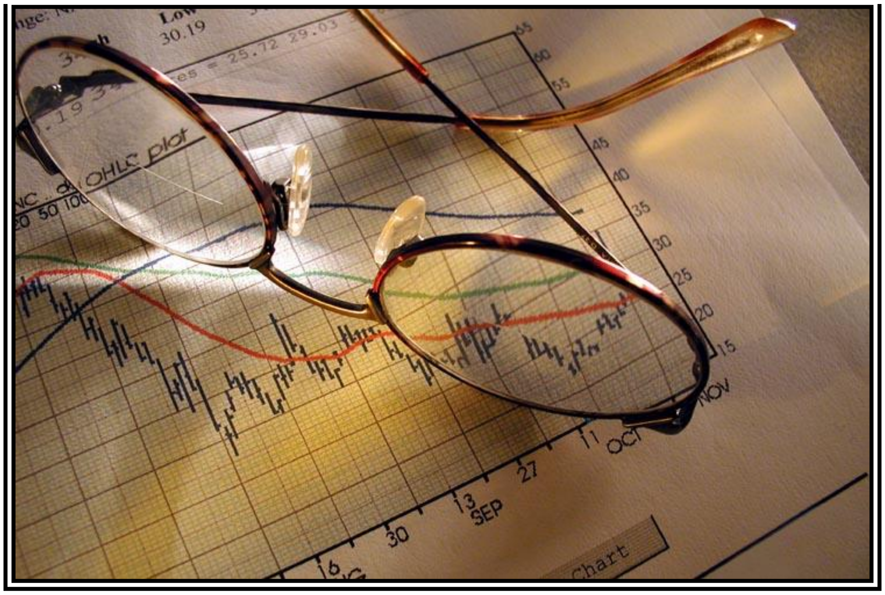
Columbia Utilities

Forecast, Cost of Service and Rate Study – Final Report



April 2023

■ The Prime Group ■

PO Box 837

Crestwood, KY 40014

Table of Contents

1. Project History

In October 2019, the Columbia Integrated Electric Resource Master Plan Task Force hired the Prime Group to perform a rate study. The project was originally scheduled to be completed in 2020 but took longer than expected due to the following reasons: 1) The Coronavirus outbreak in 2020, 2) Siemens capital improvements plan not being completed until 2021. The financial forecast was originally based on actual data through 2019, but Columbia Utilities' staff and Water & Light Advisory Board gave the Prime Group additional time to update the financial forecast to account for two more years of actual data (2020-2021) and the completed capital improvements plan. After reviewing the results of the initial financial forecast, Columbia Utilities' staff and Water & Light Advisory Board felt that the capital improvement plan: 1) created an increase that was too large, and 2) was above what could actually be spent within the timeframe of the plan. Changes were made to the capital improvements plan and a revised version of the financial forecast was developed to incorporate these changes. Due to the age of the information in the cost-of-service study, the financial forecast was used to determine the rate of the revenue increase. The cost-of-service study was used to allocate the increase to each rate class.

1.1 Financial Forecast

The Prime Group developed a 10-year financial forecast based on the financial documents provided by Columbia Utilities for the years 2010-2019. Due to the length of the time before receiving the results from the new capital improvements plan from the IERMP task force, the model was updated to reflect actual results for the years 2020 and 2021. The table below shows the range of annual increases within each expense category:

Financial Forecast Expense Groups – Rage of Annual Increases

	Range of Annual Increases		
Production Expenses	1.50%	-	3.79%
Transmission & Distribution - Operations	1.50%	-	2.25%
Transmission & Distribution - Maintenance	1.50%	-	6.39%
Accounting & Collection	1.50%	-	5.00%
Administrative & General	1.50%	-	7.00%

Columbia Utilities' purchased power costs had an unusually large increase of 14% in 2022. By the beginning of 2023, these costs had returned to 2021 levels. The financial forecast accounts for this situation and treated 2022 power purchase costs as an anomaly. Columbia Utilities' staff and Water & Light Advisory Board directed that future years (2024-2030) should be based on a 3% increase.

Changes to the 2021 model were made in the years 2022-2030 to account for the following items: (i) future additions to the capital improvements plan, (ii) moving items from the capital improvements plan to O&M expenses, and (iii) separating future increases in purchased power cost and assuming they will be captured in a new PCA mechanism. In earlier versions of the financial forecast, purchased power increases were included in the revenue increases. This led to significantly higher proposed revenue increases for Columbia Utilities. Columbia Utilities' staff and Water & Light Advisory Board wanted to include a new power cost adjustment mechanism as part of the rate design process. By separating the future purchased power cost increases from the non-purchased power cost increases, the revenue increase that is shown focuses only on non-purchased power cost increases and assumes that the increase in purchased power related costs are being captured in a power cost adjustment mechanism.

The forecast showed that a revenue increase was necessary for 2024. The Prime Group recommended that the lifespan for revenue increases be based on a three-year period. Cost volatility makes it difficult to justify keeping the rates in place for a longer period and the staff and Water & Light Advisory Board felt that the rate process takes too long to make annual changes to rates.

The revenue increase was also based on meeting the following criteria: (i) net income must be positive in every year, (ii) the cash reserves calculation must be positive in every year, and (iii) the debt service coverage ratio cannot be below 1.2 in any year. The first version of the financial forecast, completed in 2021, included all capital improvements projects as recommended in Siemens master plan. The resulting revenue increase (which included purchased power costs) would have been $24.9 million. Columbia Utilities' staff and the Water & Light Advisory Board believed that this would have been too large of an increase, which led to changes that reduced the number of projects in the capital improvements plan. The revised financial forecast, completed in 2023, used the updated capital improvements plan and assumed future purchased power costs would be recovered through a power cost adjustment. This version of the financial forecast showed that a revenue increase of $8.3 million was necessary to meet Columbia Utilities' financial goals and recover all non-purchased power related costs. The necessary revenue increase would be $16.4 million if purchased power costs were not broken out to be recovered in a PCA and instead recovered as part of the revenue increase. The purchased power increase is based on historical escalation rates. Including a PCA mechanism allows for the actual purchased power cost to be included in rates instead of basing rates on an estimate of those costs. In this case 2021 purchased power costs were used as the base cost for the PCA mechanism. The table below shows the results from the financial forecast for these three criteria with and without the $8.3 million increase:

Financial Forecast Criteria – With and Without $8.3 Million Increase

	Net Margins		
	2024	2025	2026
With Increase	$ 3,217,889	$ 1,904,216	$ 66,775
Without Increase	$ (4,305,999)	$ (5,619,672)	$ (7,457,113)

	Cash Reserves Calculation		
	2024	2025	2026
With Increase	$ 8,084,099	$ 12,368,522	$ 6,430,771
Without Increase	$ 715,433	$ (2,524,032)	$ (15,985,670)

	Debt Service Coverage Ratio		
	2024	2025	2026
With Increase	1.89	1.73	1.58
Without Increase	1.21	1.08	0.96

1.2 Cost of Service study

The Prime Group has prepared a fully allocated embedded cost-of-service study for Columbia Utilities for the 12 months ended September 30, 2019 ("test year"). The objectives of performing a class cost-of-service study are (i) to allocate Columbia Utilities' cost of service as fairly as possible to all of the classes of customers, (ii) to determine the contribution that each customer class is making towards the utility's overall rate of return, (iii) to determine the rate of return on rate base that the utility is earning from each customer class, and (iv) to provide the data necessary to develop rate components that more accurately reflect cost causation. Cost-of-service is a standard measure of reasonableness for utility rate design. The cost-of-service study was performed using an EXCEL™ spreadsheet model that was developed by The Prime Group and that has been utilized as an aid in developing rates for hundreds of utilities across the United States.

The cost-of-service study prepared for Columbia Utilities is based on standard allocation methodologies as described in the *Electric Utility Cost Allocation Manual* published by the National Association of Utility Regulatory Commissioners ("NARUC"). NARUC methodologies are considered standard methodologies and, therefore, the cost-of-service study would be defendable if challenged.

The three principal steps of an embedded cost of service study are *functional assignment*, *classification*, and *class allocation*. These three steps are necessary to ensure that the costs allocated to a class of customers reflect the costs that they impose on the utility as accurately as possible. In the first step – ***functional assignment*** – costs are assigned (or "functionalized") to the major functional groups related to providing service. Functional assignment serves the following purposes: (1) it groups associated costs together to facilitate allocation based on cost responsibility; (2) it provides a rational mechanism for grouping costs that do not appear to be related to major service functions; and (3) it provides a device for separating assignable costs from joint costs, which must be allocated. Functional assignment involves assigning costs to the functional services provided by a utility, such as power production, purchasing electric power, the transmission of the power over high-voltage lines (typically at voltages of 69 KV or higher), and the distribution of power over distribution lines (typically at voltages of less than 69 KV). Functionally assigning all costs allows us to examine a utility's revenue requirement in finer detail and to assign cost responsibility more accurately in the next two steps of the study.

In this cost-of-service study, the following functional groups were identified to provide a high degree of detail for purposes of designing rates as well as analyzing and tracking costs:

- Purchased Power
- Station Equipment
- Primary Distribution Plant
- Secondary Distribution Plant
- Line Transformers
- Customer Services
- Meters
- Lighting Systems
- Meter Reading, Billing and Cust Service
- Marketing

In the second step – ***classification*** – the major cost drivers are identified for each group of functionally assigned costs. Identifying the major cost drivers allows the service characteristics that give rise to the costs to serve as a basis for allocation. In this study, once the costs are functionally assigned, they are then classified by the following major cost drivers:

- Energy-related costs
- Demand-related costs
- Customer-related costs

Costs classified as *energy related* vary with the amount of energy that the customer consumes measured in kilowatt-hours. Fuel and purchased power expenses billed based on an energy charge are examples of costs typically classified as energy related. Costs classified as *demand related* tend to vary with the capacity needs of customers, such as the amount of generation, transmission, or distribution equipment necessary to meet customers' maximum demands at particular points in time. Production plant purchased power expenses billed based on a demand charge, and the cost of transmission lines are examples of costs typically classified as demand costs. Those assets are sized to meet the maximum demands customers place on the system at a given time. To the extent that they are driven by the amount of equipment that a utility must install to meet customer needs, these demand related costs are also driven by customer usage patterns. Costs classified as *customer related* are not related to customer usage and include costs incurred to serve customers regardless of the quantity of electric energy they purchase, or the peak demands they place on the system. These costs include the cost of the minimum system necessary to provide a customer with access to the electric grid. As will be discussed later in this report, costs functionally assigned as Primary & Secondary Distribution Plant were classified as demand-related and customer-related using the zero-intercept methodology. Customer Services, Distribution Meters, Lighting System, Meter Reading, Billing & Customer Service were classified as customer related.

In the third and final step – ***class allocation*** – functionally assigned and classified costs are directly assigned or allocated to the customer classes based on an allocation factor that is representative of the service characteristic that drives the utility's costs. For example, energy-related costs are allocated based on the number of kilowatt hours used by the customer class and demand-related costs are allocated based on the appropriate measurement of the maximum demand that the customer class places on the system.

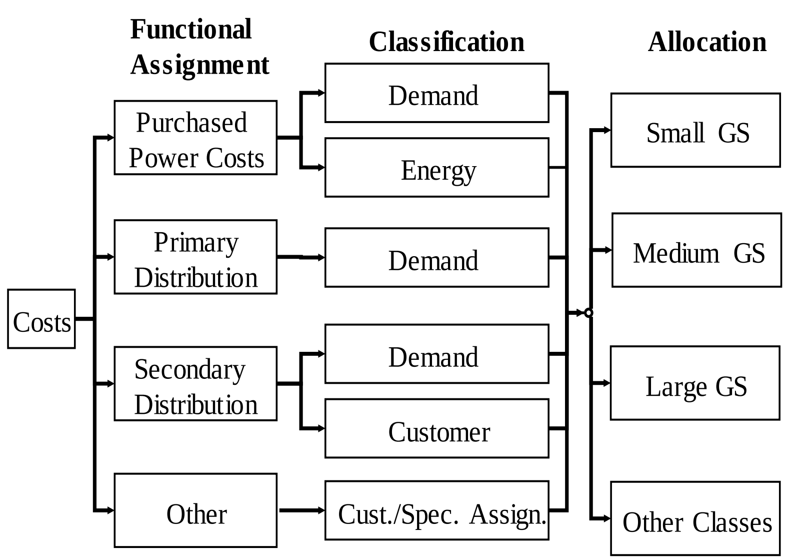
The reason that allocation procedures must be used to determine the cost of providing service to each rate class is that most of a utility's costs are represented by what are referred to as joint costs. *Joint costs* are those costs incurred jointly for two or more types of operations where each operation does not have a separate incremental cost function. In the electric utility industry, production, transmission, and most distribution facilities are jointly engaged in providing service to a multitude of customers with diverse load characteristics taking service at different rates of usage at various times of the day, month, or year. Consequently, in the utility industry very few costs can be directly attributed to specific customers or specific customer groups. Therefore, most of the utility's costs must be allocated to the customer classes based on an allocation process that reasonably attributes costs based on cost causation.

Where facilities were installed for, and used by, specific members, and those members do not receive reliability benefits from being connected to Columbia Utilities' backbone distribution system, the cost of those facilities are directly assigned to those members.

The three steps of the cost-of-service study are summarized in the graph shown in Figure 1. As explained above, costs are first assigned to the functional groups, then classified as demand-related, energy-related, or customer-related, and then allocated to the customer classes, as follows:

The Three Steps of the Cost-of-Service Process

Figure 1



The class rate of return provides information about whether each class of customers is making an appropriate contribution towards the utility's earnings requirements. If a utility is earning a low rate of return – or perhaps even a negative rate of return – from a particular class of customers, then this generally indicates that this class of customers is not paying its fair share and that the rates being charged to the customer class are too low. An important consideration is where the class rate of return falls relative to the overall rate of return earned by the utility from all customer classes. When a rate of return for a customer class is below the overall rate of return then this generally indicates that the customer class is being subsidized by other rate classes.

In terms of equity and efficiency, the rates of return should generally be the same for all classes of customers. However, in some situations the utility may consider other factors in determining the appropriate rate of return for a particular customer class. For example, the utility may want to consider the risk of serving particular customers. Some rate classes are riskier to serve than others. Residential customers tend to have revenue streams that are more volatile (because of the temperature sensitive nature of the load) and they often have a higher percentage of uncollectible revenues than other customer groups. On the other hand, some industrial customers can also create financial risks for the utility, especially large industrial customers that operate in volatile or risky industries and that create a potential for stranded utility investments. The utility may also want to consider competitive pressures from neighboring energy suppliers in establishing a targeted rate of return for a particular class of customers. Utilities will often establish a lower rate of return for a particular rate class to encourage a new energy technology as a part of a short-term marketing initiative.

Aside from these considerations, we generally recommend that the utility strive toward equalizing the rates of return for all customer classes. If a class rate of return falls significantly below the overall rate of return for the total system, then we recommend the utility consider moving the rate of return for the class in the direction of the average rate of return for the total system. Likewise, if a class rate of return is significantly above the overall system rate of return, then we recommend the utility to consider a strategy for reducing the class rate of return in the direction of the overall system average.

Unit costs for each rate class provide a good indication of what unbundled, cost-based rates would look like. In developing these unit costs, the utility's margins are reflected in the distribution and customer charges. This ensures that the utility will continue to collect all its margins, even in a retail choice environment. When margins are recovered through the distribution and customer charges, purchased power or fuel costs become a straight pass through and is collected from customers on a dollar-for-dollar basis with no margin attached. These unbundled, cost-based rate components can be compared to the utility's existing rate structure to provide an indication of how much the utility's current rate structure deviates from one that is strictly cost based.

In the cost-of-service study, revenue requirements are calculated for the following cost categories:

- Purchased Power Production Demand
- Purchased Power Production Energy
- Distribution Demand
- Distribution Customer

For the residential class (served under a two-part rate schedule consisting of a customer charge and a seasonal inclining-block energy charge), the unit cost for all demand and energy cost categories are determined by dividing the revenue requirement by annual kWh. Unit customer costs are then calculated by dividing distribution customer costs by annual customer months (i.e., the average number of customers during the test year multiplied by the number of months). For commercial and industrial customer classes with three-part rate schedules (consisting of a customer charge, demand charge, and energy charge), unit demand costs are determined by dividing production, transmission, and distribution demand costs by billing demand (kW-Months), unit energy costs are calculated by dividing energy costs by annual kWh sales, and unit customer costs are then calculated by dividing distribution customer costs by annual customer-months.

The cost-of-service study was used to determine the individual charges for each rate class and to spread the revenue increase to the rate classes as fairly as possible by allocating larger increases to rate classes that had a lower rate of return and smaller increases to rate classes that had a higher rate of return. By adjusting the individual charges to be more cost-based and allocating the increases described above, the proposed rates reduce the amount of subsidy in Columbia Utilities' rate structure. The table below shows Columbia Utilities' test year results from the cost-of-service study:

Cost-of-Service Study – Test Year Results

	Revenue	Operating Expenses	Operating Margin	Rate Base	Return on Rate Base
Residential Service - Gas Heat	$ 32,762,499	$ 33,724,125	$ (961,626)	$ 52,868,837	-1.82%
Residential Service - Electric Heat	$ 18,499,159	$ 21,128,837	$ (2,629,677)	$ 35,819,989	-7.34%
Residential Service - Heat Pump	$ 4,553,577	$ 5,015,481	$ (461,905)	$ 8,215,592	-5.62%
Small General Service - Gas Heat	$ 10,131,983	$ 8,615,774	$ 1,516,209	$ 13,133,155	11.54%
Small General Service - Electric Heat	$ 3,408,084	$ 3,071,484	$ 336,600	$ 4,815,248	6.99%
Small Commercial - Heat Pump	$ 69,941	$ 65,363	$ 4,577	$ 100,882	4.54%
Small General Service - Optional Demand	$ 669,365	$ 522,578	$ 146,787	$ 658,379	22.30%
Large General Service	$ 37,552,026	$ 29,762,716	$ 7,789,310	$ 40,553,803	19.21%
Interruptible Service	$ 255,110	$ 173,930	$ 81,180	$ 476,397	17.04%
Industrial Service	$ 22,220,594	$ 17,448,457	$ 4,772,136	$ 20,953,728	22.77%
Special Outdoor Lighting	$ 164,663	$ 132,834	$ 31,829	$ 272,642	11.67%
Dusk to Dawn Lighting	$ 364,856	$ 973,145	$ (608,289)	$ 3,112,272	-19.54%
Total	$ 130,651,858	$ 120,634,724	$ 10,017,134	$ 180,980,923	5.53%

1.3 Rate Design

When recommending changes to a utility's rate design, The Prime Group is guided by the results of the cost-of-service study. Rate classes with customer charges below the cost-based customer charges from the cost-of-service study will have higher proposed customer charges to provide fair cost recovery more adequately. Rate classes with rates of return that are much lower than the overall system rate of return will receive higher increases than classes that have rates of return that are closer to the overall system rate of return.

When developing rates, the proposed unit charges are applied to test-year billing determinants to ensure that the proposed rates will produce the revenue requirements authorized by Columbia Utilities' Board based on test-year results. Columbia Utilities' revenue requirements are based on the results of the financial forecast which showed that an $8.3 million increase was necessary to maintain Columbia Utilities' financial goals for the three-year lifespan of the proposed rate design.

The Prime Group provided the following 6 rate options for Columbia Utilities' Board to consider; (i) a rate design based on Columbia Utilities' current seasonal inclining-block rate structure, (ii) a rate design based on a modified version Columbia Utilities' current seasonal inclining-block rate structure which reduced the number of blocks by 1, (iii) a rate design based on a flat seasonal energy charge and a monthly fixed charge, (iv) a rate design based on Columbia Utilities' current seasonal inclining-block rate structure with a demand charge, (v) a rate design based on a modified version Columbia Utilities' current seasonal inclining-block rate structure which reduced the number of blocks by 1 and a demand charge, and (vi) a rate design based on a flat seasonal energy charge, a demand charge, and a monthly fixed charge. Columbia Utilities' Board chose to base the proposed rates on option (i).

Rate Design – Increases by Rate Class

City of Columbia Summary of Proposed Rate Changes				
Rate Class	**Calculated Billings**	**Proposed Rates**	**Increase**	**Percent Increase**
Residential Gas Heat	$ 29,938,259	$ 33,042,736	$ 3,104,477	10.4%
Residential Electric Heat	$ 16,927,222	$ 18,586,006	$ 1,658,784	9.8%
Residential Heat Pump	$ 4,161,651	$ 4,490,972	$ 329,321	7.9%
Small General Service Gas Heat	$ 9,309,578	$ 9,770,024	$ 460,445	4.9%
Small General Service Electric Heat	$ 3,072,027	$ 3,238,338	$ 166,310	5.4%
Small General Service Heat Pump	$ 63,904	$ 67,821	$ 3,917	6.1%
Small General Service Optional Demand	$ 615,328	$ 641,551	$ 26,222	4.3%
Large GS	$ 34,379,553	$ 35,845,047	$ 1,465,494	4.3%
Interruptible Service	$ 232,146	$ 242,141	$ 9,995	4.3%
Industrial Service	$ 20,415,027	$ 21,284,085	$ 869,058	4.3%
Special Outdoor Lighting	$ 150,084	$ 156,552	$ 6,467	4.3%
Dusk to Dawn Lighting	$ 304,849	$ 504,887	$ 200,038	65.6%
Total	$ 119,569,630	$ 127,870,157	$ 8,300,528	6.9%

1.3.1 Residential Service – Gas Heat

The rate structure for the residential service – gas heat rate class is a seasonal inclining-block rate structure. Inclining-block rates are not reflective of actual costs and create subsidies between customers in the rate class. High use customers are providing a subsidy by paying more than their fair share of these costs. Low use customers are receiving a subsidy by not fully paying their fair share of these costs. This situation is being exacerbated because the customer charge is below cost, which means customer-related costs are being recovered in the high use blocks of the energy charge instead of the customer charge. The IERMP task force wanted to look at the impact of rates on low-income users. The City provided usage data for all customers receiving financial assistance and all customers that were not receiving financial assistance. The analysis of this data showed that customers receiving financial assistance were using 17% more energy, on average, than customers who do not receive financial assistance. Because of the higher usage, this rate design also penalizes these customers relative to customers who do not receive financial assistance. The proposed inclining-block rates have a smaller differential between the first and last blocks to reduce this impact on high usage customers.

The following table for the residential service – gas heat rate class shows the current and proposed rates, the average monthly bill under both rate structures, and the percent increase for an average usage customer. The average usage is calculated by taking the total kWh for the class and dividing it by the total number of customer bills for the year. The comparison was based on an average usage customer because the increase shown would be reflective of the percent increase in the total revenue for each rate class. This is a common metric in the industry to show percentage increases. The current customer charge is $16.31. The cost-of-service study shows a cost-based customer charge of $30.19. The proposed customer charge is $22.00. Due to the difference between the current customer charge and the cost-based customer charge, The Prime Group recommended a gradual increase in the customer charge. Gradual increases allow for movement in the direction of cost-based rates while minimizing impacts to customers.

Residential Service – Gas Heat

Current and Proposed Rates

	Current Rate	Proposed Rate Current Structure
Customer Charge	$ 16.31	$ 22.00
Demand Charge	-	$ -
Energy Charge		
Non-Summer		
First 300 kWh	$ 0.0786	$ 0.0889
Next 450 kWh (First 750)	$ 0.1025	$ 0.1089
Remaining kWh	$ 0.1184	$ 0.1200
All kWh		
Summer		
First 300 kWh	$ 0.0786	$ 0.0889
Next 450 kWh (First 750)	$ 0.1025	$ 0.1089
Next 1,250 kWh	$ 0.1397	$ 0.1289
Remaining kWh	$ 0.1511	$ 0.1489
All kWh		
Avg. No. Customers	28,117	
Avg. Usage Per month	718	
Avg. Bill Per Month	$ 88.73	$ 97.93
Avg. Monthly Increase		$ 9.20
Avg. Percent Increase		10.4%

1.3.2 Residential Service – Electric Heat

The rate structure for the residential service – electric heat rate class is a seasonal inclining-block rate structure. Inclining-block rates are not reflective of actual costs and create subsidies between customers in the rate class. High use customers are providing a subsidy by paying more than their fair share of these costs. Low use customers are receiving a subsidy by not fully paying their fair share of these costs. This situation is being exacerbated because the customer charge is below cost, which means customer-related costs are being recovered in the high use blocks of the energy charge instead of the customer charge. This rate design also penalizes low-income customers who receive financial assistance because they use 46% more energy, on average, than other customers on this rate. The proposed inclining-block rates have a smaller differential between the first and last blocks to reduce this impact on high usage customers.

The following table for the residential service – electric heat rate class shows the current and proposed rates, the average monthly bill under both rate structures, and the percent increase for an average usage customer. The average usage is calculated by taking the total kWh for the class and dividing it by the total number of customer bills for the year. The comparison was based on an average usage customer because the increase shown would be reflective of the percent increase in the total revenue for each rate class. This is a common metric in the industry to show percentage increases. The current customer charge is $16.31. The cost-of-service study shows a cost-based customer charge of $30.19. The proposed customer charge is $22.00. Due to the difference between the current customer charge and the cost-based customer charge, The Prime Group recommended a gradual increase in the customer charge. Gradual increases allow for movement in the direction of cost-based rates while minimizing impacts to customers.

Residential Service – Electric Heat

Current and Proposed Rates

	Current Rate	Proposed Rate Current Structure
Customer Charge	$ 16.31	$ 22.00
Demand Charge	-	$ -
Energy Charge		
Non-Summer		
First 300 kWh	$ 0.0786	$ 0.0889
Next 450 kWh (First 750)	$ 0.1025	$ 0.1089
Remaining kWh	$ 0.0985	$ 0.1000
All kWh		
Summer		
First 300 kWh	$ 0.0786	$ 0.0889
Next 450 kWh (First 750)	$ 0.1025	$ 0.1089
Next 1,250 kWh	$ 0.1397	$ 0.1289
Remaining kWh	$ 0.1511	$ 0.1489
All kWh		
Avg. No. Customers	13,211	
Avg. Usage Per month	940	
Avg. Bill Per Month	$ 106.78	$ 117.24
Avg. Monthly Increase		$ 10.46
Avg. Percent Increase		9.8%

1.3.3 Residential Service – Heat Pump

The rate structure for the residential service – heat pump rate class is a seasonal inclining-block rate structure. Inclining-block rates are not reflective of actual costs and create subsidies between customers in the rate class. High use customers are providing a subsidy by paying more than their fair share of these costs. Low use customers are receiving a subsidy by not fully paying their fair share of these costs. This situation is being exacerbated because the customer charge is below cost, which means customer-related costs are being recovered in the high use blocks of the energy charge instead of the customer charge. The proposed inclining-block rates have a smaller differential between the first and last blocks to reduce this impact on high usage customers.

The following table for the residential service – heat pump rate class shows the current and proposed rates, the average monthly bill under both rate structures, and the percent increase for an average usage customer. The average usage is calculated by taking the total kWh for the class and dividing it by the total number of customer bills for the year. The comparison was based on an average usage customer because the increase shown would be reflective of the percent increase in the total revenue for each rate class. This is a common metric in the industry to show percentage increases. The current customer charge is $16.31. The cost-of-service study shows a cost-based customer charge of $30.19. The proposed customer charge is $22.00. Due to the difference between the current customer charge and the cost-based customer charge, The Prime Group recommended a gradual increase in the customer charge. Gradual increases allow for movement in the direction of cost-based rates while minimizing impacts to customers.

Residential Service – Heat Pump

Current and Proposed Rates

	Current Rate	Proposed Rate Current Structure
Customer Charge	$ 16.31	$ 22.00
Demand Charge	-	$ -
Energy Charge		
Non-Summer		
First 300 kWh	$ 0.0786	$ 0.0889
Next 450 kWh (First 750)	$ 0.1025	$ 0.1089
Remaining kWh	$ 0.0934	$ 0.0950
All kWh		
Summer		
First 300 kWh	$ 0.0786	$ 0.0889
Next 450 kWh (First 750)	$ 0.1025	$ 0.1089
Next 1,250 kWh	$ 0.1397	$ 0.1289
Remaining kWh	$ 0.1511	$ 0.1489
All kWh		
Avg. No. Customers	2,573	
Avg. Usage Per month	1,220	
Avg. Bill Per Month	$ 134.81	$ 145.47
Avg. Monthly Increase		$ 10.67
Avg. Percent Increase		7.9%

1.3.4 Small General Service – Gas Heat

The rate structure for the small general service – gas heat rate class is a seasonal inclining-block rate structure. Inclining-block rates are not reflective of actual costs and create subsidies between customers in the rate class. High use customers are providing a subsidy by paying more than their fair share of these costs. Low use customers are receiving a subsidy by not fully paying their fair share of these costs. This situation is being exacerbated because the customer charge is below cost, which means customer-related costs are being recovered in the high use blocks of the energy charge instead of the customer charge. The proposed inclining-block rates have a smaller differential between the first and last blocks to reduce this impact on high usage customers.

The following table for the small general service – gas heat rate class shows the current and proposed rates, the average monthly bill under both rate structures, and the percent increase for an average usage customer. The average usage is calculated by taking the total kWh for the class and dividing it by the total number of customer bills for the year. The comparison was based on an average usage customer because the increase shown would be reflective of the percent increase in the total revenue for each rate class. This is a common metric in the industry to show percentage increases. The current customer charge is $16.51 for single phase customers and $27.20 for three-phase customers. The cost-of-service study shows a cost-based customer charge of $30.14 for single phase customers and $40.83 for three-phase customers. The proposed customer charge is $22.00 for single phase customers and $33.00 for three phase customers. Due to the difference between the current customer charge and the cost-based customer charge, The Prime Group recommended a gradual increase in the customer charge. Gradual increases allow for movement in the direction of cost-based rates while minimizing impacts to customers.

Small General Service – Gas Heat

Current and Proposed Rates

	Current Rate	Proposed Rate Current Structure
1-Phase Customer Charge	$ 16.51	$ 22.00
3-Phase Customer Charge	$ 27.20	$ 33.00
Demand Charge	-	$ -
Energy Charge		
Non-Summer		
First 500 kWh	$ 0.0847	$ 0.0923
Remaining kWh	$ 0.1079	$ 0.1123
All kWh		
Summer		
First 500 kWh	$ 0.0847	$ 0.0923
Next 1000 kWh	$ 0.1079	$ 0.1123
Remaining kWh	$ 0.1489	$ 0.1373
All kWh		
Avg. No. Customers	4,362	
Avg. Usage Per month	1,426	
Avg. Bill Per Month	$ 177.85	$ 186.65
Avg. Monthly Increase		$ 8.80
Avg. Percent Increase		4.9%

1.3.5 Small General Service – Electric Heat

The rate structure for the small general service – electric heat rate class is a seasonal inclining-block rate structure. Inclining-block rates are not reflective of actual costs and create subsidies between customers in the rate class. High use customers are providing a subsidy by paying more than their fair share of these costs. Low use customers are receiving a subsidy by not fully paying their fair share of these costs. This situation is being exacerbated because the customer charge is below cost, which means customer-related costs are being recovered in the high use blocks of the energy charge instead of the customer charge. The proposed inclining-block rates have a smaller differential between the first and last blocks to reduce this impact on high usage customers.

The following table for the small general service – electric heat rate class shows the current and proposed rates, the average monthly bill under both rate structures, and the percent increase for an average usage customer. The average usage is calculated by taking the total kWh for the class and dividing it by the total number of customer bills for the year. The comparison was based on an average usage customer because the increase shown would be reflective of the percent increase in the total revenue for each rate class. This is a common metric in the industry to show percentage increases. The current customer charge is $16.51 for single phase customers and $27.20 for three-phase customers. The cost-of-service study shows a cost-based customer charge of $30.12 for single phase customers and $40.81 for three-phase customers. The proposed customer charge is $22.00 for single phase customers and $33.00 for three phase customers. Due to the difference between the current customer charge and the cost-based customer charge, The Prime Group recommended a gradual increase in the customer charge. Gradual increases allow for movement in the direction of cost-based rates while minimizing impacts to customers.

Small General Service – Electric Heat

Current and Proposed Rates

	Current Rate	Proposed Rate Current Structure
1-Phase Customer Charge	$ 16.51	$ 22.00
3-Phase Customer Charge	$ 27.20	$ 33.00
Demand Charge	-	$ -
Energy Charge		
Non-Summer		
First 500 kWh	$ 0.0847	$ 0.0923
Next 1000 kWh	$ 0.1079	$ 0.1123
Remaining kWh	$ 0.0993	$ 0.1043
All kWh		
Summer		
First 500 kWh	$ 0.0847	$ 0.0923
Next 1000 kWh	$ 0.1079	$ 0.1123
Remaining kWh	$ 0.1489	$ 0.1373
All kWh		
Avg. No. Customers	1,216	
Avg. Usage Per month	1,796	
Avg. Bill Per Month	$ 210.53	$ 221.93
Avg. Monthly Increase		$ 11.40
Avg. Percent Increase		5.4%

1.3.6 Small General Service – Heat Pump

The rate structure for the small general service –heat pump rate class is a seasonal inclining-block rate structure. Inclining-block rates are not reflective of actual costs and create subsidies between customers in the rate class. High use customers are providing a subsidy by paying more than their fair share of these costs. Low use customers are receiving a subsidy by not fully paying their fair share of these costs. This situation is being exacerbated because the customer charge is below cost, which means customer-related costs are being recovered in the high use blocks of the energy charge instead of the customer charge. The proposed inclining-block rates have a smaller differential between the first and last blocks to reduce this impact on high usage customers.

The following table for the small general service – heat pump rate class shows the current and proposed rates, the average monthly bill under both rate structures, and the percent increase for an average usage customer. The average usage is calculated by taking the total kWh for the class and dividing it by the total number of customer bills for the year. The comparison was based on an average usage customer because the increase shown would be reflective of the percent increase in the total revenue for each rate class. This is a common metric in the industry to show percentage increases. The current customer charge is $16.51 for single phase customers and $27.20 for three-phase customers. The cost-of-service study shows a cost-based customer charge of $30.43 for single phase customers and $41.12 for three-phase customers. The proposed customer charge is $22.00 for single phase customers and $33.00 for three phase customers. Due to the difference between the current customer charge and the cost-based customer charge, The Prime Group recommended a gradual increase in the customer charge. Gradual increases allow for movement in the direction of cost-based rates while minimizing impacts to customers.

Small General Service – Heat Pump

Current and Proposed Rates

	Current Rate	Proposed Rate Current Structure
1-Phase Customer Charge	$ 16.51	$ 22.00
3-Phase Customer Charge	$ 27.20	$ 33.00
Demand Charge	-	$ -
Energy Charge		
Non-Summer		
First 500 kWh	$ 0.0847	$ 0.0923
Next 1000 kWh	$ 0.1079	$ 0.1123
Remaining kWh	$ 0.0936	$ 0.0983
All kWh		
Summer		
First 500 kWh	$ 0.0847	$ 0.0923
Next 1000 kWh	$ 0.1079	$ 0.1123
Remaining kWh	$ 0.1489	$ 0.1373
All kWh		
Avg. No. Customers	29	
Avg. Usage Per month	1,600	
Avg. Bill Per Month	$ 183.63	$ 194.89
Avg. Monthly Increase		$ 11.26
Avg. Percent Increase		6.1%

1.3.7 Small General Service – Optional Demand

The rate structure for the small general service – optional demand rate class is a three-part rate structure. The customer charge is adequate, which means customer-related costs are being recovered fairly through the customer charge. The energy and demand charges were changed slightly to make them more reflective of actual costs.

The following table for the small general service – optional demand rate class shows the current and proposed rates, the average monthly bill under both rate structures, and the percent increase for an average usage customer. The average usage is calculated by taking the total kWh for the class and dividing it by the total number of customer bills for the year. The average demand is calculated by taking the total demand for the class and dividing it by the total number of customer bills for the year. The comparison was based on an average usage customer because the increase shown would be reflective of the percent increase in the total revenue for each rate class. This is a common metric in the industry to show percentage increases.

Small General Service – Optional Demand

Current and Proposed Rates

	Current Rate	Proposed Rate Current Structure
Customer Charge	$ 47.05	$ 47.05
Demand Charge		
Summer	$ 16.31	$ 17.48
Non-Summer	$ 13.07	$ 14.01
Energy Charge		
Summer	$ 0.0588	$0.0588
Non-Summer	$ 0.0513	$0.0539
Avg. No. Customers	89	
Avg. Usage Per month	6,122	
Avg. Bill Per Month	$ 577.77	$602.39
Avg. Monthly Increase		$ 24.62
Avg. Percent Increase		4.3%

1.3.8 Large General Service

The rate structure for the large general service rate class is a three-part rate structure. The customer charge is below cost, which means customer-related costs are being recovered in the demand or energy charge instead of the customer charge. This means that customers who use more energy relative to their demands are providing a subsidy by paying more than their fair share of these costs. Customers who use less energy relative to their demands are receiving a subsidy by not fully paying their fair share of these costs. The energy and demand charges were changed slightly to make them more reflective of actual costs.

The following table for the large general service rate class shows the current and proposed rates, the average monthly bill under both rate structures, and the percent increase for an average usage customer. The average usage is calculated by taking the total kWh for the class and dividing it by the total number of customer bills for the year. The average demand is calculated by taking the total demand for the class and dividing it by the total number of customer bills for the year. The comparison was based on an average usage customer because the increase shown would be reflective of the percent increase in the total revenue for each rate class. This is a common metric in the industry to show percentage increases. The current customer charge is $46.13. The cost-of-service study shows a cost-based customer charge of $72.64. The proposed customer charge is $65.00. Due to the difference between the current customer charge and the cost-based customer charge, The Prime Group recommended a gradual increase in the customer charge. Gradual increases allow for movement in the direction of cost-based rates while minimizing impacts to customers.

Large General Service

Current and Proposed Rates

	Current Rate	Proposed Rate
Customer Charge	$ 46.13	$ 65.00
Demand Charge		
Summer Addional kW	$ 15.99	$ 16.92
Non-Summer Additional kW	$ 12.81	$ 13.74
Summer First 25	$ 369.04	$ 423.00
Non-Summer First 25	$ 276.78	$ 343.50
Energy Charge		
Summer	$ 0.0577	$ 0.0570
Non-Summer	$ 0.0503	$ 0.0496
Summer Energy Storage	$ 0.0459	$ 0.0459
Winter Energy Storage	$ 0.0400	$ 0.0400
Avg. No. Customers	1,048	
Avg. Usage Per month	29,161	
Avg. Bill Per Month	$ 2,734.89	$ 2,851.47
Avg. Monthly Increase		$ 116.58
Avg. Percent Increase		4.3%

1.3.9 Interruptible Service

The rate structure for the interruptible service rate class is a three-part rate structure. The customer charge is below cost, which means customer-related costs are being recovered in the demand or energy charge instead of the customer charge. This means that customers who use more energy relative to their demands are providing a subsidy by paying more than their fair share of these costs. Customers who use less energy relative to their demands are receiving a subsidy by not fully paying their fair share of these costs. The energy and demand charges were changed slightly to make them more reflective of actual costs.

The following table for the interruptible service rate class shows the current and proposed rates, the average monthly bill under both rate structures, and the percent increase for an average usage customer. The average usage is calculated by taking the total kWh for the class and dividing it by the total number of customer bills for the year. The average demand is calculated by taking the total demand for the class and dividing it by the total number of customer bills for the year. The comparison was based on an average usage customer because the increase shown would be reflective of the percent increase in the total revenue for each rate class. This is a common metric in the industry to show percentage increases. The current customer charge is $61.20. The cost-of-service study shows a cost-based customer charge of $72.62. The proposed customer charge is $65.00. Due to the difference between the current customer charge and the cost-based customer charge, The Prime Group recommended a gradual increase in the customer charge. Gradual increases allow for movement in the direction of cost-based rates while minimizing impacts to customers.

Interruptible Service

Current and Proposed Rates

	Current Rate	Proposed Rate
Customer Charge	$ 61.20	$ 65.00
Demand Charge		
Summer	$ 10.28	$ 10.89
Non-Summer	$ 8.23	$ 8.84
Energy Charge		
Summer	$ 0.0478	$ 0.0455
Non-Summer	$ 0.0447	$ 0.0424
Avg. No. Customers	2	
Avg. Usage Per month	45,277	
Avg. Bill Per Month	$ 9,672.77	$ 10,089.21
Avg. Monthly Increase		$ 416.44
Avg. Percent Increase		4.3%

1.3.10 Industrial Service

The rate structure for the industrial service rate class is a three-part rate consisting of a customer charge, a blocked demand charge and a seasonal time-of-use energy charge. The customer charge is below cost, which means customer-related costs are being recovered in the demand or energy charge instead of the customer charge. This means that customers who use more energy relative to their demands are providing a subsidy by paying more than their fair share of these costs. Customers who use less energy relative to their demands are receiving a subsidy by not fully paying their fair share of these costs. The energy and demand charges were changed slightly to make them more reflective of actual costs.

The following table for the industrial service rate class shows the current and proposed rates, the average monthly bill under both rate structures, and the percent increase for an average usage customer. The average usage is calculated by taking the total kWh for the class and dividing it by the total number of customer bills for the year. The average demand is calculated by taking the total demand for the class and dividing it by the total number of customer bills for the year. The comparison was based on an average usage customer because the increase shown would be reflective of the percent increase in the total revenue for each rate class. This is a common metric in the industry to show percentage increases. The current customer charge is $161.45. The cost-of-service study shows a cost-based customer charge of $285.27. The proposed customer charge is $200.00. Due to the difference between the current customer charge and the cost-based customer charge, The Prime Group recommended a gradual increase in the customer charge. Gradual increases allow for movement in the direction of cost-based rates while minimizing impacts to customers.

Industrial Service

Current and Proposed Rates

	Current Rate	Proposed Rate
Customer Charge	$ 161.45	$ 200.00
Demand Charge		
Summer Addional kW	$ 22.27	$ 24.63
Non-Summer Additional kW	$ 17.76	$ 19.13
Summer First 750	$ 16,705.93	$ 18,472.50
Non-Summer First 750	$ 13,316.74	$ 14,347.50
Energy Charge		
Summer On-Peak	$ 0.0509	$ 0.0509
Summer Off_Peak	$ 0.0386	$ 0.0399
Non-Summer On-Peak	$ 0.0435	$ 0.0435
Non-Summer Off-Peak	$ 0.0346	$ 0.0345
Summer Energy Storage	$ 0.0376	$ 0.0376
Winter Energy Storage	$ 0.0337	$ 0.0337
Avg. No. Customers	27	
Avg. Usage Per month	739,897	
Avg. Bill Per Month	$ 63,047.00	$ 65,730.89
Avg. Monthly Increase		$ 2,683.88
Avg. Percent Increase		4.3%

1.3.11 Special Outdoor Lighting

The rate structure for the special outdoor lighting rate class is a two-part rate structure. The customer charge is adequate, which means customer-related costs are being recovered fairly through the customer charge. The energy charge was changed slightly to make it more reflective of actual costs.

The following table for the special outdoor lighting rate class shows the current and proposed rates, the average monthly bill under both rate structures, and the percent increase for an average usage customer. The average usage is calculated by taking the total kWh for the class and dividing it by the total number of customer bills for the year. The comparison was based on an average usage customer because the increase shown would be reflective of the percent increase in the total revenue for each rate class. This is a common metric in the industry to show percentage increases.

Special Outdoor Lighting

Current and Proposed Rates

	Current Rate	Proposed Rate
Customer Charge	$ 56.10	$ 56.10
Energy Charge		
All kWh	$ 0.1274	$ 0.1337
Avg. No. Customers	29	
Avg. Usage Per month	2,983	
Avg. Bill Per Month	$ 436.17	$ 454.96
Avg. Monthly Increase		$ 18.79
Avg. Percent Increase		4.3%

1.3.12 Dusk to Dawn Lighting

The rate structure for the dusk to dawn lighting service rate class consists of a monthly light charge that is based on lumens. The light charges are below cost, which means that the actual costs are not being recovered through the customer charge. This rate class has the lowest rate of return for any class at -19.54%. This rate class needs 198% increase to get to breakeven. The proposed increase, while significant, does not fully recover the cost of providing service to these customers.

The following table for the dusk to dawn lighting service rate class shows the current and proposed rates and the percent increase for each type of light.

Dusk to Dawn Lighting

Current and Proposed Rates

Lumen Range	Current Rate	Proposed Rate	Increase
7,000 to 11,000	$ 6.00	$ 9.94	$ 3.94
25,000 to 30,000	$ 12.97	$ 21.48	$ 8.51
42,000 to 52,000	$ 15.57	$ 25.78	$ 10.21
7,000 to 11,000 Post-top	$ 9.72	$ 16.10	$ 6.38
Avg. Percent Increase		65.6%	

1.4 Evaluation of Revenue at Risk

The goal of cost-based rate design is to recover fixed and variable costs as fairly as possible from both large and smaller usage customers. Oftentimes, rates deviate from this principle by having monthly fixed charges that are too low and energy charges that are too high. This leads to the utility being more sensitive to weather patterns. During periods of mild weather, the utility is not selling enough electricity to recover its fixed costs, meaning that the utility's revenue is at risk. The Prime Group used information in this analysis to adjust Columbia Utilities' proposed rates. Customer charges and demand charges that were too low were increased to be more reflective of cost-based rates while also considering the bill impact of these changes. The Prime Group also reduced the price differential between the first block and last block on residential and small general service rates.

The Prime Group put together a table showing the revenue that is at risk for each rate class due to the monthly customer charge being below the cost-based customer charge from the cost-of-service study:

Revenue at Risk by Rate Class – Customer Charges

	Current Charge	COSS Cost Based Charge	Annual Bills	Revenue at Risk
Residential Service - Gas Heat	$ 16.31	30.19	337,402	$ 4,682,797
Residential Service - Electric Heat	$ 16.31	30.19	158,527	$ 2,199,997
Residential Service - Heat Pump	$ 16.31	30.19	30,871	$ 428,522
Small General Service - Gas Heat 1 Phase	$ 16.51	30.14	27,336	$ 372,590
Small General Service - Gas Heat 3 Phase	$ 27.20	40.83	25,008	$ 340,859
Small General Service - Electric Heat 1 phase	$ 16.51	30.12	7,368	$ 100,278
Small General Service - Electric Heat 3 phase	$ 27.20	40.81	7,224	$ 98,319
Small Commercial - Heat Pump 1 phase	$ 16.51	30.43	240	$ 3,341
Small Commercial - Heat Pump 3 phase	$ 27.20	41.12	108	$ 1,503
Small General Service - Optional Demand	$ 47.05	39.98	1,065	$ (7,533)
Large General Service	$ 46.13	72.64	12,571	$ 333,317
Interruptible Service	$ 61.20	72.62	24	$ 274
Industrial Service	$ 161.45	285.27	324	$ 40,119
				$ 8,594,385

The Prime Group also noted that the cost of energy in the first block of the residential service, small general service, and small commercial – heat pump rates is below the average kwh rate from the cost-of-service study. The table below shows the revenue at risk for these rates:

Revenue at Risk for Residential and Small General Service Rate Classes – First Block of Energy Charge

	First Block kWh	First Block Rate	Avg. Kwh Rate	Revenue at Risk
Residential Service - Gas Heat	92,202,847	$ 0.0786	$ 0.1009	$ 2,056,123
Residential Service - Electric Heat	45,093,750	$ 0.0786	$ 0.0962	$ 793,650
Residential Service - Heat Pump	9,101,116	$ 0.0786	$ 0.0971	$ 168,371
Small General Service - Gas Heat	19,465,427	$ 0.0847	$ 0.1096	$ 484,689
Small General Service - Electric Heat	5,877,622	$ 0.0847	$ 0.1051	$ 119,903
Small Commercial - Heat Pump	150,530	$ 0.0847	$ 0.1023	$ 2,649
				$ 3,625,386

The Prime Group also noted that the demand charge in the small general service – optional demand, large general service, interruptible service, and industrial service rates is below the cost-based demand charge from the cost-of-service study. The table below shows the revenue at risk for these rates:

Revenue at Risk by Rate Class – Demand Charges

	Billed Demand	Avg. Demand Charge	COSS Demand Charge	Revenue at Risk
Small General Service - Optional Demand	15,025	$ 14.19	$ 20.04	$ 87,865
Large General Service	764,600	$ 18.77	$ 24.74	$ 4,563,652
Interruptible Service	20,332	$ 8.90	$ 7.23	$ (33,974)
Industrial Service	250,572	$ 38.15	$ 42.97	$ 1,209,391
				$ 5,826,934

The Prime Group also noted that distribution demand related costs are built into the energy charge in the residential service, small general service, and small commercial – heat pump rates. In situations where customers in these rate classes are using solar or other forms of distributed generation, the distribution demand related cost recovery is at risk. The table below shows the distribution-demand related costs per kilowatt hour at risk for these rates:

Revenue at Risk for Residential and Small General Service Rate Classes – Distribution Demand Related Costs

	Per kWh at Risk
Residential Service - Gas Heat	$ 0.0317
Residential Service - Electric Heat	$ 0.0438
Residential Service - Heat Pump	$ 0.0419
Small General Service - Gas Heat	$ 0.0272
Small General Service - Electric Heat	$ 0.0327
Small Commercial - Heat Pump	$ 0.0318

1.5 Power Cost Adjustment

A power cost adjustment (PCA) is a stand-alone adjustment mechanism that captures the change in current purchased power cost compared to purchased power cost included in base rates. PCAs ensure that customers pay the actual cost of purchased power with no margins or losses. These mechanisms protect the utility from fluctuations in purchased power cost. These types of mechanisms are very common in the industry.

The criteria used by regulators to justify the need for fuel and purchased power adjustment mechanisms includes (i) the cost is large, (ii) the cost varies over time, and (ii) the cost is out of the control of the utility.

The Council would approve the mechanism but not the individual charges or credits that the mechanism calculates. Once the mechanism is approved, the charges and credits calculated by the mechanism will be billed each month.

The utility would bill based on an approved mechanism by preparing a monthly calculation that would compare current purchased power and transmission costs to the base 2021 cost. In months where the costs increase, a charge would be applied to customers' bills. In months when the costs decrease, a refund would be applied to the customers' bills. The base purchased power cost for the PCA would be based on 2021 purchased power and transmission cost. The mechanism would use a fiscal year of costs with a true-up calculation at the end of the year. The mechanism would begin with a year of forecasted information. This forecasted information is replaced with actual data as the year progresses. The year end true-up is calculated using 12 months of actual costs and sales.

Basic Formula is as follows:

((Purchased power cost for the fiscal year – (Purchased power revenue from PCA base + PCA factors for the fiscal year)) / expected sales remaining in the fiscal year) + True-up Factor

1.6 Identification of Costs Associated with Expansion and Connection to Electric System

Line extension policies are used to ensure fairness and equity among all customers in a rate class. The purpose of a line extension policy is to make new customers look "average" for rate purposes. This is done by determining the level of investment that the rates will support. Any new homes or buildings will be given facilities consistent with what rates currently support. Line extension policies that do not achieve this goal by giving new customers more investment than the rates support will result in a utility's financial position degrading as new customers are added to the system. Conversely, line extension policies that provide less facilities than what the current rates support will require an excessive Contribution in Aid of Construction (CIAC) from new customers. Rates are averages and they recover the carrying costs associated with the average plant investment that applies to a particular rate class. Without a line extension policy, growth can cause the need for rate increases. Not only does line extension policy promote fairness and equity but it also promotes rate stability.

Rates should include some "standard" level of service facilities that are built into base rates but should not include non-standard facilities. The cost of non-standard facilities should be borne by customers that receive the benefit from their installation. Line extension policy should ensure that all customers receive a standard set of facilities and that customers who need, or want, additional facilities beyond those built into base rates, pay for those facilities through a contribution in aid of construction.

The Prime Group evaluated the economics of Columbia Utilities' current line extension policy. The results are shown in the tables below. The first table shows the amount of investment that can be supported by Columbia Utilities' rates. The amount of investment is calculated as a multiple of net revenue. Net revenue is total revenue less purchased power revenue. 6.87 times net revenue represents the maximum amount of revenue that Columbia Utilities can give as a revenue credit. It is generally recommended that utilities do not give the full amount because customers receiving the full amount would not be making any contribution to the utility's fixed costs. Under that scenario, there is no benefit to other customers from growth. As a result, utilities generally use approximately half the calculated factor in line extension policies. Many times, residential line extension policies will provide a dollar revenue credit and commercial policies will use a revenue test based on projected revenue on a case-by-case basis. For example, if a factor of 3 is used to calculate the residential credit, commercial policies will calculate the credit on an individual case by case basis, using 3 times the estimated net revenue the customer is expected to produce.

Times Net Revenue Calculation – Columbia Utilities

Assumptions:		
Investment	$ 1,000,000	
Book Life	30	
Tax Life	20	
Composite Tax Rate	0.00%	
Property Tax Rate	2.53%	
Levelized Revenue Requirement Years	30	
O&M as Percent of Investment	5.26%	
Escalation Rate for O&M	3.00%	
Results:		
Present Value Revenue Requirement	$ 2,516,141	
Levelized Revenue Requirement	$145,509	
Levelized Carrying Charge Rate	14.55%	
Level of Investment that can be Supported by Revenue	6.87	Times Net Revenue

The second table shows the amount of line extension per residential class that Columbia Utilities' rates will support using a factor of 3 times net revenue:

Line Extension Credits (Per Customer) Based on 3 Times Net Revenue – Residential Rates

	Residential Service Gas Heat	Residential Service Electric Heat	Residential Service Heat Pump	Residential Service Combined
Test Year Base Rate Revenue	$ 29,812,309.24	$ 16,776,248.37	$ 4,134,766.58	$ 50,723,324.19
Less: Purchase Power Cost	$ 15,812,521.03	$ 10,146,940.35	$ 2,558,080.57	$ 28,517,541.95
Net Revenue	$ 13,999,788.21	$ 6,629,308.02	$ 1,576,686.01	$ 22,205,782.24
Average Number of Customers	28,117	13,211	2,573	43,900
Average Non-Fuel Revenue Per Customer	$ 497.91	$ 501.82	$ 612.88	$ 505.83
Less: Average Annual Meter Reading and Billing Cost	$ 114.94	$ 114.94	$ 114.94	$ 114.94
Carrying Cost on Meter, Service, & Transformer	$ 103.60	$ 137.26	$ 149.20	$ 116.40
Average Net Revenue Per Customer	$ 279.37	$ 249.62	$ 348.74	$ 274.48
Amount Times Net Revenue Rate will Support	6.87	6.87	6.87	6.87
Amount Times Net Revenue Selected to Ensure Contribution to Fixed Cost	3.00	3.00	3.00	3.00
Cost of Line Extension (Per Customer) Provided With No Contribution	$ 838.12	$ 748.86	$ 1,046.23	$ 823.45

The third table shows the amount of line extension per small general service class that Columbia Utilities' rates will support using a factor of 3 times net revenue:

Line Extension Credits (Per Customer) Based on 3 Times Net Revenue – Small General Service Rates

	Small General Service Gas Heat	Small General Service Electric Heat	Small Commercial Heat Pump	Small General Service / Comm. Combined
Test Year Base Rate Revenue	$ 9,250,571.08	$ 3,108,042.56	$ 63,762.64	$ 12,422,376.28
Less: Purchase Power Cost	$ 4,573,498.41	$ 1,666,006.06	$ 35,334.34	$ 6,274,838.81
Net Revenue	$ 4,677,072.67	$ 1,442,036.50	$ 28,428.30	$ 6,147,537.47
Average Number of Customers	4,362	1,216	29	5,607
Average Non-Fuel Revenue Per Customer	$ 1,072.23	$ 1,185.89	$ 980.29	$ 1,096.40
Less: Average Annual Meter Reading and Billing Cost	$ 114.94	$ 114.94	$ 114.94	$ 114.94
Carrying Cost on Meter, Service, & Transformer	$ 135.59	$ 159.05	$ 144.35	$ 140.73
Average Net Revenue Per Customer	$ 821.70	$ 911.90	$ 721.00	$ 840.74
Amount Times Net Revenue Rate will Support	6.87	6.87	6.87	6.87
Amount Times Net Revenue Selected to Ensure Contribution to Fixed Cost	3.00	3.00	3.00	3.00
Cost of Line Extension (Per Customer) Provided With No Contribution	$ 2,465.10	$ 2,735.69	$ 2,162.99	$ 2,522.22

1.7 Identification of Other Potential Income Sources

The Prime Group identified several areas of focus for developing other income sources:

- Electric Vehicles
- Economic Development Rates
- Pole Attachment Charges
- Excess Facilities
- Miscellaneous Charges

Electric vehicles are a fast-growing segment of vehicle sales. Since electric vehicles are typically connected to home charging stations during off-peak hours, increased numbers of electric vehicles will result in additional revenue but typically without creating the need to install new generation, transmission or even distribution capacity to serve the load. The revenues generated by charging electric vehicles have the effect of lowering rates to other customers, by spreading utility fixed costs over a larger sales volume. Columbia Utilities could help increase electric vehicle sales by installing Level 3 charging stations in strategic areas around the city. EDRs can have the effect of lowering rates to other customers, by spreading utility fixed costs over a larger sales volume.

Economic Development Rates ("EDRs") are a vehicle for the utility to provide an incentive to large commercial or industrial customers to locate a facility in the utility service territory. EDRs can also be used for the attraction and/or retention of large commercial or industrial customers. The incentive is in the form of a discount from the utility's standard tariff rates, terms, or conditions.

Columbia Utilities can also create income through pole attachment charges. These charges are based on renting space on overhead conductor poles to other utilities (cable television, telecommunication, etc.). This type of charge is typically assessed on an annual or semi-annual basis.

Excess facilities charges are essentially the same concept as a line extension policy. These charges apply to customer requests for service arrangements requiring equipment and facilities in excess of those the utility would normally install. Examples of excess facilities include requests for non-standard facilities such as emergency backup feeds, automatic transfer switches, redundant transformer capacity, and duplicate or check meters. Excess facility charges help ensure equitable treatment of all customers on the utility's system.

The Prime Group identified several types of miscellaneous charges that could be implemented or updated:

- Late Payment Charge
- Disconnect / Reconnect Charge
- Return Check Fee
- Meter Test Charge
- Meter Pulse Charge (Demand Pulse)
- Redundant capacity charge (in combination with automatic switchgear, which could be recoverable through an Excess Facilities Charge)

1.8 Analysis of the Effect of Renewable Targets on Rates

In 2004, the City of Columbia approved an Ordinance for generating and/or purchasing increasing levels of energy from renewable resources detailed below:

- 15% of electric retail usage by December 31, 2017
- 25% of electric retail usage by December 31, 2023
- 30% of electric retail usage by December 31, 2028

The Ordinance stipulates that renewable energy cannot cause electric rates to increase more than 3% above what rates would be with non-renewable energy. The Prime Group was tasked with evaluating the rate impact of the Ordinance's renewable energy targets on rates as a part of this project.

To evaluate whether the cost of renewable energy was still within the range set by the Ordinance, a Revenue Requirement analysis was performed based on a Marginal Cost of Energy approach. This analysis compared the cost of procuring each MWh of Renewable energy based on the City's fleet of renewable facilities and PPAs to how much that MWh would have cost CWL if procured from either the MISO Market or the Sikeston Generating Station which is CWL's lowest cost fossil resource. This is a similar evaluation done by the CWL in their annual Renewable Report. The City currently procures enough capacity to meet its peak load requirements without the renewable PPAs, so the Marginal Cost analysis looks strictly at Energy costs only, removing any capacity costs from both renewables and non-renewable resources.

Once the difference between the cost of each renewable facility and the cost of non-renewable energy per MWh was determined, the difference was applied to the number of MWhs purchased from each renewable resource to determine the total cost of renewable energy with one caveat. Transmission congestion costs from the Crystal Lake Wind Farm were incorporated into that facility's cost of energy due to market charges being incurred for energy to be delivered to the City's market pricing node from the MISO market. Once the total cost of Renewable energy was determined, it was then compared to the 3% limit stipulated in the Ordinance based on the total energy revenues collected from the City during each Calendar Year. If the cost of renewables was less than the 3% limit, the difference should be applied to any congestion and loss costs incurred from procuring energy from Crystal Lake since future congestion costs were not forecast due to their complexity.

Each calendar year from 2020 to 2028 was evaluated using metrics from the Financial Forecast for increases in O&M and Purchased Power costs and changes in CWL's renewable resource portfolio. These changes were:

- Crystal Lake Repower and additional energy added in 2022/23
- Truman Solar PV added in 2021
- Expansion of Columbia Landfill Gas plant in 2022
- Net Metering increases each year based on increases from 2020 and 2021

If in any year the renewable energy target was not achieved with the contracts in place and the estimated output of the renewable resources, Wind Renewable Energy Credits ("REC") were added to ensure the renewable energy target was reached. These RECs were priced at the values seen in 2020 for future years.

The analysis showed that under the approach comparing the costs of replacement energy from the Sikeston generating station, CWL was within the 3% limit established by the ordinance for 2020 and all future years and has a reasonable cushion to absorb congestion costs. In 2021 there was a small exceedance of the 3% limit due to increased congestion costs from Crystal Lake. Using the alternative approach where replacement energy is procured from the MISO Energy Market, CWL stayed within the 3% limit in all future years prior to market congestion being factored in and had a slight exceedance the 3% limit in 2020 since the MISO market power replacement cost was lower than Sikeston. The average MISO Energy Market cost at the CWLD node was $17.97/MWh in 2020 while Sikeston was $25.86/MWh. In 2021 MISO Energy Market cost was $36.25/MWh while Sikeston was $23.75/MWh.

Ideally, CWL should use the lesser of the MISO Market or Sikeston costs on a $/MWh basis to compare the cost of renewable procurement for future analyses.

Below are the summary tables for the analysis:

Summary of Renewable Target Analysis using Sikeston replacement Energy costs

Sikeston Energy Costs	Sikeston Cost of Energy ($/MWh)	Renewable Cost of Energy ($/MWh)	Renewable Cost Impact ($)	Renewable Impact Limit on Rates (3%)	Amount of Limit Achieved *	Remaining funds for Congestion Costs	Renewable MWh	Total Sold MWh	Renewable % **
2020	25.86	36.77	$ 2,387,545	$ 3,729,407	64.02%	$ **1,341,862**	179,780	1,166,405	15.41%
2021	23.75	35.76	$ 3,945,464	$ 3,872,190	101.89%	$ **(73,275)**	178,222	1,218,313	14.63%
2022	23.99	35.76	$ 1,593,693	$ 3,903,822	40.82%	$ **2,310,128**	240,227	1,242,313	19.34%
2023	24.23	35.76	$ 1,298,312	$ 3,935,453	32.99%	$ **2,637,141**	312,988	1,251,887	25.00%
2024	24.47	35.76	$ 1,405,654	$ 3,967,083	35.43%	$ **2,561,429**	315,393	1,261,461	25.00%
2025	24.71	35.76	$ 1,547,268	$ 3,998,712	38.69%	$ **2,451,444**	317,806	1,271,034	25.00%
2026	24.96	35.76	$ 1,735,383	$ 4,030,340	43.06%	$ **2,294,957**	320,743	1,280,608	25.05%
2027	25.21	35.76	$ 1,989,364	$ 4,061,968	48.98%	$ **2,072,604**	325,687	1,290,182	25.24%
2028	25.46	35.76	$ 2,429,534	$ 4,093,595	59.35%	$ **1,664,060**	389,956	1,299,755	30.00%

Summary of Renewable Target Analysis using MISO Market replacement Energy costs

Market Energy Costs	MISO Market Cost of Energy ($/MWh)	Renewable Cost of Energy ($/MWh)	Renewable Cost Impact ($)	Renewable Impact Limit on Rates (3%)	Amount of Limit Achieved	Remaining funds for Congestion Costs	Renewable MWh	Total Sold MWh	Renewable %
2020	17.97	36.77	$ 3,806,009	$ 3,729,407	102.05%	$ (76,602)	179,780	1,166,405	15.41%
2021	36.25	35.76	$ 1,717,689	$ 3,872,190	44.36%	$ 2,154,500	178,222	1,218,313	14.63%
2022	36.61	35.76	$ (1,439,174)	$ 3,903,822	-36.87%	$ 5,342,996	240,227	1,242,313	19.34%
2023	36.98	35.76	$ (2,692,679)	$ 3,935,453	-68.42%	$ 6,628,131	312,988	1,251,887	25.00%
2024	37.35	35.76	$ (2,656,211)	$ 3,967,083	-66.96%	$ 6,623,294	315,393	1,261,461	25.00%
2025	37.72	35.76	$ (2,586,603)	$ 3,998,712	-64.69%	$ 6,585,315	317,806	1,271,034	25.00%
2026	38.10	35.76	$ (2,478,420)	$ 4,030,340	-61.49%	$ 6,508,761	320,743	1,280,608	25.05%
2027	38.48	35.76	$ (2,332,181)	$ 4,061,968	-57.42%	$ 6,394,149	325,687	1,290,182	25.24%
2028	38.86	35.76	$ (2,796,533)	$ 4,093,595	-68.31%	$ 6,890,128	389,956	1,299,755	30.00%

Future improvements related to the cost of renewable energy include the Crystal Lake expansions and repower will bring the average renewable cost down substantially in future years which will reduce the cost of renewable energy in future evaluations compared to the 2021 costs used in this analysis and if the Ironstar Wind project comes to fruition it could reduce costs ever further compared to the current PPAs depending on the delivered cost per MWh which was not factored into this analysis. Conversely, the City has received recent proposals for Solar purchased power agreements that are substantially higher than the 2021 average renewable cost of $35.76/MWh due to high demand for solar equipment and supply chain limitations. Therefore, some projects in the near-term are likely to bring the average cost of renewables lower than what was observed in 2021, but future projects may raise the average renewable costs for future analysis of the City's three percent ordinance and is important to keep in mind when agreements are signed for future renewable resources.

Future concerns related to the cost of renewable energy include future congestion costs from Crystal Lake will likely grow with the expansion and repower taking effect in 2022/2023. These costs could persist for the foreseeable future until MISO Long Range Transmission Plan projects are in service in the late 2020s/early 2030s. Additionally, if Net Metering continues to grow at similar rates as 2020 and 2021, it will become a substantial renewable cost to the City if credits remain at the current retail rates. Ideally, Net Metering customers should be credited at avoided cost rates rather than full retail rates.

1.9 Analysis of Financing Programs

The Prime Group identified several types of financing programs that are currently being implemented by other utilities:

- Pay as You Save (PAYS)
- On-Bill Loans
- Property-Assessed Clean Energy (PACE)
- Revolving Loan Funds
- Energy Efficient Mortgages
- Solar Leases and PPAs
- Shared Solar Program

Pay as You Save (PAYS) is a program where customers pay an additional fixed charge on the utility bill each month to repay the investment in energy efficient upgrades over time. The program only covers improvements where the installed costs of the measures don't exceed 80% of the estimated bill savings or over 80% of the lifetime of the measures. If upgrades do not meet this eligibility criteria, customers have the option of a co-pay to bring the final costs in line with these criteria. The additional fixed charge is capped at 80% of the estimated monthly savings. The fixed charge is removed from the bill after the cost of the upgrades is recovered by the utility. PAYS has a few advantages in that no credit score or minimum income level is required, no debt obligation or lien is placed on the property, and upfront capital is not normally required. The commitment is tied to the meter. Columbia Utilities would need to verify that the billing software has the flexibility to incorporate and track this charge. Ameren Missouri currently has a PAYS pilot program.

On-bill loan programs involve customers paying an additional fixed charge on the utility bill each month to repay the investment in energy efficient upgrades or renewable energy equipment over time. The fixed charge is removed from the bill after the cost of the upgrades is recovered by the utility. This program differs from PAYS because credit checks might be required, the utility might use bill payment history to confirm good standing, and the customer accepts a debt obligation. No upfront capital is required by the customer. The commitment is tied to the customer instead of the meter. There are two types of on-bill loan programs: on-bill financing, where the capital comes from the utility, and on-bill repayment, where the capital comes from non-utility sources. Columbia Utilities would need to verify that the billing software has the flexibility to incorporate and track this charge.

Property Assessed Clean Energy (PACE) is a program where customers voluntarily commit to an assessment process and pay an additional charge on the property tax bill each year to repay the investment in energy efficient upgrades or renewable facilities over time (usually 10 to 20 years). The commitment is tied to the property. Upfront capital is not usually required by the customer. There have been several complaints concerning this program. Eligibility is not usually based on the customer's ability to repay the obligation (income and FICO scores). There is difficulty selling homes with PACE obligations. There have been situations where there are large differences between the initial assessment estimates and final costs shown on tax bills. Also, Federal Housing Administration (FHA) insured financing is not available to homes with PACE obligations.

Revolving loan funds involve a pool of capital that is used to make loans for renewable energy projects or energy efficient upgrades. It can be advantageous because the lender can be more flexible with requirements and terms. The commitment is tied to the customer. This program usually involves a comprehensive credit check process being applied to customers. There can be an issue with the funds being slow to revolve if all loans are for long term projects. To establish a revolving loan funds program, the utility would need to go through the following steps: 1) Determine the purpose, allowed uses, and prohibited uses of the RLF, 2) Determine who will run the program including a) Oversight of program, b) Administrative duties, c) Staffing duties, d) Reviewing loan applications, 3) Set the requirements for borrowers, and 4) Set the loan terms. Additional staff might be necessary to run the program. The utility will need to determine how will the fund be capitalized (bonds, ratepayer funds, other funds, etc.). It should be noted that increased operating costs and inflation may erode the capital base over time.

Energy efficient mortgages (EEMs) allow a customer to finance renewable energy equipment as part of a single mortgage. They can be through a new loan or through refinancing an existing loan. EEMs can be obtained through conventional loans, Federal Housing Administration (FHA) loans, and Veterans Affairs (VA) loans. The borrower has a home energy assessment performed by an energy assessor who provides estimated savings and equipment value to the lender. The lender uses this information to help provide improved financing terms. FHA EEMs only require the borrower to qualify for the portion of the loan used in purchasing or refinancing the home, but a cap is placed on the renewable equipment amount that is added to the loan.

Solar leases and purchased power agreements involve a solar company or PPA financier installing equipment on a customer's roof that they own and maintain. In the case of solar leases, the customer is charged a set monthly rate. For Solar PPAs, the customer is charged a set rate for each kWh the panels generate. This can lead to fluctuation in the customer's monthly bills due to differences in seasonal production. The solar company or PPA financier retains rights to all tax credits, solar RECs, and rebates. Most companies will not require an upfront payment.

Shared solar programs (also known as "community solar") involve the utility installing a solar farm and allowing customers to receive billing credits reflective of the output from the customers' shares of the solar farm. The customer pays a fixed monthly charge for their share of the solar farm and receives billing credits based on the output of the solar share. Utilities that have implemented shared solar programs include Madison Gas and Electric Company, Kentucky Utilities Company, Ameren Missouri, and Evergy. Customers benefit from the higher efficiency of utility grade solar installations in comparison to rooftop solar installations. Utility grade solar installations can provide ancillary services such as reactive power support using smart inverters. Customers are not required to install solar panels on their property.

There are three points of emphasis that need to be considered if Columbia Utilities decides to implement any of these programs. The first point of emphasis is that Columbia Utilities needs to properly establish measurement and calculation requirements for all eligible contractors and energy assessors, as well as requirements on information that must be provided and discussed with the customer. The second point is that the customer needs to be properly educated and informed on all aspects of the program. The third point is that the program should be transparent with the customer by making sure the customer is aware of all costs and fees associated with the program before making a firm commitment.

1.10 Current Charges Compared to Other Utilities of Similar Size and Geographic Region

The Prime Group benchmarked Columbia Utilities' current residential rates in comparison to other utilities. These utilities were identified based on similar size and geographic region. Utilities were selected from the following states: Missouri, Kansas, Iowa, Illinois, Indiana, Kentucky, and Arkansas.

Utilities Used in Benchmarking Analysis

	Residential Customers	Commercial Customers	Industrial Customers	Total Customers
Columbia Water & Light (MO)	43,900	6,745	27	50,672
City Utilities of Springfield (MO)	101,310	15,515	250	117,075
Independence Power & Light Dept. (MO)	51,204	5,167	10	56,381
City Water, Light & Power Springfield (IL)	58,337	11,133	-	69,470
Dept. of Public Utilities - Electric Naperville (IL)	50,622	5,838	10	56,470
Ames Electric Utility (IA)	24,342	3,050	7	27,399
Anderson Municipal Light & Power (IN)	32,860	3,758	69	36,687
Mishawaka Utilities (IN)	23,353	3,681	-	27,034
Kansas City Board of Public Utilities (KS)	56,369	7,120	95	63,584
Cuivre River Electric Cooperative (MO)	54,253	4,895	-	59,148
Southwest Electric Cooperative (MO)	36,506	2,797	-	39,303
White River Valley Electric Cooperative (MO)	35,897	6,716	8	42,621
Midwest Energy (KS)	29,781	18,938	32	48,751
Blue Grass Energy (KY)	52,374	2,594	12	54,980
Arkansas Valley Electric Cooperative Corp. (AR)	53,161	3,967	14	57,142

Rate comparisons were made based on a Columbia Utilities residential customer's average usage. Since there is a seasonal component to Columbia Utilities' residential rates, a comparison was made based on average usage during summer and non-summer months. The average usage for a residential customer was 939 kWh during the summer months and 607 kWh during non-summer months. These average kWh numbers were used in calculating a total bill based on each utility's rate schedule. Some of the utilities in the analysis did not have seasonal rates which led to differences in the analyses of summer and non-summer months.

Comparison of an Average Usage Customer During Summer Months

Average Summer Usage	939	kWh/Month
Blue Grass Energy (KY)	$ 96.12	
Mishawaka Utilities (IN)	$ 96.60	
Southwest Electric Cooperative (MO)	$ 104.80	
Arkansas Valley Electric Cooperative Corp. (AR)	$ 104.87	
Cuivre River Electric Cooperative (MO)	$ 105.45	
Midwest Energy (KS)	$ 108.36	
Anderson Municipal Light & Power (IN)	$ 111.91	
Columbia Water & Light (MO)	$ 112.39	
City Utilities of Springfield (MO)	$ 115.26	
City Water, Light & Power Springfield (IL)	$ 116.49	
Ames Electric Utility (IA)	$ 120.88	
Dept. of Public Utilities - Electric Naperville (IL)	$ 122.38	
Kansas City Board of Public Utilities (KS)	$ 126.82	
White River Valley Electric Cooperative (MO)	$ 127.28	
Independence Power & Light Dept. (MO)	$ 159.20	

The total bill for an average usage summer customer had a range of $96.12 to $159.20. Columbia Utilities was in the middle of this group at $112.39.

Comparison of an Average Usage Customer During Non-Summer Months

Average Non-Summer Usage	607	kWh/Month
Mishawaka Utilities (IN)	$ 66.18	
Blue Grass Energy (KY)	$ 68.20	
Ames Electric Utility (IA)	$ 68.49	
City Water, Light & Power Springfield (IL)	$ 70.99	
Columbia Water & Light (MO)	$ 71.37	
City Utilities of Springfield (MO)	$ 73.13	
Southwest Electric Cooperative (MO)	$ 76.61	
Arkansas Valley Electric Cooperative Corp. (AR)	$ 78.84	
Anderson Municipal Light & Power (IN)	$ 79.34	
Midwest Energy (KS)	$ 79.97	
Cuivre River Electric Cooperative (MO)	$ 80.19	
Dept. of Public Utilities - Electric Naperville (IL)	$ 84.97	
Kansas City Board of Public Utilities (KS)	$ 89.79	
White River Valley Electric Cooperative (MO)	$ 93.27	
Independence Power & Light Dept. (MO)	$ 100.38	

The total bill for an average usage non-summer customer had a range of $66.18 to $100.38. Columbia Utilities was near the low end of this group at $71.37.