SECTION I. – EXECUTIVE SUMMARY

The City of Lamar Utilities Board (LUB), concerned about continued load growth, planned system facilities improvements, the completion of the Lamar Repowering Project by the Arkansas River Power Authority (ARPA) and necessary increases in labor and general operating expenses requested that NMPP Energy conduct a Financial Plan, Cost-of-Service and Rate Design Study, (COS/RDS). This report summarizes the findings and recommendations resulting from the development of a 5-year Financial Planning Model. Following direction from LUB Staff and the Board as the rate setting authority, the COS Study and rate design will be completed and recommendations forwarded for final consideration.

This report discusses the findings and recommendations resulting from an electric financial plan. This financial projection for the utility, based upon certain inflationary and projected power cost increases, indicates a need for a series of annual rate increases to maintain net income and cash reserves at system financial targets. The recommendation is for the new rates to include projected power costs in the base rate. The ECA formula will be adjusted to include a deviation threshold such that the ECA is not applied before the threshold is exceeded. When this amount is exceeded the staff will propose the application of the ECA for the LUB to consider. In others words the ECA is proposed to be used in cases of large deviations from budgeted cost of power or other emergencies. The Charter Appropriation Adjustment (CAA) will remain as an adder to electric bills, however it is recommended to be an annual level $/KWh vs. an amount that changes monthly. The CAA annual level is proposed to be adjusted each year during the Budget process.

New rates with 2009 Budgeted ECA revenues included will be designed to bring the classes of customers closer to their cost of service by using a rate design guideline of plus or minus 3.0% from the system average revenue increase and to rebase the current ECA in the design of June 2009 rates with a 20.5% system overall revenue change in the base rate. This will effectively eliminate the monthly ECA except in the emergency situations identified above. With the 2009 Budgeted 20.5% system increase in revenues over the application of the current rate and the current ECA recovering power costs greater than $35.00 per MWh, some classes that are below COS could receive 3% more or 23.5% while another class above cost of service could receive 3.0% less or 17.5%. Following direction from LUB's Staff and rate setting authorities, the rate design will be completed and the Final Report with recommendations for consideration will be produced. The CAA will be applied to the bills as in the past and the increase from 2008 collections is estimated to be 4.2% increase. This is a $50,548 increase in CAA revenues and represents about a $0.52 adder for each 1,000 KWh billed. For 2009 there will be no change in revenue collected from this rate.

The study includes assumptions for power supply costs from ARPA using the Wholesale rate the ARPA Board approve for April 1, 2009. The ARPA rate is assumed also to be a good approximation for the cost of power received from MEAN under the extended Market Power Purchase agreement currently in place while the Lamar Repowering Project completes its start-up phase. Other operating cost escalations, capital construction, the cost of potential long term borrowing and earnings on reserves are assumed in the Financial Planning Model. Retail rates however vary from the cost of service so

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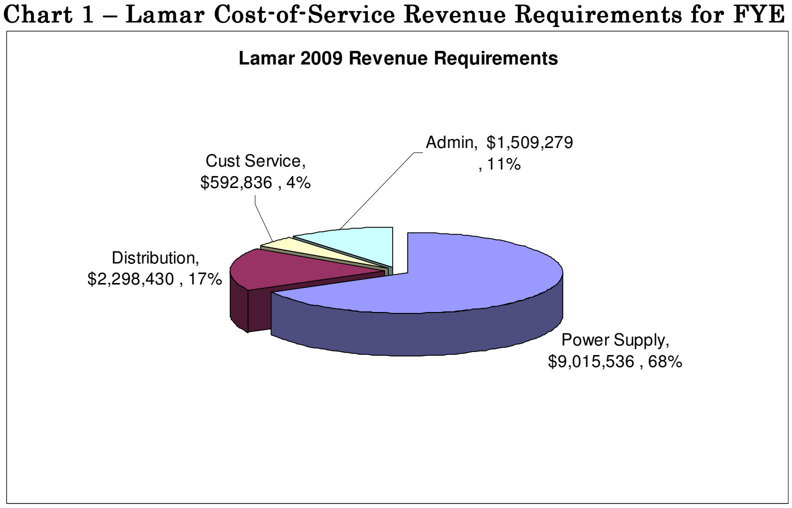
rates will be designed to bring revenues in line with the cost of service for the individual classes of customers.

About 67% of Lamar's operating costs, with a return on investment, are for power purchases and power plant expenses. ARPA will be supplying all power after Lamar's share of power from Western Area Power Administration, Colorado River Storage Project (WAPA-CRSP). The WAPA-CRSP rates increased approximately 6.0% in October 2008 and 10.7% in October 2009. Future WAPA-CRSP increases will depend on availability of water in reservoirs as they recover from an 8-year drought. With limited water stock-piles it is necessary for WAPA-CRSP to purchase replacement power to meet their contract obligations. Based on continued need to purchase replacement power and no definitive announced increase from WAPA-CRSP the assumption is an annual 4.0% annual increase after 2009. Transmission is provided by WAPA and Tri-State G&T and these are assumed to increase 3.0% per year. The combined impact of all increases in power and transmission for FYE 2009 is projected to be 13.6% and 3.2% for FYE 2010.

Below is Chart 1 showing the total revenue requirements of $13,416,081 used in the Cost of Service Study. Power Supply and Power Plant expenses with allocation of return and depreciation are $9.0 million, (68%). Distribution is 17% of total revenue requirements. Customer Service, and Administrative and General make up the balance at 4% and 11%, respectively.

Chart 1 – Lamar Cost-of-Service Revenue Requirements for FYE 2009



In addition to changes in power costs the study incorporates increases in loads and operating costs. Individual escalators for labor, supplies, capital construction, long term borrowing and earnings on reserves are used to determine the revenue requirements for the test year and for each year to FYE 2013.

Projected Revenue Requirements

A critical aspect of a cost of service analysis is determination of the utility revenue requirements. Table A (below, page 4) shows FYE 2008 actual and 2009-2013 projected statement of income and expenses. Existing rates, Budgeted Energy Cost Adjustment (ECA), Charter Appropriations

Adjustment (CAA) and other revenues are estimated in 2009 to derive $13,535,184 in revenue (line 6) resulting in $500,646 in net income (line 27) and leave cash reserves at $4,771,779 (line 66). The projections are based on LUB's Budget projections and adjustments that have or will affect each year. The revenue requirement for full cost-of-service (COS) rate recovery is $13,416,080 (line 30) includes a 5.0% return on plant investments net of depreciation. We typically recommend a net income target (line 28) between 4.0% and 9.0% return on investments (ROI) in depreciated utility plant. The current rates and the budgeted ECA are estimated to produce 5.5% ROI (line 29), and with no rate increase in the next 5 years the ROI goes negative in 2011 and drops to –6.8% in 2013. A mid-year 2009 rate adjustment is recommend to incorporate the ECA charges in to the rate base and begin the process of moving classes closer to cost of service. The Financial plan projects annual rate increases may be necessary each June through 2013 to approach net income, cash reserves and other acceptable financial targets. These projected increases are driven by assumptions of 3.5% inflationary escalators for labor, material, and 3.1% to 3.2% increase in power cost component. These will be discussed in the Findings and Recommendations section of this report.

EXECUTIVE SUMMARY

Lamar, CO
2009 Electric Financial Plan, Cost of Service and Rate Design Study

TABLE A PRO-FORMA OPERATING STATEMENTS WITHOUT RATE ADJUSTMENTS

	FYE December		2008	2009	2010	2011	2012	2013
1	**Revenues**							
2	Retail Sales		6,581,051	12,253,035	12,375,565	12,499,321	12,624,314	12,750,557
3	Charter Appropriations Adder (CAA)		1,161,601	1,212,149	1,249,003	1,261,493	1,274,108	1,286,849
4	Energy Cost Adder (ECA)		3,528,931			-	-	-
5	Other Operating Rev		-	70,000	70,700	71,407	72,121	72,842
6	**Total Revenues**		**11,271,583**	**13,535,184**	**13,695,268**	**13,832,221**	**13,970,543**	**14,110,249**
7	**Expenses**							
10	Power Purchased		6,337,637	8,330,892	8,677,467	9,025,252	9,387,021	9,767,155
12	Generation		1,039,995	72,367	74,900	77,521	80,235	83,043
14	Distribution		937,312	1,031,652	1,067,760	1,105,131	1,143,811	1,183,844
15	Customer Accounting		280,306	280,181	289,987	300,137	310,642	321,514
16	Sales Expense		13,341	15,000	15,525	16,068	16,631	17,213
17	General & Administrative		1,784,420	1,230,298	1,273,358	1,317,926	1,364,053	1,411,795
19	**Total O&M**		**10,393,011**	**10,960,390**	**11,398,997**	**11,842,036**	**12,302,393**	**12,784,564**
20	Depreciation		921,449	1,162,800	1,183,866	1,197,910	1,210,550	1,220,380
21	Non Operating Expense		12,780	6,800	6,800	6,800	6,800	6,800
22	Non Operating Income		(126,930)	(193,674)	(193,674)	(193,674)	(193,674)	(193,674)
23	Interest Income on invest.		(124,963)	(113,927)	(119,294)	(125,383)	(113,182)	(93,549)
24	Charter Appropriations(In Lieu of Tax)	13.4%	1,161,601	1,212,149	1,249,003	1,261,493	1,274,108	1,286,849
26	**Total Electric Expense**		**12,236,948**	**13,034,538**	**13,525,698**	**13,989,182**	**14,486,994**	**15,011,371**
27	**Net Operating Income**		**(965,365)**	**500,646**	**169,571**	**(156,961)**	**(516,451)**	**(901,123)**
28	**Net Income Target % of UPIS**	5.0%	**409,060**	**451,542**	**499,042**	**570,292**	**617,792**	**660,542**
29	**Net Income Actual % of UPIS**		**-11.8%**	**5.5%**	**1.7%**	**-1.4%**	**-4.2%**	**-6.8%**
30	COS Revenue Requirement			**$ 13,416,080**				
31	**Other Revenues & Expenses**							
33	Interest on existing LT Debt		$ (217,988)	$ (203,738)	$ (195,775)	$ (187,650)	$ (178,550)	$ (169,100)
40	**Total Profit / Loss**		**$ (1,183,353)**	**$ 296,908**	**$ (26,204)**	**$ (344,611)**	**$ (695,001)**	**$ (1,070,223)**
50	**Cash Inflows**							
52	Net Income		$ (1,183,353)	$ 296,908	$ (26,204)	$ (344,611)	$ (695,001)	$ (1,070,223)
55	Depreciation Expense		$ 921,449	$ 1,162,800	$ 1,183,866	$ 1,197,910	$ 1,210,550	$ 1,220,380
57	Cash Inflows		**$ (261,904)**	**$ 1,459,708**	**$ 1,157,662**	**$ 853,299**	**$ 515,549**	**$ 150,158**
58	**Cash Outflows**							
60	Capital Improvements & CWIP		$ 894,374	$ 1,000,000	$ 1,500,000	$ 1,000,000	$ 900,000	$ 700,000
61	Principal on Existing Debt		$ 240,000	$ 245,000	$ 250,000	$ 260,000	$ 270,000	$ 280,000
63	Cash Outflows		**$ 1,134,374**	**$ 1,245,000**	**$ 1,750,000**	**$ 1,260,000**	**$ 1,170,000**	**$ 980,000**
64	Change in Cash		**$ (1,396,278)**	**$ 214,708**	**$ (592,338)**	**$ (406,701)**	**$ (654,451)**	**$ (829,842)**
65	Other Cash Reserves		**$ 1,787,921**					
66	Cash Balance		**$ 4,557,070**	**$ 4,771,778**	**$ 4,179,440**	**$ 3,772,739**	**$ 3,118,288**	**$ 2,288,446**
67	Cash Balance Target		$ 4,464,985	$ 4,595,717	$ 4,748,870	$ 4,677,983	$ 4,744,466	$ 4,814,067

Projected Cash Flow

Table A, above, shows 2009 capital improvements and construction work in progress (CWIP); (line 60) is $1,000,000 and the next 4 years totals $4,100,000. By 2010 the Cash Balance (line 66) falls below the minimum reserve recommendation of $4,814,067 (line 67). Cash Reserves continue to deteriorate throughout the five-year Financial Planning Model. The minimum cash reserve is based on a recommended policy illustrated in Table B below.

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August 22, 2009

TABLE B – MINIMUM CASH RESERVE POLICY

	Cash Reserve Policy			2009
1	O&M Expenses	10,393,011	25%	2,740,098
2	Historic Utility Plant in Service (OCUP)	33,547,181	1%	345,472
3	Deposits	144,960	100%	146,410
4	Debt Service	457,988	100%	448,738
5	Current Year Capital Improvements less Borro	894,374	15%	150,000
6	Five Year Capital Improvements less Borrowin	5,294,374	15%	765,000
7	**Minimum Reserve Target**			$ 4,595,717

CASH RESERVE POLICY DISCUSSION

A minimum cash reserve target of three months or 25% of annual operation and maintenance (line 1) is a frequently used primary element of a cash reserve policy, and can be labeled as a best practice. Line 2 covers the risk and peril system facilities are exposed to, like weather, accidents and vandalisms. The 1% of utility plant is typical; however a tornado, earth-quake or ice storm prone region utility may choose a higher percentage. Deposits (line 3) and Debt Service (line 4) are contract obligations so 100% is required. The most subjective element is for capital improvements elements (Lines 5 & 6). Typically we recommend between 10% and 20%; higher percentages are recommended for utilities with more aged utility plant and where more construction is needed for replacements and renewals. A lower percent may be recommended for utilities with high growth rates and where more of construction is expansion work.

Cost of Service Summary

Table C, below, shows each class cost of service compared to the current rate $/KWh. Customer classes vary significantly from existing revenues to cost of service. The lowest cost-to-serve customer classes are LUB Usage, Sales to Public Authority, General Service Large, and Interdepartmental Sales with costs between 13.10 to 14.08 cents per kWh. The highest cost-to-service classes are Interruptible, Irrigation, Yard Lighting, and Street Lighting with costs ranging from 17.06 to 35.26 cents per kWh. A rate design to incorporate the ECA and shift costs among classes is recommended. Individual class revenues range from 85.6% under to 8.1% over cost-of-service while total revenues need be increased by 6.1% to achieve 2009 COS revenue requirements of $13,416,080 (line 30, Table A). We recommend rate adjustments, which over several years will bring classes closer to cost of service while maintaining system financial targets.

TABLE C -- AVERAGE COST PER KWH AND AVERAGE REVENUE PER KWH BY CLASS

Line	Sorted by COS $/KWh Rate Class	Current Rate and ECA Revenue	Cost of Service	Current Rate and ECA $/KWh	COS $/KWh	% Needed to COS
1	LUB Usage	-	64,661	-	0.1310	#DIV/0!
2	Sales to Public Authority	132,859	128,968	0.1358	0.1318	-2.9%
3	General Service Large	4,285,322	4,687,411	0.1287	0.1408	9.4%
4	Interdepartmental Sales	276,089	288,189	0.1352	0.1411	4.4%
5	General Service Small	1,916,402	1,957,107	0.1396	0.1426	2.1%
6	Residential	4,913,368	4,841,314	0.1531	0.1509	-1.5%
7	Interruptible	278,910	336,705	0.1318	0.1591	20.7%
8	Irrigation	563,489	712,158	0.1350	0.1706	26.4%
9	Yard Lighting	136,567	125,565	0.3248	0.2986	-8.1%
10	Street Lighting	147,594	274,005	0.1900	0.3526	85.6%
11	**Total**	**$ 12,650,601**	**$ 13,416,081**	**$ 0.1404**	**$ 0.1489**	**6.1%**

Financial Forecast and Five-Year Rate Track

Without revenue increases Table A (page 4) shows the Net Operating Income (line 27) falls below our recommended 5.0% target throughout the 5 year period (line 28) and Cash Balance starts at $4.8 million and drops to $2.3 million in 2013. This is significantly below the $4.6 to $4.8 million minimum recommendation (line 67).

Table D, below, shows budgeted 2009 revenues of $13,535,184 using the estimated ECA and CAA for 2009 and with a net zero rate change in December 2009. Then annual 2.5% rate increases are projected from June 2010 through June 2013. Net income (line 29) starts with 5.5% return in 2009 with the budgeted revenues. With the annual June 2.5% rate increase net income of 2.5% return on investment is achieved in 2013, or 2.4% points short of the 5.0% target ROI. It will take about 3.1% annual increases to achieve a 5.0% return by 2013, however the large amount of LUB generation facilities used to provide power to ARPA is skewing the plant investment higher than is needed to provide an adequate return on distribution facilities investment. We recommend a review of the Utility Plant In Service (UPIS) records to separate distribution from power production facilities and ensure the proper separation of power production facilities between Lamar and ARPA in the next update of the Financial Model in 2011.

With the recommended annual rate increases, Cash Balance (line 66) exceeds the Minimum Cash Reserve recommended target of 4.8 million by $276,000 in 2013.

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EXECUTIVE SUMMARY

Lamar, CO
2009 Electric Financial Plan, Cost of Service and Rate Design Study

TABLE D -- PROJECTED OPERATING STATEMENTS & CASH FLOW WITH FIVE-YEAR RATE TRACK

			2008	2009	2010	2011	2012	2013
b	Sales Growth Base Load		-16.8%	1.0%	1.0%	1.0%	1.0%	1.0%
c	Administration Inflation		3.5%	3.5%	3.5%	3.5%	3.5%	3.5%
d	General Inflation		3.5%	3.5%	3.5%	3.5%	3.5%	3.5%
e	Interest Rate on Cash Balances		3.0%	2.5%	2.5%	3.0%	3.0%	3.0%
f	Purchase Power Adjustments		53.7%	3.7%	3.2%	3.1%	3.1%	3.1%
g	**Rate Adjustments**		**0.0%**	**6.10%**	**2.5%**	**2.5%**	**2.5%**	**2.5%**
	Effective date			**December**	**June**	**June**	**June**	**June**
1	**Revenues**							
2	Retail Sales		6,581,051	12,253,035	12,558,133	13,006,655	13,469,307	13,944,451
3	Charter Appropriations Adder (CAA)		1,161,601	1,212,149	1,249,003	1,261,493	1,274,108	1,286,849
4	Energy Cost Adder (ECA)		3,528,931			-	-	-
5	Other Operating Rev		-	70,000	70,700	71,407	72,121	72,842
6	**Total Revenues**		**11,271,583**	**13,535,184**	**13,877,836**	**14,339,555**	**14,815,536**	**15,304,142**
7	**Expenses**							
10	Power Purchased		6,337,637	8,330,892	8,677,467	9,025,252	9,387,021	9,767,155
12	Generation		1,039,995	72,367	74,900	77,521	80,235	83,043
14	Distribution		937,312	1,031,652	1,067,760	1,105,131	1,143,811	1,183,844
15	Customer Accounting		280,306	280,181	289,987	300,137	310,642	321,514
16	Sales Expense		13,341	15,000	15,525	16,068	16,631	17,213
17	General & Administrative		1,784,420	1,230,298	1,273,358	1,317,926	1,364,053	1,411,795
19	**Total O&M**		**10,393,011**	**10,960,390**	**11,398,997**	**11,842,036**	**12,302,393**	**12,784,564**
20	Depreciation		921,449	1,162,800	1,183,866	1,197,910	1,210,550	1,220,380
21	Non Operating Expense		12,780	6,800	6,800	6,800	6,800	6,800
22	Non Operating Income		(126,930)	(193,674)	(193,674)	(193,674)	(193,674)	(193,674)
23	Interest Income on invest.		(124,963)	(113,927)	(119,294)	(130,860)	(134,044)	(140,386)
24	Charter Appropriations(In Lieu of Tax)	13.4%	1,161,601	1,212,149	1,249,003	1,261,493	1,274,108	1,286,849
26	**Total Electric Expense**		**12,236,948**	**13,034,538**	**13,525,698**	**13,983,705**	**14,466,133**	**14,964,534**
27	**Net Operating Income**		**(965,365)**	**500,646**	**352,139**	**355,850**	**349,403**	**339,608**
28	**Net Income Target % of UPIS**	**5.0%**	**409,060**	**451,542**	**499,042**	**570,292**	**617,792**	**660,542**
29	**Net Income Actual % of UPIS**		**-11.8%**	**5.5%**	**3.5%**	**3.1%**	**2.8%**	**2.6%**
30	COS Revenue Requirement			**$ 13,416,080**				
31	**Other Revenues & Expenses**							
33	Interest on existing LT Debt		$ (217,988)	$ (203,738)	$ (195,775)	$ (187,650)	$ (178,550)	$ (169,100)
40	**Total Profit / Loss**		**$ (1,183,353)**	**$ 296,908**	**$ 156,364**	**$ 168,200**	**$ 170,853**	**$ 170,508**
50	**Cash Inflows**							
52	Net Income		$ (1,183,353)	$ 296,908	$ 156,364	$ 168,200	$ 170,853	$ 170,508
55	Depreciation Expense		$ 921,449	$ 1,162,800	$ 1,183,866	$ 1,197,910	$ 1,210,550	$ 1,220,380
57	Cash Inflows		**$ (261,904)**	**$ 1,459,708**	**$ 1,340,230**	**$ 1,366,110**	**$ 1,381,403**	**$ 1,390,888**
58	**Cash Outflows**							
60	Capital Improvements & CWIP		$ 894,374	$ 1,000,000	$ 1,500,000	$ 1,000,000	$ 900,000	$ 700,000
61	Principal on Existing Debt		$ 240,000	$ 245,000	$ 250,000	$ 260,000	$ 270,000	$ 280,000
63	Cash Outflows		**$ 1,134,374**	**$ 1,245,000**	**$ 1,750,000**	**$ 1,260,000**	**$ 1,170,000**	**$ 980,000**
64	Change in Cash		**$ (1,396,278)**	**$ 214,708**	**$ (409,770)**	**$ 106,110**	**$ 211,403**	**$ 410,888**
65	Other Cash Reserves		**$ 1,787,921**					
66	Cash Balance		**$ 4,557,070**	**$ 4,771,778**	**$ 4,362,008**	**$ 4,468,118**	**$ 4,679,521**	**$ 5,090,409**
67	Cash Balance Target		$ 4,464,985	$ 4,595,717	$ 4,748,870	$ 4,677,983	$ 4,744,466	$ 4,814,067

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Table C (page 6, above) shows the current rates are 6.1% below the cost of service system wide. Residential, Sales to Public Authority and Yard Lighting are between 8.1% and 1.5% below COS. Street lighting, Irrigation, and Interruptible are 8.56%, 26.4% and 20.7% under COS, respectively and Interdepartmental Sales, General Service Small and Large are under COS by small amounts between 2.1% and 9.4. To ensure costs are more fairly recovered from customer classes, LUB is asked to consider the following recommendations:

1) Adopt the general program of rates.
    a. Rebase the current ECA into the design of December 2009 rates maintaining the Budgeted 6.1% system overall revenue change but not increasing the level of revenues. The rates are to be designed such that major rate classes are limited to a +/- 3.0% change over current billing. This means that no class would get more than a 3.0% increase or less than a -3.0% decrease in current annual billings.
    b. Consider a 2.5% rate increase for June 2010 with the major rate classes limited to the 2.5% +/- 3.0% change. This means that no class would get more than a 5.5% increase or less than a -0.5% reduction.
    c. Retain the ECA clause in the Rate Ordinance such that the LUB can invoke it in case significant revenue changes are necessary because of substantial increases in the cost of power or other emergencies that are estimated to be greater than a 10% deviation in FY power costs budgeted. For 2010 this is approximately $875,000 in cost deviation from budget which represents a 12 month ECA of about 1 cent/KWh or changes an average residential customer's bill by about $6.30/month.
    d. Determine the Charter Appropriation Adjustment (CAA) at time of Budget such that the annual CAA expense is divided by the annual estimated KWh sales and charge the same amount per KWh all year. Any significant difference in collections vs. budget and actual can be carried forward to the next budget year.

2) The Financial Plan and rate changes should be reviewed every other year and adjusted as necessary to recover higher or lower than assumed revenue, load and cost escalations. Rate adjustments for FY 2011 and 2012 can then be designed by NMPP Energy as part of the 4 year Cost of Service and Rate Design Study and Consulting service agreement to continue the process of bringing classes closer to cost of service, maintaining net operating income of at about 5.0% of distribution plant investment, and retaining a minimum cash reserve as determined by the Cash Reserve Policy.

3) Consider proceeding with the rate design in Appendix A. This design combines the Budgeted 2009 ECA into a new base rate and is planned to be effective July 1, 2009. Also included in Appendix A is a 2.5% rate increase over 2009 revenues to be effective June 1, 2010. These rate adjustments will move classes closer to a more fair and equitable recovery of costs identified in the COS study.

4) Holly Transmission Wheeling rate. The 5.0% line loss currently used is too high and LUB staff re-estimated it to 3.0% for the 30 mile 24.5 KV facility. The current billing is $3.00/MWh compared to other ARPA towns charging 2% losses and $3.50/MWH for similar services.

    The industry standard is to bill for transmission on $ per KW-month. The recommended 2009 COS rate for this line is $2.00/KW-mo. This rate will result in an annual $9,160 increase to Holly's current billing of $20,500.

The analysis also shows that a 69KV line running west to Las Animas is used as a back-up for Southeast Power Cooperative and Las Animas. Analysis of the current operation of the line and how this fits with current agreements for payment needs to be conducted to determine who benefits from this line. After that, the $2.00/KW rate may be considered as appropriate.

Direction from the LUB meeting August 25, 2009

The LUB determined on August 25, 2009 to adopt the above recommendation and have 2.5% rate increases also designed for 3 additional years to be effective June 2011, June 2012, and June 2013. Such rates could be supplemented by the ECA as recommended above. All 5 years of rate charges are incorporated the in draft resolution found in Appendix A.

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SECTION II. STUDY PURPOSE AND APPROACH

The purpose of the study is to help the LUB establish retail electric rates that are consistent with several goals. These goals were established based on consultations with Utility staff and are as follows:

- The rates should be fair, reasonable and non-discriminatory.
- The rates should collect sufficient revenue to cover expenses.
- The rates should preserve the long-term financial integrity of the Utility.
- The rates should allow the Utility to maintain stable rates over the long term.
- The rates should be compared to neighboring utilities rates and if practical the design should address economic development and customer retention objectives.

The study approach involves completing several steps. Utility staff provided finance and operations data, including expenses, customer usage, and existing rate schedules. Actual and Projection of expenses were completed for fiscal year ending December 2008 (FYE) through FYE 2013.

The level of rates was established based on the five-year Financial Plan determination of necessary revenue requirements to achieve net-income and cash reserve goals. The detailed findings of the study and the proposed rate schedule comparisons are presented below. The Financial report results were presented to the LUB on April 28, and August 11, 2009 with recommendations as stated above, however subject to legal and staff review.

Projected Operating Results

Table D above shows the projected operating results in a utility-basis 5-year Planning Proforma. The multi-year approach is necessary to determine a rate increase plan that meets financial targets. Table 1 below presents a Cash Basis of the projected operating results at existing retail rates, (Tables A and D above are on a Utility Basis.)

Table 1
Projected Operating Results
Existing Rates
Lamar, CO
2008 Cost-of-Service and Rate Design Study

		Actual FY ending June		Budget	Test Year	Proposed			
Line	**Description**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
1	**Operating Revenues**								
2	Retail Sales - Existing Rates	$ 9,778,232	$ 10,163,628	$ 6,581,051	$ 12,253,035	$ 12,375,565	$ 12,499,321	$ 12,624,314	$ 12,750,557
3	Charter Appropriations Adder (CAA)	966,604	966,604	1,161,601	$ 1,212,149	-	-	-	-
3	Energy Cost Adder			3,528,931	$ -	1,224,270	1,236,513	1,248,878	1,261,367
4	Other Operating Revenue	-	-	-	$ 70,000	70,700	71,407	72,121	72,842
5	**Total Operating Revenue**	**$ 10,744,836**	**$ 11,130,232**	**$ 11,271,583**	**$ 13,535,184**	**$ 13,670,535**	**$ 13,807,241**	**$ 13,945,313**	**$ 14,084,766**
6									
7	**Expenses**								
8	Operating Expenses								
9	Power Purchased	$ 4,881,681	$ 5,267,162	$ 6,337,637	$ 8,330,892	$ 8,677,467	$ 9,025,252	$ 9,387,021	$ 9,767,155
10	ARPA Plant Operation Payment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Generation	664,166	$ 503,939	$ 1,039,995	$ 72,367	$ 74,900	$ 77,521	$ 80,235	$ 83,043
12	Distribution	856,011	$ 1,021,650	$ 937,312	$ 1,031,652	$ 1,067,760	$ 1,105,131	$ 1,143,811	$ 1,183,844
13	Customer Accounting	292,790	$ 342,373	$ 280,306	$ 280,181	$ 289,987	$ 300,137	$ 310,642	$ 321,514
14	Sales Expense	10,798	$ 8,039	$ 13,341	$ 15,000	$ 15,525	$ 16,068	$ 16,631	$ 17,213
15	General & Administrative	1,140,894	$ 1,210,147	$ 1,784,420	$ 1,230,298	$ 1,273,358	$ 1,317,926	$ 1,364,053	$ 1,411,795
16	**Total Operating Expenses**	**$ 7,846,340**	**$ 8,353,310**	**$ 10,393,011**	**$ 10,960,390**	**$ 11,398,997**	**$ 11,842,036**	**$ 12,302,392**	**$ 12,784,564**
17									
18	**Total Operating & Personnel Expenses**	**$ 7,846,340**	**$ 8,353,310**	**$ 10,393,011**	**$ 10,960,390**	**$ 11,398,997**	**$ 11,842,036**	**$ 12,302,392**	**$ 12,784,564**
19									
20	**Operating Income**	**$ 2,898,496**	**$ 2,776,922**	**$ 878,572**	**$ 2,574,794**	**$ 2,271,538**	**$ 1,965,205**	**$ 1,642,921**	**$ 1,300,202**
21									
22	**Non-Operating Revenue/(Expense)**								
23	Depreciation	(1,105,069)	(1,140,000)	(921,449)	(1,162,800)	(1,192,643)	(1,222,485)	(1,252,328)	(1,282,171)
24	Interest Income	92,877	112,172	45,991	48,819	25,317	26,285	12,591	-
25	Non Operating Income	551,567	314,698	205,902	193,674	193,674	193,674	193,674	193,674
26	Non Operating Expense	(215,335)	(115,583)	(217,988)	(203,738)	(195,775)	(187,650)	(178,550)	(169,100)
27	Charter Appropriations(In Lieu of Tax)	-	(966,604)	(1,161,601)	(1,212,149)	(1,224,270)	(1,236,513)	(1,248,878)	(1,261,367)
28									
29									
30	**Total Non-Operating Revenue/(Expense)**	**$ (675,960)**	**$ (1,795,317)**	**$ (2,049,145)**	**$ (2,336,194)**	**$ (2,393,697)**	**$ (2,426,689)**	**$ (2,473,491)**	**$ (2,518,964)**
31									
32	**Net Income before Transfers**	**$ 2,222,536**	**$ 981,605**	**$ (1,170,573)**	**$ 238,600**	**$ (122,159)**	**$ (461,484)**	**$ (830,571)**	**$ (1,218,762)**
33									
34	**Net Transfers To/(From) Electric Utility**	**$ (966,604)**	**$ (966,604)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
35									
36									
37									
33	**Net Income**	**$ 1,255,932**	**$ 15,001**	**$ (1,170,573)**	**$ 238,600**	**$ (122,159)**	**$ (461,484)**	**$ (830,571)**	**$ (1,218,762)**

SECTION III. STUDY BACKGROUND

The LUB's Electric Utility

The Utility serves approximately 5,830 customers located in and around the City of Lamar, CO. There are approximately 4,250 residential, 1,475 commercial, and 105 industrial customers.

The Utility's peak demand is approximately 25 MW with an annual load factor of about 43.7%. Energy sales have increased an average annual rate of approximately 1.5% over the last 3 years. However, a 1.0% growth for energy and peak demands is assumed for 2009 and beyond because of the economic down turn and the current trend toward conservation.

Load factor is a measure of how much energy a customer (or group of customers) uses in a year in relation to the annual peak. Improving system load factor is one way to reduce the Utility's average power costs. A customer that uses the same amount of energy every hour would have a 100% load factor. The typical annual load factor for a municipal utility is approximately 40-50%. The LUB has an annual load factor of 43.7% that could be increased by lower summer peaks or shift on-peak sales to non-peak periods. This can also be done for example through the conversion of existing older air-conditioning units to heat pumps. This will increase winter season uses and reduce summer peak loads and usage.

Power Supply Arrangements

Power supply costs are the largest single expense item for a utility. For 2009 LUB is assumed to purchase its total capacity and energy requirements from WAPA-CRSP and ARPA using the Wholesale rate the ARPA Board approve for April 1, 2009. The ARPA rate is assumed to be a good approximation for the cost of power received from MEAN under the extended Market Power Purchase agreement that is currently in place while the Lamar Repowering Project completes its start-up phase. The LUB's power supply resources are delivered over WAPA and other transmission arranged for by ARPA. ARPA provides supplemental capacity and energy over the fixed WAPA deliveries and includes the output of ARPA and Lamar owned wind generation connected to the Lamar distribution system and the Lamar Re-powered Power Plant that is operated by LUB for ARPA. The cost of power and energy from WAPA and ARPA for the test year FYE 2009 is estimated to be 8.672 ¢/kWh, including transmission.

SECTION IV. PROJECTED OPERATING RESULTS

Key Parameters

Several parameters were established in calculating the test year revenue requirements and projected operating results. These parameters were established in consultation with the LUB, MEAN and ARPA staff. The following parameters were used and unless otherwise noted the escalation rates remained constant in FYE 2009-2013:

- Data is presented on a Calendar year Fiscal Year basis January through December.
- Escalation rates of 3.5% were used for operation and maintenance (other than power supply).
- Power supply combined costs from WAPA, ARPA including Transmission are projected to escalate on average 13.6% in 2009, and 3.2% for each year through 2013.
- WAPA rates for hydro-electric resource will increase approximately 10.7% in October 2009 are assumed 4% annually thereafter.
- Demand and energy usage are projected to grow 1.0% annually with load control and conservation programs.
- Non-retail revenue (other than interest income) is projected to increase 1.0% annually.
- Interest income is based on previous year cash balance earning 2.5% in 2009-2010 and increasing to 3.0% for years beyond.

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SECTION V: COST OF SERVICE ANALYSIS

The cost of service analysis involves several steps. Costs are assigned to a particular utility function and classified as demand related, energy related or customer related. This process is referred to as "functionalization" and "classification." The functionalized costs are allocated to each customer class on the basis of energy usage, peak demand, or number of customers. The allocated costs are compared to revenues from existing rates to assess the need for rate changes for individual rate classes.

Functionalization

Functionalization is the process of assigning the Electric Utility's revenue requirements (expenses) to utility functions. The functions for a particular utility vary based on the size and the types of services provided. The following is a list of common functions:

- Production
- Transmission
- Distribution
- Meters
- Services
- Billing and Customer Service
- Street Lighting

Costs are sometimes "sub-functionalized" within particular categories. For example, distribution expenses may be sub-functionalized to primary and secondary voltages. Generation may be sub-functionalized to purchased power and generation related costs, or to summer and winter purchased power costs.

Allocation of Costs

The goal of this task is to determine the level each rate class is responsible for utility expenses. The costs for each function are determined and then allocated to the various customer classes using generally accepted industry methodologies.

There are several different methodologies used to allocate costs. For example, energy related costs are typically allocated based on the amount of energy used by each customer class adjusted for losses. Demand related expenses are typically allocated based on the coincidental peak (customer class peak at the time of the system peak) or non-coincidental peak (customer class peak occurring at any time). Customer related expenses, such as billing and accounting, are typically allocated based on number of bills sent out or weighted customer counts.

Some expenses can be directly allocated to a class when that class receives all the benefit, for example the expenses to operate a Residential Energy Audit Program may be directly assigned to the Residential classes.

Other expenses and non-retail revenues may not be easily attributed to demand, energy, direct or customer related costs. These expenses include transfers to the general fund, miscellaneous outside services, and other miscellaneous income. There are several accepted methodologies for allocating these types of expenses however the most widely used is to allocate these on the basis of the subtotal of previously allocated and assigned expenses. This is the method used in this study unless otherwise stipulated in the study.

Cost of Service Results

Table 2 (page 13) summarizes the cost of service for each rate class for the summer and winter season. The summer season is defined as June through September, and the winter season is defined as October through May. The seasonal definition is based on the load characteristics for the Electric Utility. Table 2 lists the major components of the cost of service, including production, transmission, distribution, and customer service.

Table 3 (page 13) compares the cost of service (COS) to revenues from existing rates on an annual basis. Table 4 (see page 14) compares the cost of service revenues from existing rates on a seasonal basis. Since the LUB's has non-seasonal rates, the seasonal comparison of current revenue to cost of service differs substantially. For the summer period current rates recover $1,088,244 less than COS and in the winter $999,234 less than COS. This is largely because MEAN power rates seasonal reflect the higher cost of power in the summer than in the winter.

Unbundling

Unbundled rates represent what a distribution utility will charge for each of the several services provided in the delivery of power provide by another supplier. If power supply service was open and individual consumers could shop for other providers, the distribution utility will need to charge for use of its transmission and distribution lines, transformers, meters and services, and customer service and billing.

An analogy to unbundled electric service is telephone service. Local telephone service is billed separately from long distance service. The rates for local service may be further separated into basic service, additional services like call waiting, caller ID, and other charges such as local 911 service and Universal Service Funds. Long distance service is billed by a separate provider and is charged on a per-minute basis. In an open access electric system, power supply service is offered by competing providers, much like long distance service is offered in the telephone business.

The calculation of unbundled rates was not included in the scope of this study; however, it is a fairly simple expansion of the rate design process to calculate unbundled rates for each rate class. At this point, state legislatures in the Plains states have not deregulated electric supply and 'wires' service and do not require utilities to offer unbundled electric rates.

Table 5 and 5A (page 15) summarizes the unbundled costs for several commonly identified distribution and transmission services that may be offered. This list of services is subject to change in the future, if legislation is enacted to require unbundling of electric service. Unbundled costs are provided for information purposes and may have been used in the design of the purposed rates. These costs may be useful to management in the operation and administration of electric service.

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Table 2
Lamar, CO
Allocated Cost of Service by Season

Line		Residential	General Service Small	Yard Lighting	Public Authority	Interdepartmental Sales	Irrigation	LUB Usage	Interruptible	General Service Large	Street Lighting	Total
1	**Summer Costs**											
2	Production	$ 1,382,164	$ 512,378	$ 11,103	$ 34,008	$ 101,940	$ 266,081	$ 17,423	$ 94,718	$ 1,355,386	$ 20,435	$ 3,795,637
3	Transmission	14,418	6,105	96	433	929	1,680	195	2,314	22,923	316	49,410
4	Primary Distribution	144,029	39,039	4,331	2,236	9,263	63,672	1,074	6,343	94,256	483	364,726
5	Secondary Distribution	176,010	54,655	6,311	3,121	12,896	85,149	1,500	8,813	131,018	352	479,825
6	Lighting	-	-	-	-	-	-	-	-	-	52,259	52,259
7	Customer	148,968	59,742	12,774	2,163	4,407	16,129	1,177	673	17,321	491	263,844
8	Miscellaneous	236,478	85,171	4,388	5,319	16,407	54,850	2,709	14,306	205,462	9,423	634,511
9	**Total Summer Costs**	**2,102,068**	**757,089**	**39,002**	**47,281**	**145,842**	**487,561**	**24,076**	**127,167**	**1,826,367**	**83,758**	**$ 5,640,211**
10												
11	**Winter Costs**											
12	Production	1,696,018	794,277	24,764	58,802	95,748	148,274	28,357	151,073	2,075,064	49,412	$ 5,121,789
13	Transmission	14,212	6,017	94	427	916	1,656	192	2,281	22,594	311	48,701
14	Primary Distribution	197,150	60,433	10,811	3,730	8,703	9,917	2,135	13,086	170,233	5,969	482,168
15	Secondary Distribution	225,772	84,806	15,606	5,211	12,152	7,225	2,982	18,181	236,650	7,652	616,238
16	Lighting	-	-	-	-	-	-	-	-	-	104,518	104,518
17	Customer	297,936	119,484	25,549	4,326	8,813	32,258	2,353	1,345	34,642	982	527,688
18	Miscellaneous	308,159	134,999	9,738	9,190	16,014	25,267	4,566	23,573	321,861	21,402	874,768
19	**Total Winter Costs**	**2,739,246**	**1,200,017**	**86,563**	**81,686**	**142,347**	**224,597**	**40,585**	**209,538**	**2,861,044**	**190,247**	**$ 7,775,869**
20												
21	**Total Cost of Service**	**$ 4,841,314**	**$ 1,957,107**	**$ 125,565**	**$ 128,968**	**$ 288,189**	**$ 712,158**	**$ 64,661**	**$ 336,705**	**$ 4,687,411**	**$ 274,005**	**$ 13,416,081**

Table 3
Comparison of Cost of Service
to Revenue from Existing Rates
FYE 2009

Line	Rate Class	Revenue Existing Rates	CAA Rev	Total Current Rate and ECA + CAA Revenue	Cost of Service	Current revenue difference from COS $	Current revenue difference from COS %
1	Residential	$ 4,913,368	$ 410,120	4,913,368	$ 4,841,314	(72,055)	-1.5%
2	General Service Small	1,916,402	178,951	1,916,402	1,957,107	40,704	2.1%
3	Yard Lighting	136,567	5,543	136,567	125,565	(11,002)	-8.1%
4	Sales to Public Authority	132,859	12,853	132,859	128,968	(3,892)	-2.9%
5	Interdepartmental Sales	276,089	25,818	276,089	288,189	12,099	4.4%
6	Irrigation	563,489	52,303	563,489	712,158	148,669	26.4%
7	LUB Usage	-		-	64,661	64,661	#DIV/0!
8	Interruptible	278,910	27,935	278,910	336,705	57,795	20.7%
9	General Service Large	4,285,322	433,857	4,285,322	4,687,411	402,088	9.4%
10	Street Lighting	147,594	10,245	147,594	274,005	126,411	85.6%
11	**Total**	**$ 12,650,601**	**$ 1,157,624**	**$ 12,650,601**	**$ 13,416,081**	**$ 765,479**	6.1%

Table 4
Comparison of Cost of Service to Revenue from Existing Rates

Summer

Line	Rate Class	Revenue Existing Rates	Cost of Service	Difference $	Difference %
1	Residential	$ 1,988,708	$ 2,102,068	$ 113,360	5.7%
2	General Service Small	678,298	757,089	78,791	11.6%
3	Yard Lighting	45,575	39,002	(6,573)	-14.4%
4	Sales to Public Authority	43,962	47,281	3,320	7.6%
5	Interdepartmental Sales	130,246	145,842	15,596	12.0%
6	Irrigation	309,419	487,561	178,143	57.6%
7	LUB Usage	-	24,076	24,076	#DIV/0!
8	Interruptible	95,124	127,167	32,043	33.7%
9	General Service Large	1,549,524	1,826,367	276,843	17.9%
10	Street Lighting	48,828	83,758	34,930	71.5%
11	**Total**	**$ 4,889,684**	**$ 5,640,211**	**$ 750,528**	**13.3%**

Winter

Line	Rate Class	Revenue Existing Rates	Cost of Service	Difference $	Difference %
1	Residential	$ 2,924,661	$ 2,739,246	$ (185,414)	-6.8%
2	General Service Small	1,238,104	1,200,017	(38,087)	-3.2%
3	Yard Lighting	90,992	86,563	(4,429)	-5.1%
4	Sales to Public Authority	88,898	81,686	(7,211)	-8.8%
5	Interdepartmental Sales	145,843	142,347	(3,497)	-2.5%
6	Irrigation	254,070	224,597	(29,474)	-13.1%
7	LUB Usage	-	40,585	40,585	100.0%
8	Interruptible	183,786	209,538	25,752	12.3%
9	General Service Large	2,735,798	2,861,044	125,246	4.4%
10	Street Lighting	98,766	190,247	91,481	48.1%
11	**Total**	**$ 7,760,918**	**$ 7,775,869**	**$ 14,951**	**0.2%**

Table 5
Lamar, CO
Unbundled Cost of Service

Line		Residential	General Service Small	Yard Lighting	Sales to Public Authority	Interdepartmental Sales	Irrigation	LUB Usage	Interruptible	General Service Large	Street Lighting	Total
1	**Power Supply**											
2	Demand	$ 531,541	$ 216,723	$ 2,473	$ 15,106	$ 35,761	$ 83,454	$ 6,588	$ 77,731	$ 786,474	$ 8,138	$ 1,763,989
3	Energy	2,546,640	1,089,933	33,394	77,705	161,927	330,901	39,191	168,059	2,643,976	61,709	7,153,436
4												
5	**Transmission by Others**											
6	Lines	28,630	12,122	190	860	1,846	3,337	387	4,595	45,517	627	98,111
7	Substation	-	-	-	-	-	-	-	-	-	-	-
8												
9	**Distribution**											
10	Primary	497,347	151,846	17,980	10,129	28,325	101,094	5,289	34,622	468,359	18,938	1,333,929
11	Secondary	585,690	212,890	26,024	14,148	39,489	126,901	7,387	48,101	651,069	23,493	1,735,192
12												
13	**Customer Related**											
14	Services	153,051	56,763	29,694	2,286	4,324	19,667	1,207	1,305	18,147	4,090	290,534
15	Meters	335,434	186,607	-	7,516	14,215	25,862	3,969	1,542	49,714	-	624,858
16	Billing and Accountin	162,981	30,223	15,810	1,217	2,302	20,943	643	749	24,155	231	259,254
17												
18	**Total Cost of Service**	**$ 4,841,314**	**$ 1,957,107**	**$ 125,565**	**$ 128,968**	**$ 288,189**	**$ 712,158**	**$ 64,661**	**$ 336,705**	**$ 4,687,411**	**$ 274,005**	**$ 13,416,081**

Table 6
Lamar, CO
Summary of Cost of Service Rate Elements

Line		Residential	General Service Small	Yard Lighting	Sales to Public Authority	Interdepartmental Sales	Irrigation	LUB Usage	Interruptible	General Service Large	Street Lighting	Total
1	**Demand**											
2	Cost	1,255,831	473,587	8,786	32,164	86,896	255,820	15,471	144,615	1,635,000	65,700	**3,973,870**
3	Energy/Demand Usage	32,091,026	13,727,117	420,480	978,419	2,041,817	4,175,517	493,613	10,056	99,970	777,000	**90,121,384**
4	Rate ($/kWh), ($/kW-mo)	0.0391	0.0345	-	0.0329	0.0426	0.0613	0.0313	14.38	16.35	-	**0.0441**
5												
6	**Energy**											
7	Cost	2,869,446	1,228,090	37,627	87,555	182,453	372,845	44,159	189,362	2,979,121	195,698	**8,186,355**
8	Energy Usage	32,091,026	13,727,117	420,480	978,419	2,041,817	4,175,517	493,613	2,116,273	33,300,121	777,000	**90,121,384**
9	Rate ($/kWh)	0.0894	0.0895	-	0.0895	0.0894	0.0893	0.0895	0.0895	0.0895	-	**0.0908**
10												
11	**Customer**											
12	Cost	716,037	255,430	79,151	9,249	18,840	83,493	5,031	2,728	73,290	12,607	**1,255,856**
13	Number of Customers	4,253	753	507	27	56	116	15	3	104	1	**5,834**
14	Rate ($/month)	14.03	28.26	13.02	28.26	28.26	59.99	28.26	71.08	58.85	0.93	**17.94**

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SECTION VI. RATE DESIGN

Several factors affect the development of new rates, including:

- Rate structures that are easy to understand and administer
- Long-term rate stability.
- Price signals that encourage use in low cost periods and discourage use in high cost periods.
- Promote of economic development when applicable.

Overall Rate Changes

The proposed rates are intended to help meet the objectives listed above without degrading the financial integrity of the utility. Appendix A is a draft Rate Ordinance for the proposed rates.

Other Rate Design Changes

Appendix B includes the rate recommendations from this study. Several changes from existing rate design are recommended. These changes are as follows:

1. Seasonal Rates: Seasonal rates are not recommended at this time. ARPA does not bill power cost on a seasonal basis however WAPA-CRPS does. If seasonal rates were design the summer period would be June through September and winter period is the other 8 months. Seasonal rates tend to provide a more appropriate price signal to customer when applied to bills rendered in June, July, August and September because of the higher use in those months for air conditioning. This summer and winter bill can help customers to better understand that power cost more during peak summer period and help them to make more appropriate decisions about the purchase and use of energy using equipment and appliances.

2. Sub-transmission Rate: The Current rate form is a $/MWH charge. It is recommended to use the industry standard of $/KW month rate form. This rate is recommended to be applied to the deliveries to Holly and could be used for charges related to the users of the 69 KV line running west to Las Animas.

3. Incorporate ECA within Rates: The revenue generated from the ECA is incorporated into the rate design. Rates are set to recover costs in a fair and equitable manner. The ECA option should be left available for LUB to invoke on an emergency basis to recover unbudgeted increases in expenses or loss of revenue.

4. Move Classes Closer to Cost of Service: The cost to serve customers for each cost component is different for each class of customers as shown in Table 6 (page 17). Rates should be designed to recover these costs in a fair and equitable manner. The proposed rate adjustments are design to move rates toward COS.

- For Example the on-going **'availability to serve'** cost for electric service to residential customers includes the meter, the service wires, the line transformer and allocated portions of the distribution system that are dedicated to each customer. These facilities cost plus the monthly cost to read the meter, bill, collect and answer questions is about $14 per month. LUB's 'availability to serve' costs compares to the current customer charge of $7.50. Therefore the rate is under-collecting from small use customers, (less than 100 kWh and over collecting from the typical 650 kWh and larger usage customers. The recommended rates are design to begin the transition toward COS by increasing customer charges by $2 to $4 in 2010 and again in 2011. Future year changes continue the process.

5. Incorporate the Interruptible rate class of 3 accounts into the General Service Large rate class. LUB has not invoked an interruption for many years and the customers no longer have ability to be interrupted for the periods that are of value to LUB. The Interruptible class is 14.9% below COS and other customers are subsidizing this small group of customers.

Table 7
Comparison of Revenue from Existing Rates to Revenue from Proposed Rates

Line	Rate Class	Revenue Existing Rates	Revenue Proposed Rates	Difference $	Difference %
1	Residential	4,913,368	4,766,903	(146,465)	-3.0%
2	General Service Small	1,916,402	1,873,323	(43,079)	-2.2%
3	Yard Lighting	136,567	132,508	(4,059)	-3.0%
4	Sales to Public Authority	132,859	133,058	198	0.1%
5	Interdepartmental Sales	276,089	278,886	2,796	1.0%
6	Irrigation	563,489	580,542	17,053	3.0%
7	General Service & Interrptible	4,564,233	4,734,077	169,844	3.7%
8	Street Lighting	147,594	152,030	4,437	3.0%
9	**Total**	**$ 12,650,601**	**$ 12,651,327**	**$ 725**	**0.0%**

Table 8
Comparison of Revenue from Year 1 to Year 5 Rates

Line	Rate Class	Revenue Year 1 Rates	Revenue Year 2 Rates	Revenue Year 3 Rates	Revenue Year 4 Rates	Revenue Year 5 Rates	Difference $	Difference %	Percent Change curr. to Yr1	Yr1 to Yr2	Yr2 to Yr3	Yr3 to Yr4	Yr4 to Yr5
1	Residential	4,766,903	4,827,567	4,886,490	4,943,442	5,000,393	233,490	4.9%	-3.0%	1.3%	1.2%	1.2%	1.2%
2	General Service Small	1,873,323	1,912,892	1,948,080	1,979,481	2,007,165	133,842	7.1%	-2.2%	2.1%	1.8%	1.6%	1.4%
3	Yard Lighting	132,508	132,823	132,823	132,823	132,823	316	0.2%	-3.0%	0.2%	0.0%	0.0%	0.0%
4	Sales to Public Authority	133,058	133,794	134,776	135,757	136,903	3,845	2.9%	0.1%	0.6%	0.7%	0.7%	0.8%
5	Interdepartmental Sales	278,886	286,495	294,137	302,008	310,783	31,897	11.4%	1.0%	2.7%	2.7%	2.7%	2.9%
6	Irrigation	580,542	611,719	645,332	679,919	717,081	136,539	23.5%	3.0%	5.4%	5.5%	5.4%	5.5%
7	General Service & Interruptib	4,734,077	4,908,154	5,094,454	5,288,311	5,488,383	754,306	15.9%	3.7%	3.7%	3.8%	3.8%	3.8%
8	Street Lighting	152,030	156,657	161,361	166,165	171,160	19,129	12.6%	3.0%	3.0%	3.0%	3.0%	3.0%
9	**Total**	**$ 12,651,327**	**$ 12,970,101**	**$ 13,297,453**	**$ 13,627,907**	**$ 13,964,692**	**$ 1,313,365**	10.4%	0.0%	2.5%	2.5%	2.5%	2.5%

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Appendix Table A-1
Proposed Rate Schedule

Electric Rates effective with first billing after the dates shown below Lamar, CO					
	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Residential					
Customer Charge $ per Month	$9.50	$10.50	$10.90	$11.45	$12.00
All KWh (per kWh)	$ 0.1197	$ 0.1200	$ 0.1212	$ 0.1221	$ 0.1230
General Service Small					
Customer Charge $ per Month	$16.00	$18.10	$18.50	$20.00	$22.00
All KWh (per kWh)	$ 0.1122	$ 0.1137	$ 0.1160	$ 0.1173	$ 0.1180
General Service Large					
Customer Charge $ per Month	$21.00	$23.00	$27.00	$31.00	$33.00
All KWh (per kWh)	$ 0.08500	$ 0.08860	$ 0.09123	$ 0.09485	$ 0.09965
Demand	$11.00	$11.40	$12.20	$12.75	$13.00
Sales to Public Authority					
Customer Charge $ per Month	$6.75	$9.00	$12.00	$15.00	$18.50
All KWh (per kWh)	$ 0.1200	$ 0.1200	$ 0.1200	$ 0.1200	$ 0.1200
Interdepartmental					
Customer Charge $ per Month	$14.25	$15.25	$16.30	$18.00	$20.75
All KWh (per kWh)	$ 0.1182	$ 0.1216	$ 0.1250	$ 0.1283	$ 0.1317
Irrigation					
Customer Charge $ per Month	$12.00	$12.50	$13.25	$15.00	$18.00
All KWh (per kWh)	$ 0.1213	$ 0.1286	$ 0.1364	$ 0.1441	$ 0.1520
Interruptible (Accts. Move to GSL)					
Customer Charge $ per Month	$21.00	$23.00	$27.00	$31.00	$33.00
All KWh (per kWh)	$ 0.0850	$ 0.0886	$ 0.0912	$ 0.0949	$ 0.0997
Demand	$11.00	$11.40	$12.20	$12.75	$13.00
Street Lighting	$/month	$/month	$/month	$/month	$/month
100W Sodium =40kWh/mo.	$ 8.60	$ 8.90	$ 9.20	$ 9.50	$ 9.80
250W Sodium =100kWh/mo.	$ 15.25	$ 15.70	$ 16.25	$ 16.75	$ 17.30
400W Sodium =160kWh/mo.	$ 21.20	$ 21.85	$ 21.50	$ 22.20	$ 22.95
175W Mercury =70kWh/mo.	$ 12.00	$ 12.40	$ 12.75	$ 13.10	$ 13.55
175W Metal Halide W/o fixture =70kWh/m	$ 11.00	$ 11.30	$ 11.70	$ 12.05	$ 12.40
Area or Yard Lighting	$/month	$/month	$/month	$/month	$/month
100 W High Pressure Sodium =40kWh/mo	$ 17.60	$ 17.60	$ 17.60	$ 17.60	$ 17.60
250 W High Pressure Sodium =100kWh/m	$ 24.45	$ 24.60	$ 24.60	$ 24.60	$ 24.60
300 W Quartz =120kWh/mo.	$ 22.80	$ 27.20	$ 27.20	$ 27.20	$ 27.20
500 W Quartz =200kWh/mo.	$ 37.75	$ 36.80	$ 36.80	$ 36.80	$ 36.80
175 W Metal Halide =70kWh/mo.	$ 21.35	$ 21.70	$ 21.70	$ 21.70	$ 21.70
175 W Mercury Vapor =70kWh/mo.	$ 21.35	$ 20.60	$ 20.60	$ 20.60	$ 20.60
400 W Mercury Vapor =160kWh/mo.	$ 30.15	$ 31.45	$ 31.45	$ 31.45	$ 31.45

Appendix Table B-1
Typical Bill Comparison
Existing vs. Proposed Rates
Residential
City of Lamar

Line	Summer Rates								
	Existing					Proposed			
1	CAA Rate		cts/kWh		1.28	Minimum Bill		$	-
2	Customer Charge			$	7.50	Customer Charge		$	9.50
3	Energy	ECA Rate	0.0543	cts/kWh		Energy		cts/kWh	
		CAA Rate	0.0128				0.0137		
8	Excess			$	7.41			$	11.97

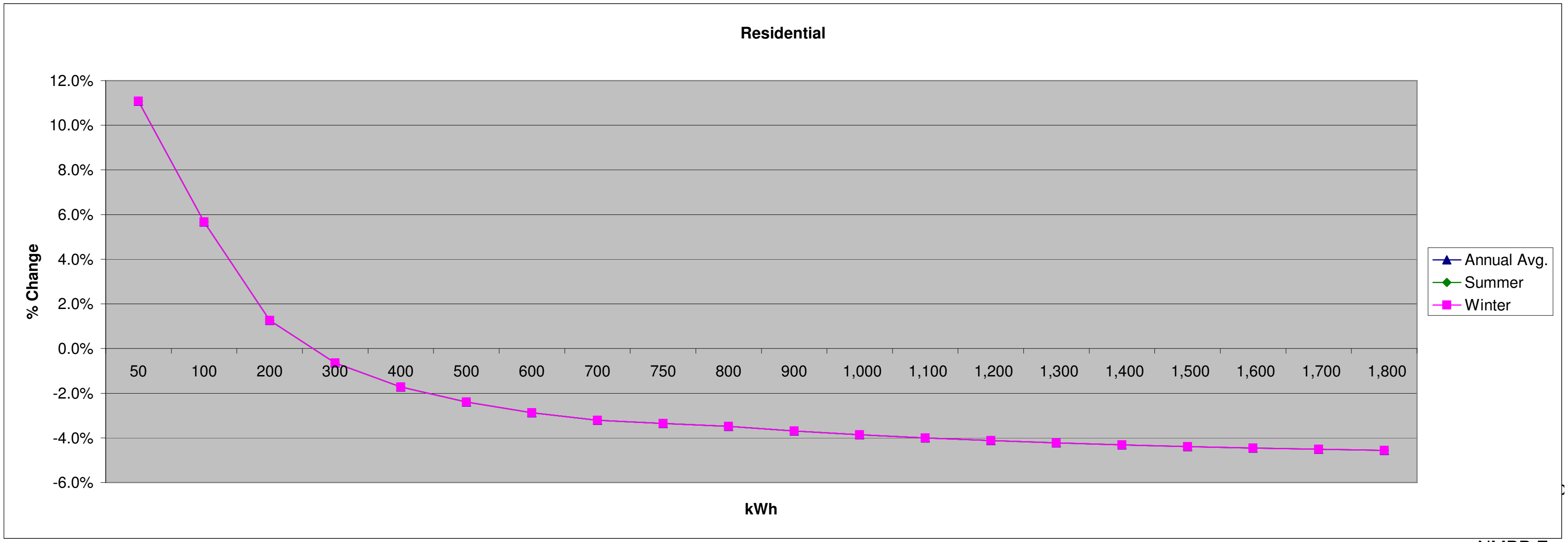
Winter Rates								
Existing					Proposed			
Minimum Bill			$	-	Minimum Bill		$	-
Customer Charge			$	7.50	Customer Charge		$	9.50
Energy	ECA Rate	0.0543	cts/kWh		Energy		cts/kWh	
	CAA Rate	0.0128				0.0137		
Excess			$	7.41			$	11.97

Existing Rate Revenue	$ 4,913,368
Proposed Rate Revenue	$ 4,766,903
Proposed Revenue Increase	-3.0%

Line	Monthly Usage (kWh)	Summer Monthly Bill Existing	Summer Monthly Bill Proposed	% Inc. / (Dec.)
9	50	$ 14.56	$ 16.17	11.1%
10	100	$ 21.62	$ 22.84	5.7%
11	200	$ 35.74	$ 36.19	1.3%

Line	Monthly Usage (kWh)	Winter Monthly Bill Existing	Winter Monthly Bill Proposed	% Inc. / (Dec.)
9	50	$ 14.56	$ 16.17	11.1%
10	100	$ 21.62	$ 22.84	5.7%
11	200	$ 35.74	$ 36.19	1.3%

Annual Avg. Existing	Annual Avg. Proposed	Annual Avg. % chgn	$Chgn/mo.
$ 174.71	$ 194.06	11.1%	$ 1.61
$ 259.42	$ 274.12	5.7%	$ 1.23
$ 428.83	$ 434.24	1.3%	$ 0.45



Appendix Table B-8
Typical Bill Comparison - Year 2
Existing vs. Proposed Rates
Residential

Line	Summer Rates								
	Existing				Proposed				
1	Minimum Bill			$ -	Minimum Bill			$ -	
2	Customer Charge			$ 9.50	Customer Charge			$ 10.50	
3	Energy			cts/kWh	Energy			cts/kWh	
	CAA Rate		0.0137				0.0137		
4	First	-	kWh	-	-	kWh	-		
5	Next	-	kWh	-	-	kWh	-		
6	Next	-	kWh	-	-	kWh	-		
7	Next	-	kWh	-	-	kWh	-		
8	Excess			$ 11.97				$ 12.00	

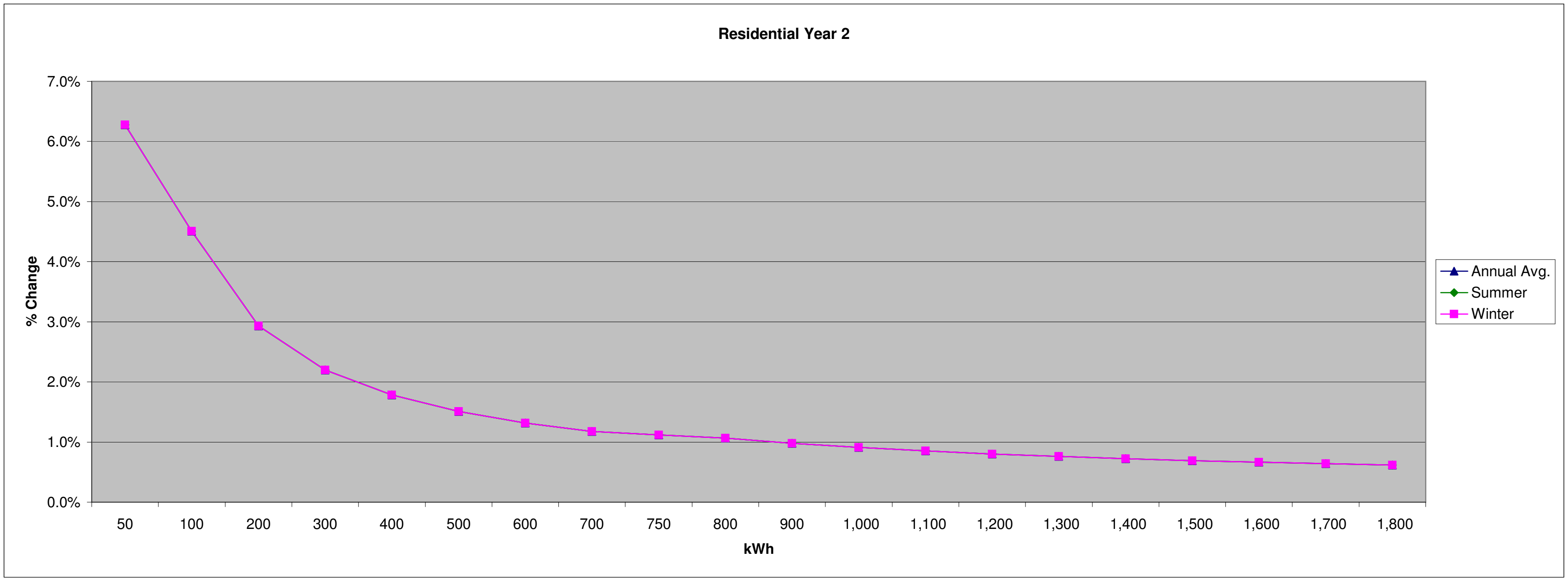
Winter Rates							
Existing				Proposed			
Minimum Bill			$ -	Minimum Bill			$ -
Customer Charge			$ 9.50	Customer Charge			$ 10.50
Energy			cts/kWh	Energy			cts/kWh
CAA Rate		0.0137				0.0137	
First	-	kWh	-	-	kWh	-	
Next	-	kWh	-	-	kWh	-	
Next	-	kWh	-	-	kWh	-	
Next	-	kWh	-	-	kWh	-	
Excess			$ 11.97				$ 12.00

Existing Rate Revenue	$ 4,766,903
Proposed Revenue	$ 4,827,567
Proposed Revenue Increase	1.3%

Line	Monthly Usage (kWh)	Summer Monthly Bill Existing	Summer Monthly Bill Proposed	% Inc. / (Dec.)
9	50	$ 16.17	$ 17.19	6.3%
10	100	$ 22.84	$ 23.87	4.5%
11	200	$ 36.19	$ 37.25	2.9%

Line	Monthly Usage (kWh)	Winter Monthly Bill Existing	Winter Monthly Bill Proposed	% Inc. / (Dec.)
9	50	$ 16.17	$ 17.19	6.3%
10	100	$ 22.84	$ 23.87	4.5%
11	200	$ 36.19	$ 37.25	2.9%

Annual Avg. Existing	Proposed	% chgn	$Chgn/mo.
$ 194.06	$ 206.24	6.3%	$ 1.02
$ 274.12	$ 286.48	4.5%	$ 1.03
$ 434.24	$ 446.96	2.9%	$ 1.06



NMPP Energy
City of Lamar
2009 Cost of Service/Rate Design Study

Appendix Table B-15
Typical Bill Comparison - Year 3
Existing vs. Proposed Rates
Residential

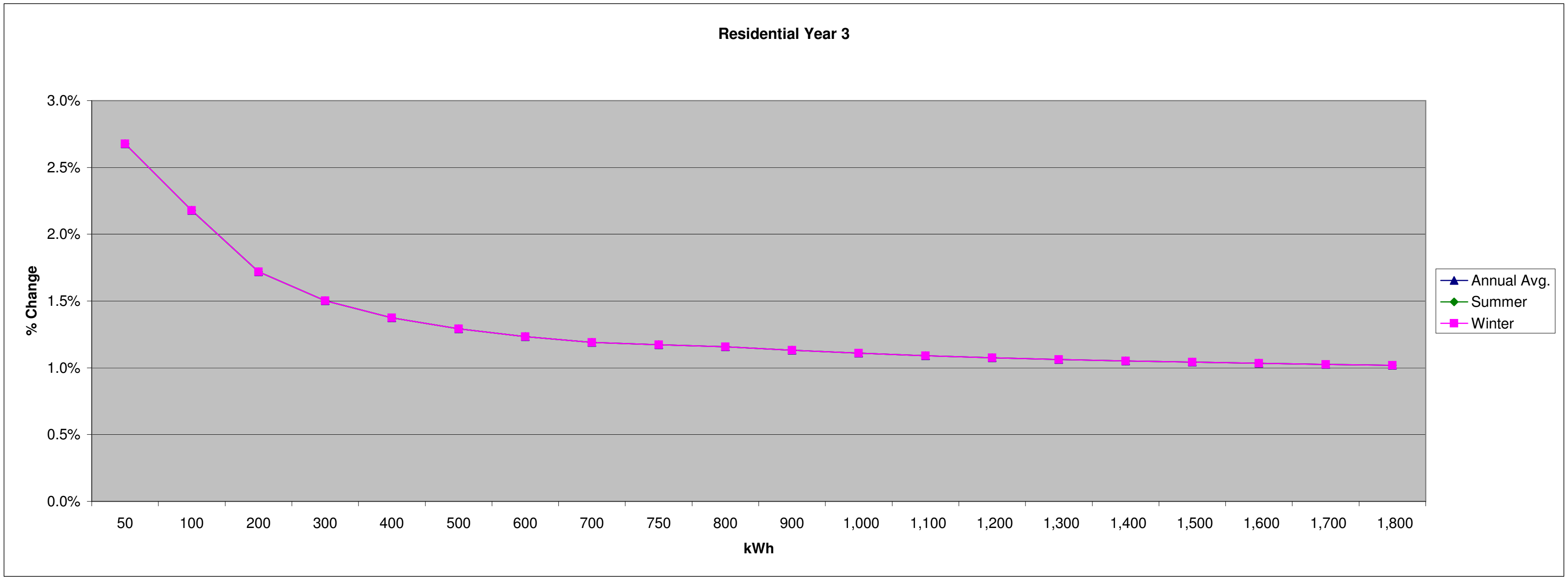
Line	Summer Rates								Winter Rates							
	Existing				Proposed				Existing				Proposed			
1	Minimum Bill			$ -	Minimum Bill			$ -	Minimum Bill			$ -	Minimum Bill			$ -
2	Customer Charge			$ 10.50	Customer Charge			$ 10.90	Customer Charge			$ 10.50	Customer Charge			$ 10.90
3	Energy			cts/kWh	Energy			cts/kWh	Energy			cts/kWh	Energy			cts/kWh
	CAA Rate		0.0137				0.0137		CAA Rate		0.0137				0.0137	
4	First	-	kWh	-	-	kWh		-	First	-	kWh	-	-	kWh		-
5	Next	-	kWh	-	-	kWh		-	Next	-	kWh	-	-	kWh		-
6	Next	-	kWh	-	-	kWh		-	Next	-	kWh	-	-	kWh		-
7	Next	-	kWh	-	-	kWh		-	Next	-	kWh	-	-	kWh		-
8	Excess			$ 12.00				12.120	Excess			$ 12.00				$ 12.12

Existing Rate Revenue	$ 4,827,567
Proposed Revenue	$ 4,886,490
Proposed Revenue Increase	1.2%

Line	Monthly Usage (kWh)	Summer Monthly Bill Existing	Summer Monthly Bill Proposed	% Inc. / (Dec.)
9	50	$ 17.19	$ 17.65	2.7%
10	100	$ 23.87	$ 24.39	2.2%
11	200	$ 37.25	$ 37.89	1.7%

Line	Monthly Usage (kWh)	Winter Monthly Bill Existing	Winter Monthly Bill Proposed	% Inc. / (Dec.)
9	50	$ 17.19	$ 17.65	2.7%
10	100	$ 23.87	$ 24.39	2.2%
11	200	$ 37.25	$ 37.89	1.7%

Annual Avg. Existing	Annual Avg. Proposed	% chgn	$Chgn/mo.
$ 206.24	$ 211.76	2.7%	$ 0.46
$ 286.48	$ 292.72	2.2%	$ 0.52
$ 446.96	$ 454.64	1.7%	$ 0.64



Appendix Table B-22
Typical Bill Comparison - Year 4
Existing vs. Proposed Rates
Residential

Line	Summer Rates: Existing				Proposed			
1	Minimum Bill			$ -	Minimum Bill			$ -
2	Customer Charge			$ 10.90	Customer Charge			$ 11.45
3	Energy			cts/kWh	Energy			cts/kWh
	CAA Rate	0.0137				0.0137		
4	First	-	kWh	-		-	kWh	-
5	Next	-	kWh	-		-	kWh	-
6	Next	-	kWh	-		-	kWh	-
7	Next	-	kWh	-		-	kWh	-
8	Excess			$ 12.12				12.210

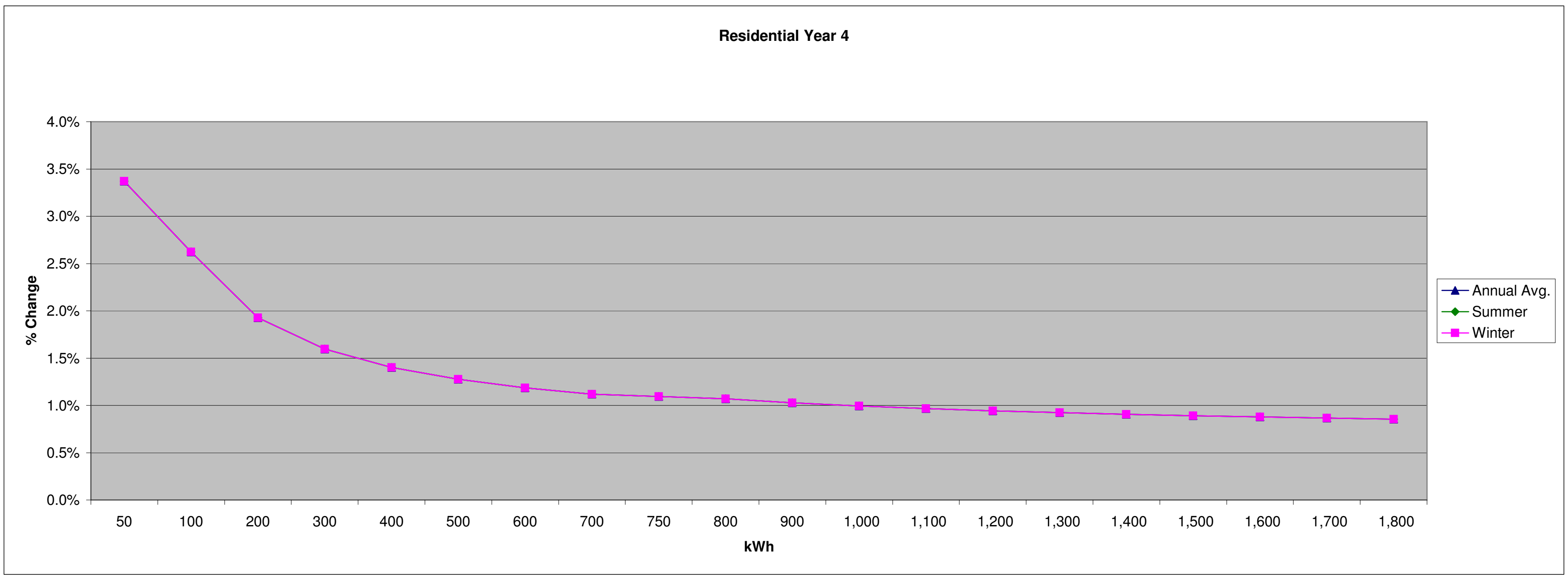
Winter Rates: Existing				Proposed			
Minimum Bill			$ -	Minimum Bill			$ -
Customer Charge			$ 10.90	Customer Charge			$ 11.45
Energy			cts/kWh	Energy			cts/kWh
CAA Rate	0.0137				0.0137		
First	-	kWh	-		-	kWh	-
Next	-	kWh	-		-	kWh	-
Next	-	kWh	-		-	kWh	-
Next	-	kWh	-		-	kWh	-
Excess			$ 12.12				$ 12.21

Existing Rate Revenue	$ 4,886,490
Proposed Revenue	$ 4,943,442
Proposed Revenue Increase	1.2%

Line	Monthly Usage (kWh)	Summer Monthly Bill: Existing	Proposed	% Inc. / (Dec.)
9	50	$ 17.65	$ 18.24	3.4%
10	100	$ 24.39	$ 25.03	2.6%
11	200	$ 37.89	$ 38.62	1.9%

Line	Monthly Usage (kWh)	Winter Monthly Bill: Existing	Proposed	% Inc. / (Dec.)
9	50	$ 17.65	$ 18.24	3.4%
10	100	$ 24.39	$ 25.03	2.6%
11	200	$ 37.89	$ 38.62	1.9%

Annual Avg.: Existing	Proposed	% chgn	$Chgn/mo.
$ 211.76	$ 218.90	3.4%	$ 0.59
$ 292.72	$ 300.40	2.6%	$ 0.64
$ 454.64	$ 463.40	1.9%	$ 0.73



Appendix Table B-29
Typical Bill Comparison - Year 5
Existing vs. Proposed Rates
Residential

Line	Summer Rates: Existing				Summer Rates: Proposed		
1	Minimum Bill			$ -	Minimum Bill		$ -
2	Customer Charge			$ 11.45	Customer Charge		$ 12.00
3	Energy			cts/kWh	Energy		cts/kWh
	CAA Rate		0.0137		0.0137		
4	First	-	kWh	-	-	kWh	-
5	Next	-	kWh	-	-	kWh	-
6	Next	-	kWh	-	-	kWh	-
7	Next	-	kWh	-	-	kWh	-
8	Excess			$ 12.21			12.300

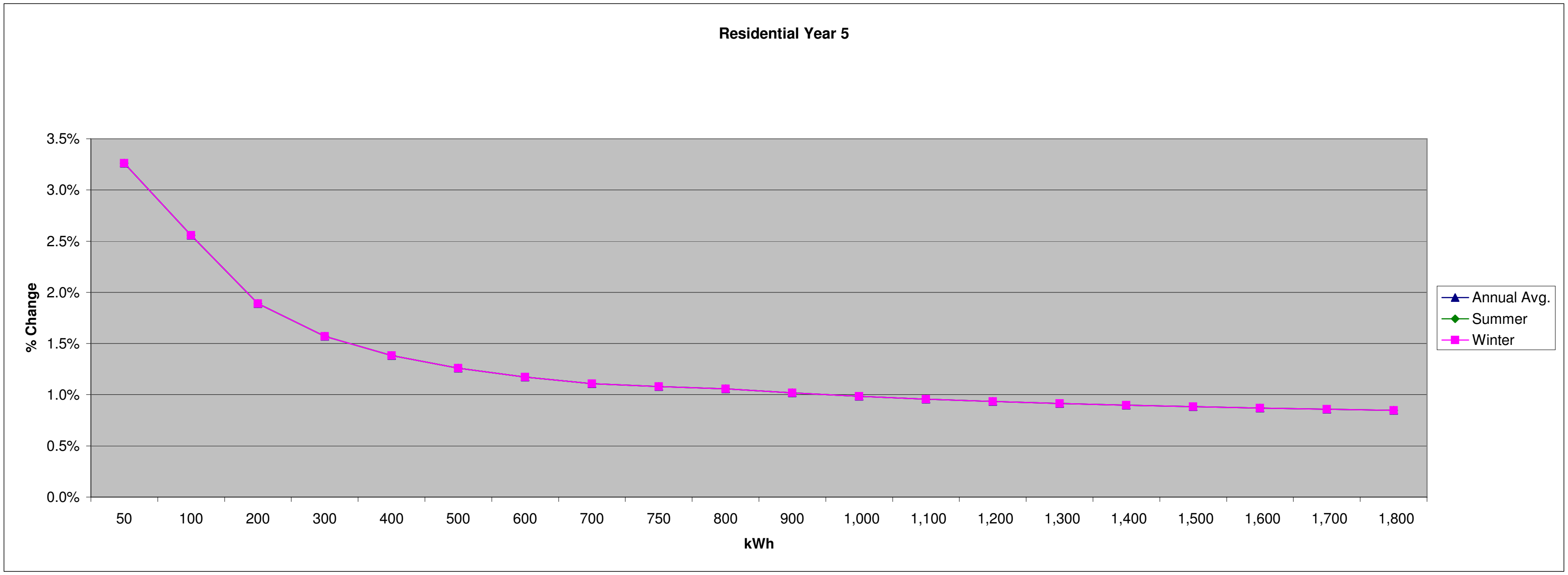
Winter Rates: Existing				Winter Rates: Proposed		
Minimum Bill			$ -	Minimum Bill		$ -
Customer Charge			$ 11.45	Customer Charge		$ 12.00
Energy			cts/kWh	Energy		cts/kWh
CAA Rate		0.0137		0.0137		
First	-	kWh	-	-	kWh	-
Next	-	kWh	-	-	kWh	-
Next	-	kWh	-	-	kWh	-
Next	-	kWh	-	-	kWh	-
Excess			$ 12.21			$ 12.30

Existing Rate Revenue	$ 4,943,442
Proposed Revenue	$ 5,000,393
Proposed Revenue Increase	1.2%

Line	Monthly Usage (kWh)	Summer Monthly Bill: Existing	Summer Monthly Bill: Proposed	% Inc. / (Dec.)
9	50	$ 18.24	$ 18.84	3.3%
10	100	$ 25.03	$ 25.67	2.6%
11	200	$ 38.62	$ 39.35	1.9%

Line	Monthly Usage (kWh)	Winter Monthly Bill: Existing	Winter Monthly Bill: Proposed	% Inc. / (Dec.)
9	50	$ 18.24	$ 18.84	3.3%
10	100	$ 25.03	$ 25.67	2.6%
11	200	$ 38.62	$ 39.35	1.9%

Annual Avg.: Existing	Proposed	% chgn	$Chgn/mo.
$ 218.90	$ 226.04	3.3%	$ 0.59
$ 300.40	$ 308.08	2.6%	$ 0.64
$ 463.40	$ 472.16	1.9%	$ 0.73



Appendix Table B-2
Typical Bill Comparison
Existing vs. Proposed Rates
General Service Small

Line	Summer Rates								Winter Rates							
	Existing				Proposed				Existing				Proposed			
1	Minimum Bill			$ -	Minimum Bill			$ -	Minimum Bill			$ -	Minimum Bill			$ -
2	Customer Charge			$ 12.31	Customer Charge			$ 16.00	Customer Charge			$ 12.31	Customer Charge			$ 16.00
3	Energy	ECA Rate	0.0543	cts/kWh	Energy			cts/kWh	Energy			cts/kWh	Energy			cts/kWh
		CAA Rate	0.0128			0.0137				CAA Rate	0.0128			0.0137		
4	First	-	kWh	-	-	kWh		-	First	-	kWh	0.000	-	kWh		-
5	Next	-	kWh	-	-	kWh		-	Next	-	kWh	0.000	-	kWh		-
6	Next	-	kWh	-	-	kWh		-	Next	-	kWh	0.000	-	kWh		-
7	Next	-	kWh	-	-	kWh		-	Next	-	kWh	-	-	kWh		-
8	Excess			$ 6.42				$ 11.22	Excess			$ 6.42				$ 11.22

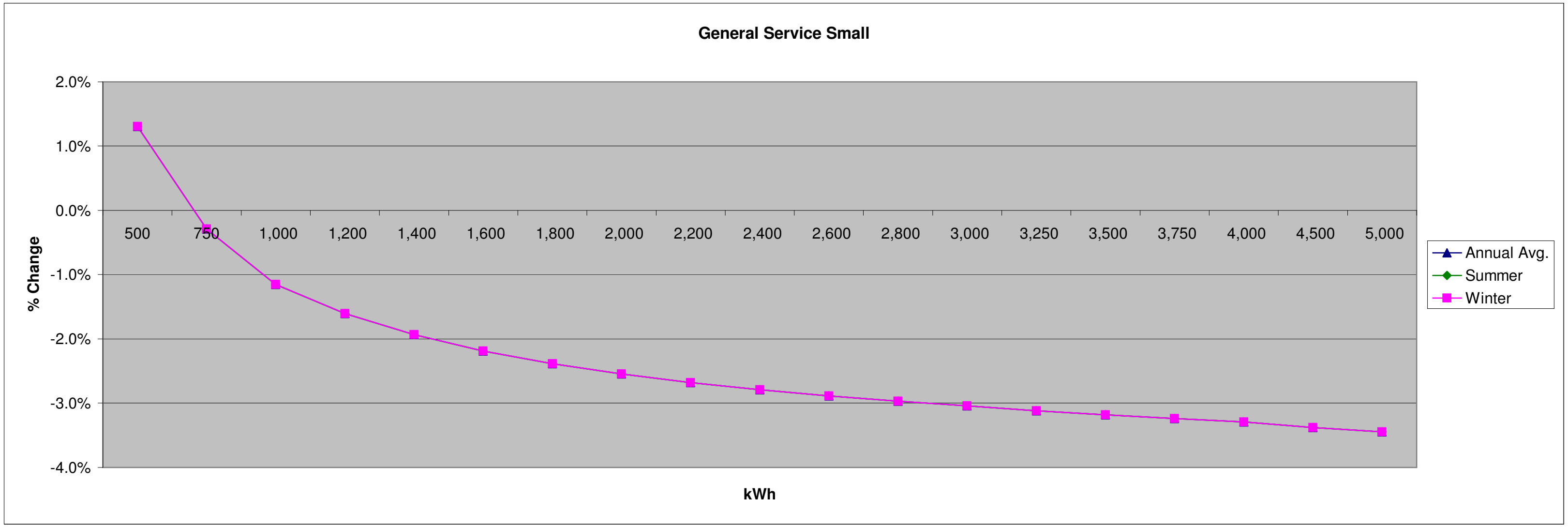
-

Existing Rate Revenue	$ 1,916,402
Proposed Rate Revenue	$ 1,873,323
Proposed Revenue Increase	-2.2%

Line	Monthly Usage (kWh)	Summer Monthly Bill Existing	Summer Monthly Bill Proposed	% Inc. / (Dec.)
9	500	$ 77.95	$ 78.97	1.3%
10	1000	$ 143.59	$ 141.93	-1.2%
11	2000	$ 274.87	$ 267.87	-2.5%

Line	Monthly Usage (kWh)	Winter Monthly Bill Existing	Winter Monthly Bill Proposed	% Inc. / (Dec.)
9	500	$ 77.95	$ 78.97	1.3%
10	1000	$ 143.59	$ 141.93	-1.2%
11	2000	$ 274.87	$ 267.87	-2.5%

Annual Avg. Existing	Annual Avg. Proposed	% chgn	$Chgn/mo.
$ 935.40	$ 947.61	1.3%	$ 1.02
$1,723.08	$1,703.22	-1.2%	$ (1.65)
$3,298.43	$3,214.44	-2.5%	$ (7.00)



Appendix Table B-9
Typical Bill Comparison - Year 2
Existing vs. Proposed
General Service Small

Line	Summer Rates: Existing				Summer Rates: Proposed			
1	Minimum Bill			$ -	Minimum Bill			$ -
2	Customer Charge			$ 16.00	Customer Charge			$ 18.10
3	Energy			cts/kWh	Energy			cts/kWh
	CAA Rate	0.0137				0.0137		
4	First	-	kWh	-	-	kWh		-
5	Next	-	kWh	-	-	kWh		-
6	Next	-	kWh	-	-	kWh		-
7	Next	-	kWh	-	-	kWh		-
8	Excess			$ 11.22				$ 11.37

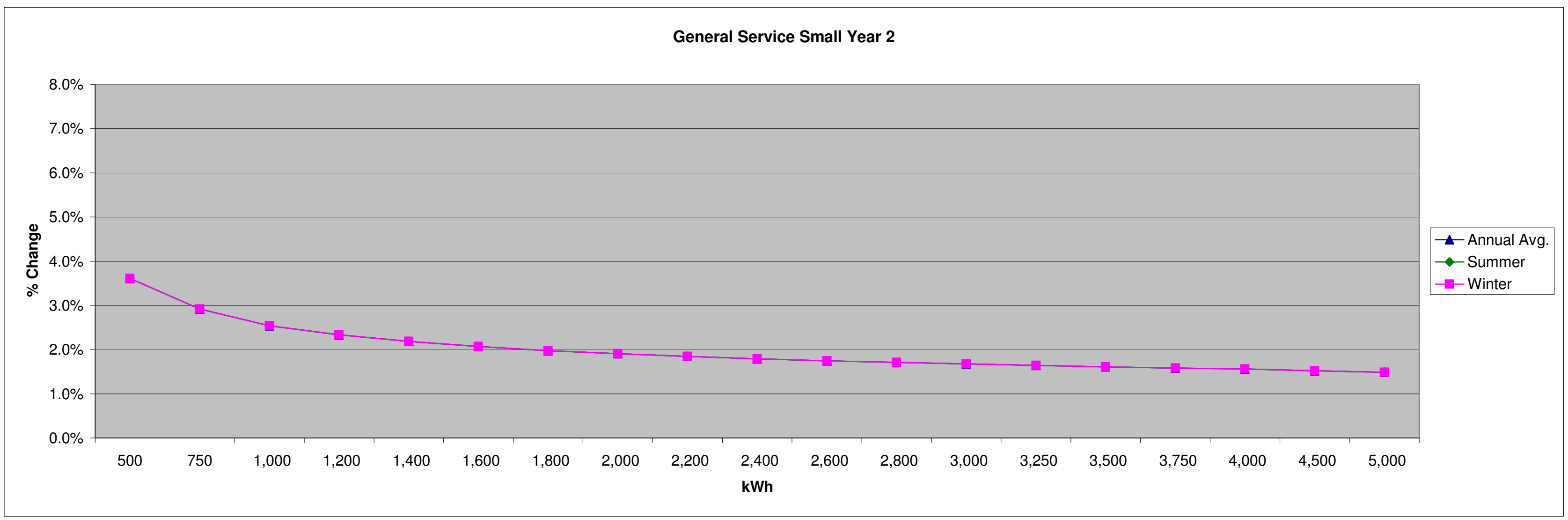
Winter Rates: Existing				Winter Rates: Proposed			
Minimum Bill			$ -	Minimum Bill			$ -
Customer Charge			$ 16.00	Customer Charge			$ 18.10
Energy			cts/kWh	Energy			cts/kWh
CAA Rate	0.0137				0.0137		
First	-	kWh	-	-	kWh		-
Next	-	kWh	-	-	kWh		-
Next	-	kWh	-	-	kWh		-
Next	-	kWh	-	-	kWh		-
Excess			$ 11.22				$ 11.37

Existing Rate Revenue	$ 1,873,323
Proposed Revenue	$ 1,912,892
Proposed Revenue Increase	2.1%

Line	Monthly Usage (kWh)	Summer Monthly Bill Existing	Summer Monthly Bill Proposed	% Inc. / (Dec.)
9	500	$ 78.97	$ 81.82	3.6%
10	1000	$ 141.93	$ 145.53	2.5%
11	2000	$ 267.87	$ 272.97	1.9%

Line	Monthly Usage (kWh)	Winter Monthly Bill Existing	Winter Monthly Bill Proposed	% Inc. / (Dec.)
9	500	$ 78.97	$ 81.82	3.6%
10	1000	$ 141.93	$ 145.53	2.5%
11	2000	$ 267.87	$ 272.97	1.9%

Annual Avg. Existing	Annual Avg. Proposed	% chgn	$Chgn/mo.
$ 947.61	$ 981.81	3.6%	$ 2.85
$1,703.22	$1,746.42	2.5%	$ 3.60
$3,214.44	$3,275.64	1.9%	$ 5.10



Appendix Table B-16
Typical Bill Comparison - Year 3
Existing vs. Proposed
General Service Small

Line	Summer Rates							
	Existing				Proposed			
1	Minimum Bill			$ -	Minimum Bill			$ -
2	Customer Charge			$ 18.10	Customer Charge			$ 18.50
3	Energy			cts/kWh	Energy			cts/kWh
		CAA Rate	0.0137			0.0137		
4	First	-	kWh	-	-	kWh		-
5	Next	-	kWh	-	-	kWh		-
6	Next	-	kWh	-	-	kWh		-
7	Next	-	kWh	-	-	kWh		-
8	Excess			11.37				11.600

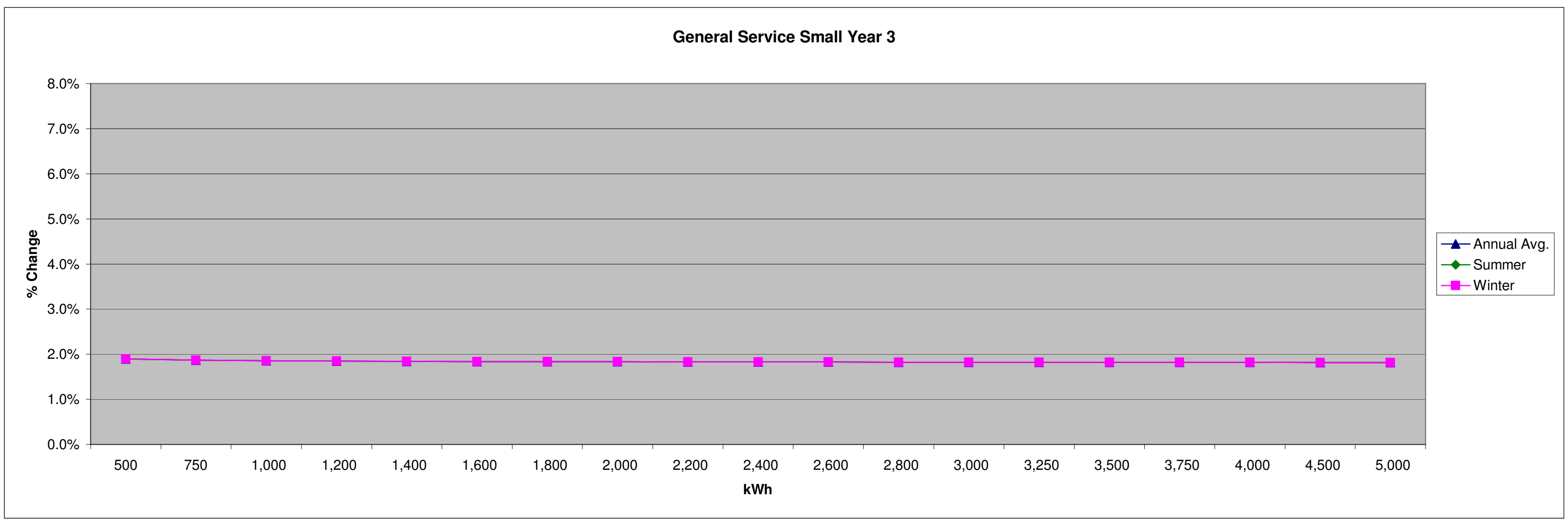
Winter Rates							
Existing				Proposed			
Minimum Bill			$ -	Minimum Bill			$ -
Customer Charge			$ 18.10	Customer Charge			$ 18.50
Energy			cts/kWh	Energy			cts/kWh
	CAA Rate	0.0137			0.0137		
First	-	kWh	-	-	kWh		-
Next	-	kWh	-	-	kWh		-
Next	-	kWh	-	-	kWh		-
Next	-	kWh	-	-	kWh		-
Excess			11.37				$ 11.60

Existing Rate Revenue	$ 1,912,892
Proposed Revenue	$ 1,948,080
Proposed Revenue Increase	1.8%

Line	Monthly Usage (kWh)	Summer Monthly Bill		% Inc. / (Dec.)
		Existing	Proposed	
9	500	$ 81.82	$ 83.37	1.9%
10	1000	$ 145.53	$ 148.23	1.9%
11	2000	$ 272.97	$ 277.97	1.8%

Line	Monthly Usage (kWh)	Winter Monthly Bill		% Inc. / (Dec.)
		Existing	Proposed	
9	500	$ 81.82	$ 83.37	1.9%
10	1000	$ 145.53	$ 148.23	1.9%
11	2000	$ 272.97	$ 277.97	1.8%

Annual Avg.			
Existing	Proposed	% chgn	$Chgn/mo.
$ 981.81	$1,000.41	1.9%	$ 1.55
$1,746.42	$1,778.82	1.9%	$ 2.70
$3,275.64	$3,335.64	1.8%	$ 5.00



Appendix Table B-23
Typical Bill Comparison - Year 4
Existing vs. Proposed
General Service Small

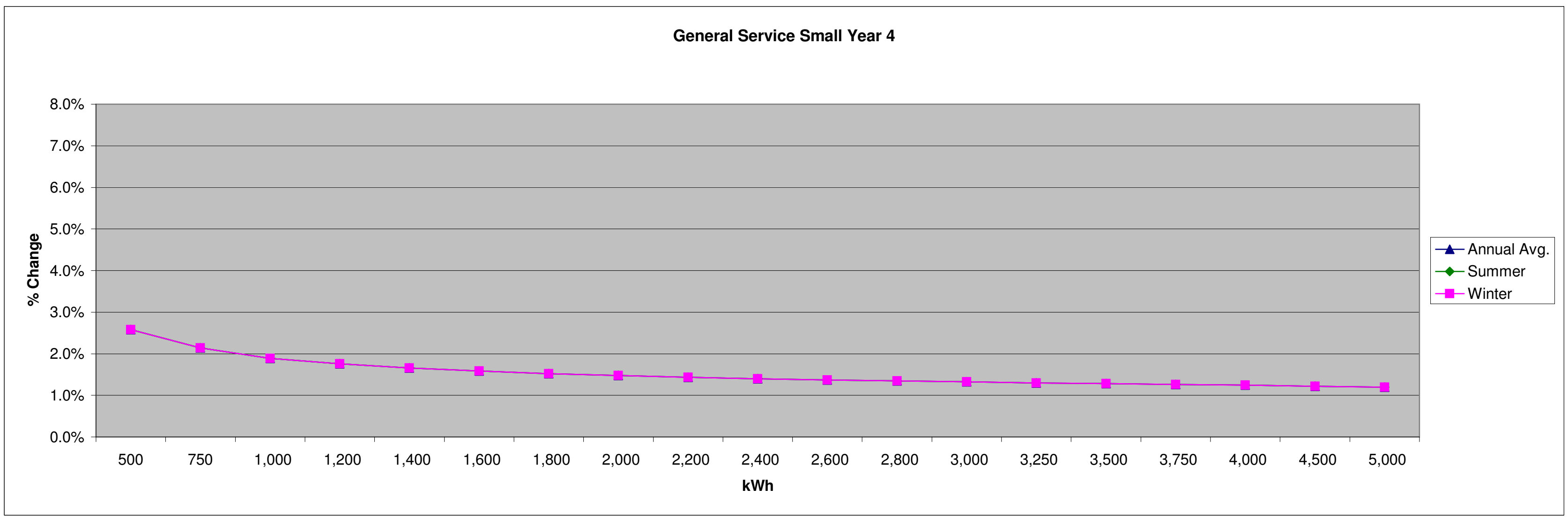
Line	Summer Rates						Winter Rates					
	Existing			Proposed			Existing			Proposed		
1	Minimum Bill		$ -	Minimum Bill		$ -	Minimum Bill		$ -	Minimum Bill		$ -
2	Customer Charge		$ 18.50	Customer Charge		$ 20.00	Customer Charge		$ 18.50	Customer Charge		$ 20.00
3	Energy		cts/kWh	Energy		cts/kWh	Energy		cts/kWh	Energy		cts/kWh
	CAA Rate	0.0137			0.0137		CAA Rate	0.0137			0.0137	
4	First	- kWh	-		- kWh	-	First	- kWh	-		- kWh	-
5	Next	- kWh	-		- kWh	-	Next	- kWh	-		- kWh	-
6	Next	- kWh	-		- kWh	-	Next	- kWh	-		- kWh	-
7	Next	- kWh	-		- kWh	-	Next	- kWh	-		- kWh	-
8	Excess		11.60			11.730	Excess		11.60			$ 11.73

Existing Rate Revenue	$ 1,948,080
Proposed Revenue	$ 1,979,481
Proposed Revenue Increase	1.6%

Line	Monthly Usage (kWh)	Summer Monthly Bill Existing	Summer Monthly Bill Proposed	% Inc. / (Dec.)
9	500	$ 83.37	$ 85.52	2.6%
10	1000	$ 148.23	$ 151.03	1.9%
11	2000	$ 277.97	$ 282.07	1.5%

Line	Monthly Usage (kWh)	Winter Monthly Bill Existing	Winter Monthly Bill Proposed	% Inc. / (Dec.)
9	500	$ 83.37	$ 85.52	2.6%
10	1000	$ 148.23	$ 151.03	1.9%
11	2000	$ 277.97	$ 282.07	1.5%

Annual Avg.			
Existing	Proposed	% chgn	$Chgn/mo.
$1,000.41	$1,026.21	2.6%	$ 2.15
$1,778.82	$1,812.42	1.9%	$ 2.80
$3,335.64	$3,384.84	1.5%	$ 4.10



Appendix Table B-30
Typical Bill Comparison - Year 5
Existing vs. Proposed
General Service Small

Line	Summer Rates – Existing				Summer Rates – Proposed		
1	Minimum Bill			$ -	Minimum Bill		$ -
2	Customer Charge			$ 20.00	Customer Charge		$ 22.00
3	Energy			cts/kWh	Energy		cts/kWh
	CAA Rate	0.0137				0.0137	
4	First	-	kWh	-	-	kWh	-
5	Next	-	kWh	-	-	kWh	-
6	Next	-	kWh	-	-	kWh	-
7	Next	-	kWh	-	-	kWh	-
8	Excess			11.73			11.800

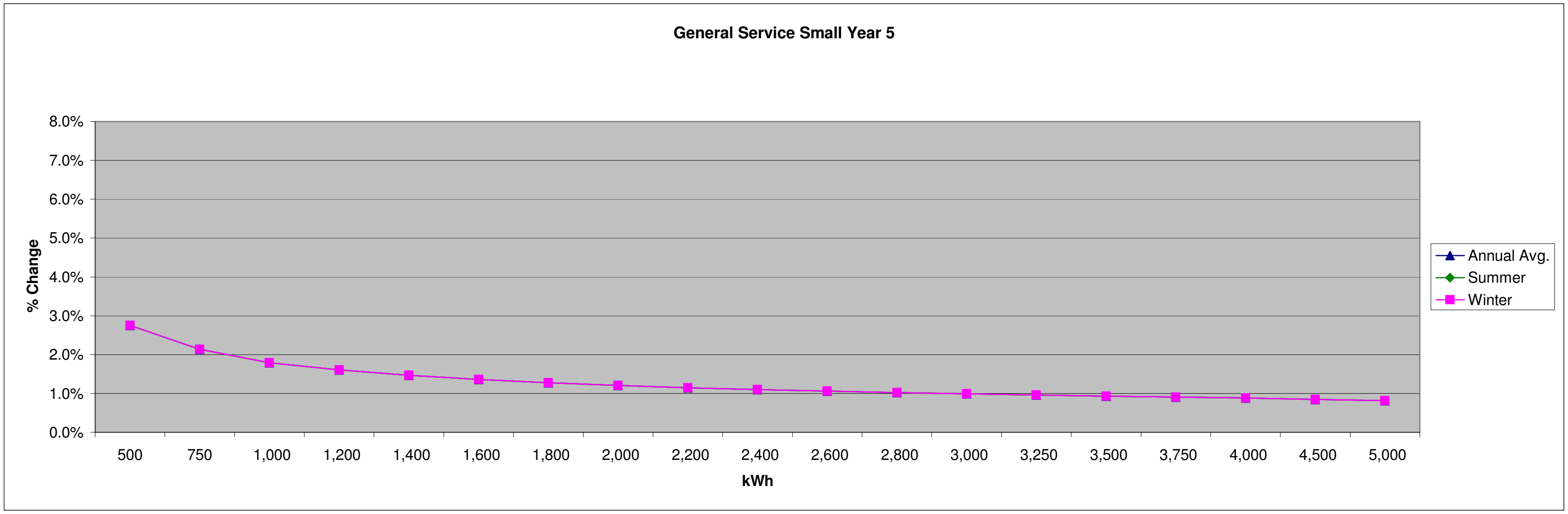
Winter Rates – Existing				Winter Rates – Proposed		
Minimum Bill			$ -	Minimum Bill		$ -
Customer Charge			$ 20.00	Customer Charge		$ 22.00
Energy			cts/kWh	Energy		cts/kWh
CAA Rate	0.0137				0.0137	
First	-	kWh	-	-	kWh	-
Next	-	kWh	-	-	kWh	-
Next	-	kWh	-	-	kWh	-
Next	-	kWh	-	-	kWh	-
Excess			11.73			$ 11.80

Existing Rate Revenue	$ 1,979,481
Proposed Revenue	$ 2,007,165
Proposed Revenue Increase	1.4%

Line	Monthly Usage (kWh)	Summer Monthly Bill Existing	Summer Monthly Bill Proposed	% Inc. / (Dec.)
9	500	$ 85.52	$ 87.87	2.7%
10	1000	$ 151.03	$ 153.73	1.8%
11	2000	$ 282.07	$ 285.47	1.2%

Line	Monthly Usage (kWh)	Winter Monthly Bill Existing	Winter Monthly Bill Proposed	% Inc. / (Dec.)
9	500	$ 85.52	$ 87.87	2.7%
10	1000	$ 151.03	$ 153.73	1.8%
11	2000	$ 282.07	$ 285.47	1.2%

Annual Avg. Existing	Proposed	% chgn	$Chgn/mo.
$1,026.21	$1,054.41	2.7%	$ 2.35
$1,812.42	$1,844.82	1.8%	$ 2.70
$3,384.84	$3,425.64	1.2%	$ 3.40



Appendix Table F-13
Calculation of Revenue from Existing Rates
Yard Lighting

Yard Lighting		
100 W High Pressure Sodium =	$	15.38
250 W High Pressure Sodium =		20.54
300 W Quartz =		18.32
500 W Quartz =		30.54
175 W Metal Halide =		18.15
175 W Mercury Vapor =		18.12
400 W Mercury Vapor =		24.77

kWh/mo.	
100 W High Pressure Sodium =	40
250 W High Pressure Sodium =	100
300 W Quartz =	120
500 W Quartz =	200
175 W Metal Halide =	70
175 W Mercury Vapor =	70
400 W Mercury Vapor =	160

Total Revenues	10,735	11,559	11,344	11,467	11,493	11,372	11,511	11,511	11,449	11,399	11,325	11,402	**136,567**
													136,567

Appendix Table F-14
Calculation of Revenue from Proposed Rates
Yard Lighting

Yard Lighting			
100 W High Pressure Sodium =	$	17.60	14.4%
250 W High Pressure Sodium =		24.45	19.0%
300 W Quartz =		22.80	24.5%
500 W Quartz =		37.75	23.6%
175 W Metal Halide =		21.35	17.6%
175 W Mercury Vapor =		21.35	17.8%
400 W Mercury Vapor =		30.15	21.7%

kWh/mo.	
100 W High Pressure Sodium =	40
250 W High Pressure Sodium =	100
300 W Quartz =	120
500 W Quartz =	200
175 W Metal Halide =	70
175 W Mercury Vapor =	70
400 W Mercury Vapor =	160

Total Revenues	10,344	11,106	11,106	11,106	11,106	11,106	11,106	11,106	11,106	11,106	11,106	11,106	**132,508**
													-2.97%

Appendix Table F-15
Calculation of Revenue from Proposed Year 2 Rates
Yard Lighting

Yard Lighting			
100 W High Pressure Sodium =	$	17.60	0.00%
250 W High Pressure Sodium =		24.60	0.61%
300 W Quartz =		27.20	19.30%
500 W Quartz =		36.80	-2.52%
175 W Metal Halide =		21.70	1.64%
175 W Mercury Vapor =		20.60	-3.51%
400 W Mercury Vapor =		31.45	4.31%

kWh/mo.	
100 W High Pressure Sodium =	40
250 W High Pressure Sodium =	100
300 W Quartz =	120
500 W Quartz =	200
175 W Metal Halide =	70
175 W Mercury Vapor =	70
400 W Mercury Vapor =	160

Total Revenues	10,370	11,132	11,132	11,132	11,132	11,132	11,132	11,132	11,132	11,132	11,132	11,132	**132,823**
													0.24%

Appendix Table F-16
Calculation of Revenue from Proposed Year 3 Rates
Yard Lighting

Yard Lighting			
100 W High Pressure Sodium =	$	17.60	0.00%
250 W High Pressure Sodium =		24.60	0.00%
300 W Quartz =		27.20	0.00%
500 W Quartz =		36.80	0.00%
175 W Metal Halide =		21.70	0.00%
175 W Mercury Vapor =		20.60	0.00%
400 W Mercury Vapor =		31.45	0.00%

kWh/mo.	
100 W High Pressure Sodium =	40
250 W High Pressure Sodium =	100
300 W Quartz =	120
500 W Quartz =	200
175 W Metal Halide =	70
175 W Mercury Vapor =	70
400 W Mercury Vapor =	160

Total Revenues	10,370	11,132	11,132	11,132	11,132	11,132	11,132	11,132	11,132	11,132	11,132	11,132	**132,823**
													0.00%

Appendix Table F-17
Calculation of Revenue from Proposed Year 4 Rates
Yard Lighting

Yard Lighting			
100 W High Pressure Sodium =	$	17.60	0.00%
250 W High Pressure Sodium =		24.60	0.00%
300 W Quartz =		27.20	0.00%
500 W Quartz =		36.80	0.00%
175 W Metal Halide =		21.70	0.00%
175 W Mercury Vapor =		20.60	0.00%
400 W Mercury Vapor =		31.45	0.00%

kWh/mo.	
100 W High Pressure Sodium =	40
250 W High Pressure Sodium =	100
300 W Quartz =	120
500 W Quartz =	200
175 W Metal Halide =	70
175 W Mercury Vapor =	70
400 W Mercury Vapor =	160

Total Revenues	10,370	11,132	11,132	11,132	11,132	11,132	11,132	11,132	11,132	11,132	11,132	11,132	**132,823**
													0.00%

Appendix Table F-18
Calculation of Revenue from Proposed Year 5 Rates
Yard Lighting

Yard Lighting			
100 W High Pressure Sodium =	$	17.60	0.00%
250 W High Pressure Sodium =		24.60	0.00%
300 W Quartz =		27.20	0.00%
500 W Quartz =		36.80	0.00%
175 W Metal Halide =		21.70	0.00%
175 W Mercury Vapor =		20.60	0.00%
400 W Mercury Vapor =		31.45	0.00%

kWh/mo.	
100 W High Pressure Sodium =	40
250 W High Pressure Sodium =	100
300 W Quartz =	120
500 W Quartz =	200
175 W Metal Halide =	70
175 W Mercury Vapor =	70
400 W Mercury Vapor =	160

Total Revenues	10,370	11,132	11,132	11,132	11,132	11,132	11,132	11,132	11,132	11,132	11,132	11,132	**132,823**
													0.00%