COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF SOUTH KENTUCKY RURAL ELECTRIC COOPERATIVE CORPORATION FOR A GENERAL ADJUSTMENT OF RATES, APPROVAL OF DEPRECATION STUDY, AND OTHER GENERAL RELIEF	))))	Case No. 2021-00407

ATTORNEY GENERAL'S RESPONSE TO SOUTH KENTUCKY RURAL ELECTRIC COOPERATIVE CORPORATION'S FIRST REQUEST FOR INFORMATION

The intervenor, the Attorney General of the Commonwealth of Kentucky, through his Office of Rate Intervention, submits the following response to South Kentucky Rural Electric Cooperative Corporation's First Request for Information ("South Kentucky RECC" or "the Company") in the above-styled matter.

Respectfully submitted,

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ATTORNEY GENERAL

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<u>Certificate of Service and Filing</u>

Pursuant to the Commission's Orders and in accord with all other applicable law, Counsel certifies that the foregoing electronic filing was transmitted to the Commission on April 1, 2022, and there are currently no parties that the Commission has excused from participation by electronic means in this proceeding.

This 1st day of April, 2022.

Angela M. Awad

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Assistant Attorney General

WITNESS RESPONSIBLE:
LANE KOLLEN

QUESTION No. 1
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Please list and provide copies of all studies or analyses that Mr. Kollen has performed analyzing electric cooperative capital rotation policies.

RESPONSE:

Refer to the attachment to this response for excerpted pages from Mr. Kollen's Exhibit___(LK-1) wherein he addressed TIER, margins, members' equity, capital credits, and/or rotation policies in testimony. The public versions of these testimonies are available on the respective state commission websites. In addition, Mr. Kollen was the project manager in several management audits of distribution cooperatives on behalf of the Louisiana Public Service Commission by J. Kennedy and Associates, Inc. Mr. Kollen evaluated the capital rotation policies of these cooperatives in those audits and noted some aspects of those policies in the report that he prepared. Mr. Kollen has attached a copy of that report to this response.

Expert Testimony Appearances
of
Lane Kollen
As of February 2022

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
* 12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
* 8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County, completion.
2/88	10064	KY	Kentucky Industrial Utility	Louisville Gas &	Revenue requirements, O&M expense, capital

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Date	Case	Jurisdict.	Party	Utility	Subject
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base.
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
3/93	93-01-EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities /Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
* 10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
4/94	U-20647 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
* 11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co., The Cleveland Electric Illuminating Co.	Competition, asset write-offs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC Docket 14965	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co., and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co., Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
* 10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness.
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
* 11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/04	SOAH Docket 473-04-4555 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	U-23327 Subdocket B	LA	Louisiana Public Service Commission Staff	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPCO	Revenue requirements.
12/04	Case Nos. 2004-00321, 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, et al.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
01/05	30485	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.
02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.
03/05	Case Nos. 2004-00426, 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.
06/05	050045-EI	FL	South Florida Hospital and Heallthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
09/05	20298-U	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.
09/05	20298-U	GA	Georgia Public Service	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization,

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Date	Case	Jurisdict.	Party	Utility	Subject
03/07	PUC Docket 33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	PUC Docket 33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.
* 03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition.
03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery.
04/07	U-29764 Supplemental and Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts.
04/07	ER07-684-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuel hedging costs and compliance with FERC USOA.
05/07	ER07-682-000 Supplemental Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts.
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC, Entergy Gulf States, Inc.	Show cause for violating LPSC Order on fuel hedging costs.
* 07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Revenue requirements, post-test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts.
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc.	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue requirements.
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
04/08	2007-00562, 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas and Electric Co.	Merger surcredit.
04/08	26837 Direct Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Suppl Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
* 06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, including costs recovered in existing rates, TIER.

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	Date	Case	Jurisdict.	Party	Utility	Subject
	02/09	EL08-51 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
*	02/09	2008-00409 Direct	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Revenue requirements.
	03/09	ER08-1056 Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
	03/09 04/09	U-21453, U-20925 U-22092 (Sub J) Direct Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
*	04/09	2009-00040 Direct-Interim (Oral)	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Emergency interim rate increase; cash requirements.
	04/09	PUC Docket 36530	TX	State Office of Administrative Hearings	Oncor Electric Delivery Company, LLC	Rate case expenses.
	05/09	ER08-1056 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
*	06/09	2009-00040 Direct-Permanent	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements, TIER, cash flow.
	07/09	080677-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Multiple test years, GBRA rider, forecast assumptions, revenue requirement, O&M expense, depreciation expense, Economic Stimulus Bill, capital structure.
	08/09	U-21453, U-20925, U-22092 (Subdocket J) Supplemental Rebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
	08/09	8516 and 29950	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Modification of PRP surcharge to include infrastructure costs.
	09/09	05-UR-104 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Revenue requirements, incentive compensation, depreciation, deferral mitigation, capital structure, cost of debt.
	09/09	09AL-299E Answer	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.

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Date	Case	Jurisdict.	Party	Utility	Subject
04/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Revenue requirement issues.
04/10	2009-00548, 2009-00549	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	Revenue requirement issues.
08/10	31647	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Revenue requirement and synergy savings issues.
08/10	31647 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Affiliate transaction and Customer First program issues.
08/10	2010-00204	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	PPL acquisition of E.ON U.S. (LG&E and KU) conditions, acquisition savings, sharing deferral mechanism.
09/10	38339 Direct and Cross-Rebuttal	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Revenue requirement issues, including consolidated tax savings adjustment, incentive compensation FIN 48; AMS surcharge including roll-in to base rates; rate case expenses.
09/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
09/10	2010-00167	KY	Gallatin Steel	East Kentucky Power Cooperative, Inc.	Revenue requirements.
09/10	U-23327 Subdocket E Direct	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
11/10	U-23327 Rebuttal	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
09/10	U-31351	LA	Louisiana Public Service Commission Staff	SWEPCO and Valley Electric Membership Cooperative	Sale of Valley assets to SWEPCO and dissolution of Valley.
10/10	10-1261-EL-UNC	OH	Ohio OCC, Ohio Manufacturers Association, Ohio Energy Group, Ohio Hospital Association, Appalachian Peace and Justice Network	Columbus Southern Power Company	Significantly excessive earnings test.
10/10	10-0713-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Company, Potomac Edison Power Company	Merger of First Energy and Allegheny Energy.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/10	U-23327 Subdocket F Direct	LA	Louisiana Public Service Commission Staff	SWEPCO	AFUDC adjustments in Formula Rate Plan.
11/10	EL10-55 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
12/10	ER10-1350 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
01/11	ER10-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
03/11 04/11	ER10-2001 Direct Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Arkansas, Inc.	EAI depreciation rates.
04/11	U-23327 Subdocket E	LA	Louisiana Public Service Commission Staff	SWEPCO	Settlement, incl resolution of S02 allowance expense, var O&M expense, sharing of OSS margins.
04/11 05/11	38306 Direct Suppl Direct	TX	Cities Served by Texas-New Mexico Power Company	Texas-New Mexico Power Company	AMS deployment plan, AMS Surcharge, rate case expenses.
05/11	11-0274-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company, Wheeling Power Company	Deferral recovery phase-in, construction surcharge.
* 05/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements.
06/11	29849	GA	Georgia Public Service Commission Staff	Georgia Power Company	Accounting issues related to Vogtle risk-sharing mechanism.
07/11	ER11-2161 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
07/11	PUE-2011-00027	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Return on equity performance incentive.
07/11	11-346-EL-SSO 11-348-EL-SSO 11-349-EL-AAM 11-350-EL-AAM	OH	Ohio Energy Group	AEP-OH	Equity Stabilization Incentive Plan; actual earned returns; ADIT offsets in riders.
08/11	U-23327 Subdocket F Rebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Depreciation rates and service lives; AFUDC adjustments.
08/11	05-UR-105	WI	Wisconsin Industrial Energy Group	WE Energies, Inc.	Suspended amortization expenses; revenue requirements.

**Expert Testimony Appearances
of
Lane Kollen
As of February 2022**

Date	Case	Jurisdict.	Party	Utility	Subject
04/13	12-2400-EL-UNC	OH	The Ohio Energy Group	Duke Energy Ohio, Inc.	Capacity charges under state compensation mechanism, deferrals, rider to recover deferrals.
04/13	2012-00578	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Resource plan, including acquisition of interest in Mitchell plant.
* 05/13	2012-00535	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
06/13	12-3254-EL-UNC	OH	The Ohio Energy Group, Inc., Office of the Ohio Consumers' Counsel	Ohio Power Company	Energy auctions under CBP, including reserve prices.
07/13	2013-00144	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Biomass renewable energy purchase agreement.
07/13	2013-00221	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Hawesville Smelter market access.
* 10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
12/13	2013-00413	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Sebree Smelter market access.
01/14	ER10-1350 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 lease accounting and treatment in annual bandwidth filings.
02/14	U-32981	LA	Louisiana Public Service Commission	Entergy Louisiana, LLC	Montauk renewable energy PPA.
04/14	ER13-432 Direct	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Union Pacific Settlement benefits and damages.
05/14	PUE-2013-00132	VA	HP Hood LLC	Shenandoah Valley Electric Cooperative	Market based rate; load control tariffs.
07/14	PUE-2014-00033	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting, change in FAC Definitional Framework.
08/14	ER13-432 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Union Pacific Settlement benefits and damages.
08/14	2014-00134	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Requirements power sales agreements with Nebraska entities.
09/14	E-015/CN-12-1163 Direct	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class cost allocation.
10/14	2014-00225	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Allocation of fuel costs to off-system sales.

**Expert Testimony Appearances
of
Lane Kollen
As of February 2022**

Date	Case	Jurisdict.	Party	Utility	Subject
03/21	2020-00349 2020-00350	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company and Louisville Gas and Electric Company	Rate base v. capitalization, retired plant costs, depreciation, securitization, staffing + payroll, pension + OPEB, AMI, off-system sales margins.
04/21 Direct 07/21	18-857-EL-UNC 19-1338-EL-UNC 20-1034-EL-UNC 20-1476-EL-UNC Supplemental Direct	OH	The Ohio Energy Group	First Energy Ohio Companies	Significantly Excessive Earnings Test; legacy nuclear plant costs.
05/21 06/21	2021-00004 Direct Supplemental Direct	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	CPCN for CCR/ELG Projects at Mitchell Plant.
06/21	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	VCM24, Vogtle 3 and 4 rate impact analyses.
06/21	2021-00103	KY	Attorney General and Nucor Steel Gallatin	East Kentucky Power Cooperative, Inc.	Revenues, depreciation, interest, TIER, O&M, regulatory asset.
07/21 08/21 10/21	U-35441 Direct Cross-Answering Surrebuttal	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Company	Revenues, O&M expense, depreciation, retirement rider.
09/21	2021-00190	KY	Attorney General	Duke Energy Kentucky	Revenues, O&M expense, depreciation, capital structure, cost of long-term debt, government mandate rider.
09/21	43838	GA	Public Interest Advocacy Staff	Georgia Power Company	Vogtle 3 base rates, NCCR rates; deferrals.
09/21	2021-00214	KY	Attorney General	Atmos Energy Corp.	NOL ADIT, working capital, affiliate expenses, amortization EDIT, capital structure, cost of debt, accelerated replacement Aldyl-A pipe, PRP Rider, Tax Act Adjustment Rider.
* 01/22	2021-00358	KY	Attorney General	Jackson Purchase Energy Corporation	Revenues, nonrecurring expenses, normalized expenses, interest expense, TIER.
01/22	2021-00421	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Proposed Mitchell Plant Operations and Maintenance and Ownership Agreements; sale of Mitchell Plant interest.
02/22	2021-00481	kY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Proposed Liberty Utilities, Inc. acquisition of Kentucky Power Company; harm to customers; conditions to mitigate harm.

REPORT TO THE

LOUISIANA PUBLIC SERVICE COMMISSION

MANAGEMENT AUDITS

OF LOUISIANA

ELECTRIC DISTRIBUTION COOPERATIVES:

Valley Electric Membership Cooperative, Inc.
Docket No. U-20802

Washington-St. Tammany Electric Cooperative, Inc.
Docket No. U-20803

Concordia Electric Cooperative, Inc.
Docket No. U-20804

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April 1995

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EXECUTIVE SUMMARY

Scope of Audits

J. Kennedy and Associates, Inc. ("Kennedy and Associates"), with the assistance of the Commission Staff, particularly Mr. Robert Crowe and Mr. Edward Gallegos, has performed a general review of the electric distribution cooperatives in Louisiana and has performed more specific management audits of the following cooperatives:

- Washington-St. Tammany Electric Cooperative, Inc. ("WST")
- Concordia Electric Cooperative, Inc. ("Concordia")
- Valley Electric Membership Cooperative, Inc. ("Valley")

The Teche Electric Membership Cooperative, Inc. management audit, initiated by the Commission last fall, is not yet complete.

The purpose of the audits was to identify the reasons for the generally higher levels of cooperative rates compared to those of the investor owned utilities ("IOUs") within the state, to identify the reasons for the significant rate disparity among the cooperatives, and to identify opportunities for organizational and cost efficiencies that could translate into lower rate levels for cooperative members. The audits were not detailed work activity and staffing reviews.

The field work, which included interviews and data requests, was completed in late 1994. Except for Washington-St. Tammany, the cooperatives' statistics have been updated based on 1994 annual report data, which was not submitted to the Commission until April 1995. Although this delayed the issuance of the report, the data is more current. No additional field work was performed in 1995.

There are three primary reasons for the rate disparity of the cooperatives compared to the investor owned utilities and between the cooperatives. First, the cost of power purchased under full-requirements contracts from Cajun is expensive compared to other available sources. That factor has been mitigated by the Commission's December 1994 order in the Cajun rate review proceeding. The cost of power purchased from Cajun affects each of the cooperatives differently on a per kWh basis, due to differing cooperative load characteristics and customer demographics. The Commission also mitigated those differences in its December 1994 order in the Cajun rate review proceeding.

Second, the sum of each cooperative's own financing and operating costs directly affects the rates each must charge. Each cooperative is largely autonomous and performs all necessary operational and administrative functions to provide electricity to its members, either through its own resources or by purchasing those services from third parties. The cooperatives achieve virtually no administrative or operating economies through consolidated or centralized activities.

Third, the level of line losses, representing the differences in the kWh purchased from Cajun and the kWh billed to the cooperatives' members, the ultimate retail consumers, is high by comparison to the IOUs and varies significantly among the cooperatives.

Summary of Conclusions and Recommendations

We have concluded that the rates of the distribution cooperatives can be reduced to levels generally competitive with the investor owned utilities in the state. Numerous structural, organizational, operating, and rate changes can and should be made to accomplish this goal.

We recommend that the Commission direct the cooperatives to pursue consolidation opportunities among themselves and with investor owned utilities, pursue cost-effective opportunities to reduce line losses and improve reliability, and exploit opportunities to recover stranded investment created by municipal annexation.

We recommend that the Commission, at a minimum, direct the cooperatives to consolidate most administrative and certain other functions at Cajun, the Association of Louisiana Electric Cooperatives ("ALEC"), or some other entity and to perform those services on a centralized basis. That consolidation should be undertaken regardless of the resolution of Cajun's bankruptcy. The cooperatives should also examine the need for both Cajun and ALEC as two separate organizations and determine whether cost savings and efficiency gains could be achieved by consolidating the functions performed by each.

We also recommend numerous specific organizational, operating, and cost efficiencies for the individual cooperatives we reviewed.

The report is structured into four additional sections. First, the Louisiana cooperatives are reviewed in the aggregate and recommendations made that apply to all twelve of them. Second, for the three cooperatives we specifically reviewed, conclusions and recommendations are made that apply specifically to each of those cooperatives.

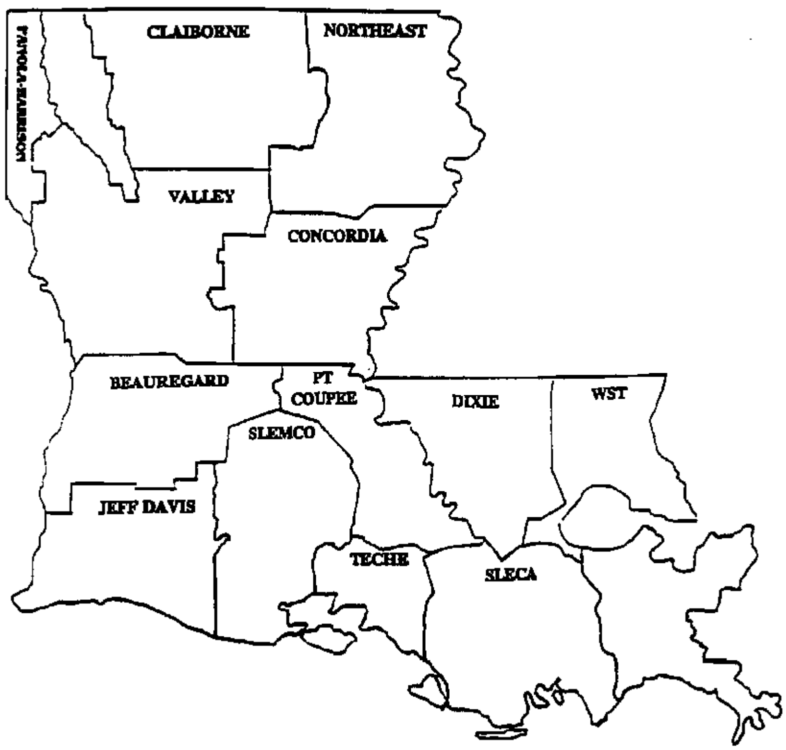
LOUISIANA ELECTRIC COOPERATIVES - GENERAL

Description of Cooperatives

There are twelve electric distribution cooperatives within the state of Louisiana.

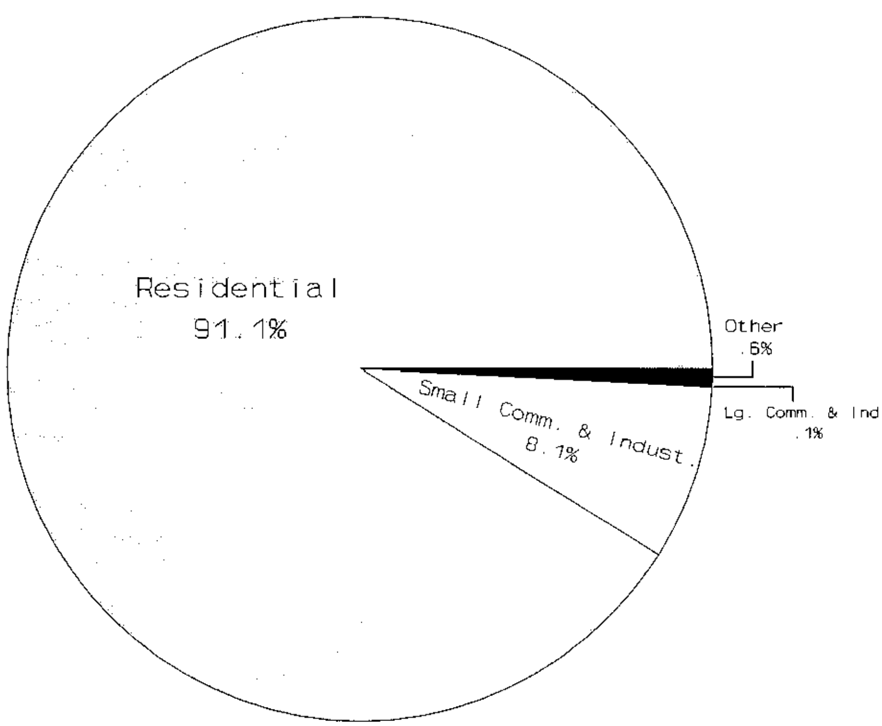
- Beauregard Electric Cooperative
- Claiborne Electric Cooperative, Inc.
- Concordia Electric Cooperative, Inc.
- Dixie Electric Membership Corporation
- Jefferson Davis Electric Cooperative, Inc.
- Northeast Louisiana Power Cooperative, Inc.
- Pointe Coupee Electric Membership Corporation
- South Louisiana Electric Co-op Association
- Southwest Louisiana Electric Membership Corporation
- Teche Electric Cooperative, Inc.
- Valley Electric Membership Corporation
- Washington-St. Tammany Electric Cooperative

The cooperatives are located in service territories portrayed on the following map. The cooperatives' territories are interconnected through a transmission system owned, operated, and maintained by Cajun and the IOUs.

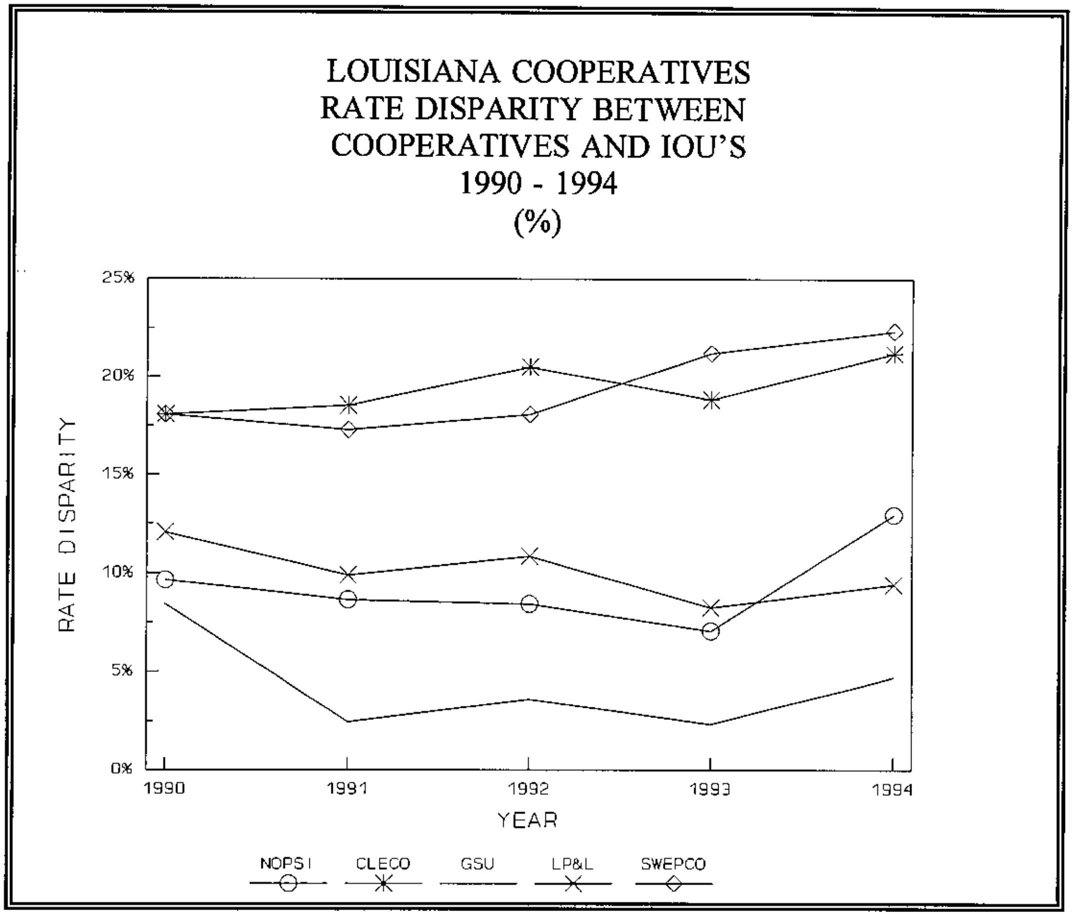


The cooperatives are relatively small and serve predominantly rural and residential areas. Because of their small size and the fact that they serve areas that are not overly populated, the cooperatives have higher costs per customer and per kWh compared to the larger IOUs. The cooperatives also have less large commercial and industrial load than the IOUs. The following graph portrays the load distribution of the cooperatives in the aggregate. More than 91% of the cooperatives' load is residential. The percentage of residential load increased slightly in 1994, reflecting a continuing trend as existing industrial load is lost and new industrial load growth lags.

LOUISIANA COOPERATIVES
LOAD DISTRIBUTION - 1994



Each cooperative competes against other utilities, primarily investor owned, within the state. The higher cooperative rates significantly undermine their competitive position. The greater the rate disparity, the less competitive are the cooperatives. The following graph illustrates the average aggregate rate disparity for the last five years, although the disparity between the individual cooperatives and the IOUs varies widely. While the disparity has been reduced against GSU and LP&L, it has increased substantially against CLECO and SWEPCO. Earlier year reductions in the disparity against NOPSI were reversed in 1994 due to NOPSI rate reductions and refunds. Several of the cooperatives have experienced significant losses of potential and existing customers to competing utilities. In addition, CLECO and SWEPCO have been actively engaged in the acquisition and attempted acquisition of the cooperatives with higher rates and costs.



The recent actions by the Commission in Docket No. U-17735 to reduce Cajun's rates, effective in January 1995, have reduced the cooperatives' purchased power costs and reduced the rate disparity between the cooperatives and IOUs and among the cooperatives. The Commission's order reduced the total cost of purchased power, modified a ratchet feature that exacerbated the rate disparity between the cooperatives, and allowed the cooperatives to target the rate reductions through rate redesigns.

Management and Board of Directors

Each cooperative is separately incorporated, with its own Charter and Bylaws, its own Board of Directors, and its own management structure. The Board members are elected by the members of each cooperative who, with certain exceptions, are also its retail customers.

The daily operations of each cooperative are managed by a General Manager. The larger cooperatives have more extensive management structures with higher staffing levels and tend to perform more functions in-house. The organizational structures of the three cooperatives specifically reviewed are addressed in the subsequent sections of the report.

The Board of Directors for each cooperative is responsible to the membership for oversight and direction of the cooperative's activities. The Board must generally vote on all major expenditures as well as all significant personnel and strategic issues. The Board may allow the membership to vote on certain major issues.

The management and the Board of each cooperative generally work together to address strategic issues. One of the most significant strategic issues confronting the cooperatives, since they are all full-requirements customers of Cajun, is the cost of purchased power. That concern extends to the RUS debt and River Bend problems of Cajun to the extent that it affects their cost of purchased power not only today but in the future.

Another significant strategic issue confronting the cooperatives is competition from neighboring investor owned utilities. The cooperatives' rates are generally higher than the neighboring IOUs. A comparison of the cooperatives' average rates is included in a subsequent section of this report. The cooperatives work closely with Cajun to develop and offer economically attractive rates to large users.

The rate disparity issue has led to increased membership pressure to affiliate with IOUs. In 1993, SWEPCO purchased Bossier Rural Electric Membership Corporation. CLECO is currently negotiating to acquire Teche Electric Membership Corporation. CLECO has also initiated actions to acquire Washington-St. Tammany Electric Cooperative. There may be other cooperatives subject to buyout pressures in the future, particularly if the rate disparity remains or increases.

The cooperatives have fought to retain their independence, despite opportunities for cost and rate reduction through affiliation with IOUs. The cooperatives have mounted aggressive public relations campaigns and initiated legal action to delay or derail the overtures of the IOUs.

Finally, the management and the Board of each cooperative are responsible to manage the cooperative in the most cost efficient manner while providing reliable service to their customers. The management and the Board are responsible for every cost that is incurred, although the cost of purchased power is subject to the rate jurisdiction of the Commission.

Functions Performed

Each distribution cooperative operates largely autonomously. It performs all necessary operational and administrative functions to provide electricity to its members. It either performs these functions through its own resources or purchases those services from third parties.

The primary functions performed by the cooperatives are related to the delivery of electricity, specifically the design, construction, operation and maintenance of the distribution systems. Most of the cooperatives rely to some extent upon third parties to design and construct their systems. The dependence on third parties varies among the cooperatives. Each of the cooperatives directly operates and maintains its distribution system, although most utilize third parties for specific activities such as forecasting, engineering, and vegetation control. To operate and maintain its system, each cooperative has a field organization that includes dispatchers, line crews, equipment operators, staking engineers, garage facilities, and warehouse facilities.

In addition to the delivery of electricity, the cooperatives also perform customer service functions. The cooperatives measure (meter) the usage of service, bill and collect, maintain customer records, and engage in limited marketing activities. Some of the cooperatives utilize third parties for the meter reading function and for billing.

Finally, the cooperatives perform all administrative and general functions, although they rely to some extent upon third parties for certain functions. That reliance varies among the cooperatives. These functions include the following:

- purchasing
- payroll processing
- general ledger accounting
- accounts payable processing
- cash flow management including treasury and payment processing
- computer information systems development, operation, and maintenance
- records management
- property and other tax management and processing
- risk management
- human resources and benefits management
- acquisition and management of outside professional services including consultants and auditors
- internal auditing
- planning

The cooperatives have made virtually no attempt to reduce their administrative or operational costs through consolidation and centralization, preferring to retain their autonomy. Although

Cajun and ALEC provide certain limited services to the cooperatives, there has been no effort to exploit cost reduction opportunities through either of these entities owned by the cooperatives.

Other companies throughout the utility and other industries have moved aggressively in recent years to reduce costs by consolidating and centralizing administrative functions and operational functions to the extent possible. Examples in Louisiana include significant consolidation by Entergy of the operations of its LP&L and NOPSI operating companies, the consolidation of the customer service functions of its operating companies into fewer locations, facilitated through telecommunications technology, and the consolidation and centralization at Entergy Services of administrative functions previously performed by each operating company.

Cooperatives and IOUs alike have recognized the necessity to consolidate and streamline in order to survive in the increasingly competitive utility industry. In addition to Entergy's activities, many other investor owned utilities have consolidated regional organizations into centralized organizations. Last year, Public Service of Colorado eliminated all but one of its customer service locations and created a network of independent pay agents. Recently, two Texas cooperatives announced that they were not only evaluating a potential merger but that they intended to consolidate and centralize many services even if the merger did not take place. The December 5, 1994 and January 23, 1995 issues of Electric Utility Week reported comments by Charles Gill, an outgoing governor of the National Rural Electric Utilities Cooperative Finance Corporation ("CFC"), in which he stated that cooperatives that expect to survive past the year

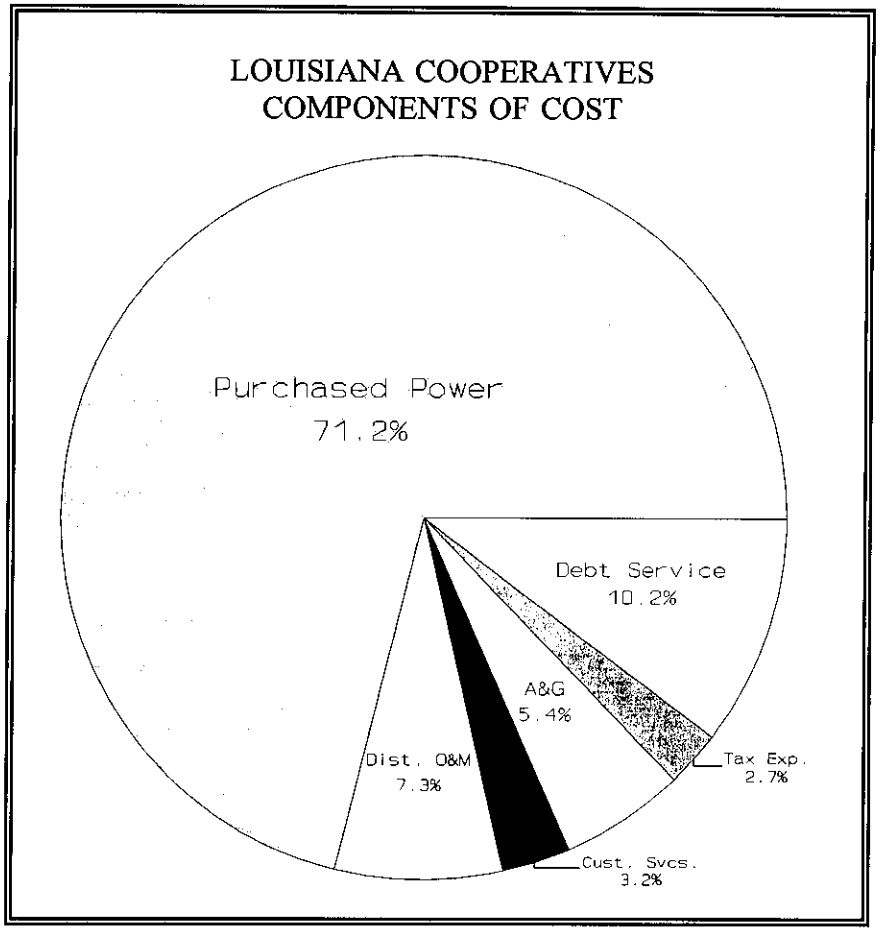
2000 should have at least 40,000 to 50,000 members. Of the Louisiana cooperatives, only Dixie and SLEMCO have more than 40,000 members.

The cooperatives and Cajun management recognize that these opportunities exist. However, the cooperatives are reluctant to relinquish their autonomy in these areas, and Cajun and ALEC are unwilling and unable to impose a consolidation and centralization of services.

Comparative Operating, Cost, and Rate Profile

Although the components of each cooperative's costs vary, the composition of the aggregate cost of service of the twelve cooperatives provides a general indication of the significance of each cost component. The most significant element of cost for the cooperatives is purchased power, representing 71% of the cooperatives' aggregate cost of service. Debt service (depreciation and interest) is the second largest element of cost, representing 10% of the aggregate. Distribution operation and maintenance is the third largest, representing 7% of the aggregate. Administrative and general is the fourth largest at 5%, and customer service is the fifth largest at 3%.

The following graph provides the percentage of each category of cost to the total cost of service for the twelve distribution cooperatives in the aggregate for 1994.



There is significant disparity in the average rate per kWh charged by each cooperative, which is primarily the result of differences in costs, line losses and customer demographics. The following table portrays the average rate disparity between the cooperatives for calendar year 1994.

LOUISIANA COOPERATIVES
AVERAGE RATE PER KWH
1994

Cooperative	Rate per KWH	Disparity from Average
Beauregard	0.08489	-0.76%
Claiborne	0.07879	-7.89%
Concordia	0.09795	14.51%
Dixie	0.08959	4.74%
Jefferson Davis	0.08715	1.88%
Northeast	0.08881	3.82%
Pointe Coupee	0.07825	-8.52%
SLECA	0.08080	-5.54%
SLEMCO	0.07488	-12.46%
Teche	0.08347	-2.42%
Valley	0.09395	9.84%
Washington-St. Tammany	0.08794	2.80%
Average	0.08554	

The rate disparity with the IOUs and between the cooperatives is also directly affected by the relative costs of the individual cooperatives. The costs of the three cooperatives specifically reviewed are addressed in subsequent sections in more detail.

Line losses also contribute to the average cost per kWh, and the variation between cooperatives directly affects the rate disparity. Line losses are affected by management's investment, operating, and maintenance decisions as well as customer demographics. The following chart portrays the range of line losses and the effect on the rates charged to the retail customers for each cooperative.

LOUISIANA COOPERATIVES
PERCENT LINE LOSSES

Cooperative	Line Loss	Effect on Rates (Cents/KWH)
Beauregard	6.28%	0.36
Claiborne	7.15%	0.41
Concordia	9.61%	0.57
Dixie	7.35%	0.44
Jefferson Davis	7.67%	0.44
Northeast	9.69%	0.61
Pointe Coupee	5.98%	0.32
SLECA	7.14%	0.40
SLEMCO	6.45%	0.36
Teche	10.44%	0.61
Valley	9.21%	0.57
Washington-St. Tammany	8.80%	0.53

Other factors also affect the rates charged to retail customers. These factors include the number of customers, their consumption, and the type of load. These factors affect the cost of service and also affect the average rate per kW and kWh. For example, it generally costs more to serve lower density service territories (measured by customers per mile). It generally costs more to serve residential and small commercial customers than large commercial and industrial customers. It generally costs more to serve territories with lower annual sales per customer. A comparison of operating, cost, and rate statistics for the twelve Louisiana distribution cooperatives is attached as Exhibit 1 to this report.

Affiliate Relationships and Effect on Costs

The distribution cooperatives have made investments in and are members of Cajun Electric Power Cooperative, Inc. The affiliate relationship with Cajun directly affects the cost of purchased power, the largest component of the cooperatives' cost of service. The cooperatives purchase all their electricity from Cajun under full-requirements contracts that extend to 2026. The cooperatives are unable to purchase power from other sources, although it is currently available at significantly lower prices.

The Commission recently ordered a reduction in Cajun's rates to approximately 48.8 mills per kWh from an average level of approximately 54.5 mills per kWh. The rate reduction was implemented through a revision to the demand billing methodology and through a uniform reduction on a per kWh basis for non-incentive rates. Because of differences among the cooperatives in the relationship between demand and energy and in the level of incentive rates, the rate reduction ranged from 8.6% for Point Coupee to 11.1% for Valley.

The revision to the demand billing methodology was intended to mitigate the disparity in the cost of purchased power on a per kWh basis between the cooperatives. The billing demand is now equal to the actual kW demand for the months of June, July, August, and September, and the lesser of 80% of the average demands for the months of June, July, August, and September or the actual demands for the months of October through May. Previously, the billing demands for the months of October through May ignored the actual demands for those months and were instead based upon the average demands for June through September. This "ratchet" tended to increase rates per kWh on average for cooperatives that had less load (compared to cooperatives in aggregate) in the months of October through May and tended to reduce rates per kWh on average for cooperatives that had more load in the months of October through May. The following table portrays the purchased power cost disparity per kWh among the cooperatives before (ranging from negative 10.1% to positive 7.2%) and after (ranging from negative 9.0% to positive 5.1%) the recent Commission order.

COST OF PURCHASED POWER
MILLS PER KWH

Cooperative	Before Reduction	Percent Disparity[1]	After Reduction	Percent Disparity[1]
Beauregard	54.5	0.7%	49.3	+1.0%
Claiborne	54.0	-0.2%	48.4	-0.8%
Concordia	54.0	-0.2%	48.1	-1.4%
Dixie	55.9	+3.3%	50.5	+3.5%
Jeff Davis	54.1	0%	48.6	-0.4%
Northeast	58.0	+7.2%	51.3	+5.1%
PTE Coupee	48.6	-10.1%	44.4	-9.0%
South LA	50.7	-0.3%	46.0	-5.7%
Slemco	52.7	-2.6%	47.9	-1.8%
Teche	52.2	-3.5%	47.5	-2.7%
Valley	56.7	+4.8%	50.4	+3.3%
Wash/St. Tam	54.4	+0.6%	49.3	+1.0%
Average	53.8		48.5	

[1] Compared to simple average

There are also other factors that cause disparity in the costs of purchased power between the cooperatives. These factors reflect the cooperatives' load characteristics, such as their load factors, voltage levels, and customer mix.

The distribution cooperatives in the aggregate oversee the operations of Cajun through their representation on the Cajun Board of Directors. Each cooperative has two members on the Cajun Board, most often the General Manager of the cooperative and the President of its Board. Each cooperative representative on the Cajun Board is paid by Cajun for his travel expenses. In addition, the cooperatives are paid $185 or a lesser amount (based on substantiated meal receipts) for each day of Cajun Board activities that its General Manager attends. Distribution cooperative Board members personally are paid $185 for each day of Cajun Board activities attended. Since 1989, Cajun Board expenses have increased at an average rate of 9.5% per year. In 1993, Cajun Board expenses exceeded a quarter million dollars.

The Board members, and thus the distribution cooperatives, are directly involved in all major issues confronting Cajun. Each member of the Cajun Board is assigned to one of three standing committees, the Power Supply and Fuels Committee, the Operation Committee, and the Finance, Audit, and Rate Committee.

Despite the ownership by the cooperatives of Cajun, and their involvement on the Cajun Board, the cooperatives are partially insulated from the direct financial repercussions of Cajun's involvement in the River Bend nuclear facility. As owners, the cooperatives would normally receive an allocation from Cajun of any margins in excess of its costs. However, Cajun's Bylaws prohibit the allocation of any Cajun losses to the Cooperatives. Thus, Cajun's losses have not been allocated to the cooperatives or their members, despite the fact that Cajun is in severe financial difficulty and has operated at a net loss each year since 1987. Since 1990, Cajun has been operating under a Debt Restructuring Agreement with the RUS and was involved in negotiations to again restructure its debt until it declared bankruptcy in December 1994.

Despite the prohibition against loss allocation, the rates paid by the cooperatives for purchased power have reflected recovery in the past for River Bend and were excessive according to the Commission's recent decision in Docket No. U-17735. Even with the exclusion of River Bend from rates, Cajun's financial condition is likely to continue to affect rates to the cooperatives in the future.

The cooperatives receive limited services from Cajun on a centralized and cost-efficient basis. However, Cajun provides services to the cooperatives only upon request. The services provided have included assistance in regulatory support, rate design including incentive rates, marketing, human resources, risk management, engineering, and substation construction and maintenance. The cooperatives make only limited use of Cajun's services, which are provided at no cost or at actual cost to the distribution cooperatives. No studies have been performed by the cooperatives or by Cajun to identify and evaluate further opportunities for consolidation and centralization of certain distribution cooperative functions.

Cajun management is not opposed to performing additional services for the distribution cooperatives. However, Cajun believes that the distribution cooperatives do not generally favor the consolidation and centralization of functions that they currently perform separately. Although Cajun's management has indicated the ability to provide certain services with existing personnel, it may require additional capital and staffing resources to provide additional centralized services.

The distribution cooperatives and Cajun also have made investments in and are members of the Association of Louisiana Electric Cooperatives. They obtain certain limited services from ALEC that are provided on a centralized basis. The services include technical and safety training as well as legislative affairs and public relations support. Since ALEC does not have a revenue source, the cooperatives directly, and indirectly through Cajun, pay assessments to fully cover its costs.

Conclusions and Recommendations

The reasons for the relatively higher rates for the distribution cooperatives compared to the investor owned utilities include the high cost of purchased power from Cajun, the inefficiencies of twelve distribution utilities independently performing functions that could be consolidated and performed on a centralized and more cost-efficient basis, the customer demographics and other load characteristics, the level of line losses from the purchase of power from Cajun to the delivery and metering at the ultimate customer, and various other organizational and cost inefficiencies at the specific cooperatives.

The reasons for the significant rate disparity among the cooperatives are similar. They include the following:

- Differences in the cost of purchased power from Cajun due to the interaction of load characteristics and the billing process.
- Differences in the size of the cooperative and other customer demographics and other load characteristics.
- Differences in the level of line losses.
- Differences in management resulting in various other organizational and cost inefficiencies at the specific cooperatives addressed in the subsequent sections of this report.

The Commission's recent order in the Cajun rate review proceeding will not only reduce the average rate disparity between the cooperatives and the IOUs but also among the cooperatives. On average, the cooperatives' rates will be reduced by more than 0.5 cents per kWh from 54.5 mills to 48.8 mills per kWh.

In addition to reducing the cost of purchased power, there are significant opportunities for organizational and cost efficiencies applicable to all the cooperatives that can be translated into further rate reductions for the retail customers. The primary opportunity is to consolidate functions -- either among the cooperatives or with investor owned utilities. At a minimum and as an initial step, the cooperatives could consolidate most administrative and certain other functions and perform those services on a centralized basis. Should Cajun emerge from bankruptcy as an independent entity, these functions could be centralized at Cajun, leaving only the necessary field personnel and equipment at the cooperatives. Otherwise, the cooperatives should seek to consolidate through ALEC or some other entity. Based upon the experience within the utility industry, the following administrative functions can be consolidated in some manner, preferably at Cajun or ALEC.

- purchasing
- payroll processing
- general ledger accounting
- accounts payable processing
- cash flow management including treasury and payment processing
- computer information systems development, operation, and maintenance
- records management
- property and other tax management and processing
- risk management
- human resources and benefits management
- acquisition and management of outside professional services including consultants and auditors
- internal auditing
- planning

Additionally, there are other functions that could be consolidated, preferably at Cajun or ALEC. These include the various customer service functions, except for in-person bill payments and certain service arrangements, primarily due to credit and collection problems. Although these two customer service functions would still be required to be performed within the service territories of each cooperative, the in-person bill payments and service arrangements could be performed exclusively by retail establishments linked to Cajun or ALEC and the cooperatives by computer. Cajun or ALEC could handle collections by telephone and mail. Connects and disconnects would continue to be performed by the distribution O&M field organizations at each cooperative. All other customer service functions including telephone inquiry and credit arrangements could be performed by Cajun or ALEC. In conjunction with this consolidation, the cooperatives may be able to allow leases to expire or to otherwise dispose of excess property including certain customer service locations and even headquarters buildings.

The cooperatives should determine the economic feasibility of jointly contracting for certain services, such as vegetation control, substation testing, and maintenance -- either directly with Cajun, or, as a unified entity, with other third parties. Similarly, opportunities to consolidate engineering contracts, such as those for work plans, sectionalization studies, and/or substation design should be investigated as should contracts for major construction projects.

As a further step, the cooperatives could combine among themselves and/or with investor owned utilities in order to achieve operating and cost efficiencies and to lower rates to their customers.

There are also significant opportunities for cost reduction to the extent that the cooperatives' line losses can be reduced. For some cooperatives, line losses add another 10% to the cost of power purchased from Cajun.

Recommendations

The Commission should direct the cooperatives to consolidate administrative, customer service, and certain construction and maintenance functions at Cajun, ALEC or other entity. Further, the Commission should direct the cooperatives to combine operational functions where there are contiguous service territories and economies that can be achieved.

The Commission should direct the cooperatives to actively search for opportunities to merge with other cooperatives and/or investor owned utilities where costs and rates can be reduced. In addition, the cooperatives should consolidate Cajun and ALEC functions into a single entity to service the cooperatives on a centralized and cost effective basis.

The Commission should direct the cooperatives to report their progress toward consolidation and centralization of functions within six months to ensure that these recommendations are pursued.

Finally, the cooperatives should diligently investigate and reduce the level of line losses to the extent that there is a positive economic benefit.

VALLEY ELECTRIC MEMBERSHIP COOPERATIVE, INC.

Description of the Cooperative

Valley Electric Membership Cooperative, Inc. ("Valley") is a rural electric distribution cooperative which serves just over 27,000 customers in the Louisiana parishes of Natchitoches, Red River, Grant, Sabine, Vernon, DeSoto, Caddo, and Winn. The service territory is divided into three service districts with offices in Natchitoches, Mansfield, and Hornbeck. Each district provides its own customer service, dispatch, operations and maintenance, and warehouse operations. As of December 31, 1994, Valley had more than 6,450 miles of energized line and 158 full time employees. Customer density averaged 4.3 customers per mile with an average annual usage of approximately 14,400 kWh per customer. More than 80% of the Cooperative's kWh sales and approximately 94% of its customer base was residential.

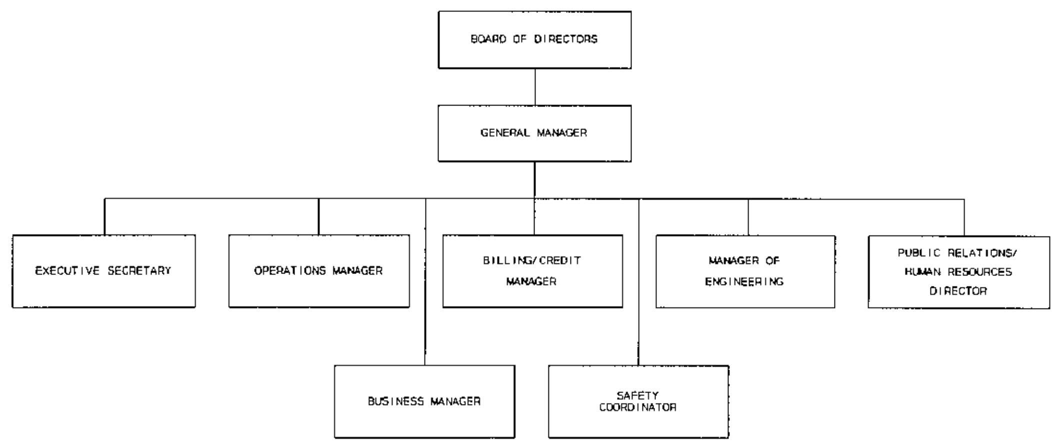
Valley's service territory is adjacent to Southwestern Electric Power Company ("SWEPCO"), Central Louisiana Electric Company ("CLECO"), and Louisiana Power and Light ("LP&L"). The rate disparity between these IOUs and Valley has made it increasingly difficult to retain load in the face of the expiration of franchises and expansion of cities in which Valley has no franchise. For example, when Valley's franchise with the city of Stonewall expired in late 1987, the Cooperative's inability to lower its rates to match those of SWEPCO resulted in the loss of as many as 430 customers and approximately 1.6% of its total revenue.

In February 1989, SWEPCO offered Valley a cash settlement of $472,000 for the purchase of its facilities located within the corporate limits of Stonewall. The Board refused SWEPCO's offer and directed its counsel to retain the customer through litigation. Valley performed no independent analysis relating to the sale. The RUS did not intervene in this matter and the mortgage agreement provided in response to discovery in this matter does not prohibit such sales but rather requires the proceeds to be applied to repayment of the debt. Valley's customer base has remained relatively flat, increasing by slightly more than 3% since 1990.

Management and Board of Directors

The following figure presents the top tier organization chart for the Cooperative. There are six managers reporting directly to the General Manager. The structure of each of the manager's functional organizations is detailed in the charts provided by Valley and attached to this report as Exhibit 2. The three district managers report directly to the Operations Manager.

VALLEY ELECTRIC MEMBERSHIP COOPERATIVE, INC.
TOP TIER ORGANIZATIONAL CHART



The General Manager is responsible to Valley's Board of Directors ("Board"). The Board is composed of nine members, seven elected by the membership, one from each of the Cooperative's seven districts, and two appointed by the Board members. According to Valley's bylaws, two Board members are appointed by the Board of Directors to ensure minority and female representation.

The Cooperative is currently restructuring and attempting to downsize its operations. Valley has already eliminated six positions, including two line foremen, one staking engineer, one billing clerk, and two contract meter readers. Management intends to continue downsizing through attrition and to further reorganize its operations. The restructuring includes consolidation of the current three district organization into two divisions and consolidation of other functions. The Cooperative plans to eliminate at least six positions in 1995, including a district manager, an additional line foremen, and a shop attendant. Management estimated that downsizing will generate annual savings of $360,000 by 1996.

Valley's long term goals and objectives are not formally documented, nor is there a strategic plan for their accomplishment. Discussions with Valley management indicated that there is no documented plan addressing what they termed the "management and administration portion of strategic planning." While there is a "time line" with a listing of potential actions, this document focuses on specific operational changes and lacks clear documentation of the tasks, schedule, budgets, etc., necessary to accomplish the desired changes. Additionally, while the activities appear to be worthwhile pursuits, the costs, benefits, and schedules associated with the individual short-term activities have not been examined within the context of strategic goals and objectives.

The Cooperative's capital outlay and construction work plans are documented in long-range and annual work plans which address primarily the technical, physical infrastructure changes identified through engineering studies. However, the most recent long range plan is dated 1982, and the most recent annual work plan is dated 1989-1990.

Valley's capital budgets are prepared by department. However, the operating budget is prepared only on a total company basis. No budget by department is prepared. Consequently, actuals are not tracked at the department level. Department managers do not have the benefit of combined capital and operating budgets nor the ability to compare actual performance on a total resource basis.

Valley indicated that it has written policies and procedures in effect only in the following areas: Safety Rules, Employee Orientation Manual, Service Rules and Regulations, Bylaws, and Materials Handling/Purchasing Procedures. There are no formal policies or procedures for other business functions such as budgeting, reporting, customer service, and payables processing. In addition, most departments do not have defined performance evaluation criteria. The Billing and Credit department was the only one for which such criteria were provided by Valley.

Management indicated that it receives limited services from Cajun, most of which are provided at no cost. Although the budget amounts were not provided, Valley also indicated that Cajun performs some transmission equipment maintenance for the Cooperative at cost. Valley's plans do not reflect consolidation of any functions at Cajun or ALEC, contracting for services from or through Cajun or ALEC, or consolidation of functions or affiliation with other cooperatives or other utilities. However, Valley's attorney has discussed the possibility of forming a consortium with the other cooperatives for the purpose of buying out the all-requirements contract with Cajun.

Throughout the audit, Valley's management was not only cooperative but openly receptive to the review process and the potential for recommendations to improve its operations and reduce costs.

Summary of Revenues, Costs, and Margins

The following tables provide a summary of Valley's actual costs by major category and various comparative measures of performance for the most recent five calendar years.

VALLEY ELECTRIC MEMBERSHIP COOPERATIVE, INC.
ACTUAL COSTS BY MAJOR CATEGORY
($000)

	1990	1991	1992	1993	1994
Purchased Power	22,937	22,252	23,258	25,634	25,273
Transmission, Distrib. O&M	2,701	3,072	3,147	3,013	2,959
Customer Service and Sales	922	1,026	1,100	1,174	1,196
A&G	2,092	2,174	2,259	2,493	2,862
Taxes	1,152	1,177	1,229	1,208	1,187
Depreciation	2,101	2,148	2,199	2,260	2,286
Interest	2,869	2,545	2,307	2,164	2,159

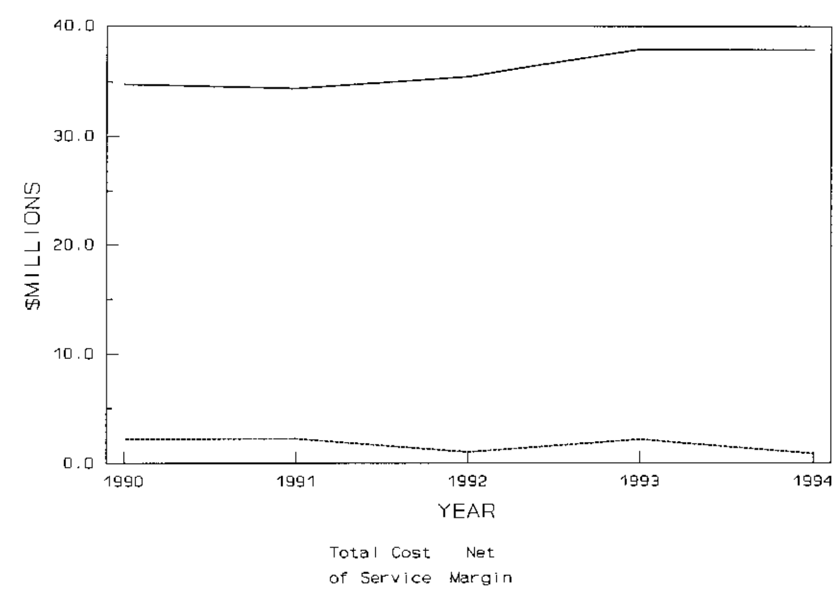
VALLEY ELECTRIC MEMBERSHIP COOPERATIVE, INC.
KEY PERFORMANCE INDICATORS

	1990	1991	1992	1993	1994
Total miles energized	6,380	6,394	6,408	6,434	6,458
No. of customers served					
Residential	25,856	26,073	26,235	26,480	26,691
Small comm. & indust.	1,502	1,525	1,537	1,536	1,547
Large comm. & indust.	2	2	1	1	1
Total cust. (incl. other)	27,375	27,615	27,788	28,031	28,254
$ net plant	$56,612,166	$56,164,519	$55,658,184	$55,575,367	$55,548,550
# full-time employees	170	169	171	161	158
Total kWh sold	371,310,628	374,163,296	374,573,397	410,791,307	407,747,278
Total kWh purchased	405,816,565	410,432,254	416,460,324	455,375,354	449,118,130
Revenue/total cust.	$1,317.83	$1,291.86	$1,296.82	$1,415.64	$1,355.87
Revenue/mile	$5,654.76	$5,579.50	$5,623.36	$6,167.80	$5,931.89
Customers/mile	4.29	4.32	4.34	4.36	4.37
$ A&G/customer	$76.42	$78.73	$81.28	$88.95	$101.29
$ Cust svc/customer	$33.68	$37.13	$39.39	$41.87	$42.33
$ O&M/mile	$4,491.13	$4,461.23	$4,644.56	$5,022.62	$4,999.97
Operating margin/rev.	3.57%	3.55%	1.45%	4.38%	1.00%
% line loss	8.50%	8.84%	10.06%	9.79%	9.21%
$ line loss	$1,950,292	$1,966,382	$2,339,223	$2,509,746	$2,328,087
Cost purch. power/kWh	0.05652	0.05422	0.05585	0.05629	0.05627
Rate per kWh sold	0.09716	0.09534	0.09621	0.09660	0.09395

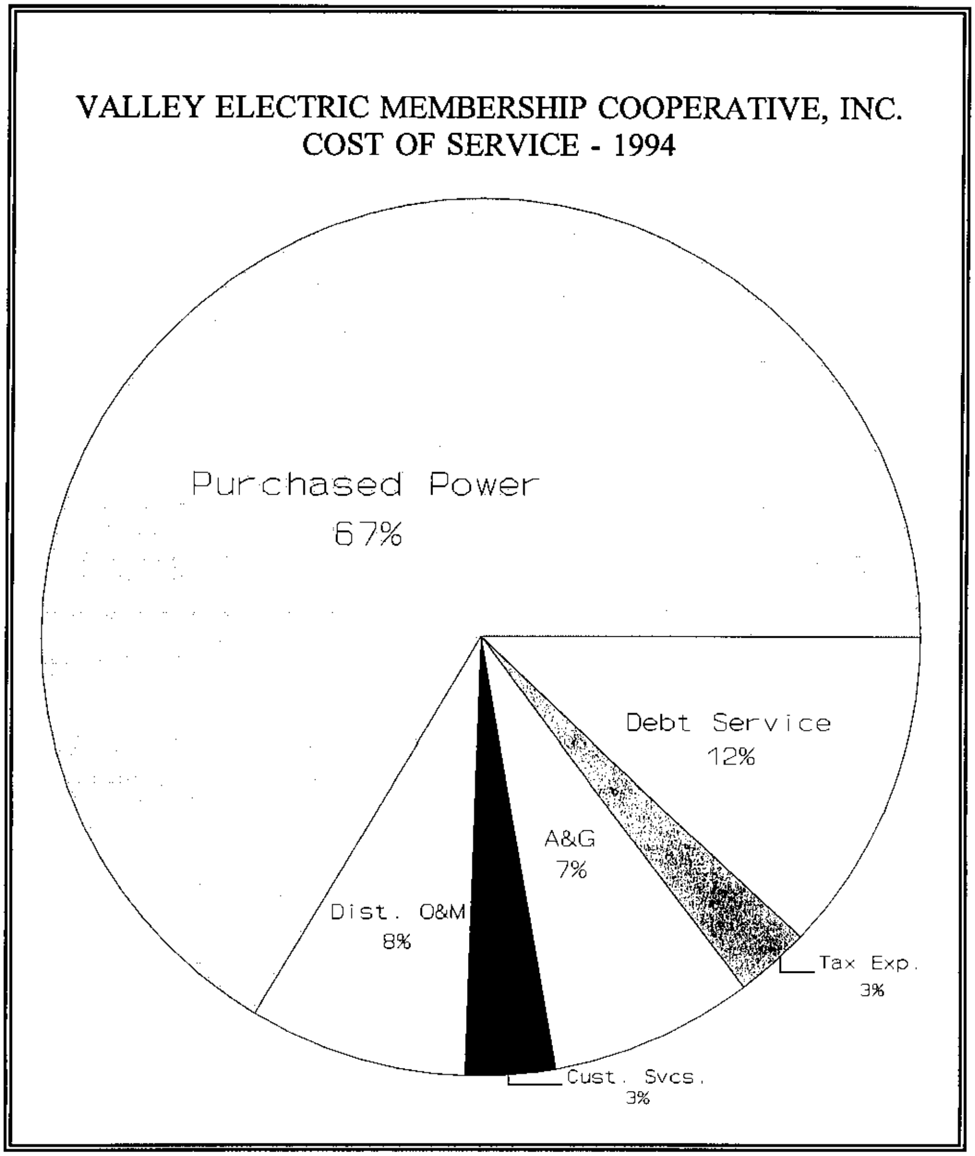
Since 1990, the Cooperative has experienced declines in net plant investment, number of employees, and cost per kWh of purchased power. It has experienced only slight growth in sales, revenues, and customers over the period. Valley has reduced its distribution O&M expenses by nearly 6% from 1990 levels. However, it has increased its A&G and customer services expenses by 37% and 25%, respectively, outpacing both inflation and growth in customers and energized miles. Although investment in general plant has increased (by more than 12% in 1994 alone), efficiencies normally gained by those types of investments have not been reflected in reduced A&G or customer service expenses.

Since 1990, the Company's total cost of service has increased at an average rate less than the rate of inflation. However, its costs increased significantly in 1993 compared to 1992 levels, primarily in the purchased power and A&G categories. The net margin has remained between $1 and $2 million. However, it dropped in 1994 compared to 1993 as declining sales and rate reductions depressed revenues while costs continued to climb. Valley's cost of service in 1994 was only .5% less than it was in 1993 while revenues were down 3.5%. Despite the decline in 1994, Valley still achieved a times interest earned ratio of 3.3x, well in excess of the 1.5x generally required under mortgage covenants on RUS debt.

VALLEY ELECTRIC MEMBERSHIP COOPERATIVE, INC.
COST OF SERVICE AND NET MARGIN



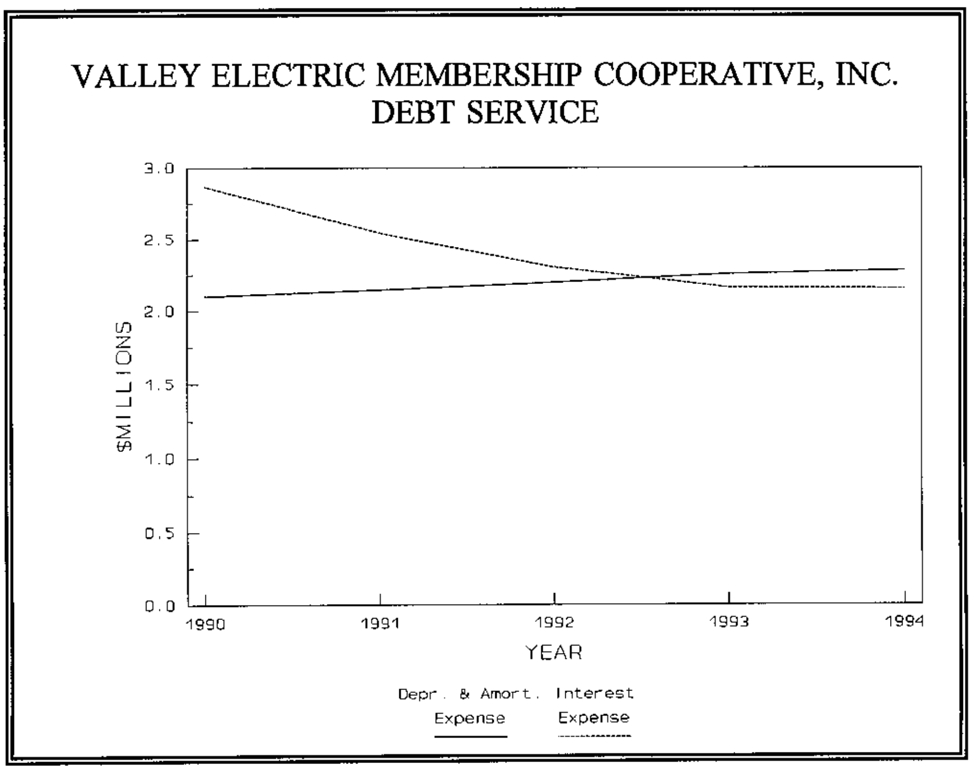
The following graph illustrates Valley's major cost components and their respective contributions to the total cost of providing electric service. Valley's cost of service composition was more heavily weighted toward A&G and debt service costs than the aggregate of the member cooperatives.



Valley has had six rate reductions in the last three and a half years, and is currently preparing to implement another decrease. The small commercial class received a rate reduction in May 1993. In December 1993, the residential rate was reduced. This was the third residential reduction in the past three years. In 1994, Valley's average residential rate was 9 cents per kWh, down from a peak of 9.5 cents in 1993, and the lowest it has been since 1983.

Debt Service (Interest and Depreciation Expense)

The following graph shows the levels of interest and depreciation and amortization for the period 1990 through 1994.



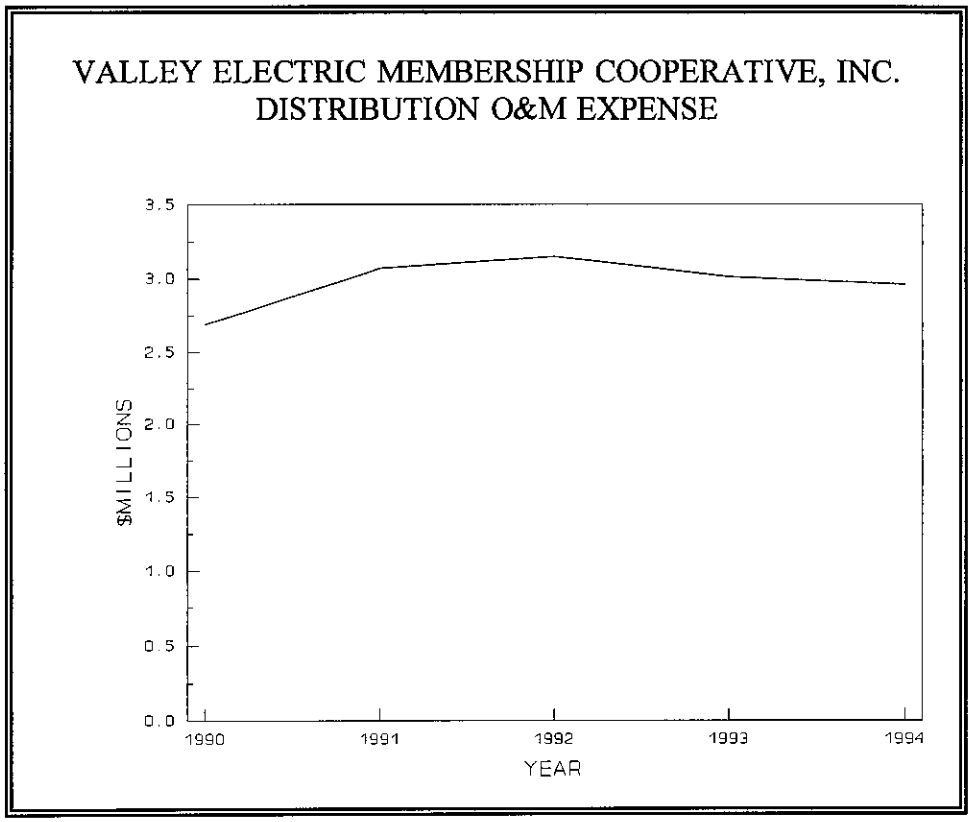
Valley's debt service comprises approximately 12% of its total cost of electric service. Interest expense levels have declined steadily since 1990. No additional long term debt has been issued. The Cooperative has reduced its debt from $46.3 million at December 31, 1990 to $42.5 million at December 31, 1994. Its effective interest rate for 1994 was 5%. Nevertheless, debt service comprises a higher percentage of Valley's cost of service than it does for the aggregate cost of service of the state's member cooperatives.

Depreciation expense has increased slightly as the Cooperative has increased its gross utility plant by 7.5% since 1990. More than 34% of that increase has occurred in the general plant category primarily in the areas of transportation and structural improvements. Although there is a budgeting process at the departmental level to control capital costs, there is no requirement to provide formal justification or economic evaluation for general plant investments.

As of December 31, 1994, the Cooperative had nearly $5.3 million in discretionary investments in U.S. Treasury bills, CFC commercial paper, and bank certificates of deposit. During 1993, Valley maintained an average of $5.6 million in temporary investments which earned just over 3% interest, substantially less than the Cooperative's effective interest rate on its outstanding debt.

Distribution Operations and Maintenance

Valley's distribution O&M expenses increased by nearly 17% between 1990 and 1992, but have declined by nearly 6% since then. The Cooperative's level of expenses in this category are well below the average for the other eleven cooperatives on a cost per energized mile basis.



In 1994, meter and miscellaneous distribution O&M expenses, which had increased dramatically between 1990 and 1992, were nearly 26% below year end 1992 levels. Valley management indicated that the institution of a cyclic meter replacement and resealing program, the purchase of new equipment, increases in chargeable payroll and fringe benefit costs, and increases in equipment maintenance and depreciation were largely responsible for the increases in the early part of the audit period. The only major O&M category that has increased at average rates greater than inflation are those related to maintenance of overhead lines, which have increased at an average rate of just under 4.5% since 1990. Over this same period, the number of energized miles increased by only 1%.

Valley management indicated that it planned to eliminate the contract meter readers it employed and to absorb that function into its in-house O&M activities in an effort to reduce costs and increase efficiency. However, it has performed no studies to demonstrate that this is the least cost method to accomplish the meter reading function. Meter reading expense increased by nearly 10% in 1994, while the number of customers increased by less than 1%.

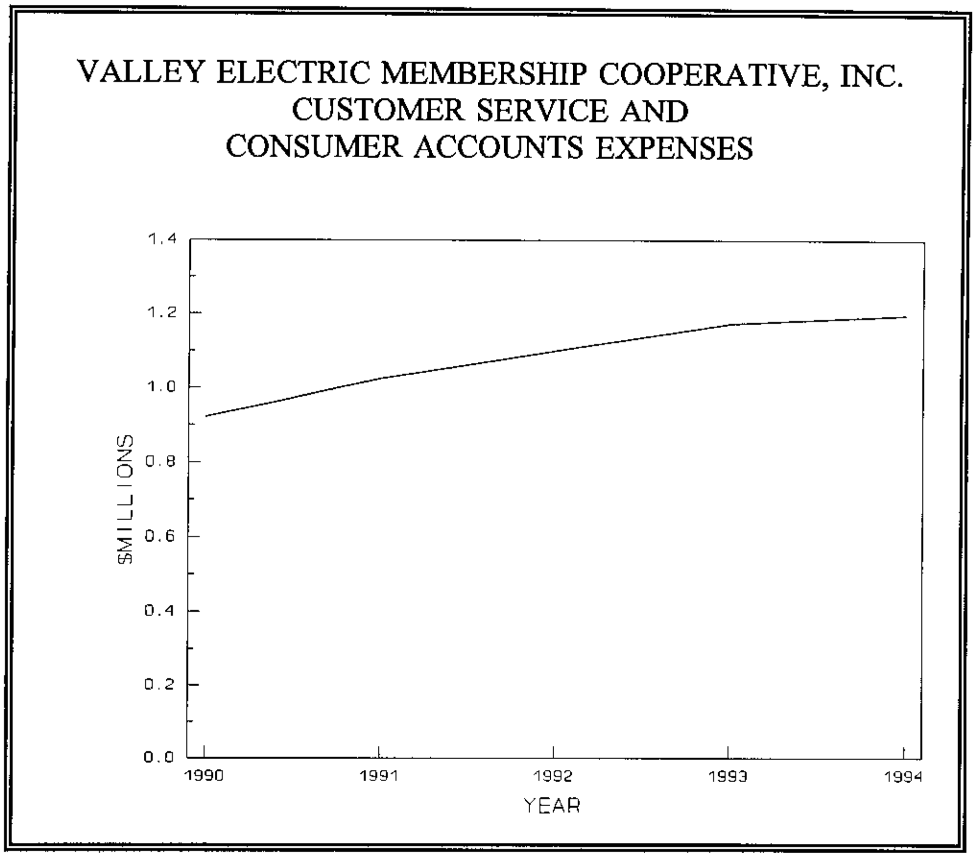
Valley currently does not maintain standard manhour estimates that could be used for gauging efficiency for maintenance tasks. Management indicated that crew time sheets capture detail such as time spent on travel vs. maintenance vs. training. However, the extent of that data and its usefulness for improving efficiency is limited.

Valley has experienced increased service interruptions since 1992. While interruptions attributable to the Cajun, extreme storm, and planned outage categories have declined over the period, those which the Cooperative categorizes as "all other" have more than doubled, averaging more than 8 hours per customer in 1994.

The Cooperative's line losses averaged more than 9.2% in 1994, with each percentage point costing the Cooperative more than $250,000. This loss percentage is higher than Valley's levels in 1990 and 1991 and 17% higher than the average of the other Cajun member Cooperatives. Valley's management recognizes the need to reduce these losses and has initiated activities, such as sectionalization studies, to reduce the losses. Management has established a target of 8%. The cooperative has no planning framework for achieving its goal.

Customer Service and Consumer Accounts

Customer service costs, which represented more than 3% of Valley's total 1994 cost of service, have increased by nearly 30% since 1990, although the number of customers has increased by only 1%.



Valley's per customer expense is approximately 14% higher than the average expense of the other Cajun membership cooperatives. These expenses are significant non-purchased power related contributors to Valley's cost of service. Most of the Cooperative's customer service efforts are directed to residential customers. Consumer accounts expense, which alone represents more than 14% of Valley's total non-purchased power O&M expense, has increased by 25% since 1990. Meter reading expenses have increased by 35% over the period, nearly 10% in 1994. Uncollectible accounts expense, while about average, have increased dramatically since 1990.

Despite the loss of one of its two large industrial customers in 1992 and its relatively small commercial and industrial customer base, the Company incurred no sales or marketing expense in 1994 and only negligible amounts in earlier years.

Valley has three "walk-in" locations (Natchitoches, Mansfield, and Hornbeck), each of which provide the following customer services:

- Applications for service.
- Payments of bills -- by mail, walk-in, and drive-through (except Mansfield).
- Reporting of unsafe conditions by phone or walk-in.
- Reporting of outages by phone or walk-in.

In addition, all three offices process applications for service, collect and post payments made to that location, answer calls concerning billing, and dispatch service personnel for outages and connection requests within their respective areas. Valley's headquarters office in Natchitoches provides additional services such as economic development, marketing, social assistance programs, credit arrangements, non-payment notices, and explanation of rates.

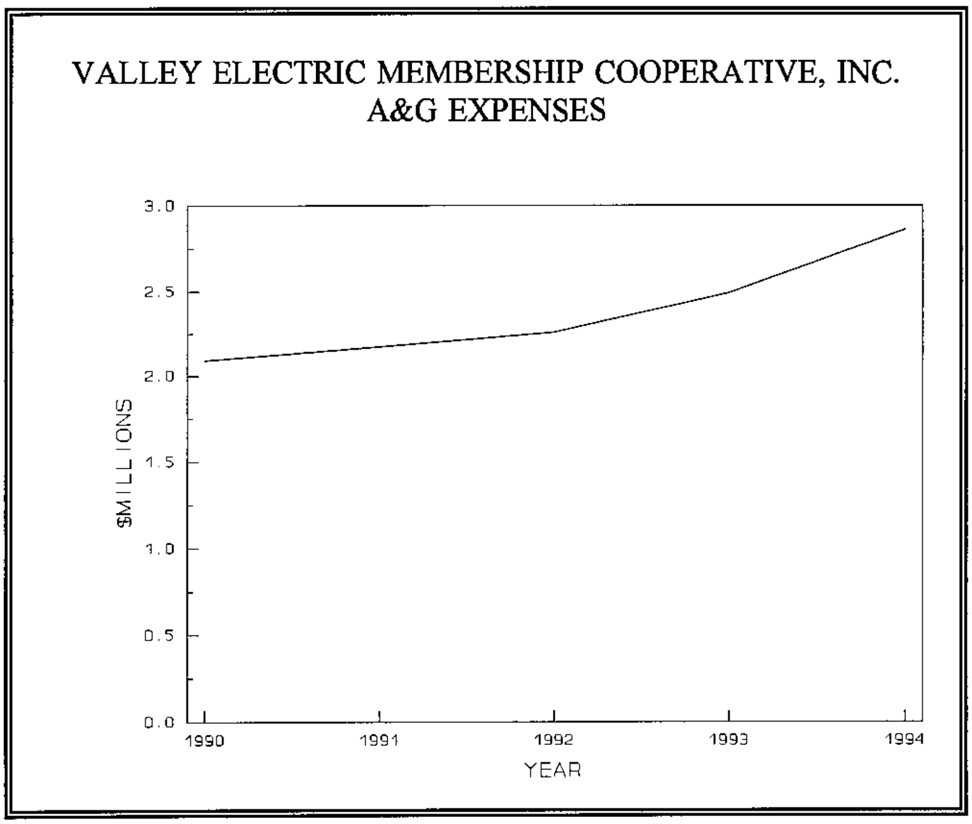
The Cooperative receives approximately 3,000 calls per month regarding billing problems, address changes, deferments, deposit information, budget billing, credit arrangements, rates, etc. There are also thirteen locations throughout the eight parish service area where customers can pay their utility bills. These collection agents are paid thirty cents per bill collected plus postage. Cooperative management indicated that records of the revenues collected by these locations are not kept by the Cooperative because the monthly fees are only between five and six hundred dollars.

Valley management believes that, regardless of the quality of service, there is an underlying dissatisfaction that Valley's rates are higher than those of the surrounding utilities. As a result, management declined to participate in the latest customer service surveys performed by ALEC.

There are no written customer service goals, objectives, or policies.

Administrative and General

A&G expenses, the third highest component of Valley's total cost of electric service, have increased by nearly 37% since 1990 and 16% in 1994 alone.



Valley's average A&G cost per customer is 19% greater than the average for the other Cajun member cooperatives. Injuries and damages expenses in 1994 were more than four times the 1990 levels and pensions and benefits expenses increased by nearly 61% over the same period.

In late 1991, Valley discontinued participation in the health benefit program provided by the National Rural Electrification Cooperative Association ("NRECA") due to annual increases in cost of 30-35%. Since then, Valley has been self-funded and pays 100% of the benefit costs. 1994 pensions and benefits expenses were more than 19% higher than 1993 levels, despite a moratorium by the NRECA on the pension program, which Valley expected to be lifted at the end of 1994. Pension payments were anticipated to equal 12.4% of total salaries due to pension payments for past service costs of $600,000.

In 1994, injuries and damages expenses totalled $305,872, a 3.5% decline from 1993 levels, but still more than four times the 1990 level. Valley indicated that the increase in injuries and damages between 1990 and 1993 was caused by a reallocation of cost from the property insurance account, which declined by $193,000 in 1993. However, Valley's property insurance premium increased in 1994 and returned to nearly the 1992 levels, while the level of injuries and damages expenses declined only slightly.

Outside services expenses declined steadily between 1988 and 1991, but increased sharply in the period 1992-1994 to more than double the 1991 level.

Conclusions and Recommendations

This Cooperative would clearly benefit from consolidation with another stronger cooperative, an IOU, or from consolidation of its administrative and certain operating functions at Cajun or ALEC. In addition to the opportunities available from consolidation, there are other opportunities to improve operations, reduce costs, and narrow the existing rate disparity between the Cooperative and neighboring investor-owned utilities.

Valley's rates are not competitive with those of the IOUs surrounding its service territory. The primary factors affecting Valley's rate levels are the high cost of purchased power, its excessive line losses, and the growth in its other costs compared to its growth in sales and revenue. Valley's service territory is characterized by low customer density, relatively low revenue per customer, a high percentage of residential load, and the difficulties in maintaining facilities in a rural environment. These factors all contribute to higher per customer and per kWh costs.

The decline in Valley's cost of electric service in 1994 was due to a reduction in sales and therefore, purchased power costs. Although management has initiated actions aimed at reducing costs, non-purchased power costs continued to increase due primarily to increases in A&G and customer services costs. At the same time, expenditures by the Cooperative in the sales and distribution O&M categories declined. That relationship is the opposite of what is necessary in order to improve the Cooperative's rate and operating performance.

1. Management and Board of Directors

Conclusions

Although the Cooperative recognizes the need to consolidate functions, downsize its operations, and generally improve its competitive position, it has not established a prioritized plan to accomplish those objectives. The Cooperative does not have the management focus or the planning process in place necessary to achieve specific goals and to ensure that gains in some areas do not result in unacceptable losses in others (e.g., savings resulting in unacceptable unreliability). The Cooperative has no strategic plan, no documented departmental goals and objectives (except for the billing and credit department), no department-level budget process, and no current work plans.

A strategic plan is a fundamental management tool for establishing goals and objectives and schedules for their accomplishment. Such a plan would provide the framework for developing work plans and ensuring that the specific projects within those work plans are prioritized, coordinated, scheduled, and budgeted to ensure that member resources are utilized in the most efficient and effective manner. It also follows that work plans must be developed, implemented, and updated to ensure the coordinated implementation of the identified tasks.

Department level operating budgets are necessary in order to plan and manage any organization. Departmental operating budgets are an essential management tool for directing and controlling expenditures, assessing departmental efficiency, and identifying areas requiring improvement. Departmental budgets help to ensure that the resources of individual departments and the entire Cooperative are directed toward accomplishment of the Cooperative's goals and objectives.

Recommendations

The Board of Directors and management should develop a strategic plan to identify and prioritize goals and establish schedules for their attainment. It should also identify, evaluate, and prioritize specific activities and projects in the context of that plan to translate those objectives into work plans. Work plans, once developed, should be actively monitored, including management's schedule and budget performance, to ensure that the selected tasks are accomplished in a timely and cost-efficient manner. Valley's current downsizing and consolidation efforts should be integrated into the planning process to ensure that all costs and savings are evaluated and that cuts are made in the most cost-effective areas.

Valley management should implement a formal operating budget process at the department level. These budgets should be developed within the context of the Cooperative's strategic plan, adherence to the budgets should be stressed, and performance to the budgets should be tracked regularly throughout the year with variances identified and addressed by management. The operating budget should be integrated with the capital budget so that total resources are budgeted. The Cooperative should also provide monthly reports of actuals and variances to departmental managers.

2. *Debt Service (Interest Expense and Depreciation Expense)*

Conclusions

The $5.3 million in discretionary investment funds is excessive. These funds either represent overcollections from customers which should be returned, or are indicative of an excessive level of debt. Furthermore, Valley has earned a poor return on its discretionary investments, less than the interest rate it pays on its outstanding debt.

The substantial increase in general plant investment does not appear to have generated value through improved productivity or reduced costs since A&G and customer service costs have continued to increase, on both a total and a per customer basis. Since the decisions to invest in transportation equipment currently require no economic justification, management does not know whether the investments in specific projects generate value.

Recommendations

The Cooperative should minimize the level of discretionary cash investments, subject to cash flow requirements. The available cash should be returned to its members or utilized to reduce Valley's costs.

Policies and procedures should be implemented requiring that investment in utility plant, particularly in general plant, be justified on basis of cost and/or efficiency improvements.

3. Operations and Maintenance

Conclusions

Valley's declines in distribution O&M costs seem to indicate that changes made in the earlier years of the audit period have been effective in reducing costs. However, there has been a dramatic increase in service interruptions since 1992. Management has not appropriately evaluated the costs and benefits of its actions on an interrelated basis, highlighting again the necessity for a strategic planning process, current work plans, and an effective budgeting process.

The lack of standard management tools, including statistical data and manpower efficiency standards, limits the Cooperative's ability to assess efficiency and effectiveness, identify opportunities for improvement, and assess the impact of procedural changes, such as the change to cyclic meter replacement.

Although Valley has decreased its line losses since 1992, it is still above the average for the cooperatives within the state. Despite its goal of 8%, the cooperative has not developed a work plan focused on attaining that goal.

Recommendations

Valley must identify and correct the causes of the marked increase in service interruptions in 1994. To the extent appropriate, this effort should be integrated with the on-going sectionalization studies. Management must take an active role in the investigation and should report frequently to both the Board and its customer service department.

Valley should study its current O&M practices and scheduling to identify opportunities to improve their efficiency and effectiveness. Additionally, implemented changes should be evaluated to determine whether they have achieved the desired effect, whether in practice their benefits outweigh their costs, and to identify any necessary adjustments. For example, the change to cyclic meter replacement was cited by management as a cause of increased costs. The incremental benefits and costs of this change should be identified and quantified.

The planned assimilation of the meter reading function into the in-house maintenance and operations departments should be similarly evaluated following implementation.

Maintenance records and scheduling should be automated. This would enable collection of data that could be used to set optimum maintenance and replacement schedules and would assist in the planning and budgeting processes. Responsibility for preventive maintenance should be centralized, and management should evaluate alternatives to the current monthly inspection/servicing, such as scheduling maintenance based on mileage or performing studies to determine the appropriate time periods for scheduled maintenance. Additionally, users requesting either replacement or new vehicles and equipment should be required to provide cost based justification for such requests. Management should also perform a study to evaluate on-site vs contract maintenance.

In order to reduce the cost of electricity to its members, Valley should redouble its efforts to reduce line losses. Studies should be performed to identify economic options to reduce the line losses. An action plan should be developed to prioritize and schedule the tasks necessary to attain or surpass management's goal of 8% line losses. Management and the Board should be diligent in monitoring the Cooperative's progress and verifying the achievement of its objectives.

4. *Administrative and General*

Conclusions

There are no A&G policies or procedures currently in effect at the Cooperative. The fact that A&G and customer service expenses are higher than average and increasing dramatically without directly increasing benefits to the Cooperative's membership, should highlight this category for a comprehensive review by management.

Recommendations

Valley should institute policies and procedures for the performance of annual comprehensive reviews of its employee compensation and employee and property insurance programs. Such a review should identify cost causation and evaluate multiple options for meeting the Cooperative's requirements. In particular, since the self-funded insurance program has been in place for three years, its performance vs. other options should be evaluated. Alternative approaches to the provision of pension benefits should also be investigated. Similarly, the Cooperative should determine and address the cause of the property insurance premium increase and evaluate the economics of alternatives, including self funding or reliance on government disaster assistance.

5. *Customer Service Operations*

Conclusions

Valley's increasing customer service costs require management attention. The current efforts to eliminate one district and downsize and consolidate functions should continue and be actively monitored by both management and the Board. A planned approach for downsizing and consolidation of these functions, as well as communication of the changes to members, is necessary in order to ensure adequate service. The flat growth in commercial customer base and the recent loss of one of Valley's two large industrial customers require attention from Valley management.

Recommendations

As previously discussed, the Cooperative's strategic planning should identify, evaluate, and implement improvements to ensure that the customer service department's efforts are focused on attracting and retaining customers, particularly commercial and industrial customers. Opportunities to consolidate and centralize operations should continue to be actively pursued. Management should focus on attracting and retaining customers and building efficient load. Customer attrition should be reviewed annually to discover the causes and develop preemptive strategies. Other cooperatives with higher commercial and industrial loads should be surveyed to identify strategies to improve Valley's competitive position.

Opportunities to centralize and streamline consumer accounting functions should be investigated. In addition, management should continue to pursue efforts to downsize its operations by consolidating the meter reading, operations, and maintenance functions among the districts in order to minimize costs and improve service. Additionally, the cause of the apparently increasing levels of uncollectible accounts should be investigated.

WASHINGTON-ST. TAMMANY ELECTRIC COOPERATIVE

Description of the Cooperative

Washington-St. Tammany Electric Cooperative, Inc. ("WST") is a rural electric distribution cooperative with 93 full-time employees serving more than 30,000 customers in the Louisiana parishes of Washington, St. Tammany, and Tangipahoa. The service territory is organized geographically with the headquarters in Franklinton and branch offices located in Folsom, Abita Springs, and Slidell. During 1993, WST had more than 4,500 miles of energized line and approximately 6.7 customers per mile. Residential customers comprised 96% of the customer base and were responsible for 80% of the Cooperative's sales, with less than 1% of its customers classified as large industrial. Annual revenues for 1993 exceeded $45.9 million on sales of 491,638 MWh. St. Tammany Parish is the fastest growing area in the state of Louisiana.

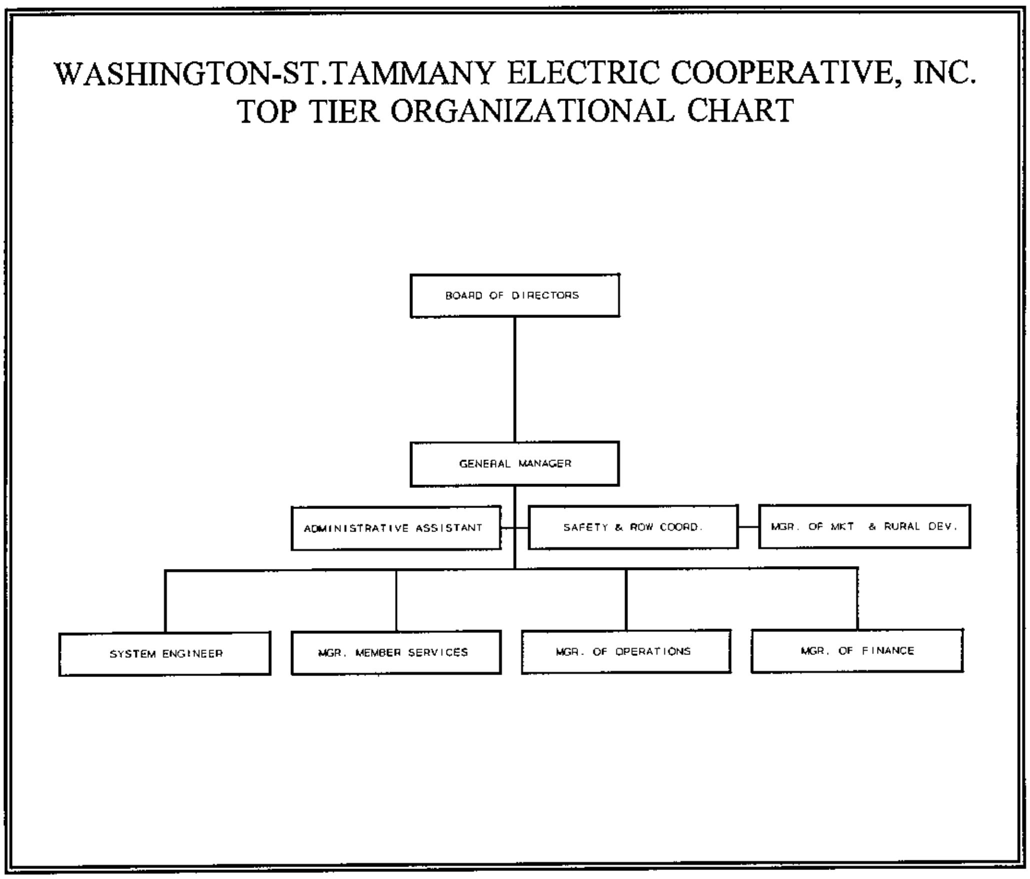
While the residential and small commercial and industrial customer base has grown, WST has lost 68% of its large commercial and industrial customers since 1989. In March 1992, WST had 32 customers classified as large industrial. By December 1993, the number had dwindled to nine. In 1992, annual sales to large commercial and industrial customers totalled 37,871,421 kWh. In 1993, annual kWh sold to this class dropped to 12,658,609 or approximately one-third of the prior year's annual sales.

Washington-St. Tammany's operations are subject to the terms and conditions of a court-ordered Plan of Reorganization ("POR"). The Cooperative initially sought protection from its creditors on July 17, 1987 and emerged from Chapter 11 bankruptcy proceedings in April 1990 under the Plan of Reorganization. The Cooperative's insolvency was precipitated primarily by a court-ordered rate refund of approximately $2.6 million and an unpaid debt balance of $26 million owed to Cajun and assumed by the RUS. The POR resulted in the restructuring of the long-term debt. The agreement also reduced the minimum times interest earned ratio and debt service coverage requirements of WST's CFC/RUS mortgage(s) and Security Agreements. The Cooperative has satisfied the repayment terms and the conditions of the Plan of Reorganization to date.

WST is surrounded by the service territories of Central Louisiana Electric Company ("CLECO") and Louisiana Power & Light ("LP&L"). According to management, WST has not experienced problems competing with LP&L. However, the rate disparity between CLECO and WST is greater than that between WST and LP&L. Additionally, WST's Cajun-sponsored heat pump incentive is not competitive with the cash incentives offered by CLECO. Management reports that Cajun is working with WST to offer a cash incentive of $200 to $300, but that will still fall short of CLECO's $1,500 offering. There are currently three territorial encroachment disputes involving WST and CLECO pending before the LPSC. WST has been approached by CLECO regarding an affiliation.

<u>Management and Board of Directors</u>

The following figure illustrates the organizational structure of WST to the manager level.



Six managers and an administrative assistant report directly to the General Manager. In 1992, the organization was restructured to be managed by function rather than location. This restructuring included the elimination of managers in each branch office and replacement with working supervisors who report to the managers at the Franklinton headquarters. For example, trained lead lineman in each branch office became supervisors of operations, reporting to the Manager of Operations. The senior clerk in each branch office became responsible for the daily operation of the service office, reporting to the member services manager in Franklinton. The structure of each of the manager's functional organizations to the supervisor level is detailed in the chart provided by WST and attached to this report as Exhibit 3.

The General Manager reports directly to WST's Board of Directors ("Board"), which is responsible to the membership for the operation of the Cooperative. The Board is composed of nine members elected by the membership in the Cooperative's three parish directorate districts, four each from Washington and St. Tammany parishes and one from Tangipahoa parish.

WST's policies and procedures manual defines a planning process for the development of goals, strategies, and measures as well as a management process for monitoring progress toward accomplishment of those goals. Nested within those procedures is a set of specific long term goals, strategies, measurements, and reporting requirements. However, many of the policies and procedures in the manual are not followed. Management planned to review and revise the Cooperative's policies and procedures in 1994 since it believed them to be impractical, cumbersome, and outdated.

WST has developed a Strategic Plan for 1994 that documents its goals and objectives, strategies for their achievement, and certain measures to be implemented. However, there are no strategies regarding the operational efficiency or costs of the Cooperative. Instead, the Strategic Plan is focused on member and media education and generalized marketing and territorial issues. There are no statements of guiding principles. There is no comprehensive implementation plan identifying specific activities, schedules, or budgets to achieve operational and cost efficiencies.

Although construction activities are not integrated with the Strategic Plan, the Cooperative has developed work plans for those activities. The Cooperative also prepares an annual budget and tracks its actual performance to that budget. However, the budget and tracking process is based on a cash rather than an accrual methodology. Typically, budgets are prepared on an accrual basis, consistent with a company's financial reporting obligations. Cash budgets are developed for cash management purposes. WST's general manager reviews budget variances with department managers and implements corrective action on a monthly basis. Aside from the budget, no formal criteria have been developed for evaluating departmental performance.

Summary of Revenues, Costs, and Margins

The following tables present a history of the Cooperative's costs by major category and various comparative measures of performance.

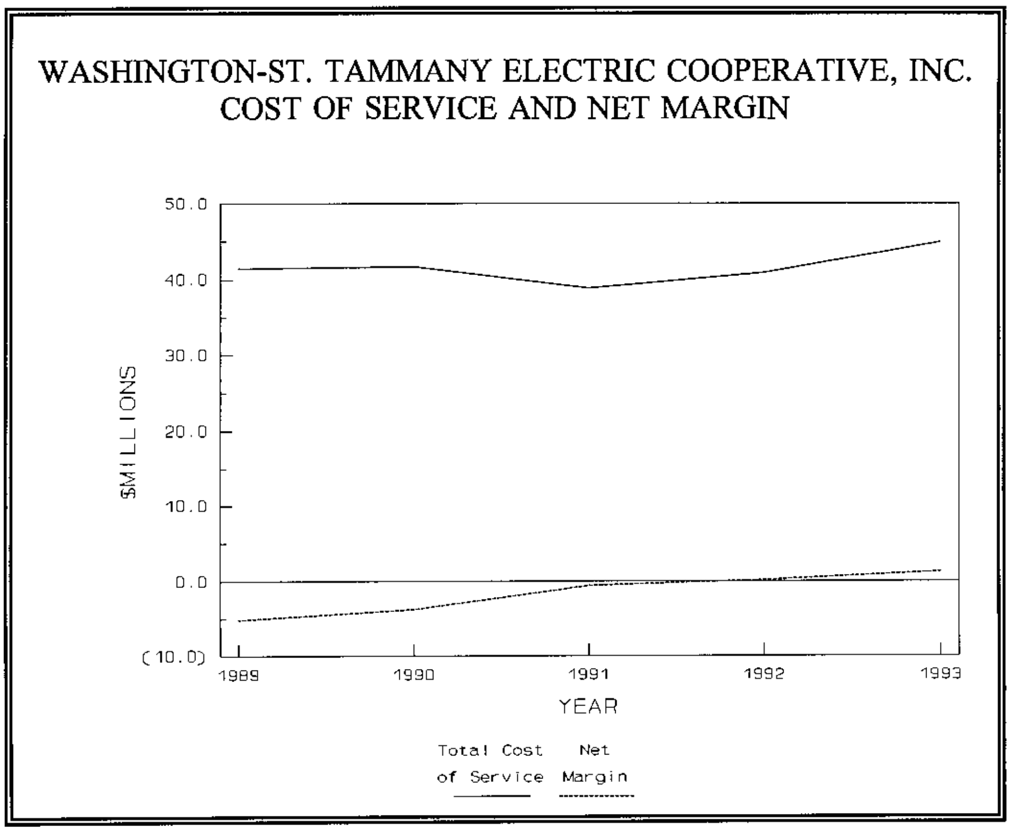
WASHINGTON-ST. TAMMANY ELECTRIC COOPERATIVE, INC.
HISTORY OF MAJOR COST CATEGORIES
($000)

	1989	1990	1991	1992	1993
Purchased Power	$27,783	$28,472	$28,150	$29,205	$31,400
Transmission, Distrib. O&M	2,067	2,196	2,292	2,367	2,940
Customer Service and Sales	1,255	1,301	1,128	1,089	1,116
A&G	2,290	2,517	1,661	1,863	2,230
Taxes	986	1,086	1,090	1,127	1,158
Depreciation	1,735	1,835	1,926	1,990	2,067
Interest	5,007	4,108	2,678	3,254	4,002

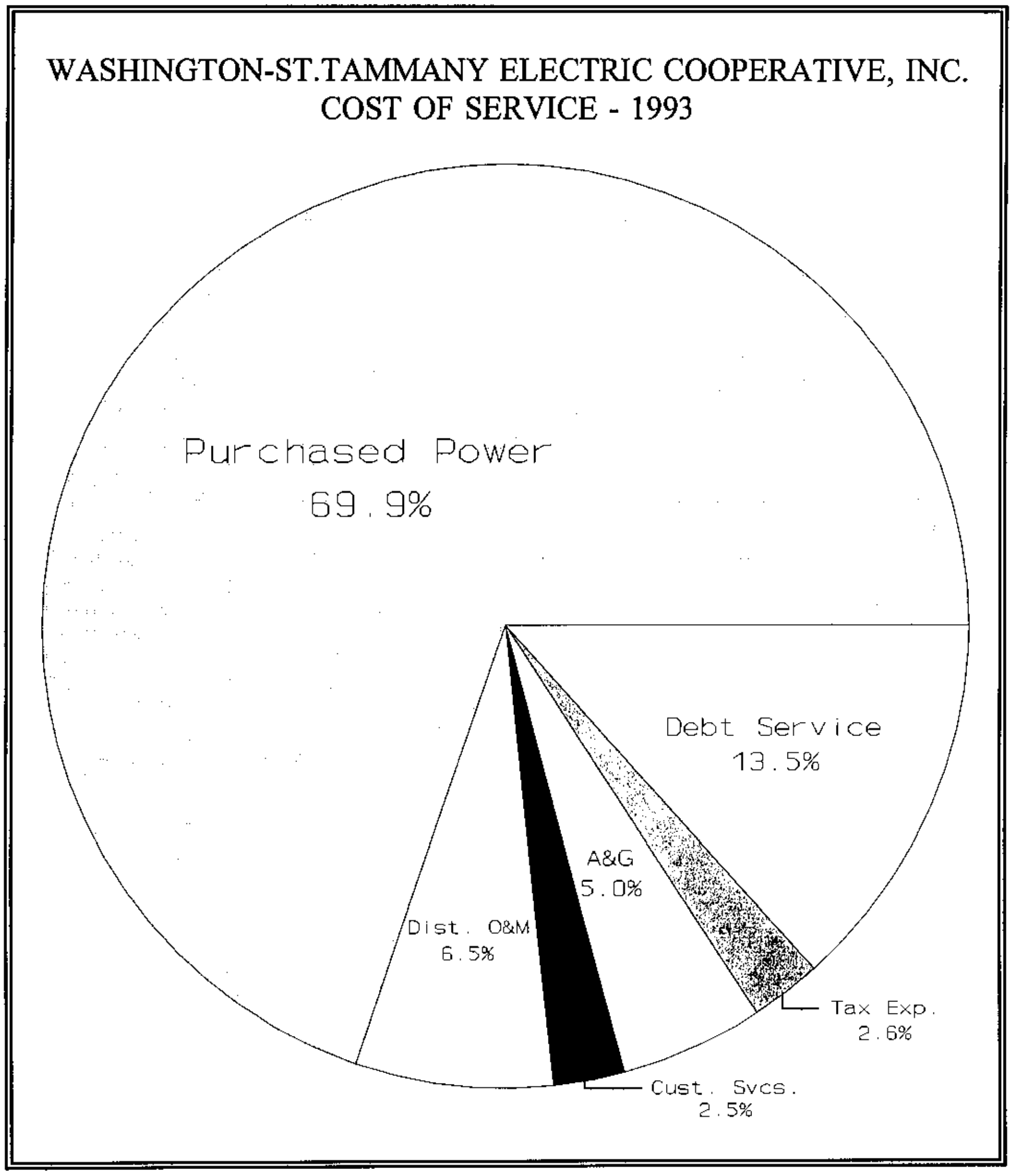
WASHINGTON-ST. TAMMANY ELECTRIC COOPERATIVE, INC.
KEY PERFORMANCE INDICATORS

	1989	1990	1991	1992	1993
Total miles energized	4,427	4,467	4,513	4,520	4,563
No. of customers served					
Residential	26,682	27,091	27,507	28,127	28,868
Small comm. & indust.	1,123	1,142	1,154	1,178	1,255
Large comm. & indust.	25	26	28	22	08
Total cust. (incl. other)	27,851	28,274	28,703	29,341	30,145
$ net plant	$52,670,669	$53,777,180	$54,833,652	$57,283,128	$60,677,913
# full-time employees	91	90	94	93	93
Total kWh sold	464,856,810	481,165,661	477,336,843	490,754,657	521,561,050
Total kWh purchased	512,566,507	515,143,263	530,099,119	532,989,453	571,888,052
Revenue/total cust.	$1,270.57	$1,355.43	$1,330.70	$1,389.19	$1,521.41
Revenue/mile	$7,993.63	$8,579.49	$8,462.84	$9,018.44	$10,051.51
Customers/mile	6.29	6.33	6.36	6.49	6.61
$ A&G/customer	$82.22	$89.02	$57.87	$63.50	$73.99
$ Cust svc/customer	$37.24	$38.02	$32.39	$33.06	$32.33
$ O&M/mile	$7,543.70	$7,720.71	$7,363.38	$7,639.02	$8,259.70
Operating margin/rev.	-17.22%	-8.93%	-1.93%	-0.34%	2.07%
% line loss	9.31%	6.60%	9.95%	7.92%	8.80%
$ line loss	$2,586,003	$1,878,001	$2,801,870	$2,314,284	$2,763,289
Cost purch. power/kWh	0.05420	0.05527	0.05310	0.05480	0.05491
Rate per kWh sold	0.07612	0.07965	0.08002	0.08306	0.08794

The total cost of service and the margins maintained by WST for the period 1989 through 1993 are presented in the following graph. In the wake of its emergence from bankruptcy in 1990 and the debt repayment restructuring with the RUS, WST significantly reduced its non-purchased power expenses. However, in 1992 and 1993, the Company's total cost of service increased.



The following graph illustrates WST's major cost areas and their respective contributions to the total cost of providing electric service in 1993.



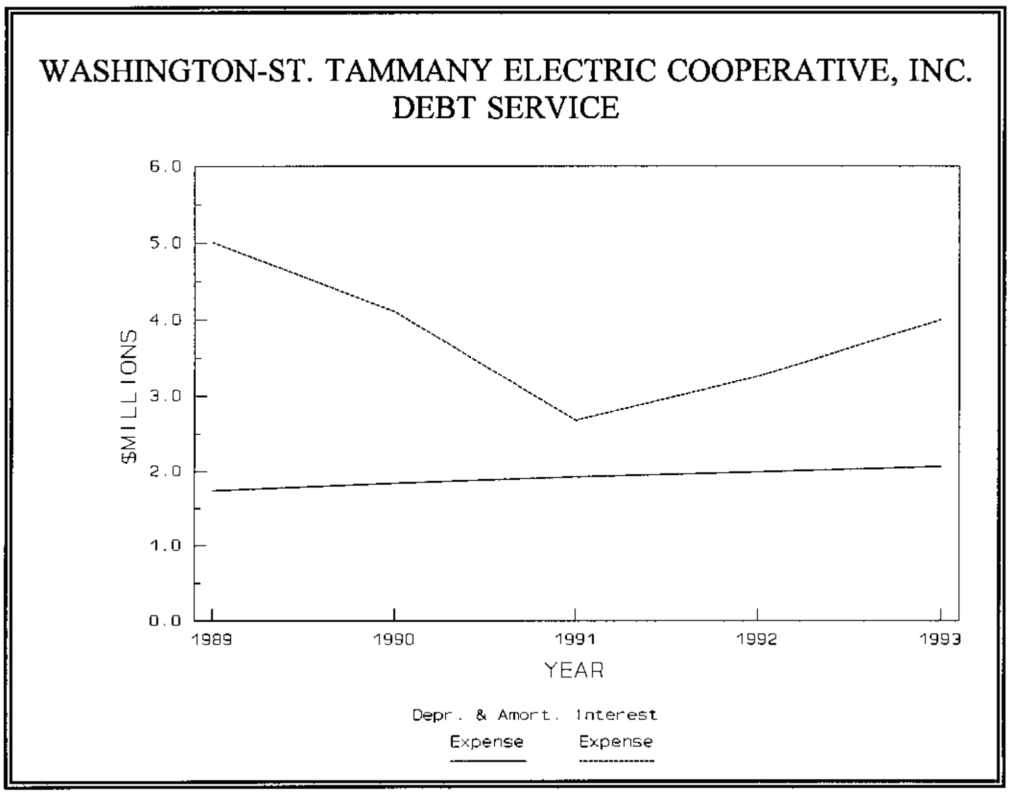
Rate increases and customer growth coupled with economies of scale and expense control in certain areas has contributed to improving margins since 1988. Customer growth has also enabled certain increased cost efficiencies. The number of customers has grown in total and on a per mile basis. In addition, the revenue per customer has increased. The average rate per kWh sold has increased due to the net effects of rate increases, increased customer usage, and the change in customer mix, while the cost per kWh purchased from Cajun has remained essentially flat.

Operating revenues have grown from $35.3 million in 1989 to $45.8 million in 1993, an annual growth rate of 6.7%. The cost of purchased power, on the other hand, has grown at a more modest annual rate of 3.1% during the same period, directly tracking the increase in sales. Distribution operation and maintenance expenses grew at a rate of 9.2% more than twice the rate of inflation and more than the rates of customer and sales growth. Customer service expense has actually been reduced. Administrative and general expenses also have been reduced since 1989 but have increased significantly over the last two years.

The recent rise in WST's total cost of service is due primarily to higher purchased power costs that have resulted from the increases in customer sales. Although the cost of purchased power has exhibited an upward trend during the period of analysis, there has not been a significant increase in wholesale power rates charged to the Cooperative. Thus, the growth in the purchased power cost is attributable to the increased kWh sales to the Cooperative's customers.

<u>Debt Service (Interest and Depreciation Expense)</u>

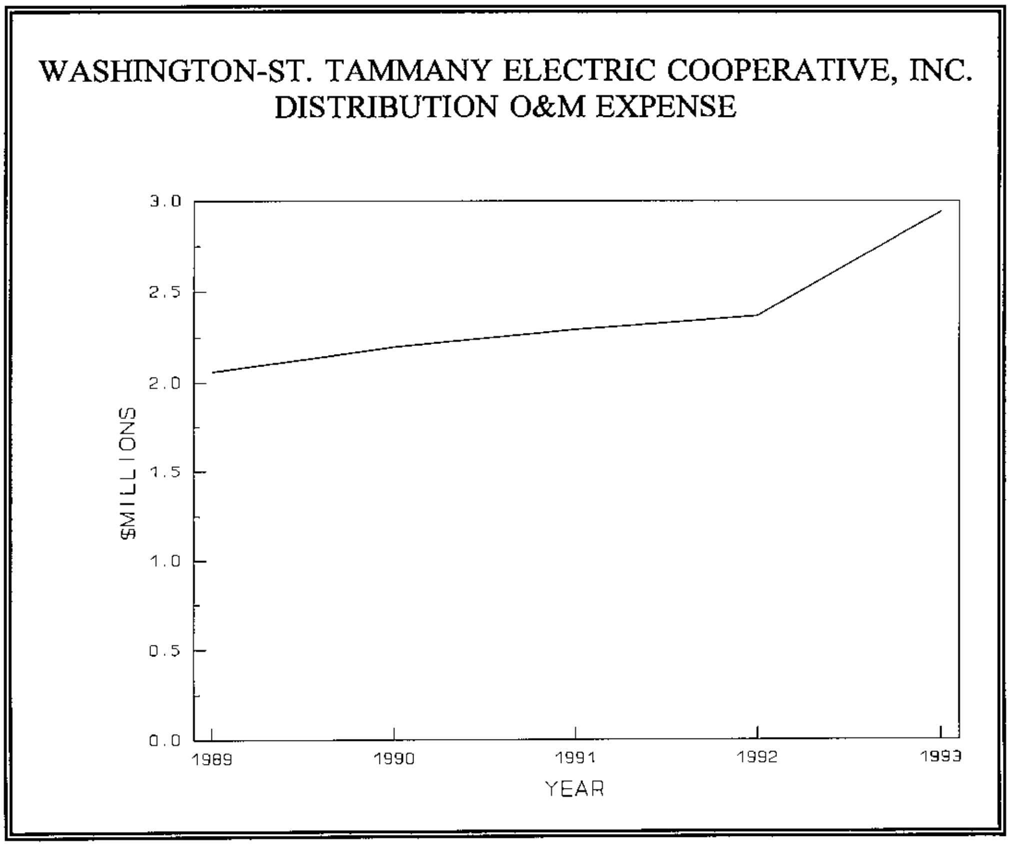
The following figure shows the historical levels of interest and depreciation expense for the period 1989 through 1993.



Debt service is the second largest component of WST's total cost of electric service. Depreciation expense has been relatively flat as the Cooperative has not engaged in any significant construction programs during the last few years, although the substantial customer growth in the service territory may require additional investment in facilities and equipment in the future. Interest expense was significantly reduced as the result of the 1989 bankruptcy filing and the 1990 Plan of Reorganization. The POR provided for a phase-in of increasing levels of debt service through 1993. The Cooperative must now meet its full debt service obligation. Under the POR, WST is required to periodically seek rate increases in order to meet the obligations of its loan agreements and pay its operating expenses. The POR also permits WST to request additional advances on outstanding RUS and CFC loans and apply for new loans in order to fund capital improvements. Property tax has remained relatively unchanged due to moderate growth in plant investments.

Distribution Operations and Maintenance

WST's distribution O&M expense has grown by 42% since 1989 but is below the average for the twelve member cooperatives on a cost per energized mile basis. Most of that growth occurred in 1993.



The primary reason for the recent increase in distribution operation and maintenance expense is overhead line operation and maintenance. The Cooperative accelerated its vegetation control cycle to a period of four to five years from an average of nineteen and a half years in order to improve service reliability. WST has procured additional equipment, increased its staffing, and increased its contract crews for vegetation control. Reliability problems, as measured by outage frequency, were the second greatest concern cited by WST members responding to a recent customer survey.

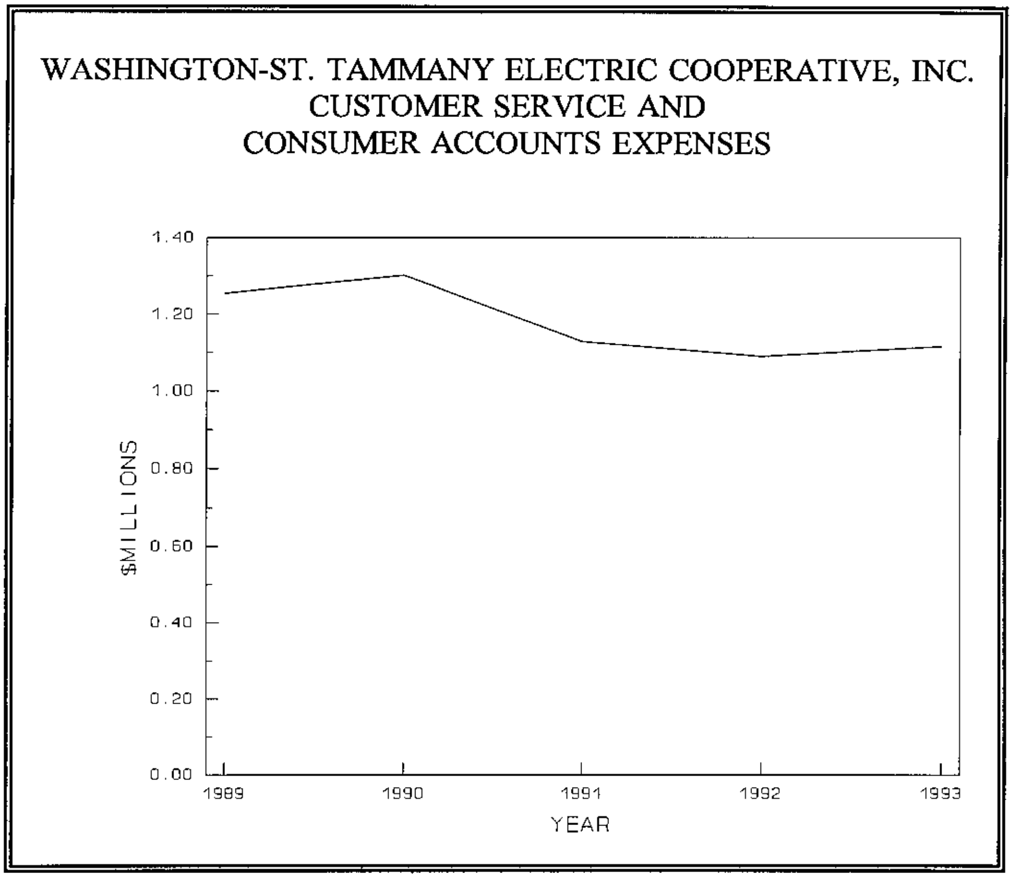
In 1993, WST's line losses averaged 8.8%, with each percentage point costing the Cooperative approximately $314,000. This loss percentage is higher than WST's levels in 1990 and 1992 and 7% higher than the average of the twelve Cajun member Cooperatives. The Cooperative significantly decreased the percentage of reported line losses when it converted from a customer-read meter reading system to an electronic, hand-held meter reading system in 1989. However, line losses were nearly 11% higher in 1993 than in 1992. The Cooperative has been performing sectionalization studies to identify the reasons for line losses and outages.

The gross investment in transportation and shop equipment was nearly $2.0 million at year-end 1993. The Cooperative has found that quantity acquisitions of vehicles have resulted in a lower per unit price. Auctions or trade-ins are the preferred method of vehicle disposal. All work conducted on a vehicle or truck, including routine maintenance such as oil changes, tune-ups, alignments, etc., are performed by outside vendors. Although WST is considering automation of its fleet maintenance scheduling and data collection, the process is currently manual. The data is collected in a log which is maintained by the operations clerk, who notifies the equipment operators when maintenance is required.

WST's maintenance and operations department, like the majority of the cooperatives, relies on Cajun only for specialized substation repairs, i.e., those requiring specialized skills and equipment that are needed infrequently by WST. Cajun provides those services to the cooperatives at cost. Cajun's management is interested in providing additional testing and maintenance of the cooperatives' equipment, particularly since much of its own equipment is in close proximity to that of the cooperatives. The Cooperative subcontracts most construction jobs requiring more than two days to complete. WST also maintains its own engineering department which contracts for engineering of new equipment and work plans.

Customer Service and Consumer Accounts

As illustrated in the following figure, customer service expenses decreased on both a total and per customer basis since 1989. The cost reductions were predominantly in sales and services rather than the consumer accounts expenses. However, these expenses are expected to increase in the upcoming years, as management plans to expand customer service programs and facilities.



Although WST's per customer expense is approximately 17% below the average of the twelve Cajun membership cooperatives, these expenses are a significant component of cost of service.

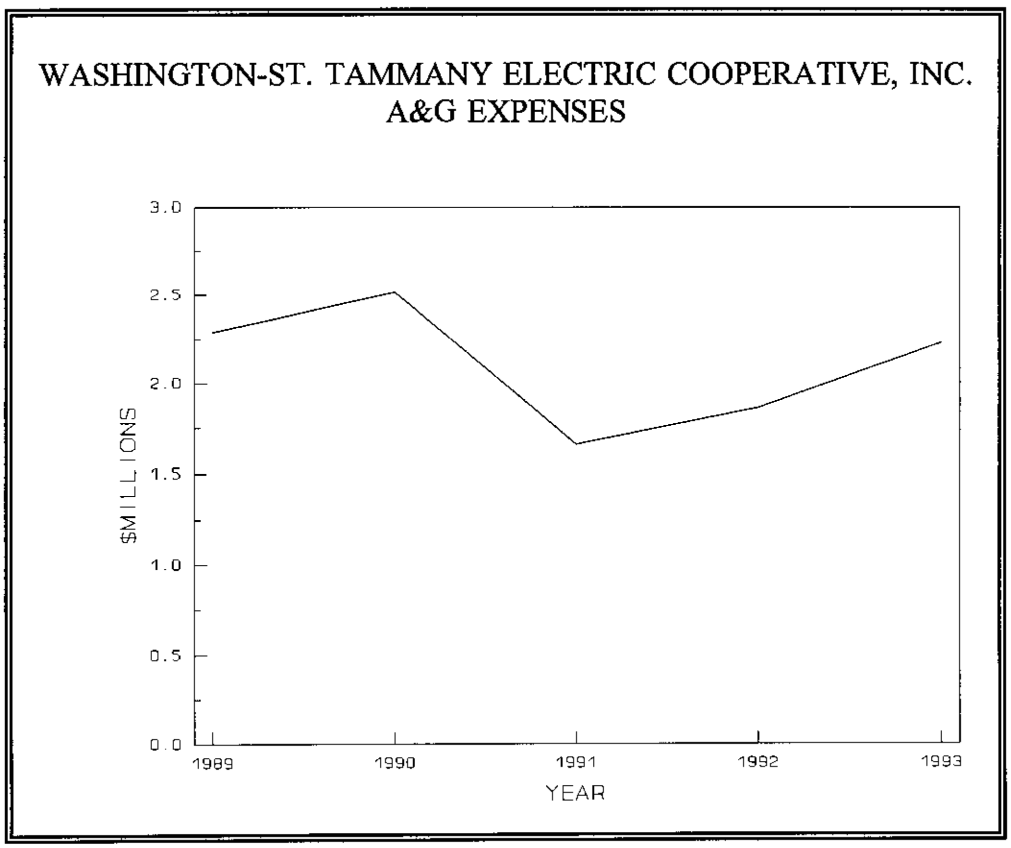
WST has four "walk-in" locations: the main office in Franklinton and three branch offices (Folsom, Abita Springs, and Slidell). Customers may pay bills, request service, report service problems, and receive rate consultation at any of the four locations. Telephone services provided at each location include outage reporting, requests for disconnection, information regarding connection of service, and bill explanations. Computerized customer billing information is available to the clerks handling telephone calls. With some exceptions, customers are required to personally appear at one of the service locations to initiate service, but other services such as bill inquiries are generally handled by telephone. The Cooperative receives most of its bill payments by mail. There are five additional locations in banks throughout the service territory where customers can pay their utility bills. WST pays no fees for these services. In a typical month, these locations typically collect approximately 13.6% of the Cooperative's member revenue.

The meter reading function has recently been converted from a customer-read system to an electronic, hand-held meter reading system. According to management, the automation not only improved the efficiency of the meter reading function but reduced the reported line losses. An additional benefit of a meter reader visiting the customer's premises each month is to identify potential line loss situations or safety hazards. A recent management change has introduced new supervision to the department. The new supervisor intends to evaluate all work processes involved with the development and assignment of meter reading routes and the billing function. Further efficiencies may be implemented in the department based upon the outcome of the study. Customer billing and posting of bill payments are handled by the billing clerks in the Franklinton office under the direction of the Billing Supervisor.

The results of a recent customer survey indicated that high rates were the most significant concern, followed by the frequency of outages.

Administrative and General

While lower than levels in 1989 and 1990, A&G costs have increased by 34% on a total basis and 28% on a per customer basis since the low in 1991.



WST's average A&G cost per customer is nearly 9% greater than the average for the twelve Cajun member cooperatives. Significant reductions in A&G salaries have been offset by increases in the pensions and benefits, injuries and damages, and outside services expense.

Despite a moratorium on pension plan contributions, pensions and benefits expenses increased by nearly 90% over the same period. The Cooperative provides medical insurance for its employees and their dependents which covers 80% of outpatient care and 100% of in-patient care, with a $200 deductible. Management estimates the value of its benefits package to be 45% of direct labor costs. WST provides hospitalization and life insurance for the Board as well as fees of $100 per meeting and expenses.

Injuries and damages expenses in 1993 were 30% higher than the 1989 levels. Management indicated that it reinstituted its Safety Incentive Program in 1992 in order to reduce its experience rating and therefore its workers' compensation insurance. This program will be reviewed annually by the Cooperative's insurance carrier. Management indicated that due to settlements between the insurance industry and the state of Louisiana, insurance costs were expected to increase in 1994.

WST has not recognized property insurance expense since 1988, nor does the Cooperative recognize an accrual for storm damage. WST has determined that insurance for electric distribution plant is not available and would not be cost-effective in any case because the Federal Emergency Management Association pays for repair of systems damaged by major disasters.

Conclusions and Recommendations

Washington-St. Tammany presents another clear opportunity to benefit from consolidation either with another cooperative, an IOU, or through consolidation of functions at Cajun, ALEC, or another entity. The consolidation opportunities have been highlighted due to the recent CLECO affiliation advances. In addition to the opportunities available from consolidation, there are opportunities to improve operations and narrow the existing rate disparity between the Cooperative and neighboring investor-owned utilities.

Although Washington-St. Tammany is currently in compliance with the Plan of Reorganization and the requirements for RUS borrowers (i.e., times interest earned ratio and debt service coverage), it must address other areas of business, particularly if the cooperative is not acquired by CLECO. These issues include, but are not limited to, maintaining competitive rates in a service territory characterized by low customer density, relatively low revenue per customer, a high percentage of residential load, a rural area that increases the difficulty of performing maintenance activities, and the threat of territorial invasion from competing utilities.

1. Management and Board of Directors

Conclusions

A properly focused strategic plan is a fundamental management tool for establishing goals and objectives and schedules for their accomplishment. A strategic plan should provide the framework for developing the budget and work plans. It would ensure that discrete projects within the budget and work plans are prioritized, coordinated, scheduled, implemented, monitored, and updated to ensure that member resources are utilized in the most efficient manner. However, WST's strategic plan is not focused on the achievement of operational efficiencies and cost control. The focus on customer and media communications, while not irrelevant, is certainly not a primary strategic concern.

Further, the Strategic Plan does not define quantitative goals for measuring success. For example, the customer service goals might identify a target number of program participants, a target increase in customers, or a target reduction in customer attrition. Such measurable goals are necessary to assess the effectiveness of strategies and work plans.

Some of WST's policies and procedures could serve as valuable management tools and provide necessary information to management and the Board. Selective enforcement of some but not all policies and procedures in the manual makes it difficult for workers and management to assess the adequacy of the systems and processes within the Cooperative, assess performance, and improve efficiency.

Departmental operating budgets are an essential management tool for directing and controlling expenditures, assessing departmental efficiency, and identifying areas requiring improvement. WST's practice of developing and monitoring the budget on a cash basis provides a measure of control, but it is inconsistent with financial reporting requirements and could yield results that are not reflective of the Cooperative's actual financial position.

Recommendations

The strategic plan should identify objectives and schedules and measurements for assessing progress toward their attainment. Compliance with this plan should be actively monitored and managed by both WST management and the Board. Specific activities, procedures, and projects should be identified, evaluated, and prioritized in the context of that plan to translate those goals into the budget and work plans. Work plans should be developed and actively monitored by management, including schedule and cost performance, to ensure that the selected tasks are accomplished in a timely and cost-efficient manner.

The strategic plan should be refocused on the issues that can have the greatest impact on the Cooperative's operations costs, and rates. Such issues include:

- Aggressive attempts to reduce costs through consolidation at Cajun, ALEC, or other entity.
- Aggressive attempts to achieve cost savings and lower rates through affiliation with a merger partner.
- Reversing the erosion of the industrial customer base.
- Reducing line losses and improving reliability.

The dramatic losses in the large commercial and industrial customer class should be addressed by management in the strategic planning process. Industrial customers represent efficient loads, and strong efforts should be made to attract and retain these customers. WST's strategic planning and work plans should identify, evaluate, and implement improvements to ensure that management's efforts are focused and effective in attracting and retaining customers, particularly commercial and industrial customers. Management should institute a policy/procedure requiring an annual review of customer attrition, identification of the causes of the attrition, and development and implementation of preemptive strategies. The methods of utilities (cooperatives and IOU's) with increasing commercial and industrial loads should be surveyed to identify strategies to improve WST's competitive position.

Management, under the Board's direction, should systematically review and revise all policies and procedures governing the performance of tasks within the context of the Cooperative's strategic plan. Policies and procedures should be distributed, implemented, and consistently followed.

2. Debt Service (Interest and Depreciation Expense)

Conclusions

The terms and conditions of the Plan of Reorganization limit the operating flexibility of the Cooperative. The plan, while allowing for an extension and phase-in of WST's debt service obligations, provided no relief from either the amounts owed or the interest on those amounts. The POR directive that WST meet its debt obligations by increasing rates has diminished its competitive position and, consequently, its ability to attract and retain customers.

Recommendations

Management should consider renegotiating the Plan of Reorganization in order to secure terms that would allow the Cooperative to be more competitive with neighboring utilities.

3. *Operations and Maintenance*

Conclusions

Distribution operation and maintenance expense has grown from $2.07 million in 1989 to more than $2.9 million in 1993 primarily due to acceleration of the vegetation control cycle. WST should determine the economic feasibility of contracting for O&M services such as vegetation control and substation testing and maintenance in conjunction with Cajun or with other cooperatives. Similarly, opportunities to consolidate engineering contracts, such as those for work plans, sectionalization studies, and/or substation design should be investigated as should consolidation of major construction projects.

Line losses cost WST members more than $2.7 million in 1993. Though improvements in the meter reading process temporarily improved the reported line losses when compared to 1989 levels, there is clearly a need for management to focus its attention on this issue.

The Cooperative's manual fleet maintenance system used to track the history and maintenance requirements of WST's $2.0 million worth of equipment rests too much responsibility in one person. Additionally, an automated system would provide data essential in making cost-based repair/replace decisions.

Recommendations

WST should redouble its efforts to reduce line losses. If necessary, it should obtain the services of a third party or of Cajun to assist it in a comprehensive review of this problem. Management should develop an action plan to complete its sectionalization studies and to prioritize and implement actions that are cost justified. Relevant budget and actual cost, schedule, and performance information should be reported to management and the Board monthly to ensure management attention and the achievement of actual improvement.

The cooperative should determine and implement an optimum vegetation control cycle for WST. To do so, it should evaluate the results of the accelerated vegetation control cycle in each section of its distribution network in order to assess the impact on line losses and service outages.

Fleet maintenance records and scheduling should be automated. This would enable collection of data that could be used to set optimum maintenance and replacement schedules and would assist in the planning and budgeting processes. It should be centralized under the direction of the fleet supervisor. A preventive maintenance scheduling program should be developed and followed.

4. *Administrative and General*

Conclusions

A&G expenses are higher than average and have increased rapidly, particularly the injuries and damages and pensions and benefits expenses. Management needs to focus on reducing these costs.

Recommendations

WST should consolidate its administration functions, along with the other cooperative, at Cajun, ALEC, or some other entity in order to reduce its costs and its rates. In the interim, it should conduct a comprehensive review of its employee compensation and employee and property insurance programs. Such a review should identify cost causation and evaluate multiple options for meeting the Cooperative's requirements. Alternative approaches to provision of pension benefits should also be investigated.

5. *Customer Service Operations*

Conclusions

Management's plans to increase customer service expense should be reviewed and evaluated in the context of its strategic plan and the recent customer attrition, to ensure that resources are directed to the most cost-effective activities. Management should aggressively pursue opportunities to reduce costs by consolidating the services offered at each of the "walk-in" customer service locations through joint efforts at Cajun, ALEC, or another entity.

Recommendations

Management should focus attention on streamlining "behind the scenes" customer accounting services such as metering, billing and payment. At a minimum, these should be consolidated at a single WST location. However, maximum efficiencies and cost reductions could be achieved through consolidation of similar functions with the other cooperatives through Cajun, ALEC, or another entity.

In addition, customer service policies and procedures, such as the requirement that customers apply for service in person, should be evaluated to determine whether opportunities for efficiency improvements exist. The Cooperative should also investigate opportunities to shift bill payment from the walk-in offices to mail and agency locations. Similarly, consolidation of telephone inquiry services should be evaluated.

CONCORDIA ELECTRIC COOPERATIVE, INC.

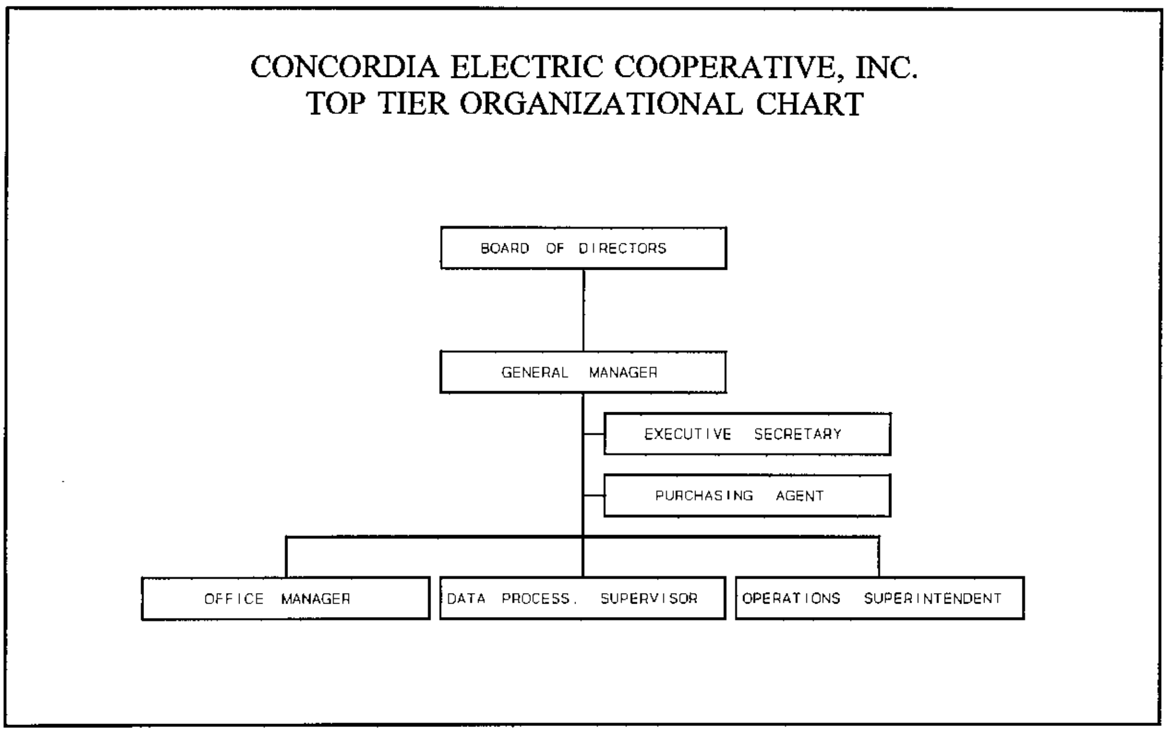
Description of the Cooperative

Concordia Electric Cooperative, Inc. ("Concordia") is a rural electric distribution cooperative which serves just over 11,300 customers in the Louisiana parishes of Catahoula, Concordia, LaSalle, Grant, Tensas, Franklin, and Caldwell. Until April of 1993, the Cooperative's headquarters was located in Ferriday, with additional offices and warehouses in Jonesville and Jena. Currently, the Cooperative operates only one office located in Jonesville, Louisiana. At the end of 1994, Concordia had 44 full time employees and nearly 2,500 energized miles. Concordia's revenue per mile was the lowest of the Cajun member cooperatives at $5,640 per mile, and its customer density, at 4.5 customers per mile, is lower than all but Valley. Nearly 67% of the Cooperative's kWh sales and approximately 88% of its customer base was residential, with nearly 12% of its customers and 30% of its sales categorized as commercial and industrial. Concordia's customer base has grown by less than 2.75% since 1990.

Concordia's service territory is adjacent to Central Louisiana Electric Company ("CLECO") and Louisiana Power and Light ("LP&L"). Management believes that Concordia's low customer density makes it an unattractive takeover target for surrounding IOUs. However, the town of Jonesville has encroached on individual customers, and due to a new industrial plant, the town of Vidalia may expand its corporate limits into Concordia territory.

Management and Board of Directors

The following figure illustrates the Cooperative's organization. The purchasing agent, office manager, data processing supervisor, and operations superintendent report directly to the General Manager. The structure of each of the functional organizations is detailed in the chart provided by Concordia and attached to this report as Exhibit 4. Management expects to maintain the current organizational structure in the future.



The General Manager is responsible to Concordia's Board of Directors ("Board"), which consists of five members elected by the membership of the Cooperative. Prior to 1990, the Board consisted of nine members, and a return to that structure is under consideration. Concordia management presents a report to the Board monthly. Generally, this report contains minutes of previous meetings, cash flow and account balances, the RUS Form 7, line loss and outage reports, transportation expense reports, attorney's reports on regulatory matters, and a general manager's report.

Concordia has no strategic plan and does not have in place even the basic management tools necessary to provide sound financial management and control information. Though specifically required by Board procedures, there has been no capital or operations budget prepared since 1986 and no work plans submitted since 1990. One of the effects of the absence of plans and standard procedures has been poor outage performance, which in 1992 prompted the LPSC to cite Concordia for failure to provide adequate electrical service to its members. Under Commission oversight, corrective action was and is continuing to be taken. However, internal management controls are essential to prevent recurrence of these problems.

Concordia's general manager assigns the blame for the poor management at the Cooperative to the former President of the Board, who passed away in January 1994. In a letter dated June 29, 1994, he stated the following in response to requests for plans, programs, budgets, reports, and internal control procedures.

> **"In reviewing most of the questions of this 'Second Set of Data Requests', it becomes very difficult to provide an answer. The reason is that the President of the Board of Directors of Concordia Electric from 1987 to his death January 10, 1994 did not allow, permit, believe in, or whatever it was, but anyway we didn't do many of those things because he said so.**
>
> **It is not a pleasant thing to do, and again very difficult to do, and that is to refer to someone that has passed on. Difficult because in most cases we knew what needed to be done, or at least knew how to get the answers. But after running into a brick wall time after time, one finally gives up.**
>
> **The previous Board of Directors, prior to January 10, 1994 and until the Annual Membership Meeting, May 7, 1994, with the exception of one Director, did nothing but go along with the President."**

He finished the comments by indicating that things would be different in the future since four new directors were elected on May 7, 1994 who "want Concordia Electric to be managed and operated as a Rural Electric Cooperative utility should be."

As of October 18, 1994, Concordia still had no operating or capital budget, though the minutes of the January 27, 1994 board meeting indicate that such a budget was to be submitted at the February 11, 1994 meeting. Further, the General Manager indicated during the audit interview that although "those things are in mind to do," there had been no action to develop a strategic plan or begin evaluation of policies and systems in place at the Cooperative. Management stated that there had been no time in the five months since the election to perform anything but "clean-up" tasks.

The general manager indicated that he expected to present a wage and salary structure, an organizational structure, and budgets to the Board in January 1995. He also indicated that the Board intended to review and revise policies and rate schedules. Although a new President of the Board was elected in January 1994, and a new Board was installed in May 1994, no plans have been developed for performing any of these tasks.

Additionally, management failed to respond to any of the questions in the last two sets of data requests issued by the LPSC. The information sought included explanations and descriptions of the functions it performs for its members. This report, therefore, relies heavily on the transcripts from the audit interview, which was conducted on October 18, 1994, and information provided in response to the two earlier sets of data requests.

Summary of Revenues, Costs, and Margins

The following tables present a history of the Cooperative's costs by major category and various comparative measures of performance.

CONCORDIA ELECTRIC COOPERATIVE, INC.
HISTORY OF MAJOR COST CATEGORIES
($000)

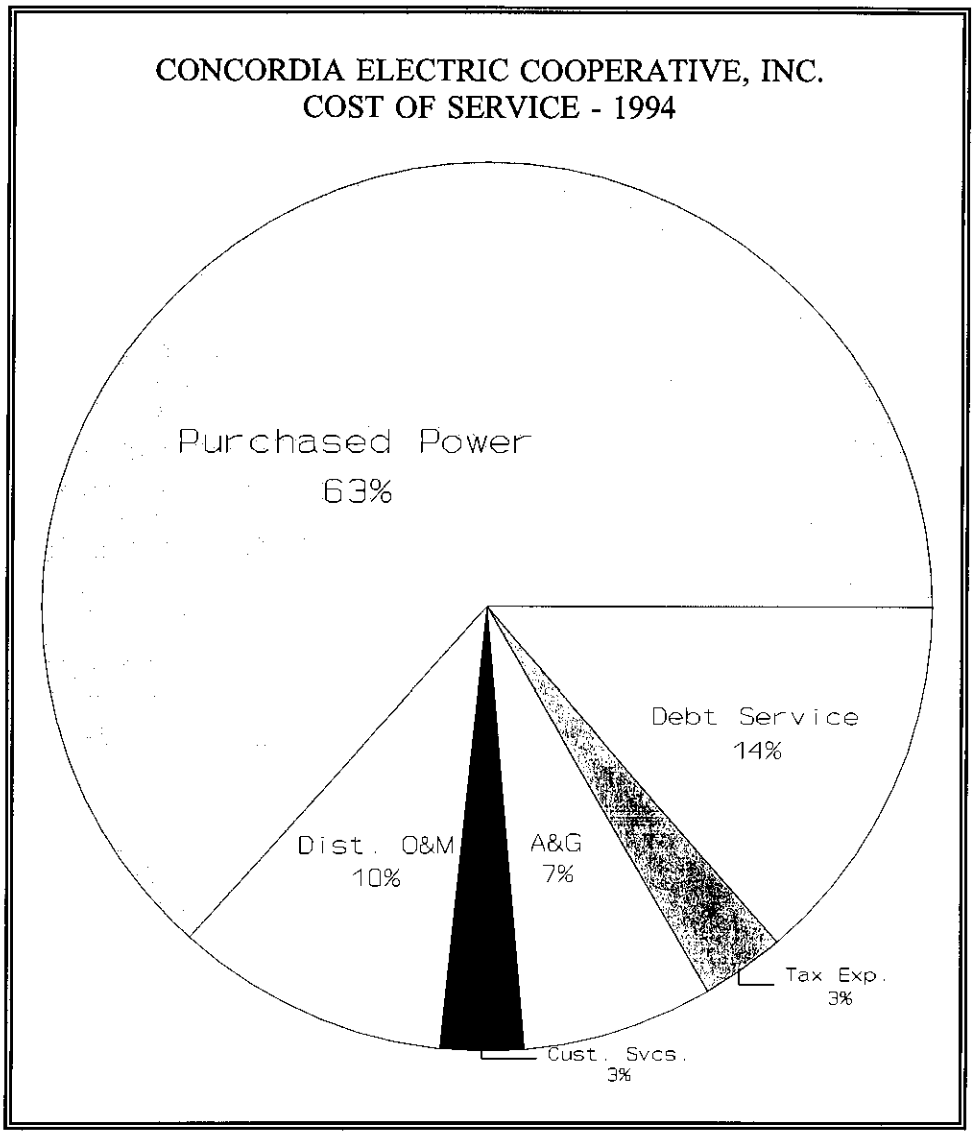
	1990	1991	1992	1993	1994
Purchased Power	8,394	8,028	7,764	8,523	8,452
Transmission, Distrib. O&M	1,033	1,022	980	1,241	1,382
Customer Service and Sales	413	393	377	342	360
A&G	859	828	761	707	911
Taxes	392	401	392	390	420
Depreciation	877	897	932	937	966
Interest	1,156	1,035	927	869	865

CONCORDIA ELECTRIC COOPERATIVE, INC.
KEY PERFORMANCE INDICATORS

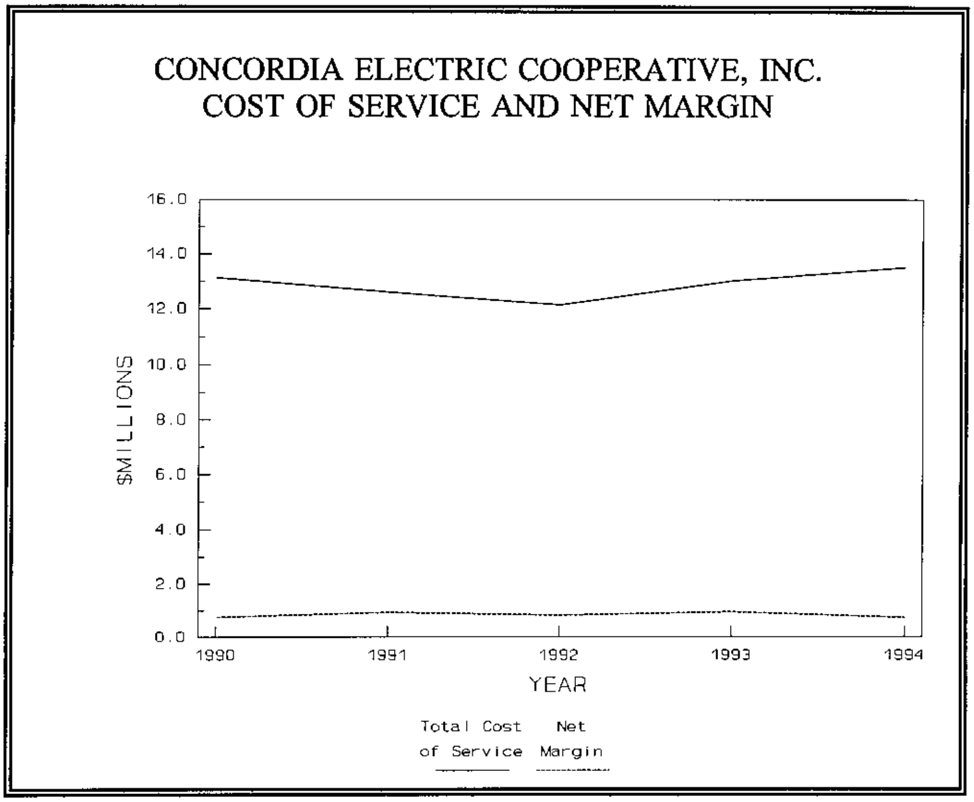
	1990	1991	1992	1993	1994
Total miles energized	2,460	2,476	2,494	2,494	2,494
No. of customers served					
Residential	9,769	9,706	9,790	9,889	10,012
Small comm. & indust.	1,247	1,281	1,299	1,312	1,312
Large comm. & indust.	2	2	2	2	2
Total cust. (incl. other)	11,049	11,016	11,116	11,227	11,350
$ net plant	$22,404,301	$22,444,770	$22,366,737	$22,478,514	$22,453,713
# full-time employees	48	44	44	39	44
Total kWh sold	139,166,330	139,572,370	127,972,107	139,879,516	143,609,646
Total kWh purchased	154,751,230	156,613,887	144,117,354	157,468,319	158,869,069
Revenue/total custs.	$1,235.77	$1,211.24	$1,150.66	$1,234.08	$1,239.32
Revenue/mile	$5,550.55	$5,388.76	$5,128.66	$5,555.26	$5,640.23
Customers/mile	4.49	4.45	4.46	4.50	4.55
$ A&G/customer	$77.75	$75.14	$68.48	$62.93	$80.23
$ Cust svc/customer	$37.35	$35.72	$33.94	$30.43	$31.71
$ O&M/mile	$4,349.23	$4,147.96	$3,962.30	$4,335.22	$4,452.37
Operating margin/rev.	3.73%	5.47%	5.12%	6.04%	3.92%
% line loss	10.07%	10.88%	11.20%	11.17%	9.61%
$ line loss	$845,348	$873,507	$869,761	$952,022	$811,800
Cost purch. power/kWh	0.05424	0.05126	0.05387	0.05413	0.05320
Rate per kWh sold	0.09812	0.09560	0.09995	0.09905	0.09795

Concordia has experienced almost no growth since 1990. The Cooperative's miles of distribution lines have increased by just over 1% and the number of customers has increased by just over 2.75% over the entire period. The Cooperative's kWh sales have increased by only 3%, while the total cost of electric service has risen by approximately 2.8%. Concordia's cash management policies as well as the deferral of maintenance activities resulted in substantial increases in margins through 1993. Margins declined in 1994, due to increases in nearly all non-purchased power expenses, including a sixteen-fold increase in the "other deductions" category. Absent the increase in "other deductions," margins would have been only slightly lower than 1993 levels. Capital investments and necessary operational changes resulting from recent engineering studies will likely cause O&M costs to increase in the future.

The following graph illustrates Concordia's major cost areas and their respective contributions to the total cost of providing electric service. Concordia's cost composition reflects the fact that its purchased power cost per kWh is less than the average of the other eleven member cooperatives.



The total cost of service and the margins maintained by Concordia for the period 1990 through 1994 are presented in the following graph.



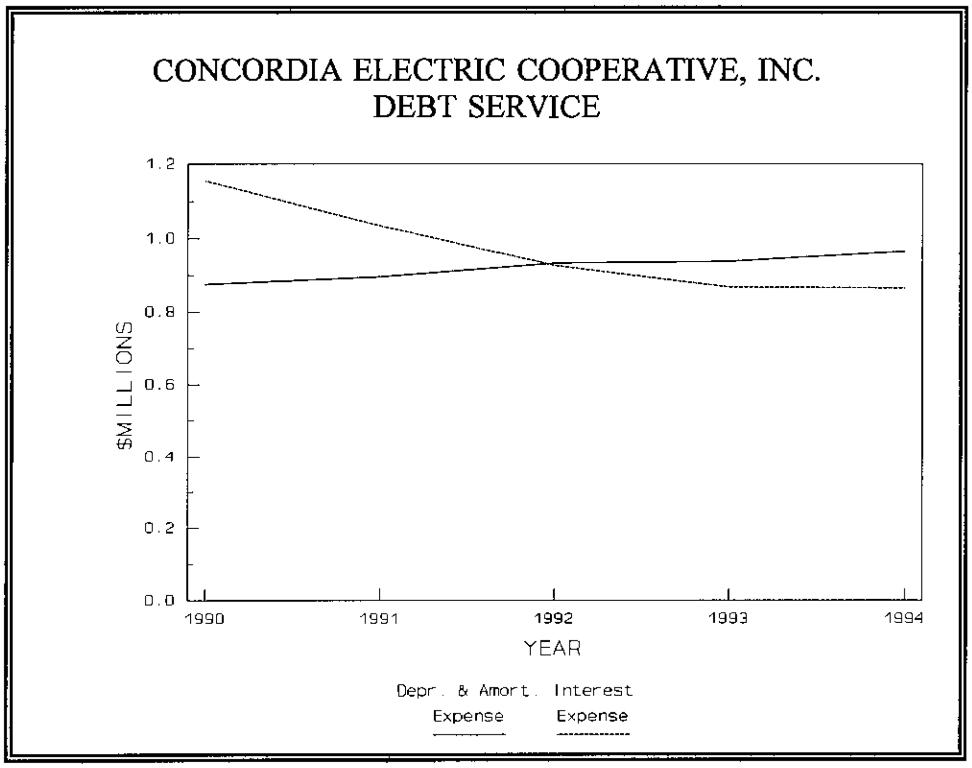
In 1994, Concordia's net margin declined to slightly below 1990 levels following increases in 1991 through 1993. Despite a decrease in purchased power expense, the Cooperative's cost of service increased by more than 12.7% in 1994.

Revenues increased by only 3% percent as consumption on both a per customer and per mile basis remained relatively static. Concordia's rates are the highest of any of the twelve Louisiana cooperatives, more than 16% higher than the average of the other cooperatives, while its cost of purchased power per kWh is slightly less than average.

Net plant investment remained relatively stable throughout the period. Distribution operations and maintenance expenses increased by 38% from the low in 1992. Similarly, administrative and general expenses increased sharply in 1993 following steady decreases from 1990 through 1993. At the end of 1994, the number of full time employees had risen to 44, returning to 1992 levels from the 1993 low of 39. In 1994, management indicated that it needed 58 to 60 employees.

Debt Service (Interest and Depreciation Expense)

The following graph shows the levels of interest and depreciation and amortization for the period 1990 through 1994.



Concordia's debt service comprises nearly 14% of its total cost of electric service. Interest expense levels have declined steadily since 1990 since no additional long term debt has been issued since 1987. Concordia's consulting engineers are currently preparing a loan application for submittal to the RUS and CFC. Concordia has increased its total utility plant by more than

5% since 1990. According to management, the additional plant has been funded through retail rates rather than debt.

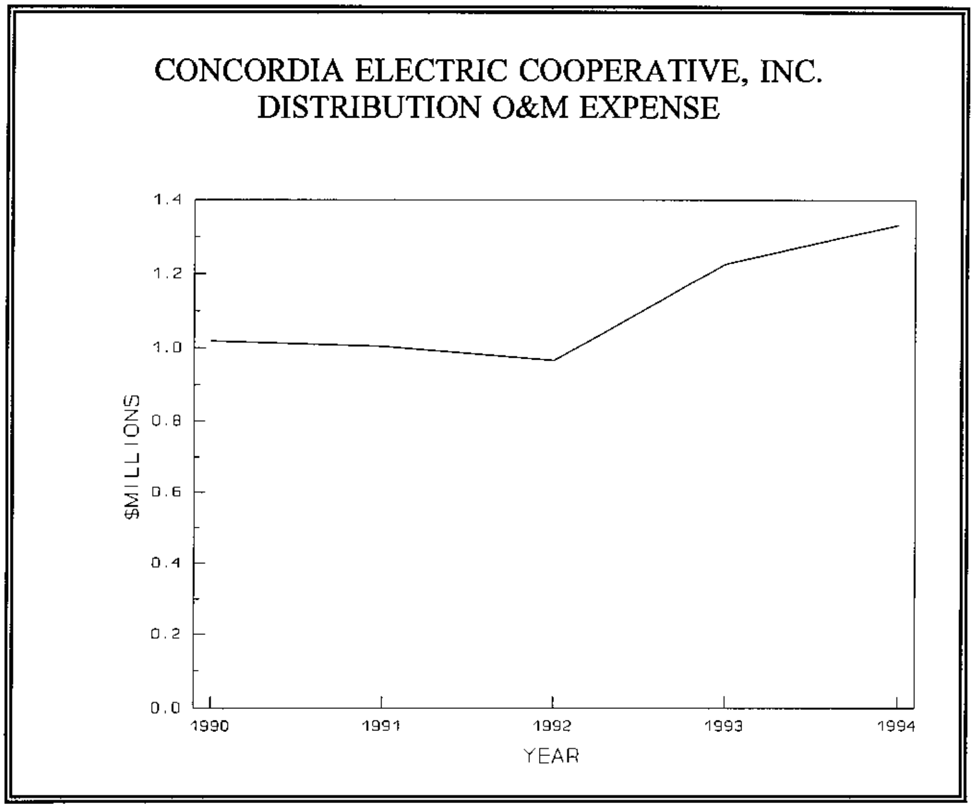
Through 1992, audits of Concordia's financial statements revealed that completed construction work orders were not being transferred from the work-in-progress account to fixed depreciable assets in a timely manner. The reports contained a continuing recommendation that the Cooperative's continuing property records should be balanced with the general ledger accounts on a monthly basis. The failure to properly clear the work-in-progress account had the effect of understating the depreciation expense and accumulated depreciation for that period of time. Improvements were noted in the 1992 report and the 1993 audit report did not contain this finding.

The general manager indicated that the Cooperative maintains at least 1.5 times its monthly obligations as cash reserve. A spot check of the treasurer's reports submitted monthly to the board indicates that the Cooperative maintains a balance well in excess of that required to meet its monthly obligations. In 1993, Concordia maintained an average monthly cash balance of $1.87 million after cash disbursements. On that amount, the Cooperative earned only $20,250, a return of only 1%. Further, at the end of 1994, more than $1.6 million was deposited in one bank, Concordia Bank and Trust Co. in Ferriday, LA. This amount is well in excess of that insured by the FDIC. Several of the Cooperative's certificates of deposit are also at levels above those insured by the FDIC.

At the end of 1994, the Cooperative had a total long-term debt balance of approximately $18.8 million at an effective interest rate of 4.5% and a times interest earned ratio of 1.88x. At year end, Concordia had more than $1.8 million in cash and more than $900,000 in certificates of deposit.

Distribution Operations and Maintenance

Concordia's distribution O&M expenses increased sharply in 1993 and 1994, following steady declines between 1990 and 1993.



The overhead distribution line expenses have increased by nearly 37% since 1990. Over this same period, the number of energized miles increased by just over 1%. Concordia management indicated that the spike in distribution maintenance expenses experienced in 1993 was the result of preventive maintenance activities that had been foregone in prior years.

Concordia has no preventive maintenance policies or procedures, and its maintenance scheduling and records are not automated. Maintenance and construction crews are assigned on a daily basis. Concordia does not evaluate the efficiency of its activities against standard manhour estimates.

Maintenance of transportation equipment is primarily the responsibility of the mechanic and vehicle operators. The mechanic maintains a manual file on each vehicle and is responsible for notifying the equipment user when service is required. A monthly transportation report is published by data processing. This report tracks the operating cost of each vehicle as well as mileage and fuel efficiency. It provides monthly actual expenses with no details as to maintenance performed or prior expense statistics.

In 1993, Concordia's line losses averaged nearly 11.2%, with each percentage point costing the Cooperative more than $85,000. In 1994, the Cooperative's line losses averaged 9.6%, a decrease of more than 4.5% from 1990 levels. Concordia's loss percentage, though no longer the highest of the member cooperatives, is still 22% higher than the average of the other 11.

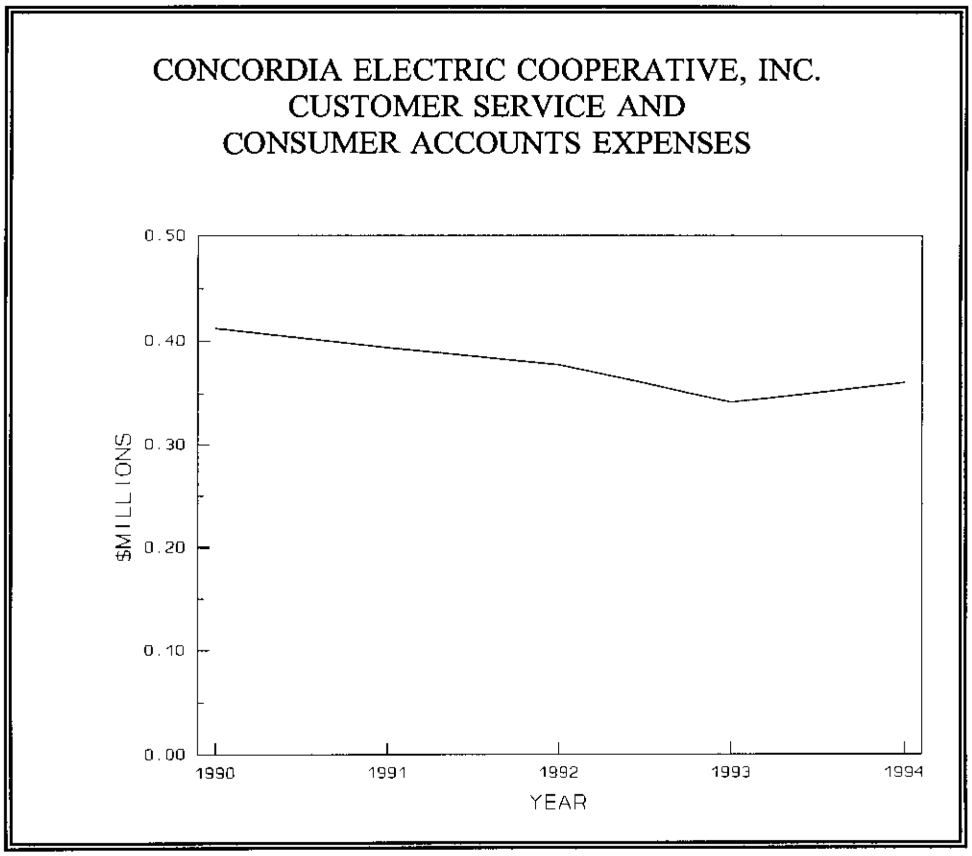
In 1992, Concordia was cited by the LPSC for failure to provide adequate electrical service to its customers. On behalf of Concordia, Brooks-Harbour and Associates performed a reliability study, making several intermediate and long-term recommendations. Again, based on customer complaints received by the Commission in December of 1993, Concordia was directed by the LPSC to retain Brooks-Harbour Consulting Engineers to survey the east side of the system. Commission Staff has reported regularly to the Commission regarding improvements recommended by Brooks-Harbour. Conversations with and documentation received from the Commission Staff indicate that the Cooperative has made significant progress toward implementing the required improvements and that customer complaints have declined.

A report generated by Federated Rural Electric Insurance Corp. as a result of a loss control assessment conducted in February, 1994, identified numerous serious conditions in the Cooperative's maintenance, safety, and materials storage and handling systems. Some of these included leaning poles, broken guys, substations indicating need for maintenance, lack of a pole inspection schedule, and unsecured, disorganized storage areas. Concordia responded that it was in the process of correcting many of the cited deficiencies and attempting to correct others. The Manager's report to the Board of Directors indicated that corrective action was underway, including pole inspections and training of personnel. The results of Federated's follow-up survey were not provided nor were specific work plans for the corrections. However, recent discussions with Commission Staff and Brooks-Harbour representatives indicate that Concordia has made progress toward correcting many of the deficiencies cited by Brooks-Harbour and others. A system-wide engineering study is scheduled to be complete in June, 1995. This study will include assessments of major performance parameters, such as outage performance and line loss and should provide a reasonable tool for assessing Concordia's progress.

Concordia's average total service interruptions have declined by more than 16% since 1992, from 11.4 to 9.5 hours per customer. However, the greatest part of that decline has been due to reductions in the extreme storm category. Those which the Cooperative attributes to itself, the "planned" and "all other" categories, declined by less than 4% since 1992. In fact the "all other," (i.e., unplanned) outages actually increased by nearly 2% since 1992.

Customer Service and Consumer Accounts

Costs associated with customer service and the management of consumer accounts, which decreased steadily between 1990 and 1993, increased by 5% in 1994. Expenditures in these categories is 17% below the average of the other eleven cooperatives. The Cooperative recorded no sales expenses throughout the period.



Concordia's residential and small commercial customer base has grown modestly since 1990, while its large industrial base has remained relatively flat. The Cooperative has the next to lowest customer density and lowest revenue per unit (mile and customer) of any of the Louisiana electric Cooperatives. Concordia has not undertaken efforts to attract large commercial or industrial load, though management indicated that it will recommend to the Board that additional personnel be hired to increase attention in this area. Management indicated that three incentive rates had recently been submitted to the LPSC for approval.

Concordia has not participated in a customer survey since 1987, but management believes that customer perception of the Cooperative's service quality, particularly due to outage performance, is poor and attributes the negative perception to the actions of the previous Board.

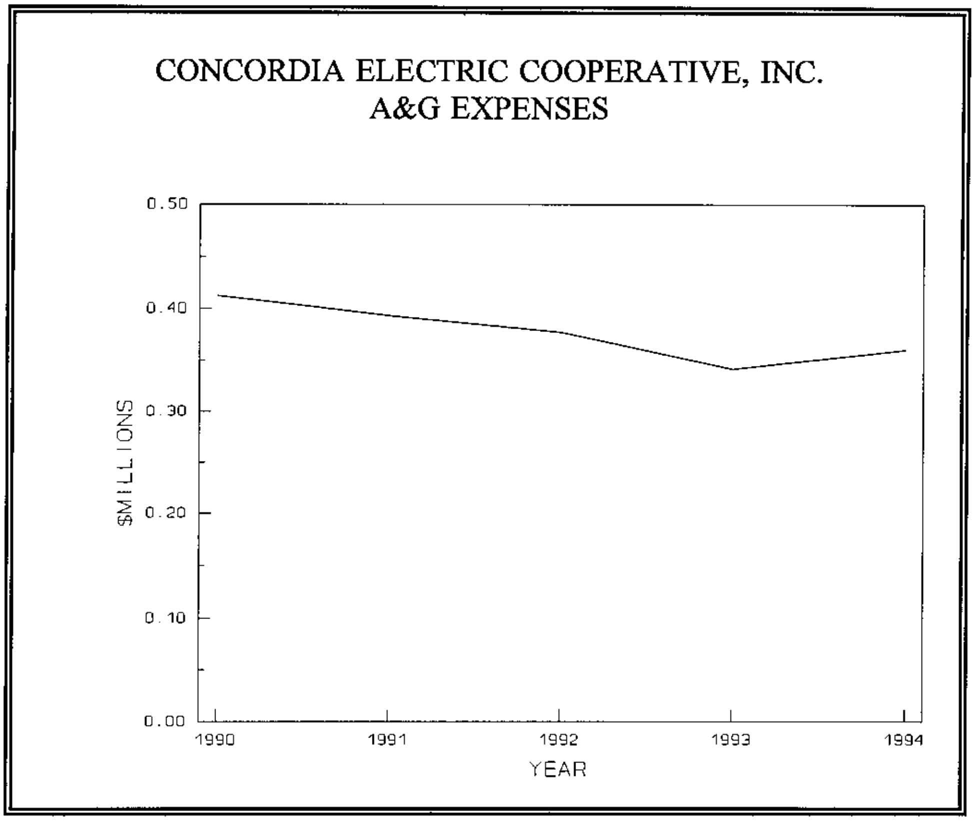
Written requests for specific information regarding Concordia's customer service and consumer accounts functions have not been answered by management. Therefore, the following description of service was based upon the audit interview in October 1994. Concordia has one customer service location, in its Jonesville headquarters, at which members may pay their bills, request service, and make billing inquiries. Additionally, members may pay their bills by mail and may request information and file complaints by telephone. There is no written policy for handling customer complaints and no means of logging or tracking them.

Concordia has only one billing cycle per month. Contractors read the meters and manually record them in the middle of the month. Readings are then submitted to the billing department for data entry. Bills are processed and issued at the beginning of the month. A three-cycle billing month had been rejected by the previous Board for "political" reasons. Management intended to discontinue the use of contract meter readers, automate the meter reading and billing process, and implement a three-cycle billing month. However, no studies have been conducted to determine the cost and benefits of these changes, and no implementation plans have been developed.

Management indicated that the Cooperative currently has a dozen different rate schedules which it intends to consolidate into five or six on a revenue neutral basis. Although management indicated that its twelve rate schedules should be consolidated into five or six, it had no plan or schedule for doing so. To date, no tariffs consolidating Concordia's rate schedules have been filed with the Commission.

Administrative and General

As illustrated in the following figure, Concordia's A&G expenses which had declined by 18% since 1990, increased by 29% in 1994, led by sharp increases in A&G salaries, pension and benefits, injuries and damages, and outside services. Outside services costs more than doubled in 1994. Planned increases in employment are likely to further inflate these costs, yet there have been no formal studies performed to determine whether increased employment is necessary or whether other costs will be reduced.



Concordia participates in the health benefit program provided by the National Rural Electrification Cooperative Association ("NRECA"). The Cooperative pays 50% of the premium and 80% coinsurance, with the employee contribution capped at $5,000. All negotiations are handled by NRECA.

The Cooperative also participates in the NRECA's pension program. It has made no contributions since a moratorium was placed on the plan in July 1987. Concordia expected the moratorium to be lifted in November 1994, at which time it will resume payments into the plan. Though management did not know the magnitude of the payments, it expected them to be approximately 20% higher than they were in 1987.

Concordia's property and liability insurance is underwritten by Federated Insurance Agency. The policy is reviewed annually with a Federated field representative to determine necessary changes and evaluate the adequacy of the policy. According to the Notes to Financial Statements ("Notes") in the Examination Report for the period January 1, 1993 to December 31, 1994, the Cooperative has no directors' and officers' liability insurance and no umbrella liability coverage in excess of its $1,000,000 public liability insurance coverage. The Notes also indicated that, though Concordia is not aware of claims in excess of its current coverage, its insurance advisor believes its current coverage is inadequate. Additionally, Concordia's financial statements contain no provision for contingent losses since management believes that any such losses would not be material. Management indicated that the directors' and officers' liability insurance was terminated by Federated Insurance due to the actions of the former president of the Board. Concordia has asked Federated to consider reinstatement of that coverage.

Concordia's regulatory expenses have more than tripled since 1990. Management indicated that the added expenses were caused primarily by system engineering studies ordered by the LPSC and legal fees involving the pre-regulation rate refund lawsuit. The general manager acknowledged that the engineering studies should have been conducted by Concordia without a Commission order.

As previously mentioned, Concordia relocated its headquarters from Ferriday to new offices in Jonesville, LA in April 1993. The manager's report dated January 27, 1994 indicated that several parties were interested in acquiring the former headquarters site and one offer had been received.

Conclusions and Recommendations

This cooperative has been seriously mismanaged in the past. It has improved its operation in certain respects, but much remains to be done. Its management may have an insurmountable task unless it focuses its staffing and expenditures in a prioritized and cost effective manner.

Concordia's customers would clearly be operational, cost, and rate beneficiaries of consolidation with a more focused and stable cooperative or investor owned utility. There are also opportunities to improve operational performance, reduce costs, and achieve rate reductions through consolidation of certain functions at Cajun, ALEC, or another entity. In addition, there are opportunities to improve system reliability and narrow the existing rate disparity between the Cooperative and neighboring utilities. High cost purchased power is another challenge facing Concordia in the attempt to mitigate rate disparity and provide reliable, competitively priced electricity to its members. Concordia's service territory is characterized by the lowest customer density and revenue per customer of the twelve Louisiana electric distribution cooperatives. It also has a high percentage of residential load and the difficulties attendant to maintenance of facilities located in a rural environment.

1. Management and Board of Directors

Conclusions

Concordia must build a management structure that will allow it to actively, instead of reactively, manage. It does not have the management tools necessary to plan, manage, and evaluate the use of members' resources. While able to implement repairs to its distribution system under the direction of the Commission, the Cooperative lacks the structure to ensure that deterioration does not recur. The Cooperative has no strategic plan, no documented departmental goals and objectives, no construction, capital, or operating budgets, and no work plans. It has a set of policies and procedures, but they are not followed and enforced.

Although current management assigned the blame for this situation to the deceased Board president and the former Board, only limited improvements have been achieved under the new management and Board. The failure of the Cooperative to respond to data requests submitted by the Commission is indicative of continuing management problems.

A properly focused strategic plan is a fundamental management tool for establishing objectives and schedules for their accomplishment. A strategic plan should provide the framework for developing the budget and work plans. It would ensure that specific projects within the budget and work plans are prioritized, coordinated, scheduled, implemented, monitored, and updated to ensure that member resources are utilized in the most efficient manner.

Budgets and schedules are necessary in order to plan and manage the resources of any organization. Departmental capital and operating budgets are an essential management tool for directing and controlling expenditures, assessing departmental efficiency, and identifying areas requiring improvement. Departmental budgets help to ensure that the resources of individual departments and the entire Cooperative are directed toward accomplishment of the Cooperative's goals and objectives. Construction budgets provide a means for management to plan and track expenditures to ensure efficient use of member resources.

Most importantly, to avoid the mismanagement of the past there must be clear delineation between functions to be performed by the Board and those responsibilities delegated by the Board to the General Manager, and both must be held accountable by the membership and the Commission. Similarly, each employee must understand and be held accountable by management for his/her assigned functions.

Recommendations

The cooperative should develop a strategic plan and monitor performance against that plan. The strategic plan should identify goals, objectives, and schedules for their attainment. Specific activities, procedures, and projects should be identified, evaluated, and prioritized in the context of that plan and translated into work plans and policies and procedures. Work plans should be developed and actively monitored, including schedule and budget performance, to ensure that the selected tasks are accomplished in a timely and efficient manner. The Cooperative's current set of policies and procedures should be reviewed and revised in the context of its strategic plan. Concordia's current efforts to increase staffing should also be integrated into the planning process to ensure that all costs and benefits are evaluated and that resources are invested in the most cost-effective areas.

Concordia management should implement a formal budget process at the department level. These budgets should be developed within the context of the Cooperative's strategic plan. Adherence to the budgets should be stressed. Actual performance against the budgets should be tracked regularly throughout the year, with variances identified and addressed by management and the Board. As part of this process, management should also develop financial statements and cash flow budgets in order to manage its financial results, minimize its rates, and optimize its cash flow.

The Commission should extend its oversight of Concordia and should require that the Cooperative submit a report documenting its progress toward the development and implementation of the basic management structure and tools recommended within six months.

2. *Debt Service (Interest Expense and Depreciation Expense)*

Conclusions

Concordia has both underborrowed and overcollected from its customers in order to support its capital requirements. Concordia's reliance on retail rates to fund growth and improvements in utility plant has resulted in unnecessarily high rates to customers, thereby further harming Concordia's competitive position. It has also resulted in the postponement of improvements necessary to ensure system reliability.

The Cooperative not only has an excess level of cash and other short-term investments, but it is earning less on those amounts than the effective interest rate it pays for its debt.

Recommendations

Rather than recovering excessive amounts from its customers, Concordia should optimize its borrowing to fund capital improvements identified in the context of an appropriate strategic plan coupled with detailed work plans.

Concordia should immediately review the level of its cash and short-term investments. It should consider an immediate refund and a prospective rate reduction to avoid further accumulations of cash. Concordia should also maximize the return on investment funds (consistent with the safety of principal) for its customers.

3. *<u>Operations and Maintenance</u>*

Conclusions

Although the Cooperative has endeavored to improve its outage performance under the active oversight of the Commission, it does not have the management controls and procedures in place to assure that improvement continues and that there is no recurring deterioration. The fact that Federated Insurance Company's loss control assessment in February 1994 identified numerous maintenance and housekeeping deficiencies, some serious enough to cause a loss of coverage, indicates the need for improved procedures and more active management oversight.

The Cooperative's reliability and line loss performance is dismal and requires focused management attention. The sectionalizing studies and the Work Plan currently underway are an important step in identifying the sources of its problems and planning for their correction. Nevertheless, there has been a lackadaisical attitude in the past toward reliability issues that were addressed only because of the Commission's intervention.

Recommendation

Sectionalizing studies underway at the Cooperative should be completed as soon as possible in order to identify the causes for Concordia's poor outage and line loss performance. The Cooperative should then develop specific work plans to remedy the problems it has identified and improve its performance. Relevant budget and schedule performance information should be reported to management and the Board monthly. The results of the study currently being conducted by Brooks-Harbour should be furnished to both the Board and the LPSC within six months. Periodic status reports on the progress of corrective action should be submitted to the Commission semi-annually. Comparative line loss and outage statistics should be developed and reviewed monthly by management and the Board in order to determine the effectiveness and persistence of the improvements implemented.

Concordia should review its current O&M practices and scheduling to identify opportunities to improve efficiency and effectiveness and prevent recurring reliability problems. It should obtain assistance from third parties or from Cajun if necessary. Standard procedures for performance and scheduling of maintenance should be developed and implemented. Additionally, implemented changes should be continuously evaluated to determine whether they have achieved the desired effect, whether in practice their benefits outweigh their costs, and to identify any necessary adjustments.

Maintenance records and scheduling should be automated. This would enable collection of data that could be used to set optimum maintenance and replacement schedules and would assist in the planning and budgeting processes. Responsibility for preventive maintenance should be centralized and management should evaluate alternatives to the current monthly inspection/servicing, such as scheduling maintenance based on mileage or performing studies to determine the appropriate time periods for scheduled maintenance. Additionally, users requesting either replacement or new vehicles and equipment should be required to provide cost based justification for such requests. Management should also perform a study to evaluate on-site vs. contract maintenance.

4. *Administrative and General*

Conclusions

The sharp increase in expenses in nearly all of the major accounts in this category demands the attention of management. Concordia has no policies or procedures requiring management to evaluate alternatives to either its NRECA-sponsored health and pension programs or its property and liability insurance. Additionally, absent the control of an operating budget and monthly variance reporting these rapidly escalating costs could continue unchecked. Similarly, there are no prescribed procedures for ensuring that members recover the maximum benefit from disposition of abandoned or stranded facilities.

Recommendations

A focused plan to identify and address the causes of the increases in each account should be prepared by management and presented to the Board before the end of the calendar year.

Concordia should institute policies and procedures for the performance of annual comprehensive reviews of its employee compensation and employee and property insurance programs. Such a review should identify cost causation and evaluate multiple options for meeting the Cooperative's requirements. Alternative approaches to provision of pension benefits should also be investigated. The Board should immediately require a review of the Cooperative's insurance coverage to determine its adequacy and make any necessary adjustments.

Management and the Board should pursue immediate and fair payment for its abandoned plant investment. Any such divestiture should be evaluated in the context of the strategic plan considering future strategic and operational goals.

5. Customer Service Operations

Conclusions

Concordia's customer service operations are primarily focused on residential customers. There has been almost no focus on attracting or retaining load, particularly large commercial and industrial customers. That complacency, which is clear from flat growth in Concordia's customer base, revenue, and sales, is surprising given its customer density and revenue statistics.

The single billing cycle coupled with a manual consumer accounts system is, as recognized by management, inefficient. Efforts to consolidate Concordia's rate schedules would simplify the billing process and should be pursued.

Recommendations

The Cooperative's strategic planning should identify, evaluate, and implement improvements to ensure that the customer service department's efforts are focused on attracting and retaining customers, particularly large commercial and industrial customers. Management should focus on attracting and retaining customers and building efficient load. Customer attrition and losses of potential customers to neighboring utilities should be reviewed to identify the causes and develop preemptive strategies. Other cooperatives that have been successful in attracting large commercial and industrial loads should be surveyed to identify strategies to improve Concordia's competitive position.

Opportunities to automate and streamline consumer accounts functions should be pursued. Management's current plan to bring the meter reading function in-house should be evaluated on an economic basis. This review should assess the costs and benefits of each alternative to ensure the most effective use of member resources.

Financial Results: 1994
(per REA Form 7)

	BEAU	CLAIB	CONC	DIXIE	JD	NE	PC	SLECA	SLEMCO	TECHE	VALLEY	WST[1]	AVERAGE
1 Oper revs & patr cap.	$40,354,078	$25,667,538	$14,066,731	$90,090,484	$13,833,124	$16,385,604	$12,606,711	$28,097,178	$93,904,613	$12,365,367	$38,308,351	$45,863,510	$35,978,626
2 Power prod. expense													
3 Cost of purch. power	27,056,592	18,601,769	8,451,823	60,431,621	9,162,324	11,579,620	8,799,521	19,498,851	70,615,486	8,704,172	25,273,494	31,400,475	24,961,297
4 Transm. expense	34,410	15,770	46,233	154,467	12,064	0	12,366	3,424	336,263	0	0	0	51,417
5 Distr. exp – operation	798,161	646,525	607,696	2,043,538	289,907	489,204	146,375	619,302	2,634,211	407,624	898,600	1,085,554	880,906
6 Distr. exp – maint.	1,785,486	2,439,846	825,930	4,470,950	667,197	693,183	354,798	730,330	3,916,405	315,194	2,060,117	1,854,785	1,674,517
7 Consumer accts exp.	1,172,539	549,411	339,664	2,190,647	329,185	548,363	354,000	484,234	2,925,596	160,389	998,821	961,224	917,856
8 Cust. svc & info exp.	164,667	109,661	20,049	307,184	0	0	58,458	97,600	253,610	0	197,179	13,237	101,604
9 Sales expense	124,927	57,108	0	420,696	22,380	0	150	27,479	174,699	330,320	0	141,896	108,305
10 Admin and gen. exp.	1,517,220	1,327,491	910,608	4,762,161	708,500	843,475	1,186,649	1,548,796	3,375,249	1,432,814	2,861,816	2,230,592	1,890,448
11 Total O&M expense	32,634,004	23,949,601	11,104,203	74,781,244	11,191,557	14,153,845	10,894,319	23,009,816	84,231,519	11,350,713	32,290,027	37,687,763	30,606,551
12 Depr. and amort exp.	1,904,146	1,215,609	965,649	5,508,066	782,800	682,989	612,908	1,662,080	4,977,250	659,432	2,286,157	2,067,154	1,936,353
13 Tax exp. – property	851,257	289,732	352,027	1,970,000	403,786	199,379	165,261	692,999	1,806,019	182,525	876,730	662,765	720,957
14 Tax expense – other	204,839	252,602	67,781	971,149	75,046	94,527	128,015	13,945	417,068	72,527	309,929	295,383	241,901
15 Interest on L.T. debt	2,286,031	1,039,414	650,669	2,174,216	606,379	661,397	684,011	1,534,977	2,536,444	243,039	2,117,631	3,655,486	1,549,060
16 Int. charged to constr.	(32,222)	0	0	0	0	0	0	0	0	0	(37,270)	0	(5,791)
17 Int. exp. – other	302,422	43,033	14,746	100,684	0	0	13,144	30,705	361,588	0	78,822	347,357	109,375
18 Other deductions	(317,267)	9,268	160,675	1,019,172	2,679	0	36,033	37,703	116,622	46,150	2,423	0	92,890
19 Total cost of elec svc	37,832,210	26,799,277	13,516,770	86,524,531	13,262,249	15,792,137	12,533,691	26,982,225	94,464,710	12,456,366	37,924,449	44,915,908	35,250,295
20 Patr. cap & op. marg.	2,521,868	(1,131,739)	550,961	3,565,953	570,876	593,467	273,020	1,114,953	(559,897)	(90,999)	383,902	947,602	728,331
21 Non op. margins – int.	253,428	278,178	136,509	283,428	59,842	133,050	115,766	253,546	542,612	24,161	444,849	83,672	217,622
22 AFUDC	0	0	0	0	0	0	0	0	0	0	0	57,884	4,824
23 Non–op. marg–other	23,365	8,970	66,249	53,026	25,395	7,062	11,906	17,265	2,306,369	0	21,879	56,033	216,632
24 G&T transm. cap. cr.	0	0	0	0	0	0	0	0	0	0	0	0	0
25 Other cap. cr&patr divs	278,423	55,997	9,838	298,005	36,953	34,961	0	23,034	109,747	20,469	67,876	151,099	90,535
26 Extraordinary items	(2,747,435)	0	0	(3,348,159)	0	0	0	11,390	0	(967,170)	0	0	(587,615)
27 Patr. cap. or margins	329,669	(788,594)	765,557	852,253	693,065	768,580	400,714	1,420,188	2,399,051	(1,013,539)	918,506	1,298,490	670,326

(1) Due to unavailability of 1994 data, 1993 data was used for Washington–St. Tammany.

Key Operating Statistics
1994

	BEAU	CLAIB	CONC	DIXIE	JD	NE	PC	SLECA	SLEMCO	TECHE	VALLEY	WST[1]	AVERAGE
Total miles energized	4,615	3,691	2,494	6,658	1,543	2,340	936	1,213	7,714	855	6,458	4,563	3,606.66
#res. custs.	28,033	17,732	10,012	58,792	7,509	10,200	6,948	13,378	61,277	8,045	26,691	28,868	23,123.63
#small C&I custs.	1,762	2,153	1,312	3,560	1,206	2,316	1,595	1,802	5,357	830	1,547	1,255	2,059.48
#lg. C&I custs.	0	24	2	241	3	31	7	20	10	3	1	8	29.13
Tot. custs. (incl other)	29,800	19,914	11,350	62,746	8,793	13,946	8,667	15,347	68,645	8,878	28,254	30,145	25,374
$ net plant	$52,513,529	$27,765,214	$22,453,713	$140,612,496	$21,950,002	$17,220,118	$17,060,496	$45,453,229	$141,092,768	$15,494,022	$55,548,550	$60,677,913	$51,486,837
# of full-time emp.	105	89	44	194	41	56	37	76	260	39	156	93	99
Total kWh sold	475,374,169	325,791,179	143,609,646	1,005,571,690	158,728,547	184,509,314	163,673,696	347,751,805	1,254,019,778	148,150,460	407,747,278	521,561,050	428,040,719
Total kWh purchased	507,247,027	350,683,641	158,869,069	1,085,295,515	171,921,791	204,296,373	174,092,849	374,489,332	1,340,518,051	165,412,739	449,118,130	571,868,052	462,834,381
Revenue/customer	$1,354.15	$1,288.94	$1,239.32	$1,435.81	$1,573.23	$1,174.93	$1,477.60	$1,830.85	$1,409.04	$1,392.89	$1,355.87	$1,521.41	$1,417.95
Revenue/mile	$8,744.11	$6,954.09	$5,640.23	$13,136.55	$8,963.28	$7,002.39	$13,682.38	$23,163.38	$12,173.30	$14,462.44	$5,931.89	$10,051.51	$9,975.54
Customers/mile	6.46	5.40	4.55	9.15	5.70	5.96	9.26	12.65	8.64	10.38	4.37	6.61	7.04
$ A&G/customer	$50.91	$66.68	$80.23	$75.90	$80.58	$60.48	$134.60	$100.92	$50.65	$161.40	$101.29	$73.99	$74.50
$ Cust svc/customer	$44.87	$33.10	$31.71	$39.81	$37.44	$39.32	$47.59	$37.91	$47.70	$18.07	$42.33	$32.33	$40.19
$ O&M/mile	$7,071.29	$6,488.65	$4,452.37	$10,904.24	$7,251.66	$6,048.65	$11,639.23	$18,969.35	$10,919.31	$13,275.69	$4,999.97	$8,259.70	$8,486.07
Oper. margin/revenue	6.25%	−4.41%	3.92%	3.96%	4.13%	3.62%	2.13%	3.97%	−0.60%	−0.74%	1.00%	2.07%	2.02%
% line loss	6.28%	7.15%	9.61%	7.35%	7.67%	9.69%	5.98%	7.14%	6.45%	10.44%	9.21%	8.80%	7.52%
$ line loss	$1,700,099	$1,343,582	$811,800	$4,439,196	$703,115	$1,121,540	$528,636	$1,392,151	$4,556,535	$908,357	$2,328,067	$2,763,289	$1,877,974
Cost of prch pwr/kWh	0.05334	0.05359	0.05320	0.05568	0.05329	0.05668	0.05054	0.05207	0.05268	0.05262	0.05627	0.05491	0.05397
Rate per kWh sold	0.08489	0.07879	0.09795	0.08959	0.08715	0.08881	0.07825	0.08080	0.07488	0.08347	0.09395	0.08794	0.08405

(1) Due to unavailability of 1994 data, 1993 data was used for Washington-St. Tammany.

Financial Results: 1993
(per REA Form 7)

	BEAU	CLAIB	CONC	DIXIE	JD	NE	PC	SLECA	SLEMCO	TECHE	VALLEY	WST	AVERAGE
1 Oper revs & patr cap.	$39,517,153	$26,270,500	$13,854,808	$87,033,912	$13,714,047	$16,235,721	$12,846,009	$27,231,993	$93,470,205	$12,677,220	$39,682,281	$45,863,510	$35,699,780
2 Power prod. expense													
3 Cost of purch. power	26,572,743	18,911,351	8,523,224	60,680,353	9,100,006	11,562,638	8,561,113	19,151,207	71,035,989	8,667,276	25,634,205	31,400,475	25,000,048
4 Transm. expense	10,027	6,635	14008	139,638	25,502	3,666	4,800	4,228	240,856	0	648	0	37,501
5 Distr. exp -- operation	862,764	663,684	342,512	1,671,386	494,327	497,856	164,533	598,038	2,200,998	396,814	1,072,749	1,085,554	839,251
6 Distr. exp -- maint.	1,855,595	1,254,671	664,146	4,467,005	595,762	583,841	303,947	703,823	3,458,048	377,976	1,939,772	1,854,785	1,523,281
7 Consumer accts exp.	1,163,265	602,050	321,861	2,071,280	366,589	536,937	328,513	484,774	2,450,984	211,216	991,965	961,224	874,222
8 Cust. svc & info exp.	129,354	103,122	19,753	259,531	11,316	0	45,041	90,441	241,132	0	181,591	13,237	91,210
9 Sales expense	69,003	66,590	0	404,711	46,657	0	1,615	12,554	135,234	251,611	114	141,896	94,165
10 Admin and gen. exp.	1,439,666	983,797	706,535	4,245,664	717,078	806,533	871,417	1,537,293	3,091,603	868,294	2,493,418	2,230,592	1,665,994
11 Total O&M expense	32,102,437	22,611,900	10,812,039	73,939,569	11,357,237	13,991,271	10,280,980	22,582,358	82,854,644	10,973,189	32,314,462	37,687,763	30,125,672
12 Depr. and amort exp.	1,850,556	1,171,937	937,387	5,300,506	764,046	668,380	602,432	1,637,833	4,836,465	497,912	2,259,740	2,067,154	1,662,662
13 Tax exp. -- property	826,591	293,915	331,675	1,967,357	370,832	194,507	159,968	701,369	1,778,203	197,486	896,197	662,765	715,074
14 Tax expense -- other	200,096	263,619	58,632	995,367	96,504	102,372	125,843	23,165	442,855	79,870	311,605	295,383	249,609
15 Interest on L.T. debt	2,374,530	1,053,404	854,788	2,764,145	837,274	708,433	248,470	1,568,509	2,290,042	242,952	2,130,496	3,655,486	1,560,711
16 Int. charged to constr.	(65,374)	0	0	0	0	0	0	0	0	0	(39,766)	0	(8,762)
17 Int. exp. -- other	400,966	39,029	13,756	87,092	592	0	15,749	31,021	203,858	0	72,945	347,357	101,030
18 Other deductions	(195,048)	0	10,000	152,679	1,985	5,114	13,672	77,997	128,657	35,075	277	0	19,217
19 Total cost of elec svc	37,494,754	25,433,805	13,018,277	85,205,736	13,428,470	15,670,077	11,447,133	26,622,252	92,535,124	12,026,484	37,945,958	44,915,908	34,645,415
20 Patr. cap & op. marg.	2,022,399	836,695	836,531	1,827,177	285,577	565,644	1,398,876	609,741	935,081	650,736	1,736,323	947,602	1,054,365
21 Non op. margins -- int.	249,502	284,902	99,125	268,276	75,346	105,066	66,864	238,915	319,210	24,256	360,233	83,872	182,964
22 AFUDC	0	0	0	0	0	0	0	0	0	0	0	57,884	4,824
23 Non-op. marg -- other	19,365	16,675	4,950	265	16,580	5,665	(7,517)	62,771	2,435,797	0	830	58,033	217,818
24 G&T transm. cap. cr.	0	0	0	0	0	0	0	0	0	0	0	0	0
25 Other cap. cr&patr divs	260,924	65,594	25,852	339,466	0	45,667	0	68,432	131,494	2,415	65,929	151,099	98,073
26 Extraordinary items	0	0	0	(1,959,663)	0	0	0	17,274	0	0	0	0	(161,882)
27 Patr. cap. or margins	2,552,190	1,204,066	966,458	475,321	377,503	722,242	1,458,223	997,133	3,821,582	677,407	2,203,315	1,298,490	1,396,161

Key Operating Statistics
1993

	BEAU	CLAIB	CONC	DIXIE	JD	NE	PC	SLECA	SLEMCO	TECHE	VALLEY	WST	AVERAGE
Total miles energized	4,568	3,664	2,494.00	6,721	1,533.22	2,331	931	1,203	7,679	852	6,433.78	4,563	3,581.07
#res. custs.	27,873	17,470	9,889	57,100	7,399	10,133	6,880	13,252	60,474	7,906	31,387	28,868	23,219.19
#small C&I custs.	1,742	2,140	1,312	3,421	1,160	2,268	1,578	1,752	5,332	803	2,954	1,255	2,144.71
#lg. C&I custs.	0	23	2	225	3	30	7	20	11	4	1	8	27.75
Tot. custs. (incl other)	29,620	19,637	11,227	60,882	8,655	13,764	8,613	15,178	65,816	8,713	34,365	30,145	25,551
$ net plant	$51,070,034	$27,092,604	$22,478,514	$132,570,415	N/A	$16,920,722	$17,060,496	$45,453,229	$141,092,768	$15,608,146	$55,575,367	$60,677,913	$53,236,382
# of full-time emp.	103	63	39	198	48	56	37	77	280	41	161	93	100
Total kWh sold	436,372,381	326,661,842	139,879,516	979,108,210	151,091,150	180,404,886	163,873,698	347,751,805	1,254,019,778	155,831,064	410,791,307	521,561,050	422,262,224
Total kWh purchased	475,663,628	353,482,503	157,468,319	1,077,094,821	167,668,625	200,698,369	174,092,849	374,489,332	1,340,518,051	171,391,625	455,375,354	571,888,052	460,002,627
Revenue/customer	$1,334.13	$1,337.81	$1,234.08	$1,429.54	$1,584.55	$1,179.54	$1,491.51	$1,794.14	$1,420.17	$1,454.96	$1,154.74	$1,521.41	$1,397.18
Revenue/mile	$8,650.87	$7,169.90	$5,555.26	$12,949.55	$8,944.80	$6,965.13	$13,798.08	$22,636.74	$12,172.18	$14,879.37	$6,167.80	$10,051.51	$9,969.02
Customers/mile	6.48	5.36	4.50	9.06	5.64	5.90	9.25	12.62	8.57	10.23	5.34	6.61	7.14
$ A&G/customer	$46.61	$50.10	$62.93	$69.74	$82.85	$58.60	$101.18	$101.28	$46.97	$99.65	$72.56	$73.99	$65.20
$ Cust svc/customer	$43.64	$35.91	$30.43	$38.26	$43.66	$39.01	$43.37	$37.90	$40.90	$24.24	$34.15	$32.33	$37.78
$ O&M/mile	$7,027.68	$6,171.37	$4,335.22	$11,001.28	$7,407.44	$6,002.26	$11,042.94	$18,771.70	$10,789.80	$12,879.33	$5,022.62	$8,259.70	$8,412.48
Oper. margin/revenue	5.12%	3.18%	6.04%	2.10%	2.08%	3.48%	10.89%	2.24%	1.00%	5.13%	4.38%	2.07%	2.95%
% line loss	8.30%	7.59%	11.17%	9.10%	9.89%	10.11%	5.98%	7.14%	6.45%	9.08%	9.79%	8.80%	8.20%
$ line loss	$2,205,234	$1,434,908	$952,022	$5,520,277	$899,722	$1,169,149	$512,368	$1,367,344	$4,583,669	$805,056	$2,509,746	$2,763,289	$2,051,101
Cost of prch pwr/kWh	0.05584	0.05350	0.05413	0.05634	0.05427	0.05761	0.04918	0.05114	0.05299	0.05174	0.05629	0.05491	0.05435
Rate per kWh sold	0.09056	0.08042	0.09905	0.08889	0.09077	0.09000	0.07849	0.07831	0.07454	0.08135	0.09660	0.08794	0.08454

ITEM	1992 BREMCO	BEAUREGARD	CLAIBORNE	CONCORDIA	DEMCO	JEFF. DAVIS	NORTHEAST LA.
Purchased Power Exp.	$9,101,301	$24,482,538	$16,875,229	$7,763,750	$55,580,088	$8,671,401	$10,596,047
Distribution Exp.–Oper.	$419,894	$653,095	$619,910	$396,576	$1,777,409	$472,427	$492,907
Distribution Exp.–Maint.	$995,191	$1,782,943	$993,350	$596,086	$4,089,890	$711,399	$535,926
Consuner Accounts Exp.	$408,574	$1,170,505	$522,216	$357,980	$2,000,075	$374,680	$549,555
Customer Service & Informtl. Exp.	$31,047	$76,547	$101,118	$19,297	$238,565	$19,284	$0
Sales Expense	$0	$35,169	$170,985	$0	$212,136	$35,690	$1,146
Administrative & General Exp.	$1,024,114	$1,251,481	$943,146	$761,286	$4,643,991	$729,610	$769,456
Total Oper. & Maint. Exp.	$11,980,121	$29,465,572	$20,141,375	$9,881,983	$68,742,707	$11,036,388	$12,947,153
Interest on L–T Debt	$1,028,430	$2,351,214	$1,100,401	$913,553	$3,024,017	$858,945	$710,756
Interest Exp. Other	$151,826	$444,034	$34,962	$12,960	$111,388	$9,019	$0
Total Plant	$30,548,578	$65,934,424	$40,577,505	$33,537,188	$164,614,253	$28,525,884	$23,562,039
Net Plant	$21,125,777	$50,424,317	$26,939,080	$22,366,737	$128,968,637	$21,712,871	$16,604,029
No. of Customers (end of Yr.)	12,073	29,067	19,419	11,168	60,013	8,598	13,602
No. of Distribution Miles	1,923	4,426	3,537	2,411	6,421	3,137	2,315
No. of KWHs Sold	145,730,295	403,451,539	289,438,439	128,699,315	914,455,321	148,834,354	166,677,923
No. of Employees	49	103	82	44	193	49	61
Residential KWH sales	112,845,973	330,448,468	173,745,525	90,275,194	759,979,024	81,406,101	123,935,067
Commercial KWH sales	6,891,388	29,699,770	68,576,144	36,051,161	54,303,208	21,495,230	17,915,730
Residential Customers	11,183	25,999	17,280	9,836	56,331	7,353	10,101
Cummercial Customers	671	1,629	2,113	1,327	3,322	1,025	2,155
Industrial KWH sales	25,858,718	39,305,837	46,283,160	2,151,200	93,255,526	44,763,955	10,652,792
KWHs Purchased	162,097,647	437,758,033	314,535,076	144,117,354	991,553,058	162,795,679	185,814,092

ITEM	POINTE COUPEE	SLECA	SLEMCO	TECHE	VALLEY	WASH. ST.TAM.
Purchased Power Exp.	$7,851,186	$18,513,598	$66,989,869	$8,286,957	$23,257,704	$29,205,518
Distribution Exp.–Oper.	$149,090	$574,752	$2,007,165	$527,028	$1,164,089	$863,802
Distribution Exp.–Maint.	$401,368	$592,910	$3,082,278	$429,111	$1,981,724	$1,502,198
Consuner Accounts Exp.	$297,785	$492,343	$2,336,022	$115,402	$926,700	$956,097
Customer Service & Informtl. Exp.	$33,629	$83,180	$210,418	$0	$167,753	$14,048
Sales Expense	$4,304	$13,113	$145,187	$135,950	$5,581	$133,443
Administrative & General Exp.	$796,086	$1,376,287	$2,592,464	$853,604	$2,310,076	$1,863,265
Total Oper. & Maint. Exp.	$9,538,821	$21,649,487	$77,625,145	$10,356,572	$29,647,520	$34,526,019
Interest on L–T Debt	$241,410	$1,752,420	$2,467,343	$272,113	$2,270,153	$3,081,373
Interest Exp. Other	$71,333	$33,134	$200,456	$0	$73,383	$90,639
Total Plant	$22,414,638	$56,875,419	$165,414,289	$18,242,375	$73,824,623	$72,905,241
Net Plant	$17,016,506	$45,041,797	$136,707,269	$14,952,204	$55,658,184	$57,283,128
No. of Customers (end of Yr.)	8,608	15,043	65,609	8,610	34,194	29,757
No. of Distribution Miles	877	1,157	7,454	830	6,308	4,385
No. of KWHs Sold	142,958,638	335,675,899	1,187,956,259	141,328,798	374,565,397	451,858,138
No. of Employees	37	77	265	42	171	93
Residential KWH sales	72,188,658	171,085,059	873,377,323	97,135,693	305,801,968	360,462,702
Commercial KWH sales	27,555,439	90,461,723	191,234,796	10,040,900	40,178,709	56,196,702
Residential Customers	6,874	13,129	60,266	7,831	31,196	28,528
Cummercial Customers	1,581	1,738	5,332	619	2,920	1,196
Industrial KWH sales	42,013,960	70,632,610	123,344,140	34,152,203	28,523,092	34,759,813
KWHs Purchased	155,787,466	362,369,631	1,271,634,707	156,380,475	416,460,324	532,989,453

1992

[illegible]	BREMCO	BEAUREGARD	CLAIBORNE	CONCORDIA	DEMCO	JEFF. DAVIS	NORTHEAST LA.
Purchased Power/Cust	$753.9	$842.3	$869.0	$695.2	$926.1	$1,008.5	$779.0
Purchased Power/KWH Purchased	$0.0561	$0.0559	$0.0537	$0.0539	$0.0561	$0.0533	$0.0570
Purchased Power/KWH	$0.0625	$0.0607	$0.0583	$0.0603	$0.0608	$0.0583	$0.0636
Distribution Exp. Oper./Cust	$34.8	$22.5	$31.9	$35.5	$29.6	$54.9	$36.2
Distribution Exp. Oper./Mile	$218.4	$147.6	$175.3	$164.5	$276.8	$150.6	$212.9
Distribution Exp. Oper./KWH	$0.0029	$0.0016	$0.0021	$0.0031	$0.0019	$0.0032	$0.0030
Distribution Exp.–Maint./Cust.	$82.4	$61.3	$51.2	$53.4	$68.2	$82.7	$39.4
Distribution Exp.–Maint./Mile	$517.5	$402.8	$280.8	$247.2	$637.0	$226.8	$231.5
Distribution Exp.–Maint./KWH	$0.0068	$0.0044	$0.0034	$0.0046	$0.0045	$0.0048	$0.0032
Distribution Exp.–Total/Cust.	$117.2	$83.8	$83.1	$88.9	$97.8	$137.7	$75.6
Distribution Exp.–Total/Mile	$735.9	$550.4	$456.1	$411.7	$913.8	$377.4	$444.4
Distribution Exp.–Total/KWH	$0.0097	$0.0060	$0.0056	$0.0077	$0.0064	$0.0080	$0.0062
Consumer Accounts Exp./Cust.	$33.8	$40.3	$26.9	$32.1	$33.3	$43.6	$40.4
Consumer Accounts Exp./Mile	$212.5	$264.5	$147.6	$148.5	$311.5	$119.4	$237.4
Consumer Accounts Exp./KWH	$0.0028	$0.0029	$0.0018	$0.0028	$0.0022	$0.0025	$0.0033
Customer Ser. & Informtl. Exp./Cust.	$2.6	$2.6	$5.2	$1.7	$4.0	$2.2	$0.0
Customer Ser. & Informtl. Exp./Mile	$16.1	$17.3	$28.6	$8.0	$37.2	$6.1	$0.0
Customer Ser. & Informtl. Exp./KWH	$0.0002	$0.0002	$0.0003	$0.0001	$0.0003	$0.0001	$0.0000
Customer Exp. Total/Cust.	$36.4	$42.9	$32.1	$33.8	$37.3	$45.8	$40.4
Customer Exp. Total/Mile	$228.6	$281.8	$176.2	$156.5	$348.6	$125.6	$237.4
Customer Exp. Total/KWH	$0.0030	$0.0031	$0.0022	$0.0029	$0.0024	$0.0026	$0.0033
Sales Expense/Cust.	$0.0	$1.2	$8.8	$0.0	$3.5	$4.2	$0.1
Sales Expense/Mile	$0.0	$7.9	$48.3	$0.0	$33.0	$11.4	$0.5
Sales Expense/KWH	$0.0000	$0.0001	$0.0006	$0.0000	$0.0002	$0.0002	$0.0000
Administrative & General Exp./Cust.	$84.8	$43.1	$48.6	$68.2	$77.4	$84.9	$56.6
Administrative & General Exp./Mile	$532.6	$282.8	$266.7	$315.8	$723.3	$232.6	$332.4
Administrative & General Exp./KWH	$0.0070	$0.0031	$0.0033	$0.0059	$0.0051	$0.0049	$0.0046
Administrative & General Exp./Emply.	$20,900.29	$12,150.30	$11,501.78	$17,301.95	$24,062.13	$14,890.00	$12,614.03
Total Oper. & Maint. Exp./Cust.	$992.3	$1,013.7	$1,037.2	$884.8	$1,145.5	$1,283.6	$951.9
Total Oper. & Maint. Exp./Mile	$6,229.9	$6,657.4	$5,694.5	$4,098.7	$10,705.9	$3,518.1	$5,592.7
Total Oper. & Maint. Exp./KWH	$0.0822	$0.0730	$0.0696	$0.0768	$0.0752	$0.0742	$0.0777
Interest on L–T Debt/Cust.	$85.2	$80.9	$56.7	$81.8	$50.4	$99.9	$52.3
Interest Exp. Other/Cust.	$12.6	$15.3	$1.8	$1.2	$1.9	$1.0	$0.0
Total Plant/Cust.	$2,530.3	$2,268.4	$2,089.6	$3,003.0	$2,743.0	$3,317.7	$1,732.2
Total Plant/Mile	$15,885.9	$14,897.1	$11,472.3	$13,910.1	$25,636.9	$9,093.4	$10,178.0
Total Plant/KWH	$0.2096	$0.1634	$0.1402	$0.2606	$0.1800	$0.1917	$0.1414
Net Plant/Cust.	$1,749.8	$1,734.8	$1,387.3	$2,002.8	$2,149.0	$2,525.3	$1,220.7
Net Plant/Mile	$10,985.8	$11,392.8	$7,616.4	$9,277.0	$20,085.4	$6,921.5	$7,172.4
Net Plant/KWH	$0.1450	$0.1250	$0.0931	$0.1738	$0.1410	$0.1459	$0.0996
Customers/Employee	246.39	282.20	236.82	253.82	310.95	175.47	222.98
Miles/Employee	39.24	42.97	43.13	54.80	33.27	64.02	37.95
KWH Sales/Cust.	12,071	13,880	14,905	11,524	15,238	17,310	12,254
Customers/Dist. Mile	6.28	6.57	5.49	4.63	9.35	[illegible]	[illegible]
KWH/Customer Residential	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[redacted]	POINTE COUPEE	SLECA	SLEMCO	TECHE	VALLEY	WASH. ST.TAM	AVERAGES
Purchased Power/Cust	$912.1	$1,230.7	$1,021.0	$962.5	$680.2	$981.5	$897.1
Purchased Power/KWH Purchased	$0.0504	$0.0511	$0.0527	$0.0530	$0.0558	$0.0548	$0.0541
Purchased Power/KWH	$0.0549	$0.0552	$0.0564	$0.0586	$0.0621	$0.0646	$0.0597
Distribution Exp. Oper./Cust	$17.3	$38.2	$30.6	$61.2	$34.0	$29.0	$35.1
Distribution Exp. Oper./Mile	$170.0	$496.8	$269.3	$635.0	$184.5	$197.0	$253.7
Distribution Exp. Oper./KWH	$0.0010	$0.0017	$0.0017	$0.0037	$0.0031	$0.0019	$0.0024
Distribution Exp.–Maint./Cust.	$46.6	$39.4	$47.0	$49.8	$58.0	$50.5	$56.1
Distribution Exp.–Maint./Mile	$457.7	$512.5	$413.5	$517.0	$314.2	$342.6	$392.4
Distribution Exp.–Maint./KWH	$0.0028	$0.0018	$0.0026	$0.0030	$0.0053	$0.0033	$0.0039
Distribution Exp.–Total/Cust.	$63.9	$77.6	$77.6	$111.0	$92.0	$79.5	$91.2
Distribution Exp.–Total/Mile	$627.7	$1,009.2	$682.8	$1,152.0	$498.7	$539.6	$646.1
Distribution Exp.–Total/KWH	$0.0039	$0.0035	$0.0043	$0.0068	$0.0084	$0.0052	$0.0063
Consumer Accounts Exp./Cust.	$34.6	$32.7	$35.6	$13.4	$27.1	$32.1	$32.8
Consumer Accounts Exp./Mile	$339.5	$425.5	$313.4	$139.0	$146.9	$218.1	$232.6
Consumer Accounts Exp./KWH	$0.0021	$0.0015	$0.0020	$0.0008	$0.0025	$0.0021	$0.0022
Customer Ser. & Informtl. Exp./Cust.	$3.9	$5.5	$3.2	$0.0	$4.9	$0.5	$2.8
Customer Ser. & Informtl. Exp./Mile	$38.3	$71.9	$28.2	$0.0	$26.6	$3.2	$21.7
Customer Ser. & Informtl. Exp./KWH	$0.0002	$0.0002	$0.0002	$0.0000	$0.0004	$0.0000	$0.0002
Customer Exp. Total/Cust.	$38.5	$38.3	$38.8	$13.4	$32.0	$32.6	$35.6
Customer Exp. Total/Mile	$377.9	$497.4	$341.6	$139.0	$173.5	$221.3	$254.3
Customer Exp. Total/KWH	$0.0023	$0.0017	$0.0021	$0.0008	$0.0029	$0.0021	$0.0024
Sales Expense/Cust.	$0.5	$0.9	$2.2	$15.8	$0.2	$4.5	$3.2
Sales Expense/Mile	$4.9	$11.3	$19.5	$163.8	$0.9	$30.4	$25.5
Sales Expense/KWH	$0.0000	$0.0000	$0.0001	$0.0010	$0.0000	$0.0003	$0.0002
Administrative & General Exp./Cust.	$92.5	$91.5	$39.5	$99.1	$67.6	$62.6	$70.5
Administrative & General Exp./Mile	$907.7	$1,189.5	$347.8	$1,028.4	$366.2	$425.0	$534.7
Administrative & General Exp./KWH	$0.0056	$0.0041	$0.0022	$0.0060	$0.0062	$0.0041	$0.0048
Administrative & General Exp./Emply.	$21,515.84	$17,873.86	$9,782.88	$20,323.90	$13,509.22	$20,035.11	$16,650.87
Total Oper. & Maint. Exp./Cust.	$1,108.1	$1,439.2	$1,183.1	$1,202.9	$867.0	$1,160.3	$1,097.7
Total Oper. & Maint. Exp./Mile	$10,876.6	$18,711.7	$10,413.9	$12,477.8	$4,700.0	$7,874.6	$8,273.2
Total Oper. & Maint. Exp./KWH	$0.0667	$0.0645	$0.0653	$0.0733	$0.0792	$0.0764	$0.0734
Interest on L–T Debt/Cust.	$28.0	$116.5	$37.6	$31.6	$66.4	$103.6	$68.5
Interest Exp. Other/Cust.	$8.3	$2.2	$3.1	$0.0	$2.1	$3.0	$4.0
Total Plant/Cust.	$2,603.9	$3,780.9	$2,521.2	$2,118.7	$2,159.0	$2,450.0	$2,562.9
Total Plant/Mile	$25,558.3	$49,157.7	$22,191.3	$21,978.8	$11,703.3	$16,627.9	$19,099.3
Total Plant/KWH	$0.1568	$0.1694	$0.1392	$0.1291	$0.1971	$0.1613	$0.1723
Net Plant/Cust.	$1,976.8	$2,994.2	$2,083.7	$1,736.6	$1,627.7	$1,925.0	$1,931.8
Net Plant/Mile	$19,403.1	$38,929.8	$18,340.1	$18,014.7	$8,823.4	$13,064.9	$14,617.5
Net Plant/KWH	$0.1190	$0.1342	$0.1151	$0.1058	$0.1486	$0.1268	$0.1287
Customers/Employee	232.65	195.36	247.58	205.00	199.96	319.97	240.70
Miles/Employee	23.70	15.03	28.13	19.76	36.89	47.15	37.39
KWH Sales/Cust.	16,608	22,314	18,107	16,414	10,954	15,185	15,136
Customers/Dist. Mile	9.82	13.00	8.80	10.37	5.42	6.79	7.32
KWH/Customer Residential	10,502	13,031	14,492	[illegible]	[illegible]	[illegible]	[illegible]

1991

ITEM	BREMCO	BEAUREGARD	CLAIBORNE	CONCORDIA	DEMCO	JEFF. DAVIS	NORTHEAST LA.
Purchased Power Exp.	$8,946,316	$23,571,071	$15,872,012	$8,027,652	$52,895,372	$8,478,430	$10,286,023
Distribution Exp.–Oper.	$437,398	$708,368	$617,273	$470,627	$1,756,031	$439,759	$466,043
Distribution Exp.–Maint.	$635,440	$1,659,199	$1,228,890	$533,413	$3,834,383	$689,489	$538,314
Consuner Accounts Exp.	$395,904	$1,138,165	$442,119	$373,797	$1,920,371	$371,421	$528,944
Customer Service & Informtl. Exp.	$38,290	$123,491	$95,947	$19,675	$235,994	$18,921	$0
Sales Expense	$875	$69,925	$87,627	$0	$252,770	$32,755	$0
Administrative & General Exp.	$870,804	$1,272,455	$817,485	$827,701	$3,691,687	$746,110	$704,095
Total Oper. & Maint. Exp.	$11,325,027	$28,552,674	$19,168,164	$10,270,359	$64,816,891	$10,806,203	$12,527,164
Interest on L–T Debt	$1,107,329	$2,943,370	$1,143,757	$1,021,892	$3,127,354	$905,400	$742,576
Interest Exp. Other	$91,182	$382,170	$42,864	$13,306	$109,882	$13,972	$319
Total Plant	$30,148,244	$63,989,682	$38,269,344	$32,948,081	$159,272,287	$28,095,073	$22,952,068
Net Plant	$21,363,956	$49,396,918	$25,631,643	$22,444,770	$127,438,837	$21,663,899	$16,368,873
No. of Customers (end of Yr.)	11,957	29,107	19,078	11,025	58,288	8,610	13,443
No. of Distribution Miles	1,909	4,410	3,506	2,393	6,344	1,404	2,310
No. of KWHs Sold	152,806,903	402,769,543	279,548,539	139,106,412	905,305,494	150,032,888	172,445,548
No. of Employees	50	105	77	44	195	48	61
Residential KWH sales	118,051,378	330,448,468	173,170,116	92,395,382	752,407,599	84,417,443	126,760,025
Commercial KWH sales	7,340,785	29,699,770	61,282,773	34,486,430	57,747,624	22,623,624	17,355,894
Residential Customer	11,129	26,055	16,942	9,718	54,803	7,335	10,042
Cummercial Customer	661	1,616	2,110	1,302	3,131	1,054	2,142
Industrial Sales							
KWHs Purchased	167,571,289	435,777,921	302,110,567	156,613,887	981,293,728	164,539,725	190,301,363

ITEM	POINTE COUPEE	SLECA	SLEMCO	TECHE	VALLEY	WASH. ST.TAM.
Purchased Power Exp.	$6,609,305	$18,512,565	$68,571,546	$8,102,044	$22,252,265	$28,150,199
Distribution Exp.–Oper.	$133,631	$649,747	$2,065,734	$466,932	$1,175,190	$897,063
Distribution Exp.–Maint.	$355,113	$737,432	$2,961,860	$371,818	$1,893,733	$1,395,569
Consuner Accounts Exp.	$338,619	$486,781	$2,427,411	$104,815	$878,905	$913,966
Customer Service & Informtl. Exp.	$46,800	$82,656	$211,570	$0	$146,421	$15,774
Sales Expense	$3,315	$15,688	$148,533	$133,387	$706	$198,718
Administrative & General Exp.	$824,964	$1,351,780	$2,662,986	$770,499	$2,174,080	$1,661,061
Total Oper. & Maint. Exp.	$8,314,352	$21,850,274	$79,350,676	$9,949,495	$28,524,528	$33,232,647
Interest on L–T Debt	$308,403	$1,910,701	$2,336,786	$293,194	$2,502,633	$2,689,174
Interest Exp. Other	$161,357	$21,079	$261,281	$0	$80,278	$75,523
Total Plant	$22,146,019	$55,840,964	$160,830,902	$15,691,444	$72,684,449	$69,469,587
Net Plant	$17,303,352	$44,968,750	$133,124,706	$12,666,085	$56,164,519	$54,833,652
No. of Customers (end of Yr.)	8,561	15,097	65,513	8,662	33,905	28,941
No. of Distribution Miles	875	1,146	7,437	825	6,297	4,378
No. of KWHs Sold	111,178,336	354,168,734	1,258,185,046	147,314,404	374,163,296	483,103,461
No. of Employees	38	78	268	43	169	94
Residential KWH sales	72,512,339	177,004,354	934,154,140	102,828,566	306,272,165	383,505,446
Commercial KWH sales	28,006,265	95,499,137	222,243,154	10,893,530	41,289,995	59,752,012
Residential Customer	6,809	13,107	60,159	7,944	30,963	27,507
Cummercial Customer	1,600	1,512	5,343	620	2,864	1,154
Industrial Sales						
KWHs Purchased	122,741,945	378,661,950	1,340,711,516	156,859,461	410,432,254	530,099,119

1991

[redacted]	BREMCO	BEAUREGARD	CLAIBORNE	CONCORDIA	DEMCO	JEFF. DAVIS	NORTHEAST LA.
Purchased Power/Cust	$748.2	$809.8	$832.0	$728.1	$907.5	$984.7	$765.2
Purchased Power/KWH Purchased	$0.0534	$0.0541	$0.0525	$0.0513	$0.0539	$0.0515	$0.0541
Purchased Power/KWH	$0.0585	$0.0585	$0.0568	$0.0577	$0.0584	$0.0565	$0.0596
Distribution Exp. Oper./Cust	$36.6	$24.3	$32.4	$42.7	$30.1	$51.1	$34.7
Distribution Exp. Oper./Mile	$229.1	$160.6	$176.1	$196.7	$276.8	$313.2	$201.8
Distribution Exp. Oper./KWH	$0.0029	$0.0018	$0.0022	$0.0034	$0.0019	$0.0029	$0.0027
Distribution Exp.–Maint./Cust.	$53.1	$57.0	$64.4	$48.4	$65.8	$80.1	$40.0
Distribution Exp.–Maint./Mile	$332.9	$376.2	$350.5	$222.9	$604.4	$491.1	$233.0
Distribution Exp.–Maint./KWH	$0.0042	$0.0041	$0.0044	$0.0038	$0.0042	$0.0046	$0.0031
Distribution Exp.–Total/Cust.	$89.7	$81.3	$96.8	$91.1	$95.9	$131.2	$74.7
Distribution Exp.–Total/Mile	$562.0	$536.9	$526.6	$419.6	$881.2	$804.3	$434.8
Distribution Exp.–Total/KWH	$0.0070	$0.0059	$0.0066	$0.0072	$0.0062	$0.0075	$0.0058
Consumer Accounts Exp./Cust.	$33.1	$39.1	$23.2	$33.9	$32.9	$43.1	$39.3
Consumer Accounts Exp./Mile	$207.4	$258.1	$126.1	$156.2	$302.7	$264.5	$229.0
Consumer Accounts Exp./KWH	$0.0026	$0.0028	$0.0016	$0.0027	$0.0021	$0.0025	$0.0031
Customer Ser. & Informtl. Exp./Cust.	$3.2	$4.2	$5.0	$1.8	$4.0	$2.2	$0.0
Customer Ser. & Informtl. Exp./Mile	$20.1	$28.0	$27.4	$8.2	$37.2	$13.5	$0.0
Customer Ser. & Informtl. Exp./KWH	$0.0003	$0.0003	$0.0003	$0.0001	$0.0003	$0.0001	$0.0000
Customer Exp. Total/Cust.	$36.3	$43.3	$28.2	$35.7	$37.0	$45.3	$39.3
Customer Exp. Total/Mile	$227.4	$286.1	$153.5	$164.4	$339.9	$278.0	$229.0
Customer Exp. Total/KWH	$0.0028	$0.0031	$0.0019	$0.0028	$0.0024	$0.0026	$0.0031
Sales Expense/Cust.	$0.1	$2.4	$4.6	$0.0	$4.3	$3.8	$0.0
Sales Expense/Mile	$0.5	$15.9	$25.0	$0.0	$39.8	$23.3	$0.0
Sales Expense/KWH	$0.0000	$0.0002	$0.0003	$0.0000	$0.0003	$0.0002	$0.0000
Administrative & General Exp./Cust.	$72.8	$43.7	$42.8	$75.1	$63.3	$86.7	$52.4
Administrative & General Exp./Mile	$456.2	$288.5	$233.2	$345.9	$581.9	$531.4	$304.8
Administrative & General Exp./KWH	$0.0057	$0.0032	$0.0029	$0.0060	$0.0041	$0.0050	$0.0041
Administrative & General Exp./Emply.	$17,416.08	$12,118.62	$10,616.69	$18,811.39	$18,931.73	$15,543.96	$11,542.54
Total Oper. & Maint. Exp./Cust.	$947.1	$981.0	$1,004.7	$931.6	$1,112.0	$1,255.1	$931.9
Total Oper. & Maint. Exp./Mile	$5,932.4	$6,474.5	$5,467.2	$4,291.8	$10,217.0	$7,696.7	$5,423.0
Total Oper. & Maint. Exp./KWH	$0.0741	$0.0709	$0.0686	$0.0738	$0.0716	$0.0720	$0.0726
nterest on L–T Debt/Cust.	$92.6	$101.1	$60.0	$92.7	$53.7	$105.2	$55.2
nterest Exp. Other/Cust.	$7.6	$13.1	$2.2	$1.2	$1.9	$1.6	$0.0
otal Plant/Cust.	$2,521.4	$2,198.4	$2,005.9	$2,988.5	$2,732.5	$3,263.1	$1,707.4
otal Plant/Mile	$15,792.7	$14,510.1	$10,915.4	$13,768.5	$25,106.0	$20,010.7	$9,936.0
otal Plant/KWH	$0.1973	$0.1589	$0.1369	$0.2369	$0.1759	$0.1873	$0.1331
let Plant/Cust.	$1,786.7	$1,697.1	$1,343.5	$2,035.8	$2,186.4	$2,516.1	$1,217.7
let Plant/Mile	$11,191.2	$11,201.1	$7,310.8	$9,379.3	$20,088.1	$15,430.1	$7,086.1
let Plant/KWH	$0.1398	$0.1226	$0.0917	$0.1613	$0.1408	$0.1444	$0.0949
ustomers/Employee	239.14	277.21	247.77	250.57	298.91	179.38	220.38
liles/Employee	38.18	42.00	45.53	54.39	32.53	29.25	37.87
WH Sales/Cust.	12,780	13,838	14,653	12,617	15,532	17,425	12,828
ustomers/Dist. Mile	6.26	6.60	5.44	4.61	9.19	[illegible]	[illegible]
WH/Customer Residential	10,608	[illegible]					

[redacted]	POINTE COUPEE	SLECA	SLEMCO	TECHE	VALLEY	WASH. ST.TAM	AVERAGES
Purchased Power/Cust	$772.0	$1,226.2	$1,046.7	$935.4	$656.3	$972.7	$875.8
Purchased Power/KWH Purchased	$0.0538	$0.0489	$0.0511	$0.0517	$0.0542	$0.0531	$0.0526
Purchased Power/KWH	$0.0594	$0.0523	$0.0545	$0.0550	$0.0595	$0.0583	$0.0573
Distribution Exp. Oper./Cust	$15.6	$43.0	$31.5	$53.9	$34.7	$31.0	$35.5
Distribution Exp. Oper./Mile	$152.7	$567.0	$277.8	$566.0	$186.6	$204.9	$269.9
Distribution Exp. Oper./KWH	$0.0012	$0.0018	$0.0016	$0.0032	$0.0031	$0.0019	$0.0024
Distribution Exp.-Maint./Cust.	$41.5	$48.8	$45.2	$42.9	$55.9	$48.2	$53.2
Distribution Exp.-Maint./Mile	$405.8	$643.5	$398.3	$450.7	$300.7	$318.8	$394.5
Distribution Exp.-Maint./KWH	$0.0032	$0.0021	$0.0024	$0.0025	$0.0051	$0.0029	$0.0036
Distribution Exp.-Total/Cust.	$57.1	$91.9	$76.7	$96.8	$90.5	$79.2	$88.7
Distribution Exp.-Total/Mile	$558.6	$1,210.5	$676.0	$1,016.7	$487.4	$523.7	$664.5
Distribution Exp.-Total/KWH	$0.0044	$0.0039	$0.0040	$0.0057	$0.0082	$0.0047	$0.0059
Consumer Accounts Exp./Cust.	$39.6	$32.2	$37.1	$12.1	$25.9	$31.6	$32.6
Consumer Accounts Exp./Mile	$387.0	$424.8	$328.4	$127.0	$139.6	$208.8	$242.9
Consumer Accounts Exp./KWH	$0.0030	$0.0014	$0.0019	$0.0007	$0.0023	$0.0019	$0.0022
Customer Ser. & Informtl. Exp./Cust.	$5.5	$5.5	$3.2	$0.0	$4.3	$0.5	$3.0
Customer Ser. & Informtl. Exp./Mile	$53.5	$72.1	$28.4	$0.0	$23.3	$3.6	$24.2
Customer Ser. & Informtl. Exp./KWH	$0.0004	$0.0002	$0.0002	$0.0000	$0.0004	$0.0000	$0.0002
Customer Exp. Total/Cust.	$45.0	$37.7	$40.3	$12.1	$30.2	$32.1	$35.6
Customer Exp. Total/Mile	$440.5	$496.9	$354.8	$127.0	$162.8	$212.4	$287.1
Customer Exp. Total/KWH	$0.0035	$0.0016	$0.0021	$0.0007	$0.0027	$0.0019	$0.0024
Sales Expense/Cust.	$0.4	$1.0	$2.3	$15.4	$0.0	$6.9	$3.2
Sales Expense/Mile	$3.8	$13.7	$20.0	$161.7	$0.1	$45.4	$26.9
Sales Expense/KWH	$0.0000	$0.0000	$0.0001	$0.0009	$0.0000	$0.0004	$0.0002
Administrative & General Exp./Cust.	$96.4	$89.5	$40.6	$89.0	$64.1	$57.4	$67.2
Administrative & General Exp./Mile	$942.8	$1,179.6	$358.1	$933.9	$345.3	$379.4	$529.3
Administrative & General Exp./KWH	$0.0074	$0.0038	$0.0021	$0.0052	$0.0058	$0.0034	$0.0045
Administrative & General Exp./Emply.	$21,709.58	$17,330.51	$9,936.51	$17,918.58	$12,864.38	$17,670.86	$15,570.11
Total Oper. & Maint. Exp./Cust.	$971.2	$1,447.3	$1,211.2	$1,148.6	$841.3	$1,148.3	$1,071.6
Total Oper. & Maint. Exp./Mile	$9,502.1	$19,066.6	$10,669.7	$12,060.0	$4,529.9	$7,590.8	$8,378.6
Total Oper. & Maint. Exp./KWH	$0.0748	$0.0617	$0.0631	$0.0675	$0.0762	$0.0688	$0.0704
Interest on L-T Debt/Cust.	$36.0	$126.6	$35.7	$33.8	$73.8	$92.9	$73.8
Interest Exp. Other/Cust.	$18.8	$1.4	$4.0	$0.0	$2.4	$2.6	$4.4
Total Plant/Cust.	$2,586.8	$3,698.8	$2,454.9	$1,811.5	$2,143.8	$2,400.4	$2,501.0
Total Plant/Mile	$25,309.7	$48,726.8	$21,625.8	$19,019.9	$11,542.7	$15,867.9	$19,394.8
Total Plant/KWH	$0.1992	$0.1577	$0.1278	$0.1065	$0.1943	$0.1438	$0.1658
Net Plant/Cust.	$2,021.2	$2,978.7	$2,032.0	$1,462.3	$1,856.5	$1,894.7	$1,909.9
Net Plant/Mile	$19,775.3	$39,239.7	$17,900.3	$15,352.8	$8,919.3	$12,524.8	$15,030.7
Net Plant/KWH	$0.1556	$0.1270	$0.1058	$0.0860	$0.1501	$0.1135	$0.1257
Customers/Employee	225.29	193.55	244.45	201.44	200.62	307.88	237.43
Miles/Employee	23.03	14.69	27.75	19.19	37.26	46.57	34.48
KWH Sales/Cust.	12,987	23,460	19,205	17,007	11,036	16,693	15,389
Customers/Dist. Mile	9.78	13.17	8.81	10.50	5.38	6.61	7.56
KWH/Customer Residential	10,649	13,505	15,528	12,944	9,892	13,942	12,103
KWH/Customer Commercial	17,504	63,161	41,595	17,570	14,417	51,778	26,081
Industrial KWH Sales as % of Total	8.54%	22.07%	9.68%	22.80%	6.94%	8.15%	13.56%

ITEM	1990 BREMCO	BEAUREGARD	CLAIBORNE	CONCORDIA	DEMCO	JEFF. DAVIS	NORTHEAST LA.
Purchased Power Exp.	$9,286,662	$23,867,763	$16,031,197	$8,393,937	$52,835,083	$9,516,691	$10,468,854
Distribution Exp.–Oper.	$398,424	$643,133	$550,063	$440,285	$1,590,370	$462,559	$476,537
Distribution Exp.–Maint.	$687,566	$1,480,705	$1,041,036	$579,176	$2,977,028	$617,135	$484,784
Consumer Accounts Exp.	$421,898	$1,128,805	$393,302	$394,963	$2,042,652	$354,730	$550,264
Customer Service & Informtl. Exp.	$44,521	$133,684	$88,132	$17,696	$238,816	$15,932	$0
Sales Expense	$794	$86,427	$169,418	$0	$290,143	$32,982	$2,100
Administrative & General Exp.	$824,192	$1,221,107	$812,917	$859,039	$3,683,862	$679,800	$679,330
Total Oper. & Maint. Exp.	$11,664,057	$28,605,404	$19,012,041	$10,699,104	$63,897,315	$11,707,863	$12,668,049
Interest on L–T Debt	$1,193,764	$3,175,944	$1,133,270	$1,142,552	$6,663,243	$954,186	$765,795
Interest Exp. Other	$110,015	$278,445	$40,810	$13,186	$108,327	$14,409	$711
Total Plant	$29,735,405	$61,670,316	$37,025,637	$32,704,472	$153,942,596	$27,294,833	$22,352,724
Net Plant	$21,638,164	$48,107,818	$25,278,514	$22,404,301	$125,045,125	$21,169,456	$16,140,781
No. of Customers (end of Yr.)	12,307	28,622	18,748	11,085	57,019	8,600	13,317
No. of Distribution Miles	1,919	4,379	3,475	2,377	6,274	1,398	2,302
No. of KWHs Sold	150,037,748	395,299,226	268,030,890	139,283,228	874,264,531	171,650,837	165,683,732
No. of Employees	61	103	79	48	189	49	61
Residential KWH sales	116,569,726	320,205,392	168,571,436	92,950,701	726,452,295	83,739,820	125,674,606
Commercial KWH sales	7,221,501	33,476,750	63,764,929	36,063,500	57,421,033	23,084,433	17,374,982
Residential Customers	11,361	25,560	16,627	9,756	53,666	7,339	10,053
Cummercial Customers	672	1,616	2,103	1,324	2,997	1,040	2,140
Industrial KWH sales	26,014,823	38,276,685	34,883,380	10,068,800	84,100,918	63,350,785	9,654,605
KWHs Purchased	164,418,010	426,290,556	291,569,007	154,751,230	943,168,536	185,952,968	182,376,933

ITEM	POINTE COUPEE	SLECA	SLEMCO	TECHE	VALLEY	WASH. ST.TAM.
Purchased Power Exp.	$6,693,916	$18,382,756	$73,913,810	$8,649,387	$22,936,942	$28,472,860
Distribution Exp.–Oper.	$149,632	$599,884	$2,029,829	$450,623	$914,355	$891,656
Distribution Exp.–Maint.	$358,184	$858,276	$2,896,233	$289,885	$1,775,566	$1,304,742
Consumer Accounts Exp.	$334,655	$499,710	$2,349,398	$99,522	$741,152	$1,051,662
Customer Service & Informtl. Exp.	$30,615	$72,311	$216,020	$103	$124,938	$23,310
Sales Expense	$560	$23,657	$134,958	$87,223	$0	$249,776
Administrative & General Exp.	$722,992	$1,304,788	$2,981,226	$740,961	$2,091,905	$2,517,004
Total Oper. & Maint. Exp.	$8,295,145	$21,751,661	$84,865,084	$10,317,705	$28,471,063	$34,487,700
Interest on L–T Debt	$801,894	$2,125,188	$2,348,260	$177,203	$2,700,400	$3,159,758
Interest Exp. Other	$127,377	$15,826	$263,796	$18,375	$168,613	$1,670,865
Total Plant	$21,676,656	$54,604,620	$160,349,368	$13,887,946	$71,650,918	$66,999,163
Net Plant	$17,377,227	$44,883,038	$133,715,838	$11,149,546	$56,612,166	$53,777,180
No. of Customers (end of Yr.)	8,507	14,940	72,047	8,568	33,838	28,429
No. of Distribution Miles	871	1,139	7,444	815	6,282	4,332
No. of KWHs Sold	108,543,780	340,694,872	1,355,407,590	146,993,133	371,310,628	484,999,805
No. of Employees	37	76	269	40	170	90
Residential KWH sales	71,480,992	174,929,133	978,248,625	101,977,639	306,257,515	381,698,735
Commercial KWH sales	29,360,109	88,555,466	246,349,215	10,996,247	41,166,656	59,330,287
Residential Customers	6,770	12,945	65,649	7,794	30,909	27,252
Cummercial Customers	1,588	1,815	6,386	612	2,856	1,150
Industrial KWH sales	6,571,600	73,712,954	130,809,750	34,019,247	23,196,205	43,525,983
KWHs Purchased	118,607,454	362,456,644	1,401,903,802	157,854,270	405,816,565	515,143,263

1990

[redacted]	BREMCO	BEAUREGARD	CLAIBORNE	CONCORDIA	DEMCO	JEFF. DAVIS	NORTHEAST LA.
Purchased Power/Cust	$754.6	$833.9	$855.1	$757.2	$926.6	$1,106.6	$786.1
Purchased Power/KWH Purchased	$0.0565	$0.0560	$0.0550	$0.0542	$0.0560	$0.0512	$0.0574
Purchased Power/KWH	$0.0619	$0.0604	$0.0598	$0.0603	$0.0604	$0.0554	$0.0632
Distribution Exp. Oper./Cust	$32.4	$22.5	$29.3	$39.7	$27.9	$53.8	$35.8
Distribution Exp. Oper./Mile	$207.6	$146.9	$158.3	$185.2	$253.5	$330.9	$207.0
Distribution Exp. Oper./KWH	$0.0027	$0.0016	$0.0021	$0.0032	$0.0018	$0.0027	$0.0029
Distribution Exp.–Maint./Cust.	$55.9	$51.7	$55.5	$52.2	$52.2	$71.8	$36.4
Distribution Exp.–Maint./Mile	$358.3	$338.1	$299.6	$243.7	$474.5	$441.4	$210.6
Distribution Exp.–Maint./KWH	$0.0046	$0.0037	$0.0039	$0.0042	$0.0034	$0.0036	$0.0029
Distribution Exp.–Total/Cust.	$88.2	$74.2	$84.9	$92.0	$80.1	$125.5	$72.2
Distribution Exp.–Total/Mile	$565.9	$485.0	$457.9	$428.9	$728.0	$772.3	$417.6
Distribution Exp.–Total/KWH	$0.0072	$0.0054	$0.0059	$0.0073	$0.0052	$0.0063	$0.0058
Consumer Accounts Exp./Cust.	$34.3	$39.4	$21.0	$35.6	$35.8	$41.2	$41.3
Consumer Accounts Exp./Mile	$219.9	$257.8	$113.2	$166.2	$325.6	$253.7	$239.0
Consumer Accounts Exp./KWH	$0.0028	$0.0029	$0.0015	$0.0028	$0.0023	$0.0021	$0.0033
Customer Ser. & Informtl. Exp./Cust.	$3.6	$4.7	$4.7	$1.6	$4.2	$1.9	$0.0
Customer Ser. & Informtl. Exp./Mile	$23.2	$30.5	$25.4	$7.4	$38.1	$11.4	$0.0
Customer Ser. & Informtl. Exp./KWH	$0.0003	$0.0003	$0.0003	$0.0001	$0.0003	$0.0001	$0.0000
Customer Exp. Total/Cust.	$37.9	$44.1	$25.7	$37.2	$40.0	$43.1	$41.3
Customer Exp. Total/Mile	$243.1	$288.3	$138.5	$173.6	$363.6	$265.1	$239.0
Customer Exp. Total/KWH	$0.0031	$0.0032	$0.0018	$0.0030	$0.0026	$0.0022	$0.0033
Sales Expense/Cust.	$0.1	$3.0	$9.0	$0.0	$5.1	$3.8	$0.2
Sales Expense/Mile	$0.4	$19.7	$48.8	$0.0	$46.2	$23.6	$0.9
Sales Expense/KWH	$0.0000	$0.0002	$0.0006	$0.0000	$0.0003	$0.0002	$0.0000
Administrative & General Exp./Cust.	$67.0	$42.7	$43.4	$77.5	$64.6	$79.0	$51.0
Administrative & General Exp./Mile	$429.5	$278.9	$233.9	$361.4	$567.2	$486.3	$295.1
Administrative & General Exp./KWH	$0.0055	$0.0031	$0.0030	$0.0062	$0.0042	$0.0040	$0.0041
Administrative & General Exp./Emply.	$13,511.3443	$11,855.4078	$10,290.0886	$17,896.6458	$19,491.3333	$13,873.4694	$11,136.5574
Total Oper. & Maint. Exp./Cust.	$947.8	$999.4	$1,014.1	$965.2	$1,120.6	$1,361.4	$951.3
Total Oper. & Maint. Exp./Mile	$6,078.2	$6,532.4	$5,471.1	$4,501.1	$10,184.5	$8,374.7	$5,503.1
Total Oper. & Maint. Exp./KWH	$0.0777	$0.0724	$0.0709	$0.0768	$0.0731	$0.0682	$0.0765
Interest on L–T Debt/Cust.	$97.0	$111.0	$60.4	$103.1	$116.9	$111.0	$57.5
Interest Exp. Other/Cust.	$8.9	$9.7	$2.2	$1.2	$1.9	$1.7	$0.1
Total Plant/Cust.	$2,416.1	$2,154.6	$1,974.9	$2,950.3	$2,699.8	$3,173.8	$1,678.5
Total Plant/Mile	$15,495.3	$14,083.2	$10,654.9	$13,758.7	$24,536.6	$19,524.2	$9,710.1
Total Plant/KWH	$0.1982	$0.1560	$0.1381	$0.2348	$0.1761	$0.1590	$0.1349
Net Plant/Cust.	$1,758.2	$1,680.8	$1,348.3	$2,021.1	$2,193.0	$2,461.6	$1,212.0
Net Plant/Mile	$11,275.7	$10,986.0	$7,274.4	$9,425.5	$19,930.7	$15,142.7	$7,011.6
Net Plant/KWH	$0.1442	$0.1217	$0.0943	$0.1609	$0.1430	$0.1233	$0.0974
Customers/Employee	201.75	277.88	237.32	230.94	301.69	175.51	218.31
Miles/Employee	31.46	42.51	43.99	49.52	33.20	28.53	37.74
KWH Sales/Cust.	12,191	13,811	14,297	12,565	15,333	19,959	12,442
Customers/Dist. Mile	6.41	6.54	5.40	4.66	[illegible]		

[redacted]	POINTE COUPEE	SLECA	SLEMCO	TECHE	VALLEY	WASH. ST.TAM	AVERAGES
Purchased Power/Cust	$786.9	$1,230.4	$1,025.9	$1,009.5	$677.8	$1,001.5	$904.0
Purchased Power/KWH Purchased	$0.0564	$0.0507	$0.0527	$0.0548	$0.0565	$0.0553	$0.0548
Purchased Power/KWH	$0.0617	$0.0540	$0.0545	$0.0588	$0.0618	$0.0587	$0.0593
Distribution Exp. Oper./Cust	$17.6	$40.2	$28.2	$52.6	$27.0	$31.4	$33.7
Distribution Exp. Oper./Mile	$171.8	$526.7	$272.7	$552.9	$145.6	$205.8	$258.8
Distribution Exp. Oper./KWH	$0.0014	$0.0018	$0.0015	$0.0031	$0.0025	$0.0018	$0.0022
Distribution Exp.–Maint./Cust.	$42.1	$57.4	$40.2	$33.8	$52.5	$45.9	$49.8
Distribution Exp.–Maint./Mile	$411.2	$753.5	$389.1	$355.7	$282.6	$301.2	$373.8
Distribution Exp.–Maint./KWH	$0.0033	$0.0025	$0.0021	$0.0020	$0.0048	$0.0027	$0.0034
Distribution Exp.–Total/Cust.	$59.7	$97.6	$68.4	$86.4	$79.5	$77.3	$83.5
Distribution Exp.–Total/Mile	$583.0	$1,280.2	$661.7	$908.6	$428.2	$507.0	$632.6
Distribution Exp.–Total/KWH	$0.0047	$0.0043	$0.0036	$0.0050	$0.0072	$0.0045	$0.0056
Consumer Accounts Exp./Cust.	$39.3	$33.4	$32.6	$11.6	$21.9	$37.0	$32.7
Consumer Accounts Exp./Mile	$384.2	$438.7	$315.6	$122.1	$118.0	$242.8	$245.9
Consumer Accounts Exp./KWH	$0.0031	$0.0015	$0.0017	$0.0007	$0.0020	$0.0022	$0.0022
Customer Ser. & Informtl. Exp./Cust.	$3.6	$4.8	$3.0	$0.0	$3.7	$0.8	$2.8
Customer Ser. & Informtl. Exp./Mile	$35.1	$63.5	$29.0	$0.1	$19.9	$5.4	$22.2
Customer Ser. & Informtl. Exp./KWH	$0.0003	$0.0002	$0.0002	$0.0000	$0.0003	$0.0000	$0.0002
Customer Exp. Total/Cust.	$42.9	$38.3	$35.6	$11.6	$25.6	$37.8	$35.5
Customer Exp. Total/Mile	$419.4	$502.2	$344.6	$122.2	$137.9	$248.1	$268.1
Customer Exp. Total/KWH	$0.0034	$0.0017	$0.0019	$0.0007	$0.0023	$0.0022	$0.0024
Sales Expense/Cust.	$0.1	$1.6	$1.9	$10.2	$0.0	$8.8	$3.4
Sales Expense/Mile	$0.6	$20.8	$18.1	$107.0	$0.0	$57.7	$26.5
Sales Expense/KWH	$0.0000	$0.0001	$0.0001	$0.0006	$0.0000	$0.0005	$0.0002
Administrative & General Exp./Cust.	$85.0	$87.3	$41.4	$86.5	$61.8	$88.5	$67.4
Administrative & General Exp./Mile	$830.1	$1,145.6	$400.5	$909.2	$333.0	$581.0	$528.6
Administrative & General Exp./KWH	$0.0067	$0.0038	$0.0022	$0.0050	$0.0056	$0.0052	$0.0045
Administrative & General Exp./Emply.	$19,540.3243	$17,168.2632	$11,082.6245	$18,524.0250	$12,305.3235	$27,966.7111	$15,741.70
Total Oper. & Maint. Exp./Cust.	$975.1	$1,455.9	$1,177.9	$1,204.2	$841.4	$1,213.1	$1,094.4
Total Oper. & Maint. Exp./Mile	$9,523.7	$19,097.2	$11,400.5	$12,659.8	$4,532.2	$7,961.1	$8,601.5
Total Oper. & Maint. Exp./KWH	$0.0764	$0.0638	$0.0626	$0.0702	$0.0767	$0.0711	$0.0720
Interest on L–T Debt/Cust.	$94.3	$142.2	$32.6	$20.7	$79.8	$111.1	$87.5
Interest Exp. Other/Cust.	$15.0	$1.1	$3.7	$2.1	$5.0	$58.8	$8.6
Total Plant/Cust.	$2,548.1	$3,654.9	$2,225.6	$1,620.9	$2,117.5	$2,356.7	$2,428.6
Total Plant/Mile	$24,887.1	$47,940.8	$21,540.8	$17,040.4	$11,405.7	$15,466.1	$18,926.5
Total Plant/KWH	$0.1997	$0.1603	$0.1183	$0.0945	$0.1930	$0.1381	$0.1616
Net Plant/Cust.	$2,042.7	$3,004.2	$1,856.0	$1,301.3	$1,673.0	$1,891.6	$1,880.3
Net Plant/Mile	$19,950.9	$39,405.7	$17,962.9	$13,680.4	$9,011.8	$12,413.9	$14,882.5
Net Plant/KWH	$0.1601	$0.1317	$0.0987	$0.0759	$0.1525	$0.1109	$0.1242
Customers/Employee	229.92	196.58	267.83	214.20	199.05	315.88	235.91
Miles/Employee	23.54	14.99	27.67	20.38	36.95	48.13	33.74
KWH Sales/Cust.	12,759	22,804	18,813	17,156	10,973	17,060	[illegible]
Customers/Dist. Mile	9.77	13.12	[illegible]				

1989

ITEM	BREMCO	BEAUREGARD	CLAIBORNE	CONCORDIA	DEMCO	JEFF. DAVIS	NORTHEAST LA.
Purchased Power Exp.	$8,881,358	$22,284,889	$14,892,359	$8,498,892	$50,704,500	$9,162,167	$9,567,891
Distribution Exp.–Oper.	$396,144	$653,287	$494,601	$478,595	$1,322,451	$451,546	$394,286
Distribution Exp.–Maint.	$760,902	$2,075,836	$754,283	$816,235	$2,607,349	$675,667	$525,947
Consuner Accounts Exp.	$431,264	$1,197,944	$468,644	$384,585	$1,997,036	$348,754	$517,360
Customer Service & Informtl. Exp.	$29,665	$116,406	$100,809	$30,375	$223,448	$16,104	$0
Sales Expense	($214)	$36,440	$145,917	$0	$157,598	$22,180	$200
Administrative & General Exp.	$855,438	$1,199,074	$772,868	$803,388	$3,515,525	$676,336	$661,937
Total Oper. & Maint. Exp.	$11,354,557	$17,573,876	$17,534,404	$11,026,078	$60,734,094	$11,370,853	$11,671,707
Interest on L–T Debt	$1,250,090	$3,199,864	$980,929	$1,214,184	$6,451,917	$909,464	$789,022
Interest Exp. Other	$60,207	$184,735	$39,555	$15,027	$129,069	$15,385	$1,399
Total Plant	$29,213,609	$59,860,556	$35,959,372	$31,933,030	$145,426,790	$25,632,603	$21,403,170
Net Plant	$21,740,766	$47,453,267	$25,052,638	$22,484,835	$119,969,624	$20,153,309	$15,629,351
No. of Customers (end of Yr.)	12,203	28,186	18,601	11,002	55,935	8,543	13,200
No. of Distribution Miles	1,905	4,348	3,447	2,439	6,218	1,397	2,296
No. of KWHs Sold	143,307,791	366,002,839	245,909,501	143,158,849	828,864,451	168,394,499	149,869,975
No. of Employees	58	104	80	51	187	49	61
Residential KWH sales	110,974,168	298,472,882	157,142,960	87,718,951	685,305,850	79,634,056	117,554,269
Commercial KWH sales	7,346,978	26,301,124	58,961,594	33,578,052	55,805,889	21,587,295	15,881,770
Residential Customer	11,361	25,264	16,519	9,730	52,845	7,301	10,044
Cummercial Customer	672	1,506	2,065	1,266	2,737	1,026	2,069
Industrial KWH sales	24,757,990	28,229,693	28,990,752	21,646,806	82,054,433	65,924,931	5,874,195
KWHs Purchased	159,936,791	403,476,932	272,564,361	161,566,563	922,420,946	183,402,028	168,727,724

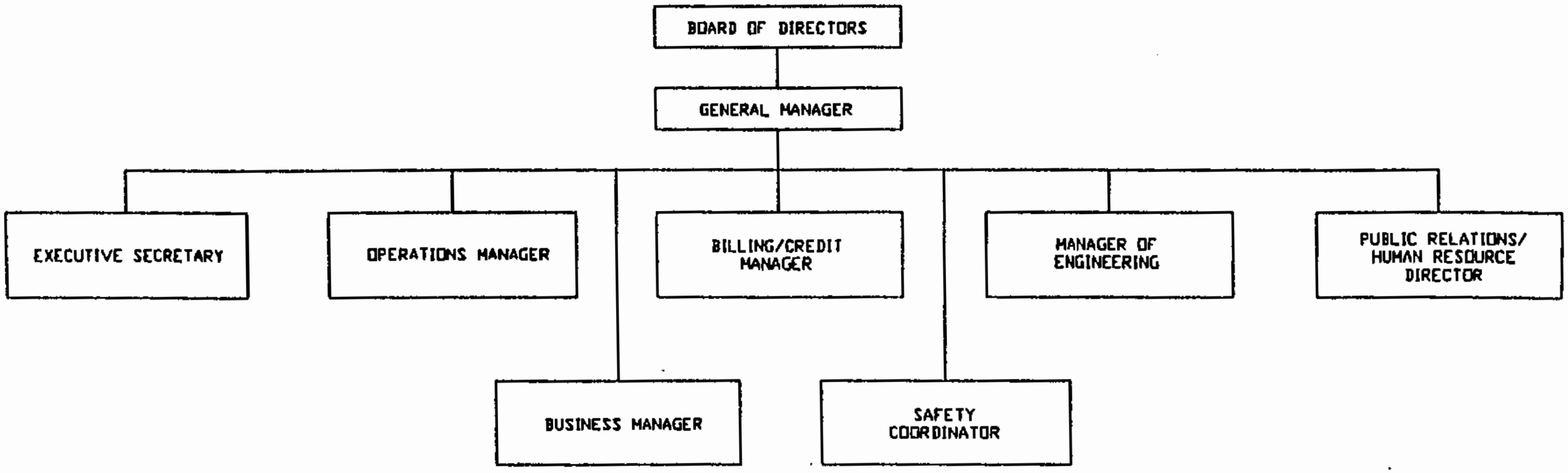
ITEM	POINTE COUPEE	SLECA	SLEMCO	TECHE	VALLEY	WASH. ST.TAM.
Purchased Power Exp.	$6,283,263	$17,401,379	$72,151,237	$8,752,642	$22,030,516	$27,782,581
Distribution Exp.–Oper.	$156,629	$565,352	$2,038,024	$421,145	$858,475	$900,337
Distribution Exp.–Maint.	$425,685	$614,192	$2,990,236	$247,201	$1,709,419	$1,159,896
Consuner Accounts Exp.	$311,056	$458,862	$2,798,781	$102,045	$737,205	$1,005,122
Customer Service & Informtl. Exp.	$49,724	$134,852	$120,570	$3,730	$89,461	$32,150
Sales Expense	$750	$29,630	$170,434	$55,556	$141	$250,258
Administrative & General Exp.	$953,172	$1,219,439	$3,003,593	$737,670	$2,058,254	$2,289,938
Total Oper. & Maint. Exp.	$8,186,970	$19,802,480	$83,520,339	$10,319,990	$27,396,071	$33,394,745
Interest on L–T Debt	$827,613	$2,225,072	$2,362,471	$139,225	$2,851,132	$821,391
Interest Exp. Other	$82,403	$24,500	$264,556	$0	$203,173	$164,172
Total Plant	$20,253,064	$53,599,593	$153,933,947	$12,653,822	$70,213,305	$64,772,353
Net Plant	$16,417,521	$44,694,762	$128,499,102	$10,177,710	$56,441,183	$52,670,669
No. of Customers (end of Yr.)	8,509	14,753	71,929	8,425	33,788	28,057
No. of Distribution Miles	867	1,132	7,376	807	6,268	4,292
No. of KWHs Sold	99,808,998	316,770,067	1,308,976,353	146,505,873	362,683,609	456,255,043
No. of Employees	37	72	272	43	164	91
Residential KWH sales	65,163,444	164,064,476	955,670,381	95,116,695	297,273,657	363,660,555
Commercial KWH sales	28,383,188	82,941,880	240,216,689	11,588,984	41,252,759	52,103,120
Residential Customer	6,767	12,766	65,507	7,646	30,867	26,878
Cummercial Customer	1,597	1,807	6,410	775	2,843	1,133
Industrial KWH sales	5,181,400	66,076,880	113,089,283	39,800,194	23,463,360	40,033,873
KWHs Purchased	112,815,037	346,227,814	1,399,238,649	163,067,886	398,613,229	512,566,507

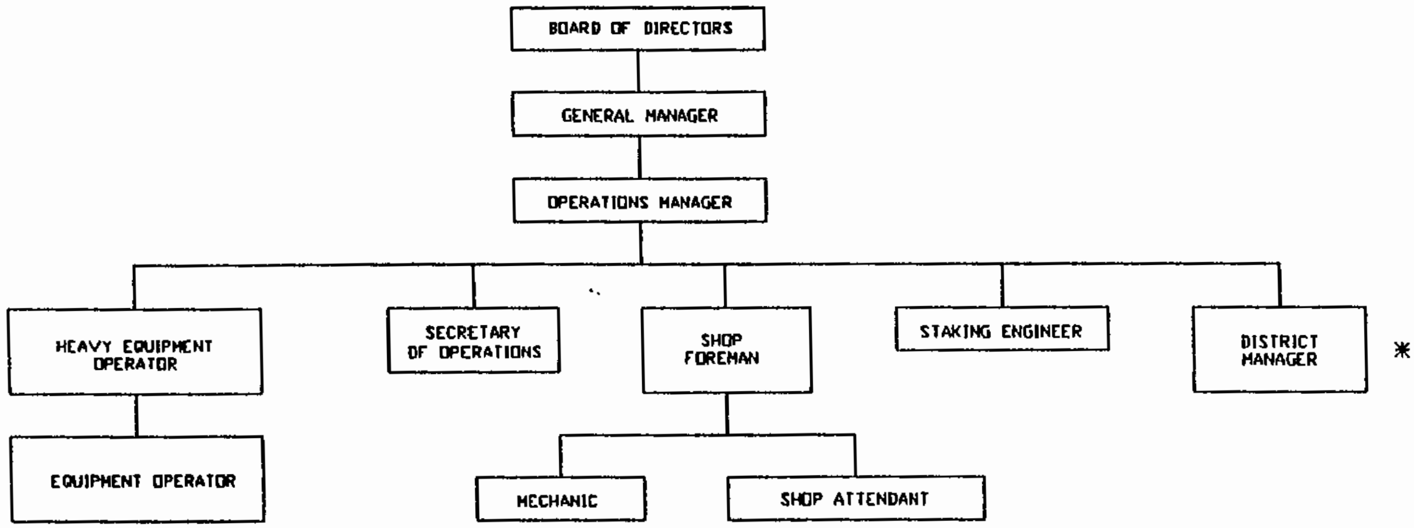
1989

	BREMCO	BEAUREGARD	CLAIBORNE	CONCORDIA	DEMCO	JEFF. DAVIS	NORTHEAST LA.
Purchased Power/Cust	$727.8	$790.6	$800.6	$772.5	$906.5	$1,072.5	$724.8
Purchased Power/KWH Purchased	$0.0555	$0.0552	$0.0546	$0.0526	$0.0550	$0.0500	$0.0567
Purchased Power/KWH Sold	$0.0620	$0.0609	$0.0606	$0.0594	$0.0612	$0.0544	$0.0638
Distribution Exp. Oper./Cust	$32.5	$23.2	$26.6	$43.5	$23.6	$52.9	$29.9
Distribution Exp. Oper./Mile	$207.9	$150.3	$143.5	$196.2	$212.7	$323.2	$171.7
Distribution Exp. Oper./KWH	$0.0028	$0.0018	$0.0020	$0.0033	$0.0016	$0.0027	$0.0026
Distribution Exp.-Maint./Cust.	$62.4	$73.6	$40.6	$74.2	$46.6	$79.1	$39.8
Distribution Exp.-Maint./Mile	$399.4	$477.4	$218.8	$334.7	$419.3	$483.7	$229.1
Distribution Exp.-Maint./KWH	$0.0053	$0.0057	$0.0031	$0.0057	$0.0031	$0.0040	$0.0035
Distribution Exp.-Total/Cust.	$94.8	$96.8	$67.1	$117.7	$70.3	$131.9	$69.7
Distribution Exp.-Total/Mile	$607.4	$627.7	$362.3	$530.9	$632.0	$806.9	$400.8
Distribution Exp.-Total/KWH	$0.0081	$0.0075	$0.0051	$0.0090	$0.0047	$0.0067	$0.0061
Consumer Accounts Exp./Cust.	$35.3	$42.5	$25.2	$35.0	$35.7	$40.8	$39.2
Consumer Accounts Exp./Mile	$226.4	$275.5	$136.0	$157.7	$321.2	$249.6	$225.3
Consumer Accounts Exp./KWH	$0.0030	$0.0033	$0.0019	$0.0027	$0.0024	$0.0021	$0.0035
Customer Ser. & Informtl. Exp./Cust.	$2.4	$4.1	$5.4	$2.8	$4.0	$1.9	$0.0
Customer Ser. & Informtl. Exp./Mile	$15.6	$26.8	$29.2	$12.5	$35.9	$11.5	$0.0
Customer Ser. & Informtl. Exp./KWH	$0.0002	$0.0003	$0.0004	$0.0002	$0.0003	$0.0001	$0.0000
Customer Exp. Total/Cust.	$37.8	$46.6	$30.6	$37.7	$39.7	$42.7	$39.2
Customer Exp. Total/Mile	$242.0	$302.3	$165.2	$170.1	$357.1	$261.2	$225.3
Customer Exp. Total/KWH	$0.0032	$0.0036	$0.0023	$0.0029	$0.0027	$0.0022	$0.0035
Sales Expense/Cust.	($0.0)	$1.3	$7.8	$0.0	$2.8	$2.6	$0.0
Sales Expense/Mile	($0.1)	$8.4	$42.3	$0.0	$25.3	$15.9	$0.1
Sales Expense/KWH	($0.0000)	$0.0001	$0.0006	$0.0000	$0.0002	$0.0001	$0.0000
Administrative & General Exp./Cust.	$70.1	$42.5	$41.5	$73.0	$62.9	$79.2	$50.1
Administrative & General Exp./Mile	$449.0	$275.8	$224.2	$329.4	$565.4	$484.1	$288.3
Administrative & General Exp./KWH	$0.0060	$0.0033	$0.0031	$0.0056	$0.0042	$0.0040	$0.0044
Administrative & General Exp./Emply.	$14,748.9310	$11,529.5577	$9,660.8500	$15,752.7059	$18,799.5989	$13,802.7755	$10,851.4262
Total Oper. & Maint. Exp./Cust.	$930.5	$623.5	$942.7	$1,002.2	$1,085.8	$1,331.0	$884.2
Total Oper. & Maint. Exp./Mile	$5,960.4	$4,041.8	$5,086.9	$4,520.7	$9,767.5	$8,139.5	$5,083.5
Total Oper. & Maint. Exp./KWH	$0.0792	$0.0480	$0.0713	$0.0770	$0.0733	$0.0675	$0.0779
Interest on L-T Debt/Cust.	$102.4	$113.5	$52.7	$110.4	$115.3	$106.5	$59.8
Interest Exp. Other/Cust.	$4.9	$6.6	$2.1	$1.4	$2.3	$1.8	$0.1
Total Plant/Cust.	$2,394.0	$2,123.8	$1,933.2	$2,902.5	$2,599.9	$3,000.4	$1,621.5
Total Plant/Mile	$15,335.2	$13,767.4	$10,432.1	$13,092.7	$23,388.0	$18,348.3	$9,321.9
Total Plant/KWH	$0.2039	$0.1636	$0.1462	$0.2231	$0.1755	$0.1522	$0.1428
Net Plant/Cust.	$1,781.6	$1,683.6	$1,346.8	$2,043.7	$2,144.8	$2,359.0	$1,184.0
Net Plant/Mile	$11,412.5	$10,913.8	$7,268.0	$9,218.9	$19,293.9	$14,426.1	$6,807.2
Net Plant/KWH	$0.1517	$0.1297	$0.1019	$0.1571	$0.1447	$0.1197	$0.1043
Customers/Employee	210.40	271.02	232.51	215.73	299.12	174.35	216.39
Miles/Employee	32.84	41.81	43.09	47.82	33.25	28.51	37.64
KWH Sales/Cust.	11,744	12,985	13,220	13,012	14,818	19,711	11,354
Customers/Dist. Mile	6.41	6.48	5.40	4.51	9.00	6.12	5.75
KWH/Customer Residential	9,768	11,814	9,513	9,015	12,968	10,907	11,704
KWH/Customer Commercial	10,933	17,464	28,553	26,523	20,389	21,040	7,676
Industrial KWH Sales as % of Total	18.98%	11.19%	18.01%	8.38%	10.64%	24.94%	9.06%

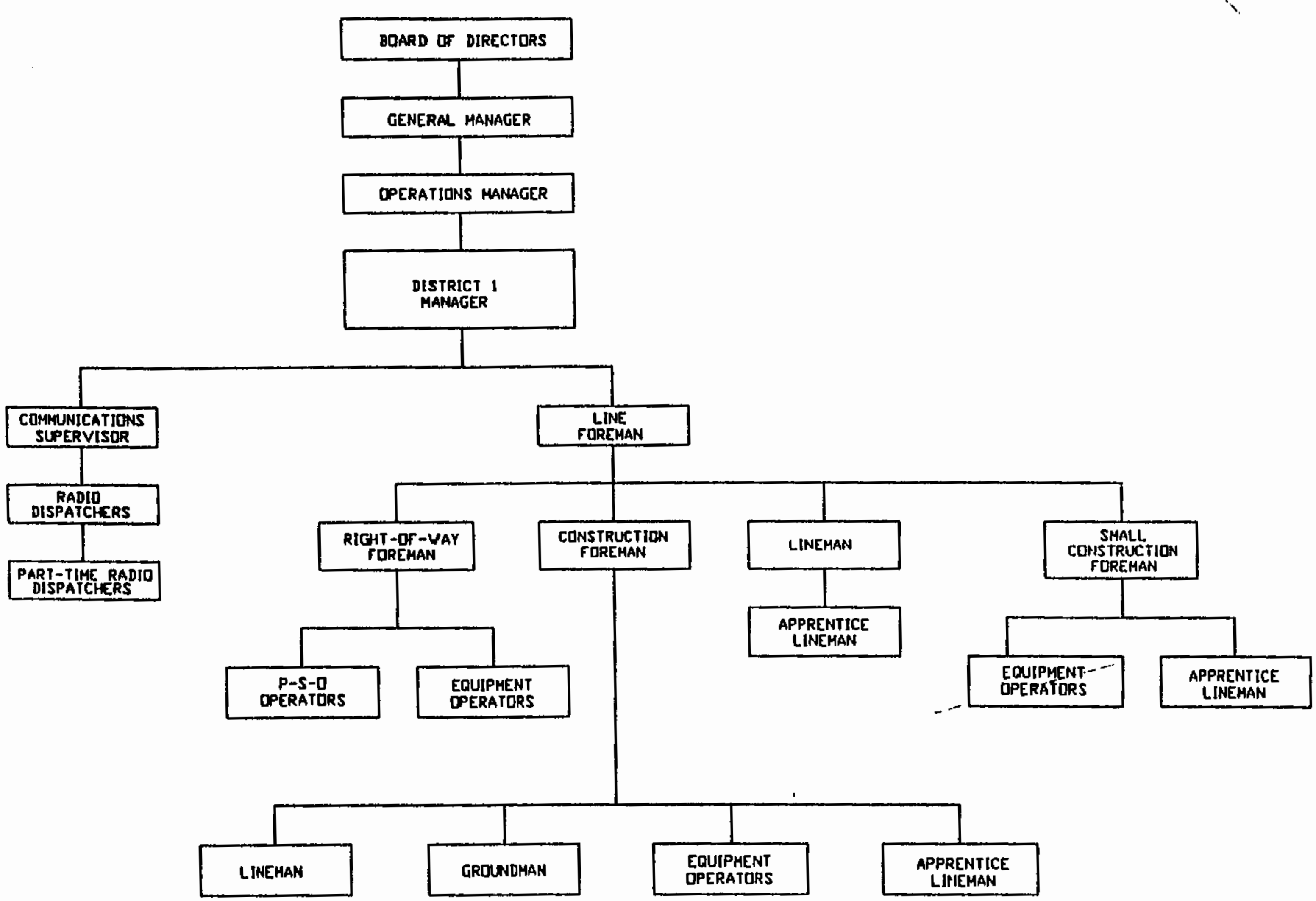
[redacted]	POINTE COUPEE	SLECA	SLEMCO	TECHE	VALLEY	WASH. ST.TAM	AVERAGES
Purchased Power/Cust	$738.4	$1,179.5	$1,003.1	$1,038.9	$652.0	$990.2	$876.7
Purchased Power/KWH Purchased	$0.0557	$0.0503	$0.0516	$0.0537	$0.0553	$0.0542	$0.0539
Purchased Power/KWH Sold	$0.0630	$0.0549	$0.0551	$0.0597	$0.0607	$0.0609	$0.0597
Distribution Exp. Oper./Cust	$18.4	$38.3	$28.3	$50.0	$25.4	$32.1	$32.7
Distribution Exp. Oper./Mile	$180.7	$499.4	$276.3	$521.9	$137.0	$209.8	$248.5
Distribution Exp. Oper./KWH	$0.0016	$0.0018	$0.0016	$0.0029	$0.0024	$0.0020	$0.0022
Distribution Exp.-Maint./Cust.	$50.0	$41.6	$41.6	$29.3	$50.6	$41.3	$51.6
Distribution Exp.-Maint./Mile	$491.0	$542.6	$405.4	$306.3	$272.7	$270.2	$373.1
Distribution Exp.-Maint./KWH	$0.0043	$0.0019	$0.0023	$0.0017	$0.0047	$0.0025	$0.0037
Distribution Exp.-Total/Cust.	$68.4	$80.0	$69.9	$79.3	$76.0	$73.4	$84.3
Distribution Exp.-Total/Mile	$671.6	$1,042.0	$681.7	$828.2	$409.7	$480.0	$621.6
Distribution Exp.-Total/KWH	$0.0058	$0.0037	$0.0038	$0.0046	$0.0071	$0.0045	$0.0059
Consumer Accounts Exp./Cust.	$36.6	$31.1	$38.9	$12.1	$21.8	$35.8	$33.1
Consumer Accounts Exp./Mile	$358.8	$405.4	$379.4	$126.4	$117.6	$234.2	$247.2
Consumer Accounts Exp./KWH	$0.0031	$0.0014	$0.0021	$0.0007	$0.0020	$0.0022	$0.0023
Customer Ser. & Informtl. Exp./Cust.	$5.8	$9.1	$1.7	$0.4	$2.6	$1.1	$3.2
Customer Ser. & Informtl. Exp./Mile	$57.4	$119.1	$16.3	$4.6	$14.3	$7.5	$27.0
Customer Ser. & Informtl. Exp./KWH	$0.0005	$0.0004	$0.0001	$0.0000	$0.0002	$0.0001	$0.0002
Customer Exp. Total/Cust.	$42.4	$40.2	$40.6	$12.6	$24.5	$37.0	$36.3
Customer Exp. Total/Mile	$416.1	$524.5	$395.8	$131.1	$131.9	$241.7	$274.2
Customer Exp. Total/KWH	$0.0036	$0.0019	$0.0022	$0.0007	$0.0023	$0.0023	$0.0026
Sales Expense/Cust.	$0.1	$2.0	$2.4	$6.6	$0.0	$8.9	$2.7
Sales Expense/Mile	$0.9	$26.2	$23.1	$68.8	$0.0	$58.3	$20.7
Sales Expense/KWH	$0.0000	$0.0001	$0.0001	$0.0004	$0.0000	$0.0005	$0.0002
Administrative & General Exp./Cust.	$112.0	$82.7	$41.8	$87.6	$60.9	$81.6	$68.1
Administrative & General Exp./Mile	$1,099.4	$1,077.2	$407.2	$914.1	$328.4	$533.5	$536.6
Administrative & General Exp./KWH	$0.0095	$0.0038	$0.0023	$0.0050	$0.0057	$0.0050	$0.0048
Administrative & General Exp./Emply.	$25,761.4054	$16,936.6528	$11,042.6213	$17,155.1163	$12,550.3293	$25,164.1538	$15,673.55
Total Oper. & Maint. Exp./Cust.	$962.2	$1,342.3	$1,161.1	$1,224.9	$810.8	$1,190.2	$1,037.8
Total Oper. & Maint. Exp./Mile	$9,442.9	$17,493.4	$11,323.3	$12,788.1	$4,370.8	$7,780.7	$8,138.4
Total Oper. & Maint. Exp./KWH	$0.0820	$0.0625	$0.0638	$0.0704	$0.0755	$0.0732	$0.0709
Interest on L-T Debt/Cust.	$97.3	$150.8	$32.8	$16.5	$84.4	$29.3	$82.4
Interest Exp. Other/Cust.	$9.7	$1.7	$3.7	$0.0	$6.0	$5.9	$3.5
Total Plant/Cust.	$2,380.2	$3,633.1	$2,140.1	$1,501.9	$2,078.1	$2,308.6	$2,355.2
Total Plant/Mile	$23,359.9	$47,349.5	$20,869.6	$15,680.1	$11,201.9	$15,091.4	$18,249.1
Total Plant/KWH	$0.2029	$0.1692	$0.1176	$0.0864	$0.1936	$0.1420	$0.1630
Net Plant/Cust.	$1,929.4	$3,029.5	$1,786.5	$1,208.0	$1,670.5	$1,877.3	$1,849.6
Net Plant/Mile	$18,936.0	$39,483.0	$17,421.2	$12,611.8	$9,004.7	$12,271.8	$14,543.8
Net Plant/KWH	$0.1645	$0.1411	$0.0982	$0.0695	$0.1556	$0.1154	$0.1272
Customers/Employee	229.97	204.90	264.44	195.93	206.02	308.32	233.01
Miles/Employee	23.43	15.72	27.12	18.77	38.22	47.16	33.49
KWH Sales/Cust.	11,730	21,472	18,198	17,389	10,734	16,262	14,818
Customers/Dist. Mile	9.81	13.03	9.75	10.44	5.39	6.54	7.59
KWH/Customer Residential	9,630	12,852	14,589	12,440	9,631	13,530	11,412
KWH/Customer Commercial	17,773	45,900	37,475	14,954	14,510	45,987	23,783
Industrial KWH Sales as % of Total	9.51%	24.68%	9.30%	22.93%	7.16%	8.63%	14.11%

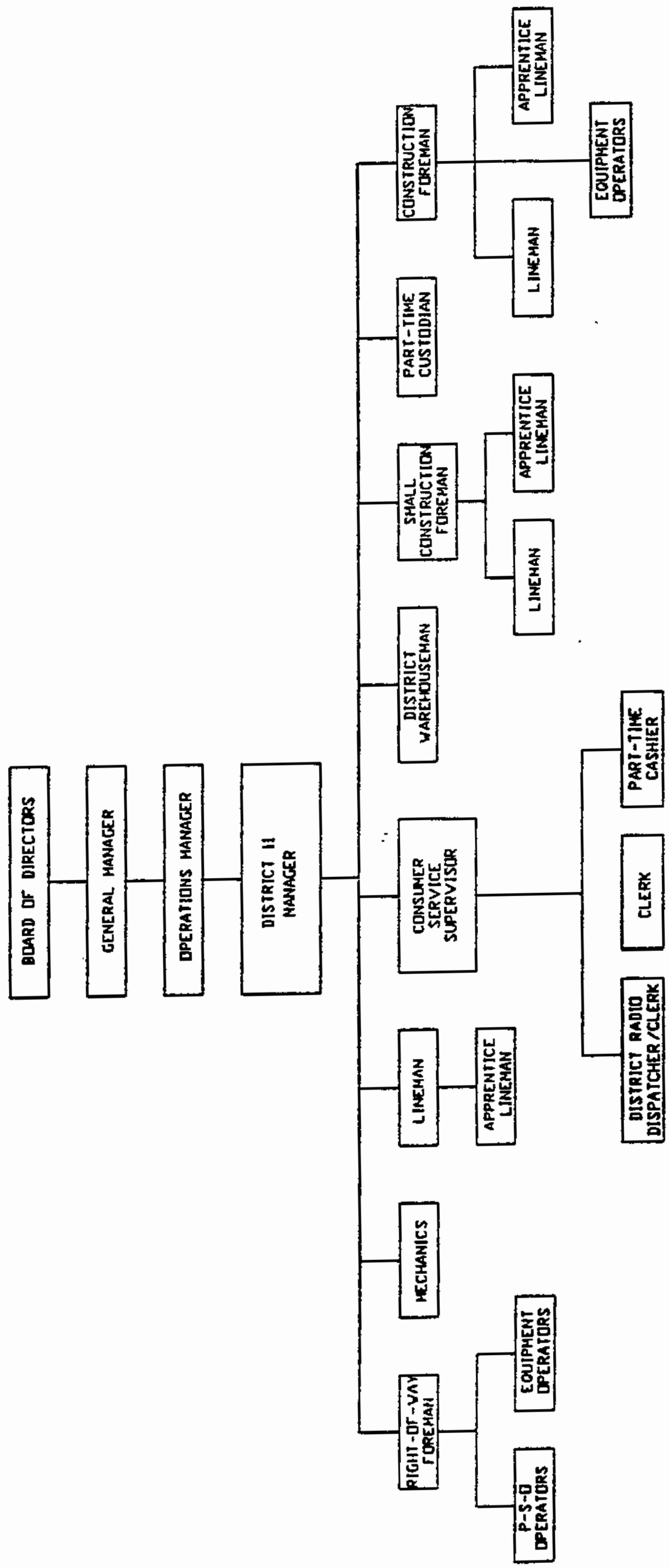
Current Organization Charts


BOARD OF DIRECTORS
GENERAL MANAGER
EXECUTIVE SECRETARY
OPERATIONS MANAGER
BILLING/CREDIT MANAGER
MANAGER OF ENGINEERING
PUBLIC RELATIONS/ HUMAN RESOURCE DIRECTOR
BUSINESS MANAGER
SAFETY COORDINATOR



* NOTE: SEPARATE LINES OF PROGRESSION.


BOARD OF DIRECTORS
GENERAL MANAGER
OPERATIONS MANAGER
DISTRICT 1 MANAGER
COMMUNICATIONS SUPERVISOR
LINE FOREMAN
RADIO DISPATCHERS
PART-TIME RADIO DISPATCHERS
RIGHT-OF-WAY FOREMAN
CONSTRUCTION FOREMAN
LINEMAN
SMALL CONSTRUCTION FOREMAN
APPRENTICE LINEMAN
P-S-O OPERATORS
EQUIPMENT OPERATORS
EQUIPMENT OPERATORS
APPRENTICE LINEMAN
LINEMAN
GROUNDMAN
EQUIPMENT OPERATORS
APPRENTICE LINEMAN


BOARD OF DIRECTORS
GENERAL MANAGER
OPERATIONS MANAGER
DISTRICT 11 MANAGER
RIGHT-OF-WAY FOREMAN
P-S-O OPERATORS
EQUIPMENT OPERATORS
MECHANICS
LINEMAN
APPRENTICE LINEMAN
CONSUMER SERVICE SUPERVISOR
DISTRICT RADIO DISPATCHER/CLERK
CLERK
PART-TIME CASHIER
DISTRICT WAREHOUSEMAN
SMALL CONSTRUCTION FOREMAN
LINEMAN
APPRENTICE LINEMAN
PART-TIME CUSTODIAN
CONSTRUCTION FOREMAN
LINEMAN
APPRENTICE LINEMAN
EQUIPMENT OPERATORS

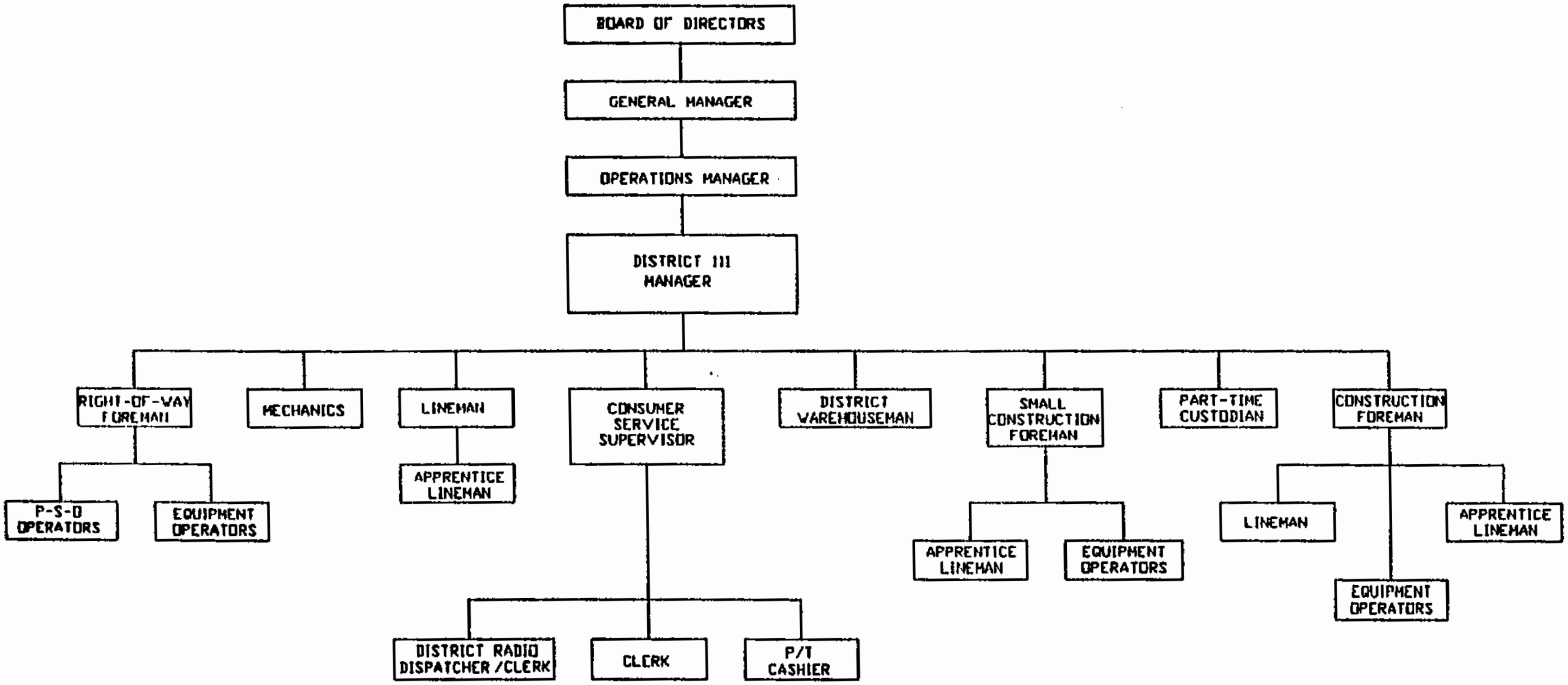
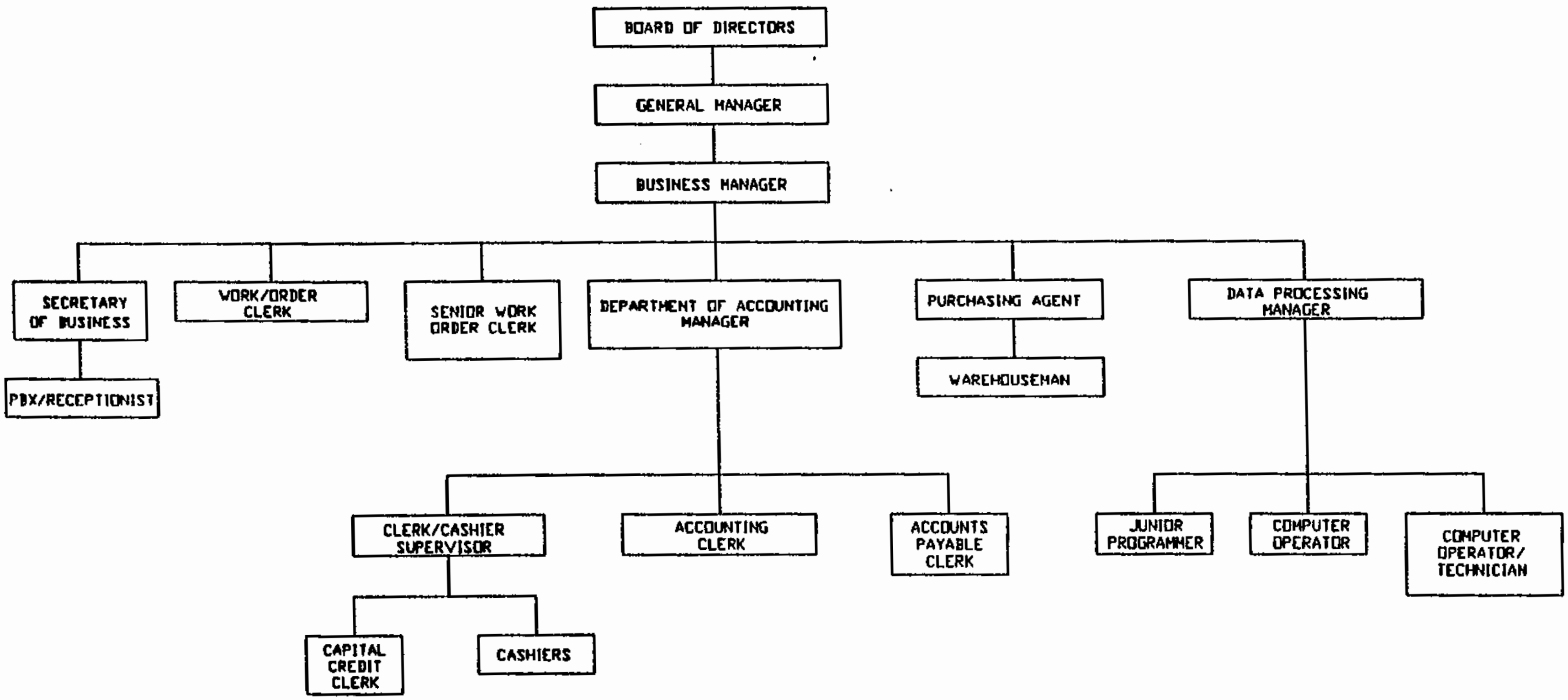
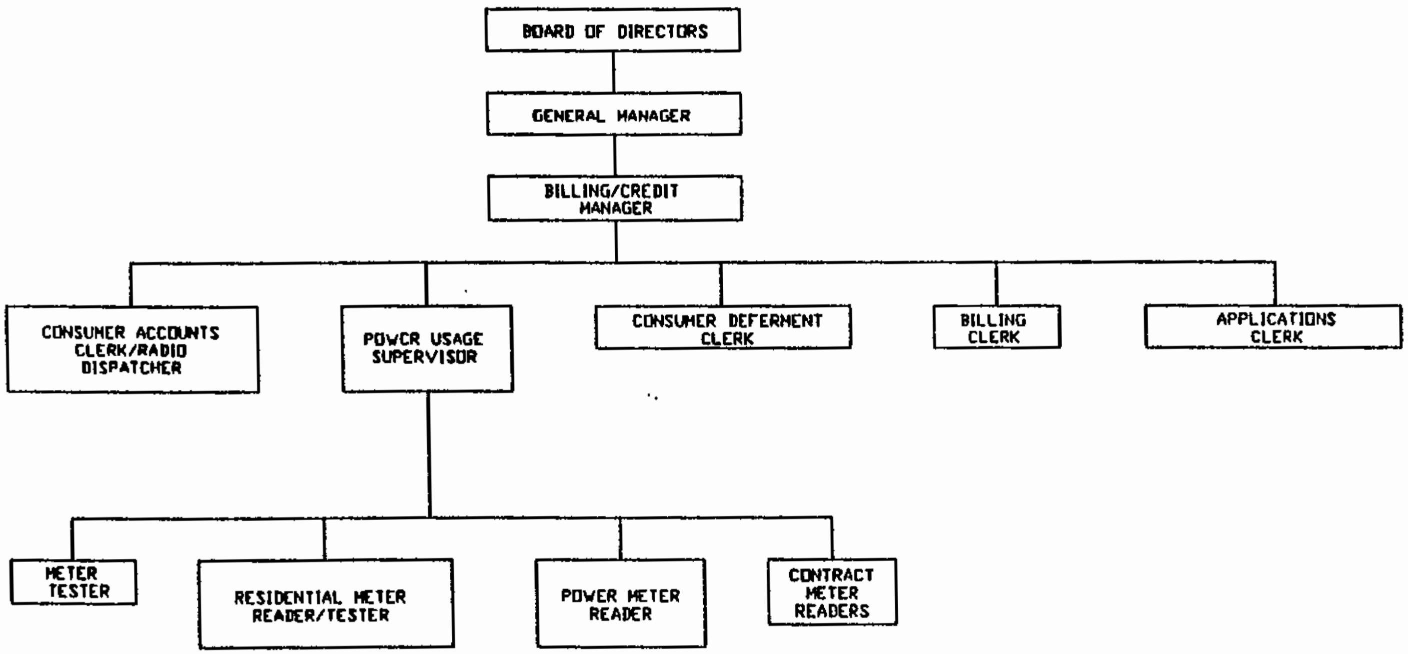
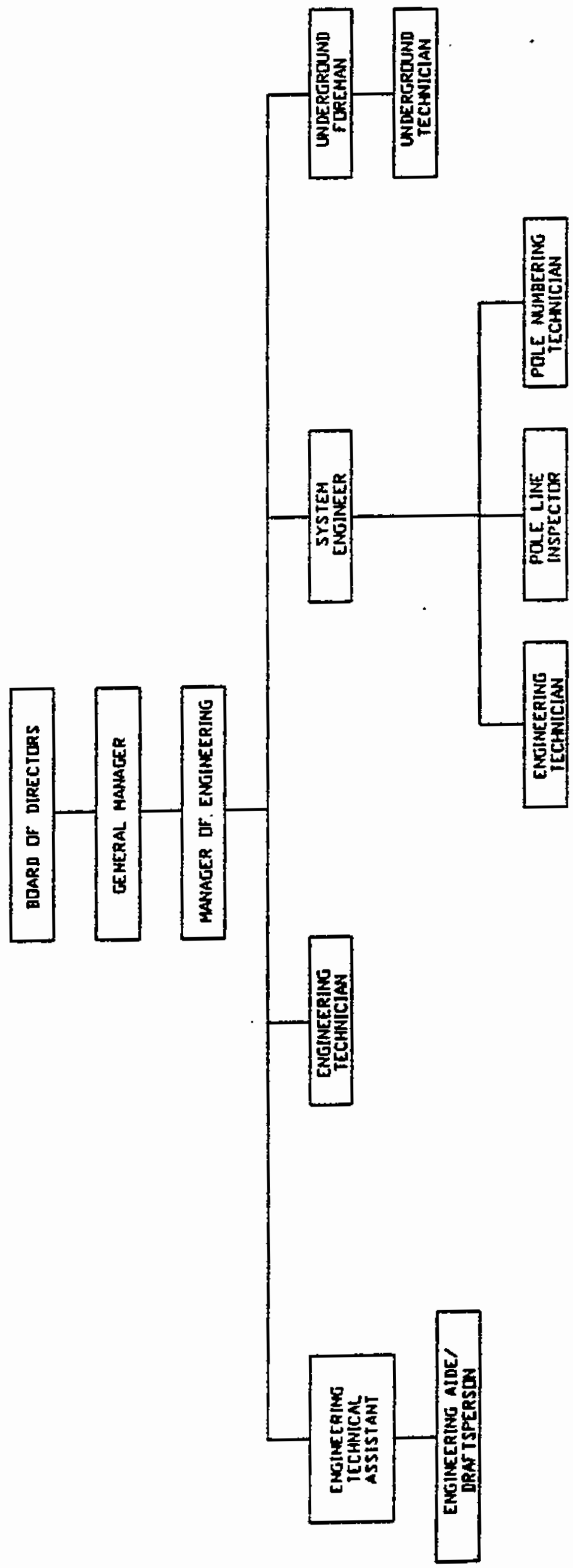
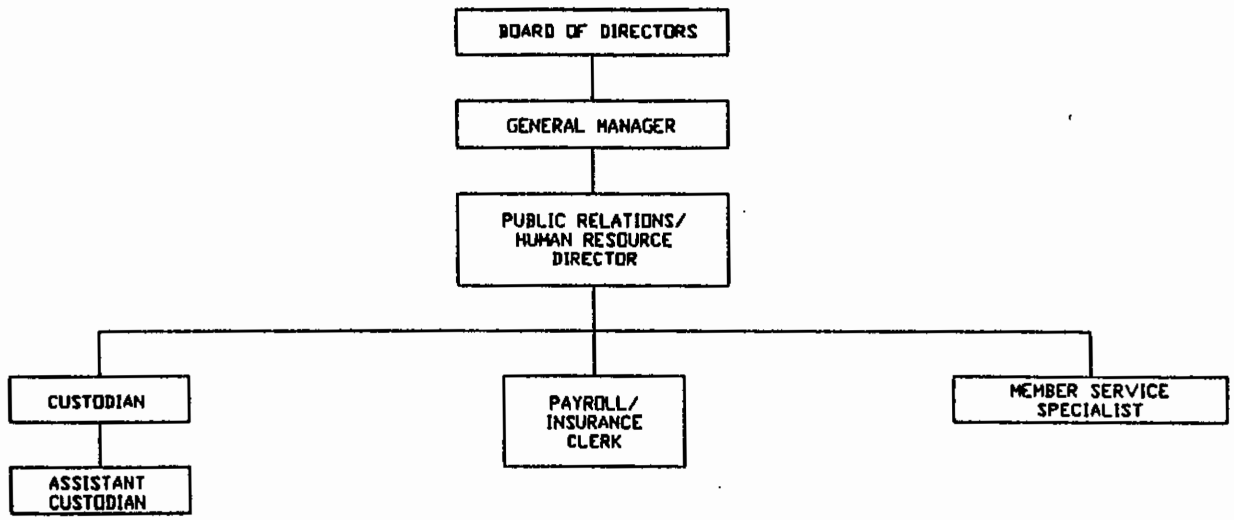


Exhibit 2
Page 6 of 10


BOARD OF DIRECTORS
GENERAL MANAGER
BUSINESS MANAGER
SECRETARY OF BUSINESS
PBX/RECEPTIONIST
WORK/ORDER CLERK
SENIOR WORK ORDER CLERK
DEPARTMENT OF ACCOUNTING MANAGER
PURCHASING AGENT
WAREHOUSEMAN
DATA PROCESSING MANAGER
CLERK/CASHIER SUPERVISOR
ACCOUNTING CLERK
ACCOUNTS PAYABLE CLERK
JUNIOR PROGRAMMER
COMPUTER OPERATOR
COMPUTER OPERATOR/ TECHNICIAN
CAPITAL CREDIT CLERK
CASHIERS

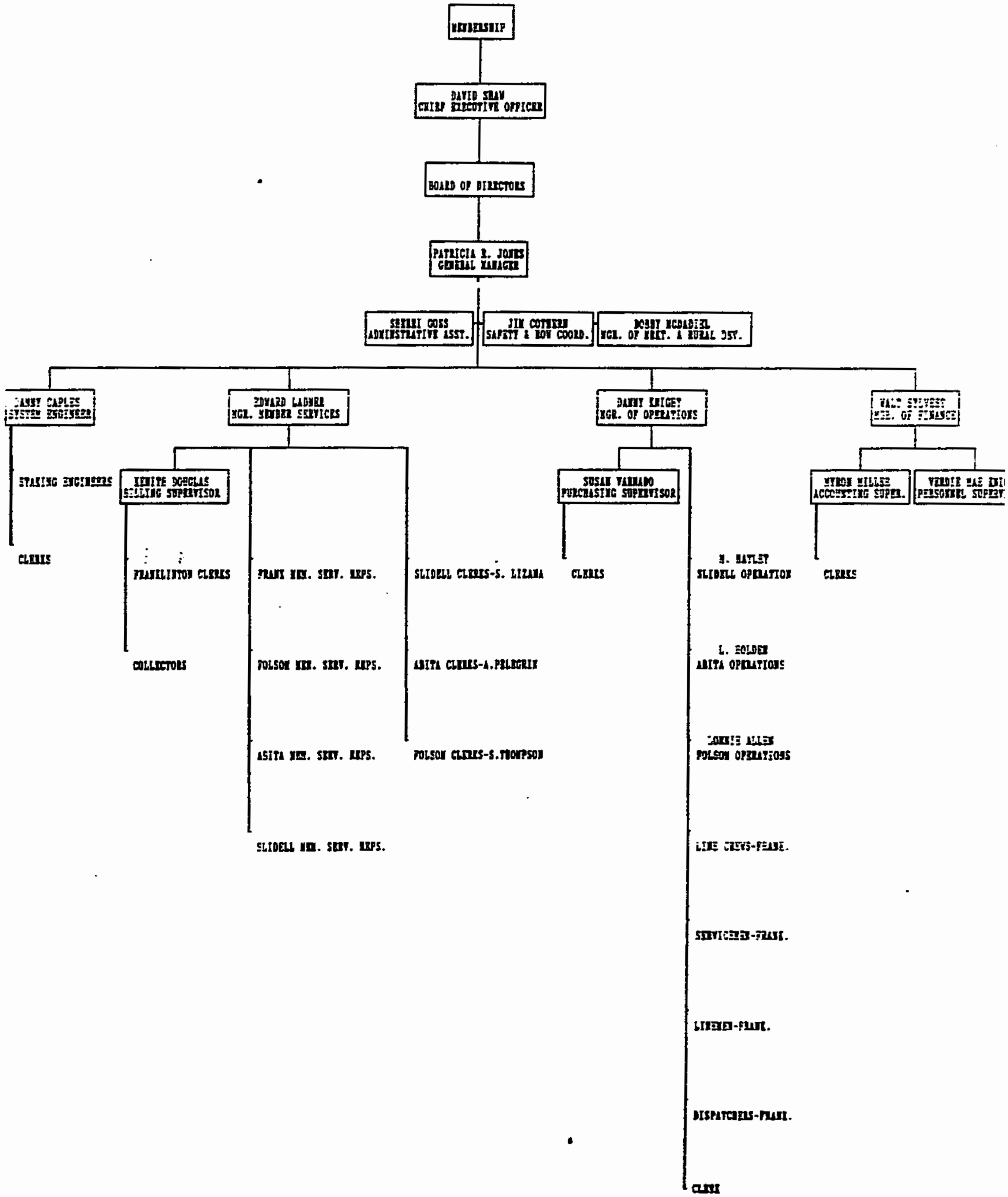

BOARD OF DIRECTORS
GENERAL MANAGER
BILLING/CREDIT MANAGER
CONSUMER ACCOUNTS CLERK/RADIO DISPATCHER
POWER USAGE SUPERVISOR
CONSUMER DEFERMENT CLERK
BILLING CLERK
APPLICATIONS CLERK
METER TESTER
RESIDENTIAL METER READER/TESTER
POWER METER READER
CONTRACT METER READERS


BOARD OF DIRECTORS
GENERAL MANAGER
MANAGER OF ENGINEERING
ENGINEERING TECHNICAL ASSISTANT
ENGINEERING AIDE/ DRAFTSPERSON
ENGINEERING TECHNICIAN
SYSTEM ENGINEER
ENGINEERING TECHNICIAN
POLE LINE INSPECTOR
POLE NUMBERING TECHNICIAN
UNDERGROUND FOREMAN
UNDERGROUND TECHNICIAN


BOARD OF DIRECTORS
GENERAL MANAGER
PUBLIC RELATIONS/ HUMAN RESOURCE DIRECTOR
CUSTODIAN
ASSISTANT CUSTODIAN
PAYROLL/ INSURANCE CLERK
MEMBER SERVICE SPECIALIST

Preliminary Discovery

WASHINGTON-ST.TAMMANY ELECTRIC, INC.
EFFECTIVE OCTOBER 12, 1993



ORGANIZATION CHART CONCORDIA ELECTRIC COOPERATIVE, INC.

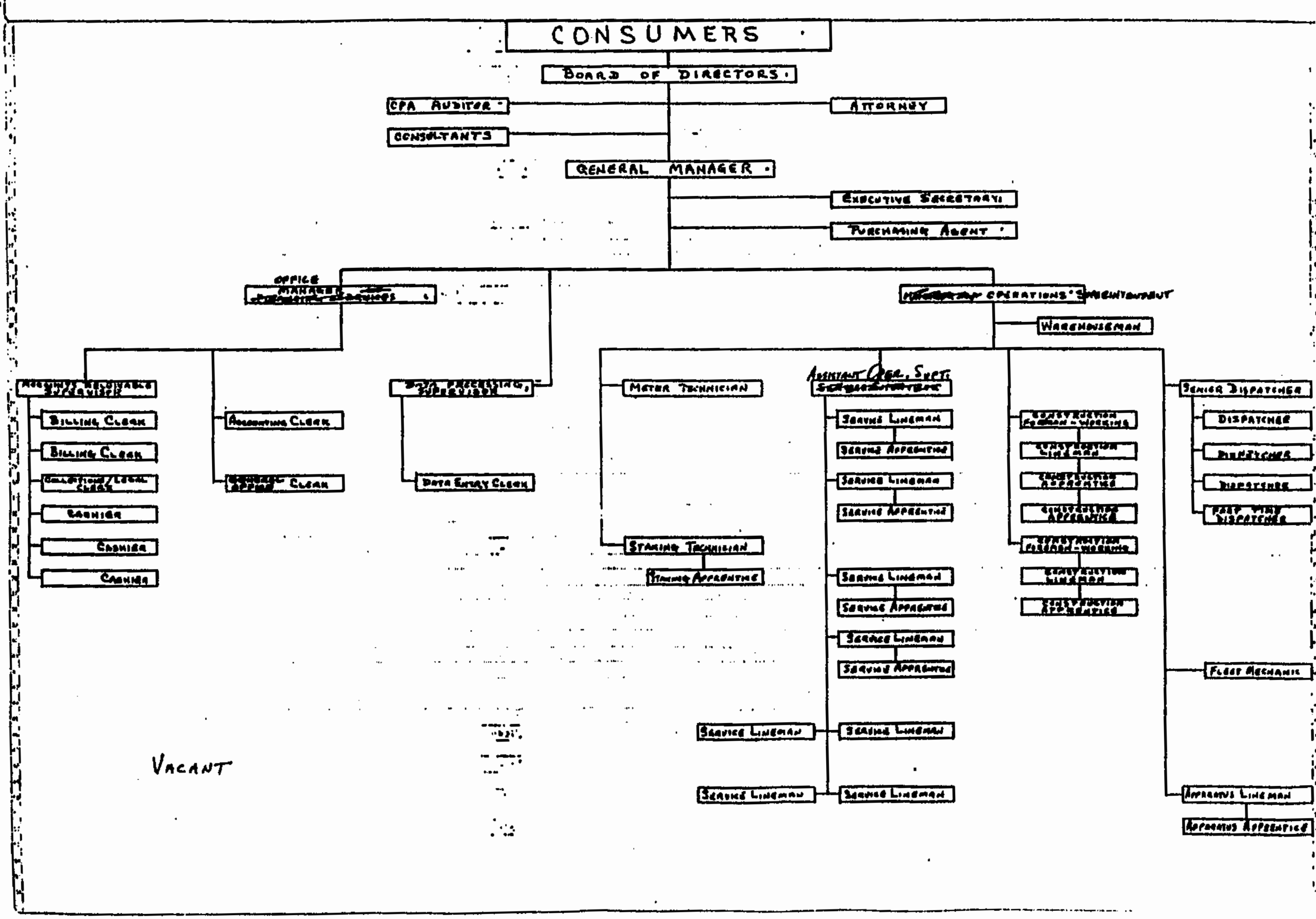


Exhibit 4
Page 1 of 1

WITNESS RESPONSIBLE:
LANE KOLLEN

QUESTION No. 2
Page 1 of 1

Please provide copies of each presentation that Mr. Kollen has made regarding electric cooperative capital rotation policies.

RESPONSE:

Refer to the prior response to Item 1-1. Mr. Kollen has not made any presentations on this subject other than through testimony filed in regulatory proceedings.

WITNESSES RESPONSIBLE:
LANE KOLLEN

QUESTION No. 3
Page 1 of 1

Please provide copies of any journal articles or other publications prepared by Mr. Kollen regarding electric utility capital credit rotation policies.

RESPONSE:

Mr. Kollen has not prepared any journal articles or other publications on this topic.

WITNESS RESPONSIBLE:
LANE KOLLEN

QUESTION No. 4
Page 1 of 1

Provide a list of each electric cooperative for which Mr. Kollen has provided advice to the electric cooperative regarding its capital credit rotation policies.

RESPONSE:

J. Kennedy and Associates, Inc. and Mr. Kollen do not provide services to electric cooperatives in such matters.

WITNESS RESPONSIBLE:
LANE KOLLEN

QUESTION No. 5
Page 1 of 1

Provide all studies or research that Mr. Kollen has conducted regarding the capital credit policies of electric cooperatives in the United States.

RESPONSE:

Refer to the prior response to Item 1-1. Refer also to South Kentucky RECC's response to Staff 2-2. The response to Staff 2-2(a) describes the Company's most recent review of its capital credit policies. The response to Staff 2-2(b) includes South Kentucky RECC's Capital Credit Policy, the Capital Credit Task Force Report, and the Capital Credit Task Force Report Legal Supplement. The Capital Credit Task Force Report describes widely divergent capital credit policies among cooperatives.

WITNESS RESPONSIBLE:
LANE KOLLEN

QUESTION No. 6
Page 1 of 1

For each electric cooperative for which Mr. Kollen has provided consulting services, please indicate the methodology that was used to determine revenue requirements, namely, return on rate base, TIER, OTIER, DSC, or other.

RESPONSE:

Refer to the prior response to Item 1-4.

WITNESS RESPONSIBLE:
LANE KOLLEN

QUESTION No. 7
Page 1 of 1

On page 30 of his testimony Mr. Kollen states that a "1.50 TIER will allow growth in members' equity of 1.95% annually."

a. Provide Mr. Kollen's definition of members' equity showing the formula used to calculate members' equity, indicating whether members' equity includes all capital credits from EKPC.
b. Provide the detailed analysis and source documents that Mr. Kollen relied on to determine the 1.95% in members' equity.
c. Please indicate whether the analysis reflects the impact of inflation or other cost increases.
d. Provide an analysis of the change in members' equity for the next five years based on a 1.50 TIER reflecting forecasted expense increases for South Kentucky, providing all assumptions.

RESPONSE:

a. Mr. Kollen relied on the members' equity reflected in the Company's financial statements. The members' equity reflects both the capital credits from EKPC and the capital credits from the Company's own margins.

b. Refer to Mr. Kollen's testimony at 36-37 wherein he describes his calculations based on the Company's requested 2.0 TIER and its requested interest expense, as adjusted for the error described by Mr. Kollen, divided by the members equity shown on Exhibit 11 to the Company's Application in this proceeding. As Mr. Kollen notes, the Company's request would result in annual growth in members' equity of 3.9%, all else equal. The subsequent reference in Mr. Kollen's testimony at 39 to a growth rate of 1.95% reflecting a 1.50 TIER is based on the same analysis used to calculate the 3.9%, but divided by 2.

c. Refer to the response to part (b) of this Item.

d. Mr. Kollen has not performed the requested analysis and does have the forecast information available necessary to perform the requested analysis.

WITNESS RESPONSIBLE:
LANE KOLLEN

QUESTION No. 8
Page 1 of 1

Provide all analytic support that Mr. Kollen relied on in arriving at his specific 1.50 TIER recommendation. In other words, provide the detailed calculations and support for how Mr. Kollen derived the 1.50 figure he recommends.

RESPONSE:

Mr. Kollen provided a description of his analysis in his testimony at 34-39. The detailed calculations for the effect of Mr. Kollen's recommendations are included in the Excel workbook filed contemporaneously with Mr. Kollen's testimony.

WITNESS RESPONSIBLE:
LANE KOLLEN

QUESTION No. 9
Page 1 of 1

Provide a complete description of Mr. Kollen's analysis of and all assumptions he made in evaluating the risk impact and reserve requirements necessary to account for the following uncertainties and cost volatilities in the determination of his 1.50 TIER: (1) impacts of weather variability, (2) capital cost and income impacts of normal and unusual levels of storm damage, (3) expense and impact of higher than normal inflation, (4) the impact on income from pandemics, (5) costs and income impacts from international impacts.

RESPONSE:

Refer to the prior response to Item 1-8. Mr. Kollen did not explicitly analyze each of the uncertainties and cost volatilities listed in the question to determine that a 1.50 TIER is reasonable, nor did the Company in its filing. Mr. Kollen notes that the question did not include customer growth and the effects on revenues and margins in the list of factors that can or will affect the margins and earned TIER. However, the Company has had growth in revenues since the end of the test year that are not included in the calculation of the revenue requirement or deficiency. The additional revenue will increase the margins and earned TIER. Similarly, the question did not include the reductions in interest expense due to the Company's repayment of outstanding debt since the end of the test year. The reductions in interest expense will increase the margins and earned TIER. Mr. Kollen also notes that weather variability can result in more revenues or less revenues, so the variability can go either way.

WITNESS RESPONSIBLE:
LANE KOLLEN

QUESTION No. 10
Page 1 of 1

Provide a copy of all research that Mr. Kollen has performed regarding the levels of TIER and OTIER used by electric cooperatives in the United States during the last five years.

RESPONSE:

Mr. Kollen has not performed independent research on this issue. However, Mr. Kollen notes that such statistics typically are *earned* TIER and OTIER as opposed to *authorized* TIER for ratemaking purposes, thus negating any probative value of any such research for ratemaking purposes. Mr. Kollen notes that the *earned* TIER includes G&T capital credits income, which historically the Commission has not included in the calculation of the TIER used for ratemaking purposes.

Mr. Kollen also notes that most cooperatives are not regulated for ratemaking purposes by the state public service commission, but rather essentially are self-regulated in that their Boards set their rates, including their target TIER and OTIER. Thus, there is a limited subset of TIER or OTIER authorized by the state public service commission for comparative purposes compared to the universe of distribution cooperatives. In Louisiana, like Kentucky, the cooperatives are regulated for ratemaking purposes. Mr. Kollen is aware that the Louisiana Public Service Commission has authorized TIERs ranging from 1.50 to 1.75.

WITNESS RESPONSIBLE:
LANE KOLLEN

QUESTION No. 11
Page 1 of 1

What date did Mr. Kollen assume that South Kentucky terminated the use of its temporary office staffing? How is this date significant?

RESPONSE:

The Company terminated the temporary office staffing in 2020, according to Mr. Simmons' testimony at 8 dated December 14, 2021 ("Similarly, in the last year we eliminated most of our temporary staffing assistance at our office district locations. Saving approximately $180,000 a year.") and its response to AG 1-49, which shows a reduction from $126,905 in 2019 to $28,850 in 2020 and to $19,767 in 2021. Based on these two sources, Mr. Kollen determined that the reductions in expense occurred near the end of the Company's historic test year. This date is significant because the Company made no proforma adjustment to reduce its historic test year expenses to reflect this known and measurable change.

WITNESS RESPONSIBLE:
LANE KOLLEN

QUESTION No. 12
Page 1 of 1

Please describe in detail Mr. Kollen's understanding of whether South Kentucky declared a general retirement of capital credits to occur in the years 2020 and 2021? If so, what amount was retired, and what years did the payouts represent. Did this also include any retirements of EKPC capital credits?

RESPONSE:

Yes, as to 2020 and 2019. Mr. Kollen does not know whether there was a general retirement of capital credits in 2021. Exhibit 17 to the Company's Application provides the audited financial statements for the years ending December 31, 2020 and December 31, 2019. Exhibit 17 at 8 shows "refunds of capital credits to members" in 2020 of $1.924 million and in 2019 of $0.504 million. Exhibit 17 at 7 provides additional detail on the refund of capital credits separated into refunds to estates and general retirement refunds. Based on Mr. Kollen's review of the Company's present capital credits retirement policy, none of the refunds in 2020 and 2019 would reflect the retirement of EKPC capital credits. In any event, these questions go to factual matters within the Company's knowledge and control, and not within Mr. Kollen's knowledge and control, except to the extent the information is available in this proceeding or in another publicly available source.

WITNESS RESPONSIBLE:
LANE KOLLEN

QUESTION No. 13
Page 1 of 1

Please describe in detail whether the interest rate earned on the Cushion of Credit funds will change on October 1, 2022 and annually going forward? Does Mr. Kollen know what the interest rate will be on October 1, 2022?

RESPONSE:

Yes.

No, nor does the Company.

WITNESS RESPONSIBLE:
LANE KOLLEN

QUESTION No. 14
Page 1 of 1

Please indicate whether South Kentucky provided a footnote with the website location as to where it sourced the Treasury Rate assumptions used in the NPV scenario when using the cushion of credit to repay long term debt? (Reference Commission's Third Request for Information, Request No. 8).

RESPONSE:

There is a footnote reference on the Excel workbook attachment to a ycharts website. As Mr. Kollen noted in his testimony at 33, lines 3-6, the Company's assumption was that the Treasury rate assumptions in the Company's so-called analysis would rise to 2.86% "based on an average of historic interest rates. There is no support provided for this assumption." There is no support for the use of historic interest rates as the assumption for future interest rates in this so-called analysis. Even more importantly, the so-called analysis was not performed or used by the Company to make its decision not to prepay its highest cost RUS/FFB debt. It is an after the fact analysis performed in response to Staff discovery in an attempt to justify an unreasonable decision.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

LANE KOLLEN, being duly sworn, deposes and states: that the attached are his sworn responses and that the statements contained are true and correct to the best of his knowledge, information and belief.

Lane Kollen

Sworn to and subscribed before me on this
1st day of April 2022.

Notary Public

RANDY A FUTRAL
MY COMMISSION EXPIRES
NOTARY
PUBLIC
AUGUST 26, 2024
COBB COUNTY, GEORGIA