CITY OF

Clearwater

Natural Gas Rate Study

Draft Report / December 17, 2020

RAFTELIS

December 17, 2020

Mr. Jay Ravins
Finance Director
City of Clearwater
100 South Myrtle Ave.
Clearwater, FL 33756

Subject: Natural Gas Rate Study

Dear Mr. Ravins,

Raftelis Financial Consultants, Inc. (Raftelis) is pleased to provide this Natural Gas Rate Study Report (Report) for the City of Clearwater (City) to address the needs facing the City's natural gas utility.

The major objectives of the study include the following:

- Evaluate the adequacy of existing rate revenues to support the continued financial sustainability of the natural gas utility going forward;
- Determine the cost of serving each customer class in accordance with each class's use of the natural gas system;
- Recommend rate revenue adjustments to better align the cost of serving each class with the revenues generated by that class; and
- Recommend rate structure adjustments to better align the City's rate structure with industry best practices for natural gas utility rates.

The Report summarizes our key findings and recommendations.

It has been a pleasure working with you, and we thank you and the City staff for the support provided during the course of this study.

Sincerely,

Bart Kreps
Vice President

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1. Executive Summary

1.1. Introduction

The City of Clearwater, Florida, (the City) owns and operates the Clearwater Gas System (CGS), which serves approximately 28,000 customers in Pinellas and Pasco Counties. The City engaged Raftelis Financial Consultants, Inc. (Raftelis) in collaboration with Navillus Utility Consulting, LLC (Navillus) (collectively, the Raftelis Team) to conduct a comprehensive financial planning, cost of service and rate design study. The Raftelis Team worked closely with City staff develop an understanding of the financial and operational characteristics of the CGS system in order to develop appropriate assumptions and reasonable allocations.

The primary outcomes of this study are rate recommendations which sustainably fund CGS operations, reasonably align cost recovery (i.e., what CGS charges customers) with cost incurrence (i.e., how those customers use the CGS system) and improve alignment with industry best practices for natural gas ratemaking. Developing these recommendations involves the following 3 steps:

1. Establish the overall level of revenue needed to fund CGS operations in a financially sustainable manner (Financial Plan)
2. Determine the cost of serving each customer class in accordance with each class's use of the gas system (Cost of Service Analysis)
3. Calculate rate adjustments to better align the cost of serving each class with the revenues generated by that class and improved alignment with industry best practices (Rate Design).

1.2. Financial Plan

Process

The financial plan conducted for this study evaluated whether CGS's existing revenue levels were appropriate, given projected operating and capital expenditures and defined financial performance metrics. This evaluation involved detailed projections of revenues and expenditures based on CGS's customer billing data, budget, capital improvement plan and actual historical financial performance. Appropriateness for the purposes of this study was measured in terms of reserve levels, debt service coverage ratios, return on rate base and return on equity.

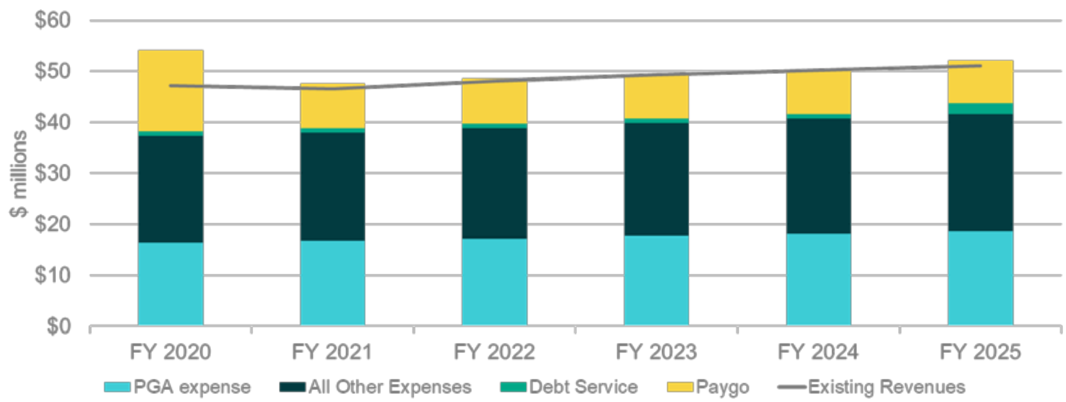
CGS's rate structure for customers receiving firm natural gas service consists of three distinct groups of charges: a purchased gas adjustment (PGA) rate, rate riders and base rates. The PGA rate is the mechanism by which CGS recovers the cost of natural gas it purchases and distributes to customers. The energy conservation adjustment (ECA) is designed to recover costs associated with energy conservation and demand management. The usage and inflation adjustment (UIA) is designed to mitigate operational and financial risk associated with fluctuations in demand and inflationary cost increases. The Regulatory Imposition Adjustment (RIA) is designed to recover the cost of regulatory imposed programs. The final component of CGS's rate structure are the base rates (customer charge and commodity charge), which effectively recover all other costs of distributing natural gas to customers. The base rates were the primary focus of the cost of service analysis discussed below.

The Raftelis Team worked with City staff to develop a projection of future account and customer growth with consideration for potential impacts associated with the novel coronavirus pandemic (COVID-19). These demand projections were used to calculate revenues based on CGS's existing rate structure for comparison with projected operating and capital expenditures over a five-year forecast period. The sufficiency of projected revenues was then assessed based on established financial metrics targeting liquidity, debt management, and rate of return.

Findings and Recommendations

Existing CGS revenues are sufficient to fund ongoing operations and capital renewal, replacements, and improvements while maintaining adequate reserve levels and debt service coverage. Forecasted revenues generated based on existing rates produce a reasonable rate of return for City of Clearwater taxpayers, consistent with rates of return provided to private, regulated natural gas utilities. **Figure 1** summarizes the financial plan over the five-year forecast period.

Figure 1 – CGS Cash Flow Forecast



1.3. Cost of Service Analysis

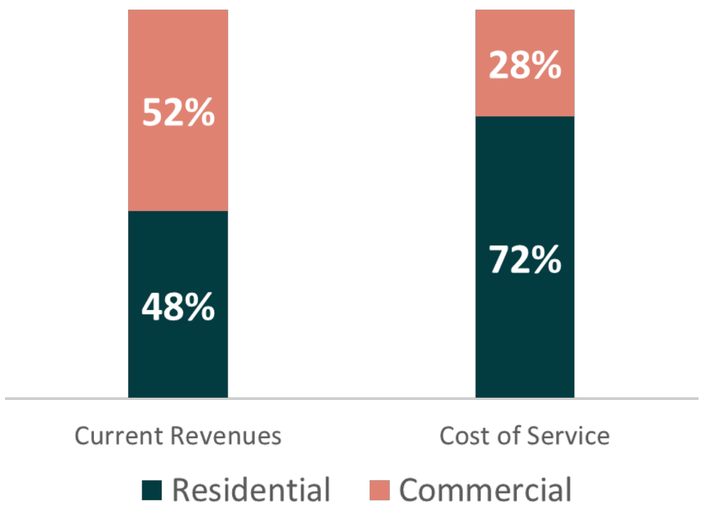
Process

While the financial plan determines the overall level of rate revenue necessary to support the gas system, the cost of service analysis determines what proportion of that overall requirement should be recovered from each of the City's customer classes. The driving principal of a cost of service analysis is to allocate costs to users in proportion to their use of the gas system and services provided by the CGS. For this study, costs were broken down between commodity related costs (the cost of meeting annual system requirements), capacity related costs (the cost of meeting peak demand), customer related costs (the cost of connecting and serving individual customers) and direct costs (costs related to specific cost centers and rate riders). Typically, a cost of service analysis is performed using projected annual costs for a specific future year, referred to the "test year." For this study, the City's fiscal year ending September 1, 2021 (FY 2021) was used as the test year.

Findings and Recommendations

After allocating test year costs of service to the various customer classes on the basis of units of service, our analysis revealed that the residential and commercial classes may need rate adjustments to cover their costs of service. Current residential revenues are not sufficient to cover the costs allocated to the class. This under recovery of costs by the residential class is offset by an over recovery by commercial classes. As a result, rate revenues should be adjusted to appropriately reflect the cost-of-service results. Figure 2 presents a comparison of the class cost of service study for base rates compared to current revenues. Given the current variance between revenue generation and cost of service, we recommend a gradual movement towards cost of service, using a phase-in approach.

Figure 2 – Class Cost of Service vs. Current Revenues



1.4. Rate Design

Process

The objective of rate design is to reasonably and fairly set rates to recover the net revenue requirement in a manner aligned with utility pricing objectives and industry practices. Although recovering the revenue requirement is the ultimate goal, rates must be reasonable and remain competitive with neighboring utilities. In the case of CGS, it is more prudent to establish a directional goal of achieving cost of service over time by implementing incremental shifts towards customer class parity while remaining competitive with neighboring utilities and fuel alternatives.

Findings and Recommendations

Based on the results shown above, CGS's rate revenue is adequate to meet its operating needs over the forecast period. However, individual class rates could be adjusted to improvement alignment between CGS's cost to serve each class and the revenues recovered from that class. The following summarizes our recommendations.

Purchased Gas Adjustment

The PGA is reviewed by CGS monthly and adjusted periodically based on actual and projected gas supply costs, other applicable expenses, and projected demand. As such, the Raftelis Team does not recommend a specific PGA rate as part of this study. However, we do recommend the following modifications to the calculation methodology. First, all customer service costs recovered in the PGA should be shifted for recovery in base rates via the customer charge. Second, the PGA should not include the under-recovery of ECA costs not assessed to non-standard and contract customers.

Riders

The ECA is applicable to all firm natural gas customers but not assessed to non-standard and contract customers. Current rate ordinances allow the City to collect this portion of ECA costs through the PGA. The Raftelis Team recommends the ECA be calculated based on customers that pay it rather than shifting a portion to the PGA. The UIA should be remain at the current level and adjusted as necessary to account for changes in inflation and customer usage. The UIA should reset to $0.00 at the beginning of FY 2022. The RIA should be set to $0.00 until the surplus currently generated by this rate is exhausted, then set to recover budgeted regulatory imposition costs. All customer service costs recovered in the ECA and RIA should be shifted for recovery in base rates via the customer charge.

Base Rates

Our recommendation is that the current customer charge for single-family residential be increased from $12.00 to $16.00. The commodity charge for single-family residential should remain the same at $0.44. The customer charge for small, medium and large commercial classes should remain the same at $25.00, $40.00 and $95.00, respectively. The commodity charge for small, medium and large commercial classes should all decrease $.04 to $0.38, $0.34 and $0.30, respectively. We also recommend that Central Pasco customers continue to pay the Pasco Surcharge in addition to the customer charge monthly. The Pasco Surcharge results in an additional $8.00 for single-family, $15.00 for small commercial, $40.00 for medium commercial, and $65.00 for large commercial monthly.

Tables 1 and 2 present the proposed base rates and customer bill impacts, respectively. These rate recommendations still lead to an under-recovery for single-family residential and represent a phase-in to cost of service. Future rate changes are likely to achieve cost of service in a gradual way as to avoid rate-shock for CGS customers. Figure 3 presents customer class revenues under current rates, cost of service and under the proposed rates shown in Table 1, which reflect the proposed phase-in approach. **Note that these recommendations are revenue neutral in that they are designed to recover the same amount of revenue as CGS's existing rate structure, with the only difference being the distribution of revenue recovery between classes and rates.**

Table 1 – Existing and Proposed Base Rates

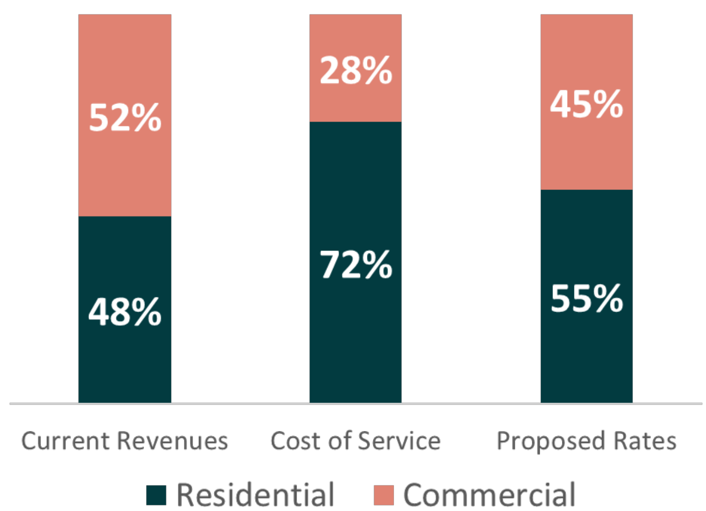
Customer Class	Class Code	Per	Existing		Proposed			
			Pinellas & West Pasco	Central Pasco	Pinellas & West Pasco	% Change	Central Pasco	% Change
Single-Family								
Customer Charge	RS	Month	$ 12.00	$ 20.00	$ 16.00	33%	$ 24.00	20%
Commodity Charge		Therm	$ 0.44	$ 0.44	$ 0.44	0%	$ 0.44	0%
Small Multi-Family								
Customer Charge	NSFD	Month	$ 25.00	$ 40.00	$ 25.00	0%	$ 40.00	0%
Commodity Charge		Therm	$ 0.44	$ 0.44	$ 0.44	0%	$ 0.44	0%
Medium Multi-Family								
Customer Charge	NMFD	Month	$ 40.00	$ 70.00	$ 40.00	0%	$ 70.00	0%
Commodity Charge		Therm	$ 0.44	$ 0.44	$ 0.44	0%	$ 0.44	0%
Large Multi-Family								
Customer Charge	NLFD	Month	$ 95.00	$ 160.00	$ 95.00	0%	$ 160.00	0%
Commodity Charge		Therm	$ 0.44	$ 0.44	$ 0.44	0%	$ 0.44	0%
Small Commercial								
Customer Charge	SFC	Month	$ 25.00	$ 40.00	$ 25.00	0%	$ 40.00	0%
Commodity Charge	SGS	Therm	$ 0.42	$ 0.42	$ 0.38	-10%	$ 0.38	-10%
Medium Commercial								
Customer Charge	MFC	Month	$ 40.00	$ 70.00	$ 40.00	0%	$ 70.00	0%
Commodity Charge	MGC	Therm	$ 0.38	$ 0.38	$ 0.34	-11%	$ 0.34	-11%
Large Commercial								
Customer Charge	LFC	Month	$ 95.00	$ 160.00	$ 95.00	0%	$ 160.00	0%
Commodity Charge	LGS	Therm	$ 0.34	$ 0.34	$ 0.30	-12%	$ 0.30	-12%

Table 2 – Monthly Bill Impacts

Customer Class	Usage (Therms)	Existing	Proposed	$ Change
Single Family (Summer)	10	$25.80	$29.80	$4.00
Single Family (Winter)	30	$53.40	$57.40	$4.00
Small Multi-Family	50	$94.00	$94.00	No Change
Medium Multi-Family	2,600	3,628.00	$3,628.00	No Change
Large Multi-Family	n/a	n/a	n/a	n/a
Small Commercial	350	$522.00	$508.00	-$14.00
Medium Commercial	2,500	$3,490.00	$3,390.00	-$100.00
Large Commercial	11,000	$14,835.00	$14,395.00	-$440.00

Note: For illustration purposes, assumes no change from most recent month PGA and riders. Recommendations are designed to be revenue nuetral.

Figure 3 – Current Revenues, Cost of Service and Proposed Rates



2. Financial Plan

2.1. Financial Planning Metrics & Process

The financial plan establishes the overall level of revenue required to fund ongoing operations and capital repair, replacements, and improvements in a financially sustainable manner. This involves three steps:

1. A forecast of revenue under existing rates, which forms the baseline against which any adjustment of revenues can be considered.
2. A forecast of operation and maintenance (O&M) and capital expenditures.
3. A detailed cash flow forecast which compares revenues and expenditures and evaluates the appropriateness of existing revenues through the context of defined financial metrics.

The specific financial metrics used in this study include days O&M expenses, debt service coverage, return on rate base, and return on equity.

Days O&M Expenses is a measure of the ability of the utility to deal with unanticipated declines in revenue, emergency expenditures, or general working capital needs without reducing service quality or dramatically increasing rates. The City's adopted policy for unrestricted utility fund balances (working capital reserves) requires at least six months, or 180 days, O&M expenses. While the number of days a utility will seek to maintain will vary by utility, we typically recommend a minimum of 180 days, which is consistent with City policy. This can be used for working capital (timing differences in revenues and expenditures), temporary revenue shortfalls, or emergency capital repairs.

Debt Service Coverage Ratios are a measure of how much current revenues exceed current debt service obligations, after operating expenses have been funded. A ratio above 1 indicates that current net revenues (operating revenues less expenses) are sufficient to meet current debt service obligations with additional free cash flow for capital investment and/or contributions to reserves. A ratio of less than 1 would mean that the utility does not have sufficient current revenues to cover operating expenses and meet debt service payment obligations. Coverage requirements vary by the type of debt issued and bond covenants, as well as an individual utility's goals for credit ratings. For the purpose of this study, the financial plan developed for the City is based on maintaining a coverage ratio of at least 1.50 times.

Return on Rate Base is the measurement of operating profit on investments in assets. It is calculated by dividing operating income (before allowance for dividends and interest on long-term debt) by rate base, or the value of assets less accumulated depreciation (net utility plant). Return on rate base is a common financial metric used by a public service commission when assessing the reasonableness of regulated natural gas utility rates.

Return on Equity (ROE) is a subset of return on rate base and measures the profit available for equity holders after creditors have been paid. It is calculated by dividing operating income (after interest on long-term debt) by equity. ROE is also a common financial metric used by a public service commission when assessing the reasonableness of regulated natural gas utility rates; however, a reasonable ROE will differ by utility depending on its capital structure.

These various metrics provided a framework to help determine the necessity for revenue adjustments.

2.2. Projected Revenues

2.2.1. EXISTING RATES/STRUCTURE

CGS provides natural gas and propane services to residential, commercial and industrial customers in Pinellas and Pasco Counties. CGS's rate structure for customers receiving firm natural gas service consists of three distinct groups of charges: a purchased gas adjustment (PGA) rate, rate riders and base rates.

The **purchased gas adjustment (PGA)** rate is the mechanism by which CGS recovers the cost of natural gas and propane it purchases to distribute to customers. Purchased gas and propane expenses can fluctuate significantly due to changes in market prices and weather conditions. The cost of these commodity purchases is passed on to CGS customers through the PGA. The PGA is reviewed monthly and adjusted periodically based on actual and projected gas and propane supply costs, all other applicable expenses, and projected demand. Per the City's ordinance, the adjustment of the PGA to reflect the over or under recovery of costs is made at the discretion of the City Manager or designee. CGS employs different PGA rates for different classes of customers depending on the cost to purchase gas on their behalf, which varies based on service arrangements and location.

Most CGS customers pay the firm PGA rate. Interruptible customers pay a reduced PGA, which excludes demand related charges because CGS can interrupt service to these customers during times of peak demand. CGS also employs contract rates for certain customers in situations where the firm rate would not be competitive with other providers. Finally, customers in central Pasco County (generally east of Suncoast Parkway), pay an additional surcharge which reflects the incremental cost of gas purchased to serve them.

CGS also has multiple **rate riders** designed to recover certain costs or mitigate operational risk. Specifically, CGS' rate structure includes an Energy Conservation Adjustment (ECA), a Usage and Inflation Adjustment (UIA), and a Regulatory Imposition Adjustment (RIA).

The *Energy Conservation Adjustment (ECA)* is designed to recover costs associated with energy conservation and demand management including rebates and incentive programs. The ECA is applicable to all firm natural gas and propane customers. The ECA is reviewed monthly and adjusted periodically based on actual and projected energy conservation program costs and projected demand. The adjustment to the ECA to reflect the over or under recovery of costs is made at the discretion of the City Manager or designee.

The *Usage and Inflation Adjustment (UIA)* is designed to mitigate operational and financial risks associated with fluctuations in demand and inflationary cost increases. The UIA is applicable to all firm natural gas and propane customers. The UIA may be implemented at the discretion of the City Manager or designee based on variations in estimated use per customer and inflationary assumptions identified in this rate study. The UIA forecasted revenues are based on an August CPI of 249.639[1] and an assumed increase of 2.5% annually.

The *Regulatory Imposition Adjustment (RIA)* is designed to recover the cost of environmental, operator qualification, distribution integrity, inspection, survey, and other regulatory imposed program requirements. The RIA is appliable to all firm natural and propane customers. The RIA is normally reviewed periodically and adjusted to reflect the over or under recovery of costs at the discretion of the City Manager or designee.

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[1] Consumer Price Index all items in South urban, all urban customers, not seasonally adjusted.

The final components of CGS's rate structure are the **base rates**. The primary[2] customer classes served under the base rates fall into the categories indicated in **Table 3**. The size distinction (small, medium, large) is based on the average annual throughput of the customer. As noted above, the PGA rate is the mechanism by which the purchase of gas is recovered. The rate riders are intended to isolate the recovery of specifically defined costs in order to mitigate operational risk. Base rates, by contrast, are intended to recover CGS's cost of *distributing* natural gas to customers after PGA and rider specific costs have been excluded. In other words, while the PGA and rider related costs are specifically defined, the costs recovered by the base rates are driven by demands placed on the CGS system by customers, which drive the design and operation of that system. Therefore, it is appropriate to design the base rates around each customer class's proportionate contribution to these demands. Accordingly, the base rates are the focus of the cost of service analysis in **Section 3**.

Table 3 – Existing Base Rates

Customer Class	Per	Pinellas & West Pasco	Central Pasco
Single-Family (RS)			
Customer Charge	Month	$ 12.00	$ 20.00
Commodity Charge	Therm	$ 0.44	$ 0.44
Small Multi-Family (NSFD)			
Customer Charge	Month	$ 25.00	$ 40.00
Commodity Charge	Therm	$ 0.44	$ 0.44
Medium Multi-Family (NMFD)			
Customer Charge	Month	$ 40.00	$ 70.00
Commodity Charge	Therm	$ 0.44	$ 0.44
Large Multi-Family (NLFD)			
Customer Charge	Month	$ 95.00	$ 160.00
Commodity Charge	Therm	$ 0.44	$ 0.44
Small Commercial (SFC, SGS)			
Customer Charge	Month	$ 25.00	$ 40.00
Commodity Charge	Therm	$ 0.42	$ 0.42
Medium Commercial (MFC, MGS)			
Customer Charge	Month	$ 40.00	$ 70.00
Commodity Charge	Therm	$ 0.38	$ 0.38
Large Commercial (LFC, LGS)			
Customer Charge	Month	$ 95.00	$ 160.00
Commodity Charge	Therm	$ 0.34	$ 0.34

[2] In addition to the rates shown below, CGS employs a variety of market based rates including propane rates, natural gas vehicle sales, contract rates and interruptible rates. Customers served under the market based rates have alternatives to CGS service. Accordingly, CGS sets these rates to be competitive with other providers.

2.2.2. ACCOUNT GROWTH AND USAGE FORECAST

To forecast revenue under existing rates, Raftelis worked with City staff to develop projections of future account growth and customer usage.

Customer account growth is influenced by development within the CGS service area as well as customer conversion to natural gas from propane and electric service. Over the past decade, the City has experienced a consistent increase in natural gas customers that has expanded more rapidly over the past several years. The expansion of the system has, and continues to be, a priority identified in the City's strategic plan, which targets goals for annual account growth through fiscal year (FY) 2025. Specifically, the City's strategic plan targets a net addition of approximately 2,000 accounts annually. Although current indications suggest continued robust levels of account growth, through discussion with City staff, it was determined that account growth assumed within financial plan should be based on a reasonable level of conservatism, particularly in light of ongoing economic disruptions due to the novel coronavirus pandemic (COVID-19). As such, the financial plan projects a growth of approximately 1,200 accounts annually, which is substantively less than historical trends and the City's target but reflective of economic uncertainties due to COVID-19. **Table 3** presented historical and projected account growth by customer class.

Baseline natural gas usage needs to be normalized due to fluctuations in usage arising from weather. Typically, to normalize usage, a regression analysis is performed to assess the correlation between usage and heating degree-days, particularly for weather sensitive customer classes (e.g. residential and small commercial). The correlation can then be used to project usage based on normal or expected heating degree-days, which are based on a historical average. This leads to a normalized usage-per account. Due to data constraints, a full weather normalization analysis was not performed, and a multi-year average of usage-per-account was used for each customer class instead. The financial plan assumes the calculated usage-per-account remains constant over forecast period for all customer classes. Any lost revenue from future decline in usage-per-account, or any usage below the forecast, can be recovered through the UIA. For the purpose of this study, normalized usage per account for firm natural gas single-family residential customers and commercial customers was 185 therms and 5,877. therms, respectively. **Tables 4 and 5** present historical and projected usage (therms), respectively.

Table 4 – Historical and Projected Customer Account Growth

Description	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025
Residential Service										
Single-Family (RS)	17,310	18,182	19,463	21,053	22,137	23,299	24,389	25,543	26,765	27,765
Small Multi-Family (NSFD)	106	104	103	102	102	102	102	102	102	102
Medium Multi-Family (NMFD)	2	2	2	2	2	2	2	2	2	2
Large Multi-Family (NLFD)	1	1	1	1	1	1	1	1	1	1
Subtotal Residential Service	**17,419**	**18,289**	**19,569**	**21,158**	**22,242**	**23,404**	**24,494**	**25,648**	**26,870**	**27,870**
Commercial Service										
Small Commercial (SFC)	103	102	101	100	100	100	100	100	100	100
Medium Commercial (MFC)	6	5	5	5	5	5	5	5	5	5
Large Commercial (LFC)	-	-	-	-	-	-	-	-	-	-
Small Commercial (SGS)	1,860	1,903	1,956	2,005	2,054	2,104	2,155	2,208	2,256	2,305
Medium Commercial (MGS)	112	112	113	115	118	120	123	126	128	131
Large Commercial (LGS)	4	4	5	5	5	5	5	5	6	6
Subtotal Commercial Service	**2,085**	**2,126**	**2,180**	**2,230**	**2,281**	**2,334**	**2,389**	**2,445**	**2,495**	**2,547**
All Other										
Vehicle (NGV)	1	1	1	1	1	1	1	1	1	1
Standby (NSS)	35	37	39	43	44	45	46	47	48	49
Lights (SL no Maint.)	-	1	1	1	1	1	1	1	1	1
Lights (SL with Maint.)	-	-	-	-	-	-	-	-	-	-
Air Conditioning	1	1	1	1	1	1	1	1	1	1
Contracts	188	188	188	188	172	172	172	172	172	172
Interruptible	17	17	18	18	18	18	18	18	18	18
Subtotal All Other	**242**	**245**	**248**	**252**	**237**	**238**	**239**	**240**	**241**	**242**
Grand Total	**19,746**	**20,660**	**21,997**	**23,640**	**24,760**	**25,976**	**27,122**	**28,333**	**29,607**	**30,659**
		4.63%	**6.47%**	**7.47%**	**4.74%**	**4.91%**	**4.41%**	**4.47%**	**4.50%**	**3.56%**

Table 5 – Historical and Projected Customer Usage (Therms)

Description	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025
Residential Service										
Single-Family (RS)	3,174,691	3,231,402	3,744,841	3,802,055	4,197,296	4,430,413	4,647,552	4,877,944	5,122,524	5,318,641
Small Multi-Family (NSFD)	67,285	68,227	69,734	68,514	66,332	66,332	66,332	66,332	66,332	66,332
Medium Multi-Family (NMFD)	58,447	61,488	65,074	65,319	64,838	64,838	64,838	64,838	64,838	64,838
Large Multi-Family (NLFD)	108	127	130	136	2,973	2,973	2,973	2,973	2,973	2,973
Subtotal Residential Service	**3,300,530**	**3,361,242**	**3,879,779**	**3,936,023**	**4,331,440**	**4,564,556**	**4,781,696**	**5,012,087**	**5,256,668**	**5,452,784**
Commercial Service										
Small Commercial (SFC)	214,612	206,620	224,823	204,842	207,438	207,446	207,455	207,464	207,470	207,476
Medium Commercial (MFC)	74,263	71,592	77,786	70,568	66,657	66,657	66,657	66,657	66,657	66,657
Large Commercial (LFC)	-	-	-	-	-	-	-	-	-	-
Small Commercial (SGS)	7,217,344	7,453,438	7,932,921	7,985,520	8,157,394	8,364,584	8,578,120	8,798,239	8,991,199	9,188,528
Medium Commercial (MGS)	2,981,217	2,847,630	2,984,783	2,876,192	3,093,758	3,165,939	3,240,080	3,316,244	3,386,545	3,458,373
Large Commercial (LGS)	590,646	580,040	663,706	673,888	725,068	739,570	754,361	769,448	784,837	800,534
Subtotal Commercial Service	**11,078,081**	**11,159,320**	**11,884,019**	**11,811,010**	**12,250,315**	**12,544,196**	**12,846,673**	**13,158,052**	**13,436,708**	**13,721,567**
All Other										
Vehicle (NGV)	477,771	528,849	743,619	543,853	527,662	538,215	548,979	559,959	571,158	582,581
Standby (NSS)	5,529	6,919	13,911	7,396	9,669	9,863	10,062	10,265	10,470	10,680
Lights (SL no Maint.)	603	4,680	3,623	-	1,694	1,728	1,762	1,797	1,833	1,870
Lights (SL with Maint.)	-	-	-	-	-	-	-	-	-	-
Air Conditioning	-	-	5,696	20,907	5,321	5,321	5,321	5,321	5,321	5,321
Contracts	2,015,645	2,162,956	1,886,749	1,963,374	1,895,992	1,895,992	1,895,992	1,895,992	1,895,992	1,895,992
Interruptible	6,836,099	7,022,297	6,899,299	7,429,515	7,288,220	7,288,220	7,288,220	7,288,220	7,288,220	7,288,220
Subtotal All Other	**9,335,648**	**9,725,701**	**9,552,897**	**9,965,045**	**9,728,557**	**9,739,339**	**9,750,336**	**9,761,554**	**9,772,995**	**9,784,664**
Grand Total	**23,714,259**	**24,246,263**	**25,316,695**	**25,712,078**	**26,310,311**	**26,848,091**	**27,378,704**	**27,931,693**	**28,466,371**	**28,959,015**
		2.24%	**4.41%**	**1.56%**	**2.33%**	**2.04%**	**1.98%**	**2.02%**	**1.91%**	**1.73%**

2.2.3. PROJECTED REVENUES UNDER EXISTING RATES

Given the growth in accounts and usage over the forecast period, both fixed and variable revenues are projected to increase. **Table 6** shows projected revenue based on existing rates over the five-year forecast period. In addition to natural gas sales, there are other ancillary sources of revenue from propane sales, gas service charges, appliance sales, installation charges, material charges, inspection fees, late payment fees, franchise fees, and gross receipts tax collection. In our projection, we assume that revenues collected for franchise fees and gross receipts taxes are equal to the expenses incurred. Additional information on both franchise fees and gross receipts taxes is provided in Section 2.3.5.

Table 6 – Revenue Under Existing Rates

Description	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025
PGA Revenues	**$ 20,259,797**	**$ 20,738,421**	**$ 21,210,667**	**$ 21,702,827**	**$ 22,178,690**	**$ 22,617,143**
Rider Revenues						
ECA	$ 5,030,557	$ 5,242,160	$ 5,323,214	$ 5,406,294	$ 5,491,452	$ 5,578,738
RIA	-	-	381,790	498,169	510,623	523,388
UIA	1,038,528	323,590	477,742	489,686	501,928	514,476
Subtotal Rider Revenues	**$ 6,069,085**	**$ 5,565,750**	**$ 6,182,746**	**$ 6,394,149**	**$ 6,504,002**	**$ 6,616,603**
Base Rate Revenues						
Residential	$ 5,126,261	$ 5,396,126	$ 5,648,624	$ 5,916,166	$ 6,199,800	$ 6,430,088
Commercial	5,674,594	5,810,495	5,950,380	6,094,390	6,223,151	6,354,780
Subtotal Base Rate Revenues	**$ 10,800,855**	**$ 11,206,622**	**$ 11,599,004**	**$ 12,010,556**	**$ 12,422,951**	**$ 12,784,868**
All Other Revenues						
Market Driven Revenues	$ 2,374,651	$ 2,378,286	$ 2,381,997	$ 2,385,785	$ 2,389,608	$ 2,393,509
Propane Non-Fuel Revenues	550,330	550,330	550,330	550,330	550,330	550,330
Appliance Sales and Service	1,300,000	1,300,000	1,300,000	1,300,000	1,300,000	1,300,000
Other Revenues	3,828,470	2,875,300	2,875,300	2,875,300	2,875,300	2,875,300
Fees and Taxes	2,037,000	2,037,000	2,037,000	2,037,000	2,037,000	2,037,000
Subtotal All Other Revenues	**$ 10,090,451**	**$ 9,140,916**	**$ 9,144,627**	**$ 9,148,416**	**$ 9,152,239**	**$ 9,156,139**
Grand Total Revenues	**$ 47,220,189**	**$ 46,651,709**	**$ 48,137,044**	**$ 49,255,947**	**$ 50,257,882**	**$ 51,174,753**
		-1.20%	**3.18%**	**2.32%**	**2.03%**	**1.82%**

2.3. Projected Revenue Requirements

2.3.1. OPERATING EXPENSES

The basis for the operating expense forecast is CGS's FY 2020 budget. Based on a review of historical actual performance, and through discussions with CGS staff, we reduced the budget to 95% of the approved amounts. We then applied an assumed inflation rate of 2.5% per year to reflect anticipated inflation over the 5-year forecast period. As described above, CGS currently has a UIA rate which is designed to capture any inflation that occurs over time. The rate recommendations presented in this report assume that the UIA will remain at its current level and then reset to $0.00 at the beginning of FY 2022 with adjustments as needed to reflect inflationary impacts. **Table 7** shows a summary of CGS's forecast operating expenses. These expenses fall into 4 broad categories: PGA specific, Rider specific, All Other and Taxes.

PGA specific costs include the cost of purchasing gas for customers as well as a portion of other operating costs including customer service and billing costs, administrative costs and a portion of the dividend to the City of Clearwater. As described in further detail in Sections 3 and 4, we recommend that the City shift some of these costs out of the PGA and into the base rates, where they are more appropriately recovered. That said, it is important to recognize that this would not necessarily impact what the customer pays but would improve alignment between the intent of the PGA and the costs which are recovered by it.

Rider specific costs include the specific costs associated with performing these activities (as described in Section 2.2.1) and a portion of other operating costs including customer service and billing cost, administrative costs and a portion of the dividend to the City. As noted above, the costs associated with these riders are accounted for within specific costs centers in CGS's detailed budgeting and financial reporting records. Raftelis segmented these costs from the overall budget to ensure that the costs associated with these riders are transparently excluded from base rates. Similar to the PGA, we are recommending adjustments to the calculations of these riders to improve alignment between the intent of the rider and the costs which are recovered by it.

All other operating costs include administrative and customer service costs not attributed to the PGA or riders and all other costs related to CGS's operation of the gas system.

Taxes relate to franchise fees and taxes imposed on CGS by governmental jurisdictions within which CGS provides gas service. CGS levies a charge on every purchase of gas within a jurisdiction to recover the costs assessed by governmental entities in accordance with the franchise agreement in force between CGS and other governmental entities. The fees collected within each governmental jurisdiction are used exclusively to pay the franchise fees and other governmental fees, taxes, and other impositions levied on services within that governmental jurisdiction. All taxes due to the appropriate governmental entity (such as but not limited to the State of Florida sales tax, county sales tax, municipal utility tax, and others) which may be legally levied on the purchase of gas are billed to the customers receiving such service. For the purposes of this rate study, franchise fees and taxes are shown as pass-through revenue and expense.

Table 7 – Forecast Operating Expenses

Description	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025
PGA Expense	$ 15,675,941	$ 16,067,839	$ 16,469,535	$ 16,881,273	$ 17,303,305	$ 17,735,888
PGA Billing/CS	750,550	769,314	788,547	808,260	828,467	849,178
ECA Expenses	3,242,160	3,323,214	3,406,294	3,491,452	3,578,738	3,668,206
ECA Billing/CS	49,200	50,430	51,691	52,983	54,308	55,665
RIA Expenses	474,164	486,018	498,169	510,623	523,388	536,473
All Other Admin	1,201,627	1,231,667	1,262,459	1,294,020	1,326,371	1,359,530
All Other Billing/CS	185,690	190,332	195,091	199,968	204,967	210,091
All Other Non-Fuel	13,633,260	13,828,029	14,173,730	14,528,073	14,891,275	15,263,557
Taxes	2,037,000	2,037,000	2,037,000	2,037,000	2,037,000	2,037,000
Total	**$ 37,249,591**	**$ 37,983,843**	**$ 38,882,514**	**$ 39,803,652**	**$ 40,747,819**	**$ 41,715,589**
		1.97%	**2.37%**	**2.37%**	**2.37%**	**2.38%**

2.3.2. CAPITAL EXPENDITURES

Capital expenditures are incurred to recapitalize and make additions to gas system assets. For the purposes of this rate study, capital expenditures have been identified on a cash basis, which includes principal and interest payments on debt obligations, rate financed capital, and contribution to reserves. The City has two outstanding debt obligations on the natural gas system including the Series 2013 and Series 2014 revenue bonds. Annual debt service payments for these obligations are approximately $900,000 annually, with a balloon principal payment due on the Series 2013 revenue bonds occurring in FY 2025. **Table 8** presents CGS's annual debt service payments over the forecast period.

Table 8 – Annual Debt Service

Description	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025
Gas Refunding Bonds Series 2013						
Principal	$ 400,000	$ 410,000	$ 425,000	$ 435,000	$ 440,000	$ 1,485,000
Interest	123,272	113,632	103,751	93,508	83,025	72,421
Subtotal Series 2013	**$ 523,272**	**$ 523,632**	**$ 528,751**	**$ 528,508**	**$ 523,025**	**$ 1,557,421**
Gas Refunding Bonds Series 2014						
Principal	$ 275,000	$ 285,000	$ 285,000	$ 300,000	$ 305,000	$ 315,000
Interest	110,271	102,929	95,319	87,710	79,700	71,556
Subtotal Series 2014	**$ 385,271**	**$ 387,929**	**$ 380,319**	**$ 387,710**	**$ 384,700**	**$ 386,556**
Grand Total	**$ 908,543**	**$ 911,560**	**$ 909,070**	**$ 916,218**	**$ 907,724**	**$ 1,943,977**

CGS develops an annual Capital Improvements Plan (CIP) that identifies specific projects the City would like to undertake over the next five years. The current five-year CIP includes replacements and upgrades to the transmission and distribution system, service extensions, expanded energy conservation, completion of the campus rebuild, and other projects. Raftelis worked closely with City staff to develop a plan to finance these future investments. Based on current levels of liquidity and projected free cash flow generated from rates, Raftelis recommends that the CGS CIP be financed entirely with cash. Projects identified specifically for expanded energy conservation should be funded through the ECA. The CIP sources and uses are show in **Table 9**.

Table 9 – Capital Improvements Plan

Description	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025
Uses of CIP Financing						
Line Relocation Pinellas - Maintenance	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000
Gas Meter Changeout - Pinellas Capitalized	250,000	250,000	250,000	250,000	250,000	250,000
Line Relocation Pinellas - Capitalized	300,000	300,000	300,000	300,000	300,000	300,000
Line Relocation Pasco - Maintenance	25,000	25,000	25,000	25,000	25,000	25,000
Pinellas New Mains & Service Lines	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000
Pasco New Mains & Service Lines	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000
Gas Meter Change Out - Pasco Capitalized	250,000	250,000	250,000	250,000	250,000	250,000
Line Relocation Pasco - Capitalized	300,000	300,000	300,000	300,000	300,000	300,000
Expanded Energy Conservation	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000
Natural Gas Vehicle	200,000	200,000	200,000	200,000	200,000	200,000
Future IMS Software and Hardware	500,000	500,000	500,000	250,000	250,000	250,000
Gas System - Pasco Building	250,000	250,000	250,000	250,000	250,000	250,000
Pinellas Building: Equip R&R	200,000	200,000	200,000	200,000	200,000	200,000
Campus Rebuild	7,300,000	-	-	-	-	-
Total Uses	**$ 16,100,000**	**$ 8,800,000**	**$ 8,800,000**	**$ 8,550,000**	**$ 8,550,000**	**$ 8,550,000**
Sources of CIP Financing						
PAYGO	$ 14,100,000	$ 6,800,000	$ 6,800,000	$ 6,550,000	$ 6,550,000	$ 6,550,000
ECA PAYGO	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000
Total Sources	**$ 16,100,000**	**$ 8,800,000**	**$ 8,800,000**	**$ 8,550,000**	**$ 8,550,000**	**$ 8,550,000**

2.3.3. DIVIDEND TO CITY OF CLEARWATER

Per adopted City policy, CGS makes an annual payment to the City in the form of a dividend. The dividend is calculated as 50% of CGS' prior year net income but not less than $1.7 million. The projected dividend payment in the financial forecast is based on the FY 2020 budget. Transfers between the City owned utility and the City's general government are common throughout the municipal utility industry. CGS benefits from a wide variety of services provided by the City but does not pay property taxes. If the City did not provide these services, CGS would need to either hire additional staff to perform the same functions or contract them out.

The dividend, in part, recognizes the cost of services provided. It is our understanding that the City's water and wastewater utilities pay a Payment in Lieu of Taxes (PILOT) based on a percentage of revenues, in recognition of this same concept. In addition, the dividend recognizes the investment City taxpayers have made in order to enter the competitive gas industry. As described in the next section, the dividend provides a reasonable return to City taxpayers in recognition of the investment they have made in the gas utility.

2.3.4. CASH FLOW FORECAST

The final step in the financial planning process involves compiling a cash flow forecast and evaluating the appropriateness of CGS's current revenue levels given the financial performance metrics identified in **Section 2.1**: days O&M expenses, debt service coverage ratios, return on rate base and return on equity (ROE). **Table 10** indicates the cash flow forecast for the 5-year period. As indicated, although projected revenue from existing rates generates a cash deficit over the forecast period, current levels of reserves are above the minimum policy target of 180 days O&M expenses. One of the primary drivers in the reduction of reserves is the completion of the campus rebuild project in FY 2020, which is a large capital investment in various facilities funded entirely with cash. Debt service coverage remains strong and is considerably above minimum policy targets.

Table 10 - Cash Flow Forecast

Description	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025
Revenues						
PGA Revenues	$ 20,259,797	$ 20,738,421	$ 21,210,667	$ 21,702,827	$ 22,178,690	$ 22,617,143
Rider Revenues	6,069,085	5,565,750	6,182,746	6,394,149	6,504,002	6,616,603
Base Rate Revenues	10,800,855	11,206,622	11,599,004	12,010,556	12,422,951	12,784,868
All Other Revenues	10,090,451	9,140,916	9,144,627	9,148,416	9,152,239	9,156,139
Total Revenues	**$ 47,220,189**	**$ 46,651,709**	**$ 48,137,044**	**$ 49,255,947**	**$ 50,257,882**	**$ 51,174,753**
Operating Expenses						
PGA Expense	$ 15,675,941	$ 16,067,839	$ 16,469,535	$ 16,881,273	$ 17,303,305	$ 17,735,888
PGA Billing/CS	750,550	769,314	788,547	808,260	828,467	849,178
ECA Expenses	3,242,160	3,323,214	3,406,294	3,491,452	3,578,738	3,668,206
ECA Billing/CS	49,200	50,430	51,691	52,983	54,308	55,665
RIA Expenses	474,164	486,018	498,169	510,623	523,388	536,473
All Other Admin	1,201,627	1,231,667	1,262,459	1,294,020	1,326,371	1,359,530
All Other Billing/CS	185,690	190,332	195,091	199,968	204,967	210,091
All Other Non-Fuel	13,633,260	13,828,029	14,173,730	14,528,073	14,891,275	15,263,557
Taxes	2,037,000	2,037,000	2,037,000	2,037,000	2,037,000	2,037,000
Subtotal Operating	**$ 37,249,591**	**$ 37,983,843**	**$ 38,882,514**	**$ 39,803,652**	**$ 40,747,819**	**$ 41,715,589**
Capital Expenditures						
Debt Service	$ 908,543	$ 911,560	$ 909,070	$ 916,218	$ 907,724	$ 1,943,977
PAYGO	16,100,000	8,800,000	8,800,000	8,550,000	8,550,000	8,550,000
Subtotal Capital	**$ 17,008,543**	**$ 9,711,560**	**$ 9,709,070**	**$ 9,466,218**	**$ 9,457,724**	**$ 10,493,977**
Total Expenditures	**$ 54,258,134**	**$ 47,695,403**	**$ 48,591,584**	**$ 49,269,870**	**$ 50,205,543**	**$ 52,209,565**
Financial Performance						
Beginning Balance	$ 30,871,394	$ 23,833,449	$ 22,789,755	$ 22,335,215	$ 22,321,293	$ 22,373,633
Surplus/ (Deficit)	(7,037,945)	(1,043,694)	(454,540)	(13,922)	52,340	(1,034,813)
Ending Balance	$ 23,833,449	$ 22,789,755	$ 22,335,215	$ 22,321,293	$ 22,373,633	$ 21,338,820
Days Cash	**234**	**219**	**210**	**205**	**200**	**187**
Revenue Bond DSCR	**9.97**	**8.51**	**9.18**	**9.32**	**9.48**	**3.87**

In order to assess the projected level of return on rate base and return on equity Raftelis developed a pro-forma income statement shown on **Table 11** for the 5-year forecast period. **Table 12** indicates the calculated rate of return on equity which is projected to decrease from 8.6% to 7.1% over the forecast period. Since CGS's capital structure is almost entirely equity, the projected ROE is comparable to what a regulated utility would be granted assuming a similar capital structure. **Table 12** also indicates the calculated return on rate base which is projected to decrease from 7.5% to 6.5% over the forecast period. This range is comparable to rates of return granted recently by state public service commissions in regulated natural gas utility rate filings.

Also shown is a rate of return calculation including a hypothetical PILOT based on 5.5% of gross revenues, similar to what is paid by other City enterprise funds. This return is more comparable to investor-owned utilities, which would earn a rate of return after paying taxes. If the City were to assess a PILOT to CGS, the projected rate of return would be in the range of 3.75% - 4.75%. This is *lower* than what is typically granted to regulated utilities. In other words, the return being earned by CGS is not unreasonable with respect to its investor-owned peers. Finally, it is important to note that—unlike investor-owned utilities—the return being earned by CGS does not go to shareholders. It is used to fund general government services that would otherwise by funded by taxes.

Based on the above, CGS's existing revenues are reasonable and produce a fair rate of return for City of Clearwater taxpayers. We recommend maintaining levels of revenue that can be generated based on current rates until the completion of CGS's next rate study at which point revenue adjustments can be reevaluated.

Table 11 – Pro-forma Income Statement

Description	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025
Revenues	**$ 47,220,189**	**$ 46,651,709**	**$ 48,137,044**	**$ 49,255,947**	**$ 50,257,882**	**$ 51,174,753**
Operating Expenses						
PGA	$ 14,407,361	$ 14,767,545	$ 15,136,733	$ 15,515,151	$ 15,903,030	$ 16,300,606
All Other	18,479,431	18,795,354	19,265,238	19,746,869	20,240,540	20,746,554
Taxes	2,037,000	2,037,000	2,037,000	2,037,000	2,037,000	2,037,000
PILOT**	-	-	-	-	-	-
Depreciation	3,563,757	3,818,091	4,072,424	4,291,043	4,509,662	4,728,281
Subtotal Operating Expenses	**$ 38,487,548**	**$ 39,417,989**	**$ 40,511,395**	**$ 41,590,063**	**$ 42,690,233**	**$ 43,812,441**
Operating Income	**$ 8,732,640**	**$ 7,233,720**	**$ 7,625,650**	**$ 7,665,884**	**$ 7,567,650**	**$ 7,362,312**
Non-Operating Rev/(Exp)	**316,458**	**333,440**	**350,931**	**368,783**	**387,276**	**406,024**
Income/(Loss) Before Transfers	9,049,098	7,567,160	7,976,580	8,034,667	7,954,926	7,768,335
Dividends to GF (Transfer Out)	(3,982,667)	(2,533,215)	(2,516,973)	(2,729,804)	(2,652,431)	(2,651,247)
Net Change in Fund Equity	**$ 5,066,430**	**$ 5,033,945**	**$ 5,459,608**	**$ 5,304,863**	**$ 5,302,494**	**$ 5,117,088**

Table 12 – Return on Equity/Rate Base Calculation

Description	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025
Return on Equity						
Income/(Loss) Before Transfers	$ 9,049,098	$ 7,567,160	$ 7,976,580	$ 8,034,667	$ 7,954,926	$ 7,768,335
Divided by: Equity	$ 82,487,665	$ 88,164,575	$ 93,602,151	$ 98,596,107	$ 103,381,445	$ 109,003,164
Return on Equity	**11.0%**	**8.6%**	**8.5%**	**8.1%**	**7.7%**	**7.1%**
Return on Rate Base						
Operating Income	$ 8,732,640	$ 7,233,720	$ 7,625,650	$ 7,665,884	$ 7,567,650	$ 7,362,312
Divide by: Rate Base	$ 91,057,665	$ 96,039,575	$ 100,767,151	$ 105,026,107	$ 109,066,445	$ 112,888,164
Equals: Return on Rate Base	**9.6%**	**7.5%**	**7.6%**	**7.3%**	**6.9%**	**6.5%**
Return on Rate Base						
Operating Income Above	$ 8,732,640	$ 7,233,720	$ 7,625,650	$ 7,665,884	$ 7,567,650	$ 7,362,312
Less: PILOT @ 5.5% Prior Year Revs	$ (2,558,205)	$ (2,597,110)	$ (2,565,844)	$ (2,647,537)	$ (2,709,077)	$ (2,764,184)
Equals: Adj. Operating Income	$ 6,174,435	$ 4,636,610	$ 5,059,806	$ 5,018,347	$ 4,858,573	$ 4,598,128
Divide by: Rate Base	$ 91,057,665	$ 96,039,575	$ 100,767,151	$ 105,026,107	$ 109,066,445	$ 112,888,164
Equals: Return on Rate Base	**6.8%**	**4.8%**	**5.0%**	**4.8%**	**4.5%**	**4.1%**

Financial Plan – Key Findings and Recommendations

- **Key Findings** –
  1. Existing CGS revenues are sufficient to fund ongoing operations, capital renewal and replacement while maintaining reserve levels and debt service coverage ratios.
  2. Existing CGS revenues produce a reasonable rate of return for City of Clearwater taxpayers.
- **Recommendations** – Maintain level of revenue that can be generated based on existing rates.

3. Cost of Service Analysis

While the financial plan determines the overall level of rate revenue required to support the gas utility, the cost of service analysis is one tool that can be used to determine each customer class's share of rate revenue based on their proportionate share of the system (the customer class revenue requirement).

3.1. Process

Cost of service allocations provide a measure of determining the proportionate responsibility of each customer class for the service provided. Analysis of these costs provides guidelines for rate design and for comparing revenue derived by the present rates from each class with the cost associated with providing service. Cost of service allocations are based upon conditions estimated for a test year that reflects typical operations of the gas utility. For this study, the test year is the City's fiscal year ending September 30, 2021 (FY 2021).

Following the development of the test year revenue requirement, the proportion of the total revenue requirement (i.e. O&M and capital) allocable to each customer class must be determined. This allocation represents the level of revenues that should be recovered from each customer class, given the operational demands that class places on the gas utility system. This allocation is performed via the following steps:

1. Allocation of Costs to Cost Drivers
2. Determination of Units of Service
3. Distribution of Cost to Customer Classes

3.2. Allocation of Costs to Cost Drivers

Cost drivers represent the types of customer demand which drive variation in CGS's costs. The costs drivers used for this study are:

- Commodity
- Capacity
- Customer - Readiness to Serve (RTS)
- Meters/Regulators
- Services
- Customer – Accts
- Direct (PGA, ECA, RIA)

Commodity costs are associated with volumetric throughput. **Capacity costs** are associated with providing adequate capacity in the transmission and distribution system to meet peak demand. **Customer-Readiness to Serve (RTS)** costs are associated with extending the distribution system to customers such that service is available to CGS customer 24/7/365 regardless of how much gas is used. **Meters/regulators, service lines and customer accounts** costs are all associated with delivering, measuring, and administering service at the customer level.

As discussed in Section 2.1, CGS has three distinct types of rates: the PGA, riders and base rates. Accordingly, the cost of service analysis segments these costs into these three categories for cost allocation purposes. Table 12 indicates the percentage allocation of each component of the revenue requirement. **Table 13** indicates the resulting dollar allocations.

Costs related to the PGA and riders (ECA, RIA) are directly assigned to those cost drivers. This step is necessary to isolate the PGA and rider specific costs to ensure they are not included in the base rates. The one exception is billing and customer service costs, a portion of which have historically been recovered in the PGA and riders. We believe these costs are more appropriately recovered in base rates because they relate to providing service to CGS customers more generally, rather than being specifically related to either the purchase of gas, or the activities covered by the riders.

Costs related to base rates are allocated primarily based on CGS's plant investment (Plant allocator). Raftelis utilized CGS's plant investment records combined with Navillus' experiencing conducting detailed evaluations of natural gas assets to develop the plant allocator used to allocate these costs. The use of a plant allocator to allocate costs is common throughout the municipal utility industry and is based on the presumption that CGS incurs operating costs in proportion to the investment in gas infrastructure used to provide service to customers. Costs related to billing and customer service were directly allocated to "Customer – Accts." Administrative costs and taxes were allocated using a composite allocator based on the allocation of the other operating costs (O&M allocator).

In addition to allocating CGS expenses to cost drivers, it is also important to allocate additional sources of revenue recovered by CGS which represent offsets to the revenues which must be recovered from base rates, the PGA and the riders. These are referred to as revenue credits and are indicated on the bottom half of **Tables 13 and 14**. The primary groupings are as follows:

1. **Appliance sales and other services** revenues, which represent payments from customers for ancillary services provided by CGS such as the sale and installation of natural gas appliances and plumbing.
2. **Market PGA, Market Base Rates and Propane** revenues, which are driven by market conditions (and not cost of service), so these revenues are credited against system revenue requirements rather than being included in the cost of service analysis.
3. **Taxes** which represent a pass-through of revenue collected on behalf of the taxing jurisdictions, accordingly, it is shown as both an expense and a revenue credit.
4. **Pasco surcharge revenue**, which, as indicated in Section 2.1 represents the recovery of additional purchased gas costs related to serving these customers.

In addition to these four categories of credits are a cash flow credit and a margin credit. The cash flow credit accounts for the fact that the FY 2021 test year assumes CGS will use existing cash, rather than current revenues, to fund approximately $1 million in utility expenses. This reduces the amount of revenue needed from customers rates by $1 million. Accordingly, this amount is included as a revenue credit, reducing the amount of revenue needed from customer rates.

The margin credit reflects the estimated PGA over recovery relative to the cost basis identified in this study. Based on an annualized rate of $0.89 and the costs attributable to the PGA in CGS's budget, the PGA recovers an estimated $3.8 million that could be shifted to the base rates. However, as noted previously, costs associated with the PGA change frequently, so the margin credit is likely a timing issue that will be adjusted through a reduction in the PGA subsequent to the analytical phase of this study. To the extent a margin credit exists, CGS should shift the recovery of these costs from the PGA to the base rates. As discussed above, and again in Section 4, our rate recommendations begin this process by shifting the billing and customer service costs that were previously attributed to the PGA, to the base rates. Similar to the treatment of expenses, the revenue credits are allocated based on either direct, plant or O&M allocators.

As described throughout this report, the PGA and riders are evaluated on a monthly basis and adjusted such that the rates recover cost of service. Accordingly, the remainder of the cost of service analysis focuses on allocating the portion of the revenue requirement that will be recovered from base rates. As indicated in Table 13, the net revenue requirement for base rates is $11.8 million.

Table 13 – Revenue Requirement Allocation to Cost Drivers (%)

Description	Allocation Basis	Base Rates						Direct PGA	Riders	
		Commodity	Capacity	Customer - RTS	Meters/Reg	Services	Customer - Accts		Direct ECA	Direct RIA
Expenses										
PGA Expense	PGA							100%		
PGA Billing/CS	Cust - Accts						100%			
ECA Expenses	ECA								100%	
RIA Expenses	RIA									100%
ECA Billing/CS	Cust - Accts						100%			
ECA PAYGO	ECA								100%	
All Other Admin	O&M	4%	17%	21%	37%	14%	7%			
All Other Billing/CS	Cust - Accts						100%			
All Other Non-Fuel	Plant	6%	23%	28%	23%	19%	1%			
Taxes	O&M	4%	17%	21%	37%	14%	7%			
Debt Service	Plant	6%	23%	28%	23%	19%	1%			
PAYGO	Plant	6%	23%	28%	23%	19%	1%			
Subtotal	**100.0%**	**2.6%**	**10.6%**	**13.2%**	**12.0%**	**8.8%**	**2.9%**	**38.6%**	**10.3%**	**0.9%**
Revenue Credits										
Margin Credit	Plant	6%	23%	28%	23%	19%	1%			
Cash Flow +/-	Plant	6%	23%	28%	23%	19%	1%			
Pasco Surcharge	PGA/ECA							50%	50%	
Propane PGA	PGA							100%		
Propane Non-Fuel	Plant	6%	23%	28%	23%	19%	1%			
Propane - ECA	ECA								100%	
Propane - RIA	RIA									100%
Appliance Sales	Plant	6%	23%	28%	23%	19%	1%			
Other Revenues	Plant	6%	23%	28%	23%	19%	1%			
Market PGA	PGA							100%		
Market Base Rates	Plant	6%	23%	28%	23%	19%	1%			
Taxes	O&M	4%	17%	21%	37%	14%	7%			
Subtotal	**100.0%**	**3.8%**	**15.3%**	**19.2%**	**17.6%**	**12.8%**	**1.4%**	**27.3%**	**2.6%**	**0.1%**
Net Revenue Req.	**100.0%**	**1.9%**	**7.6%**	**9.4%**	**8.4%**	**6.3%**	**3.8%**	**45.8%**	**15.3%**	**1.5%**

Table 14 – Revenue Requirement Allocation to Cost Drivers ($)

Description	Total	Base Rates						Direct PGA	Riders	
		Commodity	Capacity	Customer - RTS	Meters/Reg	Services	Customer - Accts		Direct ECA	Direct RIA
Expenses										
PGA Expense	$ 19,881,532	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,881,532	$ -	$ -
PGA Billing/CS	769,314	-	-	-	-	-	769,314	-	-	-
ECA Expenses	3,323,214	-	-	-	-	-	-	-	3,323,214	-
RIA Expenses	486,018	-	-	-	-	-	-	-	-	486,018
ECA Billing/CS	50,430	-	-	-	-	-	50,430	-	-	-
ECA PAYGO	2,000,000	-	-	-	-	-	-	-	2,000,000	-
All Other Admin	1,231,667	51,652	206,608	258,260	459,129	172,174	83,843	-	-	-
All Other Billing/CS	190,332	-	-	-	-	-	190,332	-	-	-
All Other Non-Fuel	13,828,029	786,054	3,144,214	3,930,268	3,182,898	2,620,179	164,417	-	-	-
Taxes	2,037,000	85,425	341,700	427,125	759,334	284,750	138,665	-	-	-
Debt Service	911,560	51,818	207,270	259,088	209,820	172,725	10,839	-	-	-
PAYGO	6,800,000	386,546	1,546,183	1,932,728	1,565,205	1,288,485	80,853	-	-	-
Subtotal	**$ 51,509,096**	**$ 1,361,494**	**$ 5,445,976**	**$ 6,807,470**	**$ 6,176,387**	**$ 4,538,313**	**$ 1,488,692**	**$ 19,881,532**	**$ 5,323,214**	**$ 486,018**
Revenue Credits										
Margin Credit	$ (3,813,693)	$ (216,789)	$ (867,157)	$ (1,083,946)	$ (877,826)	$ (722,631)	$ (45,345)	$ -	$ -	$ -
Cash Flow +/-	(1,043,694)	(59,329)	(237,315)	(296,644)	(240,235)	(197,762)	(12,410)	-	-	-
Pasco Surcharge	(840,365)	-	-	-	-	-	-	(420,182)	(420,182)	-
Propane PGA	(649,372)	-	-	-	-	-	-	(649,372)	-	-
Propane Non-Fuel	(550,330)	(31,283)	(125,134)	(156,417)	(126,674)	(104,278)	(6,543)	-	-	-
Propane - ECA	(89,057)	-	-	-	-	-	-	-	(89,057)	-
Propane - RIA	(14,843)	-	-	-	-	-	-	-	-	(14,843)
Appliance Sales	(1,300,000)	(73,898)	(295,594)	(369,492)	(299,230)	(246,328)	(15,457)	-	-	-
Other Revenues	(2,875,300)	(163,446)	(653,785)	(817,231)	(661,829)	(544,821)	(34,188)	-	-	-
Market PGA	(4,372,932)	-	-	-	-	-	-	(4,372,932)	-	-
Market Base Rates	(2,378,286)	(135,194)	(540,774)	(675,968)	(547,427)	(450,645)	(28,278)	-	-	-
Taxes	(2,037,000)	(85,425)	(341,700)	(427,125)	(759,334)	(284,750)	(138,665)	-	-	-
Subtotal	**$(19,964,872)**	**$ (765,365)**	**$ (3,061,459)**	**$ (3,826,824)**	**$ (3,512,554)**	**$ (2,551,216)**	**$ (280,886)**	**$ (5,442,486)**	**$ (509,239)**	**$ (14,843)**
Net Revenue Req.	**$ 31,544,225**	**$ 596,129**	**$ 2,384,517**	**$ 2,980,646**	**$ 2,663,833**	**$ 1,987,097**	**$ 1,207,806**	**$ 14,439,046**	**$ 4,813,975**	**$ 471,175**

3.3. Determination of Units of Service

The next step in the cost allocation process is to summarize the units of service, which are the basis for the allocation of the total revenue requirement to each of the customer classes. Costs are allocated to customer classes in proportion to the class responsibility for use of the gas system. The units used to allocate costs are commodity units, capacity units and customer units.

Commodity units are used to distribute costs which are incurred to support average demand and are calculated from annual throughput (dekatherms or dth) to assign commodity related costs to each customer class.

Capacity units are used to distribute costs related to peak demand and annual throughput and estimated load factors. Load factors are used to calculate peak demand by showing the ratio of average load to peak load. Similar to an interstate highway system, a gas system must be designed and operated to meet both average and peak demands. Load factors attribute the cost of meeting peak demand with the customers that contribute to peak demand. A perfect load factor is 100%, meaning the customer uses gas at a constant rate without any fluctuations in demand. Load factors are typically estimated using a multivariate regression analysis which ascertains the relationship between temperature and natural gas usage under average conditions then applies it to an assumed low temperature to determine estimated peak demand. Customer data were not available at a sufficiently detailed level to perform this analysis for each customer class. Accordingly, the factors from CGS's prior study were maintained. Raftelis did perform the regression analysis at a high level (residential and commercial) and confirmed that the existing load factors are reasonable.

Customer units are used to distribute costs which are incurred regardless of how much gas a customer uses. These include costs relate to making the gas system available to customers (Customer – RTS), the cost of installing and maintaining meters, regulators and customer service lines and the cost of providing customer service and billing. A weighting factor is used to recognize differences in potential demand and the larger and more expensive equipment typically required to serve larger customers.

Table 15 indicates the development of the distribution factors, which represent each customer class's share of commodity, capacity and customer costs based on their unique demand characteristics.

Table 15 – Development of Distribution Factors

Customer Class	Commodity		Capacity			Customer			
	Annual Usage (dth)	%	Load Factor	Peak Demand (dth/d)	%	Customers	Cust. Factor	Weighted Customers	%
Single-Family (RS)	443,041	**25.9%**	13.0%	9,370	**46.0%**	23,299	1.00	23,299	**81.6%**
Small Multi-Family (NSFD)	6,633	**0.4%**	14.3%	127	**0.6%**	102	2.08	212	**0.7%**
Medium Multi-Family (NMFD)	6,484	**0.4%**	17.6%	101	**0.5%**	2	3.33	7	**0.0%**
Large Multi-Family (NLFD)	297	**0.0%**	12.2%	7	**0.0%**	1	7.92	8	**0.0%**
Small Commercial (SFC)	20,745	**1.2%**	9.9%	577	**2.8%**	100	2.08	208	**0.7%**
Medium Commercial (MFC)	6,666	**0.4%**	11.4%	160	**0.8%**	5	3.33	17	**0.1%**
Large Commercial (LFC)	-	**0.0%**	11.4%	-	**0.0%**	-	7.92	-	**0.0%**
Small Commercial (SGS)	836,458	**48.9%**	31.2%	7,337	**36.1%**	2,104	2.08	4,376	**15.3%**
Medium Commercial (MGS)	316,594	**18.5%**	40.5%	2,144	**10.5%**	120	3.33	400	**1.4%**
Large Commercial (LGS)	73,957	**4.3%**	38.5%	526	**2.6%**	5	7.92	41	**0.1%**
Total	**1,710,875**	**100.0%**		**20,348**	**100.0%**	**25,738**		**28,568**	**100.0%**

3.4. Distribution of Costs to Customer Classes

Table 16 indicates the application of the development of commodity, capacity and customer distribution factors from **Table 15.** For example, Single Family Residential (RS) customers represent 46% of the capacity units and are allocated 46% of the capacity cost (i.e. $2.4 million x 0.46 = $1.1 million). This process is repeated for each customer class and cost driver to determine class cost of service indicated in the "total" column in **Table 16**.

Table 16 – Distribution of Costs to Customer Classes

Customer Class	Total	Commodity	Capacity	Customer - RTS	Meters/Reg	Services	Customer - Accts
		dth	dth/d	Wtd Cust			
Single-Family (RS)	$ 8,461,395	$ 154,371	$ 1,098,028	$ 2,430,878	$ 2,172,500	$ 1,620,586	$ 985,031
Small Multi-Family (NSFD)	82,878	2,311	14,921	22,136	19,783	14,757	8,970
Medium Multi-Family (NMFD)	16,135	2,259	11,815	695	621	463	282
Large Multi-Family (NLFD)	3,339	104	784	826	739	551	335
Small Commercial (SFC)	139,214	7,228	67,561	21,724	19,415	14,483	8,803
Medium Commercial (MFC)	26,250	2,323	18,775	1,737	1,553	1,158	704
Large Commercial (LFC)	-	-	-	-	-	-	-
Small Commercial (SGS)	2,505,243	291,452	859,803	456,566	408,037	304,377	185,008
Medium Commercial (MGS)	485,437	110,312	251,207	41,785	37,344	27,857	16,932
Large Commercial (LGS)	100,139	25,769	61,622	4,299	3,842	2,866	1,742
Total	**$11,820,029**	**$ 596,129**	**$ 2,384,517**	**$ 2,980,646**	**$ 2,663,833**	**$ 1,987,097**	**$ 1,207,806**

Table 17 indicates a comparison of the calculated cost of service to revenues under the existing base rates. Cost of service, in total, exceeds revenues under existing rates due to an assumed shift of billing and customer service costs from the PGA and riders to the base rates. In addition, there are significant variances between class cost of service and existing base rate revenue. In general, residential customers (single and multi) are paying less than cost of service and non-residential customers are paying more than cost of service. Section 4 overviews recommended adjustments which CGS could make to improve the alignment between the costs incurred to serve each class and the revenues recovered from that class.

Table 17 – Comparison of Cost of Service to Revenue Under Existing Rates

Customer Class	Cost of Service	Existing Rates	$ Difference	% Difference
Single-Family (RS)	$ 8,461,395	$ 5,304,403	$ (3,156,992)	-37.3%
Small Multi-Family (NSFD)	82,878	59,786	(23,092)	-27.9%
Medium Multi-Family (NMFD)	16,135	29,489	13,354	82.8%
Large Multi-Family (NLFD)	3,339	2,448	(890)	-26.7%
Small Commercial (SFC)	139,214	117,158	(22,056)	-15.8%
Medium Commercial (MFC)	26,250	27,730	1,480	5.6%
Large Commercial (LFC)	-	-	-	0.0%
Small Commercial (SGS)	2,505,243	4,144,273	1,639,030	65.4%
Medium Commercial (MGS)	485,437	1,263,951	778,514	160.4%
Large Commercial (LGS)	100,139	257,384	157,245	157.0%
Total Utility	**$ 11,820,029**	**$ 11,206,622**	**$ (613,407)**	**-5.2%**

Cost of Service Analysis – Key Findings and Recommendations

- **Key Findings** –
  1. PGA recovers costs, which could be more appropriately included in base rates.
  2. Residential customers are paying less than cost of service
  3. Non-Residential customers are paying more than cost of service
- **Recommendations** –
  1. Consider shifting revenue recovery from PGA to base rates
  2. Consider shifting revenue recovery from non-residential customers to residential customers

4. Rate Design

The objective of rate design is to reasonably and fairly set rates to recover the net revenue requirement. While recovering the revenue requirement for each class is the ultimate goal, rates must be reasonable and remain competitive with neighboring utilities. In the case of CGS, for each class to recover the class revenue requirements determined in the cost-of-service analysis, major changes are needed to the rate structure. For single-family residential, the largest class in CGS, this would mean drastic increases that may lead to rate shock for customers. As a result, it is more prudent to establish a directional goal of achieving cost of service over time by implementing incremental shifts toward customer class parity while remaining competitive with neighboring utilities such as Teco/Peoples Gas, Central Florida Gas, Florida City Gas and Florida Public Utilities.

4.1. Rate Recommendations

4.1.1. PGA

The PGA is reviewed monthly and adjusted periodically based on actual and projected gas and propane supply costs, all other applicable expenses, and projected demand. As such, Raftelis does not recommend a specific PGA rate as part of this study. However, we do recommend the following modifications to the calculation methodology. First, all customer service costs currently recovered in the PGA should be allocated for recover in the customer charge. Second, the PGA should not include the under-recovery of ECA costs not assessed to non-standard and contract customers (see ECA recommendation below).

4.1.2. RIDERS

As discussed in Section 2.3.2, CGS has several rate riders that recover specific costs or designed to mitigate financial and operational risk. Raftelis reviewed the costs allocated to each rider and recommends several calculation modifications for consideration including:

Energy Conservation Adjustment

The ECA is applicable to all firm natural gas and propane customers but not assessed to non-standard and contract customers. However, based on current rate ordinances the City can collect a portion of ECA costs as part of the PGA, which can be up to one-half of the annual average ECA billing rate. Alternatively, Raftelis recommends the ECA be calculated based customer that actually pay it rather than shifting a portion of this responsibility to the PGA. Raftelis also recommends that all customer service costs currently recovered through the ECA be allocated for recovery in the customer charge. Since the ECA is reviewed by CGS staff on a monthly basis, Raftelis recommends the City adopt the new methodology and then calculate the resulting rate based on actual costs consistent with current practices.

Usage and Inflation Adjustment

Per City ordinances, the UIA should remain at current levels and then reset to $0.00 in the beginning of FY 2022. As noted previously, the financial forecast is based on an August CPI of 249.639 and an assumed increase of 2.5% annually. Normalized usage per account for firm natural gas single-family residential customers and commercial customers was 185 therms and 5,877 therms, respectively. To the extent that inflation or usage differs from these amounts, the City should adjust the UIA rate, as needed, to account for changes inflation or customer usage. As noted above, the financial forecast assumes and inflationary increase in costs during FY 2021, so it would be expected that the UIA would be used to recover these costs during the test year.

Regulatory Imposition Adjustment

Based on information provided by CGS staff, the RIA has currently over-recovered its costs by approximately $930,000 through FY 2020. These excess funds are held in reserve. Raftelis recommends the RIA be set at $0.00 per therm until excess reserves are exhausted. The rate can then be recalculated to recover budgeted regulatory imposition costs. Going forward, Raftelis recommends that all customer service costs currently recovered through the RIA be allocated for recovery in the customer charge.

4.1.3. MARKET BASED RATES

We are not proposing any changes to the propane or contract rates at this time. CGS should continue to set the market based rates as needed to remain competitive with neighboring utilities and other sources of energy.

4.1.4. BASE RATES

As indicated in Section 3, there are significant variances between class cost of service and class revenue generation. In general, we recommend CGS continue to evaluate cost of service and continue to shift (as needed) revenue recovery from non-residential customers to residential customers.

An appropriate first step in this shift would be to increase the customer charge for single family customers from $12.00 to $16.00. This rate would be sufficient to recover the costs associated with meters and regulators, customer service lines and customer service and billing costs. Readiness to serve costs would continue to be recovered in the volume rate, which we recommend CGS maintain at $0.44 per therm. These changes accomplish two objectives. First, it moves single family residential customers closer to cost of service which represents an improvement in equity. Second, it increases fixed revenue recovery, which increases the stability of CGS's revenues. This is important, because, excluding the PGA, the vast majority of CGS's cost are incurred on a fixed basis. Increasing fixed revenue recovery improves the alignment between cost incurrence and cost recovery, reducing the risk that CGS will under-recover revenues in a lower usage year.

Non-residential customer charges should be held constant. The commodity charges for this class should be reduced by $0.04 per therm, which moves these customers closer to cost of service. Similar to the recommendation regarding single family residential rates, this change represents an improvement in equity.

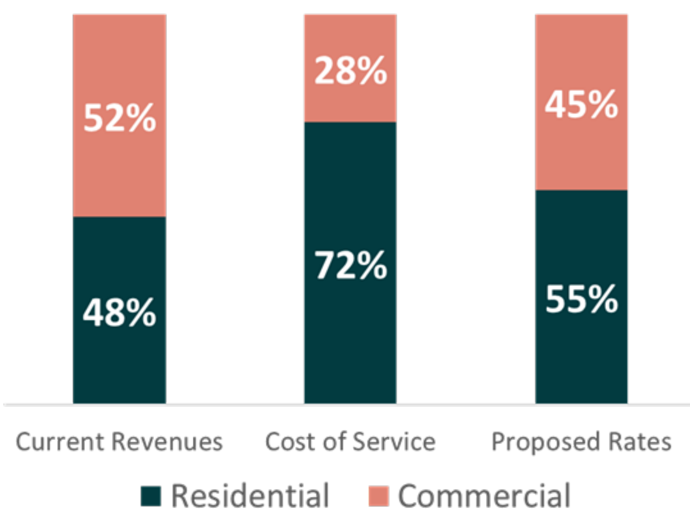
Table 18 presents the existing and proposed base rates. **Figure 3** presents customer class revenues under current rates, cost of service and under the proposed rates shown in **Table 18**, which reflect the proposed phase-in approach. **Note that these recommendations are revenue neutral in that they are designed to recover the same amount of revenue as CGS's existing rate structure, with the only difference being the distribution of revenue recovery between classes and rates.**

Table 18 – Existing and Proposed Base Rates

Customer Class	Class Code	Per	Existing		Proposed			
			Pinellas & West Pasco	Central Pasco	Pinellas & West Pasco	% Change	Central Pasco	% Change
Single-Family								
Customer Charge	RS	Month	$ 12.00	$ 20.00	$ 16.00	33%	$ 24.00	20%
Commodity Charge		Therm	$ 0.44	$ 0.44	$ 0.44	0%	$ 0.44	0%
Small Multi-Family								
Customer Charge	NSFD	Month	$ 25.00	$ 40.00	$ 25.00	0%	$ 40.00	0%
Commodity Charge		Therm	$ 0.44	$ 0.44	$ 0.44	0%	$ 0.44	0%
Medium Multi-Family								
Customer Charge	NMFD	Month	$ 40.00	$ 70.00	$ 40.00	0%	$ 70.00	0%
Commodity Charge		Therm	$ 0.44	$ 0.44	$ 0.44	0%	$ 0.44	0%
Large Multi-Family								
Customer Charge	NLFD	Month	$ 95.00	$ 160.00	$ 95.00	0%	$ 160.00	0%
Commodity Charge		Therm	$ 0.44	$ 0.44	$ 0.44	0%	$ 0.44	0%
Small Commercial								
Customer Charge	SFC	Month	$ 25.00	$ 40.00	$ 25.00	0%	$ 40.00	0%
Commodity Charge	SGS	Therm	$ 0.42	$ 0.42	$ 0.38	-10%	$ 0.38	-10%
Medium Commercial								
Customer Charge	MFC	Month	$ 40.00	$ 70.00	$ 40.00	0%	$ 70.00	0%
Commodity Charge	MGC	Therm	$ 0.38	$ 0.38	$ 0.34	-11%	$ 0.34	-11%
Large Commercial								
Customer Charge	LFC	Month	$ 95.00	$ 160.00	$ 95.00	0%	$ 160.00	0%
Commodity Charge	LGS	Therm	$ 0.34	$ 0.34	$ 0.30	-12%	$ 0.30	-12%

Note: Central Pasco Surcharge will be maintained

Figure 4 – Current Revenues, Cost of Service and Proposed Rates



4.1.5. RATE COMPARISON TO NEIGHBORING UTILITIES

As previously mentioned, it is important to compare the City natural gas rates to neighboring utilities to assess overall competitiveness. The following table compares the City's existing and proposed rates to a regional proxy group including Teco/Peoples Gas, Central Florida Gas, Florida City Gas and Florida Public Utilities.

Table 19 – Rate Comparison to Neighboring Utilities

Customer Class	Clearwater		People's Gas		Central Florida	Florida City Gas	Florida Public Utilities
	Existing	Proposed	Existing	Jan 1, 2021			
Single Family							
Customer	$12.00	$16.00	$14.25	$18.10	$19.00	$12.00	$11.00
Commodity	$0.44	$0.44	$0.25	$0.27	$0.46	$0.46	$0.50
Small Commercial							
Customer	$25.00	$25.00	$33.26	$45.00	$34.00	$25.00	$33.00
Commodity	$0.42	$0.38	$0.25	$0.31	$0.32	$0.38	$0.39
Med Commercial							
Customer	$40.00	$40.00	$47.52	$82.00	$108.00	$35.00	$90.00
Commodity	$0.38	$0.34	$0.22	$0.27	$0.24	$0.34	$0.35
Lrg Commercial							
Customer	$95.00	$95.00	$142.55	$420.00	$600.00	$150.00	$90.00
Commodity	$0.34	$0.30	$0.19	$0.22	$0.15	$0.33	$0.35

Note: Central Pasco Surcharge will be maintained

4.2. Bill Impacts

The changes to the rate structure will have impacts on customer monthly bills. **Table 20** demonstrates the impact on monthly bills for the CGS' various customer classes. Due to the increase to the customer charge for single-family residential, low usage customers in that class will see the largest percent increase on their bills. Due to the decrease in the commodity charge in the commercial classes, the largest percent decrease in bills will be seen on the higher users.

Table 20 – Monthly Bill Impact

Customer Class	Usage (Therms)	Existing	Proposed	$ Change
Single Family (Summer)	10	$25.80	$29.80	$4.00
Single Family (Winter)	30	$53.40	$57.40	$4.00
Small Multi-Family	50	$94.00	$94.00	No Change
Medium Multi-Family	2,600	3,628.00	$3,628.00	No Change
Large Multi-Family	n/a	n/a	n/a	n/a
Small Commercial	350	$522.00	$508.00	-$14.00
Medium Commercial	2,500	$3,490.00	$3,390.00	-$100.00
Large Commercial	11,000	$14,835.00	$14,395.00	-$440.00

Note: For illustration purposes, assumes no change from most recent month PGA and riders. Recommendations are designed to be revenue nuetral.

Another important factor for CGS is remaining competitive against electric utilities. Despite increases for single family residential customers, CGS is still able to save its customers' money compared to the rates Duke Energy offers for electric service. In **Table 20** below, there is a comparison of the recommended CGS rate and the current Duke Energy rate, demonstrating the cost savings offered by natural gas.

Table 21 – Annual Cost Comparison CGS Gas Service vs. Electric Service

Description	Clearwater[1]	Duke Energy
Total Rate per Unit	$ 1.38	$ 0.14
Estimated Energy Use	**Therms**	**kWh**
Heating[2]	150	2,250
Hot Water	170	5,000
Cooking	45	2,000
Total	**365**	**9,250**
Annual Cost		
Heating	$ 207.00	$ 322.34
Hot Water	$ 234.60	$ 716.30
Cooking	$ 62.10	$ 286.52
Total	**$ 503.70**	**$ 1,325.16**
Savings vs. Electric	**$ Savings**	**% Savings**
Heating	$ (115.34)	-35.8%
Hot Water	$ (481.70)	-67.2%
Cooking	$ (224.42)	-78.3%
Total	**$ (821.46)**	**-62.0%**

(1) Total proposed volumetric rate
(2) Electric Assumes 200 percent efficient air to air heat pump and gas assumes 90 percent efficient furnace

Finally, it is noteworthy that the currently proposed all-in rate of $1.38 per therm represents a decrease from the all-in rate of $1.65 per therm, which was effective in November of 2014. In other words, even with the proposed increase to the residential base rate, the average residential customers' bill is about the same as it was approximately 6 years ago.

2014 Average Bill - $1.65/therm @ 15 therms + $12.00 = $36.75
2021 Average Bill - $1.38/therm @ 15 therms + $16.00 = $36.70

Rate Design – Key Findings and Recommendations

» **Key Findings** –

1.
2. Current PGA calculation includes a portion of under-recovery from ECA rate not charged to contract customers.
3. Current ECA rate does not fully recover ECA costs, a portion of which are shifted to the PGA.
4. Current PGA, ECA and RIA calculation includes a portion of billing and customer service costs.
5. RIA revenues have recently exceeded RIA costs, generating a surplus.
6. Residential base rate adjustments could be made while maintaining competitiveness with peer utilities and electric service.

» **Recommendations** –

1. Consider reducing PGA and increasing base rates to align PGA rate with PGA costs.
2. Calculate PGA rate excluding any under-recovery from the ECA.
3. Calculate ECA rate based on the customers that pay it, rather than shifting the under-recovery to the PGA.
4. Maintain current UIA rate and reset to $0.00 in the beginning of FY 2022.
5. Exclude customer service and billing costs from calculation of PGA and riders. Recover these costs in base rates through the customer charge.
6. Set RIA rate to $0.00/therm until surplus is exhausted, then recalculate to recover budgeted regulatory imposition costs.
7. Increase residential customer charge from $12.00 to $16.00
8. Reduce non-residential commodity rates by $0.04 per therm to improve alignment with cost of service.
9. Maintain Central Pasco Surcharges

APPENDIX A:
Proposed Rate Ordinance