FINAL REPORT | April 2018

ELECTRIC RATE STUDY

City of Dover, Delaware

Dover Electric Utility

PREPARED BY:

NewGen Strategies & Solutions

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PROJECT SUMMARY

Introduction

In December 2017, the City of Dover, Delaware (City)/ Dover Electric Utility (Dover) retained NewGen Strategies and Solutions, LLC (NewGen) to develop a cost of service (COS) and proposed Rate Design Study (Study).

The Study determined the total cost of providing electric services, the allocation of costs to the various customer classes, and the design of rates to safeguard the financial integrity of the utility. The total cost of providing services predominately includes operations and maintenance (O&M) expenses, debt service, and cash capital outlays required to operate and maintain the Electric System (System) with high reliability. This Electric Rate Study Report (Report) discusses the process, analyses, and recommendations related to the Study.

Dover's fiscal year (FY) is from July 1st to June 30th. Unless otherwise stated in this Report, all data presented herein is shown in FYs. The Study included an analysis of estimated revenue requirements, an unbundled COS analysis based on the average of the forecasted period FY 2019 – FY 2023 (Test Year), a rate analysis, and the development of proposed new electric rates for several customer class. Various policy issues were also identified and discussed. Dover provided the majority of the System-specific data utilized for the Study. In certain cases, where information was not available, NewGen developed estimates based on our experience and publicly available information. Analyses were performed in accordance with generally accepted industry practices for municipal electric utilities.

Our report contains five sections as follows:

- **Section 1 – Project Summary**: Provides an overview of Study and Dover
- **Section 2 – Revenue Requirement**: Discusses the development of the revenue requirement
- **Section 3 – Cost of Service**: Provides the COS result
- **Section 4 – Rate Design**: Presents the proposed electric rates for full requirements service
- **Section 5 – Conclusions and Recommendations**: Summarizes conclusions and recommendations

Electric Utility Description

During the Test Year, Dover is projected to serve, on average, approximately 24,600 retail electric customers with average annual electricity sales of approximately 753,062,000 kilowatt-hours (kWh) per year. The Electrical System serves all customers within the City as well as some customers outside the City.

Dover Generation

The City owns two generating plants, the McKee Run and the VanSant generating stations. McKee Run consists of three steam turbine generating units and is nominally rated at a capacity of 148 megawatts

(MW). VanSant is a simple cycle turbine unit that is nominally rated at 45 MW. Both plants are operated by the NAES Corporation under a contract with the City.

Wholesale Power

The City has contracted with The Energy Authority, Inc (TEA) to assist with energy procurement, energy sales, purchase of fuels, establishment and management of risk policies, and the development and management of hedging protocols and related energy procurement. The City is a member of the Delaware Municipal Electric Corporation (DEMEC), which provides wholesale power.

Dover Distribution/ Transmission

The Dover distribution/transmission system consists of a total of approximately 470 circuit miles of conductor. Approximately 44 miles is overhead transmission lines and 0.12 miles of underground transmission lines. The City serves five customers directly from its 69 kilovolt (kV) transmission system (Transmission customers). The City has approximately 135 miles of overhead distribution and 291 miles of underground distribution.

Projected Energy Requirements

Dover's electric consumption used in the Study is shown in Table 1-1. Total consumption reflects sales to Dover retail customers plus System losses of approximately 4.4%. Study energy production and sales to customers were based on Dover's projected energy sales during the Study period.

Table 1-1
Estimated Annual Energy Requirements

Test Year	Retail Sales (kWh)	System Losses	Total Net Energy for Load (kWh)
Test Year	753,062,440	32,979,332	786,041,772

Usage Characteristics by Class

The COS analysis examines detailed customer usage characteristics by customer class. Table 1-2 summarizes these characteristics for the existing customer classes, including estimated revenue generated during Test Year by each class and the number of customers in each class, according to Dover's electric utility statistics.

Table 1-2
Test Year Summary of Electric Utility Characteristics by Customer Class

Class / Service	Retail kWh Sales	No. of Customers	Revenue at Current Rates (1)	Avg. Annual kWh Sales per Customer	Avg. Annual Revenue per Customer
Residential Service	207,590,560	21,187	$26,866,925	9,798	$1,268
Small Commercial	26,763,191	2,350	3,005,296	11,389	1,279
Medium Commercial	44,548,921	598	5,308,488	74,497	8,877
Large Commercial	162,084,240	448	18,276,854	361,795	40,797
Primary Service	188,909,620	43	18,344,980	4,393,247	426,627
Lighting (2)	8,144,840	8,390	1,208,940	N/A	N/A
Transmission Service	115,020,700	5	9,710,659	23,004,140	$1,942,132
Total	753,062,072	24,631	$82,722,143		

(1) Excludes PPA Credit, see text.

(2) Lighting count based on inventory 02-05-2018, excluded from number of customers.

Cost of Service and Rate Design Process Overview

Typically, the COS and rate design process includes five steps as follows:

1. *Determination of the Revenue Requirement* – This first step examines the utility's financial needs and determines the amount of revenue that must be generated from rates. For municipal utilities, the revenue requirement is determined on a "cash basis." A "cash basis" analysis examines the cash obligations of the utility such as O&M expenses, debt service, cash funded capital projects, transfers, and payments to the City. Rates are set such that the utility can pay its bills on an annual going-forward basis.

   In preparing our analysis of the electric rates and the development of the revenue requirement, NewGen relied upon the City's financial planning model; records of operation; customer billing data; and other detailed information and data compiled and provided by the City and Dover's management and staff.

2. *Functionalization and Sub-functionalization of Costs* – The revenue requirement is then assigned to the particular function or sub-function of the utility. Utilities like Dover typically have power supply / production, transmission, distribution, and customer services functions. Distribution sub-functions may include distribution infrastructure by voltage, metering, billing, collection, etc. Customer sub-functions include billing and collections, customer service, meter reading, etc.

3. *Classification of Costs* – Once costs are functionalized, costs are then classified based on the underlying nature of the costs. Of particular importance is the determination of fixed versus variable costs. Fixed costs remain a financial obligation of the utility regardless of the amount of energy produced whereas variable costs fluctuate based on System energy requirements. Further, fixed and variable costs are associated with utility requirements to meet customer demand, energy, and customer service needs.

4. *Allocation of Costs* – Once costs are classified, they are then allocated to the various customer classes. Allocation factors align with cost classification. Therefore, demand-related costs are

allocated on measures of class demand such as class contribution to the System coincident peak (CP). Energy allocation factors are based on energy consumed by customers. Customer allocation factors are based on the number of customers.

5. *Rate Design* – The fifth, and final, step is rate design, which translates COS results into rates for each customer class.

These first four steps in the COS process are depicted in the figure below.

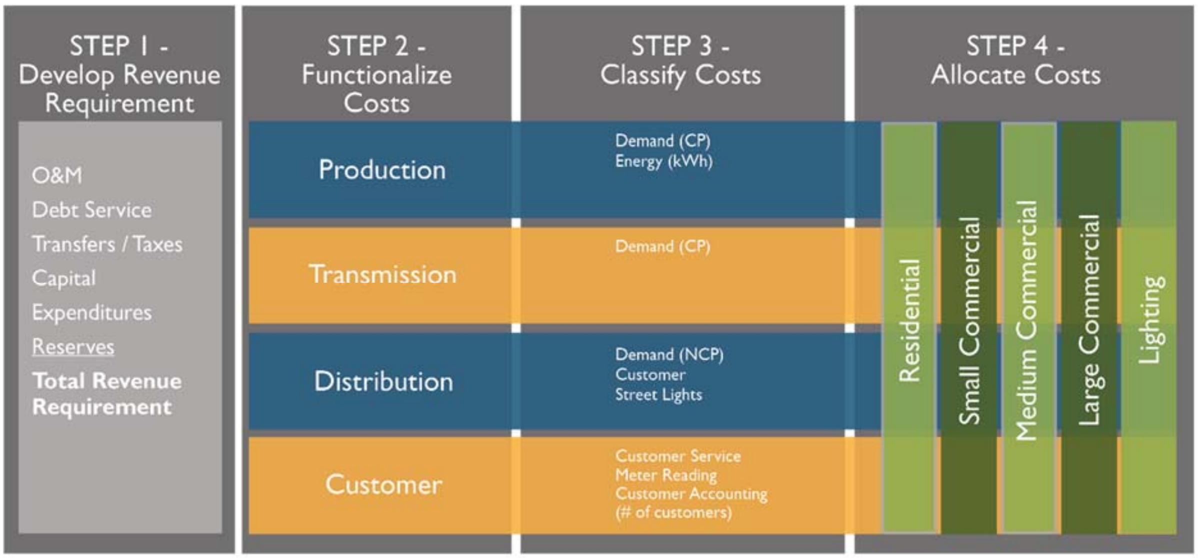

Figure 1-1. Typical Cost of Service Process

Cost of Service Results

Section 3 of the Report describes the COS process. The results of the COS analysis provide a detailed assessment of the costs required to serve each of the customer classes. These customer class costs are unbundled into utility functions and classified into demand, energy, and customer components. Customer class costs are compared to the projected revenues under current rates to determine if current rates are sufficient to meet costs. Once completed, the COS analysis is the basis for rate design. A comparison of the revenue requirement by class and revenues collected under current tariffs is shown in Table 1-3.

Table 1-3
Comparison of Current Rate Revenues with Cost of Service Results (1)

Class / Service	TY Revenue Requirement ($)	Projected Revenues Under Current Rates ($)	Projected Over / Under Recovery ($)	Difference (%)
Residential	$29,096,655	$26,866,925	($2,229,729)	(8.3%)
Small Commercial	4,005,492	3,005,296	(1,000,196)	(33.3%)
Medium Commercial	4,939,079	5,308,488	369,408	7.0%
Large Commercial	15,588,846	18,276,854	2,688,009	14.7%
Primary	15,398,953	18,344,980	2,946,027	16.1%
Lighting	805,647	1,208,940	403,293	33.4%
Transmission	8,502,989	9,710,659	1,207,671	12.4%
Total	$78,337,661	$82,722,143	$4,384,483	5.3%

(1) Excludes PPA Credits

The COS indicates that overall System rate revenues exceed projected costs by approximately 5.3%, excluding the PPA credit, as discussed herein. At the class level, current residential class and small commercial are below their respective cost to serve. All other rate classes are above their respective cost to serve.

Rate Design

Rate design is the culmination of a COS study as the rates and charges for each customer class are designed to equitably and fully recover the System-wide COS and customer class revenue requirements by the end of the rate period. Section 4 of the Report describes proposed rate design for each customer class. Dover's rates include the following components:

- Base rate (customer charge, energy-charge, demand-charge)
- Green Energy Fee (GEF)
- Power Purchase Adjustment (PPA)
- Utility Tax

Base rates are applied to the appropriate monthly billing determinants (e.g. number of customer months, kWh consumption, etc.) to project the new rate revenues by customer class. These projected revenues from the proposed rates are compared to the revenue requirements to ensure that rates generate sufficient revenue to recover the COS. The GEF is a state mandated charge for the municipal green energy fund and is collected from every consumer based on energy usage and used to fund environmental programs for conservation and energy efficiency within the City's service territory. No changes in the GEF are proposed for this Study. The base rates and GEF are combined in the process known as the "revenue adequacy" test.

The PPA is a monthly purchased power adjustment charge utilized to recover fluctuating power supply costs by recurring changes in the price of purchased power. The City currently utilizes the PPA to return surplus funds to its customers as a $/kWh credit. For 2017 and 2018, Dover has utilized the PPA to return surplus funds from its working capital reserve. For the purposes of this Study, we have assumed that the City will continue to refund surplus in 2019 and 2020. After that time, we estimate that the City's working capital fund will be within an average balance that reflects its policy objectives. However, depending on future costs and/or revenue collection, the City may need to adjust the PPA as an additional credit or as a charge. We recommend the City continue to evaluate the projection of its PPA relative to its working capital fund balance, as well as potential changes to its power supply costs, on an annual basis.

The City collects a Utility Tax from several customer classes based on a percentage of the total billed amount. The utility tax rate varies by customer class. For the purposes of this Study, we have assumed the Utility Tax will continue to be implemented in its current form. We have not included the Utility Tax in our analysis of revenues or costs, or in the analysis of rate impacts.

Based on a review of the existing rate structure, it was determined that the cost recovery components (e.g. customer, energy, and/or demand charges) of the current rates were not in alignment with the COS results and/or the City's policy objectives. Proposed rates in the Study were designed to move each customer class closer to its COS while evaluating the impact of rate changes on customers' monthly bills. NewGen performed a detailed analysis of monthly bill impacts associated with proposed rates on the majority of Dover customers. In consideration of customer bill impacts, proposed rates, although moving closer to the class COS, do not precisely match the classification of costs for each rate class. The City's policy objectives for rate design, as discussed herein, were also incorporated into the proposed rate design.

Based on our analysis of rate impacts and conversations with Dover management and staff, it was determined that new rates would be phased in over the five-year period on a bi-annual basis. The first rate changes would be implemented on July 1, 2018, the second on July 1, 2020, and the third on July 1, 2022. This implementation reduces the overall rate impact from the proposed changes in base rates and reduction in the current PPA credit. Additional information and analysis for Dover's proposed rates are included in Section 4 of the Report.

Section 2
REVENUE REQUIREMENT

As part of the Study, NewGen developed a Test Year revenue requirement inclusive of all of Dover's cash operating and capital expenses from rates. The Test Year revenue requirement is based on projected Test Year operating and financial results. Development of the Test Year revenue requirement was based on projected cost information provided by the City. The Test Year revenue requirement development process is detailed in this section.

Test Year Revenue Requirement

To remain financially sound, Dover's electric rates must produce sufficient revenues to recover the total costs of providing electric service to their customers. These costs imposed on the System by customers are commonly referred to as the utility's "revenue requirement" and consist of normal operating expenses, debt service, capital improvements and additions, transfers to the City, non-operating expenses, and reserve requirements. These total revenue requirements are then compared to utility revenues to evaluate the need for rate changes. The revenue requirement acts as the foundation of a COS study.

The following is a discussion of the core components of the Test Year revenue requirement and significant differences from FY 2017.

Power Supply Expenses

The production expenses are primarily associated with Dover's purchased power expenses, as well as expenses related to their power production facilities. The Test Year production expense is $48,254,380. Total power supply costs include estimates from the City's power marketing agent, TEA, and are expected to increase by approximately 11%, or $4,848,066, from FY 2017 to the Test Year period. Power supply projections were provided by TEA in March 2018.

Transmission / Distribution Expenses

The City combines its transmission and distribution expenses for purposes of its budget process. For this Study, we have kept these expenses combined for the revenue requirement. However, for the COS process, we separated the transmission and distribution expenses based on available City plant accounting data.

The Test Year transmission and distribution expenses are projected to be $6,404,541, which represents an increase of approximately 13% or $738,027 from FY 2017.

Customer Expenses

The Test Year customer expenses are projected to be $1,232,579 for the Test Year, which is an increase of approximately 16%, or $167,757, from FY 2017.

Administrative & General Expenses

The Test Year Administrative & General (A&G) expenses are projected to be $15,273,941 for the Test Year, which is an increase of approximately 6%, or $842,239, from FY 2017.

Debt Service

The Test Year Debt Service expense is $1,608,520.

Capital Expenditures Funded from Current Earnings

NewGen reviewed the City's five-year Capital Improvement Program (CIP) plan and normal capital needs. Capital paid from current earnings for the Test Year is anticipated to be $6,351,800 in the Test Year. This represents a reduction of approximately $5,049,990 from FY 2017 and the anticipated draw down of reserves for capital needs.

Other Revenues/Expenses

Other revenues include non-rate related revenues such as green energy revenue from DEMEC, penalties from late payments, general service billing, miscellaneous service revenue, reconnection fees, return check fees, bad debt collections, new service fees, and rent revenue. The total of other revenues/expenses is a net revenue for the Test Year of $788,100.

Test Year Revenue Requirement

Table 2-1 provides a summary of the comparison to FY 2017 and the Test Year values utilized to generate the revenue requirement for the System.

Table 2-1
FY 2017 and Test Year Revenue Requirements

Item	FY 2017	Test Year	Change
Production	$43,406,314	$48,254,380	$4,848,066
Transmission / Distribution	5,666,514	6,404,541	738,027
Customer	1,064,823	1,232,579	167,757
Administrative & General	14,431,702	15,273,941	842,239
Debt Service	1,610,945	1,608,520	(2,425)
Capital Funded by Cash	11,401,790	6,351,800	(5,049,990)
Other Expense/(Revenue)	(922,030)	(788,100)	133,930
Total Revenue Requirement	$76,660,057	$78,337,661	$1,677,604

Section 3
COST OF SERVICE

After determining the System revenue requirement, a COS for each customer class is developed to determine the specific costs to serve each class. Customer class revenues are compared to class revenue requirements to evaluate the current rate's abilities to recover costs. NewGen analyzed the cost to serve each customer class based on the revenue requirement developed in Section 2.

Once completed, the COS results indicate the degree to which existing rates recover the costs to serve customers. The COS results are then used to design new electric rates.

The COS analyses relied on the following key supporting data and analysis:

- Test Year reported revenue requirements and revenues based on current rates;
- Total System and customer class demand and energy requirements;
- Actual and assumed customer service characteristics; and
- Information obtained from customer accounts and records.

Electric Rate Functions

Dover's electric rates were unbundled into four functions: power supply, transmission, distribution, and customer service. The assignment of costs by function falls into two general categories: 1) direct assignments and 2) derived allocations. Direct assignments are costs that are readily associated with a specific utility function and are directly assigned to that function. For example, the energy expense is clearly an expense solely related to the power supply, so it is directly assigned to that function.

Derived allocators are allocation factors that are based on the sum, average, or weighted effect of different underlying factors. Derived allocators can be complex and should reflect the logical answer to the following question – what underlying activities drive the cost of this item? For example, A&G expenses are associated with the O&M of all utility functions. Thus, A&G expenses are allocated to each utility function using a derived allocator. Each of the four utility functions is described below.

Power Supply Function

The power supply function consists of costs associated with the cost of purchased power and procuring and administering power supply contracts. For Dover, this cost is primarily associated with its purchases of power through DEMEC, TEA in the PJM market, as well as costs associated with operating and maintaining its production facilities.

Transmission Function

For the purposes of this Study, we have identified transmission function as costs associated with operating and maintaining the City's local high-voltage transmission system and making capital investments, as necessary. The transmission facilities transmit electricity at high voltage from the generation stations to the distribution system and directly to transmission class customers.

Distribution Function

The distribution function consists of costs associated with operating and maintaining the distribution portion of the electric grid and making capital investments, as necessary. The distribution facilities deliver power to most retail customers after it has been transmitted. This includes low voltage distribution lines, distribution poles, underground lines, customer service connections, meters, and lighting-related assets.

Customer Service Function

The customer service function consists of costs associated with operating and maintaining the customer-related facilities to meet customer support needs. This includes, but is not limited to, customer service, billing and collection, and meter reading.

Unbundling of Revenue Requirement

The revenue requirement determined for the Test Year was "unbundled" into the four functional areas of the System – power supply, transmission, distribution, and customer. The results of the functional unbundling are summarized in Table 3-1.

Table 3-1
Functionalized Test Year Revenue Requirement

Function	Revenue Requirement	$/kWh (1)	% of Total
Power Supply	$60,825,759	$0.0808	77.6%
Transmission	4,715,806	0.0063	6.0%
Distribution (2)	8,424,269	0.0112	10.8%
Customer	4,371,827	0.0058	5.6%
Total	$78,337,661	$0.1040	100.0%

(1) Based on Test Year energy sales of 753,062,440 kWh; numbers may not add due to rounding.

(2) Distribution includes directly assigned costs to street lighting.

The power supply function represents approximately 78% of the Test Year revenue requirement. The distribution function is the second largest cost center representing approximately 11% of the Test Year revenue requirement. The transmission and customer function represent approximately 6%, respectively, of the Test Year revenue requirement.

Classification of Costs

To provide a reasonable basis for the assignment of total revenue requirements (costs) to each customer class, costs for each function in the Electric System have been analyzed and classified into four rate-making cost classifications, as described below.

- **Demand Costs** – Capacity (fixed- or demand-related) costs are those costs incurred to maintain a utility system in a state of readiness to serve, enabling it to meet the total combined demands of its customers. Capacity costs include the portion of O&M expenses, debt service, capital expenditures, and other costs that are generally fixed and do not vary materially with the quantity of usage or that cannot be designated specifically as a customer or variable cost.

- **Energy Costs** – Energy, or variable costs, are costs that vary directly with energy usage, including such items as fuel, energy-related purchased power, and a portion of O&M expenses.
- **Customer Costs** – Customer costs are those costs directly related to the number and type of customers, such as customer accounting, billing, and meter related expenses.
- **Direct Assignment Costs** – Direct assignment costs are those costs that are readily identifiable and applicable to a particular customer or customer class (e.g. Lighting).

Once the costs within each function are assigned to each service category, the demand, energy, customer, and direct assignment component of each service is calculated. As provided in Table 3-2, three major cost categories (demand, energy, and customer) cover the majority of all functional costs. This breakdown of demand, energy, customer, and direct assignment costs is later applied to each customer class to facilitate rate design, as provided in Section 4.

Table 3-2
Classified Test Year Revenue Requirement

Classification	Revenue Requirement	$/kWh (1)	% of Total
Production			
Demand	$25,957,956	$0.0345	33.1%
Energy	34,867,803	0.0463	45.5%
Subtotal	*$60,825,759*	*$0.0808*	*77.6%*
Transmission			
Demand	$4,715,806	$0.0063	6.0%
Distribution			
Demand	$8,104,714	$0.0108	10.3%
Direct Assignment – Lighting	319,555	0.0004	0.4%
Subtotal	*$8,424,269*	*$0.0112*	*10.8%*
Customer			
Customer	$4,371,827	$0.0058	5.6%
Total Costs	$78,337,661	$0.1040	100.0%

(1) Based on Test Year energy sales of 753,062,440 kWh. Numbers may not add due to rounding.

In total, approximately 45.5% of Dover's total revenue requirement is energy-related or variable costs. The remaining 54.5% of the revenue requirement is fixed in nature and classified as demand, customer, or directly assigned to particular customer classes.

Allocation of Costs

Once costs are functionalized and classified, they are then allocated to the various customer classes. Customer classes represent aggregations of customers that have similar customer usage characteristics and use the System in a similar manner. These groups of customers have similar COS results, which justify similar rates.

Class Allocation Factors

Based upon actual and assumed customer service characteristics, NewGen developed various factors for use in allocating the adjusted revenue requirements to individual customer classes. These allocation factors reflect accepted ratemaking principles and were based upon embedded cost allocation procedures.

We have developed demand-related, energy-related, customer-related, and direct assignment allocation factors, as described below.

Demand Allocations

Demand allocators are derived based on the demand requirements of individual customers and classes of customers. Production-related demand costs are allocated to classes based on the class contribution to the System peak, or coincident peak allocators. This is a measure of each classes cost responsibility associated with the infrastructure required to meet the System peak demand. As you move from the generator to the meter, the measure of peak demand responsibility changes from a System perspective (coincident peak), to a class perspective (non-coincident peak), to a customer perspective (demand at meter). Demand contributions at these various points in the System are determined based on load research, billing data provided by Dover, and industry research and experience. Demand cost allocators can be based on the one peak month during a year, multiple months (such as the four summer months) or the 12 months of the year, depending on how the underlying costs are incurred (cost causation).

For this Study, the 4-month coincident peak (4CP), 12-month non-coincident peak (12NCP), and a Secondary/Transformer (based on the 12NCP and sum of max demands (SMD)) methods were used to allocate demand-related production-, transmission-, and distribution-related costs, respectively, to individual customer classes.

The 4CP allocator was used to allocate costs of generation demand, based on analysis of the Dover's load profile. Transmission costs for Dover's owned System were allocated using the 12NCP method, which recognizes that the diversity in the use of the transmission system by individual customer classes over the year (therefore, based on their class demand, or Non-Coincident Demand).

Similarly, distribution costs are designed to meet the maximum demands of the localized System or customers, so class demand allocation factors are used. Distribution demand-related costs were allocated to customer classes based on either a 12NCP or a combination of 12NCP and the total demand by meter (SMD).

An NCP allocator is typically used to allocate distribution costs, as these facilities are sized to meet localized peak demands rather than the System peak demand. The 12NCP method was used to allocate the distribution System demand-related costs associated with substations, poles, and conductors. This process excluded transmission level customers, which do not utilize the distribution system. The Secondary/Transformer method, excluding the transmission and primary voltage customer classes, was used to allocate demand costs related to secondary distribution system and distribution transformers. For customer classes that are billed for demand, this method is based on annual billed demand data (SMD). For customers that are not billed for demand (residential, small commercial, and lighting), this method is based on the class 12NCP, which reflects diversity of the loads for these classes.

Table 3-3 compares the various demand allocators utilized in the Study.

Table 3-3
Demand Allocator Comparisons

Customer Class	4CP (%)	12NCP (kW)	Secondary / Transformers (kW)
Residential	40%	41%	54%
Small Commercial	5%	5%	7%
Medium Commercial	6%	6%	9%
Large Commercial	19%	20%	28%
Primary	19%	18%	0%
Lighting	0%	1%	1%
Transmission	11%	9%	0%
Total	100%	100%	100%

Energy Allocations

Energy allocation factors are the basis for allocating costs or expenses classified as variable or energy-related and are assumed to vary directly with kWh sales. Energy-related costs classified as variable were wholesale energy costs. Typically, net energy for load (NEFL), or the energy necessary to supply each customer class, is used to allocate these types of costs to individual customer classes. NEFL is also sometimes called adjusted metered load or energy at generation, as it takes into consideration energy losses that occur on the transmission and distribution systems between the power supplier delivery point and the customer's meter. Energy losses for Dover were provided by the City and ranged from approximately 2.0% for the secondary distribution system, 1.5% for the primary distribution system, and 1.24% for the transmission system. Table 3-4 lists the energy allocation factor utilized in the Study, which incorporates the losses at the various levels of the System.

Table 3-4
Energy Allocator

Customer Class	Net Energy for Load
Residential	28%
Small Commercial	4%
Medium Commercial	6%
Large Commercial	22%
Primary	25%
Lighting	1%
Transmission	15%
Total	100%

Customer Allocations

Customer costs are defined as those costs related to the number of customers and the type of service required. Included in the customer-related costs are the costs associated with meter reading, customer service, sales, billing, collection, and other customer-related activities. The customer allocation factors were largely based on the number of customers in each class.

In allocating certain customer-related costs to the various customer classifications, weighted customer allocation factors were utilized. Weighting reflects that servicing certain types of customers requires more effort and expenses than other types of customers. Weighting factors were developed based on discussions with Dover staff, as well as applying industry knowledge and practices. Weighting factors derive relationships between the customer classes and equipment or services needed to serve the class and the relative costs of those items.

Cost of Service Results

The unbundled COS results by customer class is shown in Table 3-5.

Table 3-5
Unbundled Cost of Service Results by Class

Classification	Residential	Small Commercial	Medium Commercial	Large Commercial	Primary	Lighting	Transmission	Total
Power Supply								
Demand	$10,340,216	$1,257,803	$1,651,249	$5,050,420	$4,809,245	$0	$2,849,022	$25,957,956
Energy	9,650,327	1,301,144	2,165,776	7,534,861	8,608,460	378,632	5,228,603	34,867,803
Subtotal Power Supply	*$19,990,543*	*$2,558,948*	*$3,817,026*	*$12,585,281*	*$13,417,705*	*$378,632*	*$8,077,625*	*$60,825,759*
Transmission								
Demand	$1,928,299	$246,491	$303,235	$919,955	$859,629	$35,657	$422,539	$4,715,806
Distribution								
Substations	$1,755,821	$224,443	$276,112	$837,669	$782,739	$32,467	$0	$3,909,250
Lines – Primary	722,926	92,410	113,684	344,894	322,278	13,368	0	1,609,560
Lines – Secondary	872,993	111,593	150,904	457,926	0	16,143	0	1,609,560
Transformers – Demand	529,549	67,691	91,537	277,774	0	9,792	0	976,343
Transformers – Customer	296,476	82,329	20,822	18,807	0	0	0	418,433
Meters	711,520	197,583	49,971	45,135	5,776	34	1,007	1,011,026
Direct-Street Lighting	0	0	0	0	0	319,555	0	319,555
Subtotal Distribution	*$4,889,285*	*$776,050*	*$703,030*	*$1,982,205*	*$1,110,793*	*$391,359*	*$1,007*	*$9,853,728*
Customer								
Meter Reading	$1,013,705	$112,599	$28,477	$21,435	$2,057	$0	$287	$1,178,560
Customer Accounting	136,721	37,966	9,602	8,673	1,110	0	194	194,265
Customer Service	943,452	261,988	66,260	59,847	7,659	0	1,336	1,340,542
Uncollectible Accounts	194,650	11,450	11,450	11,450	0	0	$0	229,000
Subtotal Customer	*$2,288,527*	*$424,003*	*$115,789*	*$101,405*	*$10,826*	*$0*	*$1,817*	*$2,942,368*
Total Costs	$29,096,655	$4,005,492	$4,939,079	$15,588,846	$15,398,953	$805,647	$8,502,989	$78,337,661
Summarized Total								
Demand	$16,149,804	$2,000,433	$2,586,721	$7,888,638	$6,773,890	$107,427	$3,271,562	$38,778,476
Energy	9,650,327	1,301,144	2,165,776	7,534,861	8,608,460	378,632	5,228,603	34,867,803
Customer	3,296,523	703,915	186,582	165,347	16,602	34	2,824	4,371,827
Directly Assign	0	0	0	0	0	319,555	0	319,555
Total	$29,096,655	$4,005,492	$4,939,079	$15,588,846	$15,398,953	$805,647	$8,502,989	$78,337,661

Cost of Service Results Compared to Current Revenue

To evaluate the ability of current rates to adequately recover the COS, NewGen estimated revenues based on Test Year billing data and current rates, then compared resulting revenues to the COS for each customer class. The results of the comparison are shown in Table 3-6.

Residential and Small Commercial are currently under collecting their respective COS, whereas the remaining classes are over collecting their allocated COS during the Test Year period.

Table 3-6
Comparison of Current Rate Revenues with
Cost of Service Results for Test Year

Class / Service	Revenue Requirement	Estimated Revenues Under Current Rates	Projected Over/(Under) Recovery	Difference
Residential	$29,096,655	$26,866,925	($2,229,729)	(8.3%)
Small Commercial	4,005,492	3,005,296	(1,000,196)	(33.3%)
Medium Commercial	4,939,079	5,308,488	369,408	7.0%
Large Commercial	15,588,846	18,276,854	2,688,009	14.7%
Primary	15,398,953	18,344,980	2,946,027	16.1%
Lighting	805,647	1,208,940	403,293	33.4%
Transmission	8,502,989	9,710,659	1,207,671	12.4%
Total	$78,337,661	$82,722,143	$4,384,483	5.3%

Also shown in Table 3-6 is the approximate percentage increase/(decrease) in each customer class' revenues necessary to fully recover the identified COS. The percentage increase or decrease shown in the table above provides guidance for future rate design. Recommendations for new rate designs are presented in Section 4.

Section 4
RATE DESIGN

Rate design is the culmination of a COS study where the rates and charges for each customer classification are established in such a manner that the total revenue requirement of the utility will be recovered in the most equitable manner and consistent, to the extent reasonable and practical, in accordance with Dover's policies. Consideration was given to the recovery of fixed costs in the customer and demand charges, as well as phasing in the proposed rates over time.

Rate Design Objectives

In general, proposed rate structures that are developed and submitted for adoption should meet the following objectives and best practices:

- Rates should be equitable among customer classes and individuals within classes, taking into consideration the costs incurred to serve each customer class.
- Rates may take into consideration other important factors, such as competitive concerns, policies, etc.
- Rates should be simple and understandable.

It is common that the foundation of rate design is COS results tempered with policy considerations important to the community. Specific rate design goals for Dover include:

- Based on COS results, improve fixed cost recovery.
- Move towards COS results by class to decrease intra class subsidization.
- Reduce demand rates to respond to competitive pressure from the neighboring utility's rate structures.
- Move rates toward COS, yet to the extent possible, minimize customer and class adverse impacts of the proposed rates.

Electric Rate Structure

The proposed base electric rates include a customer charge, energy charge, and demand charge, where applicable. The customer charge should be designed to recover customer-related costs and the energy charge should be designed to recover all fuel and applicable power production costs. Additionally, the demand charge should be designed to recover demand-related costs. The customer, energy, and demand charges are commonly referred to as "base rates."

Customer and demand charges collect revenues that cover Dover's fixed costs. However, energy may collect revenues to recover both fixed and variable costs. For customer classes that do not have demand charges, a large portion of fixed costs are collected through the energy charge.

COS results indicate that customer charges for many of Dover's customer classes are too low and should be raised. This is a common result for many utilities throughout the industry.

The GEF is a rate rider that is mandated by the State of Delaware. The current rate for the GEF is $0.000178/kWh. We do not recommend a change in this rate over the Test Year period.

As indicated previously, the PPA is referred to as a pass-through adjustment. This adjustment is in the form of an energy charge to recover fluctuating power supply costs caused by recurring changes in the price of purchased power. The City is currently utilizing the PPA as a credit mechanism to reduce its balance of funds. We have proposed a reduction in the PPA credit for FY 2019 and FY 2020 (Phase I), and an elimination of the PPA credit in Phase 2 and Phase 3. The PPA proposed for FY 2019 and FY 2020 is $0.00382/kWh.

Rate Design Results

The proposed rates and average bill impacts are summarized for each customer class below. A graph including a histogram of customer monthly billing impacts (for Phase I rate changes) and effective rates by load factor or consumption is included to illustrate and compare current rates, proposed rates, and COS results. These rate impacts compare current rates to the proposed rates and include the adjustment to the base rates and the PPA. Histograms of bill impacts are based on customer usage patterns from January 2017 to December 2017 provided by the City.

Residential Service

The Residential class is composed of residential customers served on a retail basis. Table 4-1 compares the current rates, the COS rates and the proposed rates.

Table 4-1
Residential Service
Current, Cost of Service, and Proposed Rates

Item	Unit	Current	Proposed July 1, 2018	Proposed July 1, 2020	Proposed July 1, 2022	Cost of Service
Customer	$/Month	7.50	8.46	9.42	10.38	12.97
Energy (1)	$/Month	0.1203	0.1206	0.1209	0.1212	0.1243
Green Energy Charge	$/kWh	0.000178	0.000178	0.000178	0.000178	0.000000
PPA	$/kWh	(0.00855)	(0.00382)	0.00000	0.00000	0.00000

(1) The fixed demand-related costs are shown in the energy COS because this class does not have a demand charge.

The COS analysis indicates that the current customer charge and energy charge should be increased. Table 4-1 shows that the COS per customer is $12.97. The proposed customer charge increases by $0.96 per phase, which is a step towards improved fixed cost recovery via the customer charge. The proposed energy charge is projected to increase by $0.0003/kWh during each of the three phases over the Test Year period.

Figure 4-1 shows the relationship between customer usage and average COS. Low energy users have a higher average COS than high energy users. This relationship exists because each customer has a similar fixed cost associated with infrastructure required to connect the customer to the System and meet their peak demand requirements. High users are able to spread these fixed costs over more energy resulting in a lower rate. Increasing residential class customer charges improves cost recovery of the rate and reduce subsidy between customers in the residential class. Under the current rate structure, high energy users subsidize low energy users.

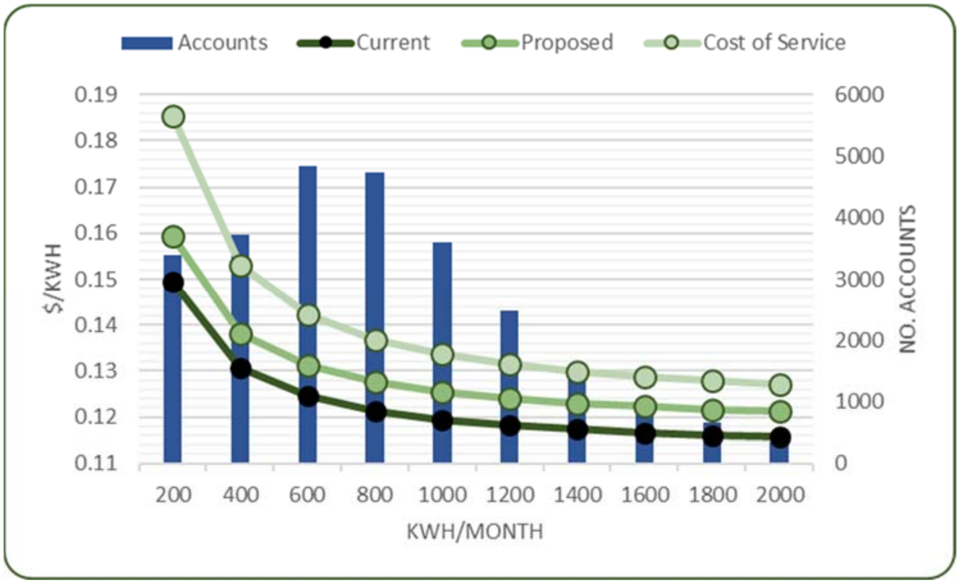

Figure 4-1. Residential Rate Comparison

Billing Impacts

The median monthly energy consumption in the Residential customer class is 661 kWh per month. The median monthly bill for a residential customer is projected to increase by $4.28, or 5.3%, for Phase I. Customer bill impacts on a percentage change for all residential customers is shown in Figure 4-2 (for Phase I).

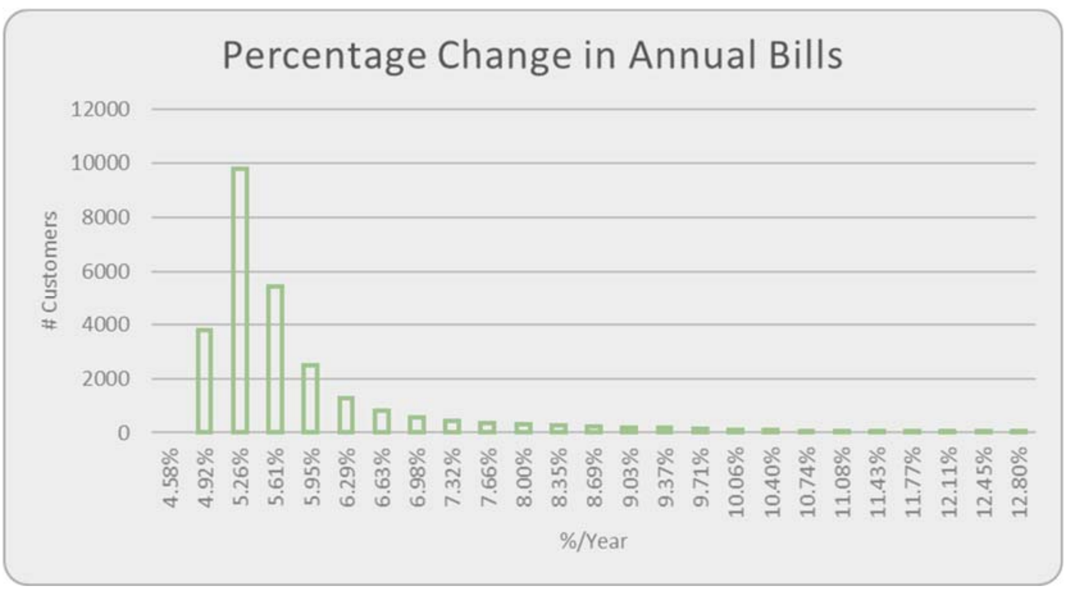

Figure 4-2. Residential Billing Impacts: Percent Change in Bills

Customer bill impacts on an average monthly billing basis for all residential customers is shown in Figure 4-3 (for Phase I).

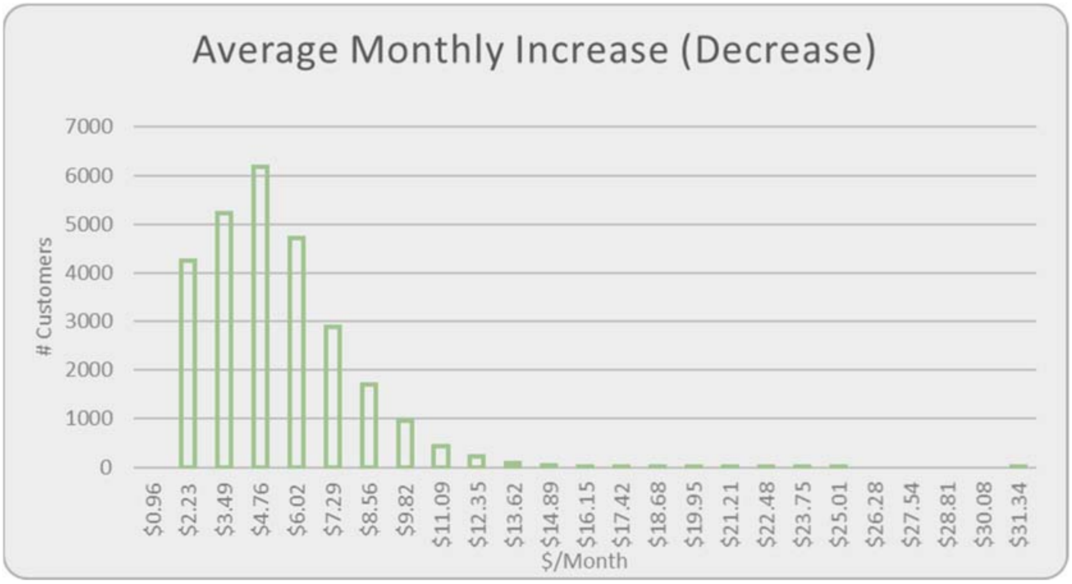

Figure 4-3. Residential Billing Impacts: Dollar Change in Bills

Small General Service

The Small General Service rate class is composed of commercial users served at secondary voltages with maximum monthly usage that does not exceed 3,500 kWh per month. Customers served under this tariff can take service through single phase or three phase, which are reflected in a difference in their customer charge. The COS analysis indicates that the current customer charge should be increased. Table 4-2 shows that the average COS per customer is $24.93.

Table 4-2
Small General Service
Current, Cost of Service, and Proposed Rates

Item	Unit	Current	Proposed July 1, 2018	Proposed July 1, 2020	Proposed July 1, 2022	Cost of Service (1)
Customer - 1 Phase	$/Month	7.50	8.39	9.28	10.17	24.93
Customer - 3 Phase	$/Month	22.50	23.39	24.28	25.17	24.93
Energy (2)	$/kWh	0.1004	0.1006	0.1008	0.1010	0.1234
Green Energy Fee	$/kWh	0.000178	0.000178	0.000178	0.000178	0.000000
PPA	$/kWh	(0.00855)	(0.00382)	0.00000	0.00000	0.00000

(1) Cost of service represents average costs for customer charge.

(2) The fixed demand-related costs are shown in the energy COS because this class does not have a demand charge.

An important rate design objective is to improve fixed cost recovery. Because the Small General Service rate design does not include a demand charge, the majority of fixed costs are being recovered through the energy charge. The result of this rate structure is that very low energy usage customers are being subsidized by high energy usage customers. There is a fixed cost to Dover for each customer that is connected to the System. The COS indicated customer charge is higher than the current customer charge. We recommend an increase in the customer charge to improve fixed cost recovery as well as an increase in the energy charge.

Figure 4-4 compares the unit costs ($/kWh) for the current and proposed rates, as well as the COS for a series of monthly energy usage amounts.

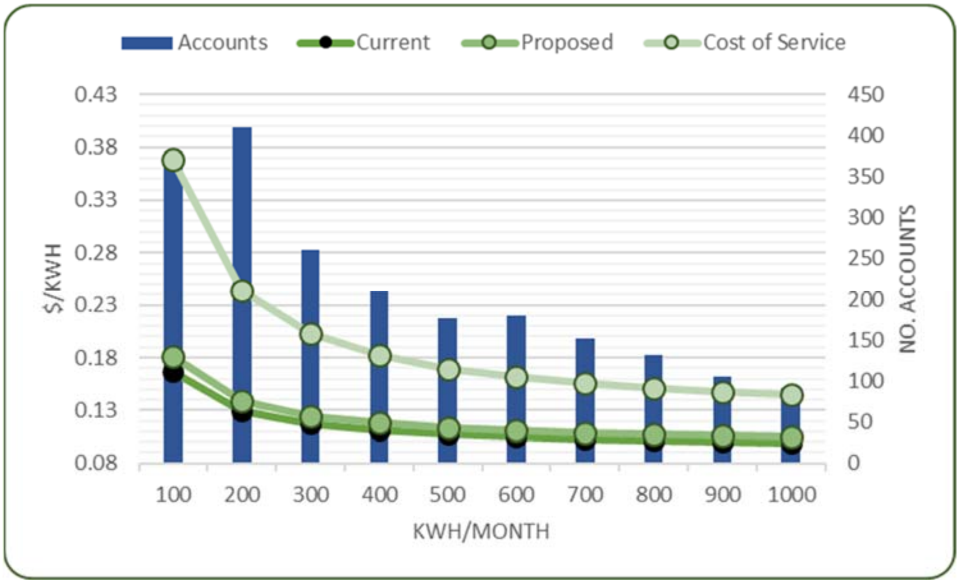

Figure 4-4. Proposed Small Commercial Service Rate Compared to Current Rates and Cost of Service

Billing Impacts

The median customer in the Small Commercial uses 546 kWh per month. The monthly bill for the median customer is projected to increase by $3.58, or 6.1% for Phase I under the proposed rates. Customer bill impacts for customers in this class are provided in Figure 4-5 and Figure 4-6.

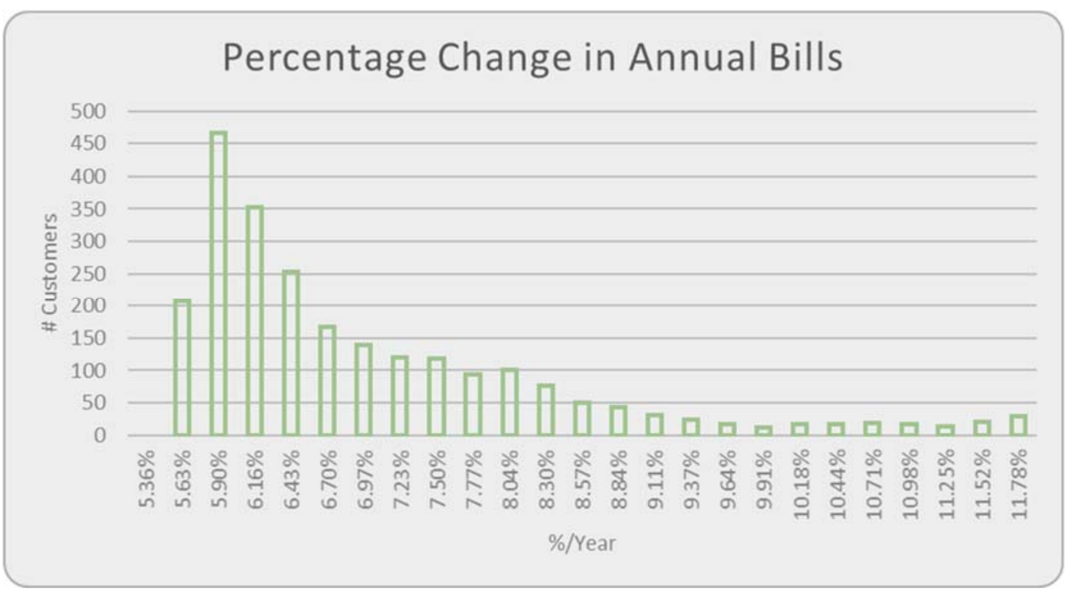

Figure 4-5. Small Commercial Service Billing Impacts: Percent Change in Bills

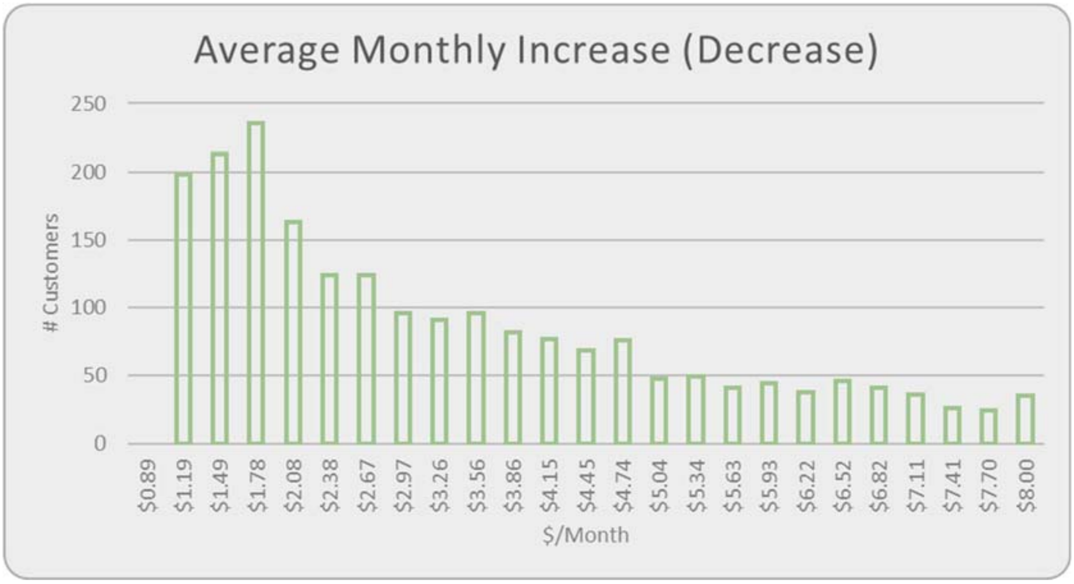

Figure 4-6. Small Commercial Service Billing Impacts: Dollar Change in Bills

Medium Commercial

The Medium Commercial tariff is for commercial and industrial customers having monthly usage of more than 3,500 kWh for two consecutive months. These customers are billed on a demand basis. Similar to the Small Commercial customers, these customers can take service at single phase or three phase, which results in a different customer charge. The COS analysis indicates that the current customer charge should be increased. Table 4-3 shows that the average COS per customer is $26.12. The proposed monthly customer charge increases by $4.23 per phase, which is a step towards improved fixed cost recovery via the customer charge. The COS suggests an increase in the demand charge for this customer class; however, the City has requested a reduction in demand rates for its commercial customers, as discussed herein. Therefore, we have proposed that energy charge and demand charge for these customers to decrease over the implementation period of this Study.

Table 4-3
Medium Commercial Service
Current, Cost of Service, and Proposed Rates

Item	Unit	Current	Proposed July 1, 2018	Proposed July 1, 2020	Proposed July 1, 2022	Cost of Service (1)
Customer - 1 Phase	$/Month	7.50	11.73	15.96	20.19	26.12
Customer - 3 Phase	$/Month	22.50	26.73	30.96	35.19	26.12
Energy	$/kWh	0.0677	0.0658	0.0639	0.0620	0.0486
Demand	$/kW	13.95	13.40	12.85	12.30	16.66
Green Energy Fee	$/kWh	0.000178	0.000178	0.000178	0.000178	0.000000
PPA	$/kWh	(0.00855)	(0.00382)	0.00000	0.00000	0.00000

(1) Cost of service represents average costs for customer charge.

Figure 4-7 shows the relationship between customer usage and average COS. Low energy users have a higher average COS than high energy users. This relationship exists because each customer has a similar fixed cost associated with infrastructure required to connect the customer to the System and meet their peak demand requirements. High users are able to spread these fixed costs over more energy resulting in a lower rate. Increasing residential class customer charges improves cost recovery of the rate and reduce subsidy between customers in the residential class. The majority of these customers are within a load factor range of between 30% and 60%. Load factor is a measure of efficiency and is the relationship between monthly demand and monthly energy usage.

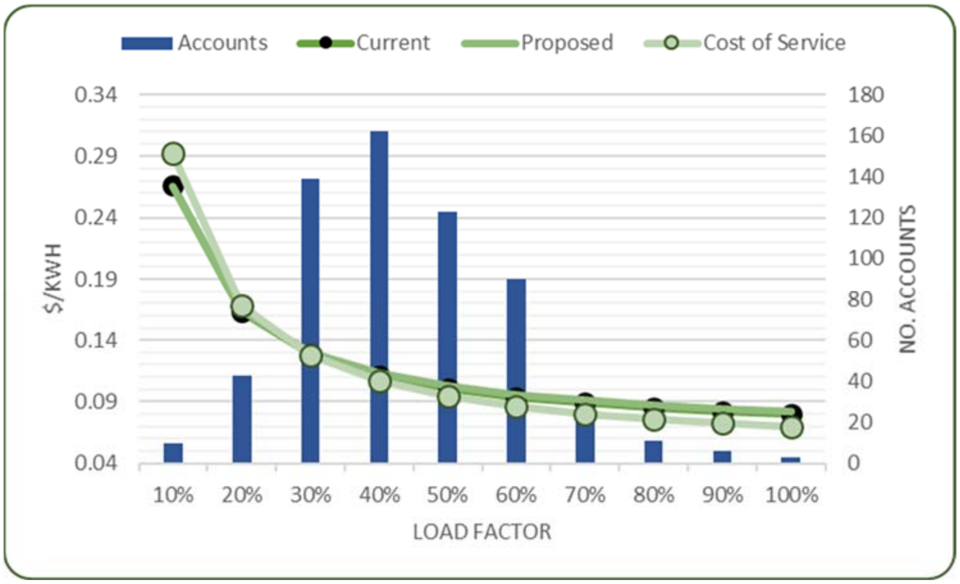

Figure 4-7. Medium Commercial Rate Comparison

Billing Impacts

The median monthly energy consumption in the Medium Commercial customer class is 4,627 kWh per month. The monthly bill for the median customer in this class is projected to increase by $7.80, or 1.4% for Phase I. Phase I customer bill impacts for all Medium Commercial customers is provided in Figure 4-8 and Figure 4-9.

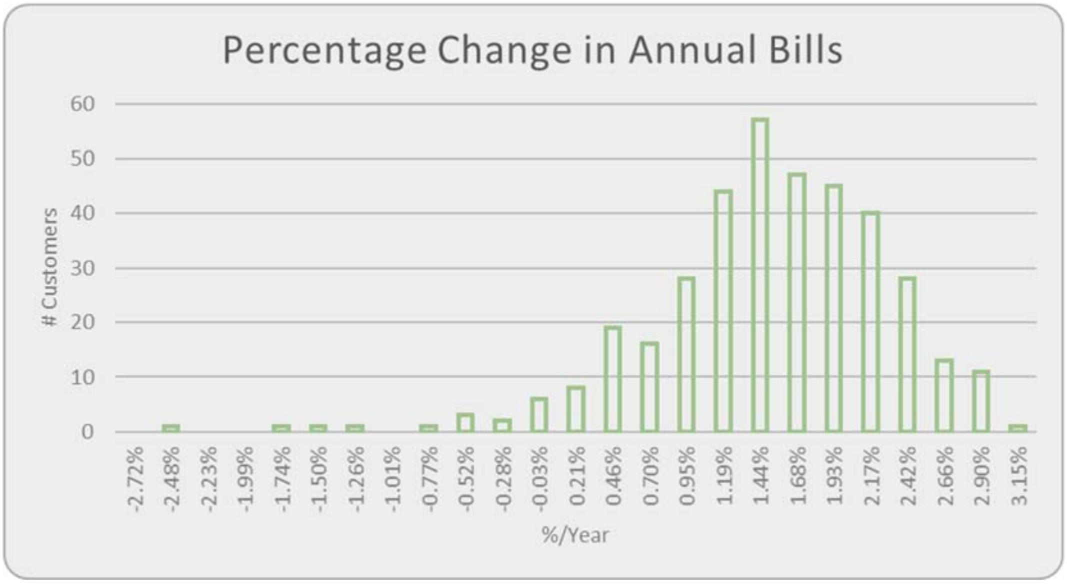

Figure 4-8. Medium Commercial Billing Impacts: Percent Change in Bills

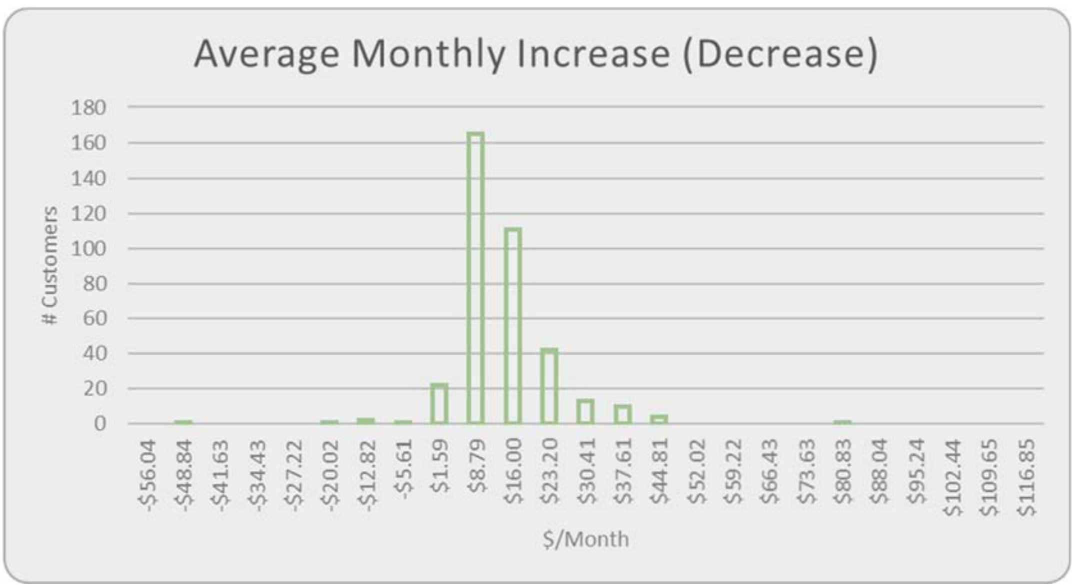

Figure 4-9. Medium Commercial Billing Impacts: Dollar Change in Bills

Large Commercial Service

The Large Commercial Service rate class is composed of commercial and industrial purposes having instrument rated metering served at secondary voltages. Service can be provided at single or three phases; however, the customer charge is the same for either. Table 4-4 shows that the COS per customer is $30.76 and the customer charge is proposed to increase at each of the three rate phases, which is a step towards improved fixed cost recovery via the customer charge. Similar to the other commercial classes, the COS suggests an increase in the demand charge for this customer class. However, the City has requested a reduction in demand rates for its commercial customers, as discussed herein. Therefore, the recommended rate changes for this class include increasing the customer service charge and decreasing the energy and demand rates.

Table 4-4
Large Commercial Service
Current, Cost of Service, and Proposed Rates

Item	Unit	Current	Proposed July 1, 2018	Proposed July 1, 2020	Proposed July 1, 2022	Cost of Service
Customer	$/Month	22.50	25.05	27.06	30.15	30.76
Energy	$/kWh	0.0677	0.0649	0.0621	0.0593	0.0465
Demand	$/kWh	13.90	13.38	12.86	12.34	16.74
Green Energy Fee	$/kW	0.000178	0.000178	0.000178	0.000178	0.000000
PPA	$/kWh	(0.00855)	(0.00382)	0.00000	0.00000	0.00000

Figure 4-10 compares the unit costs ($/kWh) for the current and proposed rates, as well as the COS for a series of customer load factors. As shown in the figure, the high load factor customers are paying more than their COS and the low load factor customers are paying less than their COS.

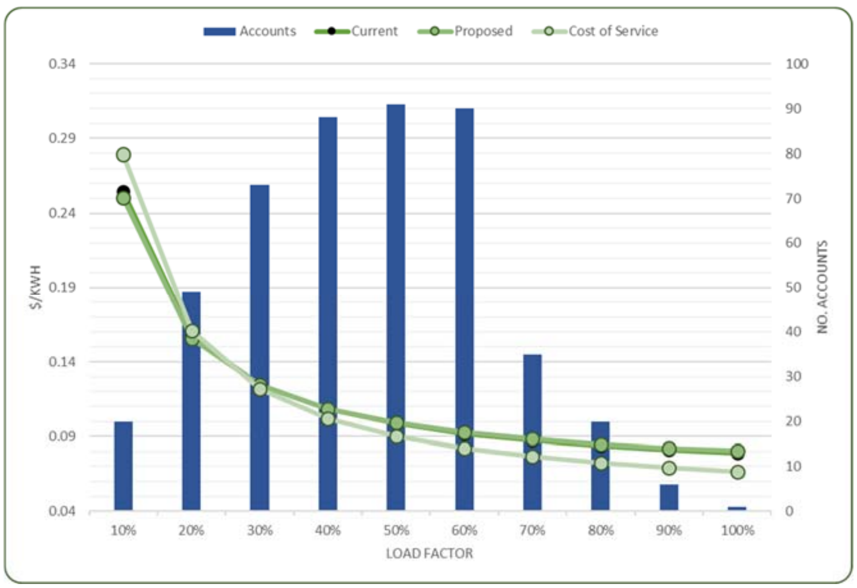

Figure 4-10. Proposed Large Commercial Service Rate Compared to Current Rates and Cost of Service

Billing Impacts: Large Commercial Service

The median monthly energy consumption in the Large Commercial customer class is 14,560 kWh per month. The monthly bill for the median customer in this class is projected to increase by $5.37, or 0.4% for Phase I. Phase I customer bill impacts for all Large Commercial customers is provided in Figure 4-11 and Figure 4-12.

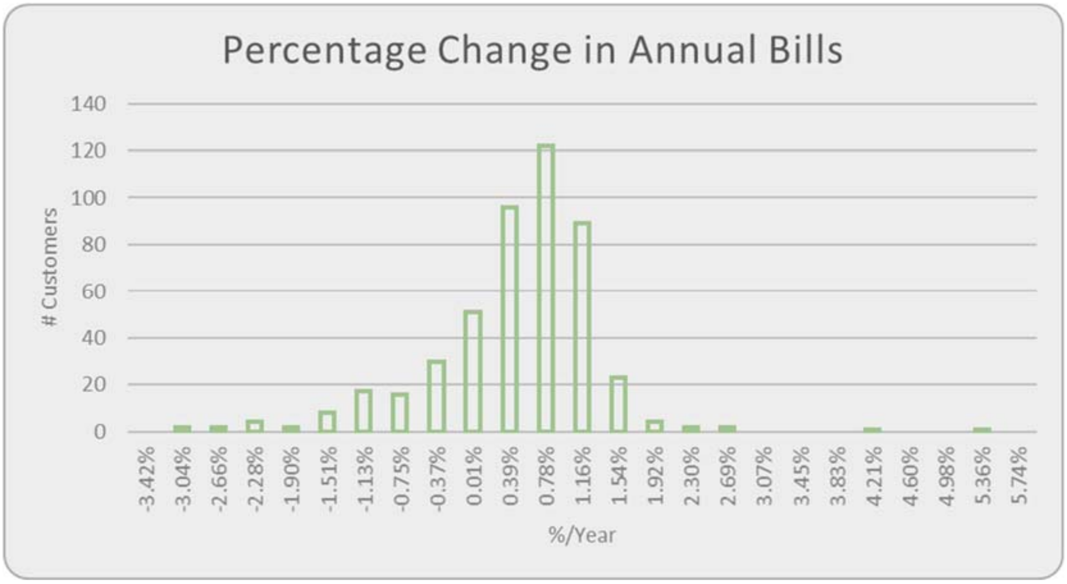

Figure 4-11. Large Commercial Service Billing Impacts: Percent Change in Bills

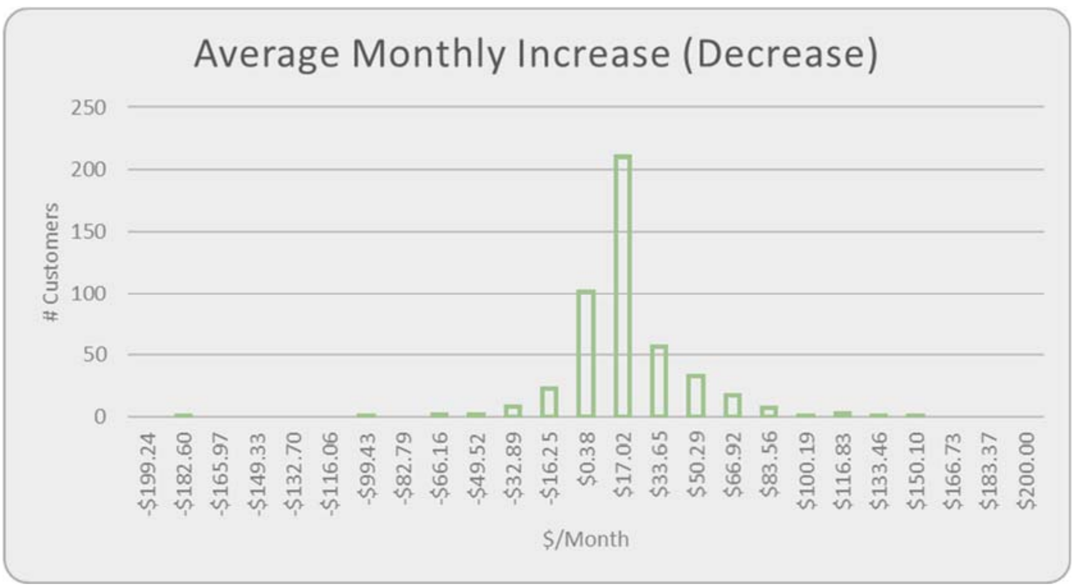

Figure 4-12. Large Commercial Service Billing Impacts: Dollar Change in Bills

Primary Service

The Primary Service rate class is composed of commercial users served at primary voltages where customers own their transformers and primary conductors. Table 4-5 shows that the COS per customer is $32.18 per month and the customer charge is proposed to increase at each of the three rate phases, which is a step towards improved fixed cost recovery via the customer charge. As with the other commercial customer classes, the COS suggests an increase in the demand charge for the Primary service class. However, the City has requested a reduction in demand rates for its commercial customers, as discussed herein. Therefore, we have proposed that recommended rate changes for this class include increasing the customer service charge and decreasing the energy and demand rates, as indicated below.

Table 4-5
Primary Service
Current, Cost of Service, and Proposed Rates

Item	Unit	Current	Proposed July 1, 2018	Proposed July 1, 2020	Proposed July 1, 2022	Cost of Service
Customer	$/Month	15.00	19.66	24.32	28.98	32.18
Energy	$/kWh	0.0676	0.0654	0.0632	0.0610	0.0456
Demand	$/kW	11.25	10.67	10.09	9.51	15.09
Green Energy Fee	$/kW	0.000178	0.000178	0.000178	0.000178	0.000000
PCA	$/kWh	(0.00855)	(0.00382)	0.00000	0.00000	0.00000

Figure 4-13 compares the unit costs ($/kWh) for the current and proposed rates, as well as the COS for a series of customer load factors. This figure also provides a histogram of Primary customers relative to their load factors, as determined from Dover's 2017 billing database.

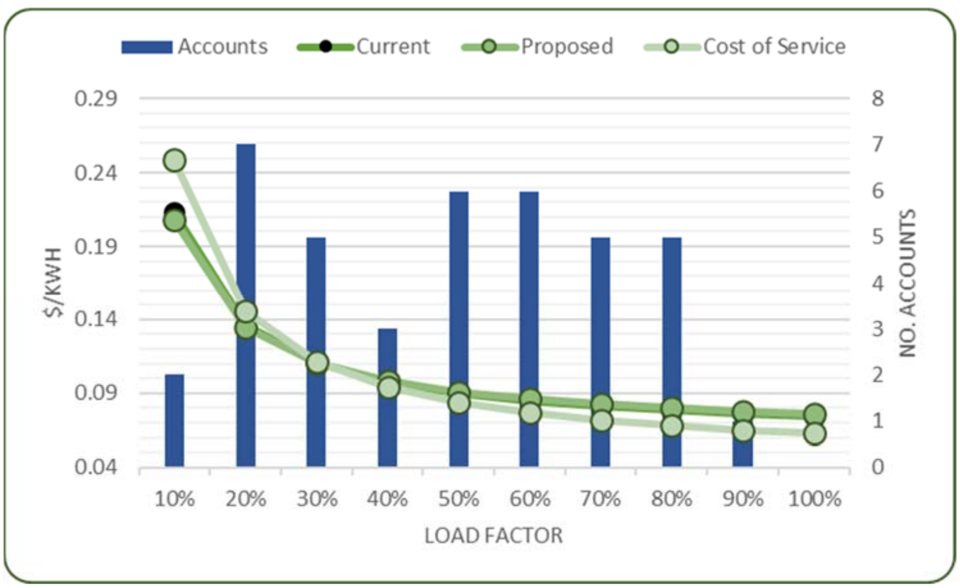

Figure 4-13. Proposed Primary Service Rate Compared to Current Rates and Cost of Service

Billing Impacts

The median monthly energy consumption in the Primary customer class is 140,300 kWh per month. The median monthly bill for a customer is projected to increase by $105.46, or 0.9% for Phase I. Phase I customer bill impacts for all Primary customers is provided in Figure 4-14 and Figure 4-15.

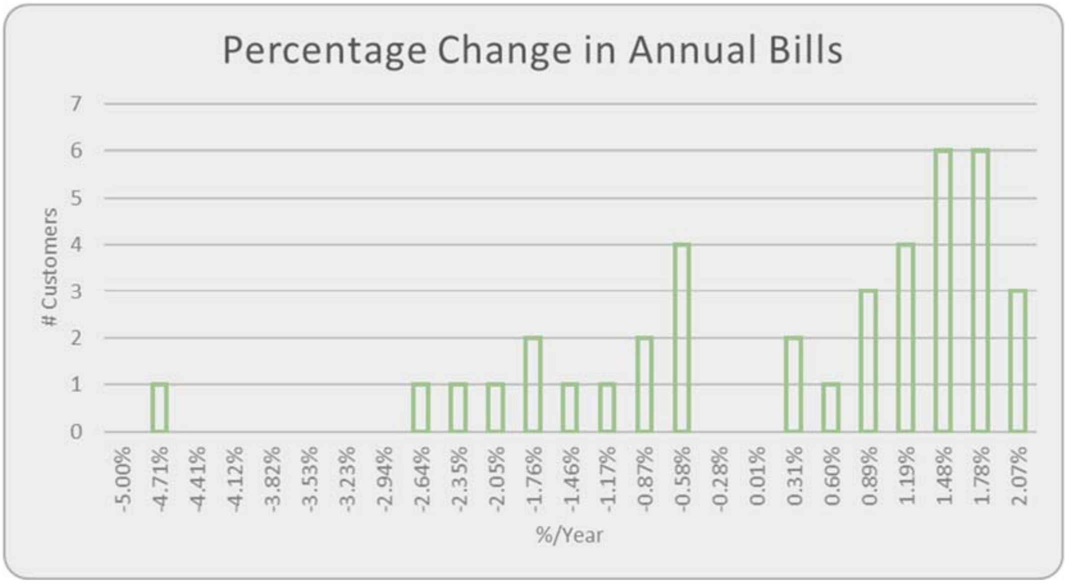

Figure 4-14. Large Primary Service Billing Impacts: Percent Change in Bills

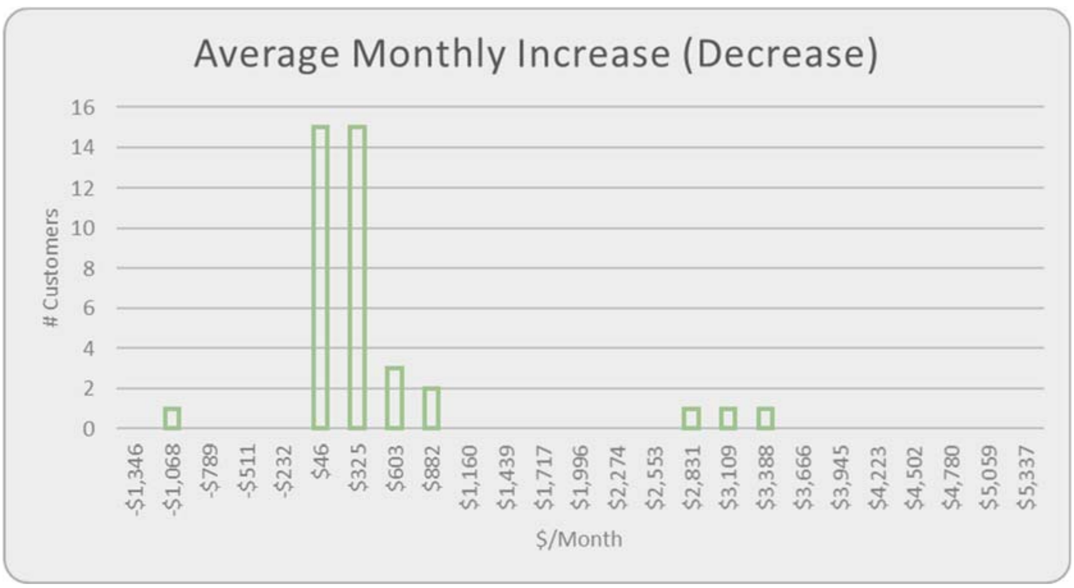

Figure 4-15. Large Primary Service – Primary Billing Impacts: Dollar Change in Bills

Transmission Voltage Service

The Transmission Voltage Service rate class is for customers in the electric service area that take service at 69 kV. There are currently five customers that take service at the transmission level from the City. Table 4-6 shows that the COS per customer is $39.22; however, as is typical for very large customer classes, the City does not charge a customer charge for these customers. Recommended changes include a gradual reduction of both the energy and demand rates for this class. The energy rate reduction is consistent with the COS. As with the other commercial customer classes, the COS suggests an increase in the demand charge for this class. However, the City has requested a reduction in demand rates, which is consistent with Dover's rate policy as discussed herein. Because of the small number of customers in this class, we have not provided specific bill impacts for each customer.

Table 4-6
Transmission Service – Commercial
Current, Cost of Service, and Proposed Rates

Item	Unit	Current	Proposed July 1, 2018	Proposed July 1, 2020	Proposed July 1, 2022	Cost of Service
Customer	$/Month	0.00	0.00	0.00	0.00	39.22
Energy	$/kWh	0.0637	0.0618	0.0599	0.0580	0.0455
Demand	$/kW	10.50	9.82	9.14	8.46	15.03
Green Energy Fee	$/kWh	0.000178	0.000178	0.000178	0.000178	0.000000
PCA	$/kWh	(0.00855)	(0.00382)	0.00000	0.00000	0.00000

Lighting

Dover currently offers two lighting tariffs under its Outdoor Developing Lighting Rate (OL) and Private Outdoor Lighting service classification. The OL rates are metered service, which includes a customer charge and energy charge. Dover provides lighting service for the City and is in the process of replacing its existing inventory of street lights with light-emitting diode (LED) lighting systems. Therefore, for the purposes of this Study, we propose to not change the existing lighting tariffs at this time. Rather, we propose to introduce an LED lighting tariff for Private Outdoor Lighting on a pilot basis. Table 4-7 provides the proposed LED lighting by existing light type and estimated LED replacement. We propose to keep the existing customer charges for non-metered service of $7.50/month for Residential customers and $22.50/month for Commercial customers. The City should evaluate the estimated costs and associated expenses associated with its proposed LED lighting replacement program to determine if the prosed LED rates described in Table 4-7 below are sufficient to recover its costs.

Table 4-7
LED Pilot – Private Outdoor Lighting Unmetered Service
Current Standard and Proposed LED Rates

Lamp Type	Current ($/Month)	Estimated LED Replacement (Watt)	Proposed LED ($/Month)
Security Lights			
100 watt HPS	$7.70	53	$5.19
175 watt HPS	$9.08	74	$5.34
Decorative Lighting			
70 watt HPS w/o ladder rest	$11.65	29	$9.56
150 watt HPS w/o ladder rest	$14.51	74	$11.35
250 watt HPS w/o ladder rest	$20.31	102	$14.44
Roadway/Area Lighting			
100 watt HPS	$9.41	53	$6.90
175 watt MV	$10.30	29	$4.79
250 watt HPS	$14.29	102	$8.42
250 watt MV	$14.29	53	$6.49
400 watt MV	$19.16	102	$8.11
400 watt HPS	$19.25	139	$9.55

Other Rates

Dover provides a series of other rate offerings including transmission voltage service to the Federal Government customers (Rate FT), firm standby and supplemental service (Rate SS), a Business Retention Rates Schedule (Rate BR), two water pump service classifications (FP and F2), and Net Energy Metering service (Rate NM). Each of these are discussed below.

Rate FT

Rate FT provides transmission level service to Federal Government entities within Dover's service territory. The existing tariff is identical to the Transmission service tariff with the exception that the FT energy rate is reduced by $0.002/kWh. For the purposes of this Study, we are proposing to maintain the $0.002/kWh difference. Therefore, the proposed rates for the Transmission tariff are appropriate for the proposed Rate FT for the demand charges, the GEF, and the PPA. However, the proposed rates for the energy charge are reduced by $0.002/kWh. Table 4-8 provides a summary of the proposed rate changes for this tariff.

Table 4-8
Transmission Service – Federal Government
Current, Cost of Service, and Proposed Rates

Item	Unit	Current	Proposed July 1, 2018	Proposed July 1, 2020	Proposed July 1, 2022	Cost of Service
Customer	$/Month	0.00	0.00	0.00	0.00	39.22
Energy	$/kWh	0.0635	0.0616	0.0597	0.0578	0.0455
Demand	$/kW	10.50	9.82	9.14	8.46	15.03
Green Energy Fee	$/kWh	0.000178	0.000178	0.000178	0.000178	0.000000
PCA	$/kWh	(0.00855)	(0.00382)	0.00000	0.00000	0.00000

Rate SS

Rate SS provides firm standby and/or supplemental electric service for commercial and industrial purposes. The current tariff covers customers that otherwise would be billed at Large Commercial service (C5), Primary service, or Transmission level service. We propose that each class have its own unique SS rate; therefore, the City may choose to offer a Rate SS-C5, SS-P, and SS-T service tariff. We have developed the following Rate SS-C5 as shown in Table 4-9, as there is currently one customer taking service under the current Rate SS that would otherwise take service under the C5 tariff.

The proposed changes to this tariff include increasing the customer charge to represent the time and effort expended by the City for the customer in this class. Additionally, the reservation charge should be increased to recognize a portion of the production-related demand charge and the entirety of the transmission and distribution demand charges for this class. The daily demand charge should be increased to reflect the difference between the reservation charge and proposed demand charge for the Large Customer class for the peak periods of the month. The energy charge should be updated to reflect the proposed energy charge for this class. To reduce the impact of these rate changes to the customer in this class, we recommend phasing in the changes to the customer charge and reservation charge over the rate Study period.

Table 4-9
Firm Standby and Supplemental Service – Rate SS
Current, Cost of Service, and Proposed Rates

Item	Unit	Current	Proposed July 1, 2018	Proposed July 1, 2020	Proposed July 1, 2022
Customer	$/Month	30.00	76.18	122.37	169.95
Energy	$/kWh	0.0584	0.0590	0.0590	0.0590
Demand	$/kW – day	0.14	0.23	0.23	0.23
Reservation Charge ($/Contract Standby Billing Demand)	$/kW	2.24	4.93	5.96	7.03
Standby Demand - Primary	$/kW	1.65	Included	Included	Included
Standby Demand - Secondary	$/kW	2.16	Included	Included	Included
Green Energy Fee	$/kWh	0.000178	0.000178	0.000178	0.000178
PCA	$/kWh	(0.00855)	(0.00382)	0.00000	0.00000
Supplemental Service		At Applicable Rate	At C5 Rate	At C5 Rate	At C5 Rate

Business Retention

The City offered a Business Retention rate (BR) for certain customers that met specific requirements regarding size of service, potential for relocation, and other requirements per terms and conditions of a Business Retention Agreement. The current tariff states that "All Business Retention Agreements must be executed prior to June 30, 2016, after which no further agreement will be executed." Dover management requested a potential BR rate for consideration by the City Council. Table 4-10 provides a summary of the potential rate offerings under the existing two-year construct for BR, as updated to the proposed service offerings for the Primary service class. Adjustments to the PPA and the GEF would be similar to those proposed for the Primary service class.

Table 4-10
Business Retention Rate
Current, Cost of Service, and Proposed Rates

Rate Component	Unit	Current	Proposed July 1, 2018	Proposed July 1, 2020	Proposed July 1, 2022	Cost of Service
Year 1						
Energy	$/kWh	0.0582	0.0565	0.0547	0.0530	0.0455
Demand	$/kW	7.15	6.69	6.22	5.76	15.03
Year 2						
Energy	$/kWh	0.0610	0.0592	0.0574	0.0555	0.0455
Demand	$/kW	8.8	8.23	7.66	7.09	15.03

Water Pump Service (FP and F2)

The City currently offers two water pump tariffs (FP and F2). Tariff FP is for emergency firefighting purposes and related equipment and tariff F2 is available by contract. The two tariffs are similar in their demand and energy charge; however, they vary in their customer charge. Tariff FP has a flat customer charge of $15/month, whereas F2 has a tiered customer charge based on the horsepower (hp) rating of the water pump served by the utility. We have proposed the following base rate changes for the FP and F2 rates, as provided in Table 4-11.

Table 4-11
Water Pump Service (FP and F2)
Current, Cost of Service, and Proposed Rates

Item	Unit	Current	Proposed July 1, 2018	Proposed July 1, 2020	Proposed July 1, 2022	Cost of Service
Customer						
FP	$/Month	15.00	15.00	15.00	15.00	26.12
F2 – up to 50 hp	$/Month	100.00	100.00	100.00	100.00	26.12
F2 – >50 hp, < 100 hp	$/Month	150.00	150.00	150.00	150.00	26.12
F2 – >100 hp	$/Month	300.00	300.00	300.00	300.00	26.12
Energy	$/kWh	0.1466	0.1425	0.1384	0.1343	0.0486
Demand	$/kW	9.00	8.65	8.29	7.94	16.66
Green Energy Fee	$/kWh	0.000178	0.000178	0.000178	0.000178	0.000000
PCA	$/kWh	(0.00855)	(0.00382)	0.00000	0.00000	0.00000

Net Energy Metering (NEM)

The City offers Net Energy Metering rates that apply to all customer classes (except standby service SS) for customers that own and operate electric generation facility on their premises that produces energy to offset part or all of the electricity requirements. Customers pay for all electricity delivered by the City and are currently credited at their applicable energy rate. The existing tariff language provides a credit value on a $/kWh basis. However, the existing tariff is not how the City currently credits customers for over production from their on-premise systems. It is our understanding from discussions with City management that the current Delaware law requires that the utility purchase any production from the applicable on-site systems at the full retail rate for energy. We recommend that the City update its tariff language to reflect this requirement.

Transmission Supplemental Services

The City has a tariff for supplemental service for interruptible services for the NRG Energy Center. However, the NRG Energy Center is not currently served by this tariff. We recommend that the City update this tariff language to reflect revised demand and energy rates, as provided below. However, we recommend that the City include revised language regarding interruption of service and requirements that service be curtailed during on-peak times, as appropriate. This tariff should also be revised to include a requirement for customer installation of required metering and communication equipment to facilitate curtailment of service at the City’s request.

Other Tariffs

The City currently has three separate tariffs for 69 kV transmission service for 16 MW Exempt Wholesale Generator (EWG), 88 MW EWG, and White Oak Solar that do not appear to be in use. We recommend that the City remove these service offerings from its tariffs.

The City currently charges a power factor penalty for its large customer classes (Large Commercial and higher). The penalty is charged on a leading and lagging factor and the charge is realized through the billing demand for these customers. No changes to the City’s power factor adjustment mechanism is recommended as part of this Study.

Revenue Adequacy of Proposed Electric Rates

The rates presented in this section have been designed to recover revenues slightly less than the Test Year revenue requirement in the final year of the rate plan to incorporate the rate strategies enclosed herein. Rates were designed based on forecasted billing information provided by Dover and utilizing information in the 2017 billing data system. To the extent actual billing determinants vary from projections provided by Dover, actual revenues may vary from the expected revenues as presented herein.

Table 4-12 shows the projected Test Year revenue requirement and the proposed rate revenue excluding the proposed PPA for the first two years of the Study period (Phase I).

Table 4-12
TY Revenue Requirement and Projected Rate Revenue from Proposed Rates (1)

Customer Class	TY Revenue Requirement	Projected Revenue FY 2019 (2)	Projected Revenue FY 2020	Projected Revenue FY 2021 (3)	Projected Revenue FY 2022	Projected Revenue FY 2023 (4)
Residential	$29,096,655	$27,195,081	$27,167,851	$27,474,144	$27,474,144	$27,780,437
Small Commercial	4,005,492	3,038,137	3,035,235	3,065,649	3,065,649	3,096,064
Medium Commercial	4,939,079	5,173,043	5,167,689	5,027,932	5,027,932	4,888,174
Large Commercial	15,588,846	17,558,773	17,541,387	16,879,373	16,879,373	16,218,336
Primary	15,398,953	17,666,018	17,648,359	16,955,409	16,955,409	16,262,459
Transmission	8,502,989	9,351,727	9,342,434	8,976,140	8,976,140	8,609,847
Lighting	805,647	1,209,900	1,208,700	1,208,700	1,208,700	1,208,700
Total System	$78,337,661	$81,192,679	$81,111,655	$79,587,347	$79,587,347	$78,064,017

(1) Excludes PPA Credit.
(2) Includes base rate changes as proposed herein (Phase I – FY 2019), excludes projected PPA Credit.
(3) Includes base rate changes as proposed herein (Phase 2 – FY 2021).
(4) Includes base rate changes as proposed herein (Phase 3 – FY 2023).

Table 4-13 below provides a summary of the projected revenues with the proposed rate changes, excluding the PPA credit, compared to the annual projected revenue requirements for each year of the Study period. The projected revenues exceed the revenue requirement during the first four years of the Study period and is projected to be below the revenue requirement in the last year of the Study period. On average for the Test Year, the projected revenue is estimated to exceed projected costs by approximately $1.5 million.

We recommend the City evaluate its projected costs at the end of each fiscal period to determine if projected revenues will be sufficient to meet its cash needs and its reserve requirement policies. Additionally, we recommend the City re-analyze its COS analysis at the end of FY 2020 to determine if sufficient changes to the System warrant adjustments to the projected rates and associated rate revenue.

Table 4-13
Annual Revenue Requirement and Projected Rate Revenue from Proposed Rates (1)

Item	FY 2019 (2)	FY 2020	FY 2021 (3)	FY 2022	FY 2023 (4)	TY Average
Projected Revenue	$81,192,679	$81,111,655	$79,587,347	$79,587,347	$78,064,017	$79,908,609
Projected Revenue Requirement	$79,550,900	$79,239,100	$76,569,700	$77,294,901	$79,033,702	$78,337,661
Contribution / (Withdraw) from Reserves	$1,641,779	$1,872,555	$3,017,647	$2,292,446	($969,685)	$1,570,949

(1) Excludes PPA Credit.

(2) Includes base rate changes as proposed herein (Phase I – FY 2019), excludes projected PPA Credit.

(3) Includes base rate changes as proposed herein (Phase 2 – FY 2021).

(4) Includes base rate changes as proposed herein (Phase 3 – FY 2023).

Section 5
CONCLUSIONS AND RECOMMENDATIONS

In reliance upon the data received by Dover, and the analyses described herein, we conclude and recommend the following.

Conclusions

- Revenue Requirement
  - Based on our development of the Test Year revenue requirement, current rates exceed current and projected costs. On a System-wide basis, current rate revenues require a 5.3% decrease.
- Cost of Service
  - The Residential and Small Commercial customer classes are below their respective COS. All other rate classes are above their respective COS.
- Rate Design
  - Dover's base rates require modification to better align with the COS results.
  - Dover requests a reduction in the demand component to its commercial and industrial customers to address competitive concerns.

Recommendations

Based on our conclusions, and supporting analyses, NewGen recommends the following:

- Dover should adopt rates that reduce subsidization between customer classes. The majority of Dover's rate structure should be modified to improve fixed cost recovery in the customer charges.
- Dover should adopt the rate plan as proposed in this Report, including adjustments to its tariffs for supplemental / standby service, as described herein.
- Dover should evaluate its street lighting costs and revenues relative to the proposed LED street lighting project to determine if proposed LED rates, as provided herein, are sufficient to recover its costs. As the City implements its LED street lighting project, it should update its accounting records for street light plant data.
- The City should investigate its plant accounting data to determine appropriate FERC level accounting for its System.
- Dover should continue to perform a comprehensive COS study every two to three -years, or when aligned with a major change in operations such as changes in projected price for purchased power, a new large industrial customer, or significant change in System operations.
- Dover should continue to evaluate the balance of its working capital fund relative its PPA credit and its on-going cash needs.