City of Naperville

Electric Cost of Service Study and Financial Projection

October 2024

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UTILITY FINANCIAL SOLUTIONS, LLC

October 2024

Brian Groth, P.E.
Director, Electric Utility
City of Naperville
1392 Aurora Avenue
Naperville, IL 60540

Dear Mr. Groth:

We are pleased to present this Final Report for the electric cost of service study and financial projection for the City of Naperville (NAP). This report was prepared to provide NAP 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 2025
- 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
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1. Introduction

This report was prepared to provide the City of Naperville (NAP) 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 2025*.** NAP's revenue requirements were projected for the period from 2025 – 2027 and included adjustments for the following:
    a. Projected power costs
    b. Projected inflation on utility expenses
    c. Capital improvement plan projected over next three years

2) ***Identify if cross-subsidies 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 2025 projected revenues and expenses. The financial projections are for the period from 2025 – 2027.

3) ***Identify cost-based power supply and distribution rates.*** The cost of providing electricity to customers consists of several components, including power generation, distribution, customer services, transmission, and transfers to the general fund. Electric unbundling identifies the cost of each component to assist the utility in preparing for electric restructuring and understanding its cost structure.

4) ***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.

5) ***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 NAP to help ensure the financial stability of the utility in future years.

2. Cost of Service Summary

Utility Rate Process

NAP retained Utility Financial Solutions, LLC 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 unbundling study and recommendations on future rate designs.

Utility Revenue Requirements

To determine revenue requirements, the revenues and expenses for fiscal years 2022 and 2023, 2024 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 2025-2027.

The following pages review cash flow, debt coverage ratio, and rate of return which are important indicators of financial health.

Table 1 – Financial Statements (without rate adjustments*)

Description	Projected 2025	Projected 2026	Projected 2027
Operating Revenues:			
Charges for Services	$ 138,078,503	$ 135,316,933	$ 132,610,594
Sales for Resale (CoGen Credit)	204,894	204,894	204,894
Additional revenue from Cust less CoGen	4,091,088	4,091,088	4,091,088
Miscellaneous	1,385,000	1,385,000	1,385,000
Additional PPA Revenues		0	0
Total Operating Revenues	$ 143,759,485	$ 140,997,915	$ 138,291,576
Operating Expenses:			
Purchased Power Cost (before CoGen Credit)	$ 103,367,774	$ 101,300,418	$ 99,274,410
Inventory Issues - CONTRA : 40251300 : 549999	(3,000,000)	(3,000,000)	(3,000,000)
Distribution			
Operations	11,737,563	12,207,066	12,695,348
Distribution	3,152,070	3,278,153	3,409,279
Other Operating Expenses (Revenues)			
Other Operating Expenses (adjusted)	23,239,133	24,168,698	25,135,446
Depreciation Expense	14,334,210	15,624,839	16,892,242
Total Operating Expenses	$ 152,830,749	$ 153,579,173	$ 154,406,725
Operating Income (Loss)	$ (9,071,264)	$ (12,581,259)	$ (16,115,149)
Nonoperating Income/(Expense)			
Interest on Investments Income(loss)	$ 152,856	$ 23,406	$ -
Capital Fees (customer reimbursement)	3,075,000	2,653,000	2,743,000
Capital Fees (grant support reimbursement)	-	743,000	1,093,000
Interest Expense - Bonds	(474,320)	(799,525)	(743,015)
Total Nonoperating Income/(Expense)	**$ 2,753,536**	**$ 2,619,881**	**$ 3,092,985**
Net Income	**$ (6,317,728)**	**$ (9,961,378)**	**$ (13,022,164)**
Adjusted Operating Income	**$ (9,071,264)**	**$ (12,581,259)**	**$ (16,115,149)**

Projected Cash Flow

Table 2 is the projected cash flow for 2025 – 2027, including projections of capital improvements as provided by NAP. Changes in the capital improvement plan can greatly affect the cash balance and recommended minimum cash reserve target. The cash balance for 2025 is projected at $2.34M and $-36.97M in 2027. The recommended minimum cash reserve level for 2025 is $38.76M and $39.72M for 2027.

Table 2 – Projected Cash Flows (without rate adjustments*)

Description	Projected 2025	Projected 2026	Projected 2027
Projected Cash Flows			
Add Net Income/(Loss)	$ (6,317,728)	$ (9,961,378)	$ (13,022,164)
Add back Depreciation Expense	14,334,210	15,624,839	16,892,242
Subtract Debt Principal	(1,908,613)	(1,347,755)	(1,361,665)
Add CIP reimbursed by customer	3,075,000	3,396,000	3,836,000
Add Bond Sale Proceeds	7,500,000	10,000,000	-
Cash Available from Operations	$ 16,682,868	$ 17,711,706	$ 6,344,412
Estimated Annual Capital Additions (less CIP Labor)	(29,627,816)	(34,903,642)	(28,466,500)
Net Cash From Operations	$ (12,944,948)	$ (17,191,936)	$ (22,122,088)
Beginning Cash Balance	$ 15,285,584	$ 2,340,636	$ (14,851,300)
Year Ending Cash Balance	$ 2,340,636	$ (14,851,300)	$ (36,973,388)
Total Cash Available	**$ 2,340,636**	**$ (14,851,300)**	**$ (36,973,388)**
Recommended Minimum	**$ 38,760,102**	**$ 39,211,829**	**$ 39,721,081**

Cash balances continue to decrease through the projection period and include optional borrowing in 2025 and 2026.

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 an assessment of working capital needs to fund operating expenses, capital improvements, annual debt service payments, and utility's exposure to risks related to catastrophic events, exposure to market risks, changes in fuel costs, loss of major customers, and utility's ability to timely recover changes in power supply expenses. The minimum level has been reduced by $10M, similar to the calculated emergency reserve, as the City can support this amount in an emergency event. Based on these assumptions, NAP should maintain a minimum of $38.76M in cash reserves for 2025 and $39.72M in 2027.

Table 3 – Minimum Cash Reserves (without rate adjustments*)

Description	Projected 2025	Projected 2026	Projected 2027
Minimum Cash Reserve Levels Determinants			
O&M Less Depreciation & P/S Expense	$ 38,128,766	$ 39,653,916	$ 41,240,073
Annual Power Supply Expense	100,367,774	98,300,418	96,274,410
Historical Rate Base (less IMEA Participation)	538,700,511	573,604,153	602,070,653
Current Portion of Debt Service	2,382,933	2,147,281	2,104,681
Three Year Capital Improvements - Net of bond proceeds	75,497,958	75,497,958	75,497,958
Minimum Cash Reserve Allocation			
O&M Less Depreciation & P/S Expense (30 day W/C)	8.2%	8.2%	8.2%
Annual Power Supply Expense (Max bill / annual P/S cost)	7.5%	7.5%	7.5%
Historical Rate Base (based on age of assets)	2%	2%	2%
Current Portion of Debt Service (principal + half annual intrest)	92%	92%	92%
Three Year Capital Improvements - Net of bond proceeds	33%	33%	33%
% Plant Depreciated	59%	58%	58%
Calculated Minimum Cash Level			
O&M Less Depreciation & P/S Expense **(30 day W/C)**	$ 3,133,871	$ 3,259,226	$ 3,389,595
Annual Power Supply Expense **(Max bill / annual P/S cost)**	7,487,021	7,332,804	7,181,673
Emergency Fund	10,774,010	11,472,083	12,041,413
Current Portion of Debt Service **(principal + half annual intrest)**	2,199,214	1,981,730	1,942,414
Three Year Capital Improvements - Net of bond proceeds	25,165,986	25,165,986	25,165,986
Less allocation of City cash fund available if needed	(10,000,000)	(10,000,000)	(10,000,000)
Minimum Cash Reserve Levels	**$ 38,760,102**	**$ 39,211,829**	**$ 39,721,081**
Projected Cash Reserves	**$ 2,340,636**	**$ (14,851,300)**	**$ (36,973,388)**
NAP Policy (30 Days Cash on Hand)	$ 11,383,277	$ 11,338,712	$ 11,302,560

Projected cash balances fall below UFS recommended minimums during the projection period and also fall below NAP requirements to maintain 30 days cash on hand.

Debt Coverage Ratio

Table 4 is the projected debt coverage ratios with capital additions as provided by NAP. Debt coverage ratio is a measurement of debt affordability and measures the cash flow from operations in that fiscal year. A ratio of 1, indicates there was enough cash flow from operations to pay the debt payment one time. The minimum recommended debt coverage ratio for prudent financial planning purposes is 1.40.

Maintaining a 1.40 debt coverage ratio is good business practice and helps to achieve the following:

a. Helps to ensure debt coverage ratios are met in years when sales are low due to cold or wet summers or loss of a major customer(s).

b. When debt coverage ratios are consistently met, it may help obtain a 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 2025	Projected 2026	Projected 2027
Debt Coverage Ratio			
Net Income	$ (6,317,728)	$ (9,961,378)	$ (13,022,164)
Add Depreciation/Amortization Expense	14,334,210	15,624,839	16,892,242
Add Interest Expense	474,320	799,525	743,015
Cash Generated from Operations	$ 8,490,801	$ 6,462,986	$ 4,613,093
Debt Principal and Interest	$ 2,382,933	$ 2,147,281	$ 2,104,681
Projected Debt Coverage Ratio (Covenants)	**3.56**	**3.01**	**2.19**
UFS Minimum Debt Coverage Ratio	**1.4**	**1.4**	**1.4**
IMEA Minimum Debt Coverage Ratio	1.2	1.2	1.2

Debt coverage is adequate for the projection period without changes in rates. NAP has debt issued through the City as general obligation bonds, and this debt coverage ratio requirement is related to revenue bonds that are typically utilized by utilities.

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.

E. The rate of return identifies the target operating income and is used to identify the appropriate funding for replacement of existing infrastructure to recover in rates charged to customers.

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. Table 5 identifies the utility basis target established for 2025 is $16.41M and increases to $18.12M in 2027.

Table 5 – Rate of Return Calculation (without rate adjustments*)

Description	Projected 2025	Projected 2026	Projected 2027
Optimal Operating Income Determinants			
Net Book Value/Working Capital	$ 221,945,728	$ 241,224,531	$ 252,798,790
Outstanding Principal on Debt	10,098,137	18,750,382	17,388,716
System Equity	$ 211,847,591	$ 222,474,150	$ 235,410,074
Debt:Equity Ratio	5%	8%	7%
Optimal Operating Income Allocation			
Interest on Debt	4.70%	4.26%	4.27%
System Equity	7.52%	7.37%	7.38%
Optimal Operating Income			
Interest on Debt	$ 474,320	$ 799,525	$ 743,015
System Equity	$ 15,939,908	$ 16,399,555	$ 17,380,377
Target Operating Income	**$ 16,414,228**	**$ 17,199,081**	**$ 18,123,393**
Projected Operating Income	**$ (9,071,264)**	**$ (12,581,259)**	**$ (16,115,149)**
Rate of Return in %	**7.4%**	**7.1%**	**7.2%**

Operating income is projected to fall below the target operating income for each year.

Projected Rate Track

Adjusting system revenue requires balancing the financial health of the utility with the financial impact on customers and cost of service results. Table 6 is the summary financial projection without any rate changes. Cash balances, operating income and the debt coverage ratio fall to critical levels.

Table 6 – Summary of Financials without Rate Adjustments

Fiscal Year	Projected Rate Adjustments	Debt Coverage Ratio	Operating Income	UFS Optimal Operating Income	Projected Cash Balances	UFS Recommended Minimum Cash	NAP Days Working Cash	Optional Borrowing (20Yr @ 4%)
2025	0.0%	3.56	$ (9,071,264)	$16,414,228	$ 2,340,636	$ 38,760,102	6	$ 7,500,000
2026	0.0%	3.01	(12,581,259)	17,199,081	(14,851,300)	39,211,829	-39	10,000,000
2027	0.0%	2.19	(16,115,149)	18,123,393	(36,973,388)	39,721,081	-98	-

The study identifies increasing current revenues in all three years to maintain financial targets. Table 7 is a summary of the financial results detailing the projected revenue adjustments.

Table 7 – Projected Revenue Adjustments

Fiscal Year	Projected Rate Adjustments	Debt Coverage Ratio	Operating Income	UFS Optimal Operating Income	Projected Cash Balances	UFS Recommended Minimum Cash	NAP Days Working Cash	Optional Borrowing (20Yr @ 4%)
2025	6.5%	7.33	$ (96,162)	$16,414,228	$11,315,739	$ 38,760,102	30	$ 7,500,000
2026	5.1%	10.57	3,564,081	17,199,081	10,358,894	39,211,829	27	10,000,000
2027	5.1%	13.36	7,277,369	18,123,393	11,732,912	39,721,081	31	-

This rate track will increase the operating income and projected cash balances through 2027 and projects NAP to maintain 30 days working cash through-out the projection period. Due to cost changes, inflationary factors, and growth, financial projections should be reviewed on an annual basis. Depending on the system improvement timetable, additional changes may be needed throughout the projection period.

Debt to Equity Ratio

Debt to equity identifies the amount of existing infrastructure financed through debt and is used to determine the amount the system is leveraged in debt. For distribution systems the debt to equity ratio is normally between 30% and 35%. Table 8 details the debt/equity ratio.

Table 8 – Debt/Equity Ratio

Description	Projected 2025	Projected 2026	Projected 2027
Optimal Operating Income Determinants			
Net Book Value/Working Capital	$ 221,945,728	$ 241,224,531	$ 252,798,790
Outstanding Principal on Debt	10,098,137	18,750,382	17,388,716
Debt:Equity Ratio	5%	8%	7%

Age of Infrastructure

NAP is currently 59% depreciated. Average infrastructure is approximately 50% to 55% depreciated, indicating NAP has not consistently funded replacement of infrastructure. Replacement of infrastructure tends to indicate the utility's ability to consistently provide a reliable system to customers, its ability to withstand catastrophic weather events, and unexpected replacement of system infrastructure. NAP's system age indicates it will remain in the higher than average range of infrastructure age. Table 9 identifies the depreciated plant.

Table 9 – Age of Infrastructure

Description	Projected 2025	Projected 2026	Projected 2027
Asset Invetments	$ 538,700,511	$ 573,604,153	$ 602,070,653
NBV	$ 221,945,728	$ 241,224,531	$ 252,798,790
% Depreciated	59%	58%	58%

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 2025.
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 10 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.

No utility charges 100% cost of service-based rates because retail rates are based on customers usage patterns that are largely driven by variations in weather. Due to these variations, it is recommended that rates move toward cost of service slowly with a general tolerance of a 10% variation between projected revenue and cost of service. The cost of service summary "% change" column indicates not all major customer classes fall within this variation.

Table 10 – Cost of Service Summary

Customer Class	Cost of Service	Projected Revenues	Effective % Change
Residential RS	$ 82,900,548	$ 64,585,655	28.4%
General Service GS1	19,241,441	16,750,176	14.9%
Street Lights SL	318,574	-	
Metered Outdoor Lighting OLR	232,666	202,312	15.0%
General Service GS2	47,822,911	43,754,646	9.3%
Primary PRIM	12,831,782	12,489,587	2.7%
Transmission (no PPA) TRAN	216,071	296,127	-27.0%
Total	**$ 163,563,996**	**$ 138,078,503**	**18.5%**

Cost of Service Results

Table 11 shows the average cost of service per kWh and compares the cost to the average revenue per kWh for each customer class. This table is for information purposes only and is not used in the setting of rates. Average cost per kWh varies due to fixed cost recoveries such as meter costs and infrastructure needs of the customer. In general customer classes that use energy consistently have a lower average kWh cost to serve compared with customer classes that use energy only part of the day or year.

Table 11 – Average Cost per kWh vs. Average Revenue per kWh

Customer Class	Cost of Service $/kWh	Projected Revenues $/kWh
Residential RS	$ 0.1680	$ 0.1309
General Service GS1	0.1507	0.1312
Street Lights SL	0.0789	-
Metered Outdoor Lighting OLR	0.1631	0.1418
General Service GS2	0.1170	0.1070
Primary PRIM	0.0876	0.0853
Transmission (no PPA) TRAN	0.1548	0.2122

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

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 general fund
- 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 parameters (kW or kWh) to recover the cost to operate and maintain the distribution system. Table 12 identifies the cost-based distribution rates for customer classes.

Table 12 – Distribution Costs by Customer Class (COS)

Customer Class	COS Customer Charge	Current Average Customer Charge
Residential RS	$ 23.78	$ 17.00
General Service GS1	45.86	33.65
Metered Outdoor Lighting OLR	15.86	30.65
General Service GS2	146.97	90.00
Primary PRIM	203.64	180.00
Transmission (no PPA) TRAN	705.15	400.00

The cost of service based monthly customer charge for residential customers recovers 36% of the fixed cost of delivery of electricity. UFS averages across the United States show 40% to 60% fixed cost recovery in the residential customer charge.

Power Supply Costs

Table 13 identifies the average cost of providing power supply to customers of NAP.

Table 13 – Power Supply Costs by Customer Class

Customer Class	Demand	Billing Basis	Energy	Billing Basis
Residential RS	$ 0.0404	kWh	$ 0.0433	kWh
General Service GS1	0.0400	kWh	0.0444	kWh
Street Lights SL	-	kWh	0.0449	kWh
Metered Outdoor Lighting OLR	-	kWh	0.0446	kWh
General Service GS2	14.11	KW	0.0445	kWh
Primary PRIM	13.78	KW	0.0438	kWh
Transmission (no PPA) TRAN	7.73	KW	0.0482	kWh

Demand recovers costs for power supply and transmission fixed demand related costs. Energy is cost recovery for variable power supply costs.

Combined Cost Summary

Table 14 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 14 – Total Costs by Customer Class

Customer Class	Current Average Customer Charge	COS Customer Charge	Demand	Energy
Residential RS	$ 17.00	$ 23.78	$ -	$ 0.1374
General Service GS1	33.65	45.86	-	0.1219
Street Lights SL	-	3.77	-	0.0788
Metered Outdoor Lighting OLR	30.65	15.86	-	0.1460
General Service GS2	90.00	146.97	25.96	0.0445
Primary PRIM	180.00	203.64	25.33	0.0438
Transmission (no PPA) TRAN	400.00	705.15	10.46	0.0482

Residential Customer Charge

The customer charge consists of expenses related to, 1) providing a minimum amount of electricity to the residential customer, and 2) expenses related to servicing a meter on the customer's premises; together they reflect the cost to deliver a single kWh of electricity to the customer. The methodology used in this study is consistent with methodologies and practices used in the electric industry.

The customer charge includes two types of charges called minimum system charges and direct charges.

Minimum System Charges:

The cost to provide the minimum level of service. NAP provides wires to connect the transmission system to customer homes and businesses. This wire is required to provide even the minimal amount of service to a customer. For cost of service purposes, the total cost of the distribution infrastructure is broken into two components: 1) the minimum system costs, in effect to provide a customer with a single kWh of electricity which should be recovered through the customer charge, and 2) demand related costs to recover the additional infrastructure costs for when a customer uses more than a single kWh, which should be recovered through the usage component. The distribution system is sized to handle the customers' peak demands and the cost above the minimum system is recovered through the usage component (for residential customers this is included in the kWh charge).

The first step in identifying the cost related to the minimum system is obtaining information on the number and current replacement costs of NAP distribution system. For example: UFS used information on the number and size of all the poles and the cost to replace the poles. The minimum size pole was identified and the cost to construct NAP's system at the minimum sizing was determined. This process was completed for all NAP's distribution system, including overhead and underground conductors and devices, line transformers, etc. Based on this methodology, 64% of NAP's total distribution costs should be recovered by the usage component and 36% recovered in the fixed customer charge component.

Direct Charges

Costs related to maintaining a customer's account. These costs include the cost to operate and maintain the meter, including meter installation, meter repair and replacement costs, the cost to read the meter, billings and collections, customer service personnel to assist with questions and maintain the account, and the cost of the "service drop" to connect the home to the distribution line. These costs are direct costs of serving a residential account.

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 NAP, 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
  Reactive Power Supply
  Power losses from use of transmission system

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.

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 NAP are approximately 3.4%. (Typical municipal system losses are approximately 5.4%)

4. Unbundling Process

The cost of power supply, distribution, and customer services are identified as part of the unbundling process and are the first step in determining unbundled charges to customers. The total revenue requirements of $163.56M are separated into four categories identified in Table 15.

Table 15 – Breakdown of NAP Cost Structure

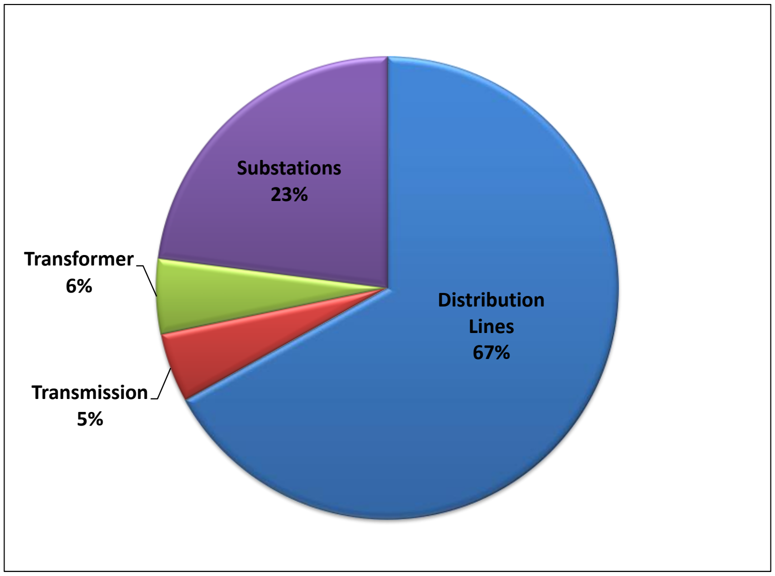
Expense Type		Amount	Percentage
Power Supply	$	96,071,792	59%
Distribution/Transmission		60,428,641	37%
Customer Service		7,063,563	4%
Total	$	163,563,996	100%

NAP is projected to expend 59% of its total costs toward power supply. Distribution/transmission-related costs are 37%; and customer service 4%. These components are broken down into subcomponents and are identified in the following sections.

Distribution Breakdown

Distribution rates consist of several different components. Total distribution-related costs of $60.43M for 2025 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

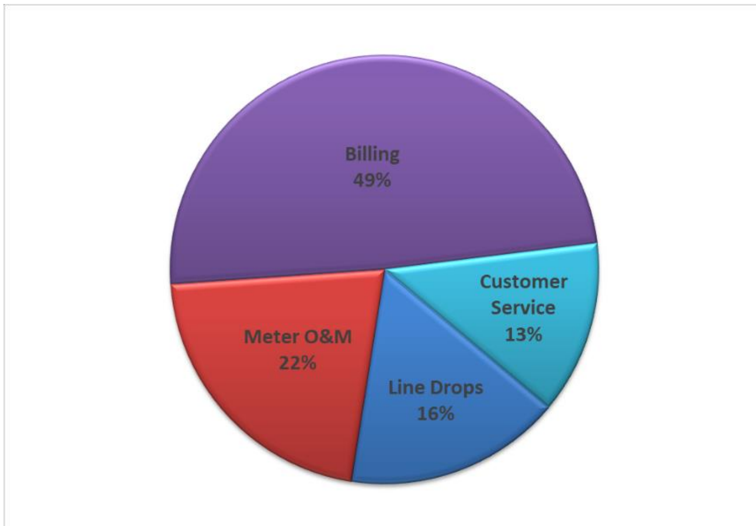


Each of these components is allocated to customer groups based on certain factors established in the study. These factors are based on the efficiency of each customer class and the time of day or the season the electricity is used. Other factors are also considered, such as the length of line extensions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

Customer-Related Cost Breakdown

NAP total expenses for customer-related costs are $7.06M for 2025. 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 2025 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 unbundling study for NAP and the related significant assumptions.

Forecasted Operating Expenses

Forecasted expenses were based on 2022 and 2023, 2024 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 16 – Projected Operating Expenses for 2025– 2027

Description	Projected 2025	Projected 2026	Projected 2027
Operating Expenses:			
Purchased Power Cost (before CoGen Credit)	$ 103,367,774	$ 101,300,418	$ 99,274,410
Inventory Issues - CONTRA : 40251300 : 549999	(3,000,000)	(3,000,000)	(3,000,000)
Distribution			
Operations	11,737,563	12,207,066	12,695,348
Distribution	3,152,070	3,278,153	3,409,279
Other Operating Expenses (Revenues)			
Other Operating Expenses (adjusted)	23,239,133	24,168,698	25,135,446
Depreciation Expense	14,334,210	15,624,839	16,892,242
Total Operating Expenses	$ 152,830,749	$ 153,579,173	$ 154,406,725

Power supply costs from 2025 – 2027 are based on NAP'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 FY2023 actual adjusted for growth. Table 17 details growth, inflation of expenses, changes in purchase power costs, interest earned on investments.

Table 17 – Projection Annual Escalation Factors 2025– 2027

Fiscal Year	Inflation	Growth	Retail MWh Sales	IMEA Avg. Cost including CoGen Credit ($/MWh)	Investment Income	Capital Program	Capital Reimbursed by Customer/Grant	Total Capital funded in Operations Labor	Optional Borrowing (20Yr @ 4%)
2025	5.5%	-2.0%	1,183,292	$ 86.00	1.0%	$26,552,816	$ 3,075,000	$ 29,627,816	$ 7,500,000
2026	4.0%	-2.0%	1,159,626	$ 86.00	1.0%	31,507,642	3,396,000	34,903,642	10,000,000
2027	4.0%	-2.0%	1,136,434	$ 86.00	1.0%	24,630,500	3,836,000	28,466,500	-

System Loss Factors

Losses occurring from the transmission and distribution of electricity can vary from year to year depending upon weather and system loading. The distribution loss factor used for the cost of service study was based on historic losses at 3.4%.

Revenue Forecast

The revenue forecast was based on FY2023 usages adjusted for growth rate assumptions.

6. Considerations and Additional Information

NAP Financial Considerations

1. NAP is projected to require increases in rates charged to customers to move toward key financial metrics.

Fiscal Year	Projected Rate Adjustments	Debt Coverage Ratio	Operating Income	UFS Optimal Operating Income	Projected Cash Balances	UFS Recommended Minimum Cash	NAP Days Working Cash	Optional Borrowing (20Yr @ 4%)
2025	6.5%	7.33	$ (96,162)	$16,414,228	$11,315,739	$ 38,760,102	30	$ 7,500,000
2026	5.1%	10.57	3,564,081	17,199,081	10,358,894	39,211,829	27	10,000,000
2027	5.1%	13.36	7,277,369	18,123,393	11,732,912	39,721,081	31	-

2. Projected rate adjustments will maintain the NAP 30 days working cash policy and move cash balances towards UFS recommended minimums over the projection period.

3. Debt Coverage Ratio is above recommended minimum levels throughout the projection period with projected rate adjustments.

4. Operating income levels will increase annually with recommended rate adjustment and move toward optimal levels over the projection period. Meeting the operating income level indicates current rates are fully funding system revenue requirements and future replacement cost of current infrastructure.

5. Infrastructure of NAP is older than the national average. The infrastructure in total is approximately 59% depreciated compared with the national average between 50% - 55%. This indicates NAP has older infrastructure.

6. NAP system losses are below average resulting in lower power supply cost for customers. The average system losses and unaccounted for energy for NAP are approximately 3.4% compared to typical municipal system losses of approximately 5.4%.

Rate-Related Considerations

1. The cost-based residential customer charge represents 36% of the fixed cost of delivery of electricity.

2. Revenue recovered by each major class of customers is lower than the cost of providing service to the customer class.

3. The table below compares current customer charges with the cost-based customer charge. It is recommended that movements toward the cost-based customer charge occur with the additional revenue used to lower the energy rates for customers in the class.

Customer Class	COS Customer Charge	Current Average Customer Charge
Residential RS	$ 23.78	$ 17.00
General Service GS1	45.86	33.65
Metered Outdoor Lighting OLR	15.86	30.65
General Service GS2	146.97	90.00
Primary PRIM	203.64	180.00
Transmission (no PPA) TRAN	705.15	400.00

4. NAP may consider movements toward cost of service. The cost of service study indicates a variance exists between revenues and costs for certain rate classes. The study results are listed below:

Customer Class	Cost of Service	Projected Revenues	Effective % Change
Residential RS	$ 82,900,548	$ 64,585,655	28.4%
General Service GS1	19,241,441	16,750,176	14.9%
Street Lights SL	318,574	-	
Metered Outdoor Lighting OLR	232,666	202,312	15.0%
General Service GS2	47,822,911	43,754,646	9.3%
Primary PRIM	12,831,782	12,489,587	2.7%
Transmission (no PPA) TRAN	216,071	296,127	-27.0%
Total	**$ 163,563,996**	**$ 138,078,503**	**18.5%**