	1.0367	15.5%
55	Oracle Corp.	$4.47	5150.00	$23,021	$7.90	4300.00	$33,970	8.1%	1.0389	28.3%
56	PepsiCo, Inc.	$7.77	1553.00	$12,067	$19.45	1500.00	$29,175	19.3%	1.0881	28.8%
57	Pfizer, Inc.	$8.52	6746.00	$57,476	$13.45	6700.00	$90,115	9.4%	1.0449	10.9%
58	Procter & Gamble	$22.46	3032.70	$68,114	$26.00	2900.00	$75,400	2.1%	1.0102	18.5%
59	Raytheon Co.	$22.71	400.10	$9,086	$39.60	350.00	$13,860	8.8%	1.0422	17.9%
60	*Sigma-Aldrich*	*$11.29*	*122.13*	*$1,379*	$18.95	120.00	$2,274	10.5%	1.0500	23.0%
61	Stryker Corp.	$13.64	396.40	$5,407	$27.10	382.00	$10,352	13.9%	1.0649	18.7%
62	Sysco Corp.	$5.67	601.23	$3,409	$8.50	560.00	$4,760	6.9%	1.0334	29.2%
63	TJX Companies	$5.17	412.82	$2,134	$10.90	340.00	$3,706	11.7%	1.0551	38.7%
64	United Parcel Serv.	$6.81	995.44	$6,779	$11.85	990.00	$11,732	11.6%	1.0548	37.4%
65	United Technologies	$16.89	942.29	$15,915	$27.75	900.00	$24,975	9.4%	1.0450	25.4%
66	Verizon Communic.	$14.68	2840.60	$41,700	$18.85	2820.00	$53,157	5.0%	1.0243	16.8%
67	Wal-Mart Stores	$16.63	3925.00	$65,273	$31.90	3450.00	$110,055	11.0%	1.0522	18.0%
68	Walgreen Co.	$13.01	989.18	$12,869	$22.20	950.00	$21,090	10.4%	1.0494	15.8%
69	*Waste Management*	*$12.03*	*490.74*	*$5,904*	$16.55	465.00	$7,696	5.4%	1.0265	17.4%

NON-UTILITY PROXY GROUP

		(a)	(a)	(f)	(i)	(j)	(k)	(l)	(m)
		Common Shares Outstanding			M/B	"sv" Factor			
	Company	2008	2012-14	Change	Ratio	s	v	sv	br + sv
1	3M Company	693.54	680.00	-0.39%	3.75	(0.0147)	0.7332	-1.08%	15.8%
2	Abbott Labs.	1522.40	1520.00	-0.03%	4.10	(0.0013)	0.7561	-0.10%	13.6%
3	Alberto-Culver	97.86	92.00	-1.23%	2.45	(0.0301)	0.5925	-1.78%	8.0%
4	Allergan, Inc.	304.09	310.00	0.39%	4.13	0.0159	0.7580	1.21%	19.2%
5	AT&T Inc.	5893.00	5900.00	0.02%	2.04	0.0005	0.5100	0.02%	5.9%
6	Automatic Data Proc.	510.30	520.00	0.38%	3.73	0.0141	0.7323	1.03%	9.8%
7	Bard (C.R.)	99.39	90.00	-1.97%	3.57	(0.0701)	0.7196	-5.04%	13.4%
8	Baxter Int'l Inc.	615.99	550.00	-2.24%	4.88	(0.1092)	0.7949	-8.68%	15.1%
9	Becton, Dickinson	243.08	227.00	-1.36%	3.02	(0.0411)	0.6694	-2.75%	12.1%
10	Bemis Co.	99.71	108.00	1.61%	2.22	0.0357	0.5493	1.96%	9.3%
11	Bristol-Myers Squibb	1974.30	1970.00	-0.04%	3.41	(0.0015)	0.7071	-0.11%	5.5%
12	Brown-Forman 'B'	150.13	145.00	-0.69%	3.17	(0.0220)	0.6850	-1.51%	12.2%
13	Cardinal Health	357.10	355.00	-0.12%	2.01	(0.0024)	0.5021	-0.12%	7.6%
14	Chevron Corp.	2004.20	1950.00	-0.55%	2.35	(0.0129)	0.5748	-0.74%	17.5%
15	Chubb Corp.	352.30	325.00	-1.60%	1.34	(0.0214)	0.2535	-0.54%	9.1%
16	Coca-Cola	2312.00	2310.00	-0.02%	5.03	(0.0009)	0.8012	-0.07%	11.1%
17	Colgate-Palmolive	501.41	480.00	-0.87%	7.20	(0.0626)	0.8612	-5.39%	19.5%
18	Commerce Bancshs.	79.68	85.00	1.30%	1.42	0.0184	0.2944	0.54%	8.2%
19	ConAgra Foods	484.37	425.00	-2.58%	2.34	(0.0604)	0.5729	-3.46%	5.9%
20	ConocoPhillips	1480.20	1500.00	0.27%	1.91	0.0051	0.4751	0.24%	17.4%
21	Costco Wholesale	432.51	410.00	-1.06%	2.50	(0.0266)	0.6000	-1.59%	8.8%
22	CVS Caremark Corp.	1438.80	1325.00	-1.63%	1.83	(0.0300)	0.4546	-1.36%	7.7%
23	Disney (Walt)	1822.90	1610.00	-2.45%	2.13	(0.0521)	0.5296	-2.76%	9.6%
24	Du Pont	902.37	850.00	-1.19%	4.06	(0.0482)	0.7536	-3.64%	4.7%
25	Eaton Corp.	165.00	170.00	0.60%	1.87	0.0112	0.4645	0.52%	7.6%
26	Ecolab Inc.	236.20	245.00	0.73%	4.90	0.0360	0.7958	2.86%	22.9%
27	Emerson Electric	771.22	700.00	-1.92%	4.40	(0.0844)	0.7725	-6.52%	7.8%
28	Everest Re Group Ltd.	65.60	60.00	-1.77%	1.29	(0.0227)	0.2223	-0.51%	10.7%
29	Exxon Mobil Corp.	4976.00	4300.00	-2.88%	2.91	(0.0837)	0.6560	-5.49%	14.6%
30	Gen'l Dynamics	386.71	365.00	-1.15%	2.64	(0.0303)	0.6208	-1.88%	12.9%
31	Gen'l Mills	337.50	300.00	-2.33%	4.20	(0.0979)	0.7621	-7.46%	6.2%
32	Grainger (W.W.)	74.78	65.00	-2.76%	3.01	(0.0833)	0.6682	-5.57%	6.9%
33	Heinz (H.J.)	315.04	310.00	-0.32%	6.10	(0.0197)	0.8362	-1.64%	15.9%
34	Hewlett-Packard	2415.00	2100.00	-2.76%	2.54	(0.0700)	0.6062	-4.24%	10.6%
35	Home Depot	1696.00	1685.00	-0.13%	2.69	(0.0035)	0.6288	-0.22%	9.9%
36	Honeywell Int'l	734.59	715.00	-0.54%	3.31	(0.0178)	0.6975	-1.24%	11.6%
37	Hormel Foods	134.52	130.00	-0.68%	2.83	(0.0193)	0.6467	-1.25%	10.1%
38	Illinois Tool Works	499.12	475.00	-0.99%	2.93	(0.0289)	0.6592	-1.91%	9.9%
39	Int'l Business Mach.	1339.10	1050.00	-4.75%	8.37	(0.3973)	0.8805	-34.98%	10.6%
40	Intel Corp.	5562.00	6000.00	1.53%	3.83	0.0584	0.7386	4.32%	15.1%
41	ITT Corp.	181.80	185.00	0.35%	2.51	0.0088	0.6024	0.53%	13.4%
42	Johnson & Johnson	2769.20	2520.00	-1.87%	3.87	(0.0723)	0.7415	-5.36%	10.8%
43	Kellogg	381.86	375.00	-0.36%	5.66	(0.0205)	0.8232	-1.69%	21.3%
44	Kimberly-Clark	413.60	415.00	0.07%	5.78	0.0039	0.8269	0.32%	23.2%
45	Kraft Foods	1469.30	1400.00	-0.96%	1.72	(0.0165)	0.4178	-0.69%	4.7%
46	Lilly (Eli)	1136.10	1150.00	0.24%	4.21	0.0102	0.7622	0.78%	17.6%
47	Lockheed Martin	393.00	330.00	-3.43%	8.57	(0.2943)	0.8833	-26.00%	19.8%
48	McCormick & Co.	130.10	135.00	0.74%	3.16	0.0235	0.6836	1.60%	13.2%
49	McDonald's Corp.	1115.30	1015.00	-1.87%	4.93	(0.0921)	0.7972	-7.34%	6.2%
50	McKesson Corp.	271.00	254.00	-1.29%	1.85	(0.0238)	0.4594	-1.09%	12.2%
51	Medtronic, Inc.	1124.90	1000.00	-2.33%	4.47	(0.1039)	0.7761	-8.06%	11.7%
52	Microsoft Corp.	9151.00	7500.00	-3.90%	6.17	(0.2407)	0.8379	-20.16%	5.0%
53	NIKE, Inc. 'B'	491.10	460.00	-1.30%	3.87	(0.0503)	0.7416	-3.73%	11.8%
54	Northrop Grumman	327.01	300.00	-1.71%	2.09	(0.0358)	0.5221	-1.87%	9.6%
55	Oracle Corp.	5150.00	4300.00	-3.54%	5.38	(0.1906)	0.8141	-15.52%	8.8%
56	PepsiCo, Inc.	1553.00	1500.00	-0.69%	5.40	(0.0374)	0.8148	-3.04%	14.0%
57	Pfizer, Inc.	6746.00	6700.00	-0.14%	1.34	(0.0018)	0.2528	-0.05%	5.9%
58	Procter & Gamble	3032.70	2900.00	-0.89%	3.65	(0.0326)	0.7263	-2.36%	8.5%
59	Raytheon Co.	400.10	350.00	-2.64%	2.53	(0.0667)	0.6040	-4.03%	9.3%
60	Sigma-Aldrich	122.13	120.00	-0.35%	3.96	(0.0139)	0.7473	-1.04%	18.1%
61	Stryker Corp	396.40	382.00	-0.74%	3.87	(0.0286)	0.7419	-2.12%	13.7%
62	Sysco Corp.	601.23	560.00	-1.41%	4.71	(0.0664)	0.7875	-5.23%	9.4%
63	TJX Companies	412.82	340.00	-3.81%	5.50	(0.2096)	0.8183	-17.15%	14.3%
64	United Parcel Serv.	995.44	990.00	-0.11%	7.81	(0.0086)	0.8719	-0.75%	16.2%
65	United Technologies	942.29	900.00	-0.91%	3.87	(0.0354)	0.7419	-2.63%	14.5%
66	Verizon Communic.	2840.60	2820.00	-0.15%	2.92	(0.0042)	0.6573	-0.28%	5.9%
67	Wal-Mart Stores	3925.00	3450.00	-2.55%	2.66	(0.0679)	0.6247	-4.24%	8.6%
68	Walgreen Co.	989.18	950.00	-0.81%	2.70	(0.0218)	0.6300	-1.37%	10.9%
69	Waste Management	490.74	465.00	-1.07%	2.57	(0.0275)	0.6106	-1.68%	6.4%

(a) www.valueline.com (retrieved Dec. 24, 2009).
(b) Average of High and Low expected market prices.
(c) Computed at (EPS - DPS) / EPS.
(d) Computed as EPS / BVPS.
(e) Product of BVPS and No. Shares Outstanding.
(f) Five-year rate of change.
(g) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(h) Product of year-end "r" for 2012-14 and Adjustment Factor.
(i) Average of High and Low expected market prices divided by 2012-14 BVPS.
(j) Product of change in common shares outstanding and M/B Ratio.
(k) Computed as 1 - B/M Ratio.
(l) Product of "s" and "v".
(m) Product of average "b" and adjusted "r", plus "sv".

CAPITAL ASSET PRICING MODEL

UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.7%	
Growth Rate (b)	9.2%	
Market Return (c)		11.9%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.4%
Market Risk Premium (e)		7.5%
Utility Proxy Group Beta (f)		0.69
Utility Proxy Group Risk Premium (g)		5.2%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.4%
Implied Cost of Equity (h)		**9.6%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Oct. 1, 2009).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 based on data from *Thomson Reuters Company Report* (Oct. 1, 2009).
(c) (a) + (b)
(d) Average yield on 20-year Treasury bonds for December 2009 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 (Nov. 6, Nov. 27, & Dec. 25, 2009).
(g) (e) x (f).
(h) (d) + (g).

CAPITAL ASSET PRICING MODEL

NON-UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.7%	
Growth Rate (b)	9.2%	
Market Return (c)		11.9%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.4%
Market Risk Premium (e)		7.5%
Non-Utility Proxy Group Beta (f)		0.79
Utility Proxy Group Risk Premium (g)		5.9%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.4%
Implied Cost of Equity (h)		**10.3%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Oct. 1, 2009).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 based on data from *Thomson Reuters Company Report* (Oct. 1, 2009).
(c) (a) + (b)
(d) Average yield on 20-year Treasury bonds for December 2009 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 Sep. 9, 2009).
(g) (e) x (f).
(h) (d) + (g).

EXPECTED EARNINGS APPROACH

UTILITY PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	ALLETE	9.0%	1.0361	9.3%
2	Alliant Energy	10.0%	1.0244	10.2%
3	Consolidated Edison	9.5%	1.0188	9.7%
4	Dominion Resources	15.5%	1.0474	16.2%
5	Duke Energy Corp.	8.0%	1.0078	8.1%
6	Entergy Corp.	14.5%	1.0262	14.9%
7	Exelon Corp.	19.0%	1.0411	$\boxed{19.8\%}$
8	PG&E Corp.	12.0%	1.0422	12.5%
9	Progress Energy	9.5%	1.0210	9.7%
10	SCANA Corp.	10.5%	1.0431	11.0%
11	Sempra Energy	12.0%	1.0475	12.6%
12	Vectren Corp.	11.0%	1.0230	11.3%
13	Wisconsin Energy	11.5%	1.0287	11.8%
14	Xcel Energy, Inc.	10.5%	1.0236	10.7%
	Average (d)			**11.4%**

(a) 3-5 year projections from The Value Line Investment Survey (Nov. 6, Nov. 27, & Dec. 25, 2009).

(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 2008 (a)			Value Line Projected (b)		
	Company	Long-term Debt	Preferred	Common Equity	Long-term Debt	Other	Common Equity
1	ALLETE	41.7%	0.0%	58.3%	49.0%	0.0%	51.0%
2	Alliant Energy	38.0%	4.9%	57.0%	37.5%	4.0%	58.5%
3	Consolidated Edison	49.5%	1.1%	49.4%	48.5%	0.0%	51.5%
4	Dominion Resources	59.8%	1.0%	39.2%	53.5%	0.5%	46.0%
5	Duke Energy Corp.	39.6%	0.0%	60.4%	48.5%	0.0%	51.5%
6	Entergy Corp.	58.6%	1.6%	39.8%	57.0%	1.0%	42.0%
7	Exelon Corp.	49.8%	2.1%	48.1%	42.5%	0.5%	57.0%
8	PG&E Corp.	50.7%	1.3%	48.0%	45.0%	1.0%	54.0%
9	Progress Energy	54.8%	0.5%	44.7%	52.5%	0.0%	47.5%
10	SCANA Corp.	58.8%	1.5%	39.7%	55.5%	1.0%	43.5%
11	Sempra Energy	45.3%	1.2%	53.5%	42.0%	1.0%	57.0%
12	Vectren Corp.	48.0%	0.0%	52.0%	50.0%	0.0%	50.0%
13	Wisconsin Energy	55.1%	0.4%	44.5%	54.5%	0.0%	45.5%
14	Xcel Energy, Inc.	54.0%	0.7%	45.3%	51.0%	0.5%	48.5%
	Average	**50.3%**	**1.2%**	**48.6%**	**49.1%**	**0.7%**	**50.3%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Nov. 6, Nov. 27, & Dec. 25, 2009).

CAPITAL STRUCTURE

UTILITY OPERATING COS.

	Company	At Fiscal Year-End 2008 (a) Long-term Debt	Preferred Stock	Common Equity
1	Carolina Power & Light Co.	44.6%	0.7%	54.7%
2	Commonweath Edison Co.	41.2%	0.0%	58.8%
3	Consolidated Edison of NY	49.4%	1.2%	49.5%
4	Duke Energy Carolinas	49.9%	0.0%	50.1%
5	Duke Energy Indiana	52.5%	0.0%	47.5%
6	Duke Energy Kentucky	45.2%	0.0%	54.8%
7	Duke Energy Ohio	22.0%	0.0%	78.0%
8	Entergy Arkansas Inc.	51.6%	3.7%	44.7%
9	Entergy Gulf States Louisiana LLC	60.6%	0.3%	39.1%
10	Entergy Louisiana LLC	44.8%	3.2%	51.9%
11	Entergy Mississippi Inc.	49.3%	3.6%	47.1%
12	Entergy New Orleans Inc.	52.1%	3.8%	44.1%
13	Entergy Texas Inc.	56.8%	0.0%	43.2%
14	Florida Power Corp.	54.9%	0.4%	44.6%
15	Interstate Power & Light	42.8%	7.9%	49.3%
16	Northern States Power Co. (MN)	49.1%	0.0%	50.9%
17	Northern States Power Co. (WI)	48.7%	0.0%	51.3%
18	Orange & Rockland	45.4%	0.0%	54.6%
19	Pacific Gas & Electric Co.	49.6%	1.3%	49.0%
20	PECO Energy Co.	44.6%	6.1%	49.3%
21	Public Service Co. of Colorado	41.0%	0.0%	59.0%
22	San Diego Gas & Electric	45.0%	1.7%	53.3%
23	South Carolina Electric & Gas	53.0%	1.9%	45.1%
24	Southwestern Public Service Co.	52.4%	0.0%	47.6%
25	Superior Water, Light & Power Co.	44.5%	0.0%	55.5%
26	Vectren Utility Holdings	40.1%	0.0%	59.9%
27	Virginia Electric Power	48.4%	2.0%	49.6%
28	Wisconsin Electric Power Co.	42.0%	0.7%	57.3%
29	Wisconsin Power & Light	39.1%	3.0%	57.9%
	Average	**46.9%**	**1.4%**	**51.7%**

(a) Company Form 10-K Reports and FERC Form-1 Reports.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	))))	CASE NO. 2009-00549

TESTIMONY OF
LONNIE E. BELLAR
VICE PRESIDENT OF STATE REGULATION AND RATES
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: January 29, 2010

Q. **Please state your name, position and business address.**

A. My name is Lonnie E. Bellar. I am the Vice President of State Regulation and Rates for Louisville Gas and Electric Company ("LG&E" or "Company") and an employee of E.ON U.S. Services, Inc., which provides services to LG&E and Kentucky Utilities Company ("KU") (collectively, "Companies"). My business address is 220 West Main Street, Louisville, Kentucky. A statement of my qualification is attached as Appendix A.

Q. **Have you previously testified before the Kentucky Public Service Commission?**

A. Yes. I have testified before the Commission multiple times, including Case Nos. 2007-00562 (LG&E) and 2007-00563 (KU) concerning the disposition of KU's and LG&E's merger surcredit mechanisms; the Companies' most recent base rate cases, Case Nos. 2008-00251 (KU) and 2008-00252 (LG&E); and most recently in the Companies' 2009 Environmental Surcharge Compliance Plan proceedings, Case Nos. 2009-00197 (KU) and 2009-00198 (LG&E).

Q. **What are the purposes of your testimony?**

A. The purposes of my testimony are: (1) to support certain exhibits required by the Commission's regulations; (2) to present the revenue effects and the bill impacts to the average residential customer; (3) to present LG&E's recommendation for the allocation of the proposed increases in revenues among the customer classes based on the results of the Company's cost-of-service study prepared by The Prime Group and sponsored by W. Steven Seelye in this case; (4) to explain the relationship of LG&E's various cost-recovery mechanisms to its base rates; and (5) to explain certain pro forma adjustments to which the testimony of S. Bradford Rives refers.

Q. Are you supporting the schedules that are required by Commission regulations 807 KAR 5:001?

A. Yes, the table of contents to LG&E's filing requirements states which schedules I am sponsoring. Please note that, though I am sponsoring LG&E's proposed gas and electric tariffs and proposed tariff changes, the testimonies of Robert M. Conroy and Mr. Seelye will address issues of electric and gas rate design, and the testimony of John Wolfram will address changes to the terms and conditions of LG&E's gas and electric services.

Revenue Effect

Q. What are the revenue effects of the proposed rates?

A. As shown in Tab 23 of the Company's Filing Requirements, attached to the Application in this case, the total increase in revenues to LG&E that would result from the proposed rate adjustments is $94.6 million for electric operations and $22.6 million for gas operations.

Q. If the Commission approves the proposed base rates, what will be the percentage increases in monthly residential gas and electric bills?

A. The average monthly residential electric bill increase due to the proposed electric base rates will be 12.2%, or approximately $8.92, for a residential customer using an average of 992 kWh of electricity.

Likewise, the monthly residential gas bill increase due to the proposed gas base rates will be 8.7%, or approximately $4.65, for a residential customer using an average of 58 Ccf of gas.

Revenue Allocation

Q. Has LG&E analyzed how the proposed increase in revenue should be allocated among its customers?

A. Yes. LG&E engaged The Prime Group to analyze the existing class rates of return to determine whether in existing rates any significant cross-subsidization existed between customer classes. The Prime Group conducted a fully allocated, embedded cost-of-service study. For electric operations, that study was also time-differentiated.

Q. What methodology did LG&E use in its electric cost-of-service study?

A. LG&E used the Base-Intermediate-Peak methodology that the Commission has followed in every LG&E rate case in the last twenty-eight years. The details of that study are presented in the testimony of Mr. Seelye. The summary of the results of that study, reflecting the pro forma rate of return for the principal rate schedules, is set forth below:

Bellar Table I – Pro Forma Electric Rates of Return

Customer Class	**LG&E Electric Actual**
Residential – Rate RS	3.19%
General Service – Rate GS	9.12%
Power Service – Rate PS	
- Primary	4.86%
- Secondary	6.62%
Commercial Time of Day	
- Commercial TOD Secondary – Rate CTODS	4.42%
- Commercial TOD Primary – Rate CTODP	4.47%
Industrial Time of Day	
- Industrial Time-of-Day – Rate ITODS	5.27%
- Industrial Time-of-Day Rate ITODP	3.31%
Retail Transmission Service – Rate RTS	2.91%
Lighting	8.80%
Special Contracts	-0.19%
Total System	4.77%

The results of the study demonstrate that class rates-of-return are within a reasonable range of the total system class rate-of-return average of 4.77%. Based on this information, I directed The Prime Group to prepare a revenue allocation that spread the increase in revenues equally across all the electric rate classes. The details of the LG&E electric revenue allocation are contained in Mr. Seeyle's testimony. The overall results are shown below:

Bellar Table II

Pro Forma Electric Rates of Return as Adjusted for Proposed Increase

Customer Class	LG&E Electric Proposed
Residential – Rate RS	5.86%
General Service – Rate GS	12.62%
Power Service – Rate PS	
- Primary	8.47%
- Secondary	10.13%
Commercial Time of Day	
- Commercial TOD Secondary – Rate CTODS	8.00%
- Commercial TOD Primary – Rate CTODP	8.72%
Industrial Time of Day	
- Industrial Time-of-Day – Rate ITODS	9.28%
- Industrial Time-of-Day Rate ITODP	6.97%
Retail Transmission Service – Rate RTS	6.53%
Lighting	11.17%
Special Contracts	2.51%
Total System	7.89%

Q. What methodology did LG&E use in its gas cost-of-service study?

A. Like the electric cost-of-service study, LG&E used the Base-Intermediate-Peak methodology. The Commission has followed this methodology in every LG&E rate case in the last twenty-eight years. The details of that study are presented in the testimony of Mr. Seelye as well. The summary of the results of that study, reflecting the pro forma rate of return for the principal rate schedules, is set forth below:

Bellar Table III– Pro Forma Gas Rates of Return

Customer Class	LG&E Gas Actual
Residential – Rate RGS	3.90%
Commercial – Rate CGS	7.01%
Industrial – Rate IGS	4.36%
As Available Service – Rate AAGS	16.85%
Firm Transportation Service – Rate FT	25.71%
Special Contracts	25.05%
Total System	5.06%

The results of the study demonstrate that class rates-of-return vary, and for two customer classes, the returns vary substantially, from the total system class rate-of-return average of 5.06%. Based on this information, I concluded that the residential customer class continued to be subsidized to some degree by other classes. Accordingly, I directed the Prime Group to prepare a revenue allocation that would recognize the subsidies between rate classes as well as the important considerations of gradualism and rate continuity to residential customers and the risk of by pass by other customer classes. The details of the LG&E gas revenue allocation are contained in Mr. Seeyle's testimony. The results of the proposed gas revenue allocation are shown below:

Bellar Table IV –

Pro Forma Gas Rates of Return as Adjusted for Proposed Increase

Customer Class	LG&E Gas Proposed
Residential – Rate RGS	6.82%
Commercial – Rate CGS	10.01%
Industrial – Rate IGS	7.12%
As Available Service – Rate AAGS	17.01%
Firm Transportation Service – Rate FT	25.90%
Special Contracts	25.25%
Total System	7.95%

The proposed residential increase strikes a balance between the cost-of-service principles of gradualism and reducing interclass subsidies.

Q. Following the results of the electric cost of service study, did LG&E provide any guidance to The Prime Group in developing the electric rates for this proceeding?

A. Yes. First, we advised The Prime Group that, with regard to the rate design, unit charges should reflect the cost-of-service study as nearly as practicable so that customer charges were more reflective of customer-related costs, demand charges were more reflective of demand-related costs, and energy/commodities charges were more reflective of energy/commodity-related costs. Finally, we advised The Prime Group to simplify rate design whenever feasible.

Q. Following the results of the gas cost of service study, did LG&E provide any guidance to The Prime Group in developing the gas rates for this proceeding?

A. Yes. First, we advised that the cost-of-service study should guide the revenue increase to the customer classes. Second, we advised The Prime Group to take into account the rate-making principle of gradualism concerning residential rate increases.

Finally, like design of the electric rates, we advised The Prime Group to simplify rate design whenever feasible.

Q. With respect to the design of the residential gas rates, did The Prime Group recommend a particular structure?

A. Yes. Based on this guidance, The Prime Group recommended using a Straight Fixed Variable rate design for residential gas service. This rate design sends customers the appropriate price signal, reduces volatility in customer bills, and is easier for customers to understand. The details of this rate design are contained in the testimony of Mr. Seeyle.

Relationship of Other Ratemaking Mechanisms to Base Rates

Q. Please give an overview of the composition of LG&E's current retail rates.

A. In addition to the base rates, certain cost items, such as fuel costs, demand-side management plan costs, and environmental compliance costs are included in our retail rates, but are assessed separately from base rates.

Q. Do ratemaking mechanisms such as the fuel adjustment clause, gas supply clause, environmental cost recovery/environmental surcharge, or demand-side management cost recovery have any effect on the base rate increase that LG&E is requesting?

A. No. As presented in the testimony of Mr. Rives and discussed in Mr. Conroy's testimony, the impact of those mechanisms has been removed from the calculation of LG&E's operating revenues and expenses for the test year ended October 31, 2009. The mechanisms, and the costs and revenues associated with them, therefore have no effect on the calculation of the revenue deficiency and corresponding base rate increases that LG&E is requesting in this case. In addition, by removing these items from the calculation of net operating income in the Application, there is no double recovery of these costs.

Electric Pro-Forma Adjustments

Q. Was an adjustment made to eliminate unbilled revenues for electric operations?

A. Yes. Consistent with prior rate cases, unbilled revenues were removed from test-year operating revenues. This adjustment is included in Reference Schedule 1.00 of Rives Exhibit 1, and is consistent with the adjustment to eliminate unbilled revenues for the gas business. The Commission approved a similar adjustment in Case No. 2003-00433, and LG&E proposed such an adjustment in Case No. 2008-00252.

Q. Has an adjustment been made to eliminate the effect of LG&E's already-terminated merger surcredit mechanism?

A. Yes. The Commission's February 5, 2009 Order in Case No. 2008-00252 recognized that LG&E's merger surcredit mechanism would terminate when the rates that Order approved went into effect on February 6, 2009, subject to a final balancing adjustment. Since then, LG&E's customers have enjoyed the full benefit of all merger savings, which have been fully embedded in base rates, and which will continue to be embedded in base rates going forward. This adjustment, however, removes the effect of the merger surcredit from the test year, and is included in Reference Schedule 1.01 of Rives Exhibit 1.

Q. Has an adjustment been made to eliminate the effect of LG&E's already-terminated Value Delivery Team surcredit ("VDT")?

A. Yes. On its own terms, the VDT surcredit terminated concurrently with the filing of LG&E's application in its most recent base rate proceeding, Case No. 2008-00252, which application LG&E filed on July 29, 2008. While the VDT terminated prior to the beginning of the test year, there remained a small amount of credits on the books during the test year due to billing adjustments. This adjustment is included in Reference Schedule 1.02 of Rives Exhibit 1.

Q. Please explain the adjustment to include the pro rata amount of depreciation expense associated with Trimble County Unit No. 2 ("TC2") Construction Work in Progress.

A. The purpose of this adjustment is to reflect the depreciation expense of LG&E's portion of the TC2 Construction Work in Progress ("CWIP") balance at the end of the test period. The depreciation rates used in this adjustment are those the Companies proposed in Case No. 2009-00329 (supported in that case by the expert testimony of John Spanos and approved by the Commission on an interim basis through its Order dated December 23, 2009). The adjustment reflects the application of those rates to the CWIP balance as of the end of the test year associated with LG&E's portion of the TC2 assets. Although the commercial operation of TC2 and some of its related transmission facilities will begin outside of the test year, it constitutes a known and measurable change of significant proportion. As described in the testimony of Paul W. Thompson, commissioning operations and check out of the unit began in November 2009, and there have been no material mishaps or delays associated with unit testing to date. That testing success, coupled with the significant daily liquidated damages under the contract that would accrue if the Companies' contractor failed to meet its June 2010 commercial operation deadline, provide a high degree of assurance that TC2 will be in full commercial operation before LG&E's new base rates go into effect on August 1, 2010 after the expected suspension period.

By the date the base rates authorized in this case take effect, TC2 and its related transmission facilities will be in commercial operation and all CWIP expenditures through the end of the test period will be reclassified from CWIP to plant-in-service. TC2 and its related transmission facilities represent a significant addition to LG&E's plant-in-service. The adjustment recognizes the known and measurable fixed cost associated with the commercialization of TC2 before the base rates authorized in this case take effect.

Shannon L. Charnas and I sponsor this adjustment, which is included in Reference Schedule 1.15 of Rives Exhibit 1.

Q. Does the Commission's practice favor post-test year adjustments?

A. No, the Commission generally has not looked favorably on post-test-year adjustments; however, as I discuss later in my testimony, the Commission has recognized exceptions to this general position. More importantly, the relationship between the expiration of the power contract with Owensboro Municipal Utility ("OMU") and the addition of the TC2 facility necessitates both events be considered together.

LG&E and KU are proposing two related post-test-period adjustments: (1) an increase in their depreciation expenses related to test-year-end CWIP for TC2 and its related transmission facilities which will become commercial in June 2010; and (2) a decrease in KU's operating expenses due to OMU's May 2010 termination of its purchased power contract with KU. Both of these proposed adjustments concern expenditures in the test year, but relate to events after the test year.

Q. In the light of the Commission's traditional practice, please explain why the Commission should accept LG&E's and KU's proposed post-test-year adjustments.

A. First, the demand for power by LG&E's and KU's native load customers will not diminish with the termination of the OMU contract. A resource of power must replace the OMU power. LG&E customers benefited from the OMU power contract through its replacement of other KU generation resources, which in turn, were used to serve LG&E customers through inter-company sales. A portion of the TC2 facility scheduled to become commercial in June 2010 will replace the OMU power contract. It is therefore appropriate to match the loss of the OMU power contract with the generation resource that will replace it, TC2. The addition of the pro rata amount of depreciation associated with LG&E's and KU's portion of test-year-end CWIP for TC2 presents the related cost of the TC2 facility based on the test year-end amount of CWIP.

Second, these two adjustments, together, create an appropriate consistency in the cost of providing service and are based on the known and measureable changes in objective data to reflect the going forward cost of providing service.

Third, establishing the revenue requirements based on these two adjustments mitigates the immediate need for another rate case by LG&E and KU once TC2 has begun commercial operation.

Q. Has the Commission approved post-test year adjustments in previous cases?

A. Yes. In certain cases the Commission has accepted post-test year adjustments as the exception to its traditional position when the proposed changes are known and measurable. For example, there is a very strong correlation between the conditions under which the Commission allowed such a depreciation adjustment for test-year-end Trimble County Unit No. 1 ("TC1") CWIP and those giving rise to the proposed TC2-related adjustment. The amount of TC2 CWIP at the end of the test year is fully known and measurable; the rates LG&E proposes to use are those it has proposed in Case No. 2009-00329, which are known and measurable and approved by the Commission on an interim basis through its Order dated December 23, 2009 in Case No. 2009-00329; and TC2 will be in commercial operation before LG&E's proposed rates go into effect, just as was true when the Commission granted LG&E its requested TC1 CWIP depreciation adjustment in Case No. 90-158.

Second, the adjustments together represent a clear certainty in events that will occur after the test period, but before the rates established in this proceeding take effect. It seems very similar to The Union Light, Heat and Power Company's adjustment the Commission approved in Case No. 2001-00092, except that it is an expense that will end, not a revenue.[1]

Concerning other kinds of post-test-period adjustments, in Case Nos. 1998-00426 (LG&E) and 1998-00474 (KU), which had test years ending December 31,

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[1] *In the Matter of: Adjustment of Gas Rates of The Union Light, Heat and Power Company*, Case No. 2001-00092, Order at 31 (Jan. 31, 2002) ("ULH&P recognized reductions in revenue due to reduced gas usage by two large customers, Johns Manville and Newport Steel. These reductions, which occurred in April 2000 for Johns Manville and March 2001 for Newport Steel, were known and measurable when ULH&P filed its application [May 4, 2001], and result in a revenue decrease of $583,000. [ULH&P's test period ended September 30, 2000.] ... Based on both the magnitude of the revenue adjustments and when the changes in the customers' gas usage occurred, the Commission will accept ULH&P's adjustment to decrease revenues by $583,000.").

1998, the Commission accepted adjustments based on LG&E's and KU's actual margins from off-system sales and purchase power expenses for the twelve months ended August 1999 (i.e., actual sales and purchases until the September 1999 hearing in those proceedings). In doing so, the Commission accepted adjustments using actual data eight months beyond the end of the test year period.[2]

All of these Commission decisions demonstrate that the Commission has accepted known and measurable changes to operating revenues and expenses, even when the events that give rise to them, or the data that support them, occur outside of the test year. It would therefore be in accordance with the Commission Orders discussed above to approve this post-test-period adjustment.

Q. Please explain the adjustment concerning LG&E's Hazard Tree Program.

A. Following the 2008 Wind Storm and the 2009 Winter Storm, both of which caused significant damage to the Companies' facilities, the Companies engaged Davies Consulting, Inc. to provide options for further improving the survivability of their electrical system. The report by Davies Consulting, Inc. was previously provided to the Commission in connection with its investigation of utilities' responses to the 2009 Winter Storm ("Davies Report"). One option the Davies Report recommends for any overall system hardening program relates to "hazard tree" removal. This is an extension of LG&E's and KU's typical tree trimming programs because the removal of these "hazardous trees" occurs outside of the Company's easements and rights-of-way. Approval of this adjustment is necessary to reflect the going forward cost of providing service. The cost of this additional vegetation management, which the

[2] *In the Matter of: The Application of Kentucky Utilities Company for Approval of an Alternative Method of Regulation of Its Rates and Services*, Case No. 1998-00474, Order at 68, 77-78 (Jan. 7, 2000).

Companies plan to implement with approval of new rates, will be $1,759,303 per year for LG&E. This adjustment is included in Reference Schedule 1.20 of Rives Exhibit 1.

Q. **Please explain the adjustment concerning the Kentucky Consortium for Carbon Storage.**

A. This adjustment is necessary to recover the costs of LG&E's investment in the Kentucky Consortium for Carbon Storage ("KCCS"). The Commission approved the establishment of a regulatory asset with regard to this investment in Case No. 2008-00308. The Companies allocate their contribution to KCCS between the two utilities on the basis of each utility's revenue, total assets, and payroll as of December 2007, resulting in a 51.22% allocation to KU and a 48.78% allocation to LG&E. LG&E proposes to amortize this regulatory asset over a period of four years, which corresponds to the duration of the project. This adjustment is included in Reference Schedule 1.29 of Rives Exhibit 1.

Q. **Please explain the adjustment concerning the Carbon Management Resource Group.**

A. This adjustment is necessary to recover the costs of LG&E's investment in the Carbon Management Resource Group ("CMRG"). The Commission approved the establishment of a regulatory asset with regard to this investment in Case No. 2008-00308. In a similar manner as discussed above for KCCS, the Companies agreement to provide CMRG up to $200,000 per year over 10 years is allocated 51.22% to KU and 48.78% to LG&E. LG&E proposes to amortize this regulatory asset over a period of ten years, which corresponds to the duration of the project. This adjustment is included in Reference Schedule 1.30 of Rives Exhibit 1.

Q. Please explain the adjustment to remove the expense associated with the Companies' settlement with the Southwest Power Pool ("SPP").

A. The Companies recently made a \$2.27 million one-time payment to SPP under a recent settlement agreement concerning SPP's provision of Independent Transmission Operator ("ITO") services to the Companies. LG&E's portion of the settlement expense was \$817,241. Because the settlement amount related to the cost of the entire 3.5-year (42-month) ITO contract with SPP, the portion of the settlement amount relating to time periods outside of the test year should be removed from test-year operating expenses. To achieve this exclusion, LG&E is removing 30/42 of its settlement amount from test-year operating expenses (\$583,743), though 12/42 of the settlement amount, representing the test-year portion of the settlement amount (\$233,498), should remain in test-year operating expenses. This adjustment is included in Reference Schedule 1.32 of Rives Exhibit 1.

Gas Pro-Forma Adjustments

Q. Was an adjustment made to eliminate unbilled revenues for gas operations?

A. Yes. Consistent with prior rate cases, unbilled revenues were removed from test-year operating revenues. This adjustment is included in Reference Schedule 1.00 of Rives Exhibit 1 and is consistent with the adjustment to eliminate unbilled revenues for the electric business. The Commission approved a similar adjustment in Case No. 2003-00433, and LG&E proposed such an adjustment in Case No. 2008-00252.

Q. Has an adjustment been made to eliminate the effect of LG&E's already-terminated Value Delivery Team surcredit ("VDT")?

A. Yes. On its own terms, the VDT surcredit terminated concurrently with the filing of LG&E's application in its most recent base rate proceeding, Case No. 2008-00252, which application LG&E filed on July 29, 2008. While the VDT terminated prior to the beginning of the test year, there remained a small amount of credits on the books during the test year due to billing adjustments. This adjustment is included in Reference Schedule 1.02 of Rives Exhibit 1.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

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

Lonnie E. Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of January 2010.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

APPENDIX A

Lonnie E. Bellar
E.ON U.S. Services Inc.
220 West Main Street
Louisville, Kentucky 40202

Education

Bachelors in Electrical Engineering;
University of Kentucky, May 1987
Bachelors in Engineering Arts;
Georgetown College, May 1987
E.ON Academy, Intercultural Effectiveness Program: 2002-2003
E.ON Finance, Harvard Business School: 2003
E.ON Executive Pool: 2003-2007
E.ON Executive Program, Harvard Business School: 2006
E.ON Academy, Personal Awareness and Impact: 2006

Professional Experience

E.ON U.S. LLC

Vice President, State Regulation and Rates	Aug. 2007 – Present
Director, Transmission	Sept. 2006 – Aug. 2007
Director, Financial Planning and Controlling	April 2005 – Sept. 2006
General Manager, Cane Run, Ohio Falls and Combustion Turbines	Feb. 2003 – April 2005
Director, Generation Services	Feb. 2000 – Feb. 2003
Manager, Generation Systems Planning	Sept. 1998 – Feb. 2000
Group Leader, Generation Planning and Sales Support	May 1998 – Sept. 1998

Kentucky Utilities Company

Manager, Generation Planning	Sept. 1995 – May 1998
Supervisor, Generation Planning	Jan. 1993 – Sept. 1995
Technical Engineer I, II and Senior, Generation System Planning	May 1987 – Jan. 1993

Professional Memberships

IEEE

Civic Activities

E.ON U.S. Power of One Co-Chair – 2007
Louisville Science Center – Board of Directors – 2008
Metro United Way Campaign – 2008
UK College of Engineering Advisory Board -- 2009

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	))))	CASE NO. 2009-00549

TESTIMONY OF
ROBERT M. CONROY
DIRECTOR, RATES
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: January 29, 2010

Q. Please state your name, position and business address.

A. My name is Robert M. Conroy. I am the Director of Rates for E.ON U.S. Services Inc., which provides services to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "Companies"). My business address is 220 West Main Street, Louisville, Kentucky. A statement of my professional history and education is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes, I have testified before the Commission on a number of occasions, including the Companies' most recent base rate cases, Case Nos. 2008-00251 & 2008-00252, the Companies' fuel adjustment clause ("FAC") review cases, Case Nos. 2009-00287 & 2009-00288, and environmental cost recovery ("ECR") proceedings, most recently in the Companies' 2009 ECR Plan proceedings, Case Nos. 2009-00197 & 2009-00198.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are: (1) to support certain exhibits identified below which are required by the Commission's regulations; (2) to explain certain proposed pro forma adjustments; and (3) to discuss and explain the various electric and gas rate and tariff changes LG&E proposes.

Q. Are you supporting certain information required by Commission regulation 807 KAR 5:001, Section 10(6)(a)-(v) and Section 10(7)(e)?

A. Yes, I am sponsoring the following schedules for the corresponding Filing Requirements:

• New Rates Effect – Overall Revenues	Section 10(6)(d)	Tab 23
• Average Customer Class Bill Impact	Section 10(6)(e)	Tab 24
• Analysis of Customer Bills	Section 10(6)(g)	Tab 26

Pro Forma Adjustments

Q. Has an adjustment been made to eliminate the mismatch in fuel cost recovery?

A. Yes. Consistent with past Commission practice, the mismatch between fuel costs and fuel cost recovery through LG&E's FAC has been eliminated. These over- and under-recoveries were taken directly from LG&E's monthly FAC filings. The Commission approved a similar adjustment in Case No. 2003-00433, and LG&E proposed such an adjustment in Case No. 2008-00252. This adjustment applies only to LG&E electric, and is included in Reference Schedule 1.03 of Rives Exhibit 1.

Q. Has an adjustment been made to annualize the level of revenues associated with the base rates for LG&E the Commission approved in Case No. 2008-00252?

A. Yes. The Commission's February 5, 2009 Order in Case No. 2008-00252 approved a reduction in annual electric revenues for LG&E of over $13 million (achieved through the reduction of certain electric base rates) and an increase in annual gas revenues of $22 million (achieved through an increase in gas base rates), which rates were to become effective for electric and gas service rendered on and after February 6, 2009. Because the test year at issue in this application is from November 1, 2008, to October 31, 2009, an adjustment is necessary to reflect the revenue impact of current gas and electric base rates for the entire test year. This adjustment applies to LG&E gas and electric, and is included in Reference Schedule 1.04 of Rives Exhibit 1. Conroy Exhibits 1 and 2 show the determination of the necessary adjustments to revenues to reflect a full year of electric and gas rates, respectively, approved in Case No. 2008-00252.

Q. Have adjustments been made to reflect the roll-in of the FAC and ECR for a full year?

A. Yes. The Commission's May 28, 2009 Order in Case No. 2008-00521, as amended by Order dated June 11, 2009, authorized the incorporation or "roll-in" of the FAC into base rates effective with the July 2009 billing cycle. In addition, the Commission's December 2, 2009 Order in Case No. 2009-00311 authorized the roll-in of the ECR into base rates to be effective with the February 2010 billing cycle. Test-year revenues have been adjusted to reflect the rolled-in level of base rates and FAC and ECR billings for a full year. Conroy Exhibit 1 shows the impact on base rate revenues of the FAC and ECR roll-ins for a full year. Conroy Exhibit 3 shows the impact on FAC billings of reflecting the new base fuel cost (Fb/Sb) for a full year. The adjustment to reflect the FAC roll-in is included in Reference Schedule 1.04, and the adjustment to reflect the ECR roll-in is included in Reference Schedule 1.06 of Rives Exhibit 1. Both of these adjustments apply only to LG&E electric, and are consistent with the methodology utilized in Case Nos. 2003-00433 and 2008-00252.

Q. Please explain the adjustment made to eliminate ECR revenues and expenses.

A. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-recovery cost trackers, an adjustment was made to eliminate ECR revenues during the test year and ECR expenses that will continue to be recovered through the ECR mechanism after the implementation of new base rates as shown in Reference Schedule 1.05 of Rives Exhibit 1. The ECR surcharge provides for full recovery of approved environmental costs that qualify for the surcharge.

In Case No. 2003-00433, LG&E proposed, and the Commission approved, the elimination of the original 1995 ECR Plan from the ECR mechanism. In a similar manner, LG&E is proposing in this proceeding to eliminate its 2001 and 2003 ECR Plans from its monthly ECR filings on a going-forward basis because the projects in those plans are now complete and have been in service for over five years, the costs of the projects in those plans are already included in base rates through a series of "roll-ins," and eliminating the two plans will simplify the oversight and administration of the ECR mechanism. As a result of eliminating the 2001 and 2003 ECR Plans, only the operating expenses associated with LG&E's 2005, 2006, 2009, and subsequent Plans that will continue to be recovered in the separate ECR mechanism are eliminated in this adjustment; however, all ECR revenues collected in the test year are eliminated because failure to do so would overstate LG&E's adjusted operating revenues by the portion of ECR revenues not received through the ECR mechanism going forward. LG&E proposes to recover the revenue requirements for the environmental compliance rate base associated with the 2001 and 2003 Plans through base rates, and proposes to continue to recover the revenue requirements of the remaining environmental compliance rate base through its monthly ECR filings. Upon approval of new base rates, LG&E will continue to use the approved ES Forms in the monthly ECR filings but exclude the cost associated with the 2001 and 2003 Plan projects in the expense month associated with the change in base rates until the next 2-year review at which time the ES Forms will be modified to reflect the elimination of the 2001 and 2003 Plans. Conroy Exhibit 4 shows the supporting data and calculations for the expenses associated with the 2001 and 2003 ECR Plans that are included in Reference Schedule 1.05 of Rives Exhibit 1

Q. Are there other adjustments necessary for the elimination of the 2001 and 2003 ECR Plans previously discussed?

A. Yes. As discussed in the testimony of Mr. Rives, LG&E's capitalization as of October 31, 2009, is adjusted to remove the environmental compliance rate base. This adjustment, shown in Column 6 on page 2 of Rives Exhibit 2, includes only the environmental compliance rate base associated with the ECR Plans that will continue to be included in the ECR monthly filings. It does not include the environmental rate base associated with the 2001 and 2003 ECR Plans or the remaining amount associated with the roll-in recently approved in Case No. 2009-00311.

Q. Please explain the adjustment made concerning off-system sales revenues related to the ECR mechanism.

A. In the determination of the monthly ECR surcharge, a portion of LG&E's environmental compliance costs are allocated to off-system sales, including intercompany sales, through the jurisdictional allocation ratio. But by including off-system and intercompany sales revenues in test-year operating results, these revenues are credited to jurisdictional customers. Moreover, because total ECR expenses are removed through the adjustment in Reference Schedule 1.05, the expenses associated with off-system and intercompany sales are understated. This results in an overstatement of margins from off-system and intercompany sales and a mismatch of the revenues and expenses related to the off-system and intercompany sales portion of the allocated environmental surcharge monthly revenue requirement. LG&E has included in this adjustment a reduction to revenues associated with ECR-related off-system and intercompany sales revenues. LG&E performed the adjustment in a manner generally consistent with the methodology prescribed in the Commission's Order on rehearing in Case No. 98-426 dated June 1, 2000, and in the manner used in Case Nos. 2003-00433 and 2008-00252; however, total off-system sales revenues, inclusive of intercompany sales, are used in the calculation.

This adjustment applies only to LG&E electric, and is included in Reference Schedule 1.07 of Rives Exhibit 1.

Q. Please explain the adjustment to eliminate DSM revenues and expenses.

A. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-recovery cost trackers, an adjustment was made to eliminate gas and electric revenues recovered through the Demand-Side Management Cost Recovery Mechanism ("DSMRM") and the corresponding demand-side management expenses recorded during the test year. The DSMRM includes a balance adjustment that automatically adjusts unit charges under the mechanism to account for differences between revenues collected and demand-side management program costs incurred during the applicable period. LG&E proposed a similar adjustment in its most recent base rate case, Case No. 2008-00252, and a similar adjustment was also approved by the Commission in Case No. 2003-00433. This adjustment applies to LG&E gas and electric, and is included in Reference Schedule 1.10 of Rives Exhibit 1.

Q. Please explain the adjustment to reflect billing corrections and customers switching to other rates during the test year.

A. LG&E must adjust its operating revenues to account for test-year billing corrections to four major electric accounts and one major gas account. Customer A was inadvertently double-billed in October 2009, the final month of the test year, and the correction to the customer's account was not entered until November 2009. Therefore, LG&E's operating revenues for the test year are overstated by the amount of the customer's October bill.

Customer B was inadvertently not billed in October 2008 and was double-billed in November 2008, resulting in an overstatement of test year revenues. Though no correction to the customer's account was required, because a billing cycle was skipped, an adjustment to test year revenues is appropriate because test year revenue includes an amount related to a billing cycle outside of the test period.

Customer C was not billed in the May 2009 billing cycle and was billed twice in June 2009. Though both periods are in the test year, the customer is billed a seasonal demand rate, and May is currently a winter month with a lower demand rate than June, which is a summer month. The customer's account was not corrected for the over-billed demand charges until after the end of the test period. LG&E is making an adjustment to test year revenues for the difference in the billing demand at the lower winter rate and the billing demand at the higher summer rate for the May metered demands.

For the months of March 2004 through February 2009, primary voltage electric Customer D was inadvertently billed as a secondary voltage customer, resulting in over-billed demand charges. In March 2009, a bill credit was issued to the customer for the amount of over-billings for the entire period, including months not in the test period. Therefore, LG&E is making an adjustment to test year revenues to remove the impact of those months not in the test period.

Beginning in June 2007 through March 2009, Customer E, a gas customer, was billed incorrectly due to a metering error. In April 2009, a billing adjustment was made that included correct billings for the entire period, including the months not in the test period. Therefore, LG&E is making an adjustment to test year revenues to remove the impact of those months not in the test period.

In addition to these billing corrections, LG&E proposes to adjust its gas operating revenues to account for two customers' rate-switching. One customer switched from Rate IGS to Rate FT; the other went from a special contract to Rate FT. Conroy Exhibit 5 applies the two customers' new rates to their full test-year usage, supporting a corresponding reduction to LG&E's test-year gas operating revenues. LG&E proposed an adjustment concerning customer rate-switching in Case No. 2008-00252. These adjustments are included in Reference Schedule 1.13 of Rives Exhibit 1.

Q. Please explain the adjustment to revenues and expenses to eliminate Gas Supply Clause ("GSC") recoveries and expenses.

A. This adjustment has been made to eliminate the effect of GSC recoveries and gas supply expenses for the test year. The supporting calculations are contained in Conroy Exhibit 6. This adjustment is included in Reference Schedule 1.39 of Rives

Exhibit 1. This adjustment is consistent with the methodology used in Case No. 2003-00433 and 2008-00252.

Electric Rate Design

Q. What efforts have LG&E and KU made towards harmonizing the service schedules offered by each company?

A. The Companies continue to take strides towards harmonizing their rate schedules by consolidating, renaming, adding, and revising them to be as consistent as possible between the two Companies. The table below summarizes the changes being made to the current rate schedule designations to transition towards a uniform set of rate schedules between the two Companies.

Current Rate Schedule	Proposed Rate Schedule	Availability kW or kVA
RS	RS	All
GS	GS	0 - 50
IPS Secondary	PS (Secondary)	50 - 250
CPS Secondary		
IPS Primary	PS (Primary)	0 - 250
CPS Primary		
CTOD Secondary	CTODS (Secondary)	250 - 5,000
ITOD Secondary	ITODS (Secondary)	250 - 5,000
ITOD Primary	ITODP (Primary)	250 - 75,000 kVA
CTOD Primary	CTODP (Primary)	250 - 75,000 kVA
RTS	RTS	0 - 75,000 kVA
IS	FLS	20,000 - 200,000 kVA

Although the Companies are not yet able to completely harmonize their rate schedules, the transition that began in the last two rate cases has continued through this proceeding. Conroy Exhibit 7 is a visual comparison of LG&E's and KU's rate schedules.

Q. What is the basic objective of the rate design being proposed?

A. It is the Companies' intent to continue the principles followed in the previous two cases of gradually eliminating cross-subsidization and bringing both the structure and the charges of the rate design in line with the results of the cost of service study. My testimony addresses changes the Company is proposing to the structure of the various rate schedules. These rate design principles and all charges are supported by the testimony and exhibits of W. Steven Seelye.

Q. Is LG&E proposing any general changes to its electric tariff?

A. Yes. The term "Customer Charge" is being changed to "Basic Service Charge" throughout the tariff to better reflect the reason for the charge and the costs it is designed to recover. Also, the winter and summer billing periods associated with the power rates are being redefined to include May in the summer billing period.

Q. Does LG&E propose to change all of its rate structures?

A. No. Though LG&E proposes to change most charges, it proposes structural changes only to its Power Service and time-of-day rate schedules. I will address only those rate schedules the Company proposes to change structurally or with significant text changes. Mr. Seelye supports all LG&E's proposed structural changes and charges in his testimony and exhibits.

Q. Does LG&E propose to modify the Industrial Power Service (Rate IPS) and Commercial Power Service (Rate CPS)?

A. Yes. LG&E proposes to combine the rates into a single rate named Power Service (Rate PS), harmonizing the rate with the rate design of KU. Otherwise, LG&E

proposes to retain the existing three-part rate structure consisting of a basic service charge, a flat energy charge, and a demand charge with a seasonal differential.

Also, the Rate PS minimum bill has been redesigned to more accurately reflect the purpose of a minimum billing provision. The purpose of a minimum bill is to ensure recovery of fixed costs associated with demand charges only. To that end, LG&E proposes a minimum tied only to a customer's demand. Though similar to the existing minimum, the proposed minimum for a given month is based only on demand and is the greatest of: (a) that month's maximum load; (b) fifty percent (50%) of the monthly maximum load during the preceding eleven billing periods; and (c) sixty percent (60%) of the contract capacity based on the expected maximum load on the system or the kW capacity of facilities specified by the customer. The charges and the minimum design are supported by the testimony and exhibits of Mr. Seelye.

Q. Is LG&E proposing to modify the Industrial Time-of-Day (Rate ITOD)?

A. Yes. Currently Rate ITOD is available for secondary and primary service. LG&E is proposing to leave customers under the current Rate ITOD receiving service at the secondary level on that rate schedule but rename it Industrial Time-of-Day Secondary (Rate ITODS). Rate ITODS will be available for secondary customers with loads between 250 kW and 5,000 kW. Primary service under the current Rate ITOD will be migrated to a new rate named Industrial Time-of-Day Primary (Rate ITODP). Rate ITODP will be available for primary customers with minimum average loads of 250 kVA and maximum loads of 75,000 kVA. The move to kVA billing and the potential increase to 75,000 kVA for industrial primary customers are further discussed below.

Q. Please describe other changes proposed for Rate ITODS.

A. The current rate for secondary service under the existing Rate ITOD employs two time periods. The length of the on-peak period makes it difficult for customers to shift load. To encourage load shifting away from the system peak hours, the on-peak period is being reduced and an additional intermediate time period is being introduced. LG&E is proposing a three-part rate structure consisting of a basic service charge, a flat energy charge, and a three-time-period (Peak, Intermediate, and Base) demand charge, harmonizing LG&E's design with that of KU.

Additionally, the minimum has been redesigned to match KU's proposed minimum, which uses an eleven-month, rather than a four-month, ratchet. The proposed minimum is applied for each demand time period. For the Peak and Intermediate periods, the proposed minimum for a given month is the greatest of: (a) that month's maximum load; and (b) fifty percent (50%) of the monthly maximum load during the preceding eleven billing periods. For the Base period, the proposed minimum for a given month is based only on demand and is the greatest of: (a) that month's maximum load but not less than 250 kW; (b) seventy-five percent (75%) of the monthly maximum load during the preceding eleven billing periods; and (c) seventy-five (75%) of the contract capacity based on either the expected maximum load on the system or the kW capacity of facilities specified by the customer.

These charges are supported by the testimony and exhibits of Mr. Seelye.

Q. Please describe other changes proposed for Rate ITODP.

A. The current rate for primary service under existing Rate ITOD employs two time periods with kW-based demand billing. Continuing the move in the last rate case where kVA billing was introduced for transmission deliveries, LG&E is proposing kVA billing for Rate ITODP. The length of the on-peak periods makes it difficult for customers to shift load. To encourage load shifting away from the system peak hours, the on-peak period is being reduced and an additional intermediate time period is being introduced. LG&E is proposing a three-part rate structure consisting of a basic service charge, a flat energy charge, and a three-time-period (Peak, Intermediate, and Base) demand charge, harmonizing LG&E's design with that of KU.

Additionally, the minimum has been redesigned to match the proposed minimum of KU, which utilizes an eleven-month, rather than a four-month, ratchet. The proposed minimum is applied for each demand time period. For the Peak and Intermediate periods, the proposed minimum for a given month is the greatest of: (a) that month's maximum load; and (b) fifty percent (50%) of the monthly maximum load during the preceding eleven billing periods. For the Base period, the proposed minimum for a given month is based only on demand and is the greatest of: (a) that month's maximum load but not less than 250 kVA; (b) seventy-five percent (75%) of the monthly maximum load during the preceding eleven billing periods; and (c) seventy-five (75%) of the contract capacity based on either the expected maximum load on the system or the kW capacity of facilities specified by the customer.

One other difference between Rate ITODP and primary service under Rate ITOD it is replacing should be noted. The maximum load permitted on Rate ITODP is 75,000 kVA, compared to the current 50,000 kW for primary service under the current Rate ITOD. Existing customers can increase their loads up to 75,000 kVA with annual increases not exceeding 2,000 kVA unless approved by the Company's transmission operator. New loads coming onto the system cannot exceed 50,000 kVA; however, once they are an existing customer they have the ability to increase their load as previously mentioned. This change is made to allow for growth of customers' loads while taking into consideration system constraints.

These charges and minimum design are supported by the testimony and exhibits of Mr. Seelye.

Q. Is LG&E proposing to modify the Commercial Time-of-Day (Rate CTOD)?

A. Yes. Currently Rate CTOD is available for secondary and primary services. In a similar manner as discussed above for the existing Rate ITOD, LG&E is proposing to leave customers under the current Rate CTOD receiving service at the secondary level on that rate schedule but rename it Commercial Time-of-Day Secondary (Rate CTODS). Rate CTODS will be available for secondary customers with loads between 250 kW and 5,000 kW. Primary service under the current Rate CTOD will be migrated to a new rate named Commercial Time-of-Day Primary (Rate CTODP). Rate CTODP will be available for primary customers with minimum average loads of 250 kVA and maximum loads of 75,000 kVA. The move to kVA billing and the potential increase to 75,000 kVA for commercial primary customers are further discussed below.

Q. Please describe other changes proposed for Rate CTODS.

A. The current rate for secondary service under the existing Rate CTOD employs two time periods. The length of the on-peak period makes it difficult for customers to shift load. To encourage load shifting away from the system peak hours, the on-peak period is being reduced and an additional intermediate time period is being introduced. LG&E is proposing a three-part rate structure consisting of a basic service charge, a flat energy charge, and a three-time-period (Peak, Intermediate, and Base) demand charge, harmonizing the LG&E design with that of KU.

Additionally, the minimum has been redesigned to match KU's proposed minimum, which utilizes an eleven-month, rather than a four-month, ratchet. The proposed minimum is applied for each demand time period. For the Peak and Intermediate periods, the proposed minimum for a given month is the greatest of: (a) that month's maximum load; and (b) fifty percent (50%) of the monthly maximum load during the preceding eleven billing periods. For the Base period, the proposed minimum for a given month is based only on demand and is the greatest of: (a) that month's maximum load but not less than 250 kW; (b) seventy-five percent (75%) of the monthly maximum load during the preceding eleven billing periods; and (c) seventy-five percent (75%) of the contract capacity based on either the expected maximum load on the system or the kW capacity of facilities specified by the customer.

These charges are supported by the testimony and exhibits of Mr. Seelye.

Q. Please describe other changes proposed for Rate CTODP.

A. The current rate for primary service under existing Rate CTOD employs two time periods with kW-based demand billing. Continuing the move in the last rate case where kVA billing was introduced for transmission deliveries, LG&E is proposing kVA billing for Rate CTODP. The length of the on-peak periods makes it difficult for customers to shift load. To encourage load shifting away from the system peak hours, the on-peak period is being reduced, and an additional intermediate time period is being introduced. LG&E is proposing a three-part rate structure consisting of a basic service charge, a flat energy charge, and a three-time-period (Peak, Intermediate, and Base) demand charge, harmonizing LG&E's design with that of KU.

Additionally, the minimum has been redesigned to match the proposed minimum of KU, which uses an eleven-month ratchet. The proposed minimum is applied for each demand time period. For the Peak and Intermediate periods, the proposed minimum for a given month is the greatest of: (a) that month's maximum load; and (b) fifty percent (50%) of the monthly maximum load during the preceding eleven billing periods. For the Base period, the proposed minimum for a given month is based only on demand and is the greatest of: (a) that month's maximum load but not less than 250 kVA; (b) seventy-five percent (75%) of the monthly maximum load during the preceding eleven billing periods; and (c) seventy-five percent (75%) of the contract capacity based on either the expected maximum load on the system or the kW capacity of facilities specified by the customer.

One other difference between Rate CTODP and primary service under Rate CTOD it is replacing should be noted. The maximum load permitted on CTODP is 75,000 kVA as compared to the current 50,000 kW for primary service under the current Rate CTOD. Existing customers can increase their loads up to 75,000 kVA with annual increases not exceeding 2,000 kVA unless approved by the Company's transmission operator. New loads coming onto the system cannot exceed 50,000 kVA; however, once they are an existing customer they have the ability to increase their load as previously mentioned. This change is made to allow for growth of the customer's load while taking into consideration system constraints.

These charges and minimum design are supported by the testimony and exhibits of Mr. Seelye.

Q. Is LG&E proposing to modify Retail Transmission Service (Rate RTS)?

A. Yes. Consistent with the changes to Rate ITOD and Rate CTOD discussed above, LG&E proposes to introduce three demand time periods, alter the minimum billing, and increase the availability cap for Rate RTS.

The length of the on-peak periods makes it difficult for customers to shift load. To encourage load shifting away from the system peak hours, the on-peak period is being reduced and an additional intermediate time period is being introduced. LG&E is proposing a three-part rate structure consisting of a basic service charge, a flat energy charge, and a three-time-period (Peak, Intermediate, and Base) demand charge, harmonizing LG&E's design with that of KU.

Additionally, the minimum has been redesigned to match the proposed minimum of KU, which utilizes an eleven-month ratchet. The proposed minimum is applied for each demand time period. For the Peak and Intermediate periods, the proposed minimum for a given month is the greatest of: (a) that month's maximum load; and (b) fifty percent (50%) of the monthly maximum load during the preceding eleven billing periods. For the base period, the proposed minimum for a given month is based only on demand and is the greatest of: (a) that month's maximum load but not less than 250 kVA; (b) seventy-five percent (75%) of the monthly maximum load during the preceding eleven billing periods; and (c) seventy-five percent (75%) of the contract capacity based on either the expected maximum load on the system or the kW capacity of facilities specified by the customer.

In addition, as discussed above for Rate ITODP and CTODP, the maximum load permitted on Rate RTS is 75,000 kVA, compared to the current 50,000 kVA. Existing customers can increase their loads up to 75,000 kVA with annual increases not exceeding 2,000 kVA unless approved by the Company's transmission operator. New loads coming onto the system cannot exceed 50,000 kVA; however, once they are an existing customer they have the ability to increase their load as previously mentioned. This change is made to allow for growth of the customer's load while taking into consideration system constraints.

These charges and minimum design are supported by the testimony and exhibits of Mr. Seelye.

Q. Is LG&E proposing to modify the Industrial Service (Rate IS)?

A. Yes, LG&E proposes to rename "Industrial Service" to be "Fluctuating Load Service (Rate FLS)" because it more accurately describes the rate. In addition, LG&E proposes to modify Rate FLS to match the changes made to the proposed Rate ITODP, CTODP, and RTS, with the notable exception that Rate FLS will be based on a 5-minute demand billing interval. Rate FLS will continue to be available for primary and transmission service.

LG&E proposes to introduce three demand time periods, eliminate the 15-minute demand charges, and base the demand charges only on 5-minute demand intervals. The length of the on-peak periods makes it difficult for customers to shift load. To encourage load shifting away from the system peak hours, the on-peak period is being reduced and an additional intermediate time period is being introduced. LG&E is proposing a three-part rate structure consisting of a basic service charge, a flat energy charge, and a three-time-period (Peak, Intermediate, and Base) demand charge, harmonizing LG&E's design with that of KU.

Additionally, the minimum has been redesigned to match the 5-minute demand intervals and the three-time-period design. The proposed minimum is based only on demand and is applied for each demand time period. For the Peak and Intermediate periods for a given month, it is the greatest of: (a) that month's maximum load; and (b) sixty percent (60%) of the monthly maximum load during the preceding eleven billing periods. For the Base period, the proposed minimum for a given month is based only on demand and is the greatest of: (a) that month's maximum load but not less than 20,000 kVA; (b) seventy-five percent (75%) of the monthly maximum load during the preceding eleven billing periods; and (c) seventy-five percent (75%) of the contract capacity based on either the expected maximum load on the system or the kW capacity of facilities specified by the customer.

These charges and minimum design are supported by the testimony and exhibits of Mr. Seelye.

Q. What changes are LG&E proposing to its lighting rates Lighting Service LS and Restricted Lighting Service RLS?

A. LG&E is not proposing any language changes to the RLS lighting tariff, but will be revising the various charges. The changes for the LS lighting are primarily associated with formatting for clarity and harmonizing the language with that of KU. An effort has also been made to more clearly define what facilities are provided with each type light and service. All charges are supported by the testimony and exhibits of Mr. Seelye.

Q. Is LG&E proposing any additions to its lighting service?

A. Yes. LG&E added a Contemporary "fixture only" option to its current underground selections for LS. Although not a new fixture type, this new option will allow for the installation of multiple fixtures on a single pole. Such change was in response to numerous customer requests.

Q. Does LG&E propose to modify its Cable Television Attachment Charges (Rate CTAC)?

A. Yes, LG&E proposes to modify Rate CTAC tariff to match KU's Rate CTAC tariff (as it is being proposed in KU's concurrently filed base rate case), further harmonizing the Companies' electric tariffs. (KU's proposed Rate CTAC tariff is the same as its current Rate CTAC tariff, except for a change in the amount of the attachment charge, an extension of the bill due date, and the elimination of several redundant paragraphs in the Terms and Conditions section.) LG&E's revised Rate CTAC creates a single attachment charge, billed semi-annually based on installed facilities as of June 1 and December 1 of each year. Mr. Seelye's testimony explains and supports the attachment charge.

Q. Is LG&E proposing to modify its Curtailable Service Riders?

A. Yes. LG&E currently has three Curtailable Service Riders, CSR1, CSR2, and CSR3. CSR1 and CSR3 are restricted to customers currently on the rate. All three current CSR riders vary by the number of hours of curtailment that may be requested, the credit charge that is given, and whether buy-through is available. In place of CSR1, CSR2, and CSR3, LG&E proposes a single CSR, which would allow 500 hours of curtailment in any 12-month period. Physical curtailment would be required for 100 hours, and the other 400 hours of curtailment would be met by either physical curtailment or an automatic buy-through at a formulaic price. These charges are supported by the testimony and exhibits of Mr. Seelye.

Q. What changes does LG&E propose to make to its Excess Facilities Rider (Rider EF)?

A. The rider currently allows a customer to use facilities beyond those normally provided for service by paying either: (1) a monthly charge reflecting a return on the installed cost of the facilities, plus maintenance costs; or (2) paying the installed cost of the facilities in advance, plus a monthly charge based on maintenance costs. Under the current Rider EF, a customer who paid upfront for the installed cost of any excess facilities must pay for them again if the facilities fail. LG&E proposes to modify the Rider EF to make LG&E responsible for replacing excess facilities that fail. Mr. Seelye's testimony and exhibits support Rider EF and LG&E's proposed changes thereto.

Q. Is LG&E proposing to rename any other tariffs or add any new tariffs?

A. Yes, LG&E proposes to rename the "Intermittent/Fluctuating Load Rider" to be the "Intermittent Load Rider" to avoid any confusion with the Fluctuating Load Service, though it proposes no other changes to the rider. Also, LG&E proposes to add a Low Emissions Vehicle Rate, which John Wolfram addresses in his testimony.

Q. How will this proceeding affect the Company's proposed changes to the Small Green Energy Rider ("SGE") and Large Green Energy Rider ("LGE") submitted in Case No. 2009-00467?

A. The Company does not propose to make any substantive changes to Riders SGE and LGE as a result of this proceeding, though the Company will make basic formatting and other generally applicable changes to the draft rider proposed in Case No. 2009-00467 pending the outcome of that proceeding before filing the final tariff in this proceeding.

Q. What changes does LG&E propose to make to its Environmental Cost Recovery Surcharge rider?

A. LG&E proposes to make only minor change to the listing of the specific rate schedules to which the ECR applies under the section for "Availability of Service" to reflect the appropriate name changes proposed above.

Q. Does LG&E propose any changes to the Demand-Side Management Cost Recovery Mechanism schedule (Adjustment Clause DSM)?

A. Yes, though the changes LG&E proposes are minor. The only substantive change LG&E proposes is to add a definition of "industrial customer." If the Commission approves LG&E's proposed tariff changes, there will no longer be any "industrial" rates. It is therefore necessary to add a definition of "industrial customer" to the DSM tariff sheets to determine which customers could qualify for industrial DSM programs.

The only other changes LG&E proposes are those necessary to track the renaming of rate schedules LG&E is proposing in this proceeding.

Gas Rate Design

Q. Is LG&E proposing any general changes to its gas tariff?

A. Yes. The term "Customer Charge" is being changed to "Basic Service Charge" throughout the tariff to better reflect the reason for the charge and the costs it is designed to recover.

Q. Does LG&E propose to change all of its gas rate structures?

A. No. Though LG&E proposes to change most gas charges, the rate structures themselves are not changing, with the exception of the Excess Facilities Rider. I will address only those rate schedules to which LG&E proposes to make significant text changes. The structural change to the Excess Facilities Rider and all charge changes are supported by the testimony and exhibits of Mr. Seelye.

Q. Are any changes being proposed for the Residential Gas Service, Rate RGS?

A. Yes. In addition to the changes in rates, additional language has been added under the Availability of Service section to clarify the types of customers to be served under the schedule and to better define the term "residential customer." There is no change in the actual kinds of customers intended to be served under this rate schedule.

Q. Are any changes being proposed for the Firm Commercial Gas Service, Rate CGS?

A. Yes. In addition to the changes in rates, additional language has been added under the Availability of Service section to clarify the types of customers to be served under the schedule and to better define the term "commercial customer." There is no change in the actual kinds of customers intended to be served under this rate schedule.

Q. Are any changes being proposed for the Firm Industrial Gas Service, Rate IGS?

A. Yes. In addition to the changes in rates, additional language has been added under Availability of Service section to clarify the types of customers to be served under the schedule and to better define the term "industrial customer." There is no change in the actual kinds of customers intended to be served under this rate schedule.

Q. Does the Company propose to make any changes to its Distributed Generation Gas Service tariff (Rate DGGS)?

A. Yes. Rate DGGS was proposed for the first time in the last rate case and just became effective on February 6, 2009. Following the 2008 Wind Storm and the 2009 Winter Storm, the Company saw a significant increase in the number of commercial customers interested in natural gas generators for back-up purposes. As LG&E engaged in discussions with such customers regarding the appropriate tariff for service, it became clear that there was significant confusion regarding the DGGS tariff and, specifically, the calculation of charges under that tariff. Because of the confusion over the application of the Rate and the calculation of charges, the Company elected not to apply the tariff to any applicable installations. Instead, LG&E has served those installations under other existing rate schedules. Therefore, there are currently no customers taking service under Rate DGGS.

Q. What changes does the Company propose to make to Rate DGGS?

A. The most significant change the Company proposes is to "grandfather" all existing gas-fired electric generation currently installed, as well as all those installed and operating by the ninetieth day following the effective date of the revised tariff sheet. In this case, "grandfathering" means excluding such generators from taking service under Rate DGGS; rather, they will continue to take service under otherwise-applicable tariff sheets. The Company will use the 90-day period following the effective date of the revised DGGS tariff to communicate clearly with customers concerning the requirements of DGGS, as well as to allow installations already under construction to be completed before DGGS would apply to them.

The second change to Rate DGGS is the inclusion of residential customers in its applicability if a residential customer requests an additional, separate point of delivery to provide gas for use in standby electric generation.

The third change to Rate DGGS is to add a per-delivery-point Basic Service Charge for customers whose meters have a capacity of less than 5,000 cf/hour. (Consistent with Rates CGS and IGS, the higher Basic Service Charge remains for customers whose meters have capacities of greater than, or equal to, 5,000 cf/hour.) This change will allow customers with smaller electric generation facilities to take service under Rate DGGS without its being cost-prohibitive, while still comporting with cost-causation principles.

The fourth and final change is to set the Monthly Billing Demand to be the Maximum Daily Quantity ("MDQ"), which in turn is 24 times the Maximum Hourly Rate ("MHR"). The MHR is the maximum hourly connected gas load in Ccf that the Customer's installation will require when operating at full capacity. If the MDQ is less than 10 Ccf, the revised DGGS tariff sets the minimum Monthly Billing Demand to be 10 Ccf.

Q. Is LG&E proposing any new schedules?

A. Yes. LG&E is proposing a new rider Gas Meter Pulse Service (Rider GMPS), available to commercial and industrial customers. It is similar to the Meter Pulse Charge offered by the LG&E electric business and KU. The tariff fully describes the requirements and services provided by the tariff. It will permit customers to evaluate their gas consumption on a real-time basis. The charges are supported by the testimony and exhibits of Mr. Seelye.

Q. Are any changes being proposed for the Pooling Service-TS or Pooling Service-FT?

A. Yes. A minor change has been made under Terms and Conditions paragraph 3. A statement has been added regarding the use of financial instruments as surety in lieu of a cash deposit.

Q. Is any change being proposed for the Excess Facilities Rider (Rider EF)?

A. The rider currently allows a customer to use facilities beyond those normally provided for service by paying either: (1) a monthly charge reflecting a return on the installed cost of the facilities, plus maintenance costs; or (2) paying the installed cost of the facilities in advance, plus a monthly charge based on maintenance costs. Under the current Rider EF, a customer who paid upfront for the installed cost of any excess facilities must pay for them again if the facilities fail. LG&E proposes to modify the Rider EF to make LG&E responsible for replacing excess facilities that fail. Mr. Seelye's testimony and exhibits support the Rider EF.

Q. Is any change being proposed for the Gas Supply Clause?

A. Yes, a sentence was added on Rate Sheet No. 85.1 for greater flexibility in administering the GSC by allowing for "out-of-period" filings. Currently LG&E updates the GSC every three months to be effective for a three-month period. The language being added specifies that LG&E may make such a filing outside of the three-month cycle if conditions in the natural gas market change significantly and such a filing is warranted.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Director - Rates for E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert M. Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of January 2010.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

APPENDIX A

Robert M. Conroy
Director, Rates
E.ON U.S. Services Inc.
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-3324

Education

Masters of Business Administration
Indiana University (Southeast campus), December 1998. GPA: 3.9

Bachelor of Science in Electrical Engineering
Rose Hulman Institute of Technology, May 1987. GPA: 3.3

Essentials of Leadership, London Business School, 2004

Center for Creative Leadership, Foundations in Leadership program, 1998

Registered Professional Engineer in Kentucky, 1995

Previous Positions

Manager, Rates	April 2004 – Feb 2008
Manager, Generation Systems Planning	Feb. 2001 – April 2004
Group Leader, Generation Systems Planning	Feb. 2000 – Feb. 2001
Lead Planning Engineer	Oct. 1999 – Feb. 2000
Consulting System Planning Analyst	April 1996 – Oct. 1999
System Planning Analyst III & IV	Oct. 1992 - April 1996
System Planning Analyst II	Jan. 1991 - Oct. 1992
Electrical Engineer II	Jun. 1990 - Jan. 1991
Electrical Engineer I	Jun. 1987 - Jun. 1990

Professional/Trade Memberships

Registered Professional Engineer in Kentucky, 1995

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations showing the effect on Base Rate Revenue of the New Base Rates for a full year
Based on Sales for the 12 months ended October 31, 2009

		PSC 7 Rates for Full Year		FAC Rollin Rates for Full Year		ECR Rollin Rates for Full Year	
	As Billed Base Rate Revenues	Calculated Base Rate Revenues	Change in Revenues	Calculated Base Rate Revenues	Change in Revenues	Calculated Base Rate Revenues	Change in Revenues
RESIDENTIAL SERVICE	$ 285,705,345	$ 284,532,774	$ (1,172,571)	$ 293,534,537	$ 9,001,762	$ 295,829,437	$ 2,294,901
GENERAL SERVICE	$ 106,997,266	$ 107,706,985	$ 709,719	$ 110,923,952	$ 3,216,967	$ 113,393,157	$ 2,469,205
COMMERCIAL SERVICE							
Primary	$ 9,159,678	$ 8,975,333	$ (184,345)	$ 9,364,993	$ 389,660	$ 9,433,772	$ 68,779
Secondary	$ 120,703,771	$ 119,175,698	$ (1,528,073)	$ 123,634,319	$ 4,458,621	$ 124,524,435	$ 890,116
COMMERCIAL TIME OF DAY SERVICE							
Primary	$ 16,853,278	$ 16,886,230	$ 32,951	$ 17,648,035	$ 761,805	$ 17,756,702	$ 108,667
Secondary	$ 19,553,468	$ 20,398,969	$ 845,501	$ 21,258,567	$ 859,598	$ 21,383,611	$ 125,044
INDUSTRIAL SERVICE							
Primary	$ 5,878,328	$ 5,874,788	$ (3,540)	$ 6,141,140	$ 266,352	$ 6,186,022	$ 44,881
Secondary	$ 29,899,861	$ 29,758,020	$ (141,841)	$ 30,906,041	$ 1,148,021	$ 31,118,907	$ 212,866
INDUSTRIAL TIME OF DAY SERVICE							
Primary	$ 72,869,538	$ 73,426,859	$ 557,321	$ 76,907,144	$ 3,480,285	$ 77,291,276	$ 384,132
Secondary	$ 2,375,054	$ 2,364,348	$ (10,706)	$ 2,454,463	$ 90,115	$ 2,466,858	$ 12,394
RETAIL TRANSMISSION SERVICE	$ 19,310,974	$ 18,899,136	$ (411,838)	$ 19,861,065	$ 961,929	$ 19,989,801	$ 128,736
STREET LIGHTING ENERGY RATE SLE	$ 166,627	$ 165,338	$ (1,289)	$ 174,964	$ 9,626	$ 174,514	$ (450)
TRAFFIC LIGHTING ENERGY RATE TLE	$ 230,451	$ 229,390	$ (1,061)	$ 238,377	$ 8,987	$ 237,941	$ (436)
OUTDOOR LIGHTING RATE LS	$ 14,307,359	$ 14,247,188	$ (60,171)	$ 14,541,404	$ 294,216	$ 14,570,871	$ 29,467
Subtotal before Special Contract Revenue	$ 704,010,998	$ 702,641,056	$ (1,369,942)	$ 727,589,001	$ 24,947,945	$ 734,357,303	$ 6,768,302
Special Contracts	$ 13,321,648	$ 12,085,342	$ (1,236,307)	$ 12,734,186	$ 648,844	$ 12,819,808	$ 85,622
Total Revenues	$ 717,332,647	$ 714,726,398	$ (2,606,249)	$ 740,323,187	$ 25,596,789	$ 747,177,111	$ 6,853,924

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculations showing the effect on Base Rate Revenue of the Revised Base Rates, the FAC Roll-in and the ECR Roll-in for a full year

Based on Sales for the 12 months ended October 31, 2009

					"As Billed Rates" During 12 Month Period		P.S.C. 7 for Full Year		FAC Rollin Rates for Full Year		"Current Rates" ECR Rollin Rates for Full Year	
	Customers 12mos Oct 2009	Basic Demand	Peak Demand	kWh's	Unit Charges	Calculated Revenue	Unit Charges	Calculated Revenue	Unit Charges	Calculated Revenue	Unit Charges	Calculated Revenue
RESIDENTIAL RATE RS												
Customers For the 12 Month Period	4,131,523				$ 5.00	$ 20,657,615	$ 5.00	$ 20,657,615	$ 5.00	$ 20,657,615	$ 5.00	$ 20,657,615
kWh Nov08-Jan09 Rates:				1,156,527,466	$ 0.06404	$ 74,064,019	$ 0.06303	$ 72,895,926	$ 0.06658	$ 77,001,599	$ 0.06714	$ 77,649,254
kWh Feb09-Jun09 Rates:				1,369,360,091	$ 0.06303	$ 86,310,767	$ 0.06303	$ 86,310,767	$ 0.06658	$ 91,171,995	$ 0.06714	$ 91,938,837
kWh Jul09-Oct09 Rates:				1,558,510,791	$ 0.06658	$ 103,765,648	$ 0.06658	$ 103,765,648	$ 0.06658	$ 103,765,648	$ 0.06714	$ 104,638,415
Minimum and Partial Month Billings						$ 27,531		$ 27,680		$ 27,679		$ 27,676
TOTAL	4,131,523			4,084,398,348		$ 284,825,580		$ 283,657,637		$ 292,624,536		$ 294,911,796
RATE WH - RESIDENTIAL												
Customers For the 12 Month Period	53,195				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
kWh Nov08-Jan09 Rates:				4,074,839	$ 0.06404	$ 260,953	$ 0.06303	$ 256,837	$ 0.06658	$ 271,303	$ 0.06714	$ 273,585
kWh Feb09-Jun09 Rates:				4,819,881	$ 0.06303	$ 303,797	$ 0.06303	$ 303,797	$ 0.06658	$ 320,908	$ 0.06714	$ 323,607
kWh Jul09-Oct09 Rates:				3,311,861	$ 0.06658	$ 220,504	$ 0.06658	$ 220,504	$ 0.06658	$ 220,504	$ 0.06714	$ 222,358
Minimum and Partial Month Billings		-				$ 77		$ 77		$ 77		$ 77
TOTAL	53,195			12,206,581		785,331		781,215		812,791		819,627
RATE RRP - RESIDENTIAL RESPONSIVE PRICING												
Customers For the 12 Month Period	1,150				$ 10.00	$ 11,500	$ 10.00	$ 11,500	$ 10.00	$ 11,500	$ 10.00	$ 11,500
kWh Nov08-Jan09 Rates: Period 1				198,370	$ 0.04359	$ 8,647	$ 0.04217	$ 8,365	$ 0.04572	$ 9,069	$ 0.04628	$ 9,181
kWh Feb09-Jun09 Rates: Period 1				346,729	$ 0.04217	$ 14,622	$ 0.04217	$ 14,622	$ 0.04572	$ 15,852	$ 0.04628	$ 16,047
kWh Jul09-Oct09 Rates: Period 1				274,971	$ 0.04572	$ 12,572	$ 0.04572	$ 12,572	$ 0.04572	$ 12,572	$ 0.04628	$ 12,726
kWh Nov08-Jan09 Rates: Period 2				117,942	$ 0.05589	$ 6,592	$ 0.05448	$ 6,425	$ 0.05803	$ 6,844	$ 0.05859	$ 6,910
kWh Feb09-Jun09 Rates: Period 2				156,184	$ 0.05448	$ 8,509	$ 0.05448	$ 8,509	$ 0.05803	$ 9,063	$ 0.05859	$ 9,151
kWh Jul09-Oct09 Rates: Period 2				158,896	$ 0.05803	$ 9,221	$ 0.05803	$ 9,221	$ 0.05803	$ 9,221	$ 0.05859	$ 9,310
kWh Nov08-Jan09 Rates: Period 3				45,185	$ 0.11007	$ 4,974	$ 0.10867	$ 4,910	$ 0.11222	$ 5,071	$ 0.11278	$ 5,096
kWh Feb09-Jun09 Rates: Period 3				59,732	$ 0.10867	$ 6,491	$ 0.10867	$ 6,491	$ 0.11222	$ 6,703	$ 0.11278	$ 6,737
kWh Jul09-Oct09 Rates: Period 3				72,986	$ 0.11222	$ 8,190	$ 0.11222	$ 8,190	$ 0.11222	$ 8,190	$ 0.11278	$ 8,231
kWh Nov08-Jan09 Rates: Period 4				-	$ 0.30476	$ -	$ 0.30332	$ -	$ 0.30687	$ -	$ 0.30743	$ -
kWh Feb09-Jun09 Rates: Period 4				1,693	$ 0.30332	$ 514	$ 0.30332	$ 514	$ 0.30687	$ 520	$ 0.30743	$ 520
kWh Jul09-Oct09 Rates: Period 4				4,458	$ 0.30687	$ 1,368	$ 0.30687	$ 1,368	$ 0.30687	$ 1,368	$ 0.30743	$ 1,371
Minimum and Partial Month Billings						$ 1,236		$ 1,236		$ 1,236		$ 1,236
TOTAL	1,150			1,437,146		$ 94,434		$ 93,923		$ 97,209		$ 98,014
TOTAL RESIDENTIAL	4,185,868			4,098,042,075		$ 285,705,345		$ 284,532,774		$ 293,534,537		$ 295,829,437

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculations showing the effect on Base Rate Revenue of the Revised Base Rates, the FAC Roll-in and the ECR Roll-in for a full year

Based on Sales for the 12 months ended October 31, 2009

	Customers 12mos Oct 2009	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period Unit Charges	"As Billed Rates" During 12 Month Period Calculated Revenue	P.S.C. 7 for Full Year Unit Charges	P.S.C. 7 for Full Year Calculated Revenue	FAC Rollin Rates for Full Year Unit Charges	FAC Rollin Rates for Full Year Calculated Revenue	"Current Rates" ECR Rollin Rates for Full Year Unit Charges	"Current Rates" ECR Rollin Rates for Full Year Calculated Revenue
GENERAL SERVICE RATE GS												
Single Phase Customers For the 12 Month F	353,877				10.00	3,538,770	10.00	3,538,770	10.00	3,538,770	10.00	3,538,770
kWh Nov08-Jan09 Rates:				-	0.07621	-	-	-	-	-	-	-
Summer Rates				123,101,454	0.06849	8,431,219	0.07050	8,678,653	0.07405	9,115,663	0.07579	9,329,859
Winter Rates				151,531,324	0.07050	10,682,958	0.07050	10,682,958	0.07405	11,220,895	0.07579	11,484,559
kWh Feb09-Jun09 Rates:				327,236,231	0.07405	24,231,843	0.07405	24,231,843	0.07405	24,231,843	0.07579	24,801,234
kWh Jul09-Oct09 Rates:												
Minimum and Partial Month Billings						184,318		184,318		184,318		184,315
TOTAL	353,877			601,869,009		47,069,108		47,316,542		48,291,488		49,338,737
Three Phase Customers For the 12 Month F	139,826				15.00	2,097,390	15.00	2,097,390	15.00	2,097,390	15.00	2,097,390
kWh Nov08-Jan09 Rates:				-	0.07621	-	$0.00000	-	-	-	-	-
Summer Rates				263,952,166	0.06849	18,078,084	0.07050	18,608,628	0.07405	19,545,658	0.07579	20,004,935
Winter Rates				345,349,794	0.07050	24,347,160	0.07050	24,347,160	0.07405	25,573,152	0.07579	26,174,061
kWh Feb09-Jun09 Rates:				178,083,965	0.07405	13,187,118	0.07405	13,187,118	0.07405	13,187,118	0.07579	13,496,984
kWh Jul09-Oct09 Rates:												
Minimum and Partial Month Billings						18,132		18,132		18,132		18,132
TOTAL	139,826			787,385,925		57,727,884		58,258,428		60,421,449		61,791,501
GSWH Customers For the 12 Month Period	999				-	-	-	-	-	-	-	-
kWh Nov08-Jan09 Rates:				-	0.07621	-	0.07050	-	0.07405	-	0.07579	-
Summer Rates				63,500	0.06849	4,349	0.07050	4,477	0.07405	4,702	0.07579	4,813
Winter Rates				92,028	0.07050	6,488	0.07050	6,488	0.07405	6,815	0.07579	6,975
kWh Feb09-Jun09 Rates:				77,729	0.07405	5,756	0.07405	5,756	0.07405	5,756	0.07579	5,891
kWh Jul09-Oct09 Rates:												
Minimum and Partial Month Billings						(10)		(10)		(10)		(10)
TOTAL	999			233,257		16,583		16,711		17,263		17,669
Space Heating Rider Customers For the 12	10,412				-	-	-	-	-	-	-	-
kWh Nov08-Jan09 Rates:				-	0.07621	-	0.07050	-	$0.07405	-	0.07579	-
Summer Rates				11,626,286	0.06849	796,284	0.07050	819,653	$0.07405	860,926	0.07579	881,156
Winter Rates				10,468,323	0.07050	738,017	0.07050	738,017	$0.07405	775,179	0.07579	793,394
kWh Feb09-Jun09 Rates:				7,492,069	0.07405	554,788	0.07405	554,788	$0.07405	554,788	0.07579	567,824
kWh Jul09-Oct09 Rates:												
Minimum and Partial Month Billings						1,832		1,832		1,832		1,832
TOTAL	10,412			29,586,678		2,090,921		2,114,290		2,192,726		2,244,207
Three Phase Primary Customers For the 12	42				15.00	630	-	-	-	-	-	-
kWh Nov08-Jan09 Rates:				-	0.07621	-	-	-	-	-	-	-
Summer Rates				1,406,205	0.06849	96,311	-	-	-	-	-	-
Winter Rates				-	-	-	-	-	-	-	-	-
kWh Feb09-Jun09 Rates:				-	-	-	-	-	-	-	-	-
kWh Jul09-Oct09 Rates:												
Primary Service Discount						(5,186)		(0)		(0)		(0)
Minimum and Partial Month Billings						(0)		(0)		(0)		(0)
TOTAL	42			1,406,205		91,755		(0)		(0)		(0)
RATE GRP - GENERAL SERVICE RESPONSIVE PRICING												
Customers For the 12 Month Period	22				20.00	440	20.00	440	20.00	440	20.00	440
kWh Nov08-Jan09 Rates: Period 1				22	0.04776	1	0.04789	1	0.05144	1	0.05318	1
kWh Feb09-Jun09 Rates: Period 1				1,820	0.04789	87	0.04789	87	0.05144	94	0.05318	97
kWh Jul09-Oct09 Rates: Period 1				1,746	0.05144	90	0.05144	90	0.05144	90	0.05318	93
kWh Nov08-Jan09 Rates: Period 2				22	0.06266	1	0.06279	1	0.06634	1	0.06808	1
kWh Feb09-Jun09 Rates: Period 2				1,857	0.06279	117	0.06279	117	0.06634	123	0.06808	126
kWh Jul09-Oct09 Rates: Period 2				1,428	0.06634	95	0.06634	95	0.06634	95	0.06808	97
kWh Nov08-Jan09 Rates: Period 3				3	0.13703	0	0.13718	0	0.14073	0	0.14247	0
kWh Feb09-Jun09 Rates: Period 3				238	0.13718	33	0.13718	33	0.14073	33	0.14247	34
kWh Jul09-Oct09 Rates: Period 3				1,243	0.14073	175	0.14073	175	0.14073	172	0.14247	177
kWh Nov08-Jan09 Rates: Period 4				-	0.30483	-	0.30332	-	0.30687	-	0.30861	-
kWh Feb09-Jun09 Rates: Period 4				-	0.30332	-	0.30332	-	0.30687	-	0.30861	-
kWh Jul09-Oct09 Rates: Period 4				98	0.30687	30	0.30687	30	0.30687	30	0.30861	30
Minimum and Partial Month Billings						(54)		(54)		(54)		(54)
TOTAL	22			8,477		1,014		1,015		1,026		1,043
TOTAL GENERAL SERVICE	505,178			1,420,489,551		106,997,266		107,706,985		110,923,952		113,393,157

LOUISVILLE GAS AND ELECTRIC COMPANY
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	Customers 12mos Oct 2009	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period Unit Charges	Calculated Revenue	P.S.C. 7 for Full Year Unit Charges	Calculated Revenue	FAC Rollin Rates for Full Year Unit Charges	Calculated Revenue	"Current Rates" ECR Rollin Rates for Full Year Unit Charges	Calculated Revenue
COMMERCIAL POWER SERVICE RATE CPS-Primary												
Customers For the 12 Month Period	634				$ 65.00	$ 41,210	$ 65.00	$ 41,210	$ 65.00	$ 41,210	$ 65.00	$ 41,210
kW Demand Nov08-Jan09 Rates:												
Summer Rates		-			$ 12.97	$ -	$ 12.97	$ -	$ 12.97	$ -	$ 13.15	$ -
Winter Rates		117,727			$ 10.17	$ 1,197,284	$ 10.17	$ 1,197,284	$ 10.17	$ 1,197,284	$ 10.35	$ 1,218,474
kW Demand Feb09-Jun09 Rates:												
Summer Rates		38,135			$ 12.97	$ 494,611	$ 12.97	$ 494,611	$ 12.97	$ 494,611	$ 13.15	$ 501,475
Winter Rates		85,776			$ 10.17	$ 872,342	$ 10.17	$ 872,342	$ 10.17	$ 872,342	$ 10.35	$ 887,782
kW Demand Jul09-Oct09 Rates:												
Summer Rates		106,269			$ 12.97	$ 1,378,309	$ 12.97	$ 1,378,309	$ 12.97	$ 1,378,309	$ 13.15	$ 1,397,437
Winter Rates		34,199			$ 10.17	$ 347,804	$ 10.17	$ 347,804	$ 10.17	$ 347,804	$ 10.35	$ 353,960
kWh Nov08-Jan09 Rates:				47,615,136	$ 0.02702	$ 1,286,561	$ 0.02601	$ 1,238,470	$ 0.02956	$ 1,407,503	$ 0.02956	$ 1,407,503
kWh Feb09-Jun09 Rates:				62,148,384	$ 0.02601	$ 1,616,479	$ 0.02601	$ 1,616,479	$ 0.02956	$ 1,837,106	$ 0.02956	$ 1,837,106
kWh Jul09-Oct09 Rates:				60,095,840	$ 0.02956	$ 1,776,433	$ 0.02956	$ 1,776,433	$ 0.02956	$ 1,776,433	$ 0.02956	$ 1,776,433
Minimum and Partial Month Billings						$ 12,391		$ 12,391		$ 12,391		$ 12,391
TOTAL - Primary	634	382,106		169,859,360		$ 9,023,424		$ 8,975,333		$ 9,364,993		$ 9,433,772
COMMERCIAL POWER SERVICE RATE CPS-Secondary												
Customers For the 12 Month Period	32,244				$ 65.00	$ 2,095,860	$ 65.00	$ 2,095,860	$ 65.00	$ 2,095,860	$ 65.00	$ 2,095,860
kW Demand Nov08-Jan09 Rates:												
Summer Rates		-			$ 14.81	$ -	$ 14.81	$ -	$ 14.81	$ -	$ 14.99	$ -
Winter Rates		1,588,652			$ 11.75	$ 18,666,661	$ 11.75	$ 18,666,661	$ 11.75	$ 18,666,661	$ 11.93	$ 18,952,618
kW Demand Feb09-Jun09 Rates:												
Summer Rates		433,264			$ 14.81	$ 6,416,640	$ 14.81	$ 6,416,640	$ 14.81	$ 6,416,640	$ 14.99	$ 6,494,627
Winter Rates		1,178,306			$ 11.75	$ 13,845,096	$ 11.75	$ 13,845,096	$ 11.75	$ 13,845,096	$ 11.93	$ 14,057,191
kW Demand Jul09-Oct09 Rates:												
Summer Rates		1,304,929			$ 14.81	$ 19,325,998	$ 14.81	$ 19,325,998	$ 14.81	$ 19,325,998	$ 14.99	$ 19,560,886
Winter Rates		439,935			$ 11.75	$ 5,169,236	$ 11.75	$ 5,169,236	$ 11.75	$ 5,169,236	$ 11.93	$ 5,248,425
kWh Nov08-Jan09 Rates:				544,399,634	$ 0.02702	$ 14,709,678	$ 0.02601	$ 14,159,834	$ 0.02956	$ 16,092,453	$ 0.02956	$ 16,092,453
kWh Feb09-Jun09 Rates:				711,550,083	$ 0.02601	$ 18,507,418	$ 0.02601	$ 18,507,418	$ 0.02956	$ 21,033,420	$ 0.02956	$ 21,033,420
kWh Jul09-Oct09 Rates:				706,475,342	$ 0.02956	$ 20,883,411	$ 0.02956	$ 20,883,411	$ 0.02956	$ 20,883,411	$ 0.02956	$ 20,883,411
Minimum and Partial Month Billings						$ 105,544		$ 105,544		$ 105,544		$ 105,544
TOTAL - Secondary	32,244	4,945,086		1,962,425,059		$ 119,725,542		$ 119,175,698		$ 123,634,319		$ 124,524,435

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					"As Billed Rates" During 12 Month Period		P.S.C. 7 for Full Year		FAC Rollin Rates for Full Year		"Current Rates" ECR Rollin Rates for Full Year	
	Customers 12mos Oct 2009	Basic Demand	Peak Demand	kWh's	Unit Charges	Calculated Revenue	Unit Charges	Calculated Revenue	Unit Charges	Calculated Revenue	Unit Charges	Calculated Revenue
LARGE COMMERCIAL RATE LC-Small Time of Day Primary (Rate eliminated with P.S.C. 7)												
Customers Nov08-Jan09 Rates:	9				$ 80.00	$ 720	$0.00	$ -	$0.00	$ -	$0.00	$ -
kW Demand Nov08-Jan09 Rates:												
Summer Rates		-			$ 12.97	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Winter Rates		5,652			$ 10.17	$ 57,481	$ -	$ -	$ -	$ -	$ -	$ -
Basic kWh Nov08-Jan09 Rates:				1,854,600	$ 0.01723	31,955	$0.00000	-	$0.00000	-	$0.00000	-
Peak kWh Nov08-Jan09 Rates:				1,401,600	$ 0.03289	46,099	$0.00000	-	$0.00000	-	$0.00000	-
Minimum and Partial Month Billings						$ (4,529)						
TOTAL - Primary STOD	9	5,652		3,256,200		$ 136,254		$ -		$ -		$ -
LARGE COMMERCIAL RATE LC- Small Time of Day Secondary (rate eliminated with P.S.C. 7)												
Customers Nov08-Jan09 Rates:	96				$ 80.00	$ 7,680	$0.00	$ -	$0.00	$ -	$0.00	$ -
kW Demand Nov08-Jan09 Rates:												
Summer Rates		-			$ 14.81	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Winter Rates		37,656			$ 11.75	$ 442,458	$ -	$ -	$ -	$ -	$ -	$ -
Basic kWh Nov08-Jan09 Rates:				11,503,580	$ 0.01723	198,207	$0.00000	-	$0.00000	-	$0.00000	-
Peak kWh Nov08-Jan09 Rates:				9,353,660	$ 0.03289	307,642	$0.00000	-	$0.00000	-	$0.00000	-
						22,242						
TOTAL - Secondary STOD	96	37,656		20,857,240		$ 978,229		$ -		$ -		$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations showing the effect on Base Rate Revenue of the Revised Base Rates, the FAC Roll-in and the ECR Roll-in for a full year
Based on Sales for the 12 months ended October 31, 2009

	Customers 12mos Oct 2009	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period Unit Charges	"As Billed Rates" During 12 Month Period Calculated Revenue	P.S.C. 7 for Full Year Unit Charges	P.S.C. 7 for Full Year Calculated Revenue	FAC Rollin Rates for Full Year Unit Charges	FAC Rollin Rates for Full Year Calculated Revenue	"Current Rates" ECR Rollin Rates for Full Year Unit Charges	"Current Rates" ECR Rollin Rates for Full Year Calculated Revenue
COMMERCIAL POWER SERVICE TIME OF DAY RATE CTOD-Primary (includes former rate STOD Primary)												
Customers For the 12 Month Period former	9				$ -	$ -	$ 90.00	$ 810	$ 90.00	$ 810	$ 90.00	$ 810
Customers For the 12 Month Period	209				$ 90.00	$ 18,810	$ 90.00	$ 18,810	$ 90.00	$ 18,810	$ 90.00	$ 18,810
kW Basic Demand Nov08-Jan09 Rates: former STOD custome		3,094			$ -	$ -	$ 2.56	$ 7,920	$ 2.56	$ 7,920	$ 2.64	$ 8,167
kW Basic Demand Nov08-Jan09 Rates:		204,566			$ 2.56	$ 523,689	$ 2.56	$ 523,689	$ 2.56	$ 523,689	$ 2.64	$ 540,054
kW Basic Demand Feb09-Jun09 Rates:		222,988			$ 2.56	$ 570,849	$ 2.56	$ 570,849	$ 2.56	$ 570,849	$ 2.64	$ 588,688
kW Basic Demand Jul09-Oct09 Rates:		255,303			$ 2.56	$ 653,576	$ 2.56	$ 653,576	$ 2.56	$ 653,576	$ 2.64	$ 674,000
kW Peak Demand Nov08-Jan09 Rates:												
Winter Rates for former STOD customers			3,045		$ -	$ -	$ 7.62	$ 23,203	$ 7.62	$ 23,203	$ 7.70	$ 23,447
Winter Rates			200,680		$ 7.62	$ 1,529,182	$ 7.62	$ 1,529,182	$ 7.62	$ 1,529,182	$ 7.70	$ 1,545,236
kW Peak Demand Feb09-Jun09 Rates:												
Summer Rates			70,339		$ 10.42	$ 732,932	$ 10.42	$ 732,932	$ 10.42	$ 732,932	$ 10.50	$ 738,560
Winter Rates			147,996		$ 7.62	$ 1,127,730	$ 7.62	$ 1,127,730	$ 7.62	$ 1,127,730	$ 7.70	$ 1,139,569
kW Peak Demand Jul09-Oct09 Rates:												
Summer Rates			169,802		$ 10.42	$ 1,769,337	$ 10.42	$ 1,769,335	$ 10.42	$ 1,769,335	$ 10.50	$ 1,782,921
Winter Rates			80,529		$ 7.62	$ 613,631	$ 7.62	$ 613,631	$ 7.62	$ 613,631	$ 7.70	$ 620,073
kWh Nov08-Jan09 Rates: former STOD-P customers				3,256,200	$ -	$ -	$ 0.02605	$ 84,824	$ 0.02960	$ 96,384	$ 0.02960	$ 96,384
kWh Nov08-Jan09 Rates:				78,490,036	$ 0.02706	$ 2,123,940	$ 0.02605	$ 2,044,665	$ 0.02960	$ 2,323,305	$ 0.02960	$ 2,323,305
kWh Feb09-Jun09 Rates:				132,846,552	$ 0.02605	$ 3,460,653	$ 0.02605	$ 3,460,653	$ 0.02960	$ 3,932,258	$ 0.02960	$ 3,932,258
kWh Jul09-Oct09 Rates:				125,584,926	$ 0.02960	$ 3,717,314	$ 0.02960	$ 3,717,314	$ 0.02960	$ 3,717,314	$ 0.02960	$ 3,717,314
Minimum and Partial Month Billings						$ 11,635		$ 7,107		$ 7,107		$ 7,107
TOTAL - CTOD Primary	218	682,857	672,391	340,177,714		$ 16,853,278		$ 16,886,230		$ 17,648,035		$ 17,756,702