Executive Report

ROCHELLE MUNICIPAL UTILITIES

Electric Cost of Service Study and Financial Projection

April 2015

UFS
Utility Financial Solutions, LLC

Specializing in Cost of Service,
Rate Design, and Financial Analysis

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April 2015

Dan Westin
Rochelle Municipal Utilities
Rochelle, Il

Dear Mr. Westin;

We are pleased to present the Executive Report for the electric cost of service study and financial projection for the Rochelle Municipal Utilities (RMU). This report was prepared to provide RMU with a comprehensive examination of its existing rate structure by an outside party.

The specific purposes of this rate study are:

- Determine electric utility's revenue requirements for fiscal year 2016
- Identify cross-subsidies that may exist between rate classes
- Recommend rate adjustments needed to meet targeted revenue requirements
- Identify the appropriate monthly customer charge for each customer class

This report includes results of the electric cost of service study and financial projection and recommendations on future rate designs.

This report is intended for information and use by the utility and management for the purposes stated above and is not intended to be used by anyone except the specified parties.

Sincerely,

Utility Financial Solutions, LLC
Mark Beauchamp
CPA, MBA, CMA
185 Sun Meadow Ct
Holland, MI 49424

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1. Introduction

This report was prepared to provide Rochelle Municipal Utilities (RMU) with an electric cost of service study and financial projection and a comprehensive examination of its existing rate structure by an outside party. The specific purposes of the study are identified below:

1) **Determine electric utility's revenue requirements for fiscal year 2016.** RMU's revenue requirements were projected for the period from 2016 – 2020 and included adjustments for the following:
    a. Projected power costs
    b. Projected changes in staffing levels
    c. Capital improvement plan projected over next five years

2) ***Identify cross-subsidies that may exist between rate classes.*** Cross-subsidies exist when certain customer classes subsidize the electric costs of other customers. The rate study identifies if cross-subsidies exist and practical ways to reduce the subsidies. The cost of service study was completed using 2016 projected revenues and expenses. The financial projections are for the period from 2016 – 2020.

3) ***Recommend rate adjustments needed to meet targeted revenue requirements.*** The primary purpose of this study is to identify appropriate revenue requirements and the rate adjustments needed to meet targeted revenue requirements. The report includes a long-term rate track for RMU to help ensure the financial stability of the utility in future years.

4) ***Determine cost by location within the utility electric rates (commonly known as unbundling in the industry but referred to as cost by location at request of management).*** The cost of providing electricity to customers consists of a number of components, including power generation, distribution, customer services, transmission, and payment in lieu of tax to the general fund. Electric determination of costs by location identifies the cost of each component to assists the utility in preparing for electric restructuring and understanding its cost structure.

5) ***Identify the appropriate monthly customer charge for each customer class.*** The monthly customer charge consists of fixed costs to service customers that do not vary based on the amount of electricity used.

2. Cost of Service Summary

Utility Rate Process

RMU retained Utility Financial Solutions to review utility rates and cost of service and make recommendations on the appropriate course of action. This report includes results of the electric cost of service and determination of costs by location study and recommendations on future rate designs.

Utility Revenue Requirements

To determine revenue requirements, the revenues and expenses for Fiscal Years 2012, 2013 and 2014, 2015 budget were analyzed, with adjustments made to reflect projected operating characteristics. ***The projected financial statements are for cost of service purposes only.***

Table 1 is the projected financial statement for the Electric Department from 2016-2020. The 2016 rate of return calculation established an operating income target of $2.046M (See Table 5).

Operating income for 2016 is projected at $1.35M and increases to $214k in 2020. Operating income is one target that helps to determine if rate adjustments are needed. The following pages review cash flow and debt coverage ratio which are also important indicators.

Table 1 – Financial Statements (without rate adjustments)

Description	Projected 2016	Projected 2017	Projected 2018	Projected 2019	Projected 2020
Operating Revenues					
Electric Sales					
Residential	6,728,886	6,762,530	6,796,343	6,830,325	6,864,476
Commercial	6,248,470	6,279,712	6,311,111	6,342,666	6,374,379
Industrial	22,706,454	22,819,986	22,934,086	23,048,757	23,164,001
Public Street Lighting	174,175	175,046	175,921	176,801	177,685
Interdepartmental	-	-	-	-	-
Other Operating Revenue	250,000	256,250	262,656	269,223	275,953
Miscellaneous Revenues	100,000	102,500	105,063	107,689	110,381
Sales Revenue	$ 36,207,984	$ 36,396,024	$ 36,585,179	$ 36,775,460	$ 36,966,875
Power Cost Adjustment					
Power Cost	$ 24,768,204	$ 25,511,250	$ 26,276,587	$ 27,064,885	$ 27,876,832
kWh Purchases	349,466,459	351,213,791	352,969,860	354,734,709	356,508,383
Line Loses	6%	6%	6%	6%	6%
Projected kWh Sales	329,026,545	330,671,677.55	332,325,035.94	333,986,661.12	335,656,594.43
Average Power Costs	$ 0.0753	$ 0.0771	$ 0.0791	$ 0.0810	$ 0.0831
Base Power Costs	$ 0.0546	$ 0.0546	$ 0.0546	$ 0.0546	$ 0.0546
PCA	$ 0.0207	$ 0.0225	$ 0.0245	$ 0.0264	$ 0.0285
Additional PCA Revenues	$ -	645,727	1,320,791	2,018,364	2,739,132
Total Sales Revenues	**$ 36,207,984**	**$ 37,041,751**	**$ 37,905,970**	**$ 38,793,823**	**$ 39,706,007**

Description	Projected 2016	Projected 2017	Projected 2018	Projected 2019	Projected 2020
Operating Expenses					
Power Supply and Fuel					
Purchased Power (Cost of Sales and Service)	$ 24,768,204	$ 25,511,250	$ 26,276,587	$ 27,064,885	$ 27,876,832
Total Purchases Expense	$ 24,768,204	$ 25,511,250	$ 26,276,587	$ 27,064,885	$ 27,876,832
Production					
Production Expense	$ 1,242,467	$ 1,273,529	$ 1,305,367	$ 1,338,001	$ 1,371,451
Total Production Expense	$ 1,242,467	$ 1,273,529	$ 1,305,367	$ 1,338,001	$ 1,371,451
Total Power Supply Expense	$ 26,010,671	$ 26,784,779	$ 27,581,954	$ 28,402,886	$ 29,248,283
Distribution					
Total Distribution O&M	1,863,604	1,910,194	1,957,949	2,006,897	2,057,070
Total Distribution Expense	$ 1,863,604	$ 1,910,194	$ 1,957,949	$ 2,006,897	$ 2,057,070
Other Operating Expenses (Revenues)					
Customer/Sales Expense	$ 466,692	$ 478,360	$ 490,319	$ 502,577	$ 515,141
Administrative and General Expense	2,077,132	2,129,060	2,182,287	2,236,844	2,292,765
Depreciation Expense	2,536,226	2,612,618	2,765,038	2,920,163	3,083,310
Payment in Lieu of Taxes	1,674,142	1,810,399	1,852,088	1,895,299	1,939,691
Total Other Operating Expenses	$ 6,754,192	$ 7,030,437	$ 7,289,731	$ 7,554,882	$ 7,830,908
Total Operating Expenses	**$ 34,628,467**	**$ 35,725,409**	**$ 36,829,634**	**$ 37,964,666**	**$ 39,136,260**

Projected Cash Flow

Table 2 is the projected cash flow for 2016-2020, including projections of capital improvements as provided by the RMU. Changes in the capital improvement plan can greatly affect the cash balance and recommended minimum cash reserve target. The cash balance for 2016 is projected at $11.5M and $5M in 2020. The recommended minimum cash reserve level for 2016 is $10M and $12.1M for 2020.

Table 2 – Projected Cash Flows (without rate adjustments)

Description	Projected 2016	Projected 2017	Projected 2018	Projected 2019	Projected 2020
Projected Cash Flows					
Net Income	$ 1,183,033	$ 735,693	$ 513,144	$ 278,099	$ 30,505
Depreciation Expense/Amortization	2,536,226	2,612,618	2,765,038	2,920,163	3,083,310
Subtract Debt Principal	(615,000)	(645,000)	(600,000)	(615,000)	(630,000)
Add Bond Sale Proceeds	-	-	-	-	-
Cash Available from Operations	**$ 3,104,259**	**$ 2,703,311**	**$ 2,678,182**	**$ 2,583,262**	**$ 2,483,816**
Estimated Annual Capital Additions	$ 3,755,370	$ 3,819,593	$ 3,801,412	$ 3,954,875	$ 4,202,476
Net Cash From Operations	**$ (651,111)**	**$ (1,116,282)**	**$ (1,123,230)**	**$ (1,371,612)**	**$ (1,718,660)**
Beginning Cash Balance	$ 12,451,910	$ 11,800,799	$ 10,684,517	$ 9,561,287	$ 8,189,675
Total Cash Available	**$ 11,800,799**	**$ 10,684,517**	**$ 9,561,287**	**$ 8,189,675**	**$ 6,471,015**
Recommended Minimum	**$ 9,969,462**	**$ 10,207,193**	**$ 10,498,413**	**$ 10,820,541**	**$ 12,129,056**

Minimum Cash Reserve

Table 3 details the minimum level of cash reserves required to help ensure timely replacement of assets and to provide financial stability of the utility. The methodology used to establish this target is based on certain assumptions related to a percentage of operating expense, historical investment, capital improvements, and debt service to be kept in cash reserves. Based on these assumptions, RMU should maintain a minimum of $10M in cash reserves for 2016 and $12.1M in 2020.

Table 3 – Minimum Cash Reserves (without rate adjustments)

Description	Projected 2016	Projected 2017	Projected 2018	Projected 2019	Projected 2020
Minimum Cash Reserve Levels Determinants					
Operation & Maintenance Less Depreciation Expense	$ 7,324,037	$ 7,601,542	$ 7,788,008	$ 7,979,617	$ 8,176,118
Purchase Power Expense	24,768,204	25,511,250	26,276,587	27,064,885	27,876,832
Historical Rate Base	82,735,176	86,554,769	90,356,181	94,311,055	98,513,531
Current Portion of Debt Service Payment	1,284,653	1,216,615	1,213,865	1,210,190	1,208,240
Five Year Capital Improvements - Net of bond proceeds	19,533,726	20,085,893	20,681,527	21,405,722	22,089,595
Minimum Cash Reserve Allocation					
Operation & Maintenance Less Depreciation Expense	12.3%	12.3%	12.3%	12.3%	12.3%
Purchase Power Expense	9.8%	9.8%	9.8%	9.8%	9.8%
Historical Rate Base	2%	2%	2%	2%	3%
Current Portion of Debt Service Payment	83%	83%	83%	83%	83%
Five Year Capital Improvements - Net of bond proceeds	20%	20%	20%	20%	20%
Calculated Minimum Cash Level					
Operation & Maintenance Less Depreciation Expense	$ 902,964	$ 937,176	$ 960,165	$ 983,788	$ 1,008,015
Purchase Power Expense	2,438,788	2,511,952	2,587,310	2,664,930	2,744,878
Historical Rate Base	1,654,704	1,731,095	1,807,124	1,886,221	2,955,406
Current Portion of Debt Service Reserve	1,066,262	1,009,790	1,007,508	1,004,458	1,002,839
Five Year Capital Improvements - Net of bond proceeds	3,906,745	4,017,179	4,136,305	4,281,144	4,417,919
Minimum Cash Reserve Levels	**$ 9,969,462**	**$ 10,207,193**	**$ 10,498,413**	**$ 10,820,541**	**$ 12,129,056**
Projected Cash Reserves	**$ 11,800,799**	**$ 10,684,517**	**$ 9,561,287**	**$ 8,189,675**	**$ 6,471,015**

Projected cash balances fall below recommended minimums during the projection period.

Debt Coverage Ratio

Table 4 is the projected debt coverage ratios with capital additions as provided by RMU. The coverage required in bond ordinances is typically 1.15 – 1.20, however the minimum recommended debt coverage ratio is established at 1.35 – 1.40 for projection purposes a 0.20 premium to ordinance. Maintaining a higher debt coverage ratio is good business practice and helps to achieve the following:

- Helps to ensure adequate funds are available to meet debt service payments in years when sales are low due to temperature fluctuations.
- Obtain higher bond rating, if revenue bonds are sold in the future, to lower interest cost.

Table 4 – Projected Debt Coverage Ratios (without rate adjustments)

Description	Projected 2016	Projected 2017	Projected 2018	Projected 2019	Projected 2020
Debt Coverage Ratio					
Net Income	$ 1,183,033	$ 735,693	$ 513,144	$ 278,099	$ 30,505
Add Depreciation/Amortization Expense	2,536,226	2,612,618	2,765,038	2,920,163	3,083,310
Add Interest Expense	546,293	639,653	616,615	598,865	580,190
Cash Available for Debt Service	$ 4,265,552	$ 3,987,964	$ 3,894,797	$ 3,797,127	$ 3,694,006
Debt Principal and Interest	$ 1,161,293	$ 1,284,653	$ 1,216,615	$ 1,213,865	$ 1,210,190
Projected Debt Coverage Ratio (Covenants)	3.67	3.10	3.20	3.13	3.05
Minimum Debt Coverage Ratio	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**

Debt coverage is adequate for the projection period without changes in rates.

Rate of Return

The optimal target for setting rates is the establishment of a target operating income to help ensure the following:

A. Funding of interest expense on the outstanding principal on debt. Interest expense is below the operating income line and needs to be recouped through the operating income balance.
B. Funding of the inflationary increase on the assets invested in the system. The inflation on the replacement of assets invested in the utility should be recouped through the Operating Income
C. Funding of depreciation expense
D. Adequate rate of return on investment to help ensure current customers are paying their fair share of the use of the infrastructure and not deferring the charge to future generations.

As improvements are made to the system, the optimal operating income target will increase unless annual depreciation expense is greater than yearly capital improvements. The revenue requirements for the study are set on the utility basis. Charging the rates in the cost of service study would produce the target operating income identified in Table 5. The utility basis target established for 2016 is $2.046M and increases to $2.66M in 2020.

Table 5 – Rate of Return Calculation

Description	Projected 2016	Projected 2017	Projected 2018	Projected 2019	Projected 2020
Target Operating Income Determinants					
Net Book Value/Working Capital	$ 39,455,711	$ 40,674,856	$ 41,881,831	$ 42,918,205	$ 43,952,916
Outstanding Principal on Debt	16,370,000	15,780,000	15,165,000	14,520,000	13,920,000
System Equity	**$ 23,085,711**	**$ 24,894,856**	**$ 26,716,831**	**$ 28,398,205**	**$ 30,032,916**
Target Operating Income Allocation					
Interest on Debt	3.34%	4.05%	4.07%	4.12%	4.17%
System Equity	6.50%	6.60%	6.69%	6.81%	6.95%
Target Operating Income					
Interest on Debt	$ 546,293	$ 639,653	$ 616,615	$ 598,865	$ 580,190
System Equity	$ 1,500,670	$ 1,642,239	$ 1,786,812	$ 1,934,522	$ 2,086,735
Target Operating Income	**$ 2,046,963**	**$ 2,281,891**	**$ 2,403,427**	**$ 2,533,387**	**$ 2,666,925**
Projected Operating Income	**$ 1,579,517**	**$ 1,316,342**	**$ 1,076,337**	**$ 829,158**	**$ 569,747**
Rate of Return in %	**5.2%**	**5.6%**	**5.7%**	**5.9%**	**6.1%**

Recommended Rate Track

The study identifies increasing current revenues in 2016, and increase annually thereafter to maintain debt coverage ratios and minimum cash targets. Table 6 is a summary of the financial results detailing the recommended revenue adjustments required to meet target operating income.

Table 6 – Recommended Revenue Adjustments

Fiscal Year	Projected Rate Adjustments	Capital Improvements Plan	Projected Expenses	Projected Revenues	Adjusted Operating Income	Target Operating Income	Projected Cash Balances	Recommended Minimum Cash
2016	2.0%	$ 3,755,370	$ 34,628,467	$ 36,925,144	$ 2,296,677	$ 2,046,963	$ 12,517,959	$ 9,969,462
2017	1.0%	3,819,593	35,761,267	38,130,077	2,368,810	2,281,891	12,457,730	10,211,614
2018	1.0%	3,801,412	36,884,050	39,372,850	2,488,800	2,403,427	12,755,830	10,505,122
2019	1.0%	3,954,875	38,038,010	40,646,765	2,608,755	2,533,387	13,179,788	10,829,584
2020	1.0%	4,202,476	39,228,907	41,952,641	2,723,734	2,666,925	13,640,065	12,140,479

Cost of Service Summary Results

A cost of service study was completed to determine the cost of providing service to each class of customers and to assist in design of electric rates for customers. A cost of service study consists of the following general steps:

1) Determine utility revenue requirement for test year 2016
2) Classify utility expenses into common cost pools
3) Allocate costs to customer classes based on the classes' contribution to utility expenses
4) Compare revenues received from each class to the cost of service

The cost of service summary is included as Table 7 which compares the projected cost to serve each class with the revenue received from each class. The "% change" column is the revenue adjustment necessary to meet projected cost of service requirements. The cost of service summary uses the current rates including any adjustment factors.

Table 7 – Cost of Service Summary

Customer Class	Cost of Service	Projected Revenues (with PCA)	% Change
Residential (110R)	6,050,306	5,872,688	3%
Residential Heat (501RH)	810,536	780,555	4%
Small General Service (130SGS)	3,538,753	3,433,778	3%
Security Lighting (SecL)	71,055	75,643	-6%
Public Lighting (SL)	419,861	174,175	141%
Small General Service (Demand) (140SGS)	2,570,532	2,814,691	-9%
Large General Service (150LGS)	8,052,920	8,082,321	0%
Large General Service Int (151LGS)	749,126	724,049	3%
Large General Service TOU (160LGST)	5,201,629	5,355,727	-3%
Large General Service Data (163LGSD)	2,933,472	2,911,191	1%
Large General Service >5MW (165LGS)	5,927,240	5,633,165	5%
Total	**36,325,430**	**35,857,984**	**1.3%**

Cost of Service Results

Table 8 shows the average cost of service per kWh and compares the cost to the average revenue per kWh for each customer class.

Table 8 – Average Cost per kWh vs. Average Revenue per kWh

Customer Class	Cost of Service $/kWh	Projected Revenues $/kWh
Residential (110R)	0.1401	0.1360
Residential Heat (501RH)	0.1277	0.1230
Small General Service (130SGS)	0.1545	0.1499
Security Lighting (SecL)	0.1054	0.1122
Public Lighting (SL)	0.2547	0.1057
Small General Service (Demand) (140SGS)	0.1131	0.1238
Large General Service (150LGS)	0.1028	0.1031
Large General Service Int (151LGS)	0.1053	0.1018
Large General Service TOU (160LGST)	0.0979	0.1008
Large General Service Data (163LGSD)	0.0940	0.0932
Large General Service >5MW (165LGS)	0.0961	0.0913

Cost differences result from usage patterns of customers and how efficiently each class of customer use facilities based on load data provided by RMU.

Distribution Costs

Separation of distribution cost helps identify distribution charges for each customer class and the fixed monthly customer charge. Distribution rates include separation of the following costs:

- Operation and maintenance of distribution & transmission system

- Contributions to City
- Customer service
- Customer accounting
- Meter reading
- Billing
- Meter operation & maintenance
- Administrative expenses

The distribution rates consist of two components:

- Monthly customer charge to recover the costs of meter reading, billing, customer service, and a portion of maintenance and operations of the distribution system.
- Distribution rate based on billing parameter, (kW or kWh) to recover the cost to operate and maintain the distribution system. Table 9 identifies the cost-based distribution rates for customer classes.

Table 9 – Distribution Costs by Customer Class (COS)

Customer Class	Monthly Customer Charge	Distribution Rate	Billing Basis	Contribution to City	Billing Basis
Residential (110R)	$ 14.10	$ 0.0305	kWh	$ 0.0064	kWh
Residential Heat (501RH)	14.10	0.0244	kWh	0.0057	kWh
Small General Service (130SGS)	42.31	0.0360	kWh	0.0070	kWh
Security Lighting (SecL)	0.98	0.0297	kWh	0.0052	kWh
Public Lighting (SL)	0.98	0.1852	kWh	0.0049	kWh
Small General Service (Demand) (140SGS)	92.47	7.3533	kW	0.0058	kWh
Large General Service (150LGS)	141.02	8.1520	kW	0.0048	kWh
Large General Service Int (151LGS)	195.91	7.6084	kW	0.0048	kWh
Large General Service TOU (160LGST)	242.75	8.1647	kW	0.0047	kWh
Large General Service Data (163LGSD)	242.75	7.2163	kW	0.0044	kWh
Large General Service >5MW (165LGS)	211.75	8.0249	kW	0.0043	kWh

Power Supply Costs

Table 10 identifies the average cost of providing power supply to customers of RMU.

Table 10 – Power Supply Costs by Customer Class

Customer Class	Current Rates Demand	Billing Basis	Energy	Billing Basis
Residential (110R)	$ 0.0181	kWh	$ 0.0644	kWh
Residential Heat (501RH)	$ 0.0140	kWh	$ 0.0667	kWh
Small General Service (130SGS)	$ 0.0262	kWh	$ 0.0643	kWh
Security Lighting (SecL)	$ -	kWh	$ 0.0642	kWh
Public Lighting (SL)	$ -	kWh	$ 0.0642	kWh
Small General Service (Demand) (140SGS)	$ 7.02	KW	$ 0.0641	kWh
Large General Service (150LGS)	$ 7.73	KW	$ 0.0641	kWh
Large General Service Int (151LGS)	$ 7.68	KW	$ 0.0641	kWh
Large General Service TOU (160LGST)	$ 8.25	KW	$ 0.0638	kWh
Large General Service Data (163LGSD)	$ 8.26	KW	$ 0.0643	kWh
Large General Service >5MW (165LGS)	$ 9.18	KW	$ 0.0619	kWh

Combined Cost Summary

Table 11 identifies the cost of service rates for each customer class. Charging these rates would directly match the cost of providing service to customers identified in this study.

Table 11 – Total Costs by Customer Class

Customer Class	Current Customer Charge	COS Customer Charge	Annual Demand	Energy
Residential (110R)	$ 7.50	$ 14.10	$ -	$ 0.1194
Residential Heat (501RH)	7.50	14.10	-	0.1108
Small General Service (130	17.50	42.31	-	0.1336
Security Lighting (SecL)	-	0.98	-	0.0991
Public Lighting (SL)	-	0.98	-	0.2544
Small General Service (Den	100.00	92.47	14.37	0.0699
Large General Service (150	150.00	141.02	15.88	0.0689
Large General Service Int (1	225.00	195.91	15.29	0.0688
Large General Service TOU	260.00	242.75	16.41	0.0685
Large General Service Data	260.00	242.75	15.48	0.0686
Large General Service >5M'	250.00	211.75	17.20	0.0661

3. Functionalization of Costs

Delivery of electricity consists of many components that bring electricity from the power supply facilities to the communities and eventually into customer facilities. The facilities consist of four major components: transmission, distribution, customer-related services, and administration. Following are general descriptions of each of these facilities and the sub-breakdowns within each category.

Transmission

The transmission system is comprised of four types of subsystems that operate together:

1) Backbone and inter-tie transmission facilities are the network of high voltage facilities through which a utility's major production sources are integrated.
2) Generation set-up facilities are the substations through which power is transformed from a utility's generation voltages to its various transmission voltages.
3) Sub-transmission plant consists of lower voltage facilities to transfer electric energy from convenient points on a utility's backbone system to its distribution system.
4) Radial transmission facilities are those that are not networked with other transmission lines but are used to serve specific loads directly.

Operation of the transmission system also consists of providing certain services that ensure a stable supply of power. These services are typically referred to as ancillary services. The Federal Energy Regulatory Commission (FERC) has defined six ancillary service charges for the use of transmission facilities. For RMU, these charges will be passed-through charges by the control area operator. Ancillary services consist of the following:

- **Mandatory Ancillary Service Charges:**

  Reactive Supply and Voltage Control
  Regulation and Frequency Response Service
  Energy Imbalance Charges
  Operating Reserves Spinning
  Operating Reserves Supplemental

Terminology of Cost of Service

FUNCTIONALIZATION – Cost data arranged by functional category (e.g. power supply, transmission, distribution

CLASSIFICATION – Assignment of functionalized costs to cost components (e.g. demand, energy and customer related).

ALLOCATION – Allocating classified costs to each class of service based on each class's contribution to that specific cost component.

DEMAND COSTS – Costs that vary with the maximum or peak usage. Measured in kilowatts (kW)

ENERGY COSTS – Costs that vary over an extended period of time. Measured in kilowatt-hours (kWh)

CUSTOMER COSTS – Costs that vary with the number of customers on the system, e.g. metering costs.

DIRECT ASSIGNMENT – Costs identified as belonging to a specific customer or group of customers.

Reactive Power Supply
Power losses from use of transmission system

Distribution

The distribution facilities connect the customer with the transmission grid to provide the customer with access to the electrical power that has been generated and transmitted. The distribution plant includes substations, primary and secondary conductors, poles, and line transformers that are jointly used and in the public right-of-way.

Substations typically separate the distribution plant from the transmission system. The substation power transformer "steps down" the voltage to a level that is more practical to install on and under city streets.

Distribution circuits are divided into primary and secondary voltages with the primary voltages usually ranging between 35 kV and 4 kV and the secondary below 4 kV.

Distribution Customer Types

Sub-transmission customers are served directly from the substation feeder and bypass both the secondary and primary distribution lines. The charges for this type of customer should reflect the cost of the substation and not include the cost of primary or secondary line charges.

Primary customers are typically referred to as customers who have purchased, owned, and maintained their own transformers that convert the voltage to the secondary voltage level. The rates for these customers should reflect the cost of substations and the cost of primary distribution lines and not include the cost of secondary line extensions.

Secondary customers have the services provided by the utilities directly into their facilities. The utility provides the customer with the transformer and the connection on the customers' facilities.

Customer-Related Services

Certain administrative-type services are necessary to ensure customers are provided service connections and disconnections in a timely manner and the facilities are in place to read meters and bill for customer usages. These services typically consist of the following components:

- Customer Services – The cost of providing personnel to assist customers with questions and dispatch personnel to connect and disconnect meters.
- Billing and Collections – The cost of billing and collections personnel, postage, and supplies.
- Meter Reading – The cost of reading customers' meters.
- Meter Operation and Maintenance – The cost of installing and maintaining customer meters.

Administrative Services

These costs are sometimes referred to as overhead costs and relate to functions that cannot be directly-attributed to any service. These costs are spread to the other services through an allocator such as labor, expenses, or total rate base. These costs may consist of City Commission expenses, property insurance, and wages for higher level management of the utility.

System Losses

As energy moves through each component of the transmission and distribution system, some of the power is lost and cannot be sold to customers. Losses vary based on time of day and season. Typically, as system usage increases or ambient temperature increases, the percentages of losses that occur also increase. These losses are recovered from distribution customers through an analysis of the peak losses that occur in the system. The average system losses and unaccounted for energy for RMU are approximately 6.2%. (Typical municipal system losses are approximately 5.4%)

4. Determination of Costs by Location Process

The cost of power supply, distribution, and customer services are identified as part of the determination of costs by location process and are the first step in determining costs by location with the utility charges to customers. The total revenue requirements of $36.3M are separated into three categories identified in Table 12.

Table 12 – Breakdown of RMU Cost Structure

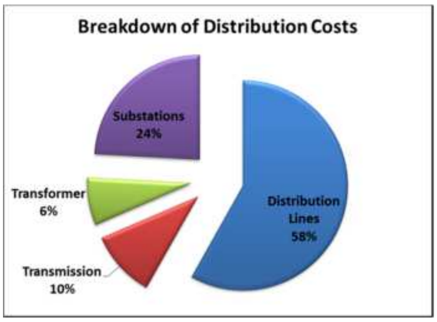
Expense Type		Amount	Percentage
Power Supply	$	26,448,119	72.8%
Distribution		6,862,192	18.9%
Customer		1,674,142	4.6%
Contribution		1,340,977	3.7%
Total	$	36,325,430	100.0%

RMU is projected to expend 72.8% of its total costs toward power supply. Distribution/transmission-related costs are 18.9%; customer service 4.6% and 3.7% contribution to the city. These components are broken down into each of the subcomponents and are identified in the following sections.

Distribution Breakdown

Distribution rates consist of a number of different components. Total distribution-related costs of $6.8M for 2016 are broken down into the main components including substations, transformers, transmission, and distribution lines. Figure 1 shows the breakdown of distribution components identified in the study.

Figure 1 – Breakdown of Distribution Costs

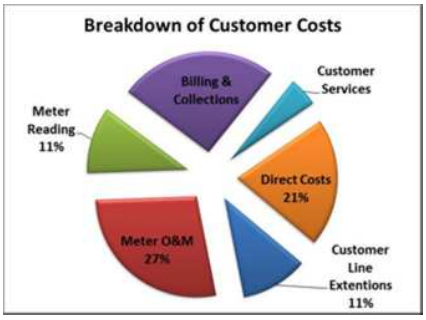


Each of these components is allocated to customer groups based on certain factors established in the study. These factors are based on the efficiency of each customer class and the time of day or the season the electricity is used. Other factors are also considered, such as the length of line extensions to reach certain customer classes.

Customer-Related Cost Breakdown

RMU total expenses for customer-related costs are $1.3M for 2016. The cost is broken down into the components identified in Figure 2.

Figure 2 – Breakdown of Customer Costs



Power Supply Cost Breakdown

Power supply costs for 2016 were made up of purchased power and fuel and internal generation expenses.

5. Significant Assumptions

This section outlines the procedures used to develop the cost of service and determination of costs by location study for RMU and the related significant assumptions.

Forecasted Operating Expenses

Forecasted expenses were based on 2012, 2013 and 2014, 2015 budget adjusted for power supply costs and inflation. The table below is a summary of the expenses used in the analysis; the projected operating expenses include an adjustment for any city contributions.

Table 13 – Projected Operating Expenses for 2016– 2020

Description	Projected 2016	Projected 2017	Projected 2018	Projected 2019	Projected 2020
Operating Expenses					
Power Supply and Fuel					
Purchased Power (Cost of Sales and Service)	$ 24,768,204	$ 25,511,250	$ 26,276,587	$ 27,064,885	$ 27,876,832
Total Purchases Expense	$ 24,768,204	$ 25,511,250	$ 26,276,587	$ 27,064,885	$ 27,876,832
Production					
Production Expense	$ 1,242,467	$ 1,273,529	$ 1,305,367	$ 1,338,001	$ 1,371,451
Total Production Expense	$ 1,242,467	$ 1,273,529	$ 1,305,367	$ 1,338,001	$ 1,371,451
Total Power Supply Expense	$ 26,010,671	$ 26,784,779	$ 27,581,954	$ 28,402,886	$ 29,248,283
Distribution					
Total Distribution O&M	1,863,604	1,910,194	1,957,949	2,006,897	2,057,070
Total Distribution Expense	$ 1,863,604	$ 1,910,194	$ 1,957,949	$ 2,006,897	$ 2,057,070
Other Operating Expenses (Revenues)					
Customer/Sales Expense	$ 466,692	$ 478,360	$ 490,319	$ 502,577	$ 515,141
Administrative and General Expense	2,077,132	2,129,060	2,182,287	2,236,844	2,292,765
Depreciation Expense	2,536,226	2,612,618	2,765,038	2,920,163	3,083,310
Payment in Lieu of Taxes	1,674,142	1,846,257	1,906,504	1,968,642	2,032,338
Total Other Operating Expenses	$ 6,754,192	$ 7,066,295	$ 7,344,147	$ 7,628,226	$ 7,923,555
Total Operating Expenses	**$ 34,628,467**	**$ 35,761,267**	**$ 36,884,050**	**$ 38,038,010**	**$ 39,228,907**

Power supply costs from 2016 – 2020 are based on RMU's current charges adjusted for system growth factors and inflation.

Load Data

Load data is one of the most critical components of a cost of service study. Information from the billing statistics were used to determine the usage patterns of each customer class after reconciling revenues with financial statements to ensure a good basis for development of the study.

Annual Projection Assumptions

The kWh sales forecast is based on FY 2014 actual. Table 14 details growth, inflation of expenses, changes in purchase power costs and interest earned on investments.

Table 14 – Projection Annual Escalation Factors 2016– 2020

Fiscal Year	Inflation	Growth	Purchase Power Change	Investment Income
2016				0.5%
2017	2.5%	0.5%	3.0%	0.5%
2018	2.5%	0.5%	3.0%	0.5%
2019	2.5%	0.5%	3.0%	0.5%
2020	2.5%	0.5%	3.0%	0.5%

System Loss Factors

Losses occurring from the transmission and distribution of electricity can vary from year to year depending upon weather and system loading.

Revenue Forecast

The revenue forecast was based on FY2014 usages adjusted for growth rate assumptions.

6. Recommendations and Additional Information

We recommend that the utility move toward cost of service for each customer class.

The study indicates rate adjustments are needed to meet debt coverage, minimum cash and operating income targets. To ensure the utility meets financial targets and remains financially stable, the rate track identified in may be considered:

Table 15 – Recommended Rate Adjustments 2016– 2020

Fiscal Year	Projected Rate Adjustments	Capital Improvements Plan	Projected Expenses	Projected Revenues	Adjusted Operating Income	Target Operating Income	Projected Cash Balances	Recommended Minimum Cash
2016	2.0%	$ 3,755,370	$ 34,628,467	$ 36,925,144	$ 2,296,677	$ 2,046,963	$ 12,517,959	$ 9,969,462
2017	1.0%	3,819,593	35,761,267	38,130,077	2,368,810	2,281,891	12,457,730	10,211,614
2018	1.0%	3,801,412	36,884,050	39,372,850	2,488,800	2,403,427	12,755,830	10,505,122
2019	1.0%	3,954,875	38,038,010	40,646,765	2,608,755	2,533,387	13,179,788	10,829,584
2020	1.0%	4,202,476	39,228,907	41,952,641	2,723,734	2,666,925	13,640,065	12,140,479

The cost of service study identified some customer classes are subsidizing other customer classes. RMU should consider movements toward cost of service using a bandwidth of plus or minus 1%. Using the 1% rate adjustment, this would result in no customer class given a rate increase greater than 3% and the lowest increase would be 1%. Table 16 identifies the cost of service charges compared with the projected current revenues for each class. Classes that indicate a lower % change than the total percentage change are providing subsidy to other customer classes, conversely customer classes with a higher % change than the total percentage are receiving subsidy.

Table 16 – Cost of Service Summary Results

Customer Class	Cost of Service	Projected Revenues (with PCA)	% Change
Residential (110R)	6,050,306	5,872,688	3%
Residential Heat (501RH)	810,536	780,555	4%
Small General Service (130SGS)	3,538,753	3,433,778	3%
Security Lighting (SecL)	71,055	75,643	-6%
Public Lighting (SL)	419,861	174,175	141%
Small General Service (Demand) (140SGS)	2,570,532	2,814,691	-9%
Large General Service (150LGS)	8,052,920	8,082,321	0%
Large General Service Int (151LGS)	749,126	724,049	3%
Large General Service TOU (160LGST)	5,201,629	5,355,727	-3%
Large General Service Data (163LGSD)	2,933,472	2,911,191	1%
Large General Service >5MW (165LGS)	5,927,240	5,633,165	5%
Total	**36,325,430**	**35,857,984**	**1.3%**

RMU may consider movements in the customer charges to move toward cost of service based customer charges to help ensure fixed distribution charges are collected in the customer charge. Table 17 compares the total cost of service monthly customer charges with the current charges. By charging cost of service rates for the monthly charge RMU reduces it risk associated with power usage fluctuations due to weather etc.

Table 17 – Customer Charge Comparison

Customer Class	Current Customer Charge	COS Customer Charge
Residential (110R)	$ 7.50	$ 14.10
Residential Heat (501RH)	7.50	14.10
Small General Service (130SGS)	17.50	42.31
Small General Service (Demand) (140SGS)	100.00	92.47
Large General Service (150LGS)	150.00	141.02
Large General Service Int (151LGS)	225.00	195.91
Large General Service TOU (160LGST)	260.00	242.75
Large General Service Data (163LGSD)	260.00	242.75
Large General Service >5MW (165LGS)	250.00	211.75

Utility Financial Solutions
185 Sun Meadow Ct.
Holland, MI 49424
Phone: 616-393-9722
Fax: 616-393-9721

Accountant's Compilation Report

Governing Body
Rochelle Municipal Utilities

The accompanying forecasted statements of revenues and expenses of the Rochelle Municipal Utilities (utility) were compiled for the year ending April 30th, 2016 in accordance with guidelines established by the American Institute of Certified Public Accountants.

The purpose of this report is to assist management in forecasting revenue requirements and determining the cost to service each customer class. This report should not be used for any other purpose.

A compilation is limited to presenting, in the form of a forecast; information represented by management and does not include evaluation of support for any assumptions used in projecting revenue requirements. We have not audited the forecast and, accordingly, do not express an opinion or any other form of assurance on the statements or assumptions accompanying this report.

Differences between forecasted and actual results will occur since some assumptions may not materialize and events and circumstances may occur that were not anticipated. Some of these variations may be material. Utility Financial Solutions has no responsibility to update this report after the date of this report.

This report is intended for information and use by the governing body and management for the purposes stated above. This report is not intended to be used by anyone except the specified parties.

UTILITY FINANCIAL SOLUTIONS

Mark Beauchamp, CPA, CMA, MBA
Holland, MI
April 2015