STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF THE CITY OF CRAWFORDSVILLE, INDIANA, BY AND THROUGH ITS MUNICIPAL ELECTRIC UTILITY, CRAWFORDSVILLE ELECTRIC LIGHT AND POWER, FOR APPROVAL OF A NEW SCHEDULE OF RATES AND CHARGES AND FOR APPROVAL TO MODIFY ITS ENERGY COST ADJUSTMENT PROCEDURES	))))))))	**CAUSE NO. 45420**

PRE-FILED VERIFIED DIRECT TESTIMONY OF

JOSEPH A. MANCINELLI

AND ATTACHMENTS JAM-1 THROUGH JAM-6

ON BEHALF OF PETITIONER

CRAWFORDSVILLE ELECTRIC LIGHT AND POWER

PETITIONER'S EXHIBIT NO. 4

AUGUST 19, 2020

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I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. My name is Joseph A. Mancinelli. I am the President and Chief Executive Officer ("CEO") of NewGen Strategies and Solutions, LLC ("NewGen"). My business address is 225 Union Boulevard, Suite 305, Lakewood, Colorado, 80228. NewGen is a consulting firm that specializes in utility rates, engineering economics, financial accounting, asset valuation, appraisals, and business strategy for electric, natural gas, water, and wastewater utilities. I am testifying on behalf of the Petitioner, Crawfordsville Electric Light & Power ("CEL&P" or the "Utility"), which is the electric utility owned and operated by the City of Crawfordsville, Indiana ("Crawfordsville").

Q2. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I have more than 30 years of experience in the areas of cost of service ("COS") and rate design for electric, natural gas, water, and wastewater utilities. I have worked closely with public utility commissions, senior management teams, utility boards, city councils, attorneys, and end-users with respect to the strategy and technical fundamentals of COS and rate design. I have taught numerous classes on COS and rate design methodology based on industry methodologies approved by the National Association of Regulatory Utility Commissioners ("NARUC") and the American Public Power Association ("APPA"). I have been extensively involved in the development of unbundled COS and pricing models during my career. A summary of my qualifications is provided within Attachment JAM-1 to this testimony.

Q3. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, as shown in Attachment JAM-1, I have testified before the Indiana Utility Regulatory Commission ("IURC") five times.

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain CEL&P's recommended rate design and supporting cost of service study. With respect to rate design, I will describe CEL&P's rate design objectives and proposed overall rate structure.

Q5. WHICH OF THE MINIMUM STANDARD FILING REQUIREMENTS IN EXHIBIT 5 ARE YOU SPONSORING IN THIS CAUSE?

A. I am sponsoring the following, which correspond to the respective Commission Minimum Standard Filing Requirement ("MSFR") found in 170 IAC 1-5 as indicated below:

- Exhibit 5 (170 IAC 1-5-8(a)(4)) – Pro Forma Revenues, Sales and Number of Customers for the Test Year
- Exhibit 5 (170 IAC 1-5-15(h)) – Cost of Service Study
- Exhibit 5 (170 IAC 1-5-16(b)) – New CEL&P Tariff, Clean Version
- Exhibit 5 (170 IAC 1-5-16(c)) – New CEL&P Tariff, Redlined Version
- Exhibit 5 (170 IAC 1-5-16(d)) – Residential Bill Comparison

Q6. WHAT ATTACHMENTS ARE YOU SPONSORING IN THIS CAUSE?

A. My direct testimony includes the following Attachments:

- Attachment JAM-1 – Resume of Joseph A. Mancinelli
- Attachment JAM-2 – Cost of Service Study Model
- Attachment JAM-3 – Rate Design Model
- Attachment JAM-4 – Clean Version of the Proposed New CEL&P Tariff
- Attachment JAM-5 – Redlined Version of the Proposed New CEL&P Tariff

- Attachment JAM-6 – Rate Comparisons

Q7. WERE THESE EXHIBITS AND ATTACHMENTS PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

II. OVERVIEW OF TESTIMONY

Q8. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY AND RECOMMENDATIONS.

A. My testimony describes the development of CEL&P's cost-of-service study, which allocates CEL&P's Test Year Revenue Requirement ("Revenue Requirement") to each rate class. The cost of service study functionalizes, sub-functionalizes, classifies, and allocates costs using generally accepted methodologies recognized by NARUC and APPA. The cost allocation methodology yields a fair and equitable result based on principles of cost causation. Also, I will discuss in detail the CEL&P's rate design objectives, class revenue targets, proposal to implement requested rate adjustments in two phases over a two-year period, and CEL&P's proposed new tariff. Important considerations in the rate design included:

1. Improving fixed cost recovery of costs associated with current rate structures;
2. Introducing demand charges to General Power ("GP") and Municipal General Power ("MGP") customers;
3. Merging the GP and MGP rate structures;
4. Adding a demand ratchet to GP, MGP, and Primary Power ("PP") rate structures; and
5. Moving certain commercial customers to the appropriate customer class.

Q9. WHAT IS THE TEST PERIOD USED TO PREPARE THE CLASS COST-OF-SERVICE STUDY IN THIS PROCEEDING?

A. The test period used to develop the class cost-of-service study is an historic test year including the twelve-month period ending February 29, 2020 ("Test Year"), with fixed, known and measurable adjustments through February 29, 2021.

Q10. WHEN WERE CEL&P'S CURRENT RATES ESTABLISHED AND APPROVED BY THE COMMISSION?

A. CEL&P's current rates were approved by the Commission's Final Order in Cause No. 44684 issued on April 13, 2006. The Order approved CEL&P's revenue requirement of $37,016,872 (the "Authorized Revenue Requirement").

Q11. DID CEL&P RECOVER THE AUTHORIZED REVENUE REQUIREMENT FOLLOWING THE COMMISSION'S ORDER IN CAUSE NO. 44684?

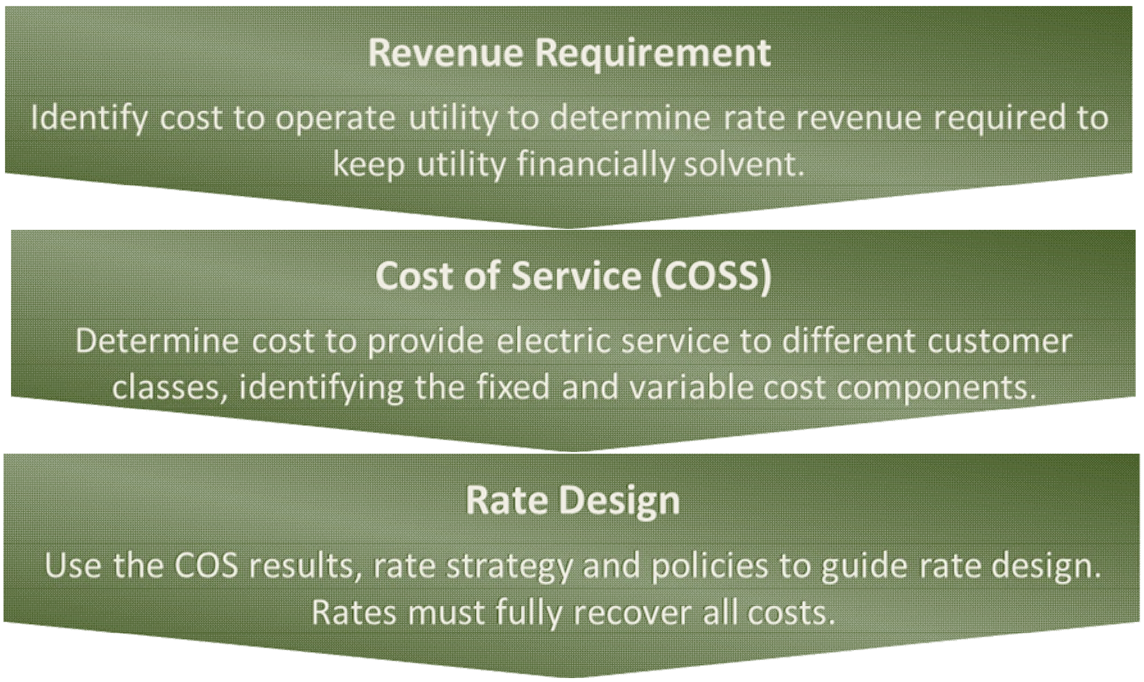
A. No. CEL&P discovered that due to a mathematic error by its prior rate consultant, the tariffed rates approved by the Commission and charged by CEL&P following the 2006 Order failed to collect the Authorized Revenue Requirement. Had CEL&P's tariff accurately calculated rates to collect the Authorized Revenue Requirement, CEL&P would have collected approximately an additional $900,000 annually through rates since the effective date of the 2016 Order. CEL&P has filed a request to correct the error in Cause No. 44684. The affidavits filed in support of CEL&P's motion provides additional facts, calculations and a proposed rider that will correct CEL&P's rates on a prospective basis. With the proposed rider, CEL&P will begin collecting the Authorized Revenue Requirement upon Commission approval of the motion until the rider is superseded by CEL&P's new rates are approved in this proceeding. To be clear, CEL&P is not seeking retroactive recovery of the under collected amounts.

III. RATEMAKING APPROACH

Q12. WHAT ARE THE BASIC STEPS IN THE RATEMAKING PROCESS?

Ratemaking is a three step process, as described in Figure JAM-1 below.

Figure JAM-1
Ratemaking Process



Q13. BRIEFLY DESCRIBE THE PURPOSE OF A COST OF SERVICE STUDY ("COSS").

A. A COSS determines cost responsibility of the various customer classes served by the Utility. Cost responsibility is primarily a function of customer service requirements and usage characteristics. For example, customer service requirements are often related to customer delivery requirements, while customer usage characteristics are related to the demand and energy needs of the customer.

Q14. WHAT ARE THE DIFFERENT TYPES OF COSTS IDENTIFIED BY A COSS?

A. A COSS identifies the underlying nature of costs (or cost classification) which are typically Demand-related, Energy-related, and Customer-related. Demand-related costs are costs that are fixed in nature and do not vary with day-to-day changes in system energy use. Demand-related costs are typically associated with system capacity requirements. To ensure high reliability, utilities like CEL&P must have sufficient infrastructure and/or contracts to meet the system peak whenever that occurs. Demand-related costs are directly attributable to customer and class contribution to localized distribution and centralized system peak demands. Energy-related costs are variable in nature and vary with day-to-day changes in system energy use. Customer-related costs such as billing, collections, and customer service functions, are driven by the number of customers on the system.

Q15. HOW IS CUSTOMER CLASS COST RESPONSIBILITY DETERMINED IN A COSS?

A. Class cost responsibility is based on class contribution to system demand, energy, and customer requirements. In other words, a utility like CEL&P incurs costs to meet customer requirements for electricity service. A COSS maps utility costs to customer classes by examining the underlying drivers of cost required to meet customer electricity needs. The underlying drivers of certain utility costs are well-known and measured. The application of these drivers are used to allocate costs to each customer class in a widely accepted non-controversial manner. For example, the underlying driver of purchased power costs billed on an energy basis is system energy requirements. Therefore, purchased power costs can be allocated to each customer class based on class energy sales adjusted for system losses. Since utilities measure energy usage for most classes, this allocation method is supported by complete information and renders a non-controversial result. However, the underlying drivers of other system costs, particularly Demand-related costs, are less well known. Demand-related costs are allocated to the various customer classes based on a measure of class contribution to peak demand at different locations on the system. Since many utilities, including CEL&P, do not routinely measure peak demand contributions by all customers on the system, the use of ancillary analyses and/or judgment and experience to develop class demand responsibility is required.

Given these cost causation principles and available information, I have prepared a comprehensive cost of service study for CEL&P current customer classes. COSS results determine the cost responsibility of each class. Further, for each class, the COSS indicates levels of customer charges, energy charges, and demand charges.

Q16. PLEASE DESCRIBE HOW YOU PREPARED THE COSS.

A. The COSS was prepared using embedded or average system costs as detailed in the Revenue Requirement for the Test Year, as calculated by witness Jennifer Z. Wilson. The Revenue Requirement was input into NewGen's unbundled cost of service model customized for the CEL&P system (see Attachment JAM-2). The model is organized consistent with an industry standard three step process of functionalization, classification, and allocation of the revenue requirement to various customer classes.

Q17. WHAT IS THE SOURCE OF THE DATA USED IN THE COSS?

A. The data used in the COSS includes:

1. Financial data as detailed in the revenue requirement was provided by CEL&P and adjusted as necessary by witnesses Jennifer Z. Wilson and Laurie A. Tomczyk. Additional financial data pertaining to labor cost by Federal Energy Regulatory Commission ("FERC") account and utility plant in service was provided by CEL&P staff;
2. Monthly system operating data and statistics pertaining to system peak demand and energy purchases was provided by CEL&P staff;

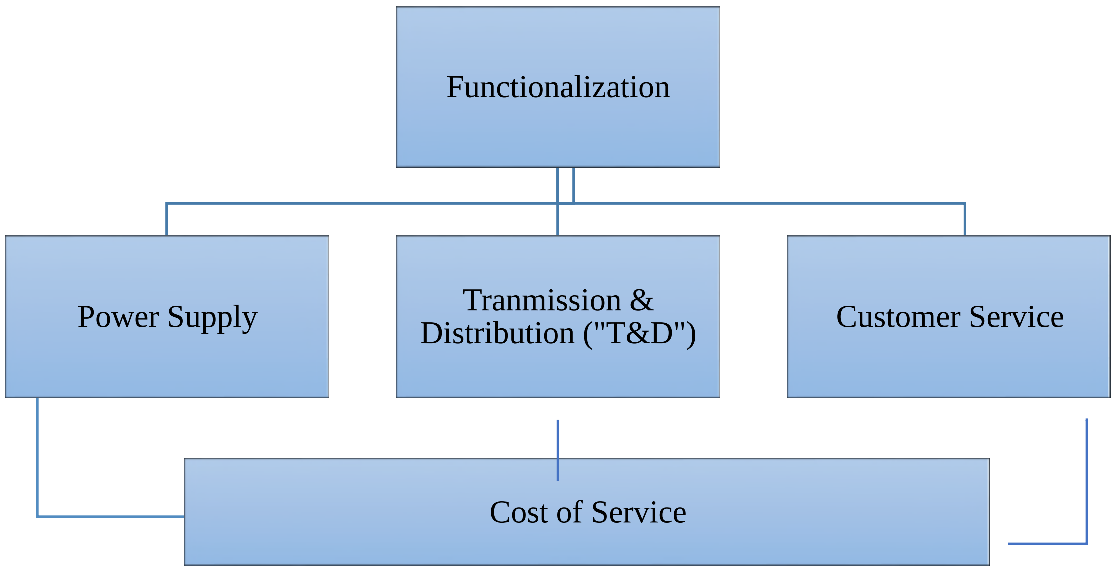
3. System sub-transmission and distribution infrastructure statistics and related cost was provided by CEL&P staff;
4. Monthly billing data and associated revenue by class was provided by CEL&P staff; and
5. Class peak demand data used in the development of demand allocation factors relied upon available Advanced Metering Infrastructure ("AMI") 1-hour interval load data all classes. Since 2014, CEL&P has initiated a system roll-out of AMI meter data and has AMI meter data for the Residential including all-electric, GP and PP rate classes.

IV. COST OF SERVICE - FUNCTIONALIZATION OF COSTS

Q18. PLEASE DESCRIBE THE COMPONENTS OF THE FUNCTIONALIZATION STEP.

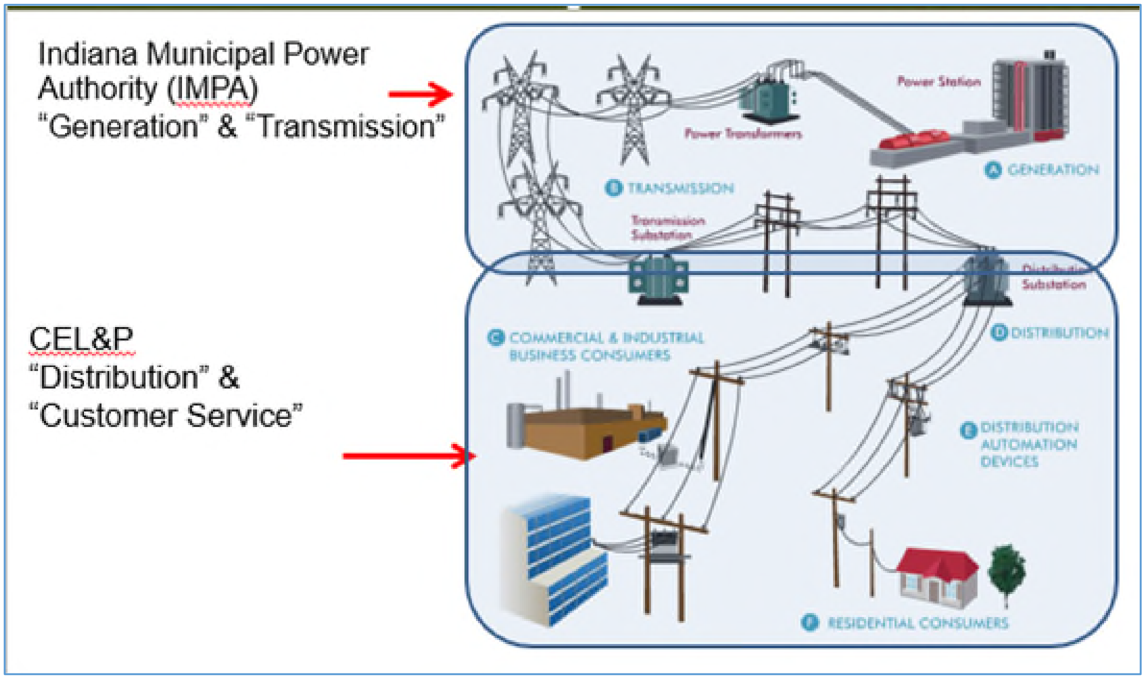
A. Functionalization (or Functional Unbundling) is the first step in the cost of service process. In this step, costs are assigned to the major CEL&P business functions of Power Supply, Sub-Transmission and Distribution, and Customer Service. Assignments are made for the detailed Revenue Requirement, as well as labor costs by FERC account and plant in service. The key components of the Functionalization step include the following modules shown in Figure JAM-2.

Figure JAM-2
COSS Modules



- Power Supply Module – The power supply function includes costs associated with purchased power from the Indiana Municipal Power Agency ("IMPA"). As indicated in the direct testimony of Phillip R. Goode, CEL&P is a full-requirements customer of IMPA. IMPA sizes its generation portfolio to meet the maximum demand requirements of CEL&P's system, along with its other members. Energy is produced to meet member retail customers' demand over time and electricity is transmitted to CEL&P via transmission lines. As shown in Figure JAM-3, the relationship between IMPA and CEL&P is as follows.

Figure JAM-3
IMPA/CEL&P Business Model



Sub-functionalized costs were classified as either Demand-related or Energy-related depending upon the underlying nature of the costs. The Revenue Requirement, labor costs, and plant in service assigned to this function were sub-functionalized and classified within this module.

- Sub-Transmission and Distribution ("T&D") Module – The Sub-Transmission and Distribution function as determined in the Functional Unbundling module is further sub-functionalized into various components of the combined sub-transmission and distribution systems. CEL&P receives purchased power at two 138 kilovolts ("kV") interconnection points. Once received, CEL&P delivers this power across its service territory via 12.55 miles of 138 kV transmission line tied to the distribution system with five 138/13.8 kV substations. The distribution system includes approximately 280.4

miles of 13.8 kV line. For the purposes of this study, we have combined transmission and distribution system assets and related costs into a single "wires" function. These costs are sub-functionalized as follows:

- Transmission
- Load Dispatch
- Substations
- Lines
- Transformers
- Service Drops
- Meters
- Outdoor Lighting
- Traffic Lighting
- Street Lighting

Depending upon the underlying nature of each sub-functional category, costs were classified as either Demand-related or Customer-related. The Revenue Requirement, labor costs, and plant in service assigned to this function were sub-functionalized and classified within this module.

- <u>Customer Service Module</u> – The Customer function as determined in the Functional Unbundling module is further sub-functionalized into various customer service activities as follows:

  - Meter Reading
  - Accounting
  - Customer Service
  - Sales
  - Uncollectibles

  All of these sub-functions were classified as Customer-related. The Revenue Requirement, labor costs and plant in service assigned to this function were sub-functionalized and classified within this module.

- <u>Cost of Service Module</u> – The COS module summarizes the sub-functionalized and classified components of each unbundling category. This detail is allocated to each customer class based on various allocations factors which agree with the category classification. The allocated components are summed for each customer class yielding cost of service results by class. Cost of service by class is then compared to Test Year rate revenues by class to determine the adequacy of current rates.

Q19. PLEASE DESCRIBE THE FUNCTIONALIZATION PROCESS.

A. As previously described, the Revenue Requirement was assigned to Power Supply, T&D, and Customer Service functions based on direct and derived allocation factors. Direct allocation factors assign costs to functions based on the underlying FERC account. For example, costs in FERC account 555 – Purchased Power were directly assigned to the Power Supply function. Derived allocation factors were used to allocate joint or common costs to the various functions. For example, costs in FERC account 920 - Administration and General Expense – Salaries-General Manager and Staff were allocated to each function based on derived allocator using labor cost directly assigned to each function.

Q20. WHAT ARE THE RESULTS OF THE FUNCTIONAL UNBUNDLING ANALYSIS?

A. The results of the functional unbundling analyses are shown in Table JAM-1.

Table JAM-1
Functional Unbundling Results(1)

Line No.	Functions	Test Year Rev. Req. ($)	% of Total(2)
1	Power Supply	$29,114,062	71.7%
2	Transmission and Distribution	9,524,438	23.5%
3	Customer	1,942,127	4.8%
4=Sum 1–3	Total	$40,580,627	100.0%
5	(1) See Attachment JAM-2, WP-14- Other Tables. Crawfordsville Electric Light and Power. Columns D-E Lines 3-6. Page 148 of 151. (2) Numbers may not add due to rounding.		

Using the energy cost adjustment ("ECA") tracker, CEL&P passes onto its customers incremental IMPA power supply costs above (or below) those costs collected in the base rates. In this study, it is CEL&P's intention to collect the entire Revenue Requirement related to power supply in base rates, which includes IMPA power supply costs. This approach will effectively reset the ECA tracker to zero. As a result, the cost of service study functionalizes, classifies, and allocates power supply costs to all customer classes. The single largest cost on the CEL&P system is related to IMPA power supply costs, which represent approximately 72% of the total Revenue Requirement.

V. COST OF SERVICE - CLASSIFICATION OF COSTS

Q21. PLEASE DESCRIBE THE COST CLASSIFICATION PROCESS.

A. Costs were classified into demand, energy, customer, and direct assignment components based on the underlying nature of the costs as previously described in my testimony. Power Supply function costs were classified as either Demand-related or Energy-related. T&D function costs were classified as either Demand- or Customer-related or were directly assigned. Customer function costs were classified as Customer-related, while some costs are directly assigned to a certain customer or class of customers.

Q22. WHAT ARE THE RESULTS OF THE CLASSIFICATION OF CUSTOMER FUNCTION COSTS?

A. Attachment JAM-2, pp. 1 through 11 of 151 presents the Revenue Requirement on a functionalized and classified basis. Summing the various Demand-related, Energy-related, Customer-related and Direct Assignment components yields the following results shown in Table JAM-2.

Table JAM-2
System Classified Costs(1)

Line No.	Classifications	Test Year Rev. Req. ($)	% of Total(2)
1	Demand-related	$26,451,857	65.2%
2	Energy-related	11,256,021	27.7%
3	Customer-related	2,616,378	6.4%
4	Direct Assignment	256,372	0.6%
5=Sum 1–4	Total	$40,580,627	100.0%
6	(1) See Attachment JAM-2, WP-14- Other Tables. Crawfordsville Electric Light and Power. Columns D-E Lines 12-16. Page 148 of 151. (2) Numbers may not add due to rounding.		

Note that direct assignments were made to CEL&P's lighting classes. Considering that Demand-related, Customer-related, and directly assigned costs are fixed in nature, approximately 72% of CEL&P's system costs are fixed and do not vary with energy usage.

Q23. PLEASE DESCRIBE THE CUSTOMER CLASSES IN WHICH COSTS WERE ALLOCATED.

A. The COSS allocates costs to current CEL&P customer classes. A description of each of these classes is shown in Table JAM-3 below.

Table JAM-3
Customer Class Criteria[1]

Line No.	Customer Class	Criteria
1	Residential Service & Residential – All Electric	Domestic use only, service provided at Secondary Distribution Voltage.
2	General Power Service	Maximum monthly demand equal to or less than 50 kilowatts ("kW") in aggregate capacity, service provided at Secondary Distribution Voltage.
3	Municipal General Power Service	Municipal customers only, Maximum monthly demand equal to or less than 50 kW in aggregate capacity, service provided at Secondary Distribution Voltage.
4	Primary Power Service	Maximum monthly demand of 50 kW or more, service provided at Primary and Secondary Distribution Voltages.[2]
5	Primary Power Off Peak Service	Optional service available to primary power service customers, service provided at Primary and Secondary Distribution Voltages. [2]
6	Industrial Power Service	Minimum demand requirement of 10 megawatts ("MW"), must directly feed from Utility's 138 kV transmission system, service provided at Transmission Voltage.[3]
7	Municipal Street Lighting Service	City lighting, service provided at Secondary Distribution Voltage
8	Outdoor Lighting Service	Outdoor lighting on private property, service provided at Secondary Distribution Voltage
9	Traffic Signal Service	Traffic signals, service provided at Secondary Distribution Voltage
10	(1) See Attachment JAM-2, WP-14- Other Tables. Crawfordsville Electric Light and Power. Columns C-D Lines 22-30. Page 149 of 151. (2) Currently there are no customers on this tariff.	

VI. COST OF SERVICE – COST ALLOCATION

Q24. WHAT HAPPENS AFTER COSTS HAVE BEEN FUNCTIONALIZED AND CLASSIFIED?

A. Once the costs have been functionalized and classified, the next step is to allocate the costs among the rate classes.

Q25. PLEASE DESCRIBE HOW YOU ALLOCATED COSTS TO THE VARIOUS CUSTOMER CLASSES.

A. Costs were allocated to the various customer classes consistent with the sub-functionalized cost classification. Specifically, class allocation factors were as follows:

(1) Power supply costs were classified as either Demand-related or Energy-related. Demand-related costs were allocated using the 12 coincident peak method ("12CP"). The 12CP was calculated coincident with the IMPA peak, which is the basis for IMPA billed demand charges. Energy-related costs were allocated to each class based on the class net energy for load ("NEFL"). NEFL is calculated for each class in consideration of the class delivery voltage and associated system losses.

(2) Transmission and distribution costs were classified as either Demand-related, Customer-related, or directly assigned. Demand-related costs were allocated to the various customer classes based on system voltage and typical system configuration. High voltage 138 kV transmission and substation facilities placed throughout the CEL&P service territory were allocated using 12CP. The 12CP was calculated coincident with the CEL&P system peak. This allocation approach recognizes that system coincidence is important in the location and sizing of these facilities. As load moves through the system, from delivery points to various neighborhoods within the CEL&P's service territory, class peak demands influence infrastructure investment; therefore, distribution lines were allocated using the class non-coincident peak ("NCP"). This allocation method recognizes that localized maximum demands drive utility distribution investment. At the customer delivery point, customer maximum demand is the primary driver of infrastructure investment at the customer premises. For CEL&P, costs associated with distribution transformers and service drops were allocated to each custom class based on the Sum of Maximum Demands ("SMD") or billing demand for customer classes with demand charges. For customers without billing

demand, SMDs were estimated using AMI data. Meters were classified as Customer-related and allocated to each customer class based on the weighted number of customers. Lighting costs were directly assigned to the outdoor lighting, street lighting and traffic lighting rate classes.

(3) Customer costs were classified as Customer-related and allocated to the various customer classes based on weighted number of customers. Weighting factors were determined based on feedback from CEL&P staff.

Q26. PLEASE DESCRIBE YOUR ALLOCATION OF THE COST OF SYSTEM LOSSES.

A. System losses were determined using available information provided by CEL&P. For the Test Year a System loss factor of 4.28% was calculated when comparing IMPA wholesale power purchases to retail system energy sales. Consistent with loss differentials associated with secondary and primary service as contained in CEL&P's current tariff, I assumed a 2.00% differential. Given this information, I calculated secondary and primary losses of 4.28% and 2.28% respectively. This calculation can be found in Attachment JAM-2, pp. 103 through 106 of 151 (Retail Loss Data). It is necessary to account for system losses so that CEL&P's rates are established and are sufficient to recover CEL&P's Revenue Requirement based on the amount of energy actually sold to retail customers and not on the amount of energy purchased at wholesale.

Q27. WHAT CRITERIA DID YOU USE TO ENSURE THAT THE ALLOCATION OF COSTS TO THE CUSTOMERS WAS APPROPRIATE?

A. To ensure a reasonable and appropriate cost of service result, I relied on actual system and class usage characteristics to the greatest extent possible to develop Demand-, Energy-, and

Customer-related allocation factors. The resulting customer class cost of service derived from the use of these allocation factors were then checked against results I would typically expect given CEL&P's cost structure and allocation methodology. Given variations in customer usage characteristics and use of system infrastructure, it is expected that classes with low monthly load factors served at distribution voltage would have the highest cost of service. For CEL&P, these customer classes are the three lighting classes (Street Lighting, Traffic Lighting and Outdoor Lighting), GP including MGP, and Residential. Customer classes with higher monthly load factors such as MGP and PP would have a lower cost to serve. These results are in fact borne out by COSS results, as shown in Table JAM-4.

Table JAM-4
Cost of Service by Rate Class(1)

Line No.	Customer Class	Average COS ($/kWh)
1	Street Lighting Service	$0.1739
2	Traffic Signal Service	0.1459
3	Outdoor Lighting Service	0.1233
4	General Power Service	0.1119
5	Residential Service(2)	0.1110
6	Municipal General Power Service	0.1050
7	Primary Power Service	0.0791
8	**Average**	**$0.0902**
9	(1) See Attachment JAM-2, WP-14- Other Tables. Crawfordsville Electric Light and Power. Columns C-D. Lines 36-43. Page 150 of 151. (2) Includes Residential All-Electric	

Further confidence in the results can be ascertained given that CEL&P is implementing a system-wide AMI program for all customers. In this study, available AMI data was used to determine demand responsibilities associated with the Residential, GP and PP customer classes. AMI data represent 15-minute interval dates for significant portion of these classes as summarized in the following table.

Table JAM-5
AMI Class Sample Size[(1)]

Line No.	Cust. Class	% of Customers in Class
1	Res	41%
2	Res- All Elec	33%
3	GP	33%
4	PP	43%
5	(1) See Attachment JAM-2, WP-14- Other Tables. Crawfordsville Electric Light and Power. Columns C-D. Lines 50-53. Page 150 of 151.	

CEL&P's MGP customers have similar usage characteristics as other GP customers, therefore AMI load usage characteristics derived from the GP class was applied to the MGP class. Load data for the lighting classes were calculated using lighting inventory, recorded energy sales and hours of daylight.

CEL&P staff indicates that deployed AMI meters represent a distributed sample of customers across the system and are not concentrated in a single geographic area or targeted at GP or PP customers of a particular size or monthly load factor. For these reasons, combined with the significant size of the sample, I find the class load profiles derived from these samples to be highly relevant and should be relied upon in the COSS.

VII. TEST YEAR RATE REVENUE ADJUSTMENTS

Q28. WAS ACTUAL RATE REVENUE FOR THE TWELVE-MONTH PERIOD ENDING FEBRUARY 2020 ADJUSTED IN DEVELOPMENT OF THE TEST YEAR?

A. Yes. Actual rate revenues reflect adjustments associated with moving nine GP customers to the PP class in consideration of customer size and class eligibility criteria and the implementation of a temporary rate rider to correct for rate design errors that occurred in the 2016 Rate Study.

Q29. PLEASE DESCRIBE THE ADJUSTMENTS RELATED TO MOVING NINE CUSTOMERS FROM THE GENERAL POWER TO PRIMARY POWER RATE CLASS?

A. In our review of customer accounts in each rate class, we discovered nine very large demand and energy customers in the GP class that could not under any circumstances meet the eligibility criteria of that class. In discussions with CEL&P staff, it was decided to move these customers into the PP class which was a good fit given the customer usage characteristics of these customers. The billing determinant associated with these customers are summarized in the following table.

Table JAM-6
General Power Customers Moved to the Primary Power Class(1)

Line No.		Actual – Twelve Months Ending February 29, 2020	Change	Test Year – Twelve Months Ending February 29, 2020
1	**Customer Months**			
2	GP	17,766	(108)	17,658
3	PP	810	108	918
4	**kWh Sales**			
5	GP	50,049,816	(7,071,650)	42,978,166
6	PP	250,989,855	7,071,650	258,061,505
7	**Billed Demand (kW)**			
8	GP	212,853	(13,678)	199,175
9	PP	485,122	13,678	498,800
10	(1) See Attachment JAM-2, WP-14- Other Tables. Crawfordsville Electric Light and Power. Columns C-D Lines 61-70. Page 151 of 151.			

To appropriately account for the transfer of these customers from one class to another, adjustments were made to the appropriate allocation factors in the COSS related to demand, energy, and customers. Rate revenue was adjusted to reflect the load of these nine customers now being served under PP rates rather than Secondary Power rates. This adjustment combined with the correction of the 2016 rate design error can be found in Exhibit JAM-2 pp. 61 through 70 of 151.

Q30. PLEASE DESCRIBE THE ADJUSTMENTS RELATED TO THE 2016 RATE DESIGN ERROR?

A. When rates were designed to support the CEL&P 2016 Settlement Revenue Requirement, improper billing units were used for all classes except lighting classes that resulted in base rates that were too low. At that time, the CEL&P rate consultant did not perform a Proof of Revenue calculation and therefore did not confirm that billing units used in rate design were appropriate and accurate. A Proof of Revenue calculation simply recreates book rate revenue by applying current rate to current billing units for each customer class. As a result, purchased energy was used to design rates rather than energy sold, with the difference being system losses.

Q31. PLEASE DESCRIBE SYSTEM LOSSES?

A. As electricity moves from the generating station to the customer, a portion of that electricity is lost. Losses typically occur when the delivery voltage is transformed from a higher voltage to a lower voltage. Also, losses occur as electricity travels over power lines. Customers, like those in the Residential class, receive electricity at lower voltages (typically referred as secondary voltage with common delivery voltages of 208/240 kV), these customers contribute to system losses greater than customers receiving power at higher primary voltage (typically 13.2 kV) and transmission voltage (typically 69 kV or higher). On a system basis, CEL&P must purchase enough electricity from IMPA so that it can deliver to customers the required amount of power after consideration of losses. For CEL&P, the 2016 COSS estimated losses by class as shown in the table below.

Table JAM-7
2016 Rate Study - Energy Losses by Customer Class
Energy Allocation Factors – Twelve Months Ended December 31, 2014

Line	Class (a)	Billed kWh (b)	Apportioned Load Loss (c)	NEFL kWh at Wholesale (d)	Loss Factor (e)
1	Residential Service	66,336,222	2,408,847	68,745,069	3.63%
2	Residential All Electric Service	17,811,912	646,799	18,458,711	3.63%
3	1 Phase General Power Service	16,763,274	608,720	17,371,994	3.63%
4	1 Phase MGP	254,925	9,257	264,182	3.63%
5	3 Phase General Power Service	36,169,742	2,054,659	38,224,401	5.68%
6	3 Phase MGP	1,062,328	60,347	1,122,675	5.68%
7	Primary Power	248,354,001	11,161,392	259,515,393	4.49%
8	Municipal Street Lighting Service	1,181,112	19,584	1,200,696	1.66%
9	Outdoor Lighting Service	1,132,998	18,786	1,151,784	1.66%
10	Traffic Signal Service	155,262	5,638	160,900	3.63%
11	Total	389,221,776	16,994,029	406,215,805	4.37%
12	Source: Verified Supplemental Testimony in support of settlement of Scott D. Bowles, P.E. Petitioner's Exhibit 5 Worksheet 3 "Pro Forma Results of Operations – Energy Allocation Factors – SETTLEMENT COMPLIANCE" in IURC Docket 44684				

As shown in the above Table JAM-7, depending upon the class, the consultant has assumed that the amount of electricity purchased from IMPA is between 1.66% to 5.68% higher than actual energy sales. Rather than using actual energy sales when designing rates (Column (b) in the above table), in error, the consultant used IMPA energy purchases by class (Column (d) in the above table).

Q32. WHAT WAS THE IMPACT OF THIS ERROR ON BASE RATES DESIGNED IN 2016?

A. Because assumed energy billing units were too high, when new rates were designed, the resulting proposed energy rates were too low creating an overall revenue shortfall. This result is summarized in Table JAM-8 below. As shown in the table, proposed rates using the 2016 Study assumed energy billing determinants and actual billing determinants were designed to meet the 2016 Settlement revenue targets.

Table JAM-8
Proof of Revenue – Proposed Rates

Line No.	Item (a)	2016 Proposed Rates with 2016 Study NEFL Billing Units (b)	2016 Current Rates with Correct Energy Sales Billing Units (c)	$ Difference (b)-(c)	% Difference (b)/(c)-1
1	(A) Revenue from Rates - Calculated	$37,026,864	$36,078,773	$948,091	2.63%
2	(B) 2016 Settlement Revenue Target	$37,016,863	$37,016,863	$0	0.00%
3	(C) Difference (A-B) - $	$10,001	($938,090)	$948,091	(101.07%)
4	(D) Difference (A)/(B)-1 - %	0.0270%	(2.5342%)	N/A	N/A
5	(E) Energy Sales - kWh	406,215,805	389,221,777	16,994,028	4.37%
6	(F) Average Rate Revenue - Settlement Target-(B)/(E)	$0.09113	$0.09510	($0.00398)	(4.18%)

In Columns (b) and (c), the 2016 Settlement revenue target is the same at $37,016,863, but because the energy sales assumed by Spectrum were too high, calculated rates to meet the revenue target were too low by about 4%. This error created an annual revenue shortfall of approximately $950,000.

Q33. HOW HAS CEL&P PROPOSED TO CORRECT THIS ERROR?

A. CEL&P has requested to correct this error in Cause No. 44684. In that filing CEL&P has developed an energy rate rider for the Residential, GP including MGP and PP rate classes that correct the rate design error. The 2016 rate design error was only related to energy (kWh) billing units. Demand (kW) and customer billing units used in designing 2016 rates were correct. Therefore, for each class, the proposed riders plus the current base energy rates equal the energy rate that should have been calculated in 2016.

Q34. WHAT IS THE OVERALL IMPACT OF THESE TWO RATE ADJUSTMENTS ON TEST YEAR REVENUES?

A. The following table summarized the impact of these two adjustments.

Table JAM-9
Rate Adjustment Impacts

Line No. (a)	Customer Class (b)	Current Revenue[1] ($) (c)	Current Revenue[1] with Customer Adjustment (CA) ($) (d)	Current Revenue[1] with CA and Temporary Rate Ride (TRR) Adjustment ($) (e)	Percent Difference - Column E Compared to Column D (f)=(e)/(d)-1
1	Residential Service [2]	$9,107,375	$9,107,375	$9,396,271	3.2%
2	General Power Service	5,270,902	4,609,276	4,809,364	4.3%
3	Municipal General Power Service	219,721	219,721	230,859	5.1%
4	Primary Power Service	19,490,874	20,077,265	20,490,008	2.1%
5	Municipal Street Lighting Service	207,972	207,972	207,972	0.0%
6	Outdoor Lighting Service	131,509	131,509	131,509	0.0%
7	Traffic Signal Service	20,390	19,135	19,135	0.0%
8 = Sum 1-7	**Total**	**$34,448,743**	**$34,372,254**	**$35,285,119**	**2.7%**
9	Difference ($)		($76,489)	$912,866	
10	Total Difference Compared to Current Revenue ($)		($76,489)	$836,376	
11	(1) Current Revenue includes Base Rate plus Energy Cost Adjustment. (2) Includes Residential All Electric				

VIII. COST OF SERVICE RESULTS

Q35. WHAT WERE THE RESULTS OF ALLOCATING COSTS TO THE INDIVIDUAL CUSTOMER CLASSES?

A. Based on the results of Test Year Revenue Requirement as compared to adjusted current rate revenue, the COSS determined that rates must be increased by 15.0% for CEL&P to recover its costs of serving electric customers. Table JAM-10 below demonstrates the results of allocating the Test Year Revenue Requirement to individual customer classes.

Table JAM-10
Cost of Service Compared to Current Rates(1)

Line No. (a)	Customer Class (b)	Current Base Rate Revenue with CA and TRR ($) (c)	Current ECA Revenue with CA and TRR ($) (d)	Current Total Revenue with CA and TRR ($) (e) = (c) + (d)	COSS ($) (f)	Difference ($) (g) = (f) - (e)	Difference (%) (h) = (f)/(e) - 1
1	Residential Service (2)	$9,820,126	($423,856)	$9,396,271	$10,999,813	$1,603,542	17.1%
2	General Power Service	4,941,636	(132,272)	4,809,364	4,959,343	149,978	3.1%
3	Municipal General Power Service	237,578	(6,719)	230,859	247,679	16,820	7.3%
4	Primary Power Service	21,382,384	(892,376)	20,490,008	23,995,632	3,505,624	17.1%
5	Municipal Street Lighting Service	215,389	(7,418)	207,972	276,337	68,366	32.9%
6	Outdoor Lighting Service	138,046	(6,537)	131,509	86,478	(45,032)	(34.2%)
7	Traffic Signal Service	20,024	(888)	19,135	15,346	(3,790)	(19.8%)
8 = Sum 1-7	**Total**	**$36,755,185**	**($1,470,065)**	**$35,285,119**	**$40,580,627**	**$5,295,508**	**15.0%**

9
(1) See Attachment JAM-3 Rate Design Model. Rate Design – WP 28 – Other Tables & Figures. Crawfordsville Electric Light and Power. Page 242 of 245.
(2) Includes Residential All Electric

Q36. WHAT WERE THE COST OF SERVICE RESULTS BY COST CLASSIFICATION?

A. The cost of service results by cost classification are shown in Table JAM-11.

Table JAM-11
Cost of Service by Classification(1)(2)

Line No. (a)	Customer Class (b)	Demand - Related ($) (c)	Energy - Related ($) (d)	Customer - Related ($) (e)	Direct Assignment(3) ($) (f)	Total ($) (g)
1	Residential Service (4)	$6,490,351	$2,466,583	$2,042,426	($13,992)	$10,999,812
2	General Power Service	3,312,715	1,252,760	383,490	8,869	4,959,343
3	Municipal General Power Service	176,045	64,090	16,004	(10,809)	247,679
4	Primary Power Service	16,443,219	7,402,818	158,083	2,853	23,995,632
5	Municipal Street Lighting Service	6,578	3,822	0	4,951	15,346
6	Outdoor Lighting Service	10,762	31,078	16,375	28,211	86,478
7	Traffic Signal Service	12,188	34,869	0	229,286	276,337
8 = Sum 1-7	**Total**	**$26,451,857**	**$11,256,021**	**$2,616,378**	**$256,372**	**$40,580,627**
9	(1) See Attachment JAM-2, WP-14- Other Tables. Crawfordsville Electric Light and Power. Columns C-D Lines 76-83. Page 151 of 151. (2) Numbers may not add due to rounding. (3) Direct Assignments includes de minimis true-up adjustments to align COSS with rate class revenue targets. (4) Includes Residential All Electric					

Q37. DOES CEL&P'S PROPOSED RATE DESIGN FOLLOW STRICT COST OF SERVICE AS REFLECTED IN THESE TABLES?

A. No. As I will explain in the next section, CEL&P instructed me to deviate from strict cost of service in order to ease the transition to new rates, mitigate rate impact, and avoid customer rate shock.

<u>IX. RATE DESIGN AND MITIGATION</u>

Q38. PLEASE EXPLAIN CEL&P'S RATE DESIGN PRINCIPLES?

A. Rate design principles represent the policies, goals, and objectives important to CEL&P and the community in which they serve. These principles are as follows:

1) Ensure revenue adequacy: Design rates that in total meet CEL&P's revenue targets over a two-year implementation period, such that at the end of the period, rates revenues meet the total system revenue requirement.
2) Implement gradualism in rate design by:
    A. Minimizing adverse rate impacts to customer by spreading rate increases over two years in two-phases, such that CEL&P anticipates Phase I will be effective when the Final Order in this Cause is issued around June 2021, then Phase II one year later in 2022;
    B. In consideration of the near-term implementation of the Temporary Rate rider, increase system revenues by a smaller amount in the first year in order to ease customers into the rate increases (5.8% and 8.7% respectively);
    C. Limiting annual residential customer class rate increases to 7%; and
    D. Allowing no customer class to receive a rate decrease.
3) Given gradualism objectives, better align rates given COSS results.
4) Improve efficiency signals sent to various commercial and industrial customer classes by introducing demand charges to GP and MGP customers.
5) Improving fixed cost recovery by:
    A. Introducing demand charges to GP and MGP customers
    B. Adding a demand ratchet to GP, MGP, and PP rate structures.
    C. Moving certain large commercial customers to the appropriate customer class.

D. Increasing customer service charges towards cost of service over the implementation period.

E. Increasing demand charges towards cost of service over the implementation period.

6) Improve consistency of pricing signals by merging the GP and MP rate structures.

7) Recalibrate the ECA so that ECA pass-through charges are near zero. As previously discussed, CEL&P has included all power supply costs in the base rates thereby resetting the ECA.

Q39. PLEASE DESCRIBE HOW CLASS REVENUE TARGETS WERE ESTABLISHED AND THE IMPACT OF PROPOSED RATE CHANGES OVER CEL&P'S TWO-PHASE RATE IMPLEMENTATION PERIOD.

A. Consistent with these rate design mitigation principles, CEL&P's class revenue targets were established by phase as outlined in the following steps:

Step 1 – Given COSS results, the total system rate increase to meet the cost of service was initially apportioned in two steps so that the total revenue from all customer classes equaled the system target revenue for each phase of the two-year phase-in. The first step took into consideration the impact of the Temporary Rate Rider such that the combined economic impact of the Temporary Rate Rider plus the Phase 1 increase was approximately half of the total indicated rate adjustment per the COSS.

Step 2 – Given the apportionment as described in Step 1, and the total indicated rate change per the COSS, the Residential class rate increases was capped at 7% in consideration of the combined impact of the Temporary Rate Rider and the Phase 1 revenue target.

Step 3 – Given the 7% residential cap, any revenue shortfall required to meet the system revenue target was prorated across all non-residential customer classes based on the class target revenue. Rates were initially designed for each phase, with consideration to COSS results and rate design objectives. Specific charges within each rate structure were gradually adjusted in two relatively equal amounts for each phase

Step 4 – Initial rate design was compared across GP, PP, and Industrial Power classes to ensure that pricing signals were consistent and transitions between classes did not unduly impact customers as they move from one class to another. The result of this four-step process is summarized in Table JAM-12.

Table JAM-12
Proposed Rates on Current Revenues by Class [(1)]

Line No. (a)	Customer Class (b)	Current Revenue with CA ($) (c)	Current Revenue with Test Year Rate Rider (TRR) ($) (d)	Current Revenue with CA and TRR Change (%) (e) = (d)/(c)-1	Phase 1 Revenue ($) (f)	Phase 1 Cumulative Change (%) (g) = (f)/(c)-1	Current with TRR and CA to Phase 1 Change (%) (h) = (f)/(d)-1	Phase 2 Revenue ($) (i)	Phase 2 Cumulative Change (%) (j) = (i)/(c)-1	Current with TRR and CA to Phase 2 Change (%) (k) = (i)/(d)-1	Phase 1 to Phase 2 Change (%) (l) = (i)/(f)-1
1	Residential Service	$9,107,375	$9,396,271	3.2%	$9,744,898	7.0%	3.7%	$10,427,027	14.5%	11.0%	7.0%
2	General Power Service	4,609,276	4,809,364	4.3%	4,829,607	4.8%	0.4%	5,061,203	9.8%	5.2%	4.8%
3	Municipal General Power Service	219,721	230,859	5.1%	229,700	4.5%	(0.5%)	237,530	8.1%	2.9%	3.4%
4	Primary Power Service	20,077,265	20,490,008	2.1%	22,148,620	10.3%	8.1%	24,420,144	21.6%	19.2%	10.3%
5	Municipal Street Lighting Service	207,972	207,972	0.0%	241,958	16.3%	16.3%	281,205	35.2%	35.2%	16.2%
6	Outdoor Lighting Service	131,509	131,509	0.0%	132,697	0.9%	0.9%	133,857	1.8%	1.8%	0.9%
7	Traffic Signal Service	19,135	19,135	0.0%	19,312	0.9%	0.9%	19,473	1.8%	1.8%	0.8%
8 = Sum 1-7	**Total**	**$34,372,254**	**$35,285,119**	**2.7%**	**$37,346,792**	**8.7%**	**5.8%**	**$40,580,440**	**18.1%**	**15.0%**	**8.7%**
9	(1) Attachment JAM-3 Rate Design Model. Rate Design – WP 28 Other Tables & Figures. Crawfordsville Electric Light and Power. Page 243 of 245										

Q40. WHAT IS THE CUMULATIVE IMPACT OF THE TWO-YEAR PHASED IN RATE PLAN COMPARED TO THE ALLOCATED CLASS-LEVEL COST OF SERVICE?

A. The cumulative impact of CEL&P's two-year phase-in plan in system revenues results in CEL&P foregoing approximately $3.2 million of the Revenue Requirement to which it would otherwise be entitled, as shown in Table JAM-13.

Table JAM-13(1)
Foregone Revenue Associated with Two-Year Phase-In

Line No.	Phase	Target Rate Revenue	TY Revenue Requirement	Difference
1	1	$37,346,792	$40,580,627	($3,233,835)
2	2	$40,580,440	$40,580,627	($187)
3 = 1+2	Total	n/a	n/a	($3,234,023)
4	(1) Attachment JAM-3 - Rate Design Model. Rate Design – WP 28 – Other Tables & Figures. Crawfordsville Electric Light and Power. Lines 57-59. Columns D-F. Page 244 of 245.			

CEL&P is committed to foregoing this $3.2 million by carefully managing its budget, expenditures and capital improvement projects in order to provide this benefit to residential customers and absorb the difference between its Test Year Revenue Requirement and the Target Rate Revenue that it will receive in Phases 1 and 2.

Q41. IN YOUR OPINION, DOES CEL&P'S PROPOSED RATE DESIGN MEET ALL OF THESE MITIGATION OBJECTIVES?

A. Yes, CEL&P's phase-in proposal meets all rate design objectives.

Q42. IN YOUR OPINION, ARE CEL&P'S PROPOSED RATES, AS MITIGATED, NONDISCRIMINATORY, REASONABLE, AND JUST?

A. Yes, in my opinion, CEL&P's proposed rates are nondiscriminatory, reasonable, and just. This is true particularly given the fact that CEL&P is proposing to completely forego millions of dollars in revenue to which it would otherwise be entitled in order to mitigate the impact to customers.

X. RESIDENTIAL RATE STRUCTURE

Q43. HOW DOES THE COST TO SERVE RESIDENTIAL CUSTOMERS COMPARE TO THE CURRENT RATE STRUCTURES DESIGNED TO RECOVER THOSE COSTS?

A. Although the COSS indicates a 17.1% increase for this customer class, in addition to the impact of the Temporary Rate Rider, RP&L proposes to cap the annual Residential rate increase to 7%, including the impact of the Temporary Rate Rider over the two year phase-in period. This results in a 14.5% rate increase for the Residential class at the end of Phase 2, rather than a 17.1% rate increase.

Q44. PLEASE DESCRIBE CEL&P'S PROPOSED CHANGES TO THE RS TARIFF.

A. As shown in that table below, the proposed Residential rate structure is similar to current rates. CEL&P is proposing to not change the current customer charge and only adjust the energy component of the rate to meet class revenue targets.

Table JAM-14

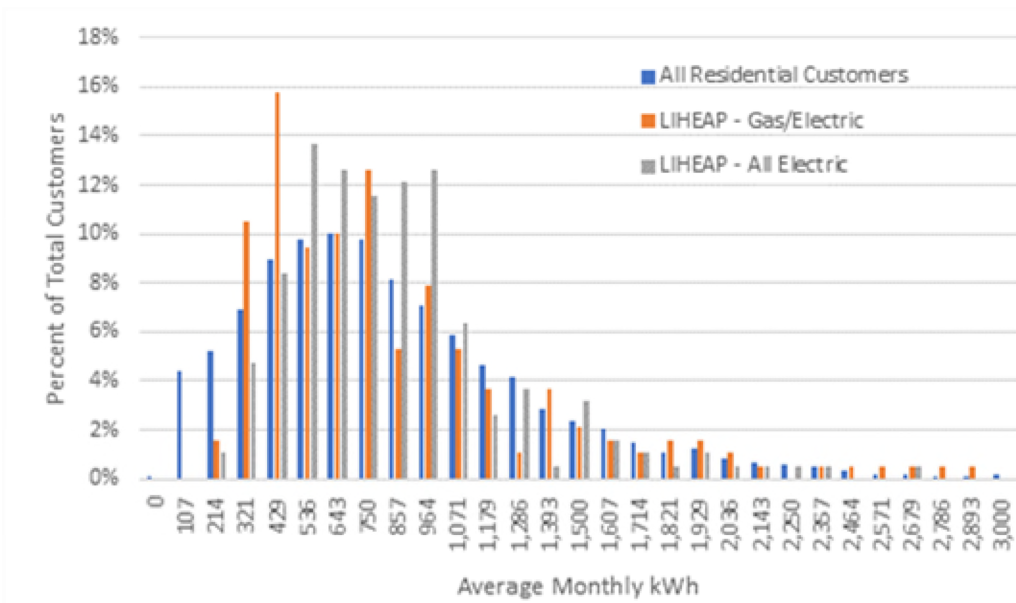
Proposed Residential Service Rate(1)

Line No.	Component	Units	Current Rate	Current with TRR	Phase 1 Rate	Phase 2 Rate
1	Customer Charge	$/Month	15.00	15.00	15.00	15.00
2	Energy Charge(2)	$/KWH	0.089877	0.093291	0.097405	0.105466
3	(1) Attachment JAM-3 - Rate Design Model. Rate Design – WP 28 – Other Tables & Figures. Crawfordsville Electric Light and Power. Lines 66-67. Columns D-H. Page 244 of 245. (2) Includes ECA which is the total revenue generate by the quarterly ECAs for the year divided by the total kWh consumed. Also includes temporary rate rider.					

Q45. HOW DOES CEL&P'S PROPOSED RESIDENTIAL RATE DESIGN IMPACT LOW-INCOME CUSTOMERS?

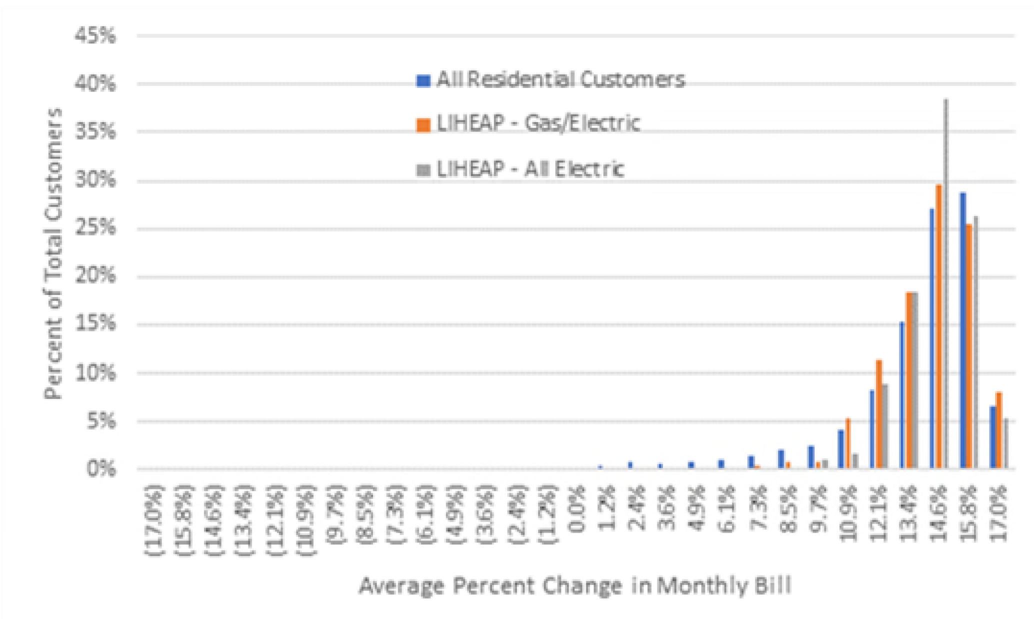
A. CEL&P does not normally track the income levels of customers. Therefore, to estimate the impact of proposed rates on low income customers, the best readily available information would be a sample of 473 Residential customers including all-electric customers that have received energy assistance from the Indiana Low Income Home Energy Assistance Program ("LIHEAP"). A comparison of the bill impact of proposed rates on the LIHEAP sample compared to the total Residential class example is shown in the following graphs. The first graph compares the average monthly consumption of LIHEAP customers to the total class Residential customers of 10,612.

Figure JAM-4
LIHEAP Customers Average Monthly kWh Consumption
Compared to the Total Residential Class Average Monthly kWh



As shown in the above graph, electric consumption of LIHEAP customers vary substantially from customer to customer and overall consumption patterns are similar to the overall Residential class. This result is not surprising as many factors influence electricity use beyond income levels. Therefore, it is difficult to develop a rate design solution that uniformly benefits all low-income customers regardless of usage. However, LIHEAP remains a resource for qualifying customers. The second graph shows the total Residential average monthly bill impact compared to average monthly bills under current rates. This comparison includes near-term implementation of the Temporary Rate Rider and Phases 1 and 2 rate adjustments.

Figure JAM-5
LIHEAP Customers Total Bill Impact
Compared to the Residential Class Total Bill Impact



As would be expected, given similarity in consumption patterns, LIHEAP customer bill impacts are similar to other customers in the Residential class.

XI. TARIFF CHANGES

Q46. PLEASE SUMMARIZE THE CHANGES PROPOSED TO CEL&P'S TARIFF.

A. The following table summarizes all proposed changes to CEL&P's current tariff. Changes include:

- Updated rate design for each customer class to agree with the two-phase plan.
- Adding demand charges to the GP rate class.
- Merging GP and MGP rate structures.
- Add a demand ratchet to GP, MGP and PP rate structures.
- Update Miscellaneous and Non-recurring Charges.
- Add LED rates into the lighting classes.
- Add a tariff for Qualified Facilities.
- Update ECA calculation.

Table JAM-15
Tariff Class Comparison – Current to Proposed

Line No.	Old Tariff	New Tariff
1	Appendix A Rate Adjustments	Modified to agree with new rate structures
2	Appendix B Average Change of Rate Adjustments	Changed to Appendix B Non-Recurring Charges
3	Residential Service (Including Residential All Electric)	Updated
4	General Power Service	Updated and added demand charge and demand ratchet
5	Municipal General Power Service	Updated and added demand charge and demand ratchet
6	Primary Power Service	Updated and added demand ratchet
7	Primary Power Off Peak Service	No Change
8	Industrial Power Service	Updated and added demand ratchet
9	Municipal Street Lighting Service	Updated and added LED charges
10	Outdoor Lighting Service	Updated and added LED charges
11	Traffic Signal Service	Updated, added preemptive signal maintenance, removed flashers

Table JAM-15
Tariff Class Comparison – Current to Proposed

Line No.	Old Tariff	New Tariff
12	Economic Development Rider	Replaced by Economic Development Rider – IMPA and Economic Development Rider - Retail
13	n/a	Economic Development Rider - IMPA
14	n/a	Economic Development Rider - Retail
15	Green Power Rider	No Change
16	Rider IS-MISO-DRS-Emergency	No Change
17	Net Metering Tariff	No Change
18	Industrial Coincident Peak Experimental Program	Deleted
19	Peak Management Credits	Deleted
20	Cogeneration Rate	Deleted
21	n/a	Qualifying Facilities
22	Note: Attachment JAM-3 – Rate Design Model. Rate Design – WP 28 Other Tables & Figures. Crawfordsville Electric Light and Power. Page 245 of 245.	

Q47. WHY IS ADDING A DEMAND COMPONENT TO THE GP RATE IMPORTANT?

A. A demand charge is an important pricing signal for customers that encourages the efficient use of electric plant. A demand charge is an important fixed cost recovery mechanism as this charge recovers the utilities infrastructure cost that insures a highly reliable supply of electricity. Utilities like CEL&P must have sufficient capacity to meet customer, and system maximum demands, therefore, a customer's contribution to power supply, transmission and distribution capacity requirements is an important driver of utility costs. A demand charge fairly recovers these costs based on a customer's usage characteristics. Importantly, a demand charge rewards higher load factor customers with a lower average rate compared with lower load factor customers. Load factor is a measure of customer use of system capacity where a high load factor customer's use of capacity investment is greater than a low load factor customer. Greater use of existing utility investments yield lower costs and lower rates. Because GP customers can be large, up to 50 kW, the introduction of a demand charge will provide an important and strong pricing signal to these customers to examine their use of electricity and seek efficiency improvements.

Q48. WHY ARE YOU PROPOSING CEL&P MERGE GP AND MP RATE CLASSES?

A. From a cost causation perspective, customers in the MGP customer class are similar to other GP customers. MGP customers are similarly sized and are connected to the system as secondary distribution voltage. The cost of service differential between the two classes is relatively small and is due to differences in the number of customers and the aggregated usage characteristics of these customers rather than any fundamental differences in service requirements or size. Given this fact, consistent pricing signals between similar classes is an important goal of rate design and helps customer "make sense" of rate structures as they compare rates from one class to another. Therefore, I propose merging the rate design of these two classes into a single rate structure.

Q49. WHY ARE YOU PROPOSING CEL&P ADD A DEMAND RATCHET TO THE GP, MP, AND PP RATE STRUCTURES?

A. A demand ratchet is an import rate design provision that ensures that a utility will recover fixed costs associated with capacity required to meet a customer's maximum demand. As previously mentioned, a demand charge provides a strong pricing signal to customers to efficiently manage their electricity so that a customer's maximum demands on the system are as low as possible relative to the customer's energy needs. However, a demand charge is designed to recover costs on a monthly basis based on the customer's maximum demand measured during the month. Under most circumstances this cost recovery method is fair and adequate as customer demand does not vary significantly from month to month. This is because, for reliability purposes, a utility must ensure that it has capacity to meet the customer's all-time maximum demand. Through rates, the cost of providing sufficient capacity to meet a customer's all-time maximum demand is recovered over the course of the year on a monthly basis. So, a customer with relatively uniform monthly demands will contribute fairly to the cost of service given that the customer's all-time maximum demand is similar to the customer's monthly demand.

However, some customers have highly variable loads with no uniform monthly demands. These customers will place very high and very low monthly demands on the system over the course of the year. Because of this variability in billing demand, these customers will not fairly contribute to their cost of service because monthly rate revenues contributed through a demand charge are not sufficient to recover the costs associated with an all-time maximum demand event. For these customers, a demand ratchet does a good job of correcting this inequity. A demand ratchet simply sets a billing demand floor based on a historical look at a customer monthly peak demand requirement. For CEL&P, the proposed demand ratchet sets the floor at 50% of the customer maximum demand over the previous twelve months as shown in the following formula.

Demand Ratchet = (50% X Highest Recorded 12-Month Historical Demand) X Applicable Demand Charge

An illustrative example of the proposal is show in the following table of measured demand for a hypothetical GP customer. The table shows monthly customer demand for a 24-month period.

Table JAM-16
Example Application of Demand Ratchet

No.	Month	Maximum Measured Demand (kW)	Minimum Demand Per Ratchet (kW)	Billing Demand (kW)	Added Billing Demand Due To Ratchet (kW)
1	Jan	10	0	10	
2	Feb	14	5	14	
3	Mar	13	7	13	
4	Apr	10	7	10	
5	May	18	7	18	
6	Jun	22	9	22	
7	Jul	27	11	27	
8	Aug	35	13.5	35	
9	Sep	40	17.5	40	
10	Oct	37	20	37	
11	Nov	25	20	25	
12	Dec	15	20	20	5
13	Jan	12	20	20	8
14	Feb	17	20	20	3
15	Mar	16	20	20	4
16	Apr	12	20	20	8
17	May	22	20	22	
18	Jun	26	20	26	
19	Jul	32	20	32	
20	Aug	42	20	42	
21	Sep	48	21	48	
22	Sep	44	24	44	
23	Sep	30	24	30	
24	Sep	18	24	24	6

As shown in the above table, a demand ratchet establishes a minimum billing demand for a commercial customers based on a customer's monthly maximum demand over the prior twelve month period. In the above table, in month nine, the customer's maximum measured demand was 40kW in September. Per the ratchet formula, this demand measure results in a billing demand floor of 20kW (40kW X 50%). Therefore, on a going forward basis, beginning in October, the customer pays the greater of the actual monthly measured demand or the ratchet demand of 20kW. In October, the customer's measured demand was 37kW which is greater than the minimum demand of 20kW, so the demand ratchet has no effect on the customer's billing demand. However, in December, the customer's measured demand was 15kW which is less than the minimum demand of 20kW, so the customer pays an incremental 5kW of billing demand due to the ratchet (20kW-15kW).

The ratchet is continuously being evaluated on a rolling 12-month basis and can go up or down depending upon the highest recorded reading during the prior period. In the above example, the customer's maximum monthly measure demand does not exceed 40KW until August (month 20) of the following year. Once the prior peak demand has been exceeded, the billing demand floor is reset, in this case at 21kW. If the customer never establishes a peak as high as 40kW again, the customer's billing demand floor would be reduced.

Setting a ratchet at 50% of the highest recorded demand over the prior twelve months still allows for a significant amount of normal fluctuation in customer monthly demand but improves fixed cost recovery associated with commercial customers with highest fluctuating loads. These customers, with the highest fluctuating loads are not meeting their cost of service obligation. Given this proposal, I estimate that the demand ratchet will increase billing demand for all GP, MP, and PP customers by approximately two percent (2%).

Q50. WHY DOES THE PROPOSED TARIFF CONTAIN A PLACEHOLDER FOR THE ENERGY COST ADJUSTMENT RIDER?

A. CEL&P anticipates that proposed rates will become effective in or near June 2021. In this filing, rate design has included Test Year IMPA costs in the base rate resulting in a zero ECA for all classes. Given the new rate structure, CEL&P anticipates an ECA filing in advance of the effective date of new rates that will reflect actual IMPA power costs as reconciled with ECA revenue and costs included in the current rate structure. Ms. Tomczyk discusses the transition from the current to the proposed ECA in her direct testimony.

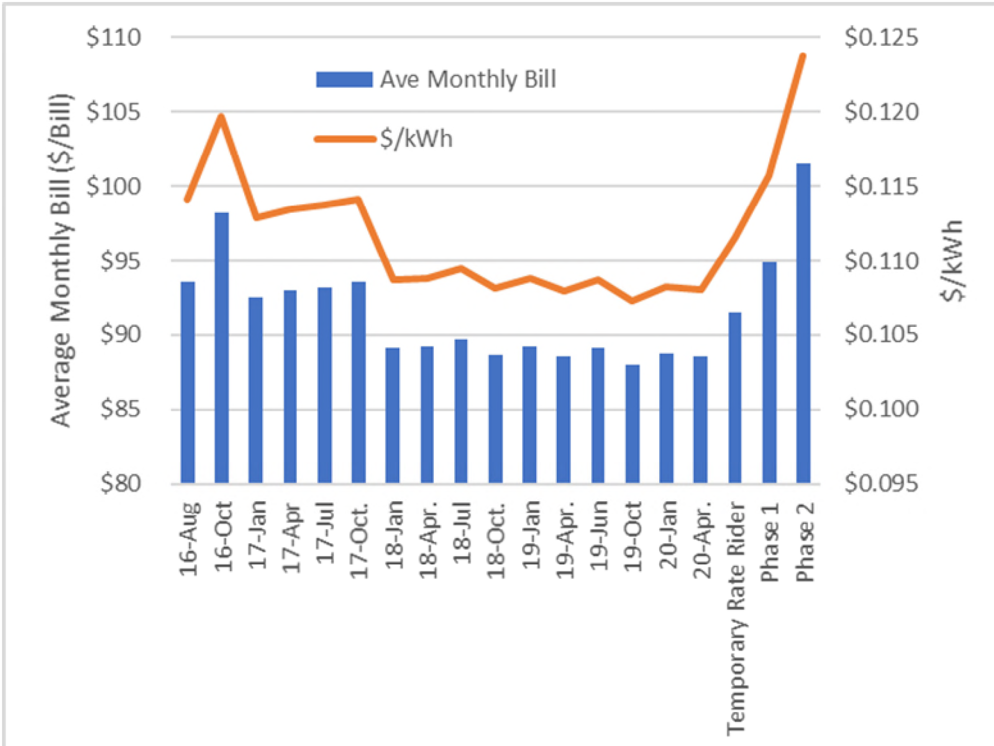
Q51. HAVE YOU CALCULATED AN AVERAGE BILL UNDER THE PROPOSED RATE STRUCTURE?

A. Yes, for each rate class, Attachment JAM-3, pp. 2 through 11 of 245 includes a comparison of average bills at the end of each of the two phases for each of the tariffed rate classes.

Q52. HOW DO CEL&P’S PROPOSED RATES AT THE END OF THE SECOND PHASE COMPARE TO THE RATES OF SURROUNDING UTILITIES?

A. At the end of the second phase, CEL&P’s proposed Residential and smaller GP (Small Commercial) rates are very favorable when compared to surrounding utilities. In fact, as demonstrated in the following graph, after Phase 2 rates have been implemented, Residential customers will pay rates only slightly higher than those paid in 2016.

Figure JAM-6
Historic Residential Bills[(1)]



(1) Attachment JAM-3 – Rate Design Model. Rate Design- WP 26 Historic Residential Bills. Crawfordsville Electric Light and Power. Page 238 of 245.

Larger GP (General Service) and PP (Large Commercial and Industrial) customer rates are higher than those utilities included in the comparison analyses as indicated by Table JAM-16 below. Note that this analysis compares CEL&P's proposed rates to be effective in 2023 with the current rates of other utilities.

Table JAM-17
Comparison of Monthly Electric Bills[(1)]

Line No.	Consumption	CEL&P Current	CEL&P Phase 2 (Est. 2023)	Tipmont REMC Current (2020)	Parke County REMC (2020)	Duke Energy IURC Cause 45253 Filed (2020)	CEL&P Phase 2 Compared to Tipmont	CEL&P Phase 2 Compared to Parke County	CEL&P Phase 2 Compared to Duke
1	**Residential Bills**								
2	500 kWh	$60.16	$67.73	$88.61	$88.77	$74.62	(24%)	(24%)	(9%)
3	1,000 kWh	$105.32	$120.47	$142.72	$145.53	$126.55	(16%)	(17%)	(5%)
4	1,500 kWh	$150.48	$173.20	$196.83	$202.30	$173.41	(12%)	(14%)	(0%)
5	2,000 kWh	$195.64	$225.93	$250.94	$259.06	$220.26	(10%)	(13%)	(3%)
6	**Small Commercial/General Service**								
7	3,000 kWh	$340.92	$301.23	$404.66	$436.19	$365.10	(26%)	(31%)	(17%)
8	7,500 kWh	$762.31	$663.08	$891.64	$917.83	$792.10	(26%)	(28%)	(16%)
9	15,000 kWh	$2,025.88	$2,461.59	$1,785.65	$1760.67	$1,503.76	38%	40%	64%
10	30,000 kWh	$3,751.75	$4,623.19	$3,461.28	$3,446.34	$3,565.76	34%	34%	30%
11	**Large Commercial/Industrial**								
12	150 kW 60,000 kWh	$5,737.37	$7,003.17	$5,988.14	$6,660.07	$5,989.19	17%	5%	17%
13	300 kW 120,000 kWh	$11,174.75	$13,706.35	$11,866.28	$13,235.15	$11,953.85	16%	4%	15%
14	1,000 kW 400,000 kWh	$36,549.16	$44,987.83	$40,728.85	$43,918.82	$34,453.91	10%	2%	31%
15	5,000 kW 2,500,000 kWh	$195,670.78	$238,033.16	$23,0416.55	$250,296.38	$207,759.07	3%	(5%)	15%
16	(1) Attachment JAM-6 – Rate Comparisons. Rate Comparisons – Summary. Crawfordsville Electric Light and Power. Columns L-U. Lines 4-18. Page 1 of 29.								

Q53. ARE THERE ANY OTHER RATE CLASSES THAT HAVE CHANGES WHICH YOU WOULD LIKE TO HIGHLIGHT?

A. Mr. Goode explains the other changes to the tariff in his testimony (Petitioner's Exhibit 1, pp. XXX).

Q54. HAVE YOU INCLUDED CLEAN AND REDLINED VERSIONS OF THE NEW TARIFF?

A. Yes, the clean version of the proposed tariff is included as Attachment JAM-4, and the redlined version is included as Attachment JAM-5.

XIII. SUMMARY AND CONCLUSION

Q55. PLEASE PROVIDE A SUMMARY OF YOUR RECOMMENDATIONS.

A. In summary, I recommend the IURC approve the following:

1. The COSS as presented herein.
2. The two-year phase-in plan with recommended class revenue targets.
3. Rate design as proposed for all customer classes.
4. Tariff revisions that not only address rates and charges for current and new customer classes but also update and refine terms of service.

Q56. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

VERIFICATION

I affirm under the penalties of perjury that the foregoing prefiled verified direct testimony is true to the best of my knowledge, information and belief as of the date here filed.

Joseph A. Mancinelli

NewGen Strategies & Solutions

Joseph Mancinelli
President & CEO
jmancinelli@newgenstrategies.net

Joseph Mancinelli has over 30 years of experience as a utility consultant to the public utility industry and serves as President & CEO of NewGen Strategies and Solutions, LLC. NewGen offers a wide range of management, planning, and engineering economic services to public power clients. His direct experience includes strategic and business planning, cost of service and rate design analyses, performance management, economic analyses, asset valuation, revenue bond financing in the roles of project manager, lead analyst, and expert witness. He regularly advises senior management teams, utility boards, city councils, attorneys, and end-users. Additionally, he has taught cost of service and rate design concepts through numerous presentations, seminars and classes in association with Electric Utility Consultants, Inc., American Public Power Association, and various cooperative organizations.

Education

He has a Master of Business Administration in Finance from the University of Colorado and a Bachelor of Science in Geophysical Engineering from the Colorado School of Mines.

Electric Cost of Service and Rate Design

Mr. Mancinelli has considerable experience leading project teams in the review and establishment of utility revenue requirements, development of cost of service analyses and retail and wholesale rate design. He works with clients and stakeholders in the understanding of cost of service and rate design principles and assists clients in the development of the underlying policies and principals important in the rate setting process. He has worked for clients across the country. Clients include wholesale and retail electric utilities, various stakeholder groups, public utility commissions and large consumers of electricity. A sample of Mr. Mancinelli's electric cost of service and rate design clients include the following:

- Austin Energy, Texas
- Bose McKinney & Evans, LLP
- Bryan Texas Utilities, Texas
- Cleveland Public Power, Ohio
- Continental Divide, New Mexico
- CPS Energy, Texas
- Deseret Power Cooperative, Utah
- Estes Park Power & Light, Colorado
- Fort Collins Utilities, Colorado
- Farmington Electric Utility System
- City of Garland Power and Light, Texas
- GEUS, Texas
- HNTB Corporation
- Keys Energy Services, Florida
- Lafayette Utilities System, Louisiana
- Lloyd Gosselink Rochelle & Townsend, P.C.
- Lubbock Power and Light, Texas
- Nebraska Public Power District
- New Braunfels Utilities, Texas
- Plains Electric Generation and Transmission Cooperative, Inc., New Mexico (now Tri-State)
- Platte River Power Authority, Colorado
- Richmond Power & Light, Indiana
- Tri-State Generation & Transmission Association, Inc., Colorado
- U.S. Army, Huntsville, Alabama
- United Power Electric Cooperative, Colorado
- Navajo Tribal Utility Authority
- Weatherford Municipal Utilities, Texas

Expert Witness and Litigation Support

Mr. Mancinelli has provided expert testimony for over 20 years regarding electric utility cost of service, rate design, and ratemaking issues before state and local regulatory bodies and courts. He has national experience providing litigation support regarding ratemaking matters at wholesale and retail levels in Alaska, California, Colorado, Guam, Indiana, Michigan, Nebraska, New Mexico, Nevada, North Carolina, Texas, and Utah.

A list of his testimony experience is included in the attached table.

Record of Testimony Submitted by Joseph A. Mancinelli

	Utility	Proceeding	Subject	Before	Client	Date
1.	Crawfordsville Electric Light & Power	Cause 44684	Temporary Rate Rider to Correct 2016 Rate Design Error	Indiana Utility Regulatory Commission	Crawfordsville Electric Light & Power	2020
2.	Tri-State Generation and Transmission Association, Inc.	Docket No. ER20-2417-000 et al.	Determinations of Appropriate Buy Down Payments Associated with Partial Requirements Membership	Federal Energy Regulatory Commission	Tri-State Generation and Transmission Association, Inc.	2020
3.	Tri-State Generation and Transmission Association, Inc.	Docket No. ER20-1559-000 et al.	Member Contract Termination Fee Methodology/ Formula/Calculation	Federal Energy Regulatory Commission	Tri-State Generation and Transmission Association, Inc.	2020
4.	Tri-State Generation and Transmission Association, Inc.	Docket No. ER20-676-000 et al.	Tri-State Generation and Transmission Association, Inc. Initial Filing of Rate Schedules FERC No. 1 through No. 261 (Wholesale Electric Service Contracts and Utility Member Agreements)	Federal Energy Regulatory Commission	Tri-State Generation and Transmission Association, Inc.	2020
5.	Richmond Power & Light	Cause 45361	Application for approval of new rates and charges for electric service.	Indiana Utility Regulatory Commission	City of Richmond, Indiana	2020
6.	Indiana Michigan Power Company	Cause No. 45235	Petition of Indiana Michigan Power Company for authority to increase its rates and charges for electric utility service.	Indiana Utility Regulatory Commission	City of Fort Wayne, City of Marion, and Marion Municipal Utilities	2019
7.	Pacific Gas & Electric Company	Application No. 18-12-009	Application of Pacific Gas & Electric Company (U 39-M) for Authority, Among Other Things, To Increase Rates for Electric and Gas Service Effective on January 1, 2020	Public Utility Commission of the State of California	Joint Community Choice Aggregators	2019
8.	Farmington Electric Utility System	Docket Nos. QF19-1082-001, QF19-1083-001, QF19-1084-001	Response to April 19, 2019 Petition for Enforcement under the Public Utility Regulatory Policies Act of 1978	Federal Energy Regulatory Commission	City of Farmington, New Mexico	2019
9.	Bryan Texas Utilities	Docket No. 48123	Application of Bryan Texas Utilities for Interim Update of Wholesale Transmission Rates Pursuant to Substantive Rule 25.192(g)(1)	Public Utility Commission of Texas	Bryan Texas Utilities	2018
10.	Southern Indiana Gas and Electric Company D/B/A Vectren Energy Delivery of Indiana, Inc.	Cause No. 43354 MCRA 21	Review of MISO cost recovery trackers proposed by Southern Indiana Gas and Electric Company D/B/A Vectren Energy Delivery of Indiana, Inc.	Indiana Utility Regulatory Commission	SABIC Innovative Plastics Mount Vernon, LLC	2017

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Utility	Proceeding	Subject	Before	Client	Date
11. Duke Energy Progress, LLC	Docket No. E-2, Sub 1142	Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	North Carolina Utilities Commission	U.S. Department of Defense and all other Federal Executive Agencies	2017
12. Nebraska Public Power District	Section 70, Article 13 Arbitration Panel	Proper Recovery of Post Retirement Benefits in Wholesale Rates	Nebraska Cities vs. Nebraska Public Power District	Nebraska Public Power District	2017
13. Northern Indiana Public Service Company	Cause No. 44733-TDSIC-1	Transmission, Distribution, and Storage System Improvement Charge	Indiana Utility Regulatory Commission	United States Steel	2016
14. Austin Energy	N/A	Austin Energy's Tariff Package: 2015 Cost of Service Study and Proposal to Change Base Electric Rate	City of Austin Impartial Hearing Examiner	Austin Energy	2016
15. Northern Indiana Public Service Company	Cause No. 44688	Interruptible Demand Credits and Cost of Service	Indiana Utility Regulatory Commission	United States Steel	2016
16. Bryan Texas Utilities	Docket No. 44467	Application of Bryan Texas Utilities for Interim Update of Wholesale Transmission Rates Pursuant to Substantive Rule 25.192(g)(1)	Public Utility Commission of Texas	Bryan Texas Utilities	2015
17. Lower Colorado River Authority	Cause No. 121-001-B	Damages Associated with Wholesale Pricing Practices	District Court of Kerr County, Texas (198th Judicial District)	City of Kerrville, acting by and through Kerrville Public Utility Board	2014-2015
18. GEUS	Docket No. 42581	Application to Change Rates for Wholesale Transmission Service	Public Utility Commission of Texas	GEUS	2014
19. Bryan Texas Utilities	Docket No. 41920	Application of Bryan Texas Utilities for Interim Update of Wholesale Transmission Rates Pursuant to Substantive Rule 25.192(g)(1)	Public Utility Commission of Texas	Bryan Texas Utilities	2013
20. Lower Colorado River Authority	Cause No. D-1GN-12-002156	Damages Associated with Wholesale Pricing Practices	District Court of Travis County, Texas (261st Judicial District)	Central Texas Electric Cooperative, Inc., Fayette Electric Cooperative, Inc., and San Bernard Electric Cooperative, Inc.	2013-2014
21. Austin Energy	SOAH Docket No. 473-13-0935 PUC Docket No. 40627	Petition by Homeowners United for Rate Fairness to Review Austin Rate Ordinance No. 20120607-055	Public Utility Commission of Texas	On behalf of the City of Austin D/B/A Austin Energy	2013

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Utility	Proceeding	Subject	Before	Client	Date
22. Guam Power Authority	Docket No. 11-09	Support of Comprehensive Rate Case	Guam Public Utilities Commission	Guam Power Authority	2012
23. Brownsville Public Utilities Board	Docket No. 38556	Application to Change Rates for Wholesale Transmission Service	Public Utility Commission of Texas	Brownsville Public Utilities Board	2010
24. Rocky Mountain Power	Docket No. 09-035-23	Testified regarding Rocky Mountain Power's Cost of Service Analysis	Utah Public Utilities Commission	Utah Division of Public Utilities	2009
25. GEUS	Docket No. 37180	Support Application to Change Rates for Wholesale Transmission Service	Public Utility Commission of Texas	GEUS	2009
26. Chugach Electric	Docket No. U-06-134	Revenue Requirement, Cost of Service Allocation, Class, and TIER Issues	Regulatory Commission of Alaska	Alaska Electric & Energy Coop/Homer Electric Association	2007
27. Sierra Pacific Power Company	Docket No. 05-10003	In Support of Reductions to Sierra Pacific Revenue Requirement and Modification to the Sierra Pacific Marginal Cost of Service Study	Public Utilities Commission of Nevada	Nevada Resort Association	2006
28. Brownsville Public Utilities Board	Docket No. 32905	Testified in Support of Transmission Costs	Texas Public Utilities Commission	Brownsville Public Utilities Board	2006
29. Cherryland Electric Cooperative vs. Traverse City Light & Power	Case No. U-13716	Evaluating Cost Basis for Proposed Large Resort Service Tax	Michigan Public Service Commission	Traverse City Light & Power	2004
30. Cherryland Electric Cooperative vs. Traverse City Light & Power	Case Nos. U-12844 and U-13071	Testified Against Damages Associated with Loss of Large Retail Load to Competing Utility	Michigan Public Service Commission	Traverse City Light & Power	2002
31. Plains Electric Generation & Transmission Cooperative	Docket No. 2797	Electric System Cost of Service and Rate Study	New Mexico Public Utilities Commission	Plains Electric Generation and Transmission Cooperative	1998
32. Environmental Protection Agency	Civil Action 96-D-2698	Radium Storage Fees	United States District Court of the District of Colorado	City and County of Denver	1997
33. Greenville Electric Utility System	Docket No. 15812	Unbundled Transmission Cost of Service/Transmission Rate Filing Compliance with Substantive Rule 23.67	Public Utility Commission of Texas	Greenville Electric Utility System	1996
34. El Jardin Water Supply Corporation	Docket No. 9013-M	Water System Revenue Requirement and Allocated Cost of Service Study	Texas Natural Resources Commission	Public Utilities Board of Brownsville, Texas	1992-1993