Utilities Advisory Board Minutes

January 12, 2021 at 12:00 p.m.

Virtual | Winter Park, Florida

Present

Jack Miles (Chair), Mary Dipboye (Vice Chair), Jacob Kuzman, Karim Arja, Michael Poole

City of Winter Park Staff

Dan D'Alessandro, Director of Electric Utility

Justin Isler, Operations Manager Electric Utility

Michael Passarella, Engineer Electric Utility

David Zusi, Director of Water & Wastewater Utility

Jason Riegler, Asst. Director of Water & Wastewater Utility

Wes Hamil, Director of Finance

Vanna Lawitzke, Chief Accountant

Kristopher Stenger, Assistant Director Building & Permitting Services

Vanessa A. Balta, Sustainability & Permitting Planner

Karen Hood, Recording Secretary

Guest

Navid Nowakhtar, FMPA

Craig Shepard, Leidos

Absent

Paul Conway

Tate Scott

Meeting called to order

The meeting was conducted via Zoom webinar. Jack Miles called the meeting to order at 12:00 p.m.

Approval of minutes

Jack Miles asked for a motion to approve the minutes from the October 27, 2020 meeting. Mary Dipboye moved to approve the minutes and Karim Arja seconded the motion. The motion was carried unanimously.

Citizen Comments

None

Items for discussion

A. Board agreed to switch the order of the first two items for discussion; the White Paper was discussed first. Navid Nowakhtar discussed how the White Paper was developed and what the purpose of the White Paper was intended to be. Michael Poole's "Comments on White Paper Date July 26 2019" previously sent to the members was discussed as well. (report attached here)

B. Craig Shepard presented a PowerPoint and went through draft 6 for the Cost of Services study. Michael Poole requested a work session to be scheduled between the next two meetings to allow more time for discussion regarding the Cost of Service Study. (report attached here)

C. Wes Hamil presented a draft of an Annual Plan outlining items the board may want to review in coming months along with contract expiration years. (report attached here)

D. Tate Scott was not available today to discuss the strategic plan and this discussion was moved forward for a future meeting. David Zusi did say he believes the strategic plan discussions should be separated for Water & Wastewater Utility and the Electric utility. Michael Poole volunteered to look into asking some Crummer MBA students to help create a strategic plan. (report attached here)

Department Updates

A. Electric Utility – not scheduled for this meeting

B. Water & Wastewater Utility – not scheduled for this meeting

C. Financial - not scheduled for this meeting

Adjournment

Jack Miles requested a motion to adjourn the meeting. Michael Poole moved to adjourn and Mary Dipboye seconded. The motion was carried unanimously.

Chmn. Miles adjourned the meeting at 2:10 p.m. Next meeting is January 26, 2021.

Respectfully Submitted,
Karen Hood
Recording Secretary
Approved: January 26, 2021

White Paper on Winter Park Rate Restructuring

Executive Summary

Problem Statement

Traditional retail electric utility rates collect the majority of all power delivery costs in a variable manner through per kilowatt-hour charges and have equitably recovered these costs for decades. In recent years, customers have taken advantage of a wide range of new energy efficiency and conservation technologies that bring many benefits but lower kilowatt-hour sales. As a result, the individual customer contribution to recover fixed utility costs has begun to tilt unfavorably toward the non-adopters. Rates should be restructured to support equitable fixed cost recovery that is necessary for a reliable grid to support all customers. At the same time, such restructuring should maintain revenue neutrality that does not arbitrarily increase retail rates.

Key White Paper Take-Aways

- The Utility Advisory Board (UAB) has become concerned over the potential long-term implications of declining kilowatt-hour sales with respect to (i) the potential erosion of revenue sufficiency resulting from collecting nearly all costs in a variable manner, and (ii) maintaining equity amongst all customers who require access to the power grid.

- Based on Winter Park's analysis of their overall power delivery costs, ~60% of all costs are fixed, but currently, ~90% of costs are collected in a variable manner through per kilowatt-hour charges.

- The UAB would like to pursue a proactive realignment of retail rates over time to better correspond to the proportion of power delivery costs that are fixed, so that every customer pays their fair share of fixed costs, and to ensure access to sustainable and reliable power supply.

Conclusion

The UAB seeks support for a cost of service study to pursue a revenue-neutral adjustment to retail rates in alignment with their desired revenue sufficiency strategy. In parallel, the UAB has championed a gradual increase in the customer charge to capture a greater portion of fixed costs in a fixed manner and to begin the process of aligning rates with actual costs. Concurrently, the UAB will work with Winter Park staff to monitor ratemaking trends among Florida municipal utilities and develop a longer-term, more nuanced rate strategy. Proactive communication with the City's customers to ensure an understanding of utility costs and the associated rate restructuring will be a key element of the long-term strategy.

White Paper on Winter Park Rate Restructuring

Current Situation

The UAB has been tracking the slow to flat growth of electric demand among Winter Park Utilities' customers over the past several years. While the number of residents and commercial developments have increased during this time period, advancements in energy efficiency and growing use of home-based energy production have offset expected usage. Such advancements are not equally accessible to all customers as a result of various factors, such as income level, renter versus owner status for a given account, and poor roof orientation or other obstructions preventing optimal home-based energy production. All customers require full-time access to the electrical grid and on-demand power irrespective of usage reductions and their ability to take advantage of technological advancements.

The UAB has become concerned over the potential long-term implications of the current trends with respect to (i) the potential erosion of revenue sufficiency resulting from collecting nearly all costs in a variable manner, (ii) maintaining equity between customers that invest in certain technologies and those that do not relative to fixed cost recovery, and (iii) seasonal or minimal users. What steps should the City take, if any, to ensure that Winter Park Electric has sufficient revenues in future years to maintain service readiness and financial solvency and that revenue collection is equitable and balanced such that all customers pay their fair share of costs?

Background

For many decades, electric utilities in the U.S. were in the business of producing, marketing and selling power. They were so successful in promoting energy-consuming, labor-saving household appliances to be the norm among American households that by the early 1970s, some utilities were discussing or instituting demand metering for water heaters and other appliances as a way of shifting electric load off peak to reduce unnecessary power plant construction. Sierra Pacific Power Company had the first Off-peak Load-shifting Advertising campaign reproduced and circulated by the Edison Electric Institute as a prototype.

The radical shift in how utilities did business was triggered by the OPEC Oil Embargo in 1973-4 and the U.S.'s subsequent drive for energy independence. Passage of the Public Utility Regulatory Policies Act (PURPA), a portion of the

National Energy Act of 1978, was expressly designed to promote energy conservation in order to reduce demand and to increase use of domestic energy (fossil fuels) and renewable energy to increase supply. Among its provisions, the Act created the Federal Energy Regulatory Commission (FERC). FERC's policy to promote open access transmission is a material benefit to Winter Park's Electric Utility as a Network Service customer supplied by Duke Energy, OUC and Covanta.

These pieces of legislation were followed by the Energy Policy Act of 1992 and the Energy Policy Act of 2005. The 2005 Act addresses energy production in the United States by changing US energy policy to provide tax incentives and loan guarantees for energy production of various types. The law also stipulated that an investor-owned utility must go through a formal process to consider net metering, which empowers, among other things, a renewable energy source (for example, a residential rooftop solar array) to connect to its grid if the equipment meets UL Certification or some other reasonable standard. Further, under the state of Florida's Net Metering requirement as passed in 2008, if the rooftop system produces excess power (over-generates) during certain optimal periods and/or low electric usage, the utility must credit the customer for that power for later use (and financially compensate the customer for any excess generation at the end of a period, in the case of Florida, a year, at the utility's avoided cost of energy).

Regulatory Environment in Florida

In Florida, investor-owned utilities are required to credit power generated from residential solar panels at full retail (at a 1:1 ratio). While rooftop solar generation is a carbon-free resource that helps the utility avoid generating energy by burning fossil fuel and should not be discouraged, it is important that all customers pay a fair share of the fixed costs of the system because those that invest in solar and other energy efficiency improvements need the same infrastructure in reliable operation as those customers that do not invest in such technologies. Further, Florida municipal utilities generally adhere to the Net Metering requirements and the same full retail credit (a 1:1 ratio) for generation from solar panels. Some municipal utilities choose to provide additional credits (e.g. capacity credits), which creates a larger misalignment in fixed cost recovery for customers that invest in technologies that reduce energy sales.

Underlying Premise of Traditional Ratemaking

Utility rate structures traditionally have built much of fixed costs into a variable cost rate structure for social reasons (to reduce the impact on low user, low income households). The higher the usage, the higher the variable rate.

While residential customers with rooftop solar arrays must have access to electric supply infrastructure for those times when solar generation is nonfunctional, to service remaining energy demand, as well as to backfeed energy from their arrays to the distribution system, they are not paying their fair share of the infrastructure costs (transmission, distribution and feeder lines; substations and service personnel) since they are also classed as low users (because of the full retail credit generally afforded them through Net Metering on all of the energy produced by the solar panels). As the residential use of solar power increases, the misalignment in cost allocations will magnify.

Concurrently, energy conservation and, more importantly, improved end-use energy efficiency (e.g. high efficiency lighting and air conditioning) also pushes customers into the lower usage strata as such impacts are realized. The result is that lower demand residential customers pay less of the fixed costs than are actually incurred to deliver power to them reliably, and the number of customers in this tier is increasing, which gradually magnifies the misalignment of costs and cost collection (rates). The same is true for seasonal customers whose consumption is intermittent but who must be planned for nonetheless from an infrastructure perspective.

Unintended Consequences of Conservation and Renewable Energy Policies

While there are positive impacts for society from these renewable energy and conservation policies and programs, there are significant unintended consequences for the long-term financial health of utilities that can also result in undue financial burden on certain classes of customers.

To understand the implications with Winter Park as an example, according to an analysis of existing budgeted costs for Winter Park as conducted by Winter Park staff, an estimated 60% of power delivery costs are fixed while about 90% of cost recovery is variable. Variable costs are limited to the cost of energy, or only 2 to 3 cents per kilowatt hour according to the Florida Municipal Power Agency (FMPA).

If 10% of Winter Park's residential customers adopted rooftop solar, the City could lose as much as 10,400 MWh of energy per year which at a theoretical cost of 10 cents/kWh would reduce revenue by ~$1.04M annually according to a presentation by FMPA. The reduction in revenue would be coupled with a reduction in fuel cost and other variable costs to the utility related to generating energy. However, fuel costs represent approximately 30% of typical wholesale power delivery costs and would only partially offset revenue reductions. Non-solar generating customers would then further “subsidize” those self-generators, and rates might need to increase to make up for the shortfall in variably collected revenues. While municipal utilities do have the authority to increase rates at any time to cover their costs, perpetual rate increases to address ever-increasing rooftop solar investments exacerbates the problem by rendering self-generation more and more attractive relative to baseline retail rates. This leads to a furthering of the misalignment over time. Such a cycle is generally not financially sustainable for the utility or for customers that remain fully dependent on grid energy for power delivery. The same or similar impacts would be felt via increasing energy efficiency across a large portion of the system or through increasing seasonality of the customer base.

Options

The growing misalignment in the current way utilities set rates and the marketplace realities led the UAB to begin investigating options last Spring. FMPA made a presentation to the UAB in June 2018 in which two options were discussed.

Option 1: Market solar access at the utility-scale via financial subscriptions at a lower cost (than it would be from a rooftop system on a home) as an alternative. Offering utility-scale solar power to interested customers through a small cost added on their bill (to cover administrative and billing costs as well as the price difference in solar energy, which could become a price credit over time) would reduce pressure on the distribution system caused by rooftop solar arrays and enable multi-family homes, low income customers, and homes unsuited for rooftop photovoltaic systems to participate.

Option 2. Gradually increase the customer charge per month across the system to ensure a reliable grid for all customers and begin the process of better aligning rates with actual costs while remaining revenue neutral in the context of this effort.

Utility-scale solar costs approximately 1/3rd the cost of rooftop solar. While 72% of customers support solar according to an FMPA customer survey, only 13% are “very likely” to pay more per month for it. Winter Park Electric is pursuing utility-scale solar via a power purchase agreement for a portion of a solar farm being built by NextEra’s Florida Renewable Partners to increase renewables in its power mix.

Option 2, to begin improving alignment between fixed and variable costs by gradually increasing the customer charge per month has been championed by the UAB. It is already beginning to be addressed nationally and statewide and the average customer charge is beginning to creep upward. Florida Rural Electric Cooperatives have raised their per meter charges to between $15 and $45. In 2018, Florida municipal and investor-owned utilities had customer charges ranging from $3.50 to $19.50. The State's Municipal average customer charge is currently $9.18, and Winter Park's is $15.44.

Implementing Option 2

There are potential negatives to fully implementing Option 2 as demonstrated in the computer modelling developed by Wes Hamil, Winter Park Electric's CFO. A subcommittee of the UAB met with him in February to generate a variety of customer charge scenarios using tiered rates. The following issues were discussed:

1. Higher customer charges may result in a "bill shock" effect for lower level users as the customer charge could eclipse their prior average bill. Tiered rates could be used to protect low end users, but a proportional shift in the burden to mid-level users would need to be managed. At the same time, the highest users would receive a discount as a function of a greater emphasis on fixed charges (and a commensurate decline in variable charges required to keep the utility revenue-neutral).
2. Depending on price sensitivity and the size of the increase, higher customer charges could reduce the incentive to reduce kWh usage.
3. Much higher customer charges would represent a major departure from other Municipal electric utilities and could invite extra scrutiny from the Florida Public Service Commission (PSC) to the extent more nuanced changes (e.g. tiers) trigger a rate structure review by PSC staff.
4. There are currently no other Florida Municipal electric utilities with tiered customer charges.

UAB Consensus & Next Steps

The UAB has recommended the following:

1. Gradually increase the customer charge between 10% and 20% per year over the next 3-5 years with recurring review of the utility's financial position and customer impacts.
2. Monitor ratemaking trends among Florida municipal utilities in the area of customer charges and benchmark Winter Park's against them.

3. Monitor Net Metering compensation trends for solar power among utilities and the regulatory climate within the PSC affecting Net Metering, which might become a tool to eliminate the cost burden for non-solar customers.
4. Develop a longer-term, more nuanced strategy to achieve a more appropriate rate structure and better align costs with reality, which might require discussions with the PSC based on how much complexity is proposed relative to the classification system used in justifying different rates between various customer classes and how significant the proposed changes are on the various classes of rate-payers.
5. In conjunction with action item 4 above, investigate utility staffing/resource/technology requirements to ensure adequate human and technological (e.g. billing system) resources are in place to effectuate a more nuanced rate strategy.
6. Proactively communicate with and educate the City's customers so they are aware of the key guiding principles of revenue neutrality and equitable fixed cost recovery in support of any potential adjustments; this is important so that customers contemplating technology investments understand the pending changes.
7. Advocate on behalf of the need for a more comprehensive rate structure realignment (that aligns with the more nuanced rate strategy that will be developed).

Role of Public Utilities Commission

There was substantial discussion this spring about the role and responsibilities of the PSC regarding municipal utilities. The FMPA provided a discussion of the PSC's statutory responsibilities and the process that it would follow for a rate structure evaluation. FMPA staff stated that, "Introduction of tiers or other charges with more limited precedent may trigger a rate structure review and could require justification." Is it cost-based; is there historical precedent; does it embody pricing concepts previously approved by the Commission; and is it not unduly discriminatory? FMPA thought that customer charge increases applied gradually without tiers and without changing existing cost ratios among retail classes "are highly unlikely to trigger rate a structure review."

Cost of Service Study

The PSC discussion led to the issue of a cost of service study which is being considered as a next step. Staff reported that there has not been one since Winter Park bought the service area from Duke Energy and the legacy rate regime was adopted without adjustments to Duke's structure. A cost of service study would enable outside experts to provide the foundation for a rate design strategy and to support interaction with the PSC when that rate design might be brought forward. Based on preliminary discussions with qualified firms, fees for executing the cost of service study in alignment with the UAB's recommendation would be $100,000 or less.

January 7, 2021

White Paper Discussion Comments by Michael Poole, UAB member

Below I provide my comments on the White Paper reviewed at the July 24, 2019 UAB meeting. I recognize that my opinions are counter to the White Paper, and hence to the views of WPE staff and some UAB board members. My hope is that this position paper will advance the conversation and result in improved policies and fair pricing to customers.

INITIAL COMMENTS

The White Paper which focuses only on residential electric utility rates is **a bad pricing strategy for residents and customers**. It creates an inequality and conflict between users by pitting rich against poor, high users against low users, and conservation versus Winter Park Electric business practices. I find nothing positive about this strategy.

The White Paper could be described as ***"a solution looking for a problem to solve"***, making its focus unnecessary. In this case, the solution is to change residential rate structure to solve (1) residential customer rate inequality caused by conservation, and (2) stop "potential erosion of revenue sufficiency" in order "that Winter Park Electric (WPE) has sufficient revenues in future years to maintain service readiness and financial solvency." Neither of these exist now nor are they projected to exist in the future.

The White Paper conjures up a financial problem based on the unfounded belief that WPE incurs a unique business risk due to a "high" level of fixed costs but collects revenue in a variable manner. This is misleading for several reasons. First, businesses of all types have both fixed and variable costs, and businesses always cover these costs through variable revenue. This is true for all products and services – cars, apparel, food, gasoline, water, etc. Second, WPE is a monopoly and business risk is substantially minimized when customers are captive. Third, WPE's fixed costs are overstated – they are closer to 25% and not 60% quoted in the White Paper.

Since 2015, the electric utility industry has bombarded electric rate commissions with increased fixed charge requests.[1] More than 70% of these requests in 2019 were rejected partially or in full. Even then, the national average monthly fixed charge is only $12 per month. WPE's fixed charge of $17 is more than 40% higher than the national average.

The UAB should recommend a rollback of the fixed charge to begin to reverse the inequality residents and customers have experienced the past four years due to the fixed Customer Charge nearly doubling.

If WPE staff and the UAB are concerned about the possible negative financial impact of residential solar, then the appropriate discussion is to revisit the City's Net-Metering policy[2]. Manipulating residential rates is not the answer.

DETAILED COMMENTS

A. **Formal approval of the White Paper by the UAB is not recorded in the approved minutes.** This could be an administrative oversight. The "final" White Paper is dated July 26, but the UAB meeting was July 24, two days earlier.

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[1] The Fifth Annual Fixed Charge Findings Blog by Samantha Williams, February 10, 2020

[2] City of Winter Park Net Metering Policy approved January 9, 2012

On a similar note, the past annual budget presentations to the Winter Park City Commission have shown the UAB endorsing the increase in the Customer Charge. I reviewed the 2018, 2019 and 2020 board minutes but did not find discussion or a vote on this endorsement. I may have missed the endorsement in the minutes or the UAB could have made this endorsement prior to 2018. Either way, rate changes should be addressed annually by the UAB and a vote should be recorded, especially if relied upon by the City Commission to approve the annual budget.

B. The White Paper conclusion conflicts with the City Commission's approved policy on Net Metering. In January 2012 the City Commission approved a net metering policy that encouraged the installation of owned solar – residential or commercial. The City Commission, the UAB, and WPE staff recommend this policy to encourage installation of solar power. This was done knowing that any rate subsidy to solar owners would be "financially de minimis" to WPE. The raising of the fixed Customer Charge undermines this policy. This conflict must be resolved.

C. Privately owned solar systems are not a major threat to the WPE kWh sales. The White Paper provides the amount of lost revenue based on 10% of residential customers (approximately 1,200 residential solar systems). Based on information provided by the City, WPE has averaged 14 new residential solar systems during the past five years. This means it will take more than 85 years before WPE reaches this assumption. The WPE/City has plenty of time to explore alternative plans if required to increase energy sales. Acting now on this issue is not urgent nor is taking strategies to discourage solar or energy conservation. BTW, the focus should be on profitability/cash flow and not top line revenue.

D. Raising the Customer Charge and lowering the Energy Charge make solar and other conservation efforts less financially attractive. This attack on conservation is counter to many initiatives of the City, local businesses, and residents (see below). While WPE/City operations might benefit, it comes at a cost of financially disadvantaging residents and businesses, and potentially increasing our community's carbon footprint. The WPE/City is sending conflicting messages regarding conservation.

The WPE/City has numerous programs, initiatives, and policies that encourage customers/residents to reduce energy consumption. The WPE then turns around and uses energy conservation as a reason to raise rates (see the Annual Budget presentations approved by the City Commission). This conflict must be resolved so that messaging and rate structure become aligned.

- **Major WPE / City Energy Conservation Initiatives**
    - Tiered energy rate to discourage usage
    - Energy audit for customers
    - Net metering for solar customers (City Policy)
    - Energy Sustainability goals adopted by the City

Per the CEO of the Florida Municipal Power Association (FMPA) raising the Customer Charge portion of electric bills will make "these (solar) net metering customers go away."

E. **Raising the fixed Customer Charge disadvantages low income and low usage users.** The White Paper acknowledges that this statement is true. Therefore, the rate hike creates a problem that does not exist today. In order to solve this problem, the White Paper concludes that a new tiered rate system be created that would be revenue neutral and subsidize these users through a lower energy rate. This only makes our rates more complicated for users. National organizations such as AARP have lobbied against the raising of fixed charges because of the negative financial impact.

F. **Electric Rates based on Usage are the most equitable for customers.** Paying for what you use has long been accepted as the most equitable pricing for products and services, including electricity. Requiring customers to pay a pro-rata fixed charge is forcing them to pay for a service they do not fully utilize. That is why electric customers have been paying usage-based rates since the beginning of distributed energy more than a century ago. The advent of energy conservation did not change this equitable pricing strategy, nor do privately owned solar systems. If the City is going to change its long-standing philosophy on pricing for services, then all services should be appropriately addressed with public input.

G. **WPE staff projects increasing revenues, increasing kWh usage, and increasing customers[3]. Thereby negating concern of revenue sufficiency, financial solvency, and system readiness.**

Staff projections approved by the City Commission show increasing revenues and energy sales for the next ten years. These projections include the impact of conservation and privately owned solar systems. In addition, these projections show net working capital of more than $40 million by 2030. This is substantial since this amount equals annual revenue, excluding taxes and fees.

Recently, staff prepared projections of energy consumption and population growth for the City initiative "Ready for 100" related to achieving 100% clean energy and carbon neutrality by 2050. These projections showed continued annual growth between .5% – 1%. Staff indicated that solar energy adoption by customers was not significant to alter these projections.

Additionally, Fitch Ratings and Moody's, major bond rating agencies, rate WPE bonds at A+ and A1, respectively. These high ratings indicate the strength of WPE's financial status. This independent analysis is a strong indicator that conservation and independently owned solar systems pose no major risk to the viability of WPE's operations.

In fiscal year 2020, WPE produced operating profits before debt service and capital expenditures of $17 million or approximately 35% of revenues. This is an extremely strong financial performance. Staff reports that debt service coverage is 3.65 versus a goal of 1.5.

The budget for FY 2021 indicates a net operating profit of $16 million, and the net profit margin increasing to 40%.[4] This is being achieved on projected lower revenue.

[3] WPE FY 2021 Ten year budget approved by the City Commission; and the "Ready for 100" financial projections 100% clean energy by 2050

[4] FY 2021 Budget – Table 1 attached

These factors prove that there is extremely limited financial risk in the WPE's future – short term or long term from conservation or solar power.

H. "High" Fixed Costs

For the most part the issue raised regarding the "misalignment" between fixed costs and variable revenue collection is a "red herring" argument meant to distract you from the underlying reasons for the change. However, I feel compelled to address the claim.

Fixed Costs: Not surprisingly, what is and is not a fixed cost is debatable. A widely accepted definition is *"A fixed cost is a cost that does not change with an increase or decrease in the amount of goods or services produced or sold. Fixed costs are expenses that have to be paid by a company, independent of any specific business activities."* [5]

The White Paper uses the cost of undergrounding of $5 million per year as part of the 60% figure quoted for total fixed costs. However, staff has put forth to the rating agencies these expenditures are discretionary each year, which would make these variable expenses, not fixed.

Also, the FMPA presentation referred to in the White Paper shows "debt" representing 40% of total costs. The actual amount for WPE is 11.6% for FY 2021. (See Table 2 attached)

A more realistic view of the WPE's fixed costs is around 25%[6]. This is substantially less than the 60% put forth in the White Paper and further undercuts the fixed costs versus the variable revenue collection argument.

CLOSING COMMENTS

There are many more points of discussion that do not support raising the fixed customer charge. You can find substantial research on the internet to help you better understand the issue. One paper that I found most helpful was "*Caught in a Fix – The Problem with Fixed Charges in Electricity*"[7] written in 2016 and prepared for the Consumers Union. The Consumers Union is an advocacy organization which owns Consumer Reports

The White Paper does not address an identified problem in the opening sentence of the *"Current Situation"* section related to "slow to flat growth of electric demand." This issue is at the crux of the fixed charge increase.

There is no discussion on how the WPE could provide additional services to create new revenue sources or increasing demand by encouraging use of battery powered equipment or electrical vehicles. There was no discussion on how the WPE could participate in the business of residential/commercial solar systems. Instead of taking a defensive posture as proposed by the White Paper, the WPE/UAB/City needs to take a strategic growth perspective.

I look forward to discussing the above comments.

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[5] https://www.investopedia.com/terms/f/fixedcost.asp

[6] Schedule of Fixed and Variable Costs FY 2021 – Table 2 attached

[7] Caught in a Fix – The Problem with Fixed Charges in Electricity

TABLE 1

WPE Income Statement	Projected FY 2021			Margin		kWh
Gross Revenues			**$ 44,270,456**	**109.1%**		**407,000,000**
Less:						**Cost/kWh**
Gross Receipts	$	(1,073,749)		-2.6%	$	(0.0026)
Franchise Fee Equivalent	$	(2,621,316)		-6.5%	$	(0.0064)
			$ (3,695,065)	-9.1%		
Base Rate Revenue	$	29,334,054		72.3%	$	0.0721
Fuel Cost Recovery	$	10,089,986		24.9%	$	0.0248
Other Revenue	$	1,151,351		2.8%		
Net Revenue			**$ 40,575,391**	**100.0%**		
Less: Other Revenue	$	1,151,351				
Net Electric Revenue	**$**	**39,424,040**			**$**	**0.0969**
EXPENSES						
FMPA	$	7,513,787		18.5%		
OUC	$	2,471,952		6.1%		
Covanta	$	5,570,362		13.7%		
Transmission	$	2,735,462		6.7%		
Sub-total Bulk Energy Cost	**$**	**18,291,563**		**45.1%**	**$**	**0.0449**
Interfund Admin Services	$	1,740,681		4.3%	$	0.0043
Tree Trimming	$	644,061		1.6%	$	0.0016
Warehousing	$	293,582		0.7%	$	0.0007
Street Lighting	$	510,000		1.3%	$	0.0013
Utility Billing	$	877,483		2.2%	$	0.0022
Meter Servicing	$	388,618		1.0%	$	0.0010
Administration	$	1,460,843		3.6%	$	0.0036
Other Transfers	$	253,317		0.6%	$	0.0006
Sub-total Operating Costs	**$**	**6,168,585**		**15.2%**	**$**	**0.0152**
Total Op & Energy Costs			**$ 24,460,148**		**$**	**0.0601**
Total Operating Profit			**$ 16,115,243**	**39.7%**	**$**	**0.0368**
Contingency & Res Bulk Pwr	$	2,071,764		5.1%	$	0.0051
Contingency - Operations	$	2,219,838		5.5%	$	0.0055
Replenish Cash Reserve	$	581,858		1.4%	$	0.0014
Total Contingency & Reserves			**$ 4,873,460**	**12.0%**	**$**	**0.0120**
Undergrounding	$	5,000,000		12.3%	$	0.0123
Meter Cap Ex	$	336,419		0.8%	$	0.0008
Electric Capital Expenditures	$	1,203,600		3.0%	$	0.0030
Debt Service	$	4,701,764		11.6%	$	0.0116
Total Cap Ex & Debt Service			**$ 11,241,783**	**27.7%**	**$**	**0.0276**
Net Cash Flow			**$ -**			

TABLE 2

WPE FY 2021 Projected Costs						
VARIABLE EXPENSES			**FIXED EXPENSES**			
FMPA	$ 7,513,787	Based on Usage	Interfund Admin Services	$ 1,740,681	Reimbursement of expenses/services
OUC	$ 2,471,952	Based on Usage	Warehousing	$ 293,582	Assumed Fixed
Covanta	$ 5,570,362	Based on Usage, minimum required	Street Lighting	$ 510,000	Assumed Fixed
Transmission	$ 2,735,462	Based on Usage	Administration	$ 1,460,843	Assumed Fixed
Tree Trimming	$ 644,061	Will decline as lines are underground	Other Transfers	$ 253,317	Assumed Fixed
Utility Billing	$ 877,483	Based on number of accounts	Electric Capital Expenditures	$ 1,203,600	Maintenance
Meter Servicing	$ 388,618	Based on number of accounts/meters	Debt Service	$ 4,701,764	Debt repaid in 2035
Contingency & Res Bulk Pwr	$ 2,071,764	Amount is optional		$10,163,787	
Contingency - Operations	$ 2,219,838	Amount is optional	Percent of Total Expenses	25.05%	
Replenish Cash Reserve	$ 581,858	Amount is optional	Fixed Exp $/kWh	$ 0.0250	
Undergrounding	$ 5,000,000	Amount is optional/ Completed 2026			
Meter Cap Ex	$ 336,419				
	$ 30,411,604				
Percent of Total Expenses	74.95%				
Variable Exp $/kWh	$ 0.0747				
kWh	4,700,000				

CITY OF WINTER PARK, FLORIDA

Cost of Service Study and Rate Design for Electric Utility

UPDATE PRESENTED BY: Craig Shepard, Project Manager

January 12, 2021

leidos

Rate Classes

- Residential
- General Service Non Demand – Small Commercial
- General Service Non Demand 100% Load Factor – Small Commercial with 100% Load Factor
- General Service Demand – Large Commercial billed based on kW Demand and kWh Energy
- General Service Demand Time of Use – Large Commercial billed based on kW Demand and Time of Use kWh Energy
- Public Authority – City, County and Schools
- Street and Private Area Lighting

Cost of Service Results

Test Year Ending September 30, 2020				
Customer Class	**Revenues ($000)**	**COS ($000)**	**Difference**	**Target**
Residential	$23,416	$22,409	-4.9%	-1.8%
Gen Service Non Demand	$1,488	$1,460	-2.2%	-2.0%
GSND 100%	$40	$40	-0.6%	0.0%
Gen Service Demand	$12,545	$13,414	8.0%	3.0%
GSD Time of Use	$4,809	$4,891	2.0%	1.0%
Public Authority	$2,129	$2,210	4.4%	2.0%
Street and Private Lighting	$485	$488	0.7%	0.0%
TOTAL SYSTEM	$44,912	$44,912	0.0%	0.0%

Residential Rates

	Existing	Proposed
Customer Charge	$16.98	$18.00
Energy Charge		
First 1,000 kWh	$0.06624	$0.06341
Additional kWh	$0.08840	$0.08557
Fuel Charge		
First 1,000 kWh	$0.01708	$0.02015
Additional kWh	$0.02708	$0.03015

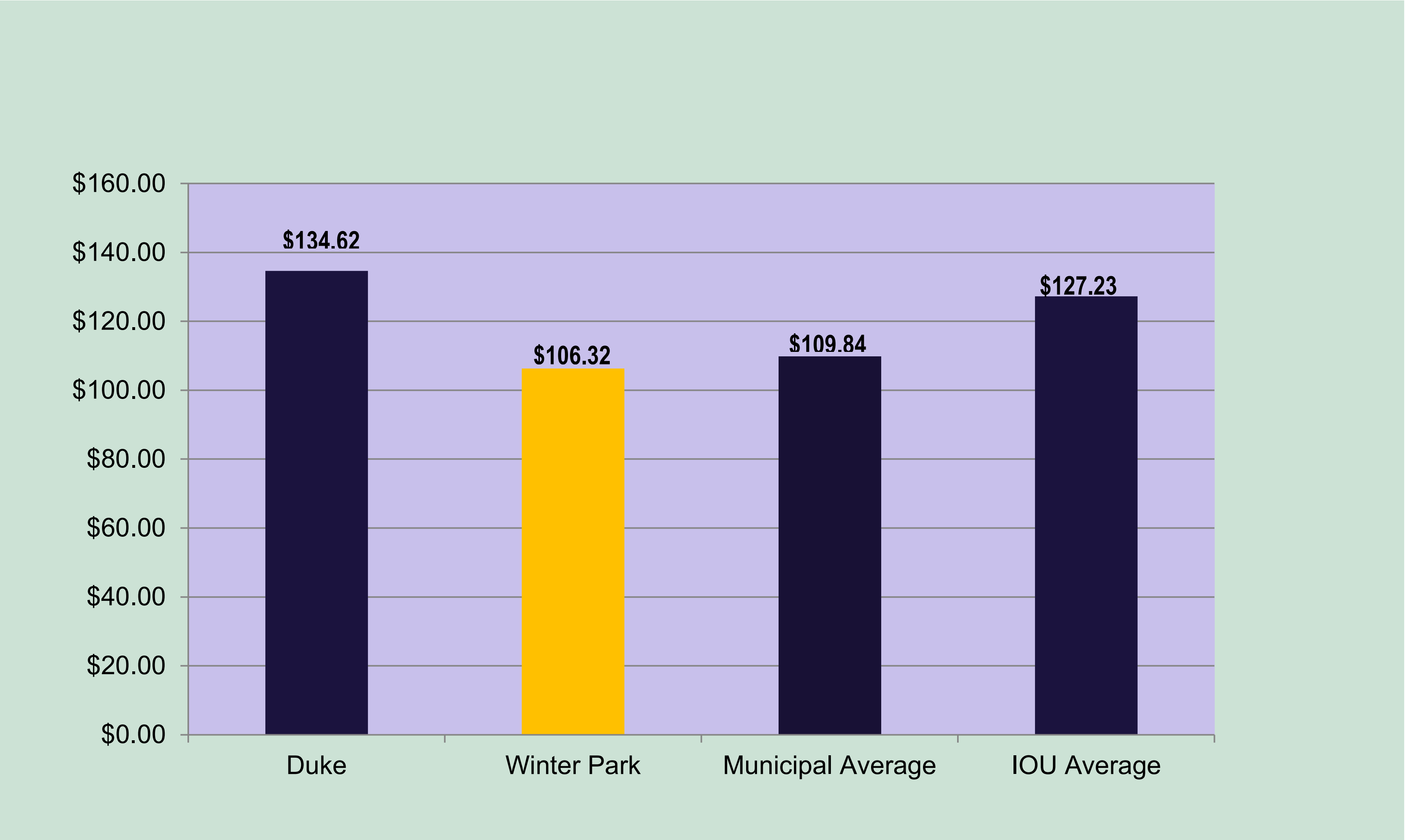
General Service Non-Demand Rates

	Existing	Proposed
Customer Charge	$17.55	$18.00
Energy Charge	$0.07368	$0.07080
Fuel Charge	$0.02103	$0.02423

General Service Demand Rates

	Existing	Proposed
Customer Charge	$18.28	$19.00
Demand Charge	$5.05	$5.82
Energy Charge	$0.04216	$0.04216
Fuel Charge	$0.02103	$0.02423

Comparison of Residential Bills 1,000 kWh – October 2020



Findings / Conclusions

- The City's financial records and data provide a good basis for conducting the COS Study.
- The City's present rates provide revenues approximately equal to the overall cost of providing service.
- The COS Study indicates small realignments of revenues among the residential and commercial classes.
- The City's costs are comparable to other Florida municipal electric utilities.
- The City's rates are comparable or lower than other Florida electric utilities.

Recommendations

- Finalize Rate Design
  - Target Adjustments by Class
  - Customer Charge Levels
  - Possible Multiple Energy Blocks
  - City Policies and Industry Standards
- Continue to Recover Fuel Costs through FCA
- Continue to Monitor Revenues and Expenses
- Periodically Update Results of the COS Study

Questions / Comments

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Draft Report

Electric Cost of Service Study

City of Winter Park, Florida

November 2020

leidos

November __, 2020

Utility Advisory Board
The Honorable Mayor and City Commission
City of Winter Park
City Hall, 401 South Park Avenue
Winter Park, Florida 32789

Subject: **Electric Cost of Service Study**

Ladies and Gentlemen:

In keeping with the provisions of the professional services agreement between the City of Winter Park, Florida (the City) and Leidos Engineering, LLC, (the Consultant) and the direction provided by the City management and staff and Utility Advisory Board, the Electric Cost of Service Study (the Report) has been completed. The Report addresses the projected financial operations of the City's electric system (Electric System) for the fiscal years ending September 30, 2020 through 2024. We have summarized our assumptions and the results of our analyses and conclusions in this Report, which we hereby submit for your consideration. This Report summarizes the basis for the proposed rates for electric service that are necessary to meet the projected revenue requirements in the near future and which rates should recover such projected requirements from the customer classes generally in accordance with the direction provided by the City, the guidelines of the Florida Public Service Commission (the PSC) and the results of the allocated cost of service analyses.

In preparing the Electric Cost of Service Study, the Consultant relied upon historical and projected data for the development of operating revenues, operating expenses and capital requirements. Historical data were obtained from various monthly reports, the City's Comprehensive Annual Financial Reports, actual customer billing records, and analyses and discussions with members of the City management and staff. Projected data were, in part, derived from the Electric System's current forecast of demand and energy requirements, the Electric System Operating Budget for Fiscal Years 2020 and 2021 (the Budgets), the Ten Year Pro Forma, and detailed information and data compiled and provided by members of the City management and staff.

The projected costs and revenues used in this Report are for the fiscal years ending September 30, 2020 through 2024, and have been developed using the City's Budgets as a basis for the projected costs. Such costs and revenues, as initially reflected in the Budgets, were adjusted for known or anticipated changes.

The City acquired the Electric System from Progress Energy Florida (now doing business as Duke Energy Florida) in June 2005 and has not previously performed a cost of service study.

SUMMARY OF FINDINGS

ADEQUACY OF EXISTING RATES

The various adjustments, assumptions and considerations are discussed in Section 2 regarding the projected number of customers, sales, and in Section 3 regarding the projected revenues and expenditures. In the fiscal years ending September 30, 2020 through 2024, the revenue requirements proposed herein include Operation and Maintenance expenses, a transfer to the City's General Fund, capital improvement expenditures, the payment of principal and interest on outstanding indebtedness, and an allowance for contingencies and reserves. Based on the foregoing, the Electric System revenue requirements for fiscal years ending September 30, 2020 through 2024 and the projected revenues, assuming the existing rates, are summarized on the following table:

Description	Projected				
	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024
Net Revenue Requirements	$44,912,177	$44,270,456	$44,662,613	$45,622,904	$45,975,542
Total Existing Rate Revenue	44,912,177	44,270,455	44,662,613	45,060,160	45,463,192
Difference	($0)	($0)	$0	($562,744)	($512,349)
Percent of Base and Fuel Revenue	0.0%	0.0%	0.0%	-1.4%	-1.3%

As shown above, the existing rates produce revenues that are approximately equal to the projected revenue requirements in the fiscal years ending September 30, 2020 through 2022 and slightly under recover the projected revenue requirements in the fiscal years ending September 30, 2023 and 2024.

Based on the analyses in this Report, the proposed rates represent a realignment of costs allocated among the residential and commercial classes. It is projected that the proposed rates will be sufficient to meet the projected revenue requirements for the fiscal years ending September 30, 2020 through 2022. For certain analyses, the “Test Year” has been identified as the fiscal year ending September 30, 2020.

COST OF SERVICE RESULTS

The Test Year revenue requirements were allocated to the customer classes based on a cost of service model that functionalizes costs among production, transmission, distribution and customer costs, and classifies costs according to demand related or energy related costs. Production (purchased power) demand related costs were allocated based on the contribution of each class to the average 12 month coincident peak demands and distribution demand related costs were allocated based on the contribution of each class to the annual system peak demand. Section 4 shows the development of allocation factors and Section 5 shows the results of the cost of service analysis.

The results of the cost of service analysis are summarized as follows:

	Test Year 2020		
	Total Existing Revenue	Target Rate Adjustments	
Customer Class	**($000)**	**($000)**	**(%) [1]**
Residential	$23,416	($377)	-1.8%
Commercial			
General Service Non-Demand	1,488	(26)	-2.0%
GS Non-Demand (100% Load Factor)	40	0	0.0%
General Service Demand	12,545	324	3.0%
General Service Demand TOU	4,809	42	1.0%
Public Authority	2,129	37	2.0%
Lighting	485	0	0.0%
Total System	$44,912	$0	0.0%

[1] Percent of base rate and fuel adjustment revenues.

RATE DESIGN

The proposed electric rates shown in Section 6 reflect, to the extent permitted, (i) the lowest possible price consistent with the projected revenue requirements, (ii) the discouragement of wasteful, unnecessary use of service, (iii) the policies of the City, and (iv) the cost of service methodologies recommended by the Florida Public Service Commission (the PSC).

The principal effects of adopting the rates proposed herein would be:

- Rate structures and levels, in general, will be based, in part, on allocated cost of service techniques.
- Fuel and purchased energy costs will continue to be shown in a separate charge, the Fuel Cost Recovery Factor.
- The proposed rates will be sufficient to meet the projected revenue requirements for the fiscal years ending September 30, 2020 through 2022.

RATE COMPARISONS

To assist the City in its evaluation and consideration of proposed rate adjustments, included in Table No. 7-1 are comparisons of typical monthly bills for the major rate classifications at various levels of usage. Typical bills calculated under the proposed rates have been compared with bills calculated under the existing rates. In addition, typical monthly bills calculated under the Electric System's existing and proposed rates have been compared with those calculated under the rates of other Florida investor-owned and municipal electric utilities in Table No. 7-2 for the billing month of June 2020.

When reviewing the comparisons of typical bills, it must be recognized that a substantial portion of the electric bill is comprised of fuel and purchased energy costs. For electric utilities other than the Electric System, the bill comparisons shown reflect fuel costs that were estimated in mid-2020 and may not reflect actual current market prices for gas, oil and purchased energy.

As shown on Table No. 7-1, typical residential and small commercial customers' bills under the proposed rates can be expected to decrease slightly and large commercial customers' bills can be expected to increase slightly.

CONCLUSIONS

Based upon the results of our studies and analyses as summarized in this Report, which should be read in its entirety in conjunction with the following, and upon the numerous underlying assumptions and considerations relied upon in making such analyses and incorporated by reference herein, and the data and information provided by the City's management and staff and others, we are of the opinion that:

(i) The City's financial records and data provide a good basis for conducting the Cost of Service Study;

(ii) The existing rates produce revenues that are approximately equal to the projected revenue requirements in the fiscal years ending September 30, 2020 through 2022 and slightly under recover the projected revenue requirements in the fiscal years ending September 30, 2023 and 2024;

(iii) The proposed rates reflect a realignment of costs among the residential and commercial rate classes, and are projected to meet the revenue requirements for the fiscal years ending September 30, 2020 through 2022.

(iv) The City's existing and proposed rates are comparable or lower than other Florida electric utilities;

(v) The City may want to investigate additional rate offerings such as Residential Time of Use Rate, Solar Subscription Rate, or Electric Vehicle Rate;

(vi) The City should continue to monitor the cost of purchased power and current market conditions and should make adjustments, if necessary, to its fuel cost recovery factor to reflect such costs and conditions and to minimize the potential to under recover or over recover its fuel costs; and

(vii) The City should consider submitting this Report, together with other appropriate filing requirements, to the PSC.

We are prepared to present our analyses and proposed rates to the City Commission and to assist the City with public meetings, with PSC filing requirements, and with presentations in connection with the adoption and implementation of the proposed rates.

We want to take this opportunity to express our appreciation for the spirited cooperation and valuable assistance given us throughout the course of this study by each member of the City management and staff, along with members of the Utility Advisory Board.

Respectfully submitted,

LEIDOS ENGINEERING, LLC

Table of Contents
List of Tables

Section 1 INTRODUCTION, PURPOSE, AND SCOPE 1-1
Introduction 1-1
Purpose 1-1
Scope 1-2

Section 2 ENERGY REQUIREMENTS AND CUSTOMER STATISTICS 2-1
General 2-1
Energy Requirements 2-1
Customer Statistics 2-3

Section 3 REVENUE REQUIREMENTS 3-1
General 3-1
Projected Revenue Requirements 3-2
Assumptions and Considerations 3-2

Section 4 FUNCTIONALIZATION AND CLASSIFICATION OF COSTS AND DEVELOPMENT OF ALLOCATION FACTORS 4-1
Functionalization and Classification 4-1
Development of Allocation Factors 4-2

Section 5 ALLOCATED COST OF SERVICE 5-1
General 5-1
Present and Proposed Rate Classifications 5-1
Allocation and Assignment of the Cost of Service 5-1

Section 6 RATE DESIGN 6-1
General Rate Design Criteria 6-1
Proposed Rates 6-1
Customer Charge 6-2
Fuel Cost Adjustment 6-2
Summary 6-2

Section 7 RATE COMPARISONS 7-1
General 7-1
Existing and Proposed Rates 7-1
Comparisons with Other Utilities 7-1

List of Tables

Table No. 2-1 Historical and Projected Customers, Billing Demand, and Energy Sales
Table No. 2-2 Annual Billing Determinants Fiscal Year Ending September 30, 2020

Table No. 3-1 Summary of Projected Revenue Requirements and Existing Rate Revenues
Table No. 3-2 Projected Revenues at Existing Rates
Table No. 3-3 Summary of Other Electric Revenues
Table No. 3-4 Calculation of Fuel Cost Recovery Factor
Table No. 3-5 Debt Service Detail
Table No. 3-6 Summary of Capital Improvement Projects

Table No. 4-1 Functionalization of Test Year 2020 Projected Revenue Requirements
Table No. 4-2 Development of Demand Allocation Factors
Table No. 4-3 Summary of Energy Allocation Factors
Table No. 4-4 Summary of Customer Allocation Factors
Table No. 4-5 Comparison of Load Research Results

Table No. 5-1 Allocated Cost of Service Summary
Table No. 5-2 Functionalization and Classification of Test Year Revenue Requirements
Table No. 5-3 Results of the Cost of Service Analysis
Table No. 5-4 Summary of Rate Design Options Pros and Cons

Table No. 6-1 Rate Summary
Table No. 6-2 Projected Revenues at Proposed Rates

Table No. 7-1 Comparison of Existing and Proposed Rates
Table No. 7-2 Inter-Utility Comparison of Typical Monthly Electric Bills

Section 1
INTRODUCTION, PURPOSE, AND SCOPE

Introduction

The City of Winter Park (City), located in Central Florida, operates a transmission and distribution only utility consisting of facilities that provide electric service to approximately 15,000 customers. The City currently meets its load requirements through power supply contracts with the Orlando Utilities Commission (OUC), Covanta Energy Marketing LLC (Covanta), and the Florida Municipal Power Agency (FMPA). As a member of FMPA, the City benefits from the associated capacity and energy to meet its customers' load requirements. Power is delivered through the City's Canton Avenue and Interlachen substations served by 69 kV transmission lines owned by Duke Energy (Duke).

Leidos Engineering, LLC, (the Consultant or the firm) conducted this 2020 Electric Cost of Service Study "Study", which relied upon historical and projected data for the development of operating revenues, operating expenses, and capital requirements. Historical data was obtained from various monthly reports, annual financial reports, actual billing records, analyses, and discussions with members of the management and staff of the City. Projected data was, in part, derived from historical data adjusted for current economic conditions, the Operating Budgets for Fiscal Years ending September 30, 2020 and 2021, the Capital Improvement Plan for Fiscal Years 2020 through 2024, the Ten Year Pro Forma projections, the City's demand and energy forecasts (including the effects of conservation), the various contracts, and the direction and instructions provided by the City, and other appropriate sources.

Purpose

The primary purposes of the Study are:

1. To determine the estimated annual revenue requirements for the Fiscal Year ending September 30, 2020, as adjusted for known changes (the Test Year); and Fiscal Years ending September 30, 2021 through 2024 (Study Period).
2. To test the adequacy of the existing rates on a system wide basis for the Fiscal Years 2020 through 2024;
3. To prepare a cost of service analysis to estimate the cost of providing electric service by customer class;
4. To adjust rate levels, if necessary, in order to recover the cost of providing electric service, and to reflect the policies established by the City; and
5. To continue to recover periodically the costs of purchased power.

Scope

The overall scope of services of the Study provided for (i) the development of revenue requirements for the Test Year and Study Period; (ii) the development of proposed rate levels and rate structures that are designed to recover the revenue requirements for the Test Year and Study Period which reflect the City's policy and industry practices; and (iii) the development of comparisons of typical bills for electric service calculated using the existing and proposed rates and the rates charged by neighboring private and public electric utilities.

The Electric Rate Study consists of two parts or phases. The results are presented in this report. Working closely with management and staff, Phase I activities include, among other things, (i) obtaining and reviewing historical billing data, (ii) reconciling such data, (iii) identifying the proper sales forecast to use for purposes of projecting rate revenues and costs (iv) projecting billing determinants in order to calculate the effect on revenues based on revised rates, (v) preparing projections of revenues by major customer class, (vi) developing projected annual revenue requirements for the Test Year and Study Period, (vii) preparing a comparison of the City's existing rates and the rates of other utilities, and (viii) preparing a Phase I report.

Phase II activities include (i) the making of revisions to the revenue requirements, (ii) the affirmation of City policies and direction, (iii) the allocation of costs, (iv) the design of proposed rates, and (v) the preparation of a final report.

General

The development of an accurate forecast of future power and energy requirements, sales, customers, and customer usage characteristics, is essential in the evaluation of the adequacy of electric rates and rate structures. This section summarizes the various factors considered and utilized in the development of the City's near term future power and energy requirements.

The estimates of energy and demand requirements developed for inclusion in this Study were based on historical sales, customers, and customer usage characteristics.

Energy Requirements

Projection of Electricity Sales to Ultimate Customers

The projections of electric energy sales to ultimate customers are based on information provided by the City and checked for reasonableness based on historical growth, usage patterns, and weather.

Based on information provided by the City, the following is a summary of Table 2-1 setting forth the historical number of residential and commercial customers and energy sales.

Historical Retail Energy Sales (MWh)			
Fiscal Year	Residential	Commercial	Total
2014	183,301	242,713	426,014
2015	187,566	241,780	429,346
2016	192,100	245,935	438,035
2017	185,518	239,657	425,175
2018	182,964	231,731	414,695
2019	190,271	235,748	426,018

Historical Number of Customers			
Fiscal Year	Residential	Commercial	Total
2014	11,610	2,938	14,548
2015	11,864	3,001	14,864
2016	11,898	3,001	14,899
2017	11,898	3,287	15,185
2018	12,084	3,298	15,382
2019	12,048	3,296	15,344

Projected Demand

The historical system peak demand for the fiscal year ended September 30, 2019 was 97.1 MW occurring in June. For purposes of this Study, it was projected that the system peak demand for fiscal year 2020 would be 95.7 MW.

Projected Energy Sales

The monthly system historical and projected energy sales are detailed in Table No. 2-1. The following tabulation is an annual summary of the historical and projected energy sales by major customer class for fiscal years 2019 and 2020:

Retail Energy Sales (MWh)			
Fiscal Year	Residential	Commercial	Total
Historical 2019	190,271	235,748	426,018
Projected 2020	187,842	232,158	420,000

As can be seen from the summary table, energy sales in fiscal year ended September 30, 2019 were 426,018 MWh. Sales in fiscal year 2020 and the Study Period are based projected amounts provided by the City.

Projected Average Number of Customers

An integral part of the forecasting process is the average number of customers the City expects to serve by major customer class. The detailed historical and projected customers are set forth on Table No. 2-1. The following is a summary of the historical and projected average number of customers used as a basis for this Study:

Average Number of Customers			
Fiscal Year	Residential	Commercial	Total
Historical 2019	12,048	3,296	15,344
Projected 2020	12,180	3,300	15,479

Purchased Power

The City purchases capacity and energy requirements from a variety of sources, including OUC, Covanta, and FMPA. The contract with Covanta ends in 2024, and the contracts with OUC and FMPA end in 2026 and 2027, respectively.

Energy Losses

The loss factors utilized in developing the projected energy requirements for the Test Year are 3.8 percent of annual energy requirements and 4.0 percent of energy sales. This factor is used to take into account transmission and distribution losses and unaccounted for energy and demand.

Summary of Projected Demand and Energy Requirements

The following tabulation sets forth the projected annual peak demand at the generation level, energy requirements and the system load factor used in this Study:

Description	2020 Test Year
Annual 60-Minute Peak Demand (MW)	95.7
Annual Energy Sales (MWh)	420,000
Losses and Unaccounted for Energy (MWh)	16,590
Annual Energy Requirements (MWh)	436,590
Annual System Load Factor (%)	52.1 %

Customer Statistics

As shown on Table No. 2-1 and Table No. 2-2, the historical number of customers and energy sales have been relatively stable. The City's customer base is somewhat unique, since the residential base includes a significant number of above average energy users, and the average use per customer is higher than for other utilities in the area, the small commercial users such as those on Park Avenue are distinctive and may have different operating hours than typical small commercial users, and the large commercial customers include unique customers such as Rollins College and the hospital.

Projected customer statistics by major rate classification are set forth on Table No. 2-1 and No. 2-2. Table No. 2-1 sets forth for fiscal years ending September 30, 2017 through 2020 the historical and projected number of customers and energy sales. Table No. 2-2 sets forth the projected annual billing determinants by major rate classes for Test Year 2020. The projected average annual number of customers and annual energy sales for the fiscal year ending September 30, 2020 incorporate the following considerations:

i. continuation of recent historical sales and/or usage characteristics;

ii. continuation of past, present, and projected conservation and demand-side management programs (if any); and

iii. continuation of the existing regulatory structure.

Any departure from those assumptions (e.g., change in economic activity) could have a material adverse effect on energy sales and revenues.

As derived from Table No. 2-1 and No. 2-2, the projected fiscal year 2020 composition of the City's ultimate customers and associated energy sales by major rate classification is tabulated below:

	Test Year 2020			
Customer Class	**Average Number of Customers**	**Percent of Total**	**Annual MWh Sales**	**Percent of Total**
Residential	12,180	78.7%	187,842	44.7%
Commercial	1,167	7.5%	11,664	2.8%
Commercial Demand	1,069	6.9%	196,182	46.7%
Public Authority	269	1.7%	22,188	5.3%
Lighting	795	5.1%	2,124	0.5%
Total	15,479	100.0%	420,000	100.0%

The projected energy sales of 420,000 MWh in the Test Year reflects an estimated normal year. For Fiscal Year 2021, the projected energy sales are 407,000 MWh to reflect the unknown impact of Covid-19 on energy sales.

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Historical and Projected Customers

Fiscal Years 2017-2020

Ln. No.	Customer Classes	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total	Average
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Historical FY 2017														
1	**Residential**	11,857	11,831	11,852	11,852	11,842	11,894	11,866	11,917	11,980	11,959	11,994	11,929	142,773	11,898
	Commercial														
2	General Service Non-Demand	1,014	1,033	1,017	1,014	1,024	1,011	1,163	1,144	1,142	1,135	1,141	1,134	12,972	1,081
3	GS Non-Demand - 100% Load Factor	36	36	36	36	36	36	36	36	36	40	40	40	444	37
	General Service Demand														
4	Primary	2	2	2	2	2	2	2	2	2	3	2	2	25	2
5	Secondary	1,144	1,136	1,137	1,131	1,136	1,138	1,005	1,028	1,031	1,036	1,036	1,042	13,000	1,083
	Time of Use														
6	Primary	1	1	1	1	1	1	1	1	1	1	1	1	12	1
7	Secondary	20	20	21	19	21	21	21	20	20	20	20	20	243	20
8	**Subtotal Commercial**	2,217	2,228	2,214	2,203	2,220	2,209	2,228	2,231	2,232	2,235	2,240	2,239	26,696	2,225
	Public Authority														
9	General Service Non-Demand	186	186	186	189	187	187	183	178	189	180	179	182	2,212	184
10	GS Non-Demand - 100% Load Factor	22	23	23	23	23	23	23	23	23	23	23	23	275	23
11	General Service Demand	58	59	56	56	56	57	60	55	63	59	60	57	696	58
	Time of Use														
12	Primary	1	1	1	1	1	1	1	1	1	1	1	1	12	1
13	Secondary	1	1	1	1	1	1	1	1	1	1	1	1	12	1
14	**Subtotal Public Authority**	268	270	267	270	268	269	268	258	277	264	264	264	3,207	267
	Lighting														
15	Residential	649	649	649	649	649	649	649	649	649	649	649	649	7,788	649
16	Commercial	146	146	146	146	146	146	146	146	146	146	146	146	1,752	146
17	**Subtotal Lighting**	795	795	795	795	795	795	795	795	795	795	795	795	9,540	795
18	**FY 2017 TOTAL CUSTOMERS**	15,137	15,124	15,128	15,120	15,125	15,167	15,157	15,201	15,284	15,253	15,293	15,227	182,216	15,185
	Historical FY 2018														
19	**Residential**	11,860	11,865	11,889	11,840	12,147	12,217	12,130	12,171	12,250	12,206	12,263	12,167	145,005	12,084
	Commercial														
20	General Service Non-Demand	1,134	1,145	1,133	1,138	1,128	1,140	1,129	1,133	1,140	1,123	1,124	1,127	13,594	1,133
21	GS Non-Demand - 100% Load Factor	40	40	40	40	40	40	40	40	40	40	40	40	480	40
	General Service Demand														
22	Primary	2	1	1	1	1	1	1	1	1	1	1	1	13	1
23	Secondary	1,050	1,035	1,043	1,043	1,043	1,038	1,040	1,045	1,042	1,034	1,044	1,040	12,497	1,041
	Time of Use														
24	Primary	1	1	1	1	1	1	1	1	1	1	1	1	12	1
25	Secondary	20	20	20	20	20	20	20	20	21	20	20	20	241	20
26	**Subtotal Commercial**	2,247	2,242	2,238	2,243	2,233	2,240	2,231	2,240	2,245	2,219	2,230	2,229	26,837	2,236
	Public Authority														
27	General Service Non-Demand	182	183	182	182	182	181	182	183	181	181	180	185	2,184	182
28	GS Non-Demand - 100% Load Factor	23	23	23	23	23	23	23	23	23	23	23	23	276	23
	General Service Demand	62	59	59	59	59	59	59	58	58	61	63	60		
	Time of Use														
29	Primary	1	1	1	1	1	1	1	1	1	1	1	1	12	1
30	Secondary	1	1	1	1	1	1	1	1	1	1	1	1	12	1
31	**Subtotal Public Authority**	269	267	266	266	266	265	266	266	264	267	268	270	2,484	267
	Lighting														
32	Residential	649	649	649	649	649	649	649	649	649	649	649	649	7,788	649
33	Commercial	146	146	146	146	146	146	146	146	146	146	146	146	1,752	146
34	**Subtotal Lighting**	795	795	795	795	795	795	795	795	795	795	795	795	9,540	795
35	**FY 2018 TOTAL CUSTOMERS**	15,171	15,169	15,188	15,144	15,441	15,517	15,422	15,472	15,554	15,487	15,556	15,461	184,582	15,382

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Historical and Projected Customers

Fiscal Years 2017-2020

Ln. No.	Customer Classes	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total	Average
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Historical FY 2019														
36	**Residential**	12,017	12,005	11,999	12,045	12,059	12,017	12,081	12,089	12,089	12,083	12,078	12,012	144,574	12,048
	Commercial														
37	General Service Non-Demand	1,134	1,128	1,127	1,127	1,116	1,114	1,107	1,115	1,102	1,069	1,107	1,099	13,345	1,112
38	GS Non-Demand - 100% Load Factor	40	40	40	40	40	40	40	40	40	40	40	40	480	40
	General Service Demand														
39	Primary	1	1	1	1	1	1	1	1	1	1	1	1	12	1
40	Secondary	1,048	1,050	1,054	1,055	1,052	1,060	1,053	1,056	1,048	1,054	1,062	1,062	12,654	1,055
	Time of Use														
41	Primary	2	2	2	2	2	2	2	1	1	1	1	1	19	2
42	Secondary	19	19	19	18	20	19	19	20	20	19	19	19	230	19
43	**Subtotal Commercial**	2,244	2,240	2,243	2,243	2,231	2,236	2,222	2,233	2,212	2,184	2,230	2,222	26,740	2,228
	Public Authority														
44	General Service Non-Demand	184	186	185	185	185	186	184	188	184	195	195	195	2,252	188
45	GS Non-Demand - 100% Load Factor	23	23	23	23	23	23	23	23	23	23	23	23	276	23
46	General Service Demand	60	59	61	61	61	60	61	61	60	59	58	60	721	60
	Time of Use														
47	Primary	1	1	1	1	1	1	1	1	1	1	1	1	12	1
48	Secondary	1	1	1	1	1	1	1	1	1	1	1	1	12	1
49	**Subtotal Public Authority**	269	270	271	271	271	271	270	274	269	279	278	280	3,273	273
	Lighting														
50	Residential	649	649	649	649	649	649	649	649	649	649	649	649	7,788	649
51	Commercial	146	146	146	146	146	146	146	146	146	146	146	146	1,752	146
52	**Subtotal Lighting**	795	795	795	795	795	795	795	795	795	795	795	795	9,540	795
53	**FY 2019 TOTAL CUSTOMERS**	15,325	15,310	15,308	15,354	15,356	15,319	15,368	15,391	15,365	15,341	15,381	15,309	184,127	15,344
	Projected FY 2020														
54	**Residential**	12,146	12,135	12,126	12,181	12,205	12,176	12,130	12,171	12,250	12,206	12,263	12,167	146,156	12,180
	Commercial														
55	General Service Non-Demand	1,134	1,128	1,127	1,127	1,116	1,114	1,129	1,133	1,140	1,123	1,124	1,127	13,522	1,127
56	GS Non-Demand - 100% Load Factor	40	40	40	40	40	40	40	40	40	40	40	40	480	40
	General Service Demand														
57	Primary	1	1	1	1	1	1	1	1	1	1	1	1	12	1
58	Secondary	1,048	1,050	1,054	1,055	1,052	1,060	1,040	1,045	1,042	1,034	1,044	1,040	12,564	1,047
	Time of Use														
59	Primary	2	2	2	2	2	2	1	1	1	1	1	1	18	2
60	Secondary	19	19	19	18	20	19	20	20	21	20	20	20	235	20
61	**Subtotal Commercial**	2,244	2,240	2,243	2,243	2,231	2,236	2,231	2,240	2,245	2,219	2,230	2,229	26,831	2,236
	Public Authority														
62	General Service Non-Demand	184	186	185	185	185	186	182	183	181	181	180	185	2,203	184
63	GS Non-Demand - 100% Load Factor	23	23	23	23	23	23	23	23	23	23	23	23	276	23
64	General Service Demand	60	59	61	61	61	60	59	58	58	61	63	60	721	60
	Time of Use														
65	Primary	1	1	1	1	1	1	1	1	1	1	1	1	12	1
66	Secondary	1	1	1	1	1	1	1	1	1	1	1	1	12	1
67	**Subtotal Public Authority**	269	270	271	271	271	271	266	266	264	267	268	270	3,224	269
	Lighting														
68	Residential	649	649	649	649	649	649	649	649	649	649	649	649	7,788	649
69	Commercial	146	146	146	146	146	146	146	146	146	146	146	146	1,752	146
70	**Subtotal Lighting**	795	795	795	795	795	795	795	795	795	795	795	795	9,540	795
71	**FY 2020 TOTAL CUSTOMERS**	15,454	15,440	15,435	15,490	15,502	15,478	15,422	15,472	15,554	15,487	15,556	15,461	185,751	15,479

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Historical and Projected Energy Sales (kWh)

Fiscal Years 2017-2020

Ln. No.	Customer Classes	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total	Average
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Historical FY 2017														
1	**Residential**	18,162,291	13,444,261	12,229,953	12,753,019	12,375,894	11,886,726	12,706,951	15,080,783	18,080,150	19,209,581	19,786,658	19,801,670	185,517,937	15,459,828
	Commercial														
2	General Service Non-Demand	1,140,723	990,553	830,686	816,031	835,218	807,783	868,318	956,483	1,066,706	1,163,831	1,231,885	1,131,986	11,840,203	986,684
3	GS Non-Demand - 100% Load Factor	33,079	32,216	34,990	33,323	33,435	34,649	33,575	33,661	34,573	37,732	36,701	36,327	414,261	34,522
	General Service Demand														
4	Primary	15,356	12,233	10,985	10,735	11,024	10,169	11,915	13,876	13,386	10,742	7,458	7,012	134,891	11,241
5	Secondary	12,551,966	10,787,867	10,157,938	10,244,128	10,103,622	10,039,367	10,461,445	11,404,196	12,448,692	13,144,289	13,690,625	13,063,011	138,097,146	11,508,096
	Time of Use														
6	Primary - On Peak	466,400	381,600	374,400	295,200	345,600	360,000	374,400	367,200	374,400	424,800	424,800	432,000	4,620,800	385,067
7	Primary - Off Peak	1,310,400	1,130,400	1,224,000	936,000	1,087,200	1,123,200	1,173,600	1,209,600	1,188,000	1,432,800	1,281,600	1,432,800	14,529,600	1,210,800
8	Secondary- On Peak	1,051,627	942,849	882,054	860,197	867,068	873,428	855,363	908,277	989,368	989,069	945,740	1,031,275	11,196,315	933,026
9	Secondary - Off Peak	3,329,281	2,863,625	2,702,333	2,612,032	2,661,695	2,667,168	2,580,285	2,742,350	3,019,714	2,959,953	2,973,516	3,137,328	34,249,280	2,854,107
10	**Subtotal Commercial**	19,898,832	17,141,343	16,217,386	15,807,646	15,944,862	15,915,764	16,358,901	17,635,643	19,134,839	20,163,216	20,592,325	20,271,739	215,082,496	17,923,541
	Public Authority														
11	General Service Non-Demand	164,771	164,911	176,300	151,704	157,379	162,094	109,898	102,263	116,236	114,220	115,423	111,081	1,646,280	137,190
12	GS Non-Demand - 100% Load Factor	8,642	8,722	8,996	8,929	8,965	8,876	8,667	8,635	8,739	8,816	8,789	8,732	105,508	8,792
13	General Service Demand	1,207,375	1,097,988	1,033,900	953,668	935,224	1,002,941	1,011,727	1,090,267	1,205,205	1,168,148	1,283,693	1,244,346	13,234,482	1,102,874
	Time of Use														
14	Primary - On Peak	182,400	158,400	160,800	115,200	136,800	158,400	148,800	151,200	163,200	158,400	158,400	199,200	1,891,200	157,600
15	Primary - Off Peak	504,000	420,000	420,000	285,600	316,800	396,000	364,800	451,200	436,800	480,000	451,200	585,600	5,112,000	426,000
16	Secondary- On Peak	11,400	10,600	8,700	9,300	8,900	9,100	9,300	10,800	10,500	13,300	12,100	12,000	126,000	10,500
17	Secondary - Off Peak	33,400	27,500	21,500	24,600	23,600	23,800	24,600	30,900	30,000	38,800	37,600	32,900	349,200	29,100
18	**Subtotal Public Authority**	2,111,988	1,888,121	1,830,196	1,549,001	1,587,668	1,761,211	1,677,792	1,845,265	1,970,680	1,981,684	2,067,205	2,193,859	22,464,670	1,872,056
	Lighting														
19	Residential	6,650	6,658	6,551	6,683	6,687	6,696	6,742	6,201	6,254	6,169	6,453	6,228	77,972	6,498
20	Commercial	50,644	50,280	51,141	50,745	46,116	46,090	46,182	47,079	46,549	46,969	48,995	56,988	587,778	48,982
21	Public Authority	120,411	120,411	122,883	120,411	120,411	120,411	120,411	120,242	120,580	119,676	119,364	119,364	1,444,575	120,381
22	**Subtotal Lighting**	177,705	177,349	180,575	177,839	173,214	173,197	173,335	173,522	173,383	172,814	174,812	182,580	2,110,325	55,479
23	**FY 2017 TOTAL ENERGY SALES**	40,350,816	32,651,074	30,458,110	30,287,505	30,081,638	29,736,898	30,916,979	34,735,213	39,359,052	41,527,295	42,621,000	42,449,848	425,175,428	35,431,286

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Historical and Projected Energy Sales (kWh)

Fiscal Years 2017-2020

Ln. No.	Customer Classes	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total	Average
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Historical FY 2018														
24	**Residential**	16,850,689	14,407,780	12,032,570	15,234,078	14,301,731	12,299,746	11,517,908	13,627,407	15,644,114	18,581,628	19,321,843	19,144,243	182,963,737	15,246,978
	Commercial														
25	General Service Non-Demand	1,053,179	868,397	742,029	840,853	777,992	782,646	722,251	866,911	964,103	1,134,793	1,169,197	1,161,213	11,083,564	923,630
26	GS Non-Demand - 100% Load Factor	32,608	36,979	36,710	37,071	37,237	35,791	34,950	36,217	36,119	36,713	36,718	37,374	434,487	36,207
	General Service Demand														
27	Primary	5,947	3,461	3,368	3,439	2,851	2,895	2,447	3,344	3,499	3,911	3,790	3,148	42,100	3,508
28	Secondary	12,009,376	11,149,369	10,056,736	10,096,683	9,956,344	10,394,018	9,353,904	10,714,394	11,506,097	12,909,653	13,246,095	13,073,342	134,466,011	11,205,501
	Time of Use														
29	Primary - On Peak	432,000	388,800	367,200	280,800	352,800	360,000	295,200	381,600	338,400	374,400	403,200	381,600	4,356,000	363,000
30	Primary - Off Peak	1,303,200	1,180,800	1,224,000	943,200	1,008,000	1,238,400	1,029,600	1,159,200	1,116,000	1,288,800	1,180,800	1,245,600	13,917,600	1,159,800
31	Secondary- On Peak	941,609	942,803	839,213	838,703	852,360	826,546	782,344	897,059	902,437	965,901	943,868	908,373	10,641,216	886,768
32	Secondary - Off Peak	2,846,322	2,944,497	2,524,442	2,573,549	2,621,439	2,541,046	2,404,222	2,672,148	2,810,231	2,910,450	2,841,201	2,843,548	32,533,095	2,711,091
33	**Subtotal Commercial**	18,624,241	17,515,106	15,793,698	15,614,298	15,609,023	16,181,342	14,624,918	16,730,873	17,676,886	19,624,621	19,824,869	19,654,198	207,474,073	17,289,506
	Public Authority														
34	General Service Non-Demand	114,894	115,928	109,981	110,757	114,320	111,722	98,509	103,008	105,150	109,929	110,004	114,121	1,318,323	109,860
35	GS Non-Demand - 100% Load Factor	8,401	8,823	8,773	8,892	8,790	8,732	8,369	8,645	8,441	8,543	8,467	8,624	103,500	8,625
36	General Service Demand	1,297,844	1,272,790	1,130,449	1,002,132	1,027,933	1,005,484	854,395	967,623	1,026,936	1,144,283	1,405,375	1,264,502	13,399,746	1,116,646
	Time of Use														
37	Primary - On Peak	172,800	172,800	156,000	132,000	172,800	144,000	124,800	153,600	146,400	146,400	151,200	170,400	1,843,200	153,600
38	Primary - Off Peak	484,800	458,400	422,400	364,800	420,000	376,800	362,400	376,800	420,000	432,000	446,400	446,400	5,011,200	417,600
39	Secondary- On Peak	11,100	10,100	8,900	10,300	9,800	9,600	8,400	9,200	10,300	11,800	11,800	11,700	123,000	10,250
40	Secondary - Off Peak	32,200	28,200	21,300	22,500	23,800	23,100	22,500	28,500	29,100	32,900	36,900	32,800	333,800	27,817
41	**Subtotal Public Authority**	2,122,039	2,067,041	1,857,803	1,651,381	1,777,443	1,679,438	1,479,373	1,647,376	1,746,327	1,885,855	2,170,146	2,048,547	22,132,769	1,844,397
	Lighting														
42	Residential	6,187	6,175	6,479	6,357	6,352	6,374	6,424	6,414	6,381	6,492	6,406	6,392	76,433	6,369
43	Commercial	51,224	48,876	53,705	51,224	48,876	53,705	51,266	51,238	51,426	50,926	51,441	51,240	615,147	51,262
44	Public Authority	119,364	119,364	119,364	119,364	119,364	119,364	119,190	119,190	119,190	119,364	119,886	119,364	1,432,368	119,364
45	**Subtotal Lighting**	176,775	174,415	179,548	176,945	174,592	179,443	176,880	176,842	176,997	176,782	177,733	176,996	2,123,948	176,996
46	**FY 2018 TOTAL ENERGY SALES**	37,773,744	34,164,342	29,863,619	32,676,702	31,862,789	30,339,969	27,799,079	32,182,498	35,244,324	40,268,886	41,494,591	41,023,984	414,694,527	34,557,877

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Historical and Projected Energy Sales (kWh)

Fiscal Years 2017-2020

Ln. No.	Customer Classes	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total	Average
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Historical FY 2019														
47	**Residential**	20,059,385	14,922,098	13,464,512	13,862,510	13,681,753	11,630,802	11,494,848	15,006,519	18,842,877	18,539,574	18,793,014	19,972,857	190,270,749	15,855,896
	Commercial														
48	General Service Non-Demand	1,204,533	933,316	770,900	751,735	790,223	728,810	752,168	956,321	1,163,356	1,156,825	1,145,296	1,198,239	11,551,722	962,644
49	GS Non-Demand - 100% Load Factor	38,794	36,755	39,084	39,832	38,145	35,374	36,685	38,009	38,426	36,047	37,648	38,309	453,108	37,759
	General Service Demand														
50	Primary	3,656	3,312	3,368	3,338	2,971	2,297	2,501	2,458	2,496	2,574	2,527	2,512	34,010	2,834
51	Secondary	13,492,224	11,398,478	10,325,682	9,949,784	9,792,865	9,724,041	9,866,903	11,770,519	13,154,629	13,264,154	13,212,298	13,975,912	139,927,489	11,660,624
	Time of Use														
52	Primary - On Peak	453,600	417,600	338,400	280,800	352,800	266,400	316,800	345,600	273,600	302,400	324,000	324,000	3,996,000	333,000
53	Primary - Off Peak	1,447,200	1,188,000	1,130,400	921,600	1,058,400	936,000	921,600	1,202,400	900,000	964,800	972,000	1,058,400	12,700,800	1,058,400
54	Secondary- On Peak	1,010,290	869,078	857,092	747,581	863,657	740,455	784,908	877,269	898,747	895,516	944,700	1,000,375	10,489,668	874,139
55	Secondary - Off Peak	3,032,333	2,556,009	2,571,460	2,295,822	2,653,437	2,261,177	2,386,991	2,656,395	2,677,335	2,750,783	2,830,329	3,076,941	31,749,012	2,645,751
56	**Subtotal Commercial**	20,682,630	17,402,548	16,036,386	14,990,492	15,552,498	14,694,554	15,068,556	17,848,971	19,108,589	19,373,099	19,468,798	20,674,688	210,901,809	17,575,151
	Public Authority														
57	General Service Non-Demand	122,071	109,533	112,667	110,221	112,497	105,229	101,151	105,126	109,302	105,008	106,120	112,766	1,311,691	109,308
58	GS Non-Demand - 100% Load Factor	8,717	8,768	8,715	9,014	8,657	8,361	8,492	8,653	8,449	8,294	8,313	8,356	102,789	8,566
59	General Service Demand	1,333,369	1,148,341	1,032,453	930,514	1,023,386	963,305	942,525	1,110,564	1,247,664	1,164,270	1,177,820	1,323,229	13,397,440	1,116,453
	Time of Use														
60	Primary - On Peak	189,600	177,600	175,200	160,800	194,400	153,600	160,800	153,600	153,600	160,800	158,400	204,000	2,042,400	170,200
61	Primary - Off Peak	540,000	453,600	477,600	412,800	448,800	415,200	386,400	429,600	451,200	424,800	444,000	520,800	5,404,800	450,400
62	Secondary- On Peak	11,300	10,500	9,900	8,800	10,000	8,600	8,200	10,100	11,600	11,800	11,600	12,500	124,900	10,408
63	Secondary - Off Peak	33,000	31,100	23,200	24,400	23,000	24,100	24,000	30,100	32,700	33,100	32,700	36,900	348,300	29,025
64	**Subtotal Public Authority**	2,238,057	1,939,442	1,839,735	1,656,549	1,820,740	1,678,395	1,631,568	1,847,743	2,014,515	1,908,072	1,938,953	2,218,551	22,732,320	1,894,360
	Lighting														
65	Residential	6,416	6,464	6,239	6,343	6,357	6,437	6,419	6,383	6,374	6,374	6,374	6,374	76,554	6,380
66	Commercial	52,350	51,982	51,094	51,194	50,938	51,022	50,873	50,339	48,709	48,929	48,732	48,506	604,668	50,389
67	Public Authority	119,364	119,364	119,364	119,364	119,364	119,364	119,364	119,364	119,364	119,364	119,364	119,364	1,432,368	119,364
68	**Subtotal Lighting**	178,130	177,810	176,697	176,901	176,659	176,823	176,656	176,086	174,447	174,667	174,470	174,244	2,113,590	176,133
69	**FY 2019 TOTAL ENERGY SALES**	43,158,202	34,441,898	31,517,330	30,686,452	31,231,650	28,180,574	28,371,628	34,879,319	40,140,428	39,995,412	40,375,235	43,040,340	426,018,468	35,501,539

CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study

Historical and Projected Energy Sales (kWh)
Fiscal Years 2017-2020

Ln. No.	Customer Classes	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total	Average
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	Projected FY 2020														
70	**Residential**	20,317,219	15,113,900	13,637,579	14,040,693	13,857,612	11,780,299	11,665,954	13,802,568	15,845,196	18,820,468	19,570,197	19,390,315	187,842,000	15,653,500
	Commercial														
71	General Service Non-Demand	1,206,568	934,893	772,203	753,005	791,558	730,041	723,471	868,376	965,732	1,136,710	1,171,173	1,163,175	11,216,906	934,742
72	GS Non-Demand - 100% Load Factor	38,860	36,817	39,150	39,899	38,209	35,434	35,009	36,278	36,180	36,775	36,780	37,437	446,829	37,236
	General Service Demand														
73	Primary	3,662	3,318	3,374	3,344	2,976	2,301	2,451	3,350	3,505	3,918	3,796	3,153	39,147	3,262
74	Secondary	13,515,022	11,417,738	10,343,129	9,966,596	9,809,412	9,740,472	9,369,709	10,732,498	11,525,539	12,931,467	13,268,477	13,095,432	135,715,493	11,309,624
	Time of Use														
75	Primary - On Peak	454,366	418,306	338,972	281,274	353,396	266,850	295,699	382,245	338,972	375,033	403,881	382,245	4,291,239	357,603
76	Primary - Off Peak	1,449,645	1,190,007	1,132,310	923,157	1,060,188	937,582	1,031,340	1,161,159	1,117,886	1,290,978	1,182,795	1,247,705	13,724,752	1,143,729
77	Secondary- On Peak	1,011,997	870,546	858,540	748,844	865,116	741,706	783,666	898,575	903,962	967,533	945,463	909,908	10,505,857	875,488
78	Secondary - Off Peak	3,037,457	2,560,328	2,575,805	2,299,701	2,657,921	2,264,998	2,408,284	2,676,663	2,814,979	2,915,368	2,846,002	2,848,353	31,905,859	2,658,822
79	**Subtotal Commercial**	20,717,578	17,431,953	16,063,483	15,015,822	15,578,777	14,719,384	14,649,630	16,759,143	17,706,755	19,657,781	19,858,367	19,687,408	207,846,082	17,320,507
	Public Authority														
80	General Service Non-Demand	122,277	109,718	112,857	110,407	112,687	105,407	98,675	103,182	105,328	110,115	110,190	114,314	1,315,157	109,596
81	GS Non-Demand - 100% Load Factor	8,732	8,783	8,730	9,029	8,672	8,375	8,383	8,660	8,455	8,557	8,481	8,639	103,496	8,625
82	General Service Demand	1,335,622	1,150,281	1,034,198	932,086	1,025,115	964,933	855,839	969,258	1,028,671	1,146,217	1,407,750	1,266,639	13,116,608	1,093,051
	Time of Use														
83	Primary - On Peak	189,920	177,900	175,496	161,072	194,728	153,860	125,011	153,860	146,647	146,647	151,455	170,688	1,947,285	162,274
84	Primary - Off Peak	540,912	454,366	478,407	413,498	449,558	415,902	363,012	377,437	420,710	432,730	447,154	447,154	5,240,841	436,737
85	Secondary- On Peak	11,319	10,518	9,917	8,815	10,017	8,615	8,414	9,216	10,317	11,820	11,820	11,720	122,507	10,209
86	Secondary - Off Peak	33,056	31,153	23,239	24,441	23,039	24,141	22,538	28,548	29,149	32,956	36,962	32,855	342,077	28,506
87	**Subtotal Public Authority**	2,241,839	1,942,719	1,842,844	1,659,348	1,823,817	1,681,231	1,481,873	1,650,160	1,749,278	1,889,042	2,173,813	2,052,008	22,187,970	1,848,998
	Lighting														
88	Residential	6,412	6,460	6,235	6,339	6,353	6,433	6,420	6,410	6,377	6,488	6,402	6,388	76,718	6,393
89	Commercial	52,318	51,950	51,063	51,163	50,907	50,991	51,235	51,207	51,394	50,895	51,409	51,209	615,740	51,312
90	Public Authority	119,291	119,291	119,291	119,291	119,291	119,291	119,117	119,117	119,117	119,291	119,813	119,291	1,431,490	119,291
91	**Subtotal Lighting**	178,021	177,701	176,589	176,793	176,551	176,715	176,772	176,734	176,889	176,674	177,624	176,888	2,123,948	176,996
92	**FY 2020 TOTAL ENERGY SALES**	43,454,657	34,666,274	31,720,494	30,892,655	31,436,757	28,357,628	27,974,228	32,388,604	35,478,118	40,543,964	41,780,002	41,306,619	420,000,000	35,000,000

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Projected Annual Billing Determinants
Fiscal Year Ending September 30, 2020

Ln. No.	Customer Class Description	Number of Bills	Billing Demand (kW)	Energy Sales (kWh)
	(a)	(b)	(c)	(d)
	Residential Service			
1	Energy < 1,000 kWh	146,156	0	113,672,573
2	Energy > 1,000 kWh	0	0	74,169,427
3	Total Residential	146,156	0	187,842,000
	Commercial Service			
	General Service Non-Demand			
4	Secondary	13,522	0	11,216,906
5	General Service Non-Demand (100% LF)	480	0	446,829
	General Service Demand			
6	Primary	12	341	39,147
7	Secondary	12,564	395,612	135,715,493
	General Service Demand Time of Use			
8	Primary On-Peak	18	33,825	4,291,239
9	Primary Off-Peak	0	33,825	13,724,752
10	Secondary On-Peak	235	80,206	10,505,857
11	Secondary Off-Peak	0	82,477	31,905,859
12	Total Commercial	26,831	626,286	207,846,082
	Public Authority			
	General Service Non-Demand			
13	Secondary	2,203	0	1,315,157
14	General Service Non-Demand (100% LF)	276	0	103,496
15	General Service Demand - Secondary	721	50,746	13,116,608
	General Service Demand Time of Use			
16	Primary On-Peak	12	21,204	1,947,285
17	Primary Off-Peak	0	21,348	5,240,841
18	Secondary On-Peak	12	1,510	122,507
19	Secondary Off-Peak	0	1,510	342,077
20	Total Public Authority	3,224	96,316	22,187,970
	Lighting			
21	Residential	7,788	0	76,718
22	Commercial	1,752	0	2,047,230
23	Total Lighting	9,540	0	2,123,948
24	**TOTAL FISCAL YEAR 2020**	**185,751**	**722,602**	**420,000,000**

Section 3
REVENUE REQUIREMENTS

General

The various components of costs associated with the operation, maintenance, funding of improvements, renewal and replacement of facilities, and assurance of the adequacy and continuity of reliable service to customers are generally referred to as the revenue requirements of a municipally owned and operated utility. The determination of the revenue requirements as they relate to the City, consistent with the methods of other publicly owned utilities, includes the various generalized cost components described below.

Operation and Maintenance Expenses: These expenses include the cost of purchased power, labor, materials, supplies, transportation, services, and other expenses, which are necessary to the operation and maintenance of the City's Electric Utility. These expenses do not include an allowance for depreciation or replacement of capital assets, any monies for the payment of interest on indebtedness or any monies transferred to a Reserve Fund.

Debt Service: Included in the debt service component of cost is the annual principal of and interest on bonds and related costs/transfers payable from the net revenues.

Capital Improvements: These expenditures are for the purpose of paying the cost of construction or acquisition of necessary improvements, betterments, extensions, enlargements or additions to, or the renewal and replacement of capital assets of the system and for unusual or extraordinary repairs thereto.

Revenues Available for Other Lawful Purposes: This component of cost is paid out of revenues and includes (a) any additional capital improvements to be financed from revenues; (b) additional working cash to provide for the payment of expenses incurred in providing service prior to the receipt of revenues associated with such service; (c) the establishment of operating reserves for special purposes such as providing funds for self-insuring the facilities against certain perils and for the stabilization of rates to smooth out rate increases and minimize customer rate shock, (d) transfers of certain amounts of revenues from the earnings of the Electric Utility to the City; and (e) allowances for any other lawful purpose. The transfers to the City include an equivalent franchise fee amount based on 6 percent of revenues. That amount is shown separately as a revenue requirement and also is included in other revenue since it is collected as a separate line item on customers' bills.

Revenue Credits: In the determination of projected annual costs, adjustments should be made to reflect among other things, (a) the receipt of revenues from the investment of monies, and (b) the receipt of revenues from other operating sources such as the rental of land, the use of poles and the sale of scrap. The recognition of these revenue credits reduces the overall annual revenue requirement from electric rates to ultimate customers.

Total Annual Net Revenue Requirements: The total of the cost components described above less other income and other operating revenues is the total annual net revenue requirements and such total represents the amount of revenues required to be recovered through rates and charges to ultimate customers.

Projected Revenue Requirements

Electric rates should be set at a level such that the revenues produced will be sufficient to meet near future revenue requirements. An important objective of a projected test year is to establish rates and rate levels that will also reflect the then current and near future costs of providing service and market conditions. Thus, it is necessary to estimate or project the various cost components over a reasonable period of time in order to determine the required rate levels. Projections must consider changes in operating practices, new facilities, increased regulatory (environmental) costs, expected changes in cost, and other factors that may affect the overall cost of operating and maintaining the utility system.

It was determined that the revenue requirements for this Electric Cost of Service Study would be predicated on the budgeted costs of the City's Electric Utility for the fiscal year ending September 30, 2020. The budgeted expenditures were used as a baseline in the development of the projections of the annual revenue requirements for the fiscal period ending September 30, 2020 through 2024. Based upon that detailed data and certain adjustments to reflect any known and anticipated changes and certain pro forma adjustments, the Consultant, together with members of the management and staff of the City, developed detailed estimates of projected expenditures for the fiscal years 2020 through 2024.

Assumptions and Considerations

The development of the projected revenue requirements for the Test Year required certain assumptions and considerations in order to reflect certain known or anticipated changes and certain pro forma adjustments. The analyses, estimates and projections summarized herein have been based upon an understanding of certain contracts, agreements, regulations, statutory requirements and planned operations. In the preparation of this report, certain assumptions have been made with respect to conditions, which may occur in the future. While these assumptions are reasonable for the preparation of this study, they are dependent upon future events and actual conditions may differ from those assumed. To the extent that actual future conditions differ from those assumed herein or provided to us by others, the actual results will vary from those projected.

The major assumptions and considerations included in the development of the projected annual revenue requirements have been divided into two categories and are listed below:

General

1. The general economic activity will not have a major impact on the City's electric sales and the annual inflation rate will be approximately 1.5 percent.
2. Existing federal and state environmental laws, including the Clean Air Act Amendments of 1990, the Clean Air Interstate Rule and the Clean Air Mercury Rule, will continue to be implemented, applied and enforced, and no new laws, regulations, rules and interpretations will be imposed on the City or its wholesale suppliers resulting in more stringent environmental restrictions in the near term.
3. There will be no material change in the taxation of fuel used to produce electricity.
4. There will be no material change in the taxation of municipally-owned or municipally financed electric generation or purchased power, transmission and distribution systems.
5. There will be no material change in the level of federal, state or local regulation of municipally-owned utilities.
6. There will be no material change in the City's existing ability to import or export power over the transmission grid.
7. The existing form of governance and policies established by the City will continue throughout the study period.
8. The City will continue to be the exclusive owner and operator of the Electric Utility, including its transmission, distribution, and customer care facilities.

Specific

1. The fiscal year period ending September 30, 2020 through 2024 revenues and expenses for the Electric Utility and the underlying assumptions included therein provide a reasonable basis and reflect normalized system operation.
2. As discussed in Section 2, the sales forecast was the basis for the development of the projected retail energy and demand requirements for the Test Year. It should be recognized that (a) any meaningful variances in the load characteristics of existing or new customers, and/or (b) any differences in expected initiation of service for anticipated new customers, and/or (c) differences in the expected effectiveness of the various conservation programs initiated and contemplated by the City and/or (d) any changes in federal or state legislation that permit customers to select their energy service provider may result in a distortion and/or an over or under recovery of revenue requirements for the Test Year.
3. Power supply costs used herein are predicated in part on cost data provided by the City and on the continued purchase of power supply from its wholesale suppliers.

4. Expenses for the fiscal years 2020 through 2024 have been increased based on the 2020 and 2021 Budgets, the 10 Year Pro Forma, an assumed inflation rate of 1.5 percent per year based on information from the U.S. Treasury, except where noted in Table No. 3-1.
5. Projected purchased power expenses have been estimated based on an analysis of purchased power expenses assuming an overall increase in kWh usage from 2020 of 0.5 percent per year.
6. Debt service has been projected based on information provided by the City, as shown on Table No. 3-5.
7. Capital improvement expenditures have been estimated each year, based on a review of the City's Capital Improvement Plan. Table No. 3-6 shows the detail of the planned capital expenditures, which include $5,000,000 per year for undergrounding. Although the undergrounding expenditures may be considered optional, they have been included in the revenue requirements to be recovered from rate.
8. Gross receipts tax is included both as an expense and a revenue, while other taxes are not included since they are collected for the City's General Fund. The gross receipts tax is levied on the revenues of the seller of electricity. Payment of the gross receipts tax to the State is an operating expense and the billing to Winter Park customers is an operating revenue. The State sales tax and utility taxes are taxes on the customer purchasing the goods and are not expenses of the electric utility. Electric utility taxes go to Orange County for the fourteen electric customers in unincorporated Orange County. The rest of the Winter Park electric customers are all inside the City limits. All utility taxes billed to those customers goes to the City's General Fund.
9. The amount for the Transfer to the General Fund has been based on an equivalent franchise fee of 6 percent of revenues.
10. Projected revenues from existing rates for fiscal year 2020 calculated on a detailed analysis by customer class are shown on Table No. 3-2.
11. Other Revenue has been projected based on the adopted fiscal year ending September 30, 2020 Budget and is set forth in Table No. 3-3.
12. Projected Revenues from the Fuel Cost Recovery Factor are based on costs shown on Table No. 3-4.
13. Projected revenues from existing rates for fiscal years 2021 through 2024 have been estimated based on the projected increases in sales from 2020 levels of 0.5 percent per year.
14. Bulk Power expenses have been reduced from the FY 2020 Budget for the Test Year to reflect the lower costs of fuel experienced in the earlier months of FY 2020.
15. Warehousing costs have been reduced from the Test Year to FY 2021 based on one less inventory specialist position.

16. Utility Billing costs have been increased from the Test Year to FY 2021 since Utility Billing is one of the last applications from the legacy ERP computer system being used, and therefore, more of the annual support costs are allocated to Utility Billing.

17. Meter Servicing costs have been increased from the Test Year to FY 2021 based on additional meters being purchased to replace aging meters.

18. An allowance for contingency was included as the difference between projected revenues and appropriation.

19. An allowance for replenishing Cash Reserves to build the cash balance of the Electric Fund through FY 2022.

20. Fuel Cost Recovery revenues are projected to drop in the Test Year, then rise in FY2021, since in FY2020, funds were transferred from the Rate Stabilization Fund to lower the Fuel Cost Recovery during the pandemic. The amount in FY2021 was based on the City's projection of costs based on its wholesale contracts.

The underlying assumptions for the Test Year on which rates are being analyzed do not vary significantly and the revenue requirements are stable, ranging from $44.9 million to $45.9 million over the Study Period.

Shown on Table No. 3-1 are the various expenditures and revenues for the fiscal years ending September 30, 2020 through 2024, and the adjustments discussed herein. In addition, each of the adjustments is noted in the footnotes to Table No. 3-1.

Summary

Based on the projected Test Year revenue requirements developed on Table No. 3-1, the existing rates produce revenues that are approximately equal to the cost of providing service on a system wide basis. The projected differences are summarized as follows.

	Projected				
Description	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024
Net Revenue Requirements	$44,912,177	$44,270,456	$44,662,613	$45,622,904	$45,975,542
Total Existing Rate Revenue	44,912,177	44,270,455	44,662,613	45,060,160	45,463,192
Difference	($0)	($0)	$0	($562,744)	($512,349)
Percent of Base and Fuel Revenue	0.0%	0.0%	0.0%	-1.4%	-1.3%

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Summary of Projected Revenue Requirements and Existing Rate Revenues

Fiscal Year Ending September 30

Ln. No.	Description	Amended Budget 2020 [1]	Adjustments to Amended Budget 2020	Test Year Revenue Requirements	2021 Revenue Requirements	2022 Revenue Requirements	2023 Revenue Requirements	2024 Revenue Requirements
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Operating Expenses [2]							
1	Operations							
2	Bulk Power [3]	$19,696,363	($1,000,000)	$18,696,363	$18,291,563	$18,739,472	$19,253,432	$19,800,728
3	Transmission [4]	3,357,884	(3,357,884)	0	0	0	0	0
4	Gross Receipts Tax	1,152,998	0	1,152,998	1,073,749	1,084,486	1,095,331	1,106,285
5	Electric Capital	1,180,000	0	1,180,000	1,203,600	1,227,672	1,252,225	1,277,270
6	Other Operations	1,836,636	0	1,836,636	2,071,764	2,123,695	2,180,517	2,230,254
7	Total Operations	27,223,881	(4,357,884)	22,865,997	22,640,676	23,175,326	23,781,506	24,414,536
8	Undergrounding [5]	6,163,873	(1,738,873)	4,425,000	5,000,000	5,000,000	5,000,000	5,000,000
9	Tree Trimming	656,996	0	656,996	644,061	623,110	603,905	610,236
10	Warehousing	378,031	0	378,031	293,582	301,704	313,346	323,995
11	Street Lighting	480,000	0	480,000	510,000	517,650	528,003	543,843
12	Utility Billing	713,923	0	713,923	877,483	893,926	916,723	946,354
13	Meter Servicing	388,618	0	388,618	725,037	737,719	754,564	277,358
14	Administration	1,148,486	0	1,148,486	1,460,843	1,491,324	1,536,238	1,587,117
15	*Total Operating Expenses*	37,153,808	(6,096,757)	31,057,051	32,151,682	32,740,760	33,434,285	33,703,440
	Other Revenue Requirements							
16	Debt Service [6]	4,791,526	0	4,791,526	4,701,764	4,703,917	4,686,940	4,680,803
17	Interfund Administrative Services	1,728,412	0	1,728,412	1,740,681	1,772,013	1,825,174	1,879,929
18	Transfer to General Fund [7]	2,545,301	0	2,545,301	2,621,316	2,660,721	2,707,374	2,728,533
19	Other Transfers	255,698	0	255,698	253,317	248,101	249,293	262,999
20	Contingency	2,219,838	0	2,219,838	2,219,838	2,219,838	2,219,838	2,219,838
21	Replenish Cash Reserves [8]	0	2,314,351	2,314,351	581,858	317,263	500,000	500,000
22	*Total Other Revenue Requirements*	11,540,775	2,314,351	13,855,126	12,118,774	11,921,853	12,188,619	12,272,102
23	**TOTAL REVENUE REQUIREMENTS**	48,694,583	(3,782,406)	44,912,177	44,270,456	44,662,613	45,622,904	45,975,542
	Projected Revenue From Sales [9]							
24	Existing Base Rate Revenues	29,990,760	281,741	30,272,501 [10]	29,334,054	29,480,724	29,628,128	29,776,268
25	Fuel Cost Recovery [11]	12,156,576	(3,324,094)	8,832,482 [10]	10,089,986	10,292,542	10,499,165	10,709,936
26	Fuel Cost Stabilization Fund	0	1,000,000	1,000,000	0	0	0	0
27	Other Revenue [12]	6,529,606	(1,722,412)	4,807,194	4,846,416	4,889,346	4,932,867	4,976,988
28	**TOTAL REVENUES FROM SALES**	48,676,942	(3,764,765)	44,912,177	44,270,455	44,662,613	45,060,160	45,463,192
29	Revenue Surplus or (Deficiency)	($17,641)	$17,641	($0)	($0)	$0	($562,744)	($512,349)
	Surplus or (Deficiency) as a % of:							
30	Existing Base Rate Revenues			0.0%	0.0%	0.0%	-1.9%	-1.7%
31	Existing Base Rate and Fuel Revenues			0.0%	0.0%	0.0%	-1.4%	-1.3%

CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study

Footnotes to Table No. 3-1

[1] Based on the 2020 Amended Budget and the 2021 Ten Year Pro Forma provided by the City.
[2] Unless otherwise noted, operating expenses are based on the 2020 Amended Budget, and the 2021 Ten Year Pro Forma.
[3] Based on the Power Costs shown on Table No. 3-4.
[4] Effective January 1, 2020, the only transmission expense is for Duke Energy transmission, which is included in the Bulk Power expense.
[5] Removal of $1,738,2873 for Fairbanks Avenue undergrounding funded by the Florida Department of Transportation.
[6] Based on the Debt Service schedule shown on Table No. 3-5.
[7] Calculated at 6% of Revenue Requirements for fiscal years 2021-2024.
[8] Additional funding to replenish cash reserves.
[9] Based on currently effective rates. Assumes sales of approximately 420,000,000 kWh in 2020, 407,000,000 kWh in 2021 and 0.5% growth in sales in 2022 through 2024.
[10] From Table No. 3-2, Page 2.
[11] Based on the fuel costs shown on Table No. 3-4.
[12] From Table No. 3-3.

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Projected Revenues at EXISTING RATES Fiscal Year Ending September 30, 2020

Ln. No.	Customer Class Description	Existing Rate	Billing Determinants	Base Rate Revenue	Fuel Cost Recovery	Total Revenue
	(a)	(b)	(c)	(d)	(e)	(f)
	Residential					
1	Customer Charge	$ 16.98	146,156	$ 2,481,729	$ -	$ 2,481,729
2	Energy Charge < 1,000 kWhs	$ 0.06624	113,672,573	7,529,671	-	7,529,671
3	Energy Charge > 1,000 kWhs	$ 0.08840	74,169,427	6,556,577	-	6,556,577
4	Fuel Cost Recovery Factor < 1,000 kWhs	$ 0.01708	113,672,573	-	1,941,528	1,941,528
5	Fuel Cost Recovery Factor > 1,000 kWhs	$ 0.02708	74,169,427	-	2,008,508	2,008,508
6	***Total Residential***			$ 16,567,977	$ 3,950,036	$ 20,518,013
	Commercial					
	General Service Non-Demand					
7	Customer Charge	$ 17.55	13,522	$ 237,311	$ -	$ 237,311
8	Energy Charge	$ 0.07368	11,216,906	826,462	-	826,462
9	Fuel Cost Recovery Factor	$ 0.02103	11,216,906	-	235,892	235,892
10	*Subtotal GSND*			$ 1,063,773	$ 235,892	$ 1,299,664
	General Service Non-Demand (100 % LF)					
11	Customer Charge	$ 18.38	480	$ 8,822	$ -	$ 8,822
12	Energy Charge	$ 0.03736	446,829	16,694	-	16,694
13	Fuel Cost Recovery Factor	$ 0.02103	446,829	-	9,397	9,397
14	*Subtotal GSND (100% LF)*			$ 25,516	$ 9,397	$ 34,913
	General Service Demand					
15	Customer Charge - Secondary	$ 18.28	12,564	$ 229,670	$ -	$ 229,670
16	Customer Charge - Primary	$ 231.26	12	2,775	-	2,775
17	Energy Charge	$ 0.04216	135,754,640	5,723,416	-	5,723,416
18	Fuel Cost Recovery Factor	$ 0.02103	135,754,640	-	2,854,920	2,854,920
19	Demand Charge	$ 5.05	395,953	1,999,562	-	1,999,562
20	*Subtotal General Service Demand*			$ 7,955,423	$ 2,854,920	$ 10,810,343
	General Service Demand Time of Use					
21	Customer Charge - Secondary	$ 29.01	235	$ 6,817	$ -	$ 6,817
22	Customer Charge - Primary	$ 234.93	18	4,229	-	4,229
23	Energy Charge - On-Peak	$ 0.07008	14,797,096	1,036,980	-	1,036,980
24	Energy Charge - Off-Peak	$ 0.02843	45,630,611	1,297,278	-	1,297,278
25	Fuel Cost Recovery - On-Peak	$ 0.02775	14,797,096	-	410,619	410,619
26	Fuel Cost Recovery - Off-Peak	$ 0.01882	45,630,611	-	858,768	858,768
27	Base Demand Charge	$ 1.27	116,302	147,704	-	147,704
28	On-Peak Demand Charge	$ 3.84	114,031	437,879	-	437,879
29	Primary Demand Charge Credit	$ (0.35)	67,650	(23,678)	-	(23,678)
30	*Subtotal General Service Demand TOU*			$ 2,907,210	$ 1,269,388	$ 4,176,598
31	***Total Commercial***			$ 11,951,922	$ 4,369,596	$ 16,321,518

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Projected Revenues at EXISTING RATES
Fiscal Year Ending September 30, 2020

Ln. No.	Customer Class Description	Existing Rate	Billing Determinants	Base Rate Revenue	Fuel Cost Recovery	Total Revenue
	(a)	(b)	(c)	(d)	(e)	(f)
	Public Authority					
	General Service Non-Demand					
32	Customer Charge Secondary	$ 17.55	2,203	$ 38,663	$ -	$ 38,663
33	Energy Charge	$ 0.07368	1,315,157	96,901	-	96,901
34	Fuel Cost Recovery Factor	$ 0.02103	1,315,157	-	27,658	27,658
	General Service Non-Demand (100 % LF)					
35	Customer Charge 100 % LF	$ 18.38	276	5,073	-	5,073
36	Energy Charge 100 % LF	$ 0.03736	103,496	3,867	-	3,867
37	Fuel Cost Recovery Factor	$ 0.02103	103,496	-	2,177	2,177
	General Service Demand					
38	Customer Charge - Secondry	$ 18.28	721	13,180	-	13,180
39	Energy Charge	$ 0.04216	13,116,608	552,996	-	552,996
40	Fuel Cost Recovery Factor	$ 0.02103	13,116,608	-	275,842	275,842
41	Demand Charge	$ 5.05	50,746	256,265	-	256,265
	General Service Demand Time of Use					
42	Customer Charge Secondary	$ 29.01	12	348	-	348
43	Customer Charge Primary	$ 234.93	12	2,819	-	2,819
44	Energy Charge - On-Peak	$ 0.07008	2,069,791	145,051	-	145,051
45	Energy Charge - Off-Peak	$ 0.02843	5,582,918	158,722	-	158,722
46	Fuel Cost Recovery - On-Peak	$ 0.02775	2,069,791	-	57,437	57,437
47	Fuel Cost Recovery - Off-Peak	$ 0.01882	5,582,918	-	105,071	105,071
48	Base Demand Charge	$ 1.27	22,858	29,029	-	29,029
49	On-Peak Demand Charge	$ 3.84	22,713	87,219	-	87,219
50	Primary Demand Charge Credit	$ (0.35)	42,552	(14,893)	-	(14,893)
51	***Total Public Authority***			$ 1,375,240	$ 468,184	$ 1,843,424
	Lighting					
52	Residential - Fuel Cost Recovery	$ 0.02103	76,718	$ 14,545	$ 1,613	$ 16,158
53	Commercial - Fuel Cost Recovery	$ 0.02103	2,047,230	362,817	43,053	405,870
54	***Total Lighting***			$ 377,362	$ 44,667	$ 422,029
55	**TOTAL SYSTEM RATE REVENUES**			$ 30,272,501	$ 8,832,482	$ 39,104,983
56	**Other Revenues**					5,807,194
57	**TOTAL SYSTEM REVENUE**					$ 44,912,177

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Summary of Other Electric Revenues

Fiscal Year Ending September 30

Ln. No.	Description	Amended Budget 2020*	Adjustments to Budget	Adjusted Test Year Revenues
	(a)	(b)	(c)	(d)
	Other Electric Revenues			
1	Franchise Fee	$2,528,840	$16,461	$2,545,301
2	Gross Receipts Tax	1,152,998	0	$1,152,998
3	Contribution in Aid of Construction	500,000	0	500,000
4	Contribution from Water and Sewer	181,995	0	181,995
5	Carry Forward - Capital Projects	1,738,873	(1,738,873)	0
6	Miscellaneous Service Charges	1,500	0	1,500
7	Connect Fees	20,000	0	20,000
8	Turn On/Off Charges	92,000	0	92,000
9	Pole Attachment Fees	115,000	0	115,000
10	Equipment Rental	70,400	0	70,400
11	Temporary Pole Service	10,000	0	10,000
12	Surge and Wire Protection	73,000	0	73,000
13	Residential Underground Service Drops	80,000	0	80,000
14	Bad Debt Expense	(62,000)	0	(62,000)
15	Demolition Disconnect	27,000	0	27,000
16	Interest Paid on Customer Deposits	(25,000)	0	(25,000)
17	Sale of Surplus Materials	25,000	0	25,000
18	**Total Other Electric Revenues**	$6,529,606	($1,722,412)	$4,807,194

*Based on the Budgeted 2020 Electric Revenue Fund provided by the City.

CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study

Calculation of Fuel Cost Recovery Factor
Fiscal Year Ending September 30

Ln. No.	Description	2020	2021	2022	2023	2024
	(a)	(b)	(c)	(d)	(e)	(f)
	Power Costs [1]					
1	FMPA		$7,513,787	$7,664,626	$7,818,493	$7,975,449
2	OUC		2,471,952	2,521,577	2,572,197	2,623,834
3	Covanta		5,570,362	5,682,187	5,796,257	5,912,617
4	Purchased Transmission		2,735,462	2,790,376	2,846,393	2,903,534
5	**Total Power Costs**	$19,696,363	$18,291,563	$18,658,766	$19,033,341	$19,415,435
6	**Total Energy Purchased (kWh)**	436,590,437	423,076,923	425,192,308	427,318,269	429,454,861
7	Total Cost Per kWh Purchased	$0.04511	$0.04323	$0.04388	$0.04454	$0.04521
8	**Total Energy Sales (kWh) [2]**	420,000,000	407,000,000	409,035,000	411,080,175	413,135,576
9	Total Cost Per kWh Sold	$0.04690	$0.04494	$0.04562	$0.04630	$0.04700
10	**Total Fuel Cost ($)**	$12,156,576	$10,089,986	10,292,542	10,499,165	10,709,936
11	Total Fuel Cost Per kWh Sold	$0.02894	$0.02479	$0.02516	$0.02554	$0.02592

[1] Based on information provided by the City.
[2] FY 2020 from Table No. 2-2; FY 2021 provided by the City; FY 2022-2024 based on a growth rate of 0.5% per year.

Table No. 3-5

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Debt Service Detail [1]

Fiscal Year Ending September 30

Ln. No.	Description	Projected FY 2020	FY 2021	FY 2022	FY 2023	FY 2024
	(a)	(b)	(c)	(d)	(e)	(f)
	Electric Revenue Bonds					
	Series 2010					
1	Principal	$ 250,000	$ 255,000	$ 265,000	$ 270,000	$ 280,000
2	Interest	109,920	101,840	93,520	84,960	76,160
3	Total Series 2010	$ 359,920	$ 356,840	$ 358,520	$ 354,960	$ 356,160
	Series 2014					
4	Principal	$ 345,000	$ 355,000	$ 365,000	$ 375,000	$ 385,000
5	Interest	167,757	158,166	148,302	138,165	127,753
6	Total Series 2014	$ 512,757	$ 513,166	$ 513,302	$ 513,165	$ 512,753
	Series 2014A					
7	Principal	$ 265,000	$ 275,000	$ 280,000	$ 290,000	$ 300,000
8	Interest	143,446	135,373	127,076	118,554	109,733
9	Total Series 2014A	$ 408,446	$ 410,373	$ 407,076	$ 408,554	$ 409,733
	Series 2016					
10	Principal	$ 640,000	$ 670,000	$ 705,000	$ 740,000	$ 775,000
11	Interest	591,418	558,668	524,293	488,168	450,293
12	Total Series 2016	$ 1,231,418	$ 1,228,668	$ 1,229,293	$ 1,228,168	$ 1,225,293
	Series 2019					
13	Principal	$ 400,000	$ 1,360,000	$ 1,395,000	$ 1,450,000	$ 1,485,000
14	Interest	636,464	846,510	798,573	749,070	698,001
15	Total Series 2019	$ 1,036,464	$ 2,206,510	$ 2,193,573	$ 2,199,070	$ 2,183,001
16	Total Existing Debt Service	$ 3,549,005	$ 4,715,557	$ 4,701,764	$ 4,703,917	$ 4,686,940
17	Future Debt Service [2]	0	0	0	0	0
18	**TOTAL DEBT SERVICE**	**$ 3,549,005**	**$ 4,715,557**	**$ 4,701,764**	**$ 4,703,917**	**$ 4,686,940**

[1] Amounts shown reflect the allocable share of accrued payments of principal and interest and exclude interest expense funded from bond proceeds.
[2] Amounts shown assume no new debt service in Fiscal Years 2020 - 2024.

CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study

Summary of Capital Improvement Projects Funded By Electric Services

Line No.	Projects	*Fiscal Years Ending September 30* 2021	2022	2023	2024	Estimated Total
	(a)	(b)	(c)	(d)	(e)	(f)
	Proposed Expenditure Descriptions [1]					
1	Undergrounding Electric Lines, R&R, and other improvements required to provide service and improve reliability of electric service.	$1,203,600	$1,227,672	$1,252,225	$1,277,270	$4,960,767
2	Undergrounding Electric Lines	5,000,000	5,000,000	5,000,000	5,000,000	20,000,000
3	Solar Awning Construction	500,000	-	-	-	500,000
4	Facility replacement of flooring, roofing, air conditioning, painting, & misc. other [2]	50,000	50,000	50,000	50,000	200,000
5	Information Technology Infrastructure Upgrades [3]	87,500	87,500	87,500	100,000	362,500
6	**Total Proposed Expenditures**	**$6,841,100**	**$6,365,172**	**$6,389,725**	**$6,427,270**	**$26,023,267**
	Funding Source					
7	Electric System Revenues	6,841,100	6,365,172	6,389,725	6,427,270	26,023,267
8	**Total Funding Sources**	**$6,841,100**	**$6,365,172**	**$6,389,725**	**$6,427,270**	**$26,023,267**

[1] Amounts shown are provided and projected by the City.
[2] A Public Works Department project where funding is allocated 65% to the General Fund, 25% to the Water and Sewer Fund and 10% to the Electric Fund.
[3] An Information Technology project where funding is allocated 50% to the General Fund, 25% to the Water and Sewer Fund and 25% to the Electric Fund.

Section 4
FUNCTIONALIZATION AND CLASSIFICATION OF COSTS AND DEVELOPMENT OF ALLOCATION FACTORS

Functionalization and Classification

In allocating utility costs to the various customer classes, there are three major processes: functionalization, classification, and allocation. The functionalization and classification of the Test Year revenue requirement are discussed in the first part of this section. The development of allocation factors for the Test Year revenue requirement is discussed and set forth in the second half of this section.

Functionalization of Test Year Expenditures

Although budgeting and accounting systems generally follow functional groups, i.e., production, transmission, etc., certain costs such as those associated with administrative and general expenses and bond service generally are not assigned by accounting and budgetary convention to a major function. A COS study usually requires the rearrangement of certain expenditures into functional groups (i) to be more representative of the expenditure causation, (ii) to combine costs that have been incurred for a similar purpose, and (iii) to facilitate the allocation of cost responsibility. Thus, the functionalization of certain costs is merely a ratemaking mechanism to apportion such costs to the common utility function.

The typical functions of the 2020 Test Year Revenue Requirements were developed in the COS model and summarized below.

Function and Description	Test Year Amount
Production. Those costs associated with generating or purchasing power and delivering that power to the utility's bulk transmission system	$23,423,367
Transmission and Distribution. Those costs incurred in connection with the delivery of power over the bulk transmission system through the primary and secondary distribution system to the utility's consumers	$19,581,738
Customer. Those costs that are related to the number, type and size of customers	$1,907,072
Total	$44,912,177

An analysis of the Test Year revenue requirements was made to estimate the functionalized Test Year revenue requirements.

Classification of Various Costs

Historically, electric utility costs or the components of the annual revenue requirement have generally been classified as (1) demand-related, (2) variable or energy-related, and (3) customer-related. Thus, if a cost or expense is fixed or does not vary directly with the level of kWh purchased or sold, the cost was assumed to be generally related to the demands or load of the customers and was allocated to the various customer classes on the basis of demand or load relationships. Debt service is one example of an expenditure generally classified as demand-related. If a cost or expense was viewed to vary with the amount of kWh the electric utility sold, the cost or expense was usually classified as energy-related and allocated to the various customer classes on the basis of kWh relationships. Purchased energy costs are a primary example of expenses classified as variable or energy-related and allocated on the basis of kWh sales. If the cost is directly related to the number of customers which are being served, these costs would generally be classified as such and allocated to the customer classes based on the customer relationship among the customer classes. An example of customer-related costs is meter reading expenses.

Until such time that the development of more detailed data with regard to hourly usage characteristics and costs is economically justified or legally required, the classification of costs described below reflects usual regulatory practice as well as a reasonable and equitable approach.

Demand (Fixed) Costs: Are defined as those costs incurred to maintain in readiness-to-serve an electric system capable of meeting the total combined demands of all classes of customers. Demand costs are those costs that are generally fixed in the short-run, that do not materially vary directly with the number of kWh generated or sold, and that are not defined as customer costs. Demand costs will include that portion of operation and maintenance expenses; debt service; renewals, replacements and improvements; and other costs which are not designated as specifically customer or variable energy costs.

Customer Costs: Are defined as those costs directly related to the number, type and size of customers, such as customer accounting and collecting, and costs of meters and services.

Energy (Variable) Costs: Are defined as those costs that vary substantially or directly with the amount of energy sold or generated and purchased, including such items as fuel and a portion of operation and maintenance expense for production facilities.

Development of Allocation Factors

General

This section discusses the development of the factors utilized to allocate the capacity related, energy related, customer related, and other costs to the various customer classes. The aforementioned costs are allocated to the customer classes according to their respective customer class, and the particular cost allocation factor developed for each class and for each type of cost. The customer classes include Residential, Commercial, Commercial Demand, and Lighting.

Allocation methodologies are based on industry practices and guidelines from the Florida Public Service Commission

Demand Allocation Factors

"Demand Allocation" refers to the basis on which capacity and other demand related costs are distributed or assigned (allocated) among the various customer classes for the purpose of determining the revenues required from each class to recover such costs. The demand allocation factors, as developed and used herein, reflect the cost responsibility for each of the various customer classes in relation to the capacity or demand related costs to be allocated. The demand allocation factors were used to apportion the following capacity or demand related costs among the various customer classes.

- Production and purchased power expenses (fixed capacity costs only);
- Transmission and distribution expenses;
- Debt service requirements;
- Allowances for renewal and replacements, and reserves; and
- Payments to the City.

The demand allocation factors were developed based on load research information provided by the City and historical demand and energy relationships filed with the Florida Public Service Commission (PSC) by the investor–owned utilities in Florida for 2018. The demand allocation factors are based on the estimated annual coincident and non-coincident peak demands.

The City’s production related demand costs are based on the monthly demand charges shown on its purchased power bills. The demand charges are based on the City’s system peak demand for that month. The contribution of each class to the monthly system peak is the basis for allocating the purchased demand cost. Over a 12 month period, the class load coincident with the time of the system peak each month allocates those costs (12 CP method).

The distribution facilities must be able to serve a class of customers at the time of the non-coincident annual peak demand. Distribution demand related costs are allocated based on the non-coincident annual peak demand for that class.

Table No. 4-2 summarizes the demand allocation factors. Table No. 4-5 shows a comparison of load research results for the City and the investor-owned utilities.

Energy Allocation Factors

Energy allocation factors are the basis for apportioning those costs or expenses classified as variable or energy related and assumed to vary directly with the level of kWh sales or generation. The costs classified herein as variable or energy related are fuel, purchased power, and the variable portion of other production expenses. The City’s production related energy costs are based on the monthly energy charges shown on its purchased power bills. Those costs are allocated based on the energy used by each class for that month.

The projected fiscal year energy sales data are discussed in Section 2. The resulting energy allocation factors are shown on Table No. 4-3.

Customer Allocation Factors

Customer costs are defined herein as those costs related to the number of customers and the size of service required. Included in the customer related costs are the costs associated with meter reading, meter maintenance, customer installations, billing, collecting, and other customer related accounting, service, and information functions. The customer allocation factors were based on the projected average number of customers in each customer classification during the Test Year.

In apportioning customer related costs and revenues to the various customer classifications, customer allocation factors were utilized that recognized weighted and unweighted customers and fixtures. The customer weighting factors were based on Duke Energy customer charges. The customer allocation factors are shown on Table No. 4-4.

Other Allocation Factors

Certain elements of the annual revenue requirement are related to revenues. Miscellaneous other allocation factors including the revenue allocation factors are included in the COS model.

Table No. 4-1

CITY OF WINTER PARK, FLORIDA
2020 Cost of Service Study
Functionalization of Test Year Revenue Requirements

Ln No	Description	FY 2020 Test Year Amount
1	Production	$ 23,423,367
2	Transmission and Distribution	$ 19,581,738
3	Customer	$ 1,907,072
4	**TOTAL REVENUE REQUIREMENTS**	**$ 44,912,177**

CITY OF WINTER PARK FLORIDA
Electric Cost of Service Study

Summary of Demand Allocation Factors

		Average 12 CP		Average Demand			PSC 12 CP Methodology				NCP Demand	
Ln. No.	Customer Class	Demand @ Source (kW)	Percent of Total (%)	2020 Energy at Source (MWh)	Average Demand (kW)	Percent of Total (%)	Avg. 12 CP @12/13 (kW)	Avg. kW @1/13 (kW)	Total (kW)	Total (%)	Demand @ Source (kW)	Percent of Total (%)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Residential	40,528	**49.83%**	195,262	22,290	**44.72%**	37,410	1,715	39,125	**49.58%**	50,430	**51.97%**
	Commercial											
2	General Service Non Demand	2,580	**3.17%**	11,660	1,331	**2.67%**	2,381	102	2,484	**3.15%**	3,060	**3.15%**
3	GS Non Demand (100% LF)	59	**0.07%**	464	53	**0.11%**	54	4	58	**0.07%**	59	**0.06%**
4	General Service Demand	25,530	**31.39%**	141,117	16,109	**32.32%**	23,566	1,239	24,805	**31.43%**	28,715	**29.59%**
5	General Service Demand TOU	7,967	**9.80%**	62,815	7,171	**14.39%**	7,354	552	7,906	**10.02%**	9,561	**9.85%**
6	Public Authority	4,173	**5.13%**	23,064	2,633	**5.28%**	3,852	203	4,054	**5.14%**	4,693	**4.84%**
7	Lighting	504	**0.62%**	2,208	252	**0.51%**	465	19	485	**0.61%**	526	**0.54%**
8	**TOTAL SYSTEM**	81,340	**100.00%**	436,590	49,839	**100.00%**	75,083	3,834	78,917	**100.00%**	97,045	**100.00%**

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Development of Demand Allocation Factors

			Average 12 CP					Non-Coincident Peak				
Ln. No.	Customer Class	Total FY 2020 Energy (MWh)	Load Factor (%) [1]	Demand @ Meter (kW)	Delivery Efficiency	Demand @ Source (kW)	Percent of Total (%)	Load Factor (%) [1]	Demand @ Meter (kW)	Delivery Efficiency	Demand @ Source (kW)	Percent of Total (%)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Residential	187,842	55.00%	38,988	0.9620	40,528	**49.83%**	44.20%	48,514	0.9620	50,430	**51.97%**
	Commercial											
2	General Service Non Demand	11,217	51.60%	2,482	0.9620	2,580	**3.17%**	43.50%	2,944	0.9620	3,060	**3.15%**
3	GS Non Demand (100% LF)	447	90.00%	57	0.9620	59	**0.07%**	90.00%	57	0.9620	59	**0.06%**
4	General Service Demand	135,755	63.10%	24,560	0.9620	25,530	**31.39%**	56.10%	27,624	0.9620	28,715	**29.59%**
5	General Service Demand TOU	60,428	90.00%	7,665	0.9620	7,967	**9.80%**	75.00%	9,198	0.9620	9,561	**9.85%**
6	Public Authority	22,188	63.10%	4,014	0.9620	4,173	**5.13%**	56.10%	4,515	0.9620	4,693	**4.84%**
7	Lighting	2,124	50.00%	485	0.9620	504	**0.62%**	47.90%	506	0.9620	526	**0.54%**
8	**TOTAL SYSTEM**	420,000		78,249		81,340	**100.00%**		93,357		97,045	**100.00%**

[1] Average 12 CP and NCP Load Factors are based on information provided by the City and Duke Energy's load research filed with the FPSC.

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Summary of Energy Allocation Factors

Fiscal Year 2020

Ln. No.	Customer Class	Energy (MWh) [1] Energy Sales	Net Generation	Allocation Factors (%) Energy Sales	Net Generation
	(a)	(b)	(c)	(d)	(e)
1	Residential	187,842	195,262	**44.72%**	**44.72%**
	Commercial				
2	General Service Non Demand	11,217	11,660	**2.67%**	**2.67%**
3	GS Non Demand (100% LF)	447	464	**0.11%**	**0.11%**
4	General Service Demand	135,755	141,117	**32.32%**	**32.32%**
5	General Service Demand TOU	60,428	62,815	**14.39%**	**14.39%**
6	Public Authority	22,188	23,064	**5.28%**	**5.28%**
7	Lighting	2,124	2,208	**0.51%**	**0.51%**
8	**TOTAL SYSTEM**	420,000	436,590	**100.00%**	**100.00%**

[1] A factor of 3.6% was assumed for System Losses based on data received from the City of Winter Park.

CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study

Summary of Customer Allocation Factors
Fiscal Year 2020

Ln. No.	Customer Class	Unweighted Customers: Customers	Unweighted Customers: Factor	Weighted Customers: Weighting Factor [1]	Weighted Customers: Customers [2]	Weighted Customers: Factor	Unweighted - No Lighting: Customers	Unweighted - No Lighting: Factor
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Residential	12,180	**78.68%**	1.00	12,180	**73.95%**	12,180	**78.68%**
	Commercial							
2	General Service Non Demand	1,127	**7.28%**	1.30	1,465	**8.89%**	1,127	**7.28%**
3	GS Non Demand (100% LF)	40	**0.26%**	1.30	52	**0.32%**	40	**0.26%**
4	General Service Demand	1,048	**6.77%**	1.30	1,362	**8.27%**	1,048	**6.77%**
5	General Service Demand TOU	21	**0.14%**	1.30	27	**0.17%**	21	**0.14%**
6	Public Authority	269	**1.74%**	1.30	349	**2.12%**	269	**1.74%**
7	Lighting	795	**5.14%**	1.30	1,034	**6.28%**	795	**5.14%**
8	**TOTAL SYSTEM**	15,479	**100.00%**		16,469	**100.00%**	15,479	**100.00%**

[1] Based on Duke Energy Florida customer charges.
[2] Weighted customers are equal to Column (b), Unweighted Customers multiplied times Column (d), the Weighting Factor.

CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study

Comparison of Load Research Results *

Ln. No.	Utility	Rate Schedule	12 CP Load Factor	NCP Load Factor
	(a)	(b)	(c)	(d)
	Residential Service			
1	Duke Energy Florida	RS-1	54.8%	37.0%
2	Florida Power & Light Company	RS-1	66.2%	50.1%
3	Tampa Electric Company	RS	56.0%	45.0%
4	Gulf Power Company	RS	58.4%	38.8%
5	City of Winter Park	RS	55.0%	44.2%
	General Service Non-Demand			
6	Duke Energy Florida	GS-1 (no demand breakpoint)	57.6%	45.1%
7	Florida Power & Light Company	GS-1 (less than 21kw)	62.3%	53.1%
8	Tampa Electric Company	GS (less than 50 kw)	58.0%	43.0%
9	Gulf Power Company	GS (less than 20 kw)	57.4%	43.5%
10	City of Winter Park	GS	51.6%	43.5%
	General Service Demand			
11	Duke Energy Florida	GSD-1 (above 24,000 kwh/year)	74.2%	62.6%
12	Florida Power & Light Company	GSD-1 (21 - 499 kw)	72.1%	64.0%
13	Tampa Electric Company	GSD-1 (50 - 999 kw)	75.0%	63.0%
14	Gulf Power Company	GSD-1 (20 - 499 kw)	74.4%	56.4%
15	City of Winter Park	GSD	59.8%	49.3%

* The information shown for the investor owned electric utilities reflects the results of 2017-2018 Load Research reported to the PSC. The load factors shown for the City of Winter Park are based on current load research analyses.

Section 5
ALLOCATED COST OF SERVICE

General

As one of the factors considered in the development of the proposed rate levels and rate structures included herein, certain analyses common in ratemaking have been employed which provide a reasonable indication of the revenue levels required to recover the full cost of service or revenue requirement of each customer class. Since it is not the practice in utility accounting to maintain a subdivision of accounts that will report the cost of rendering service to each customer class, an allocation of costs must be made on the basis of parameters predicated upon the available classifications of operating expense and utility plant.

Present and Proposed Rate Classifications

The present customer classifications are as follows:

- Residential
- Commercial
  - General Service Non-Demand
  - General Service Non-Demand (100% Load Factor)
  - General Service Demand
  - General Service Demand Time of Use
- Public Authority
- Lighting

The present customer classifications are typical for municipal electric utilities in Florida. In the future, the City may want to investigate additional rate classifications such as:

- Residential Time of Use Rate
- Solar Subscription Rate
- Electric Vehicle Rate

A summary of the pros and cons of possible new rate designs and classifications is shown on Table No. 5-4.

Allocation and Assignment of the Cost of Service

The allocated cost of service was developed, along with the target rate differences for each class, based on a comparison of existing rate revenues.

Table No. 5-1 summarizes the results of the allocated COS study. Table No. 5-2 shows the results of the functionalization and classification of the Test Year revenue requirements and Table No. 5-3 summarizes the results of the COS study by customer class.

The projected Test Year revenues under the existing rates and charges, the targeted revenue adjustments, and the percentages necessary to recover the projected cost of service for each of the major rate classifications, as summarized from the COS model are as follows**:**

	Test Year 2020		
	Total Existing Revenue	Target Rate Adjustments	
Customer Class	**($000)**	**($000)**	**(%) [1]**
Residential	$23,416	($377)	-1.8%
Commercial			
General Service Non-Demand	1,488	(26)	-2.0%
GS Non-Demand (100% Load Factor)	40	0	0.0%
General Service Demand	12,545	324	3.0%
General Service Demand TOU	4,809	42	1.0%
Public Authority	2,129	37	2.0%
Lighting	485	0	0.0%
Total System	$44,912	$0	0.0%

[1] Percent of base rate and fuel adjustment revenues.

Based on the cost of service and target decreases for the Test Year and the projected revenue requirements, the target adjustments for Fiscal Year 2021 can be estimated as follows:

Customer Class	Fiscal Year 2021 Total Existing Revenue ($000)	Target Rate Adjustments ($000)	Target Rate Adjustments (%) [1]
Residential	$23,081	($372)	-1.8%
Commercial			
General Service Non-Demand	1,467	(26)	-2.0%
GS Non-Demand (100% Load Factor)	39	0	0.0%
General Service Demand	12,366	320	3.0%
General Service Demand TOU	4,740	41	1.0%
Public Authority	2,099	36	2.0%
Lighting	478	0	0.0%
Total System	$44,270	$0	0.0%

[1] Percent of base rate and fuel adjustment revenues.

CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study
Test Year Cost of Service by Customer Class

Line No.	Description	Total	Allocation Factor	Residential	General Service Non-Demand	General Service Non-Demand (100% LF)	General Service Demand	General Service Demand TOU	Public Authority	Lighting	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Production**										
2	**Production Demand related**										
3	Production - D	9,416,193	12 CP	4,668,288	296,328	6,975	2,959,695	943,338	483,738	57,832	9,416,193
4	Blank	0	N/A	0	0	0	0	0	0	0	0
5	Blank	0	N/A	0	0	0	0	0	0	0	0
6	Blank	0	N/A	0	0	0	0	0	0	0	0
7	Blank	0	N/A	0	0	0	0	0	0	0	0
8	Blank	0	N/A	0	0	0	0	0	0	0	0
9	**Production Energy related**										
10	Fuel & PP	14,007,173	Test Year Sales - kWh	6,264,608	374,088	14,902	4,527,473	2,015,289	739,978	70,835	14,007,173
11	Variable O&M	0	N/A	0	0	0	0	0	0	0	0
12	Blank	0	N/A	0	0	0	0	0	0	0	0
13	Blank	0	N/A	0	0	0	0	0	0	0	0
14	**Production Direct Assignment**										
15	Dir. Assignment A	0	N/A	0	0	0	0	0	0	0	0
16	Other	0	N/A	0	0	0	0	0	0	0	0
17	**Total Production**	23,423,367		10,932,896	670,417	21,877	7,487,168	2,958,627	1,223,716	128,666	23,423,367
18	Check	TRUE									
19		23,423,367									
20	**Transmission**										
21	**Demand Related**										
22	115 kV	0	N/A	0	0	0	0	0	0	0	0
23	69 kV	0	N/A	0	0	0	0	0	0	0	0
24	115 kV - Sub	0	N/A	0	0	0	0	0	0	0	0
25	69 kV - Sub	0	N/A	0	0	0	0	0	0	0	0
26	Blank	0	N/A	0	0	0	0	0	0	0	0
27	Blank	0	N/A	0	0	0	0	0	0	0	0
28	**Direct Assignment**										
29	Service 1	0	N/A	0	0	0	0	0	0	0	0
30	Service 2	0	N/A	0	0	0	0	0	0	0	0
31	Blank	0	N/A	0	0	0	0	0	0	0	0
32	**Total Transmission**	0		0	0	0	0	0	0	0	0
33	Check	TRUE									
34		0									
35	**Distribution**										
36	**Demand Related**										
37	Substat.	0	N/A	0	0	0	0	0	0	0	0
38	Prim-Dmd	0	N/A	0	0	0	0	0	0	0	0
39	Sec-Dmd	0	N/A	0	0	0	0	0	0	0	0
40	Total Demand	19,581,738	1 NCP	10,175,861	617,426	11,888	5,794,188	1,929,193	947,012	106,172	19,581,738
41	Blank	0	N/A	0	0	0	0	0	0	0	0
42	Blank	0	N/A	0	0	0	0	0	0	0	0
43	**Customer Related**										
44	Prim-Cust	0	N/A	0	0	0	0	0	0	0	0
45	Sec-Cust	0	N/A	0	0	0	0	0	0	0	0
46	Serv Drp	0	N/A	0	0	0	0	0	0	0	0
47	Trans-CR	0	N/A	0	0	0	0	0	0	0	0
48	Total Cust	0	N/A	0	0	0	0	0	0	0	0
49	Blank	0	N/A	0	0	0	0	0	0	0	0

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CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study
Test Year Cost of Service by Customer Class

Line No.	Description	Total	Allocation Factor	Residential	General Service Non-Demand	General Service Non-Demand (100% LF)	General Service Demand	General Service Demand TOU	Public Authority	Lighting	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
50											
51	**Direct Assignment**										
52	Lighting	0	N/A	0	0	0	0	0	0	0	0
53	Blank	0	N/A	0	0	0	0	0	0	0	0
54	**Total Distribution**	19,581,738		10,175,861	617,426	11,888	5,794,188	1,929,193	947,012	106,172	19,581,738
55	Check	TRUE									
56		19,581,738									
57	**Customer**										
58	Meters	691,711	Weighted Customers	519,069	62,430	2,216	58,062	1,168	14,885	33,881	691,711
59	Cust. Accounting	0	Weighted Customers	0	0	0	0	0	0	0	0
60	Cust. Service	1,215,361	Weighted Customers	912,022	109,692	3,894	102,018	2,052	26,153	59,530	1,215,361
61	Sales	0	Weighted Customers	0	0	0	0	0	0	0	0
62	Blank	0	N/A	0	0	0	0	0	0	0	0
63	**Total Customer**	1,907,072		1,431,091	172,121	6,110	160,080	3,220	41,038	93,411	1,907,072
64	Check	TRUE									
65		1,907,072									
66	**Direct Assignments Other**										
67	Lighting Adjustment	0	Lighting - # of Cust/Lights	(130,616)	0	0	(27,170)	0	(2,214)	160,000	0
68	**Total Direct Assignment Other**	0		(130,616)	0	0	(27,170)	0	(2,214)	160,000	0
69	Check	TRUE									
70											
71	**Total Cost of Service**	$ 44,912,177		$ 22,409,232	$ 1,459,964	$ 39,875	$ 13,414,266	$ 4,891,040	$ 2,209,552	$ 488,249	$ 44,912,177
72	Check	TRUE									
73	Total Unit Cost ($/kWh)			$ 0.119	$ 0.130	$ 0.089	$ 0.099	$ 0.081	$ 0.100	$ 0.230	$ 0.107
74	Base Rate Unit Cost ($/kWh)			$ 0.119	$ 0.130	$ 0.089	$ 0.099	$ 0.081	$ 0.100	$ 0.230	$ 0.107
75											
76											
77	**Revenue Adequacy Check**										
78	TY Base Rate Revenue	$30,272,501	TY Base Rate Rev	$16,567,977	$1,063,773	$25,516	$7,955,423	$2,907,210	$1,375,240	$377,362	$30,272,501
79	TY Other Revenue - FCR	$8,832,482	Fuel Cost Recovery	3,950,036	235,892	9,397	2,854,920	1,269,388	468,184	44,667	8,832,482
80	TY FCR Rate Stabilization	$1,000,000	Revenue Req	498,957	32,507	888	298,678	108,902	49,197	10,871	$1,000,000
81	TY Other Revenue	$4,807,194	Revenue Req	2,398,582	156,268	4,268	1,435,802	523,515	236,500	52,260	$4,807,194
82	Subtotal	$44,912,177		$23,415,551	$1,488,439	$40,069	$12,544,822	$4,809,014	$2,129,121	$485,160	$44,912,177
83	Existing Rate Unit Cost ($/kwh)			$ 0.125	$ 0.133	$ 0.090	$ 0.092	$ 0.080	$ 0.096	$ 0.228	$ 0.107
84											
85	TY Rate Revenue	$44,912,177		$23,415,551	$1,488,439	$40,069	$12,544,822	$4,809,014	$2,129,121	$485,160	$44,912,177
86	TY Retail Rate Revenue	$0	Other Revenue	0	0	0	0	0	0	0	$0
87	TY Total Rate Revenue	$44,912,177		$23,415,551	$1,488,439	$40,069	$12,544,822	$4,809,014	$2,129,121	$485,160	$44,912,177
88											
89	TY Rate Revenue Requirement	$44,912,177		$ 22,409,232	$ 1,459,964	$ 39,875	$ 13,414,266	$ 4,891,040	$ 2,209,552	$ 488,249	$44,912,177
90	TY Other Retail Rate Revenue	$0		0	0	0	0	0	0	0	0
91	TY Total Rate Revenue Requirement	$44,912,177		$22,409,232	$1,459,964	$39,875	$13,414,266	$4,891,040	$2,209,552	$488,249	$44,912,177
92											
93	**Difference $ (Surplus)**	**($0)**		**$1,006,319**	**$28,476**	**$194**	**($869,443)**	**($82,025)**	**($80,431)**	**($3,090)**	**(0)**
94	**Difference % (Surplus)**	**0.0%**		**4.9%**	**2.2%**	**0.6%**	**-8.0%**	**-2.0%**	**-4.4%**	**-0.7%**	**0.0%**
95											
96	**Target Rate Adjustment $**	**$0**		**($376,951)**	**($25,993)**	**$0**	**$324,310**	**$41,766**	**$36,868**	**$0**	**0**
97	**Target Rate Adjustment %**	**0.0%**		**-1.8%**	**-2.0%**	**0.0%**	**3.0%**	**1.0%**	**2.0%**	**0.0%**	**0.0%**

Table No. 5-2

CITY OF WINTER PARK, FLORIDA
2020 Cost of Service Study
Classification of Test Year Revenue Requirements

Ln No	Description	FY 2020 Test Year Amount	
	Production		
1	Demand Related	$ 9,416,193	
2	Energy Related	14,007,173	
3	**Total Production**	$ 23,423,367	
	Transmission and Distribution		
4	Demand Related	$ 19,581,738	
5	Customer Related	0	
6	Direct Assignment	0	
7	**Total Distribution**	$ 19,581,738	
8	**Customer** *(Customer Related)*	1,907,072	
9	**TOTAL REVENUE REQUIREMENTS**	**$ 44,912,177**	
10	Total Demand Related	$ 28,997,932	65%
11	Total Energy Related	14,007,173	31%
12	Total Customer Related	1,907,072	4%
13	**TOTAL REVENUE REQUIREMENTS**	**$ 44,912,177**	
14	Total Fixed Including All Demand Related	$ 30,905,004	69%
15	Total Variable	14,007,173	31%
16	**TOTAL REVENUE REQUIREMENTS**	**$ 44,912,177**	
17	Total Fixed Including Only Fixed Demand [1]	$ 27,883,390	62%
18	Total Variable	17,028,788	38%
19	**TOTAL REVENUE REQUIREMENTS**	**$ 44,912,177**	

[1] Excludes FMPA and OUC demand charges.

Table No. 5-3

CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study
Results of the Cost of Service Analysis

		Test Year 2020			
Ln No	**Customer Class**	**Cost of Service**	**Existing Revenues**	**Difference**	**Difference (%)**
	(a)	(b)	(c)	(d)	(e)
1	Residential	$22,409,232	$23,415,551	$1,006,319	4.9%
	Commercial				
2	General Service Non Demand	1,459,964	1,488,439	28,476	2.2%
3	GS Non Demand (100% LF)	39,875	40,069	194	0.6%
4	General Service Demand	13,414,266	12,544,822	(869,443)	-8.0%
5	General Service Demand TOU	4,891,040	4,809,014	(82,025)	-2.0%
6	Public Authority	2,209,552	2,129,121	(80,431)	-4.4%
7	Lighting	488,249	485,160	(3,090)	-0.7%
8	**TOTAL**	$44,912,177	$44,912,177	($0)	**0.0%**

Table No. 5-4

CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study

Summary of Rate Design Options Pros and Cons

RATE DESIGN OPTION	PROS	CONS
Increased Customer Charges	Helps recover fixed costs; closer to cost of service; consistent with industry trends	Greater percentage impact on low users; may discourage solar rooftop if too high
Residential Time of Use Rate	Provides option for customer to save; may improve system load factor and reduce system cost per kWh	Increased administrative costs
Electric Vehicle Rate	Promotes electric vehicle use; provides option for customer to save if the vehicle is charged during off-peak hours	Increased administrative costs
Solar Subscription Rate	Supports the future FMPA solar projects; provides option for customer to have solar power supply without rooftop solar; ecomonies of scale compared to rooftop solar	Increased administrative costs
Large Commercial Interruptible Rate	Provides option for a large commercial customer willing and able to interrupt during peak periods and provides opportunity for customer and utility to save on power costs	Increased administrative costs; customer may not meet interruption requirements
Residential Demand Rate	Helps recover fixed costs through a demand charge; aligns more closely to the cost of service	Increased administrative costs; may be too great of an impact for customers with high demand and low energy usage; not common in Florida

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General Rate Design Criteria

Rate design is the culmination of a rate study whereby the rates and charges for each customer classification are established in such a manner that the total revenue requirement of the system will be recovered in an equitable manner consistent with the results of the allocated cost of service study and any applicable orders and/or requirements of local, state, and federal regulatory authorities. To the extent possible, rate design should consider and reflect overall revenue stability, historical rate form, conservation considerations, competitiveness with neighboring utility systems, and the policies of those charged with the management and operation of the City.

The proposed rate levels and rate structures developed and submitted to the City for consideration and adoption should continue to meet the following electric utility rate criteria for service provided by municipally owned utilities:

- Electric rates should be based on a rate policy which calls for the lowest possible prices consistent with customer requirements, quality service efficiently rendered, and a payment to the City.
- Electric rates should be simple and understandable.
- Electric rates should be equitable among classes of customers and individuals within classes, taking into consideration the cost of service.
- Electric rates should be designed to encourage the most efficient use of the utility plant and discourage unnecessary or wasteful use of service.
- Electric rates should comply with applicable orders and requirements of local, state and federal regulatory authorities that have jurisdiction.

The PSC has oversight over the City's rate structure (not total rate revenue). The City submits its rate tariff sheets to the PSC for review whenever it makes changes. The PSC will review the rates to ensure they do not unduly burden any rate class to be benefit of another.

Proposed Rates

The existing rates and the proposed rates necessary to recover the revenue requirements are summarized on Table No. 6-1. The proposed rates reflect with the required rate changes by class applied to the customer, demand and energy charges. Table No. 6-2 shows calculation of the projected revenues at the proposed rates.

Customer Charge

As with most utilities, most of the costs of providing electric service are fixed, while the revenues are mostly recovered through a variable energy (kWh) charge. To mitigate this risk, many utilities are increasing the fixed customer charges and demand charges, while lowering the energy charges. This helps to recover more of the fixed costs if the energy usage declines. For Winter Park, the fixed costs are estimated to be between 62% and 69% of the total costs. The business risk for the City when the revenue is based mostly on a variable charge is that the City may not recover its necessary revenues. Since most of the City's costs are fixed, variations in weather (heating and cooling degree days), conservation, energy efficiencies and customer usage may have an adverse effect on the City recovering its fixed costs.

The existing customer charges do not recover the total fixed distribution and customer related costs. For the Residential class, Table No. 5-1 shows that the fixed distribution costs are $10,175,861 and the fixed customer costs are $1,431,091, for a total of $11,606,952. Dividing this amount by the Residential number of customers of 12,180 equals $953 per year, or approximately $79 per month. In order to help recover the fixed costs of providing service to the customer, the proposed customer charges have been increased for each class of service.

Fuel Cost Adjustment

It is recommended that a separate rate component continue to be implemented that recovers the cost of fuel included in the purchased power. Only the fuel costs portion of bulk power purchases are passed through to the customer. The remaining bulk power costs are included in the base rates. It is proposed that this factor be calculated once a year and adjusted if necessary.

Summary

The following is a comparison of the projected Fiscal Year 2021 revenues produced by applying the projected billing determinants to the existing rates and the proposed rates for each classification:

Customer Class	Fiscal Year 2021 Existing Revenue ($000)	Proposed Revenue ($000)	Rate Adjustment (%) [1]
Residential	$23,081	$22,709	-1.8%
Commercial			
General Service Non-Demand	1,467	1,442	-2.0%
GS Non-Demand (100% Load Factor)	39	39	0.0%
General Service Demand	12,366	12,685	3.0%
General Service Demand TOU	4,740	4,781	1.0%
Public Authority	2,099	2,135	2.0%
Lighting	478	478	0.0%
Total System	$44,270	$44,270	0.0%

[1] Percent of base rate and fuel adjustment revenues.

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Summary of Existing and Proposed Rates and Charges

Ln. No.	Rate Description	Unit	Existing Rates Effective January 1, 2020	Proposed Rates Effective January 1, 2021
	(a)	(b)	(c)	(d)
	Residential Service			
	Schedule RS			
1	Monthly Customer Charge	$/Mo.	$16.98	$18.00
	Energy Charges < 1,000 kWh's			
2	Base	$/kWh	$0.06624	$0.06341
3	Fuel Cost Recovery Factor	$/kWh	$0.01708	$0.02084
	Energy Charges > 1,000 kWh's			
4	Base	$/kWh	$0.08840	$0.08557
5	Fuel Cost Recovery Factor	$/kWh	$0.02708	$0.03084
	General Service Non-Demand			
	Rate Schedule GS-1			
	Monthly Customer Charges			
6	Non Metered Accounts	$/Mo.	$7.11	$8.00
	Metered Accounts			
7	Secondary Delivery Voltage	$/Mo.	$17.55	$18.00
8	Primary Delivery Voltage	$/Mo.	$221.86	$225.00
	Energy and Demand Charges All kWh's			
9	Base	$/kWh	$0.07368	$0.07080
10	Fuel Cost Recovery Factor	$/kWh	$0.02103	$0.02479
	General Service Non-Demand			
	Rate Schedule GS-2 (100% Load Factor)			
	Monthly Customer Charge			
11	Non Metered Accounts	$/Mo.	$7.45	$8.00
12	Metered Accounts	$/Mo.	$18.38	$19.00
	Energy and Demand Charges All kWh's			
13	Base	$/kWh	$0.03736	$0.03670
14	Fuel Cost Recovery Factor	$/kWh	$0.02103	$0.02479
	General Service - Demand			
	Schedule GSD-1			
	Monthly Customer Charges			
	Metered Accounts			
15	Secondary Delivery Voltage	$/Mo.	$18.28	$19.00
16	Primary Delivery Voltage	$/Mo.	$231.26	$235.00
	Energy Charges All kWh's			
17	Base	$/kWh	$0.04216	$0.04216
18	Fuel Cost Recovery Factor	$/kWh	$0.02103	$0.02479
19	Demand Charge	$/kW	$5.05	$5.82
	General Service - Demand			
	Optional Time of Use Rate			
	Schedule GSDT-1			
	Monthly Customer Charges			
	Metered Accounts			
20	Secondary Delivery Voltage	$/Mo.	$29.01	$30.00
21	Primary Delivery Voltage	$/Mo.	$234.93	$240.00
	Energy Charges All kWh's			
22	On - Peak	$/kWh	$0.07008	$0.07008
23	Off - Peak	$/kWh	$0.02843	$0.02843
	Fuel Cost Recovery Factor			
24	On - Peak	$/kWh	$0.02775	$0.03271
25	Off - Peak	$/kWh	$0.01882	$0.02218
26	Base Demand Charge	$/kW	$1.27	$1.50
27	On-Peak Demand Charge	$/kW	$3.84	$4.00
28	Demand Charge Credit	$/kW	(0.35)	(0.35)

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Projected Revenues at PROPOSED RATES Fiscal Year Ending September 30, 2021

Ln. No.	Customer Class Description	Proposed Rate	Billing Determinants	Base Rate Revenue	Fuel Cost Recovery	Total Revenue
	(a)	(b)	(c)	(d)	(e)	(f)
	Residential					
1	Customer Charge	$ 18.00	141,625	$ 2,549,253	$ -	$ 2,549,253
2	Energy Charge < 1,000 kWhs	$ 0.06341	110,148,723	6,984,531	-	6,984,531
3	Energy Charge > 1,000 kWhs	$ 0.08557	71,870,175	6,149,931	-	6,149,931
4	Fuel Cost Recovery Factor < 1,000 kWhs	$ 0.02084	110,148,723	-	2,295,499	2,295,499
5	Fuel Cost Recovery Factor > 1,000 kWhs	$ 0.03084	71,870,175	-	2,216,476	2,216,476
6	***Total Residential***			$ 15,683,714	$ 4,511,976	$ 20,195,690
	Commercial					
	General Service Non-Demand					
7	Customer Charge	$ 18.00	13,103	$ 235,851	$ -	$ 235,851
8	Energy Charge	$ 0.07080	10,869,182	769,538	-	769,538
9	Fuel Cost Recovery Factor	$ 0.02479	10,869,182	-	269,447	269,447
10	*Subtotal GSND*			$ 1,005,389	$ 269,447	$ 1,274,836
	General Service Non-Demand (100 % LF)					
11	Customer Charge	$ 19.00	465	$ 8,837	$ -	$ 8,837
12	Energy Charge	$ 0.03670	432,977	15,890	-	15,890
13	Fuel Cost Recovery Factor	$ 0.02479	432,977	-	10,734	10,734
14	*Subtotal GSND (100% LF)*			$ 24,728	$ 10,734	$ 35,461
	General Service Demand					
15	Customer Charge - Secondary	$ 19.00	12,175	$ 231,316	$ -	$ 231,316
16	Customer Charge - Primary	$ 235.00	12	2,733	-	2,733
17	Energy Charge	$ 0.04216	131,546,246	5,545,990	-	5,545,990
18	Fuel Cost Recovery Factor	$ 0.02479	131,546,246	-	3,261,031	3,261,031
19	Demand Charge	$ 5.82	383,678	2,233,008	-	2,233,008
20	*Subtotal General Service Demand*			$ 8,013,046	$ 3,261,031	$ 11,274,078
	General Service Demand Time of Use					
21	Customer Charge - Secondary	$ 30.00	228	$ 6,831	$ -	$ 6,831
22	Customer Charge - Primary	$ 240.00	17	4,186	-	4,186
23	Energy Charge - On-Peak	$ 0.07008	14,338,386	1,004,834	-	1,004,834
24	Energy Charge - Off-Peak	$ 0.02843	44,216,062	1,257,063	-	1,257,063
25	Fuel Cost Recovery - On-Peak	$ 0.03271	14,338,386	-	469,030	469,030
26	Fuel Cost Recovery - Off-Peak	$ 0.02218	44,216,062	-	980,928	980,928
27	Base Demand Charge	$ 1.50	112,697	169,045	-	169,045
28	On-Peak Demand Charge	$ 4.00	110,496	441,984	-	441,984
29	Primary Demand Charge Credit	$ (0.35)	65,553	(22,944)	-	(22,944)
30	*Subtotal General Service Demand TOU*			$ 2,861,000	$ 1,449,957	$ 4,310,957
31	***Total Commercial***			$ 11,904,163	$ 4,991,169	$ 16,895,332

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Projected Revenues at
PROPOSED RATES
Fiscal Year Ending September 30, 2021

Ln. No.	Customer Class Description	Proposed Rate	Billing Determinants	Base Rate Revenue	Fuel Cost Recovery	Total Revenue
	(a)	(b)	(c)	(d)	(e)	(f)
	Public Authority					
	General Service Non-Demand					
32	Customer Charge Secondary	$ 18.00	2,135	$ 38,425	$ -	$ 38,425
33	Energy Charge	$ 0.07080	1,274,388	90,227	-	90,227
34	Fuel Cost Recovery Factor	$ 0.02479	1,274,388	-	31,592	31,592
	General Service Non-Demand (100 % LF)					
35	Customer Charge 100 % LF	$ 19.00	267	5,081	-	5,081
36	Energy Charge 100 % LF	$ 0.03670	100,287	3,681	-	3,681
37	Fuel Cost Recovery Factor	$ 0.02479	100,287	-	2,486	2,486
	General Service Demand					
38	Customer Charge - Secondry	$ 19.00	699	13,274	-	13,274
39	Energy Charge	$ 0.04216	12,709,993	535,853	-	535,853
40	Fuel Cost Recovery Factor	$ 0.02479	12,709,993	-	315,081	315,081
41	Demand Charge	$ 5.82	49,172	286,184	-	286,184
	General Service Demand Time of Use					
42	Customer Charge Secondary	$ 30.00	12	349	-	349
43	Customer Charge Primary	$ 240.00	12	2,791	-	2,791
44	Energy Charge - On-Peak	$ 0.07008	2,005,628	140,554	-	140,554
45	Energy Charge - Off-Peak	$ 0.02843	5,409,847	153,802	-	153,802
46	Fuel Cost Recovery - On-Peak	$ 0.03271	2,005,628	-	65,607	65,607
47	Fuel Cost Recovery - Off-Peak	$ 0.02218	5,409,847	-	120,017	120,017
48	Base Demand Charge	$ 1.50	22,149	33,223	-	33,223
49	On-Peak Demand Charge	$ 4.00	22,009	88,037	-	88,037
50	Primary Demand Charge Credit	$ (0.35)	41,233	(14,431)	-	(14,431)
51	***Total Public Authority***			$ 1,377,050	$ 534,783	$ 1,911,832
	Lighting					
52	Residential	$ 0.02479	74,340	$ 14,545	1,843	$ 16,388
53	Commercial	$ 0.02479	1,983,766	362,817	49,178	411,995
54	***Total Lighting***			$ 377,362	$ 51,020	$ 428,382
55	**TOTAL SYSTEM**			$ 29,342,289	$ 10,088,948	$ 39,431,237
56	**Other Revenues**					4,846,416
57	**TOTAL SYSTEM REVENUE**					$ 44,277,653

Section 7
RATE COMPARISONS

General

This section provides a summary of the billing effects of the proposed rates for major rate classifications. Specifically, the tables in this section provide for two types of billing comparisons for each major rate classification at various levels of usage which include (i) monthly bills calculated under the City's proposed rates compared with bills calculated under its existing rates, and (ii) monthly bills calculated under the City's existing and proposed rates compared with those calculated under the rates of selected utilities for the billing month of June 2020.

Existing and Proposed Rates

Table No. 7-1 provides a comparison of monthly bills calculated under the proposed rates and the existing rates over a wide range of usage levels.

Comparisons with Other Utilities

Table No. 7-2 show the City's existing and proposed rates along with those of other electric utilities. As can be seen from these tables, the City's rates are comparable to other utilities.

In addition to the comparisons shown on Table No. 7-2, The Florida Municipal Electric Association prepares rate comparison schedules each month. The utilities designated as "G" on the comparisons are generating utilities, and the others are distribution only utilities. These schedules provide comparisons of both residential and commercial customers of varying usage levels. While generating utilities have different costs burdens, the distribution only utilities that purchase their power help the generating utilities recover those costs at wholesale rates. It is useful to include the generating utilities in the rate comparisons to make sure the City's rates are competitive.

CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study

Comparison of Existing and Proposed Residential Service Rates [1]

			Residential Service Existing	Residential Service Proposed
Customer Charge		($)	$16.98	$18.00
Energy Charge	First 1,000 kWh	($/kWh)	$0.06624	$0.06341
Energy Charge	Additional kWh	($/kWh)	$0.08840	$0.08557
Fuel Cost [2]	First 1,000 kWh	($/kWh)	$0.02084	$0.02084
Fuel Cost [2]	Additional kWh	($/kWh)	$0.03084	$0.03084

	Existing		Proposed		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
500	60.52	12.104	60.13	12.025	(0.40)	(0.079)	-0.65%
600	69.23	11.538	68.55	11.425	(0.68)	(0.113)	-0.98%
700	77.94	11.134	76.98	10.996	(0.96)	(0.137)	-1.23%
800	86.64	10.831	85.40	10.675	(1.24)	(0.155)	-1.44%
900	95.35	10.595	93.83	10.425	(1.53)	(0.170)	-1.60%
1,000	104.06	10.406	102.25	10.225	(1.81)	(0.181)	-1.74%
1,100	115.98	10.544	113.89	10.354	(2.09)	(0.190)	-1.80%
1,200	127.91	10.659	125.53	10.461	(2.38)	(0.198)	-1.86%
1,300	139.83	10.756	137.17	10.552	(2.66)	(0.205)	-1.90%
1,400	151.76	10.840	148.81	10.630	(2.94)	(0.210)	-1.94%
1,500	163.68	10.912	160.46	10.697	(3.22)	(0.215)	-1.97%
2,000	223.30	11.165	218.66	10.933	(4.64)	(0.232)	-2.08%
2,500	282.92	11.317	276.87	11.075	(6.06)	(0.242)	-2.14%
3,000	342.54	11.418	335.07	11.169	(7.47)	(0.249)	-2.18%
4,000	461.78	11.545	451.48	11.287	(10.30)	(0.258)	-2.23%
5,000	581.02	11.620	567.89	11.358	(13.13)	(0.263)	-2.26%

[1] Amounts shown reflect single phase, inside the City service.
[2] Projected Fuel Cost Recovery Factor for Fiscal Year 2021.

CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study

Comparison of Existing and Proposed General Service Non-Demand Rates [1]

			General Service Non-Demand	
			Existing	Proposed
Customer Charge		($)	$17.55	$18.00
Energy Charge	All kWh	($/kWh)	$0.07368	$0.07080
Fuel Cost Recovery [2]		($/kWh)	$0.02479	$0.02479

	Existing	Unit Cost	Proposed		Difference		
Usage	Amount	(Cents/kWh)	Amount	Unit Cost	Amount	Unit Cost	Percent
(kWh)	($)		($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
1,000	116.02	11.602	113.59	11.359	(2.43)	11.359	-2.09%
1,250	140.64	11.251	137.49	10.999	(3.15)	(0.603)	-2.24%
1,500	165.26	11.017	161.39	10.759	(3.87)	(0.492)	-2.34%
1,750	189.87	10.850	185.28	10.588	(4.59)	(0.429)	-2.42%
1,900	204.64	10.771	199.62	10.506	(5.02)	(0.343)	-2.45%
2,000	214.49	10.725	209.18	10.459	(5.31)	(0.312)	-2.48%
3,000	312.96	10.432	304.77	10.159	(8.19)	(0.566)	-2.62%
4,000	411.43	10.286	400.36	10.009	(11.07)	(0.423)	-2.69%
5,000	509.90	10.198	495.95	9.919	(13.95)	(0.367)	-2.74%
7,500	756.08	10.081	734.93	9.799	(21.15)	(0.399)	-2.80%
10,000	1,002.25	10.023	973.90	9.739	(28.35)	(0.342)	-2.83%
11,000	1,100.72	10.007	1,069.49	9.723	(31.23)	(0.300)	-2.84%
12,000	1,199.19	9.993	1,165.08	9.709	(34.11)	(0.298)	-2.84%
13,000	1,297.66	9.982	1,260.67	9.697	(36.99)	(0.296)	-2.85%
14,000	1,396.13	9.972	1,356.26	9.688	(39.87)	(0.294)	-2.86%
15,000	1,494.60	9.964	1,451.85	9.679	(42.75)	(0.293)	-2.86%
17,250	1,716.16	9.949	1,666.93	9.663	(49.23)	(0.301)	-2.87%
20,000	1,986.95	9.935	1,929.80	9.649	(57.15)	(0.300)	-2.88%

[1] Amounts shown reflect single phase, inside the City service.
[2] Projected Fuel Cost Recovery Factor for Fiscal Year 2021.

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Comparison of Existing and Proposed Rates for General Service Demand [1]

			General Service Demand	
			Existing	Proposed
Customer Charge		($)	$18.28	$19.00
Demand Charge		($/kW)	$5.05	$5.82
Energy Charge	All kWh	($/kWh)	$0.04216	$0.04216
Fuel Cost Recovery [2]		($/kWh)	$0.02479	$0.02479

			Existing		Proposed		Difference		
Demand	Hours	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
50	200	10,000	940.28	9.403	979.50	9.795	39.22	0.392	4.17%
	300	15,000	1,275.03	8.500	1,314.25	8.762	39.22	0.261	3.08%
	400	20,000	1,609.78	8.049	1,649.00	8.245	39.22	0.196	2.44%
	500	25,000	1,944.53	7.778	1,983.75	7.935	39.22	0.157	2.02%
	600	30,000	2,279.28	7.598	2,318.50	7.728	39.22	0.131	1.72%
100	200	20,000	1,862.28	9.311	1,940.00	9.700	77.72	0.389	4.17%
	300	30,000	2,531.78	8.439	2,609.50	8.698	77.72	0.259	3.07%
	400	40,000	3,201.28	8.003	3,279.00	8.198	77.72	0.194	2.43%
	500	50,000	3,870.78	7.742	3,948.50	7.897	77.72	0.155	2.01%
	600	60,000	4,540.28	7.567	4,618.00	7.697	77.72	0.130	1.71%
500	200	100,000	9,238.28	9.238	9,624.00	9.624	385.72	0.386	4.18%
	300	150,000	12,585.78	8.391	12,971.50	8.648	385.72	0.257	3.06%
	400	200,000	15,933.28	7.967	16,319.00	8.160	385.72	0.193	2.42%
	500	250,000	19,280.78	7.712	19,666.50	7.867	385.72	0.154	2.00%
	600	300,000	22,628.28	7.543	23,014.00	7.671	385.72	0.129	1.70%

[1] Amounts shown reflect inside the City service, and exclude any applicable primary service discount or power factor correction.
[2] Projected Fuel Cost Recovery Factor for Fiscal Year 2021.

CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study

Inter-Utility Comparison of Typical Monthly Electric Bills [1]

Ln. No.	Utility	Fuel Adj. $/1000 kWh	Residential Class 250 kWh	500 kWh	750 kWh	1,000 kWh	1,200 kWh	2,000 kWh	2,500 kWh	3,000 kWh
1	City of Winter Park **(Existing)**	17.08	37.81	58.64	79.47	100.30	123.40	215.78	273.52	331.26
2	City of Winter Park **(Proposed)**	20.84	39.06	60.13	81.19	102.25	125.53	218.66	276.87	335.07
	Other Florida Municipalities:									
3	City of Alachua	0.00	32.49	55.84	79.19	102.54	123.26	206.14	257.94	309.74
4	City of Bushnell	10.00	35.16	60.33	85.49	110.65	130.78	211.30	261.63	311.95
5	Fort Pierce Utilities Authority	(13.00)	29.82	53.62	77.43	103.84	124.96	209.48	262.30	315.12
6	Gainesville Regional Utilities	30.00	41.13	67.25	93.38	123.13	148.87	251.83	316.18	380.53
7	Jacksonville Electric Authority	32.50	31.25	57.00	82.75	108.50	129.10	211.50	263.00	317.00
8	Kissimmee Utilities Authority	(51.19)	28.15	46.13	64.10	82.08	98.99	166.64	208.92	251.20
9	City of Lakeland	20.00	29.44	47.88	66.32	84.77	100.96	168.78	212.32	255.85
10	City of Leesburg	0.00	34.88	57.57	80.25	102.94	125.45	215.48	271.76	328.03
11	City of New Smyrna Beach	0.00	24.76	43.88	62.99	82.10	97.39	158.55	196.78	235.00
12	City of Newberry	5.00	35.00	61.50	88.00	114.50	142.00	226.00	278.50	331.00
13	City of Ocala	0.00	36.88	58.76	80.63	102.51	120.01	190.02	233.78	277.53
14	Orlando Utilities Commission	32.02	36.75	61.00	85.25	109.50	132.90	226.50	285.00	343.50
15	City of Tallahassee	29.39	33.59	59.26	84.92	110.59	131.12	213.26	264.60	315.93
	Florida Cooperatives									
16	Sumter Electric Cooperative	(20.70)	53.48	75.95	98.43	120.90	142.88	230.80	285.75	340.70
17	Central Florida Cooperative	(5.50)	52.58	75.70	98.83	121.95	140.45	214.45	260.70	306.95
18	Clay Electric Cooperative	17.40	45.48	67.95	90.43	112.90	134.64	221.60	275.95	330.30
	Investor-Owned Utilities: [2]									
19	Florida Power and Light	18.84	29.76	51.18	72.60	94.02	104.60	146.94	173.40	199.86
20	Gulf Power Company	32.62	48.63	78.06	107.49	136.92	160.46	254.64	313.50	372.36
21	Duke Energy	30.67	39.56	68.54	97.52	126.50	155.05	269.23	340.60	411.96
22	Tampa Electric Company	4.45	30.50	45.95	61.40	76.85	91.53	150.25	186.95	223.65

[1] Amounts shown are based on the rates for single phase service and reflect when applicable, inside city service. In addition, amounts include June 2020 fuel adjustments but do not include taxes or franchise fees.

[2] Amounts shown include the energy conservation, capacity, environmental and storm cost recovery charges where appropriate, as filed with the the Florida Public Service Commission (FPSC). Franchise fees are not included but range up to 6 percent for each of the IOU's listed.

Inter-Utility Comparison of Typical Monthly Electric Bills [1]

Ln. No.	Utility	Fuel Adj. $/1000 kWh	General Service Non-Demand Class 250 kWh	500 kWh	750 kWh	1,000 kWh	1,500 kWh	2,000 kWh	2,500 kWh	3,000 kWh
1	City of Winter Park **(Existing)**	21.03	41.23	64.91	88.58	112.26	159.62	206.97	254.33	301.68
2	City of Winter Park **(Proposed)**	24.79	41.90	65.80	89.69	113.59	161.39	209.18	256.98	304.77
	Other Florida Municipalities:									
3	City of Alachua	0.00	36.31	60.93	85.56	110.18	159.43	208.68	257.93	307.18
4	City of Bushnell	10.00	38.47	66.93	95.40	123.86	180.79	237.72	294.65	351.58
5	Fort Pierce Utilities Authority	(13.00)	32.36	58.87	85.39	111.90	164.93	217.96	270.99	324.02
6	Gainesville Regional Utilities	30.00	63.10	95.20	127.30	159.40	223.60	304.05	384.50	464.95
7	Jacksonville Electric Authority	32.50	33.65	58.05	82.44	106.84	155.64	204.43	253.23	302.02
8	Kissimmee	(54.97)	30.91	50.74	70.57	90.40	130.06	169.71	209.37	249.03
9	City of Lakeland	20.00	31.23	49.46	67.69	85.93	122.39	158.85	195.32	231.78
10	City of New Smyrna Beach	0.00	24.68	43.30	61.93	80.55	117.80	155.05	192.30	229.55
11	City of Ocala	0.00	39.21	61.42	83.63	105.84	150.26	194.68	239.10	283.52
12	Orlando Utilities Commission	19.52	37.17	59.59	82.01	104.43	149.27	194.11	238.95	283.79
13	City of Tallahassee	29.39	32.61	54.45	76.29	98.13	141.81	185.49	229.17	272.85
	Florida Cooperatives									
14	Sumter Electric Cooperative	(20.70)	56.80	80.42	104.05	127.67	174.92	222.17	269.42	316.67
15	Clay Electric Cooperative	17.40	47.68	72.35	97.03	121.70	171.05	220.40	269.75	319.10
	Investor-Owned Utilities: [2]									
16	Florida Power and Light	(0.39)	26.84	43.06	59.28	75.50	107.94	140.38	172.82	205.26
17	Gulf Power Company	32.62	55.59	85.93	116.27	146.61	207.29	267.97	328.65	389.33
18	Duke Energy	7.33	38.05	62.10	86.15	110.20	158.30	206.40	254.50	302.60
19	Tampa Electric Company	30.16	40.58	63.10	85.61	108.13	153.17	198.20	243.24	288.27

[1] Amounts shown are based on the rates for single phase service and reflect when applicable, inside city service. In addition, amounts include June 2020 fuel adjustments but do not include taxes or franchise fees.

[2] Amounts shown include the energy conservation, capacity, environmental and storm cost recovery charges where appropriate, as filed with the the Florida Public Service Commission (FPSC). Franchise fees are not included but range up to 6 percent for each of the IOU's listed.

CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study

Inter-Utility Comparison of Typical Monthly Electric Bills [1]

Ln. No.	Utility	General Service Demand Class: 50 kW 10,000 kWh	50 kW 20,000 kWh	50 kW 30,000 kWh	75 kW 15,000 kWh	75 kW 30,000 kWh	75 kW 45,000 kWh	150 kW 30,000 kWh	150 kW 60,000 kWh	150 kW 90,000 kWh
1	City of Winter Park **(Existing)**	903	1,535	2,166	1,345	2,293	3,241	2,671	4,567	6,463
2	City of Winter Park **(Proposed)**	980	1,649	2,319	1,460	2,464	3,468	2,901	4,909	6,918
	Other Florida Municipalities:									
3	Fort Pierce Utilities Authority	1,122	1,867	2,612	1,664	2,781	3,898	3,289	5,522	7,756
4	Gainesville Regional Utilities	1,561	2,514	3,467	2,291	3,720	5,150	4,482	7,341	10,200
5	Jacksonville Electric Authority	1,172	1,838	2,505	1,715	2,715	3,715	3,345	5,345	7,345
6	Kissimmee	1,003	1,505	2,008	1,476	2,230	2,984	2,897	4,405	5,912
7	City of Lakeland	883	1,304	1,726	1,303	1,935	2,568	2,564	3,828	5,093
8	City of New Smyrna Beach	1,021	1,671	2,321	1,515	2,490	3,465	2,996	4,946	6,896
9	City of Ocala	971	1,553	2,134	1,434	2,306	3,178	2,892	4,603	6,313
10	Orlando Utilities Commission	1,114	1,690	2,265	1,652	2,515	3,379	3,265	4,993	6,720
11	City of Tallahassee	1,288	1,816	2,244	1,895	2,687	3,329	3,716	5,300	6,583
	Florida Cooperatives									
12	Sumter Electric Cooperative	1,078	1,776	2,474	1,576	2,623	3,670	3,069	5,163	7,257
	Investor-Owned Utilities: [2]									
13	Florida Power and Light	1,044	1,502	1,960	1,553	2,240	2,926	3,080	4,453	5,826
14	Gulf Power Company	1,181	1,963	2,745	1,748	2,921	4,093	3,450	5,795	8,140
15	Duke Energy	1,236	1,911	2,586	1,847	2,859	3,872	3,679	5,705	7,730
16	Tampa Electric Company	925	1,228	1,531	1,372	1,826	2,281	2,714	3,623	4,532

[1] Amounts shown are based on the rates for single phase service and reflect when applicable, inside city service. In addition, amounts include June 2020 fuel adjustments but do not include taxes or franchise fees.
[2] Amounts shown include the energy conservation, capacity, environmental and storm cost recovery charges where appropriate, as filed with the the Florida Public Service Commission (FPSC). Franchise fees are not included but range up to 6 percent for each of the IOU's listed.

CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study

Inter-Utility Comparison of Typical Monthly Electric Bills [1]

		General Service Demand Class								
		200 kW			300 kW			400 kW		
Ln. No.	Utility	40,000 kWh	80,000 kWh	120,000 kWh	60,000 kWh	120,000 kWh	180,000 kWh	80,000 kWh	160,000 kWh	240,000 kWh
1	City of Winter Park **(Existing)**	3,556	6,083	8,611	5,325	9,116	12,907	7,093	12,149	17,204
2	City of Winter Park **(Proposed)**	3,861	6,539	9,217	5,782	9,799	13,816	7,703	13,059	18,415
	Other Florida Municipalities:									
3	Fort Pierce Utilities Authority	4,372	7,350	10,329	6,538	11,006	15,473	8,704	14,661	20,618
4	Gainesville Regional Utilities	5,942	9,754	13,566	8,863	14,581	20,299	11,784	19,408	27,032
5	Jacksonville Electric Authority	4,432	7,099	9,765	6,605	10,605	14,606	8,779	14,112	19,446
6	Kissimmee	3,844	5,854	7,865	5,738	8,754	11,769	7,632	11,653	15,674
7	City of Lakeland	3,404	5,091	6,777	5,085	7,615	10,144	6,767	10,139	13,512
8	City of New Smyrna Beach	3,984	6,584	9,184	5,584	9,184	12,784	7,434	12,234	17,034
9	City of Ocala	3,841	6,122	8,402	5,740	9,160	12,581	7,455	12,106	16,756
10	Orlando Utilities Commission	4,341	6,644	8,948	6,493	9,948	13,402	8,644	13,251	17,857
11	City of Tallahassee	4,930	7,042	8,753	7,358	10,526	13,092	9,786	14,010	17,431
	Florida Cooperatives									
12	Sumter Electric Cooperative	4,065	6,857	9,649	6,056	10,244	14,432	8,047	13,631	19,215
	Investor-Owned Utilities: [2]									
13	Florida Power and Light	4,097	5,928	7,759	6,133	8,879	11,625	8,168	11,830	15,491
14	Gulf Power Company	4,584	7,711	10,837	6,852	11,542	16,233	9,121	15,374	21,628
15	Duke Energy	4,901	7,602	10,302	7,344	11,395	15,447	9,788	15,189	20,591
16	Tampa Electric Company	3,608	4,820	6,032	5,397	7,215	9,033	7,186	9,610	12,034

[1] Amounts shown are based on the rates for single phase service and reflect when applicable, inside city service. In addition, amounts include June 2020 fuel adjustments but do not include taxes or franchise fees.

[2] Amounts shown include the energy conservation, capacity, environmental and storm cost recovery charges where appropriate, as filed with the the Florida Public Service Commission (FPSC). Franchise fees are not included but range up to 6 percent for each of the IOU's listed.

CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study

Inter-Utility Comparison of Typical Monthly Electric Bills [1]

General Service Large Demand Class

Ln. No.	Utility	500 kW 100,000 kWh	500 kW 200,000 kWh	500 kW 300,000 kWh	1,000 kW 200,000 kWh	1,000 kW 400,000 kWh	1,000 kW 600,000 kWh	1,500 kW 300,000 kWh	1,500 kW 600,000 kWh	1,500 kW 900,000 kWh
1	City of Winter Park **(Existing)**	8,841	15,139	21,437	17,664	30,260	42,856	26,487	45,381	64,275
2	City of Winter Park **(Proposed)**	9,624	16,319	23,014	19,229	32,619	46,009	28,834	48,919	69,004
	Other Florida Municipalities:									
3	Fort Pierce Utilities Authority	10,870	18,316	25,762	26,475	39,781	53,087	39,693	59,652	79,611
4	Gainesville Regional Utilities	14,705	24,235	33,765	29,310	48,370	67,430	43,130	70,460	97,790
5	Jacksonville Electric Authority	10,952	17,619	24,286	21,819	35,153	48,487	35,879	53,183	70,487
6	Kissimmee	10,327	14,517	18,707	20,597	28,977	37,357	30,867	43,437	56,007
7	City of Lakeland	9,144	12,937	16,731	17,812	25,400	32,987	26,481	37,862	49,243
8	City of New Smyrna Beach	9,284	15,284	21,284	18,534	30,534	42,534	27,784	45,784	63,784
9	City of Ocala	9,931	15,537	21,143	19,817	31,029	42,241	29,703	46,521	63,339
10	Orlando Utilities Commission	10,796	16,554	22,312	21,554	33,070	44,586	32,312	49,586	66,860
11	City of Tallahassee	12,153	17,372	21,618	24,232	34,670	43,161	36,311	51,968	64,705
	Florida Cooperatives									
12	Sumter Electric Cooperative	10,038	17,018	23,998	19,993	33,953	47,913	29,948	50,888	71,828
	Investor-Owned Utilities: [2]									
13	Florida Power and Light	10,972	15,080	19,188	21,865	30,081	38,297	32,758	45,082	57,406
14	Gulf Power Company	13,718	19,573	25,428	27,173	38,883	50,593	40,628	58,193	75,758
15	Duke Energy	12,198	18,917	25,636	24,382	37,820	51,258	36,566	56,723	76,880
16	Tampa Electric Company	8,975	12,005	15,035	17,920	23,980	30,040	26,865	35,955	45,045

[1] Amounts shown are based on the rates for single phase service and reflect when applicable, inside city service. In addition, amounts include June 2020 fuel adjustments but do not include taxes or franchise fees.
[2] Amounts shown include the energy conservation, capacity, environmental and storm cost recovery charges where appropriate, as filed with the the Florida Public Service Commission (FPSC). Franchise fees are not included but range up to 6 percent for each of the IOU's listed.

GLOSSARY [1]

Administrative and general expenses: Expenses of an electric utility relating to the overall directions of its corporate offices and administrative affairs, as contrasted with expenses incurred for specialized functions. Examples include office salaries, office supplies, advertising, and other general expenses.

AMI: Advanced Metering Infrastructure is a term denoting electricity meters that measure and record usage data at a minimum, in hourly intervals, and provide usage data to both consumers and energy companies at least once daily.

Base rate: A fixed kilowatthour charge for electricity consumed that is independent of other charges and/or adjustments.

Bulk power transactions: The wholesale sale, purchase, and interchange of electricity among electric utilities. Bulk power transactions are used by electric utilities for many different aspects of electric utility operations, from maintaining load to reducing costs.

Capacity (purchased): The amount of energy and capacity available for purchase from outside the system.

Capacity charge: An element in a two-part pricing method used in capacity transactions (energy charge is the other element). The capacity charge, sometimes called Demand Charge, is assessed on the amount of capacity being purchased.

Capacity factor: The ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period.

Capital cost: The cost of field development and plant construction and the equipment required for industry operations.

Class rate schedule: An electric rate schedule applicable to one or more specified classes of service, groups of businesses, or customer uses.

Classes of service: Customers grouped by similar characteristics in order to be identified for the purpose of setting a common rate for electric service. Usually classified into groups identified as residential, commercial, industrial, and other.

Coincidental demand: The sum of two or more demands that occur in the same time interval.

Coincidental peak load: The sum of two or more peak loads that occur in the same time interval.

Consumer charge: An amount charged periodically to a consumer for such utility costs as billing and meter reading, without regard to demand or energy consumption.

Cost of service: A ratemaking concept used for the design and development of rate schedules to ensure that the filed rate schedules recover only the cost of providing the electric service at issue. This concept attempts to correlate the utility's costs and revenue with the service provided to each of the various customer classes.

Demand charge: That portion of the consumer's bill for electric service based on the consumer's maximum electric capacity usage and calculated based on the billing demand charges under the applicable rate schedule.

Distribution system: The portion of the transmission and facilities of an electric system that is dedicated to delivering electric energy to an end-user.

Electric rate: The price set for a specified amount and type of electricity by class of service in an electric rate schedule or sales contract.

Electric rate schedule: A statement of the electric rate and the terms and conditions governing its application, including attendant contract terms and conditions that have been accepted by a regulatory body with appropriate oversight authority.

Electricity sales: The amount of kilowatthours sold in a given period of time; usually grouped by classes of service, such as residential, commercial, industrial, and other. "Other" sales include sales for public street and highway lighting and other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Energy charge: That portion of the charge for electric service based upon the electric energy (kWh) consumed or billed.

Federal Energy Regulatory Commission (FERC): The Federal agency with jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification. FERC is an independent regulatory agency within the Department of Energy and is the successor to the Federal Power Commission.

FERC guidelines: A compilation of the Federal Energy Regulatory Commission's enabling statutes; procedural and program regulations; and orders, opinions, and decisions.

Fixed cost (expense): An expenditure or expense that does not vary with volume level of activity.

Fixed operating costs: Costs other than those associated with capital investment that do not vary with the operation, such as maintenance and payroll.

Investor-owned utility (IOU): A privately-owned electric utility whose stock is publicly traded. It is rate regulated and authorized to achieve an allowed rate of return.

Kilowatt (kW): One thousand watts.

Kilowatthour (kWh): A measure of electricity defined as a unit of work or energy, measured as 1 kilowatt (1,000watts) of power expended for 1 hour. One kWh is equivalent to 3,412 Btu.

Load diversity: The difference between the peak of coincident and noncoincident demands of two or more individual loads.

Load factor: The ratio of the average load to peak load during a specified time interval.

Megawatt (MW): One million watts of electricity.

Megawatthour (MWh): One thousand kilowatt-hours or 1million watt-hours.

Noncoincident demand: Sum of two or more demands on individual systems that do not occur in the same demand interval.

Noncoincidental peak load: The sum of two or more peak loads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, week, month, a heating or cooling season, and usually for not more than 1 year.

O&M: Operation and Maintenance.

Peak demand: The maximum load during a specified period of time.

Purchased power: Power purchased or available for purchase from a source outside the system.

Rate schedule (electric): The rates, charges, and provisions under which service is supplied to the designated class of customers.

Ratemaking authority: A utility commission's legal authority to fix, modify, approve, or disapprove rates as determined by the powers given the commission by a State or Federal legislature.

Rates: The authorized charges per unit or level of consumption for a specified time period for any of the classes of utility services provided to a customer.

Time-of-day rate: The rate charged by an electric utility for service to various classes of customers. The rate reflects the different costs of providing the service at different times of the day.

Watt (W): The unit of electrical power equal to one ampere under a pressure of one volt. A Watt is equal to 1/746 horse power.

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[1] From U. S. Energy Information Administration Glossary https://www.eia.gov/tools/glossary/index.php?id=xyz.

Questions Submitted and Answers in Red Font

1. It would be helpful to include a glossary of major terms along with definitions. Always critical for folks to start discussions with the same understanding of terms.
   1. See attached Glossary.
2. Please provide the formulas and various numbers used in Table 5-2 of the study.
   2. See attached Table 5-2-2.
3. You recommend a shift to higher customer charges and compensating lower energy charges. Please explain the business risk that you are attempting to mitigate with this recommendation. And provide how this risk applies to our utility in numerical terms. The utility is in a very strong position as verified by our bond rating agencies and financial results.
   3. As with most utilities, most of the costs of providing electric service are fixed, while the revenues are mostly recovered through a variable energy (kWh) charge. To mitigate this risk, many utilities are increasing the fixed customer charges and demand charges, while lowering the energy charges. This helps to recover more of the fixed costs if the energy usage declines. For Winter Park, the fixed costs are estimated to be between 62% and 69% of the total costs.
4. Please revisit the capital expenditures included in Fixed Costs. I agree that the depreciation expense should not be used in determining fixed costs for our utility. Our depreciation expense is high due to abnormal capital expenditures caused by the underground program. Plus, the depreciation of the purchased assets from Progress Energy. I do not believe that the undergrounding cap-ex should be included as this is not a required investment to operate the utility. This position is supported by the annual decision by the Commission to spend these dollars along with the City telling our bond rating agencies that this expense is optional. It is one reason we get a high rating. Based on past utility budgets and actual expenditures the annual cap-ex has been $1mm. This year's budget increased the amount to $2 million. So it would seem that the correct amount is somewhere between the two. I would expect that the City has created an equipment schedule with expected replacement dates and amounts to support the maintenance cap-ex. A summary inclusion of this schedule would be helpful.
   4. See attached Table 3-6 showing the detail of the capital plan. Although the undergrounding expenses may be optional, they are included in the revenue requirements from rates. Otherwise what would be the funding source?
5. Provide an explanation of why our customer base is "unique" from other municipal utilities.
   5. The customer base in Winter Park is somewhat unique because:
   a. The residential base includes a significant number of above average energy users, and the average use per customer is higher than for other utilities in the area.
   b. The small commercial users such as those on Park Avenue are distinctive and may have different operating hours than typical small commercial users.
   c. The large commercial customers include unique customers such as Rollins College and the hospital.
6. Who determined that rates should be set based upon customer class and not perhaps a type of service? For example, a hospital willing to pay a higher rate to establish higher reliability, or a customer that wishes a rate based upon renewable sources in excess of xx%, or someone that just wants a fixed amount, etc. How was this decision made? It seems to me all we are doing

is repeating the past with some tweaks without examination of other perhaps more progressive rate structures.

7. A Cost of Service Study seeks to correlate the costs and revenues for each customer class (see Glossary). Additional classes in the future may include a Residential Time of Use Rate, a Solar Subscription Rate or an Electric Vehicle Rate. I have not seen rates based on reliability, but the utility can work with a customer to install additional distribution facilities to be paid with a Contribution in Aid of Construction (CIAC). If the City is interested in strategic planning, I can arrange for one of my colleagues to discuss that with you. He is currently working with OUC about their strategic planning. Attached is a brochure about our services in that area.
8. Are customers charged for cost only on fuel and purchased energy costs?
Only the fuel costs portion of bulk power purchases are a pass through to the customer. The remaining bulk power costs are included in the base rates.
9. Is the City required by law/regulation to submit this report? If so, on what statute is this requirement based? What will the PSC do with the Study?
The PSC has oversight over the City's rate structure (not total rate revenue). The City submits its rate tariff sheets to the PSC for review whenever it makes changes. The PSC will review the rates to ensure they do not unduly burden any rate class to be benefit of another.
10. What other utilities in Florida are distribution only utilities? How do their rates compare to the City of Winter Park? Given that the cost structure of distribution only utilities is very different from those that produce electricity, why include them in the comparison panel in Table 7-2?
The Florida Municipal Electric Association prepares rate comparison schedules each month. The most recent comparison is for August 2020 and can be found at https://assets.noviams.com/novi-file-uploads/fmea/Rates/2020/2020_august_rates.pdf. On the fourth page of the report you will note a narrow column to the right of the utility name. Some utilities have a G in that column. Those utilities generate power. The others are all distribution only utilities. These schedules provide comparisons of both residential and commercial customers of varying usage levels. While generating utilities have different costs burdens, the distribution only utilities that purchase their power are helping them recover those costs at wholesale rates. It is useful to include the generating utilities in the rate comparisons to make sure the City's rates are competitive.
11. Table 3-3, page 31. Gross Receipts tax is listed but these two taxes are not listed: Electric Utility Tax and State Sales Tax. Why are they not included? (Both appear on residential bills but I'm not sure about other customers' bills.) Re: Gross Receipts Tax and State Sales Tax: Because the City is acting as a tax collector and the amounts collected are simply passed thru to the State, why show them as revenues? What portion of the Electric Utility Tax is paid to Orange County? the City?
The gross receipts tax is levied on the revenues of the seller of electricity. Payment of the gross receipts tax to the State is an operating expense and the billing to Winter Park customers is an operating revenue. The State sales tax and utility taxes are taxes on the customer purchasing the goods. They are not expenses of the electric utility. It can definitely be confusing but, the distinction is who is being taxed, the utility or the customer. Electric utility taxes go to Orange County for the fourteen electric customers in unincorporated Orange County. The rest of the Winter Park electric customers are all inside the City limits. All utility taxes billed to those customers goes to the City's General Fund.

12. There is no identified business risk in having mismatched variable revenue vs fixed costs. And no discussion of consequences if the Customer Charge is no increased. Need to understand the business risk if we do not raise the Customer Charge? Water & sewer utility operates under these same dynamics and no industry or municipal push to change is underway.
    The business risk for the City when the revenue is based mostly on a variable charge is that the City may not recover its necessary revenues. Since most of the City's costs are fixed, variations in weather (heating and cooling degree days), conservation, energy efficiencies and customer usage may have an adverse effect on the City recovering its fixed costs.
13. Would you please reconcile the financials shown on Table 3-1 to the FY2021 Budget presented to the Commission by line item? The two are difficult to reconcile since they have different styles of presentation.
    See attached reconciliation that puts Table 3-1 in the same format as the budget. The bottom line is only different by $143,583 after considering the one-time cost of constructing a solar awning to shelter equipment that was not included in the Cost of Service Study projections.
14. Please explain the changes in costs in the Test Year and FY 2021 Projections:
    i. Decrease in Bulk Power - $1M FY 2020 to Test Year
    Reflects the lower costs of fuel being experienced in the earlier months of FY 2020. You will not the offsetting addition to fuel cost stabilization fund on line 26.
    ii. Decrease in Warehousing costs – Test Year to FY 2021
    One less inventory specialist position
    iii. Increase in Utility Billing costs – Test Year to FY 2021
    Utility billing is one of the last applications from the legacy ERP computer system being used. As such, more of the annual support costs are allocated to Utility Billing.
    iv. Increase in Meter Servicing – Test Year to FY 2021
    Additional meters being purchased to replace aging meters.
    v. How was the Contingency amount determined? (This is not found in the budgets presented to the Commission)
    Contingency was simply the difference between projected revenues and appropriation
    vi. Changes in Replenish Cash Reserves – this is a balance sheet item and not an expense
    Both lines 20 and 21 are essentially saying we are not going to spend these projected revenues and instead use them to build the cash balance of the Electric Fund. Line 21 could go to zero for 2023 and 2024 in Table 3-1 since the negative totals on line 29 are greater than the amounts on line 21.
    vii. What causes the Fuel Cost Recovery to drop in the Test Year, then rise in FY2021?
    In the Test Year FY2020, funds were transferred from the Rate Stabilization Fund to lower the Fuel Cost Recovery during the pandemic. The amount in FY2021 was based on the City's projection of costs based on its wholesale contracts.
    viii. Please address the concern that the underlying assumptions for the Test Year on which rates are being analyzed vary significantly from the years on which the new rates are being applied.
    The assumptions do not vary significantly and the revenue requirements are stable, ranging from $44.9 million to $45.9 million over the years.

15. Why was kWh projected at 407 million in FY2021?
    i. The average kWh for the past six years is 425 million, the low point was 414 million
    The decrease was to prepare for the unknown impact of Covid-19 on kWh sales
    ii. How is the 407M kWh allocated amongst the various classes?

Residential	186,002,778
Commercial	197,197,980

Public Authority	21,691,486
Street Lighting	2,123,948

iii. What would be the impact on rates using 420 million for FY 2021 in the Study? Which is the amount used in the Test Year? 420 million kWh is the sales assumption for the Test Year. The thought was that better represented a normal year of sales.

16. Table 4-1: Please provide the detailed cost components for each of the categories
    See Table 4-1 Detail
17. Table 5-1:
    a. Please provide the reasoning for using the various allocation methodologies:
    Allocation methodologies are based on industry practices and guidelines from the Florida Public Service Commission
        i. Production – Demand: PSC 12 CP Methodology Table 4-2
        The City's production related demand costs are based on the monthly demand charges shown on its purchased power bills. The demand charges are based on the City's system peak demand for that month. The contribution of each class to the monthly system peak is the basis for allocating the purchased demand cost. Over a 12 month period, the class load coincident with the time of the system peak each month allocates those costs (12 CP method).
        ii. Production – Energy: Average Demand (kWh)
        The City's production related energy costs are based on the monthly energy charges shown on its purchased power bills. Those costs are allocated based on the energy used by each class for that month.
        iii. Distribution – Demand: NCP Demand Table 4-2
        The distribution facilities must be able to serve a class of customers at the time of the non-coincident annual peak demand. Distribution demand related costs are allocated based on the non-coincident annual peak demand for that class.

    b. Rate Unit Cost Per kWh
        i. Why does the Utility sell kWh to commercial customers below the average cost?
        Because of the allocation of demand related costs, some classes may have costs below the average system costs and some may be higher than average system costs. It depends on the ratio of demand and energy usage.

        Consider the following example:

        Fixed cost = $50 per month; Variable cost = $0.05 per kWh

        Customer 1 uses 500 kWh per month; cost = $50 + 500 x $0.05 = $75 = $0.15 per kWh

        Customer 2 uses 1000 kWh per month; cost = $50 + 1000 x $0.05 = $100 = $0.10 per kWh

Observations by UAB Members

Fixed Charge increase to $79

Observations:

Adverse Impacts

Increasing the fixed charge will adversely impact several groups of customers such as low usage customers and low income customers. Increasing the fixed charge will reduce customers' control over their electric bills and will discourage investment in energy efficiency improvements and rooftop solar.

Public Reaction

In 2017, when Gulf Power proposed to increase its customer charge to $48, it spurred a strong backlash from ratepayers who sent 1,000 comments to the PSC. Gulf Power later withdrew its proposal as part of a negotiation with the Office of Public Counsel.

Rate Design

Cost of service studies are most useful when determining *how much* revenue to collect from different customers, rather than *how* to collect such revenue.

"I "I know of no ratemaking or economic principle that finds that cost structure must be replicated in rate design, especially when significant negative policy impacts are attendant to that approach."

Karl Rabago, former Texas Public Utility Commissioner

Source: Fixed Charges & Utility Customers, Prepared for Consumers Union by Synapse Energy Economics

https://www.synapse-energy.com/sites/default/files/Fixed_Charges_Factsheet.pdf

City Image

The City of Winter Park was recently designated a Solsmart Gold city by the US Department of Energy for streamlining its permitting and inspection processes for solar arrays on customers' properties. By raising the fixed charge, the City will be sending a message that the City of Winter Park is not a "solar friendly" municipality after all.

EV Rates

Observation: Vehicle to grid technology is on the horizon. For utilities, this new source of energy could be used to manage system load and improve system resilience. For customers, compensation for discharging electricity could reduce the cost of vehicle ownership.

Test Year is now History

Now that the FY ending Sept 30 has concluded, the projected data for that time period should be replaced with actual data.

Discussion Issues

a. Increasing Customer Charge (fixed portion)

   i. The recommendation is to increase the Customer Charge to capture more of the fixed charges in this fee. The Study mentions that this is a trend in the utility industry.

   ii. There is no identified business risk in having mismatched variable revenue vs fixed costs. And no discussion of consequences if the Customer Charge is no increased. Need to understand the business risk if we do not raise the Customer Charge? Water & sewer utility operates under these same dynamics and no industry or municipal push to change is underway.

   iii. There is a negative consequence for residential solar energy by raising the fixed Customer Charge and lowering the Energy Charge. This action makes residential solar energy less economical for our residents. FMPA has acknowledged this negative impact on residential solar. Given the Commission's recent desire to be more sustainable in our energy this recommendation needs to be thoroughly vetted.

b. Allocation of Costs

   i. The industry methods for allocating costs are based on investor owned utilities that own power plants. This is not our situation, we are a "distribution utility". The result of this allocation practice is that Residential Customers pay approximately 40-50% more than per kWh more than Commercial customers. We need to discuss the fairness of this major pricing discrepancy.

From: Shepard, Craig R. <CRAIG.R.SHEPARD@leidos.com>
Sent: Thursday, November 12, 2020 4:57 PM
To: Daniel D'Alessandro <ddalessandro@cityofwinterpark.org>; Wes Hamil <whamil@cityofwinterpark.org>
Subject: [External] FW: EXTERNAL: Re: Electric Cost of Service Study

[**Caution:** This email originated from outside the City of Winter Park email system. Before clicking any hyperlinks, verify the real address by hovering over the link. Do not open attachments from unknown or unverified sources.]

Dan and Wes,

The following addresses the comments below:

The Cost of Service (COS) Study has analyzed and proposed rates that are based on the City's costs, customer usage and public utility rate methods. The proposed rates are no longer based on Progress (Duke) costs, usage or methods.
It should be pointed out that the proposed residential rate in the draft COS Study (see Table 6-1) includes a modest increase in the customer charge and a corresponding modest decrease in energy charges. This was always the intent, also recognizing that a large increase in the customer charge would result in rate shock for small users. A gradual increase in customer charges is intended to help recover fixed costs over time.
The attached calculation templates provide interactive spreadsheets to see the effects of various levels of customer charges and energy charges. In all cases an increase in the customer charge results in a decrease in the energy charges to produce the exact same revenues (revenue neutral). Although it is revenue neutral for the class as a whole, it is mathematically impossible to be revenue neutral for each customer, depending on usage. There is a template that also considers a 4 block energy charge. Attached is a comparison of energy blocks in effect in Florida, and the most common is a 2 block energy charge with the break at 1,000 kWh. The calculation templates can be used by inputting values in the yellow highlighted area and seeing the effect on bills ranging from 500 to 5,000 kWh. The calculations are somewhat complicated, so use at your own risk and only change the yellow highlighted areas.
Attached is a summary of 8 different cases along with pros and cons of each case. Additional cases can be made if desired.
As far as other templates for COS evaluations, the Excel based COS models will be provided to the City so that updates can be made. Tables 3-1 and 5-1 in the Study show the details of what costs are included in the base rates and adjustments can be made.
Another point is that the City's costs include not only what it pays for purchased power, but also all distribution and customer related costs (operation and maintenance, debt service, capital improvements, administration and return to the City), so the City has to charge a higher rate to its customers than it pays for power.
It should be noted that if there is a proposed major rate structure change, we would contact the PSC to discuss prior to submitting proposed rates.

Craig

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Comparison of Residential Energy Blocks

Ln. No.	Utility	Residential Energy Blocks (kWh) First Block	Second Block	Third Block
1	City of Winter Park - **Existing**	0-1,000	>1,000	-
2	City of Winter Park - **Proposed**	0-1,000	>1,000	-
	Other Florida Municipalities:			
3	Fort Pierce Utilities Authority	0-750	>750	-
4	Gainesville Regional Utilities	0-850	>850	-
5	Jacksonville Electric Authority	0-1,000	>1,000	-
6	Kissimmee Utilities Authority	0-1,000	>1,000	-
7	City of Lakeland	0-1,000	1,001-1,500	>1,500
8	City of New Smyrna Beach	All	-	-
9	City of Ocala	All	-	-
10	Orlando Utilities Commission	0-1,000	>1,000	-
11	City of Tallahassee	All	-	-
	Florida Cooperatives			
12	Sumter Electric Cooperative	0-1,000	>1,000	-
13	Clay Electric Cooperative	0-1,000	>1,000	-
	Investor-Owned Utilities:			
14	Florida Power and Light	0-1,000	>1,000	-
15	Gulf Power Company	All	-	-
16	Duke Energy	0-1,000	>1,000	-
17	Tampa Electric Company	0-1,000	>1,000	-

CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study

Summary of Rate Design Cases Pros and Cons

RATE DESIGN CASE	PROS	CONS
Case 1 (COS Study Draft) $18 Customer Charge; existing energy block differential of $0.02216 per kWh	Helps recover fixed costs; closer to cost of service; consistent with industry trends; avoids rate shock	Greater percentage impact on low users
Case 2 $30 Customer Charge; existing energy block differential of $0.02216 per kWh	Helps recover fixed costs; closer to cost of service; consistent with industry trends	Greater percentage impact on low users; may discourage rooftop solar
Case 3 $50 Customer Charge; existing energy block differential of $0.02216 per kWh	Helps recover fixed costs; closer to cost of service	Greater percentage impact on low users; may discourage rooftop solar; may result in rate shock for some customers
Case 4 $30 Customer Charge; energy block differential of $0.04 per kWh	Helps recover fixed costs; closer to cost of service; consistent with industry trends	Greater percentage impact on low users; may discourage solar rooftop; large energy block rate differential may be concern for PSC
Case 5 $30 Customer Charge; 4 Block energy charge; energy block differential of $0.02 per kWh	Helps recover fixed costs; closer to cost of service; consistent with industry trends	Varying percentage impacts; multiple energy blocks not industry standard; rate structure change may be concern for PSC
Case 6 $50 Customer Charge; 4 Block energy charge; energy block differential of $0.02 per kWh	Helps recover fixed costs; closer to cost of service	Greater percentage impact on low users;; multiple energy blocks not industry standard; rate structure change may be concern for PSC; possible rate shock
Case 7 $30 Customer Charge; 4 Block energy charge; energy block differentials of $0.01 and $0.02 per kWh	Helps recover fixed costs; closer to cost of service	Greater percentage impact on low users;; multiple energy blocks not industry standard; rate structure change may be concern for PSC
Case 8 $50 Customer Charge; 4 Block energy charge; energy block differentials of $0.01 and $0.02 per kWh	Helps recover fixed costs; closer to cost of service	Greater percentage impact on low users;; multiple energy blocks not industry standard; rate structure change may be concern for PSC; possible rate shock

CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study

Projected Revenues at
PROPOSED RATES
Fiscal Year Ending September 30, 2021

Ln. No.	Customer Class Description	Proposed Rate	Billing Determinants	Base Rate Revenue	Fuel Cost Recovery	Total Revenue			
	(a)	(b)	(c)	(d)	(e)	(f)			
	Residential								
1	Customer Charge	$ 18.00	141,625	$ 2,549,253	$ -	$ 2,549,253	Input		
2	Energy Charge < 1,000 kWhs	$ 0.06341	110,148,723	6,984,531	-	6,984,531	Calculated		
3	Energy Charge > 1,000 kWhs	$ 0.08557	71,870,175	6,149,931	-	6,149,931	Calculated with existing differential of	$0.02216	per kWh
4	Fuel Cost Recovery Factor < 1,000 kWhs	$ 0.02084	110,148,723	-	2,295,499	2,295,499	Fixed		
5	Fuel Cost Recovery Factor > 1,000 kWhs	$ 0.03084	71,870,175	-	2,216,476	2,216,476	Fixed		
6	***Total Residential***			$ 15,683,714	$ 4,511,976	$ 20,195,690	**Fixed**		

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Comparison of Existing and Proposed Residential Service Rates [1]

			Residential Service Existing	Residential Service Proposed
Customer Charge		($)	$16.98	$18.00
Energy Charge	First 1,000 kWh	($/kWh)	$0.06624	$0.06341
Energy Charge	Additional kWh	($/kWh)	$0.08840	$0.08557
Fuel Cost [2]	First 1,000 kWh	($/kWh)	$0.02084	$0.02084
Fuel Cost [2]	Additional kWh	($/kWh)	$0.03084	$0.03084

	Existing		Proposed		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
500	60.52	12.104	60.13	12.025	(0.40)	(0.079)	-0.65%
600	69.23	11.538	68.55	11.425	(0.68)	(0.113)	-0.98%
700	77.94	11.134	76.98	10.996	(0.96)	(0.137)	-1.23%
800	86.64	10.831	85.40	10.675	(1.24)	(0.155)	-1.44%
900	95.35	10.595	93.83	10.425	(1.53)	(0.170)	-1.60%
1,000	104.06	10.406	102.25	10.225	(1.81)	(0.181)	-1.74%
1,100	115.98	10.544	113.89	10.354	(2.09)	(0.190)	-1.80%
1,200	127.91	10.659	125.53	10.461	(2.38)	(0.198)	-1.86%
1,300	139.83	10.756	137.17	10.552	(2.66)	(0.205)	-1.90%
1,400	151.76	10.840	148.81	10.630	(2.94)	(0.210)	-1.94%
1,500	163.68	10.912	160.46	10.697	(3.22)	(0.215)	-1.97%
2,000	223.30	11.165	218.66	10.933	(4.64)	(0.232)	-2.08%
2,500	282.92	11.317	276.87	11.075	(6.06)	(0.242)	-2.14%
3,000	342.54	11.418	335.07	11.169	(7.47)	(0.249)	-2.18%
4,000	461.78	11.545	451.48	11.287	(10.30)	(0.258)	-2.23%
5,000	581.02	11.620	567.89	11.358	(13.13)	(0.263)	-2.26%

[1] Amounts shown reflect single phase, inside the City service.
[2] Projected Fuel Cost Recovery Factor for Fiscal Year 2021.

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Projected Revenues at PROPOSED RATES Fiscal Year Ending September 30, 2021

Ln. No.	Customer Class Description	Proposed Rate	Billing Determinants	Base Rate Revenue	Fuel Cost Recovery	Total Revenue			
	(a)	(b)	(c)	(d)	(e)	(f)			
	Residential								
1	Customer Charge	$ 30.00	141,625	$ 4,248,755	$ -	$ 4,248,755	Input		
2	Energy Charge < 1,000 kWhs	$ 0.05407	110,148,723	5,956,077	-	5,956,077	Calculated		
3	Energy Charge > 1,000 kWhs	$ 0.07623	71,870,175	5,478,882	-	5,478,882	Calculated with existing differential of	$0.02216	per kWh
4	Fuel Cost Recovery Factor < 1,000 kWhs	$ 0.02084	110,148,723	-	2,295,499	2,295,499	Fixed		
5	Fuel Cost Recovery Factor > 1,000 kWhs	$ 0.03084	71,870,175	-	2,216,476	2,216,476	Fixed		
6	***Total Residential***			$ 15,683,714	$ 4,511,976	$ 20,195,690	**Fixed**		

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Comparison of Existing and Proposed Residential Service Rates [1]

			Residential Service Existing	Residential Service Proposed
Customer Charge		($)	$16.98	$30.00
Energy Charge	First 1,000 kWh	($/kWh)	$0.06624	$0.05407
Energy Charge	Additional kWh	($/kWh)	$0.08840	$0.07623
Fuel Cost [2]	First 1,000 kWh	($/kWh)	$0.02084	$0.02084
Fuel Cost [2]	Additional kWh	($/kWh)	$0.03084	$0.03084

	Existing		Proposed		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
500	60.52	12.104	67.46	13.491	6.94	1.387	11.46%
600	69.23	11.538	74.95	12.491	5.72	0.953	8.26%
700	77.94	11.134	82.44	11.777	4.50	0.643	5.78%
800	86.64	10.831	89.93	11.241	3.29	0.411	3.79%
900	95.35	10.595	97.42	10.825	2.07	0.230	2.17%
1,000	104.06	10.406	104.91	10.491	0.85	0.085	0.82%
1,100	115.98	10.544	115.62	10.511	(0.36)	(0.033)	-0.31%
1,200	127.91	10.659	126.33	10.527	(1.58)	(0.132)	-1.24%
1,300	139.83	10.756	137.03	10.541	(2.80)	(0.215)	-2.00%
1,400	151.76	10.840	147.74	10.553	(4.01)	(0.287)	-2.64%
1,500	163.68	10.912	158.45	10.563	(5.23)	(0.349)	-3.20%
2,000	223.30	11.165	211.99	10.599	(11.31)	(0.566)	-5.07%
2,500	282.92	11.317	265.52	10.621	(17.40)	(0.696)	-6.15%
3,000	342.54	11.418	319.06	10.635	(23.48)	(0.783)	-6.85%
4,000	461.78	11.545	426.13	10.653	(35.65)	(0.891)	-7.72%
5,000	581.02	11.620	533.21	10.664	(47.81)	(0.956)	-8.23%

[1] Amounts shown reflect single phase, inside the City service.
[2] Projected Fuel Cost Recovery Factor for Fiscal Year 2021.

CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study

Projected Revenues at
PROPOSED RATES
Fiscal Year Ending September 30, 2021

Ln. No.	Customer Class Description	Proposed Rate	Billing Determinants	Base Rate Revenue	Fuel Cost Recovery	Total Revenue		
	(a)	(b)	(c)	(d)	(e)	(f)		
	Residential							
1	Customer Charge	$ 50.00	141,625	$ 7,081,258	$ -	$ 7,081,258	Input	
2	Energy Charge < 1,000 kWhs	$ 0.03851	110,148,723	4,241,988	-	4,241,988	Calculated	
3	Energy Charge > 1,000 kWhs	$ 0.06067	71,870,175	4,360,468	-	4,360,468	Calculated with existing differential of	$0.02216 per kWh
4	Fuel Cost Recovery Factor < 1,000 kWhs	$ 0.02084	110,148,723	-	2,295,499	2,295,499	Fixed	
5	Fuel Cost Recovery Factor > 1,000 kWhs	$ 0.03084	71,870,175	-	2,216,476	2,216,476	Fixed	
6	***Total Residential***			$ 15,683,714	$ 4,511,976	$ 20,195,690	**Fixed**	

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Comparison of Existing and Proposed Residential Service Rates [1]

			Residential Service	
			Existing	Proposed
Customer Charge		($)	$16.98	$50.00
Energy Charge	First 1,000 kWh	($/kWh)	$0.06624	$0.03851
Energy Charge	Additional kWh	($/kWh)	$0.08840	$0.06067
Fuel Cost [2]	First 1,000 kWh	($/kWh)	$0.02084	$0.02084
Fuel Cost [2]	Additional kWh	($/kWh)	$0.03084	$0.03084

	Existing		Proposed		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
500	60.52	12.104	79.68	15.935	19.16	3.831	31.65%
600	69.23	11.538	85.61	14.268	16.38	2.730	23.67%
700	77.94	11.134	91.55	13.078	13.61	1.944	17.46%
800	86.64	10.831	97.48	12.185	10.84	1.355	12.51%
900	95.35	10.595	103.42	11.491	8.06	0.896	8.46%
1,000	104.06	10.406	109.35	10.935	5.29	0.529	5.09%
1,100	115.98	10.544	118.50	10.773	2.52	0.229	2.17%
1,200	127.91	10.659	127.65	10.638	(0.25)	(0.021)	-0.20%
1,300	139.83	10.756	136.80	10.523	(3.03)	(0.233)	-2.16%
1,400	151.76	10.840	145.96	10.425	(5.80)	(0.414)	-3.82%
1,500	163.68	10.912	155.11	10.340	(8.57)	(0.572)	-5.24%
2,000	223.30	11.165	200.86	10.043	(22.44)	(1.122)	-10.05%
2,500	282.92	11.317	246.62	9.865	(36.30)	(1.452)	-12.83%
3,000	342.54	11.418	292.37	9.746	(50.17)	(1.672)	-14.65%
4,000	461.78	11.545	383.89	9.597	(77.89)	(1.947)	-16.87%
5,000	581.02	11.620	475.40	9.508	(105.62)	(2.112)	-18.18%

[1] Amounts shown reflect single phase, inside the City service.
[2] Projected Fuel Cost Recovery Factor for Fiscal Year 2021.

CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study

Projected Revenues at PROPOSED RATES
Fiscal Year Ending September 30, 2021

Ln. No.	Customer Class Description	Proposed Rate	Billing Determinants	Base Rate Revenue	Fuel Cost Recovery	Total Revenue		
	(a)	(b)	(c)	(d)	(e)	(f)		
	Residential							
1	Customer Charge	$ 30.00	141,625	$ 4,248,755	$ -	$ 4,248,755	Input	
2	Energy Charge < 1,000 kWhs	$ 0.04703	110,148,723	5,180,176	-	5,180,176	Calculated	
3	Energy Charge > 1,000 kWhs	$ 0.08703	71,870,175	6,254,784	-	6,254,784	Calculated with existing differential of	$0.04000 per kWh
4	Fuel Cost Recovery Factor < 1,000 kWhs	$ 0.02084	110,148,723	-	2,295,499	2,295,499	Fixed	
5	Fuel Cost Recovery Factor > 1,000 kWhs	$ 0.03084	71,870,175	-	2,216,476	2,216,476	Fixed	
6	***Total Residential***			$ 15,683,714	$ 4,511,976	$ 20,195,690	**Fixed**	

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Comparison of Existing and Proposed Residential Service Rates [1]

			Residential Service	
			Existing	Proposed
Customer Charge		($)	$16.98	$30.00
Energy Charge	First 1,000 kWh	($/kWh)	$0.06624	$0.04703
Energy Charge	Additional kWh	($/kWh)	$0.08840	$0.08703
Fuel Cost [2]	First 1,000 kWh	($/kWh)	$0.02084	$0.02084
Fuel Cost [2]	Additional kWh	($/kWh)	$0.03084	$0.03084

	Existing		Proposed		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
500	60.52	12.104	63.93	12.787	3.41	0.683	5.64%
600	69.23	11.538	70.72	11.787	1.49	0.249	2.16%
700	77.94	11.134	77.51	11.073	(0.43)	(0.061)	-0.55%
800	86.64	10.831	84.30	10.537	(2.35)	(0.294)	-2.71%
900	95.35	10.595	91.08	10.120	(4.27)	(0.474)	-4.48%
1,000	104.06	10.406	97.87	9.787	(6.19)	(0.619)	-5.95%
1,100	115.98	10.544	109.66	9.969	(6.33)	(0.575)	-5.46%
1,200	127.91	10.659	121.44	10.120	(6.47)	(0.539)	-5.05%
1,300	139.83	10.756	133.23	10.248	(6.60)	(0.508)	-4.72%
1,400	151.76	10.840	145.02	10.358	(6.74)	(0.481)	-4.44%
1,500	163.68	10.912	156.80	10.454	(6.88)	(0.458)	-4.20%
2,000	223.30	11.165	215.74	10.787	(7.56)	(0.378)	-3.39%
2,500	282.92	11.317	274.67	10.987	(8.25)	(0.330)	-2.92%
3,000	342.54	11.418	333.61	11.120	(8.93)	(0.298)	-2.61%
4,000	461.78	11.545	451.48	11.287	(10.30)	(0.258)	-2.23%
5,000	581.02	11.620	569.34	11.387	(11.68)	(0.234)	-2.01%

[1] Amounts shown reflect single phase, inside the City service.
[2] Projected Fuel Cost Recovery Factor for Fiscal Year 2021.

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Projected Revenues at
PROPOSED RATES
Fiscal Year Ending September 30, 2021

Ln. No.	Customer Class Description	Proposed Rate	Billing Determinants	Base Rate Revenue	Fuel Cost Recovery	Total Revenue			
	(a)	(b)	(c)	(d)	(e)	(f)			
	Residential								
1	Customer Charge	$ 30.00	141,625	$ 4,248,755	$ -	$ 4,248,755	Input		
2	Energy Charge < 500 kWhs	$ 0.03723	64,560,163	2,403,578	-	2,403,578	Calculated		
3	Energy Charge 501-1,000 kWhs	$ 0.05723	45,588,560	2,609,035	-	2,609,035	Calculated with differential of	$0.020	per kWh
4	Energy Charge 1,001-1,500 kWhs	$ 0.07723	28,279,698	2,184,042	-	2,184,042	Calculated with differential of	$0.020	per kWh
5	Energy Charge > 1,500 kWhs	$ 0.09723	43,590,477	4,238,304	-	4,238,304	Calculated with differential of	$0.020	per kWh
6	Fuel Cost Recovery Factor < 1,000 kWhs	$ 0.02084	110,148,723	-	2,295,499	2,295,499	Fixed		
7	Fuel Cost Recovery Factor > 1,000 kWhs	$ 0.03084	71,870,175	-	2,216,476	2,216,476	Fixed		
8	***Total Residential***			$ 15,683,714	$ 4,511,976	$ 20,195,690	**Fixed**		

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Comparison of Existing and Proposed Residential Service Rates [1]

			Residential Service	
			Existing	Proposed
Customer Charge		($)	$16.98	$30.00
Energy Charge	First 500 kWh	($/kWh)	$0.06624	$0.03723
Energy Charge	Next 500 kWh	($/kWh)	$0.06624	$0.05723
Energy Charge	Next 500 kWh	($/kWh)	$0.08840	$0.07723
Energy Charge	Additional kWh	($/kWh)	$0.08840	$0.09723
Fuel Cost [2]	First 1,000 kWh	($/kWh)	$0.02084	$0.02084
Fuel Cost [2]	Additional kWh	($/kWh)	$0.03084	$0.03084

	Existing		Proposed		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
500	60.52	12.104	59.04	11.807	(1.48)	(0.297)	-2.45%
600	69.23	11.538	66.84	11.140	(2.39)	(0.398)	-3.45%
700	77.94	11.134	74.65	10.664	(3.29)	(0.470)	-4.22%
800	86.64	10.831	82.46	10.307	(4.19)	(0.523)	-4.83%
900	95.35	10.595	90.26	10.029	(5.09)	(0.565)	-5.34%
1,000	104.06	10.406	98.07	9.807	(5.99)	(0.599)	-5.76%
1,100	115.98	10.544	108.88	9.898	(7.11)	(0.646)	-6.13%
1,200	127.91	10.659	119.68	9.974	(8.22)	(0.685)	-6.43%
1,300	139.83	10.756	130.49	10.038	(9.34)	(0.719)	-6.68%
1,400	151.76	10.840	141.30	10.093	(10.46)	(0.747)	-6.89%
1,500	163.68	10.912	152.11	10.140	(11.57)	(0.772)	-7.07%
2,000	223.30	11.165	216.14	10.807	(7.16)	(0.358)	-3.21%
2,500	282.92	11.317	280.18	11.207	(2.74)	(0.110)	-0.97%
3,000	342.54	11.418	344.21	11.474	1.67	0.056	0.49%
4,000	461.78	11.545	472.28	11.807	10.50	0.263	2.27%
5,000	581.02	11.620	600.35	12.007	19.33	0.387	3.33%

[1] Amounts shown reflect single phase, inside the City service.
[2] Projected Fuel Cost Recovery Factor for Fiscal Year 2021.

CITY OF WINTER PARK, FLORIDA
Electric Cost of Service Study

Projected Revenues at
PROPOSED RATES
Fiscal Year Ending September 30, 2021

Ln. No.	Customer Class Description	Proposed Rate	Billing Determinants	Base Rate Revenue	Fuel Cost Recovery	Total Revenue			
	(a)	(b)	(c)	(d)	(e)	(f)			
	Residential								
1	Customer Charge	$ 50.00	141,625	$ 7,081,258	$ -	$ 7,081,258	Input		
2	Energy Charge < 500 kWhs	$ 0.02167	64,560,163	1,398,919	-	1,398,919	Calculated		
3	Energy Charge 501-1,000 kWhs	$ 0.04167	45,588,560	1,899,605	-	1,899,605	Calculated with differential of	$0.020	per kWh
4	Energy Charge 1,001-1,500 kWhs	$ 0.06167	28,279,698	1,743,965	-	1,743,965	Calculated with differential of	$0.020	per kWh
5	Energy Charge > 1,500 kWhs	$ 0.08167	43,590,477	3,559,967	-	3,559,967	Calculated with differential of	$0.020	per kWh
6	Fuel Cost Recovery Factor < 1,000 kWhs	$ 0.02084	110,148,723	-	2,295,499	2,295,499	Fixed		
7	Fuel Cost Recovery Factor > 1,000 kWhs	$ 0.03084	71,870,175	-	2,216,476	2,216,476	Fixed		
8	***Total Residential***			$ 15,683,714	$ 4,511,976	$ 20,195,690	**Fixed**		

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Comparison of Existing and Proposed Residential Service Rates [1]

			Residential Service Existing	Residential Service Proposed
Customer Charge		($)	$16.98	$50.00
Energy Charge	First 500 kWh	($/kWh)	$0.06624	$0.02167
Energy Charge	Next 500 kWh	($/kWh)	$0.06624	$0.04167
Energy Charge	Next 500 kWh	($/kWh)	$0.08840	$0.06167
Energy Charge	Additional kWh	($/kWh)	$0.08840	$0.08167
Fuel Cost [2]	First 1,000 kWh	($/kWh)	$0.02084	$0.02084
Fuel Cost [2]	Additional kWh	($/kWh)	$0.03084	$0.03084

	Existing		Proposed		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
500	60.52	12.104	71.25	14.251	10.73	2.147	17.74%
600	69.23	11.538	77.51	12.918	8.28	1.380	11.96%
700	77.94	11.134	83.76	11.965	5.82	0.831	7.47%
800	86.64	10.831	90.01	11.251	3.36	0.420	3.88%
900	95.35	10.595	96.26	10.695	0.91	0.101	0.95%
1,000	104.06	10.406	102.51	10.251	(1.55)	(0.155)	-1.49%
1,100	115.98	10.544	111.76	10.160	(4.22)	(0.384)	-3.64%
1,200	127.91	10.659	121.01	10.084	(6.90)	(0.575)	-5.39%
1,300	139.83	10.756	130.26	10.020	(9.57)	(0.736)	-6.84%
1,400	151.76	10.840	139.51	9.965	(12.24)	(0.875)	-8.07%
1,500	163.68	10.912	148.76	9.918	(14.92)	(0.994)	-9.11%
2,000	223.30	11.165	205.02	10.251	(18.28)	(0.914)	-8.19%
2,500	282.92	11.317	261.27	10.451	(21.65)	(0.866)	-7.65%
3,000	342.54	11.418	317.53	10.584	(25.01)	(0.834)	-7.30%
4,000	461.78	11.545	430.03	10.751	(31.75)	(0.794)	-6.87%
5,000	581.02	11.620	542.54	10.851	(38.48)	(0.770)	-6.62%

[1] Amounts shown reflect single phase, inside the City service.
[2] Projected Fuel Cost Recovery Factor for Fiscal Year 2021.

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Projected Revenues at
PROPOSED RATES
Fiscal Year Ending September 30, 2021

Ln. No.	Customer Class Description	Proposed Rate	Billing Determinants	Base Rate Revenue	Fuel Cost Recovery	Total Revenue			
	(a)	(b)	(c)	(d)	(e)	(f)			
	Residential								
1	Customer Charge	$ 30.00	141,625	$ 4,248,755	$ -	$ 4,248,755	Input		
2	Energy Charge < 500 kWhs	$ 0.04763	64,560,163	3,075,107	-	3,075,107	Calculated		
3	Energy Charge 501-1,000 kWhs	$ 0.05763	45,588,560	2,627,344	-	2,627,344	Calculated with differential of	$0.010	per kWh
4	Energy Charge 1,001-1,500 kWhs	$ 0.06763	28,279,698	1,912,603	-	1,912,603	Calculated with differential of	$0.010	per kWh
5	Energy Charge > 1,500 kWhs	$ 0.08763	43,590,477	3,819,905	-	3,819,905	Calculated with differential of	$0.020	per kWh
6	Fuel Cost Recovery Factor < 1,000 kWhs	$ 0.02084	110,148,723	-	2,295,499	2,295,499	Fixed		
7	Fuel Cost Recovery Factor > 1,000 kWhs	$ 0.03084	71,870,175	-	2,216,476	2,216,476	Fixed		
8	***Total Residential***			$ 15,683,714	$ 4,511,976	$ 20,195,690	**Fixed**		

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Comparison of Existing and Proposed Residential Service Rates [1]

			Residential Service	
			Existing	Proposed
Customer Charge		($)	$16.98	$30.00
Energy Charge	First 500 kWh	($/kWh)	$0.06624	$0.04763
Energy Charge	Next 500 kWh	($/kWh)	$0.06624	$0.05763
Energy Charge	Next 500 kWh	($/kWh)	$0.08840	$0.06763
Energy Charge	Additional kWh	($/kWh)	$0.08840	$0.08763
Fuel Cost [2]	First 1,000 kWh	($/kWh)	$0.02084	$0.02084
Fuel Cost [2]	Additional kWh	($/kWh)	$0.03084	$0.03084

	Existing		Proposed		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
500	60.52	12.104	64.24	12.847	3.72	0.743	6.14%
600	69.23	11.538	72.08	12.014	2.85	0.476	4.12%
700	77.94	11.134	79.93	11.419	1.99	0.285	2.56%
800	86.64	10.831	87.78	10.972	1.13	0.142	1.31%
900	95.35	10.595	95.62	10.625	0.27	0.030	0.29%
1,000	104.06	10.406	103.47	10.347	(0.59)	(0.059)	-0.57%
1,100	115.98	10.544	113.32	10.302	(2.67)	(0.242)	-2.30%
1,200	127.91	10.659	123.17	10.264	(4.74)	(0.395)	-3.71%
1,300	139.83	10.756	133.01	10.232	(6.82)	(0.525)	-4.88%
1,400	151.76	10.840	142.86	10.204	(8.90)	(0.635)	-5.86%
1,500	163.68	10.912	152.71	10.180	(10.97)	(0.732)	-6.70%
2,000	223.30	11.165	211.94	10.597	(11.36)	(0.568)	-5.09%
2,500	282.92	11.317	271.18	10.847	(11.74)	(0.470)	-4.15%
3,000	342.54	11.418	330.41	11.014	(12.13)	(0.404)	-3.54%
4,000	461.78	11.545	448.89	11.222	(12.89)	(0.322)	-2.79%
5,000	581.02	11.620	567.36	11.347	(13.66)	(0.273)	-2.35%

[1] Amounts shown reflect single phase, inside the City service.
[2] Projected Fuel Cost Recovery Factor for Fiscal Year 2021.

CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Projected Revenues at PROPOSED RATES
Fiscal Year Ending September 30, 2021

Ln. No.	Customer Class Description	Proposed Rate	Billing Determinants	Base Rate Revenue	Fuel Cost Recovery	Total Revenue			
	(a)	(b)	(c)	(d)	(e)	(f)			
	Residential								
1	Customer Charge	$ 50.00	141,625	$ 7,081,258	$ -	$ 7,081,258	Input		
2	Energy Charge < 500 kWhs	$ 0.03207	64,560,163	2,070,448	-	2,070,448	Calculated		
3	Energy Charge 501-1,000 kWhs	$ 0.04207	45,588,560	1,917,914	-	1,917,914	Calculated with differential of	$0.010	per kWh
4	Energy Charge 1,001-1,500 kWhs	$ 0.05207	28,279,698	1,472,526	-	1,472,526	Calculated with differential of	$0.010	per kWh
5	Energy Charge > 1,500 kWhs	$ 0.07207	43,590,477	3,141,568	-	3,141,568	Calculated with differential of	$0.020	per kWh
6	Fuel Cost Recovery Factor < 1,000 kWhs	$ 0.02084	110,148,723	-	2,295,499	2,295,499	Fixed		
7	Fuel Cost Recovery Factor > 1,000 kWhs	$ 0.03084	71,870,175	-	2,216,476	2,216,476	Fixed		
8	***Total Residential***			$ 15,683,714	$ 4,511,976	$ 20,195,690	**Fixed**		

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CITY OF WINTER PARK, FLORIDA

Electric Cost of Service Study

Comparison of Existing and Proposed Residential Service Rates [1]

			Residential Service	
			Existing	Proposed
Customer Charge		($)	$16.98	$50.00
Energy Charge	First 500 kWh	($/kWh)	$0.06624	$0.03207
Energy Charge	Next 500 kWh	($/kWh)	$0.06624	$0.04207
Energy Charge	Next 500 kWh	($/kWh)	$0.08840	$0.05207
Energy Charge	Additional kWh	($/kWh)	$0.08840	$0.07207
Fuel Cost [2]	First 1,000 kWh	($/kWh)	$0.02084	$0.02084
Fuel Cost [2]	Additional kWh	($/kWh)	$0.03084	$0.03084

	Existing		Proposed		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
500	60.52	12.104	76.46	15.291	15.94	3.187	26.33%
600	69.23	11.538	82.75	13.791	13.52	2.253	19.53%
700	77.94	11.134	89.04	12.720	11.10	1.586	14.24%
800	86.64	10.831	95.33	11.916	8.68	1.086	10.02%
900	95.35	10.595	101.62	11.291	6.27	0.696	6.57%
1,000	104.06	10.406	107.91	10.791	3.85	0.385	3.70%
1,100	115.98	10.544	116.20	10.564	0.22	0.020	0.19%
1,200	127.91	10.659	124.49	10.374	(3.42)	(0.285)	-2.67%
1,300	139.83	10.756	132.78	10.214	(7.05)	(0.542)	-5.04%
1,400	151.76	10.840	141.07	10.077	(10.68)	(0.763)	-7.04%
1,500	163.68	10.912	149.37	9.958	(14.31)	(0.954)	-8.75%
2,000	223.30	11.165	200.82	10.041	(22.48)	(1.124)	-10.07%
2,500	282.92	11.317	252.28	10.091	(30.64)	(1.226)	-10.83%
3,000	342.54	11.418	303.73	10.124	(38.81)	(1.294)	-11.33%
4,000	461.78	11.545	406.64	10.166	(55.14)	(1.378)	-11.94%
5,000	581.02	11.620	509.55	10.191	(71.47)	(1.429)	-12.30%

[1] Amounts shown reflect single phase, inside the City service.
[2] Projected Fuel Cost Recovery Factor for Fiscal Year 2021.

City of Winter Park
Utility Advisory Board
Monthly Meeting Plan

January	City of Winter Park Communications plan for Electric, Water & Wastewater; **City of Winter Park Communications** First Quarter, YTD Financial Review and YTD Performance Measures; **Finance & Department Heads**
February	TBD
March	Review draft of five year capital improvement plans for the and review any proposed changes/adjustments including Electric and Water & Wastewater capital projects. **Finance & Department Heads**
April	Review staff assumptions, priorities, and preliminary estimates of expected revenue available for the next fiscal year. Review Hurricane, Disaster Recovery Plan; **Emergency Management Director** Second Quarter, YTD Financial Review and YTD Performance Measures; **Finance & Department Heads**
May	Review Proposed Electric, Water & Wastewater budgets and approve with any modifications suggested, **Finance & Department Heads**
June	Follow up special meeting early in the month, if necessary, to further consider the Proposed Electric, Water & Wastewater budgets and capital improvement plans. City manager presents citywide budget and capital improvement plan to City Commission at the first July commission meeting.
July	Review Electric Utility; Water & Wastewater Management and Key Performance Indicators Third Quarter, YTD Financial Review and YTD Performance Measures; **Finance & Department Heads**

August	TBD
September	City Commissions Adopts Annual Budget
October	Fourth Quarter, YTD Financial Review and YTD Performance Measures; **Finance & Department Heads**
November	TBD – adjust meeting dates if necessary depending on agendas for the November and December meetings to avoid meetings too close to the Thanksgiving and Christmas holidays.
December	TBD

City of Winter Park
Electric Utility, Water and Wastewater Agreements

Strategy and Negotiation Discussion initiation to be on agenda at least 12 months prior to expiry.

NOTE: Provide Links or info on the agreement; a narrative and background on the agreements should be added.

2021	
2022	Community Solar Rate offering Discussion for Florida Municipal Power Authority (FMPA) agreements (2) to come online in early and late 2023
2023	St John's Water Authority; Discuss renewal of consumptive use permit including known and projected increases in demand for water and any concerns regarding availability of potable water to meet those demands (expires in 2025)
2024	Covanta; 10 Mega Watt agreement expires December 2024.

ETC…..

Performance Measures
To be presented and Reviewed Quarterly

Utility Assistance Program
- Details TBD

System Average Interruption Duration Index (SAIDI)
- Goal
- Results

Momentary Average Interruption Frequency Index (MAIFI)
- Goal
- Results

Undergrounding Miles Completed
- Total Project
- Miles to Date
- Miles Remaining
- Completion

Undergrounding Homes/buildings Completed
- Total
- Number to Date
- Remaining….by type

Winter Park Electric Rates as a % of State Municipal Average

Debt Service Coverage

Customer Service Performance
- Number of calls, City and Contractor
- Average Speed to Answer
- Talk Time
- Customer comments

Accounts Receivable/Delinquencies/Disconnects
- TBD

Utilities Advisory Board Meeting Schedule

2021

The Utilities Advisory Board regular meetings are typically held at 12 p.m. on the fourth Tuesday of each month in the Ray Beary Community Room at the Public Safety Facility.

MEETING DATES

January 12

January 26

February 23

March 23

April 27

May 25

June 22

July 27

August 24

September 28

October 26

December 7

Meetings are open to the public.
Please access cityofwinterpark.org/bpm to confirm meeting dates and times.

Tate Scott

Please put the subject of “Strategic Plan” on the next agenda to discuss:

Draft: Resolved that the UAB shall work with the Utilities Directors and others as necessary to create a Utilities Annual Strategic Planning Process and its execution.

Draft Scope: While the exact parameters of the process and plan are yet to be determined the intent is to consider a 3-5 year planning horizon. It should include such items SWOT Analysis, Vision, Mission, Goals, and Objectives. The objectives should be specific, Measurable, Achievable, Realistic, and Time-Based. Action plans to be included. Due time should be spent on the political and regulatory environment and realities under which we operate along with a deep dive into technological advancements and other potentially disruptive events, include disaster planning. It should include financial planning that coexists and dovetails from the city’s existing planning. The intent is to foster a honest review of challenges while developing pro-active solutions. It is a living document that will include a communication plan for both internal and external audiences. The exact timing of the completion of the annual Strategic Plan will be developed in consult with management to ensure relevance to other planning processes and avoid duplication.

This very rough draft was created to spark discussion and not meant to be fully inclusive of all needed aspects for a successful project.

FitchRatings

Fitch Affirms Winter Park (FL) Electric System Revs at 'A+'; Outlook Stable

Fitch Ratings - Austin - 18 March 2020:

Fitch Ratings has affirmed its 'A+' rating on the following electric revenue bonds issued by the city of Winter Park, FL:

--$18.26 million electric system revenue bonds, series 2016.

Additionally, Fitch affirmed its 'A+' Issuer Default Rating (IDR) on the city of Winter Park (FL) Electric System.

ANALYTICAL CONCLUSION

The 'A+' IDR reflects the Winter Park electric system's strong financial profile, which is supported by very low leverage metrics, but is constrained by weaker liquidity. While the system's historical leverage ratio has ranged between 6.4x and 8.9x in recent years, suggesting a potentially higher rating, cash balances have consistently been exhausted at year end to fund the city's capital projects, limiting the final rating.

Winter Park's financial profile assessment is further considered in relation to its very strong revenue defensibility and low operating risk assessments. Revenue defensibility is supported by retail distribution services to a growing customer base with favorable demographics, and a high level of rate flexibility. The system's low operating risk assessment factors the cost of power derived largely from its flexible and diverse portfolio of power supply contracts, as well as costs related to its capital plan. Winter Park's ongoing capital plan, which focused on investment in its electric line undergrounding project, is significant but manageable.

CREDIT PROFILE

Winter Park is located north of Orlando, within the Orlando metropolitan statistical area (MSA). The suburban city owns and operates the electric system that it purchased from Progress Energy in 2005. The system serves approximately 15,600 customers within a nine square mile service area of the city. Duke Energy and Orlando Utilities Commission (OUC) also serve a small portion of residential customers within the city limits.

KEY RATING DRIVERS

Revenue Defensibility:: 'aa'

Distribution Utility with Favorable Service Area and Rate Flexibility

Winter Park's retail electric services exhibit monopolistic characteristics and present a low revenue risk. Service area characteristics include consistent customer growth, favorable income and low unemployment. Rate flexibility is high reflecting the city's independent legal ability to adjust its competitive and highly affordable electric rates.

Operating Risk:: 'a'

Low Operating Cost Burden

Winter Park's operating risk reflects its role as a distribution utility and its low operating cost burden. Operating flexibility is neutral to the assessment, reflecting the diversity of its primary purchased power providers, Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA). Lifecycle investment needs are moderate based on the estimated 13-year average age of electric assets and adequately addressed through the system's capital plan.

Financial Profile:: 'a'

Very Low Leverage; Weaker Liquidity

The financial profile assessment of 'a' factors Winter Park's very low, but volatile leverage ratio, which has averaged 7.3x over the past five years but ranged between 6.4x and 8.9x, as well as the system's weaker liquidity profile and lack of cash on hand which constrain the overall assessment.

RATING SENSITIVITIES

Developments That May, Individually or Collectively, Lead to a Negative Rating Action:

-Material increase in the electric line undergrounding project scope, cost, or schedule that stresses the financial profile on a sustained basis.

Developments That May, Individually or Collectively, Lead to a Positive Rating Action

-Sufficient and sustained liquidity as measured by a liquidity cushion above 90 days and unrestricted cash above 30 days;

-Approval and implementation of rate increases to support operating income and sustain leverage at a ratio well below 8.0x;

-A sustained reduction in operating costs and more favorable operating risk assessment.

SECURITY

The bonds are payable from a first lien on net revenues of the city's electric utility system (the system).

Revenue Defensibility

The Winter Park electric utility's distribution business exhibits monopolistic characteristics and a low degree of operating revenue risk. The system provides electricity to customers within an approximately nine square mile area of the city. Electric service to a limited number of residential customers within the city is provided by Duke Energy and OUC, representing a static 6% and 2%, respectively, of the city.

Service Area Characteristics

Service area characteristics are strong. Winter Park's total retail customers have realized a five-year 1.5% compound annual rate of growth (CAGR) through fiscal 2018. Winter Park is the oldest centrally planned suburban city in central Florida. The city's population has a greater percentage of senior citizens (18%), compared with the state (13%) and the nation (11%). The percentage of the city's population with bachelors or advanced degrees (62%) is double that of the state (29%) and nation (31%). Residents are generally year-round, rather than seasonal, suggesting a greater level of stability and demand for electricity, as well as general products and services. The Winter Park economy has benefited over the past five years from growth surrounding Sun Rail commuter rail system rail station development projects. Winter Park's favorable demographic trends include median household income (MHI) at 119% and unemployment at 79% of 2018 national averages.

The city's economy also benefits from growth throughout the Orlando MSA, anchored in tourism and the Walt Disney World and Universal properties. The ripple effect of the announced closure of Disney World Resort Operations on March 16 through the end of the month is unclear, although Disney announced that it would pay its cast members during that period. The announcement indicated that Disney Resort hotels and related food and beverage operations, and transportation would remain open until further notice.

Leisure and hospitality accounted for 11.1% and 20.5% of the Orlando-Kissimmee-Stanford, FL 2018 GDP and employment base, respectively. Healthy medium-term regional growth prospects are supported by a variety of investment and development projects planned or underway. The regional economy also includes biotechnology and life sciences, healthcare, education and advanced manufacturing.

Rate Flexibility

Rate flexibility is very high as the city retains the independent legal ability to adjust its rates. Moreover, rates are competitive at 101% and 107% of the state's 2018 total electric and residential rates, respectively, and the cost of electricity is highly affordable at 2.5% of the city's MHI.

The service area exhibits no customer concentration. Residential electric revenues contribute 51% to total electric revenues and the top ten customers accounted for 23% of fiscal 2018 electric revenues. The area's largest customers participate in the stable higher education, healthcare, county government, city government and senior living sectors.

Operating Risk

Winter Park's operating cost burden is considered low. While the system's average cost/kWh has averaged 9.7 cents over the five years ending Sept. 30, 2018, figures for fiscal 2019 suggest a cost above Fitch's 10.0 cent/kWh threshold. Winter Park expects operating costs to decline beginning in fiscal 2020 as a result of changes to its power supply contracts with FMPA and OUC. A sustained improvement in the system's cost burden could support a higher assessment over time.

Operating Cost Flexibility

Winter Park's operating cost flexibility is neutral to the rating, reflecting arrangements with its two primary purchased power contract providers, OUC and FMPA. The OUC contract (term through Dec. 31, 2026) serves the full requirements of two 12.47 kV Winter Park distribution feeders (15-20 MW). The FMPA contract (term through Dec. 31, 2027) is a partial requirements/load following contract to meet all of Winter Park's requirements not met by the other providers. Winter Park has also contracted with Covanta Energy Corp to provide a 10 MW 24X7 block through Dec. 31, 2024 and with FMPA for two 10 MW solar units expected to be online in 2023. The solar contracts with FMPA will further progress toward the city's long-term goal of purchasing 50% of its purchased power from renewable sources.

Winter Park's resources are sufficient in relation to its load (97.1 MW in 2019) based on current contract arrangements through Dec. 31, 2027. Although the utility faces contract renewal and market price risk thereafter, the Florida Reliability Coordinating Council (FRCC) expects that the Florida market's reserve margin will meet or exceed 20% in each year over the next 10 years, suggesting the ongoing availability of ample generation supply options.

Capital Planning and Management

Fitch estimates a 13-year average age of Winter Park's electric system plant assets. The moderate age of plant reflects significant levels of capital spending on the city's priority to place power lines underground. Winter Park currently estimates completion of the undergrounding project in fiscal 2026 and has included $22.1 million on the project out of its $30 million five year (fiscal 2020 - 2024) capital plan. Winter Park does not anticipate additional bond issues over this period.

Financial Profile

Winter park's operating performance has been strong, albeit volatile in recent years. The electric system's leverage ratio, measured as net adjusted debt to adjusted funds available for debt service (FADS), averaged 7.3x over the past five years ending in fiscal 2018, ranging from a high of 8.9x (2017) to a low of 6.4x (2018). Year-to-year variability was influenced primarily by weather, storm-related expenses and purchased power variability, during which time debt steadily declined.

Liquidity, particularly cash on hand, has been relatively weak. The system's coverage of full obligations has generally hovered around 1.5x over the last five years, with the exception of 2017 (1.1x), which was adversely affected by Hurricane Irma. However, the electric fund reported a negative unrestricted cash position at fiscal year-end 2018. A $2.3 million 'due to other funds' position at fiscal year-end 2018 ($4.2 million unaudited at fiscal 2019 year-end) represents the electric funds obligations to other funds under the city's centrally managed pooled cash program. The electric fund's broader 84-day liquidity cushion reflects its $8 million (unused) line of credit with SunTrust Bank.

Fitch Base Case and Rating Case Scenario Analysis

Fitch's base case scenario analysis assumes that both load growth and the cost of power will remain generally flat after 0.8% growth in 2019. Other utility operating revenues and expenses are informed by Winter Park's operating proforma. Capital spending and debt service are also based on the city's electric utility operating proforma and include its 2019 refunding of series 2009A and 2009B. Transfers to the general fund approximate 6% of revenues. Other cash provided in 2019 represents release of the debt service funds pursuant to the 2019 refunding and in 2020, represent for the most part, third-party reimbursements. Fitch also estimates a 1% average rate increase per annum in fiscal 2021 through 2023 to keep pace with cost growth, fund the electric line undergrounding project and replenish cash that had been exhausted over the past five years from funding the utility's capital program, focused on the undergrounding project. Overall, the base case suggests a higher leverage ratio of 7.4x for fiscal 2019 and a steady decline thereafter based on improving operating performance and lower net debt balances.

The stress case factors reductions to energy sales for two years, followed by a three-year recovery based on Winter Park's historical energy sales trends. The electric system's financial profile remains relatively stable through the rating case, with net leverage rising to a high of 7.7x before recovering to 6.0x in 2021, benefiting from the assumed rate increase that year. The rating case adjusts transfers based on the lower level of revenues in the stress case.

In addition to the sources of information identified in Fitch's applicable criteria specified below, this action was informed by information from Lumesis.

ESG Considerations

ESG issues are credit neutral or have only a minimal credit impact on the entity(ies), either due to their nature or the way in which they are being managed by the entity(ies). For more information on Fitch's ESG Relevance Scores, visit www.fitchratings.com/esg.

VIEW ADDITIONAL RATING DETAILS

Additional information is available on www.fitchratings.com

Applicable Criteria

U.S. Public Power Rating Criteria (pub. 03 Apr 2019)
Public Sector, Revenue-Supported Entities Rating Criteria (pub. 07 Nov 2019)

Additional Disclosures

Dodd-Frank Rating Information Disclosure Form
Solicitation Status
Endorsement Policy

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