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MARITIME ELECTRIC
A FORTIS COMPANY

October 31, 2024

Island Regulatory and Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Commissioners:

2023 Cost Allocation Study

Please find attached a copy of Maritime Electric's 2023 Cost Allocation Study, for which the Company retained the services of Chymko Consulting Limited ("Chymco"). The results of the 2023 Cost Allocation Study form the basis for the Open Access Transmission Tariff Application filed in parallel with this Study.

The 2023 Cost Allocation Study followed the same three-step methodology as previous cost allocation studies with respect to functionalizing revenue requirement, classification, and allocation of expenses to the different rate classes.

The resulting revenue-to-cost ("RTC") ratios compare the revenue collected to the allocated cost of providing service for each rate class. Table 1 is a comparison of the RTC ratios for each rate classification from the 2023 and 2020 Cost Allocation Studies as well as a comparison to the RTC ratios previously provided in Table 4 of the Stage 1 Rate Design Application, which was based on the 2017 Cost Allocation Study.

Table 1
Comparison of RTC Ratios

Rate Classification	2023	2020[1]	Table 4 – Stage 1 Rate Design Application
Residential	94%	93%	93%
Residential (Seasonal)	88%	94%	96%
Farm	90%	87%	83%
General Service	122%	118%	119%
General Service (Seasonal)	108%	103%	110%
Small Industrial	96%	109%	102%
Large Industrial	97%	96%	94%
Street Lighting	66%	79%	91%
Unmetered	104%	106%	104%
Total	**100%**	**100%**	**100%**

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[1] The 2020 RTC ratios reflect the updated energy input allocator for farms as provided in Table 3 in the Company's letter to Key Murray Law dated December 12, 2023 in response to interrogatories from the PEI Federation of Agriculture on the Company's Application for an Order approving Stage 1 Rate Design Changes [Docket 22503].

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Overall, the 2023 RTC ratios are consistent with the Stage 1 Rate Design Application and the 2020 RTC ratios, thereby supporting the rate design changes proposed in the Stage 1 Rate Design Application.

Stage 1 proposed:

- Phasing out the Residential declining second block energy charge by increasing it to be the same as the first block energy change over four years, which is supported by the fact that its RTC ratio remains below the target range;
- The proposed rate increase for the Large Industrial class will result in an RTC ratio that is closer to 100 per cent and is still within the target range of 95:105 per cent;
- A rate increase for the Street Lighting classes to bring their RTC ratios into the target range of 95:105 per cent over two years, which is supported by the fact that its RTC ratio remains below the target range; and
- The additional revenue collected from the Residential, Large Industrial, and Street Lighting classes be offset by a corresponding decrease in revenue and rates for the General Service class, which is supported by the fact that the General Service RTC ratio remains above the target range.

While the Farm RTC ratio has marginally improved, it is still below the target range of 95:105 and continues to support the elimination of the Residential declining second block energy charge. As indicated in the Stage 1 Rate Design Application, the Company will conduct a subsequent cost allocation study to determine if additional rate changes are needed in Stage 2 to bring RTC ratios of all classes within the target range of 95:105 per cent.

For the Large Industrial class, the Stage 1 Rate Design Application proposed a 4.4 per cent increase in revenue to bring its RTC ratio within the target range and the 2023 Cost Allocation Study confirms that this is still appropriate.[2]

The RTC ratio for the Street Lighting class has decreased to 66 per cent, from 79 per cent in the 2020 Cost Allocation Study. The decrease is attributable to a reduction in both sales and demand resulting from the conversion to LED streetlights from high pressure sodium streetlights. What would otherwise result in lower costs allocated to this rate class is more than offset by an increased allocation of capital-related costs associated with the accelerated amortization due to the conversion to LED streetlights and increased cost of retiring lighting units, resulting in a lower RTC ratio for this rate class. In the Stage 1 Rate Design Application, the Company proposed increasing street lighting revenue by 7.4 per cent. As was the case in the 2020 Study, the 2023 Cost Allocation Study suggests that an additional increase will be required to bring the RTC ratio for this class within the target range, which the Company will address in Stage 2.

Finally, in the Stage 1 Rate Design Application the Company proposed that the additional revenue from proposed rate changes for Residential, Large Industrial and Street Lighting classes be offset by reducing the General Service class rates such that the overall impact is revenue neutral to the Company. This recommendation is supported by the fact that the 2023 Cost Allocation Study resulted in a minor increase to the General Service RTC ratio. Further Stage 2 rate design changes will be needed to bring the RTC ratio of the General Service class within the target range of 95:105 per cent.

The Small Industrial class experienced a decrease in its RTC ratio due mainly to a higher allocation of demand-related costs compared to 2020. The RTC ratio for this class is now back within the 95:105 target range. However, the Company maintains its recommendation to revisit the RTC ratio of the Small Industrial class in a future Stage 2 rate design proposal for the following reasons:

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[2] A 4.4 per cent increase to the Large Industrial class would increase the 2023 revenue from $16,362,000 to $17,081,000 compared to 2023 allocation of cost of $16,866,000, resulting in an RTC ratio of 101.

- there has been a significant drop in the RTC ratio from 109% in 2020 to 96% in 2023; and
- the Stage 1 Rate Design Application proposed that farm customers be given the option to move to the Small Industrial class if it is cost beneficial for the customer to do so and, in Section 8.5 of that application, evidence suggested that, if approved, larger farms will elect to move to the Small Industrial class after Step 2 of the elimination of the Residential declining second block energy charge. Such a reclassification of a number of large farm customers may impact the RTC ratios.

Overall, the results of the 2023 Cost Allocation Study support the rate changes proposed in the Stage 1 Rate Design Application.

The Company would also like to draw attention to additional information provided in the 2023 Cost Allocation Study, which is included in Appendix A: Classifying Distribution Infrastructure. This appendix includes an analysis performed by Chymko of demand and customer (i.e., site related) classification percentages for certain components of the distribution system.

This analysis was undertaken to fulfill a commitment made by Maritime Electric as part of its May 12, 2023 response to Interrogatories from the Commission Staff on the Company's May 14, 2021 Rate Design Application [Docket UE22503]. In particular, in the Company's response to IR-16(b), the Company committed to providing "a review of the demand and customer classification percentages for the distribution system as part of the Company's next cost allocation study…"

Chymko's analysis in Appendix A supports the continued use of the classification percentages used in past cost allocation studies, namely:

- Primary Lines – 50% demand-related and 50% customer-related;
- Distribution Transformers – 60% demand-related and 40% customer-related; and
- Secondary Lines – 50% demand-related and 50% customer-related.

Further, in Appendix A, Chymko states that Synapse's proposed use of the Basic Customer Method of classifying costs is not supported by any analysis, rationale or study. While Synapse did refer to a regulatory assistance project titled "Electric Cost Allocation for a New Era: A Manual", an examination of this document revealed that its recommendation of the Basic Customer Method was essentially a policy decision by the proponents of the study.

If you have any questions, please do not hesitate to contact me at 902-629-3701.

Yours truly,

MARITIME ELECTRIC

Michelle Francis
Vice President,
Finance & Chief Financial Officer

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Enclosure

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September 23, 2024

Gloria Crockett
Maritime Electric Company, Ltd.
180 Kent Street
Charlottetown, PE C1A 7N2

Dear Ms. Crockett

SUBJECT: 2023 Cost Allocation Study

Please find attached the findings of Chymko Consulting Ltd.'s Electric Utility cost allocation study technical update to assist Maritime Electric with its upcoming rate proposal to the Island Regulatory and Appeals Commission.

We appreciate the time and effort of Maritime Electric staff to provide us with the necessary data and information to conduct this study. Should you have any questions or comments on this report, please contact me at (403) 781-7691.

Yours truly,

Michael Turner
President

Attachment

2023 Cost Allocation Study

Maritime Electric

September 23, 2024

www.chymko.com

EXECUTIVE SUMMARY

Maritime Electric Company Limited (MECL) retained Chymko Consulting Ltd. to update the comprehensive 2020 Cost Allocation Study in support of a future rate proposal to the Island Regulatory and Appeals Commission (IRAC). The following report provides the results of this study, which is based on MECL's 2023 Financial Results for twelve months ending on December 31, 2023.

A cost allocation study first functionalizes revenue requirement (in this case, the Statement of Earnings), essentially seeking to attribute the full cost of service to a specific purpose, such as power supply, transmission, distribution network, services and metering, customer care, and lighting. Next, the cost allocation study classifies each function as demand, energy, or site-related depending upon how the cost of that function might vary with how end-use customers use the system. Finally, the cost allocation study will allocate the functionalized and classified expenses to rate classes.

Table A below summarizes MECL's allocated revenue requirement.

Table A
Allocated 2023 Net Revenue Requirement from Rates

	Revenue Collected	Allocated Cost	Revenue-to-Cost Ratio (2023)	Revenue-to-Cost Ratio (2020)
Residential	52.7%	56.3%	94%	93%
Residential (S)	2.4%	2.7%	88%	94%
Farm	2.6%	2.8%	90%	87%
General Service	28.2%	23.2%	122%	118%
General Service (S)	0.9%	0.8%	108%	103%
Small Industrial	5.5%	5.7%	96%	109%
Large Industrial	6.7%	6.9%	97%	96%
Lights	0.9%	1.4%	66%	79%
Unmetered	0.2%	0.2%	104%	106%
Total	100.0%	100.0%	100%	100%

Allocated cost is one bookend for a 2024 rate proposal, representing the cost to provide electric utility service for each rate class. If cost causation were the only consideration, for instance, Table A indicates that 2024 rates should seek to recover 56.3 per cent of 2024 revenue requirement from the Residential rate class, 2.7 per cent from the Seasonal Residential rate class, and so on.

Another consideration is how much the rate for each class of customer would have to change to recover allocated cost. By the current revenue-to-cost ratios shown in Table A above, some rates would need to change significantly. Subject to full consideration of all rate design principles and further analysis of any such change, it may well be that rate rebalancing would need to be implemented gradually over the course of multiple years.

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1 INTRODUCTION

1. Maritime Electric Company Limited (MECL) retained Chymko Consulting Ltd. (CCL) to complete a technical update to the cost allocation study conducted in support of MECL's 2024 rate proposal to the Island Regulatory and Appeals Commission (IRAC or the Commission). Based on the assumptions discussed in this report, CCL's cost allocation study takes as a starting point MECL's Statement of Earnings for twelve months, ending on December 31, 2023. Contained in MECL's December 2023 monthly financial report submitted to IRAC, the Statement of Earnings represents the total cost of providing electric utility service at a rate of return determined by IRAC in Order UE23-04.

2. A cost allocation study typically begins with determining "revenue requirement," which represents the forecast cost of providing electric utility service based on a regulator-approved rate of return. MECL's 2023 Statement of Earnings is similarly based on a rate of return deemed to be in the public interest insofar as it is compliant with Order UE23-04. Therefore, the principal difference between the Statement of Earnings and revenue requirement is that the Statement of Earnings is calculated after-the-fact and revenue requirement is typically forward-looking. MECL has traditionally filed cost allocation studies based on actual expenses from the previous calendar year, and in using the 2023 Statement of Earnings this study is no different.

3. This study examines the detailed expenses underlying the Statement of Earnings and assigns, attributes, or allocates expenses to each of MECL's rate classes. The fully-allocated 2023 Statement of Earnings by rate class then becomes an important benchmark to inform MECL's anticipated 2024 rate proposal. If the Residential rate class is attributed fifty per cent of 2023 expenses, for instance, then this information can serve as a target or objective for designing 2024 Residential rates.

4. The first step of a cost allocation model is to group similar types of expenses that make up revenue requirement into elements of service, or functions. For each function, the user of the cost allocation model must consider:

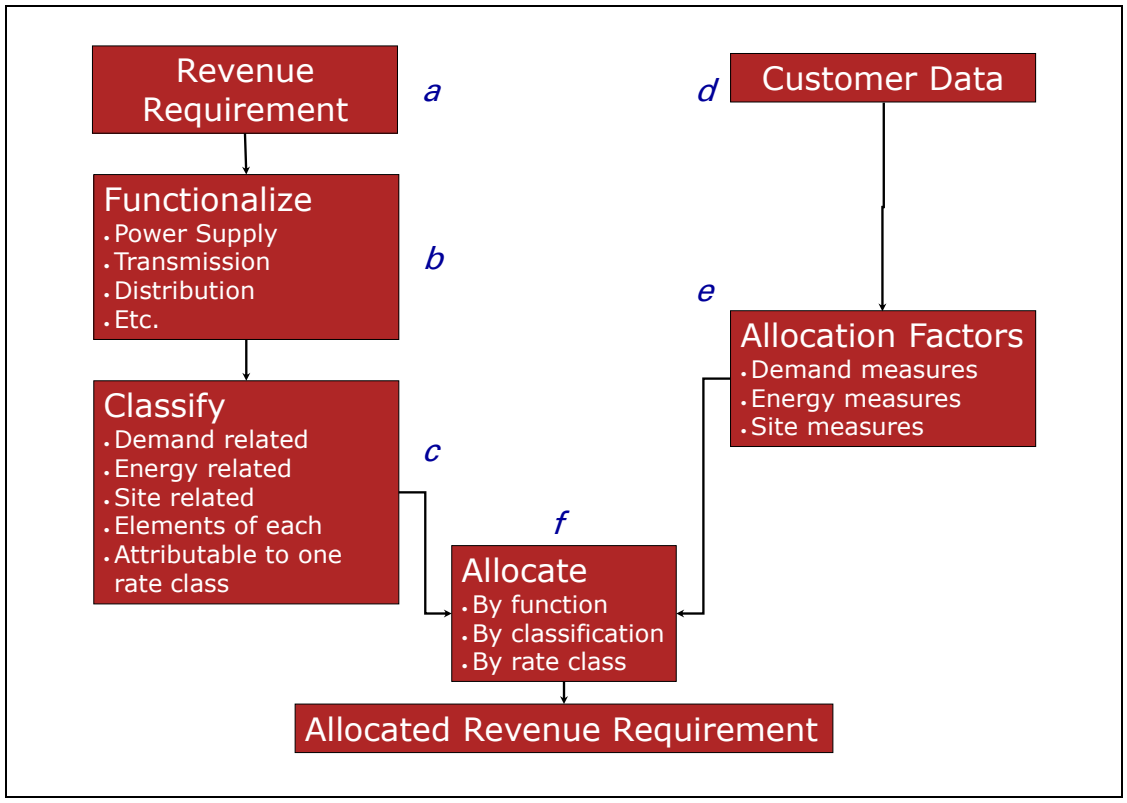
   - Is the function incurred for the purpose of servicing all rate classes, a sub-set of rate classes, or a single rate class?

   - If the function is attributable to more than one rate class, how might the cost of that function vary depending upon how end-use customers use the distribution system? For example, does the cost vary with peak daily demand changes? Does it vary with the total amount of energy delivered? Does it vary with the number of distribution sites served?

   - How does each rate class contribute to the use of distribution infrastructure? For example, how does each rate class contribute to total peak demand and total energy delivered? How many sites are served in each rate class?

5. In order to answer the above questions, cost allocation studies follow a structured process, which can be explained with the aid of Figure 1 below. Taking revenue requirement (labelled as a) as a given, the first step is known as functionalization (labelled as b), which begins with attributing each line item in the study by its purpose or function.

Figure 1: Process of a cost allocation study



6. The next step in a cost allocation study is called classification (c). The purpose of classification is to determine how each function might vary based on how end-use customers use the system. Sometimes, a function exists solely for the purpose of serving a subset of rate classes, perhaps only a single rate class. However, if the function is attributable to more than one rate class, it is necessary to explore further as to whether the expense will vary with peak demand on the system, the amount of energy consumed, or the number of sites served by the system. Thus, each function is classified as demand-related, energy-related, site-related, or a combination of the three.

7. The final step of a cost allocation study is to allocate the functionalized and classified revenue requirement to rate classes. The choice of allocation factor is to a large degree influenced by the classification of each functionalized detail of revenue requirement. For example, demand-related costs are generally allocated by the same proportions as the peak demand of each rate class. Similarly, energy-related costs are allocated by the same proportions as energy sales and site-related costs are allocated by the relative size of each rate class.

8. The development of allocation factors starts with the collection of MECL's system load data and billing statistics (d). From this foundation along with any associated load research data, it is possible to calculate allocation factors (e) based on each rate classes' peak demand, energy consumption, and the number of sites per rate class.

9. As suggested by the overview above, the process of a cost allocation study is relatively uncomplicated given there is agreement upon how a cost is to be functionalized, classified, and allocated. Thus, generally accepted principles and methods have evolved out of several years of regulatory experience. Regulated distribution utilities must file cost allocation studies to demonstrate that their tariffs are just and reasonable. Generally accepted methods typically evolve out of the regulatory process, but even these continue to evolve with industry changes and provincial government policy. Furthermore, every utility is different, and every utility service area has its own unique characteristics and issues that may justify a different method. Therefore, it is important to justify the rationale for every cost functionalization, classification, and allocation decision, regardless of whether it is a commonly accepted standard or not.

2 FUNCTIONALIZATION

10. The starting point for cost allocation is the 2023 MECL Statement of Earnings. This is summarized in Table 1 below.

Table 1[1]
MECL 2023 Statement of Earnings (Revenue Requirement, $,000)

	Twelve Months ending December 31, 2023
Operating Expenses	
Energy Costs	159,717
ECAM Adjustment	(8,641)
Net Energy Costs	151,076
Distribution	9,025
Transmission	1,795
T&D - Other	2,822
Transmission - OATT	293
General	13,502
Total Operating Expenses	178,513
Amortization	0
Amortization Other	436
Amortization - CTGS	2,134
Amortization - PP&E	27,001
Total Amortization	29,572
Total Operating Income	208,085
Financing Expenses	0
Long-Term Debt	14,742
Short-Term Debt	1,337
Interest Charged to Construction (ITC)	(779)
Interest Income	(49)
Amortization Financing Cost	25
Total Financing Expenses	15,276
Earnings before Income Tax	25,765
Income Taxes	8,026
Net Earnings	17,739
Gross Revenue Requirement	249,126
OATT Revenue	(2,725)
Other Revenue	(3,051)
Net Revenue Requirement	243,349

11. Net earnings identified is equivalent to the Company's actual return on equity for a prospective revenue requirement. MECL's 2023 earnings were less than the 9.70 percent maximum rate of return approved by the Commission in Order UE23-04, but this difference is not expected to have a material impact on the cost allocation results.[2]

[1] Table totals in this report may not reconcile due to rounding.
[2] As per Commission Order UE23-04, paragraphs 11(a) and 11(b), the Company's allowed return on common equity reflected in rates is 9.35 precent and maximum allowed return is 9.70 percent.

12. As in the 2020 Cost Allocation Study, the Statement of Earnings in Table 1 includes Pole Revenue in other revenue rather than in streetlight revenue.

2.1 METHOD

13. Consistent with the 2020 Cost Allocation Study, CCL's current study fully attributes revenue requirement in Table 1 to one of sixteen functions discussed below. For purposes of summary, the sixteen functions are also discussed under six general categories: power supply, transmission, distribution network, services and metering, customer care, and lighting.

Power Supply

- Generation: MECL's Borden and Charlottetown generating facilities, which are typically dispatched for backup purposes.

- Purchased Power: Energy supply purchases from NB Power and PEI Energy Corp, which are typically dispatched for base load and ancillary service requirements. Also included is rooftop solar power exported to the electric grid as part of the net metering program.

Transmission

- High-voltage transmission facilities operating at a voltage of 69 kV or greater.

Distribution Network

- Substations: Facilities used to regulate and step-down voltages from transmission facilities to distribution lines.

- Primary Lines: Bulk distribution lines used to deliver energy from substations to localized distribution transformers.

- Transformers: Facilities used to regulate and step-down voltages from primary distribution lines to a voltage more suitable for the end-use consumer.

- Secondary Lines: Local distribution lines operating at a consumer-level voltage that service multiple end-use customers.

Services and Metering

- Service Lines: Local distribution lines operating at a consumer-level voltage that connect the distribution network to the meter of a single, end-use customer.

- Meter Assets: Metering infrastructure used to measure and record energy consumed by each end-use customer.

- Meter Reading: The process of collecting and processing end-use customer metering data, primarily for the purpose of billing.

Customer Care

- Billing: The process of preparing and delivering invoices to end-use customers for power supply and use of the MECL system.

- Remittance & Collection: The accounts receivable process of collecting and processing end-use customer bill payments.

- Uncollectibles & Damage Claims: Uncollectibles are associated with the cost of outstanding customer invoices (e.g. bad debts), whereas damage claims represent claims against MECL for damage to customers' property.

- Service Connections: Activities related to the connection or re-connection of customers, which may include off-cycle meter reads as well as modifications or additions to secondary lines, service lines, and meters. MECL recovers the cost of these activities under sections O-1 and O-2 of its tariff.

- Late Payments: Penalty revenues associated with consumer accounts in arrears, as recovered under section O-3 of the MECL tariff.

Lighting

- Facilities dedicated to the use of providing electric service to street and area lighting, as defined under sections N-22, N-23, N-25, and N-26 of the MECL tariff.

14. CCL functionalizes revenue requirement as per a series of methods and assumptions summarized in Table 2 below, which have changed slightly from the 2020 Cost Allocation Study. Overall, this table demonstrates that sixty-one per cent of revenue requirement is directly assigned to a function. An additional thirty-four per cent is functionalized according to the same proportions as the underlying facilities and assets, the majority of which are also directly assignable because of detailed asset records. A further three per cent is allocated by the same proportions by which labour cost is functionalized, which leaves two per cent to be allocated by various methods involving professional judgement.

Table 2
Methods to Functionalize 2023 MECL Revenue Requirement

	Direct Assign	Assets & Facilities	Labour	Profes-sional Judgment	Total
Operating Expenses					
Energy Costs	99%	1%	0%	1%	100%
ECAM Adjustment	100%	0%	0%	0%	100%
Net Energy Costs	99%	1%	0%	1%	100%
Distribution	15%	81%	0%	4%	100%
Transmission	100%	0%	0%	0%	100%
T&D - Other	11%	89%	0%	0%	100%
Transmission - OATT	100%	0%	0%	0%	100%
General	9%	16%	50%	25%	100%
Total Operating Expenses	86%	7%	4%	3%	100%
Amortization					
Amortization Other	21%	14%	64%	0%	100%
Amortization - CTGS	100%	0%	0%	0%	100%
Amortization - PP&E	0%	100%	0%	0%	100%
Total Amortization	8%	92%	1%	0%	100%
Total Operating Income	75%	19%	3%	2%	100%
Financing Expenses					
Long-Term Debt	0%	100%	0%	0%	100%
Short-Term Debt	0%	100%	0%	0%	100%
ITC	0%	100%	0%	0%	100%
Interest Income	0%	100%	0%	0%	100%
Amortization Financing Cost	0%	100%	0%	0%	100%
Total Financing Expenses	0%	100%	0%	0%	100%
Earnings before Income Tax	0%	100%	0%	0%	100%
Income Taxes	0%	100%	0%	0%	100%
Net Earnings	0%	100%	0%	0%	100%
Gross Revenue Requirement	63%	33%	3%	2%	100%
OATT Revenue	100%	0%	0%	0%	100%
Other Revenue	36%	48%	0%	16%	100%
Net Revenue Requirement	63%	33%	3%	2%	100%

15. To the extent that the information exists, and it is practical to do so, the priority in functionalization is to directly attribute as much as possible to a given function without the need to allocate. The detailed financial accounting records provided by MECL allows CCL to directly assign nearly two thirds of revenue requirement to one of the sixteen functions.

16. That which cannot be directly assigned is allocated. Amortization, debt financing, return, and income tax are the most important examples of a functional allocation. These expenses comprise more than one quarter of the MECL revenue requirement and are only indirectly associated with the sixteen functions. Amortization, debt financing, and return are all calculated based on MECL's infrastructure investment and therefore the underlying infrastructure becomes a determining factor as to how these expenses should be functionalized. Moreover, MECL pays income tax only if it earns a positive return and therefore, tax is also indirectly associated with utility infrastructure.

17. CCL allocates these expenses by the same proportions as the underlying capital infrastructure, which means that gross plant and depreciation must also be fully attributed to each of the sixteen functions. MECL's detailed plant records facilitate a relatively straightforward functionalization process as shown in Schedule 4.0 of Appendix A. More than half of gross plant in service is directly attributable to a single function and an additional forty-three per cent is attributable to a narrow subset of the sixteen functions.

18. The next-most important functionalization method as it affects total revenue requirement is general operating expenses non-specific to a function. For instance, because corporate overhead costs (corporate supervisory salaries and employment benefits) exist for the purpose of all other personnel, CCL allocated such expenses by the same proportions as all other labour expenses already attributed to the sixteen functions.

19. The final category of functionalization method used is broadly described as professional judgement in Table 2. This describes seven different methods that are applied on a case-by-case basis depending upon the nature of the expense. The two most important methods, as measured by total expense allocated, are used for the allocation of energy control centre expenses and the allocation of finance administration costs. In the case of the former, this and previous studies rely on the professional judgement of MECL staff to functionalize energy control centre: one-quarter to power supply, one-quarter to transmission, and the remaining amount to the distribution network, as shown in Schedule 5.0 of Appendix A. In the case of financial administration, approximately half of the annual expense is postage and stationery associated with billing and the other half is labour cost. For the half that is labour, expenses are functionalized according to the work responsibilities of the personnel in that department.

2.2 RESULT

20. The outcome of the functionalization process is summarized in Table 3 below.

Table 3
Functionalized MECL Revenue Requirement ($,000)

	Power Supply	Trans'n	Distrib'n Network	Services and Metering	Customer Care	Lighting	Total
Operating Expenses							
Energy Costs	153,632	5,534	551	0	0	0	159,717
ECAM Adjustment	(8,641)	0	0	0	0	0	(8,641)
Net Energy Costs	144,991	5,534	551	0	0	0	151,076
Distribution	85	85	7,925	856	0	74	9,025
Transmission	0	1,795	0	0	0	0	1,795
T&D - Other	0	0	2,822	0	0	0	2,822
Transmission – OATT	0	293	0	0	0	0	293
General	1,344	2,310	5,618	1,835	2,321	73	13,502
Total Operating Expenses	146,420	10,017	16,916	2,691	2,321	147	178,513
Amortization							0
Amortization Other	137	122	139	29	9	1	436
Amortization - CTGS	2,134	0	0	0	0	0	2,134
Amortization – PP&E	2,575	3,941	15,508	4,356	112	511	27,001
Total Amortization	4,846	4,062	15,647	4,384	121	511	29,572
Total Operating Income	151,266	14,079	32,563	7,076	2,442	659	208,085
Financing Expenses							0
Long-Term Debt	1,753	2,430	8,707	1,580	45	228	14,742
Short-Term Debt	159	220	790	143	4	21	1,337
ITC	(93)	(128)	(460)	(83)	(2)	(12)	(779)
Interest Income	(6)	(8)	(29)	(5)	(0)	(1)	(49)
Amort of Financing Costs	3	4	15	3	0	0	25
Total Financing Expenses	1,816	2,518	9,023	1,637	46	236	15,276
Earnings before Income Tax	3,064	4,246	15,218	2,761	78	398	25,765
Income Taxes	954	1,323	4,740	860	24	124	8,026
Net Earnings	2,109	2,924	10,477	1,901	54	274	17,739
Gross Revenue Requirement	156,146	20,843	56,804	11,473	2,567	1,293	249,126
OATT Revenue	0	(2,725)	0	0	0	0	(2,725)
Other Revenue	(173)	(240)	(1,364)	(156)	(1,095)	(23)	(3,051)
Net Revenue Requirement	155,973	17,877	55,440	11,317	1,471	1,270	243,349

21. The results in Table 3 are relatively consistent with previous studies, which is reasonable given that CCL has followed the same methods as the previous study. Compared to CCL's 2020 Cost Allocation Study for MECL, the largest shift in functionalized expense is related to power supply, which has dropped from sixty-eight per cent to sixty-three per cent of the total functionalized cost (see Table 4 below).

22. Excluding power supply from the analysis, Table 4 also demonstrates that there is an increase of five per cent in expenses functionalized as distribution net. At the same time, costs that are functionalized as services and metering decreased at a faster rate than other functionalized costs, resulting in the function's share of revenue requirement decreasing from fifteen per cent in 2020 to twelve per cent in 2023 when power supply is excluded.

23. Expenditures within revenue requirement will shift focus over time and since 2020, MECL's revenue requirement shifted slightly from on-island generation expenses (down about three per cent of total revenue requirement) toward more expenditures on transmission,

substation, and primary lines expenses. If nothing else changes, MECL's biggest energy consumers, small and large industrials, benefit from this because generation is allocated in part based on energy sales whereas transmission, substation, and primary lines expenses are allocated based on peak demand. In other words, the evolving revenue requirement observed here has the effect of shifting more expenses to Residential and General Service and less toward Small and Large Industrial, assuming all else equal.

Table 4
Functionalized MECL Revenue Requirement

	Power Supply	Trans'n	Distrib'n Network	Services and Metering	Customer Care	Lighting	Total
Per cent of total							
2023 Revenue Requirement	64%	7%	23%	5%	1%	1%	100%
2020 Revenue Requirement	68%	7%	19%	5%	0%	0%	100%
Excluding Power Supply							
2023 Revenue Requirement	N/A	20%	63%	13%	2%	1%	100%
2020 Revenue Requirement	N/A	22%	59%	15%	1%	2%	100%

3 CLASSIFICATION

24. Functionalized revenue requirement is next classified based on the generally accepted cost drivers that can be measured in terms of how customers use the system. Costs associated with upstream functions are generally accepted to be a function of the peak demand placed on the system and are classified accordingly. At the other extreme, downstream functions, such as services and metering, are generally a function of the number of sites served.[3]

3.1 METHOD

Power Supply

25. In the context of a vertically integrated and regulated electric utility, power supply requirements are generally considered to be a function of both peak demand and total energy consumed. Power supply is a function of total energy consumed because all else equal, a utility with 50,000 GWh of annual sales would incur higher power supply costs than a utility with 1,000 GWh of annual sales. However, even among two utilities with the same annual sales, generation resource planning (and therefore, cost) will differ based on the peak hourly demand. While a consistently flat electrical load may be better served by larger generating facilities suited for full-on production, a variable and peaking load will require a different mix of generating resources. Options for meeting variable peak demand may include smaller scale facilities, technologies that are able to ramp-up production on relatively short notice, or a combination of the two.

26. In Order UE19-08, the Commission approved the Point Lepreau Cost Allocation Classification Study, which included three main changes. All three changes were introduced in the 2017 study and remain for this 2023 study.

- Twenty-five per cent of Point Lepreau's fixed costs are classified as demand-related, and seventy-five per cent of as energy-related.
- All combustion turbine fuel costs are classified as energy-related given that most of the combustion turbine's fuel usage occurs to supply energy for the system.
- A portion of wind purchase power is classified as demand-related, with the remainder energy-related. The demand portion, currently twenty-three per cent, mirrors the ratio of wind power nameplate capacity that is included as capacity for capacity planning purposes.

[3] Note that CCL's report often uses the term "sites" as opposed to "customers" in the context of a cost allocation study. The purpose of this terminology is to be clear that a cost allocation study is concerned with attributing revenue requirement to distribution points of delivery or "sites." Some customers may actually be served by multiple sites.

27. Consistent with previous studies, twenty-five percent of MECL's Energy Control Centre (ECC) is functionalized as power supply and this portion is classified as energy related. In the context of power supply, the purpose of the ECC is to manage and coordinate the delivery of energy. The remaining seventy-five percent of the ECC costs are functionalized to transmission and distribution, where classification is discussed as follows.

Transmission

28. Transmission lines are part of a bulk delivery system that ultimately services all utility customers, including wholesale customers. Transmission infrastructure is generally unaffected by the addition of one more customer, unless the addition of that customer is expected to materially affect peak system demand. CCL therefore considers transmission lines to be demand-related and allocates these functions based on coincident peak demand.[4] Coincident peak demand is appropriate for this allocation because transmission facilities must be capable of providing service during the time of system peak. PEI's demand for electricity is at its highest during the winter, and therefore MECL's backbone delivery system must be designed to accommodate peak demand at this time.

Distribution Network

29. Substations are part of a bulk delivery system that services virtually all MECL customers. Like transmission infrastructure, substations are generally unaffected by the addition of one more customer, unless the addition of that customer is expected to materially affect peak system demand. Thus, substations are classified as demand-related and allocated based on coincident peak demand.[5]

30. Functions such as primary lines, transformers, and secondary lines are also part of MECL's distribution network. These facilities must be designed to meet peak demand, the cost of these functions will increase as more customers are added to the system. Expanding the distribution system to service new customers will require MECL to extend distribution lines and install new transformers, and so there will be a base level cost regardless of the capacity that these facilities will be required to carry.

31. This cost allocation study continues with the same basic principles followed in previous MECL cost allocation studies. MECL considers that circumstances have not materially changed and the Company's objective for this study is to apply consistent methods to previous studies and facilitate a more meaningful comparison of results over time. Thus, lines are classified as fifty per cent demand-related and fifty per cent site-related[6] whereas transformers are classified as sixty per cent demand-related and forty per cent site-related.

[4] For transmission lines, peak demand is measured at the transmission system level including losses, which as noted earlier are not evenly distributed between rate classes.
[5] The allocator for substations is also adjusted to recognize that some Large Industrial customers are serviced at a transmission voltage and do not use substation facilities.
[6] For the allocation of distribution network functions, allocators are adjusted to recognize that some distribution customers are serviced at a primary voltage and do not use a MECL transformer or secondary line.

Services, Metering, and Customer Care

32. Functions such as service lines, metering, meter reading, billing, remittance & collection, and uncollectibles & damage claims are all classified as site-related. It is generally recognized that the cost of these functions will primarily vary with the number of customers served. Factors other than demand, energy or sites also play a role in cost causation, but these adjustments are made by the choice of allocation and are discussed further in Section 4.

33. Finally, functions associated with service connections and late payments are also classified as site-related. From a cost causation perspective, MECL tracks cost by rate class and so classification of these functions is mainly for presentation purposes. In Section 4, these functions are allocated to rate classes in the exact same proportion as actual revenue.

3.2 RESULT

34. MECL's classified revenue requirement is summarized in Table 5 below.

Table 5 Classified 2023 MECL Revenue Requirement ($,000)				
	Demand	Energy	Site	Total
Operating Expenses				
Energy Costs	30,066	129,522	129	159,717
ECAM Adjustment	(1,360)	(7,282)	0	(8,641)
Net Energy Costs	28,707	122,240	129	151,076
Distribution	4,776	73	4,176	9,025
Transmission	1,795	0	0	1,795
T&D - Other	1,789	0	1,033	2,822
Transmission – OATT	293	0	0	293
General	5,988	1,145	6,369	13,502
Total Operating Expenses	43,347	123,458	11,707	178,513
Amortization				
Amortization Other	231	116	89	436
Amortization - CTGS	310	1,824	0	2,134
Amortization - PP&E	13,295	2,200	11,507	27,001
Total Amortization	13,837	4,140	11,596	29,572
Total Operating Income	57,184	127,598	23,303	208,085
Financing Expenses				
Long-Term Debt	7,821	1,493	5,428	14,742
Short-Term Debt	709	135	492	1,337
ITC	(413)	(79)	(287)	(779)
Interest Income	(26)	(5)	(18)	(49)
Amortization Financing Cost	13	3	9	25
Total Financing Expenses	8,104	1,547	5,625	15,276
Earnings before Income Tax	13,668	2,609	9,487	25,765
Income Taxes	4,258	813	2,955	8,026
Net Earnings	9,411	1,797	6,532	17,739
Gross Revenue Requirement	78,957	131,754	38,414	249,126
OATT Revenue	(2,725)	0	0	(2,725)
Other Revenue	(1,025)	(148)	(1,879)	(3,051)
Net Revenue Requirement	75,207	131,607	36,535	243,349

35. CCL applied the same methods as previous studies and to the extent that results in Table 5 vary from previous studies, it is because different parts of revenue requirement change at varying rates.

36. There was a one per cent increase in the share of revenue requirement classified as site-related costs, while the share of revenue requirement classified as energy-related increased by two per cent, and the share of demand-related revenue requirement fell by three per cent. These changes were primarily caused by shifts in energy costs, amortization and financing expenses.

37. Excluding power supply from the analysis, we can see from Table 6 below that demand and site-related revenue requirements have remained stable since 2020.

Table 6 Classified MECL Revenue Requirement				
	Demand	Energy	Site	Total
Per cent of total				
2023 Revenue Requirement	31%	54%	15%	100%
2020 Revenue Requirement	35%	52%	14%	100%
Excluding Power Supply				
2023 Revenue Requirement	58%	0%	42%	100%
2020 Revenue Requirement	58%	0%	42%	100%

4 ALLOCATION

38. Once revenue requirement is classified between demand, energy, and site-related, the next step is to allocate revenue requirement to rate classes. This requires some consideration of how customers should be grouped into rate classes for purposes of allocation as well as choosing the appropriate allocator for each expense.

4.1 RATE CLASSES

39. The rate classes used in the current cost allocation study are consistent with previous cost allocation studies and remain influenced by a 1990s regulatory framework that obliged MECL to adopt the same rate schedules as New Brunswick Power. For the 2014 study, CCL modified its cost allocation model to separate farms from the Residential rate class. Until such time as the issue is resolved, the study continues to show farms as if it were a separate rate class.

4.2 ALLOCATORS

40. The final step of the cost allocation study is to allocate the utility's classified revenue requirement to rate classes. The choice of allocation factor is to a large degree influenced by classification. For example, demand-related costs are generally allocated by the same proportions as the peak demand of each rate class. Similarly, energy-related costs are allocated by the same proportions as energy sales and site-related costs are allocated by the relative number of sites within each rate class. Below are some common measures of customer usage that are often used as the basis for allocation to rate classes.

41. In 2020 we began to incorporate the findings of load research. Residential, Farm, and General Service customers are all typically cumulative-metered. Before 2020, expectations about behaviour was based on load research undertaken in the early 1990s. This new load research was able to replace or at least improve upon certain assumptions made by previous studies. Cost allocation studies are driven by relative changes, so all percentage figures quoted are in reference to the change in total share. For instance, a two-percentage point change to peak demand does not necessarily mean that peak demand increased two percentage points. This could also mean that other rate classes shrunk by a total of two percentage points – or simply grew at a slower rate.

Coincident Peak Demand (CP)

42. Coincident peak represents each rate class's contribution to the utility's peak demand day. This is typically measured over the period of one year, but other variants include the sum of peak summer and peak winter demands as well as the sum of daily peak demand for twelve consecutive months. This type of allocator is often paired with demand-related costs associated with high-voltage transmission. The MECL system peak occurs during the winter due to the combination of lighting and heating demand.

43. While the coincident peak demand allocator recognizes customers are collectively peaking, it also recognizes that individual customers use energy at different times of the day. For example, a transmission line servicing one 1 MW customer is likely to require higher capacity than a line that services one thousand 1 kW customers who collectively add up to 1 MW. Given that individual customers do not necessarily peak at the same time, this diversity can be factored into transmission system design. The calculation of coincident peak demand also reflects this diversity, making it an appropriate allocator for transmission facilities.

44. Firm load is used to allocate purchased power costs to account for the fact that interruptible load reduces the amount of generating capacity that needs to be purchased.

45. Historically, MECL could reliably depend on the MECL system peak occurring in December, when demands for lighting and heating load are at their highest. This was not the case for the last cost allocation study, nor is it the case for this study. For instance, the 2020 system peak occurred during a winter storm in January and the 2023 system peak occurred during a polar vortex in February. Both events were not typical peak days by historical standards and in that sense, both skew the allocation of demand-related cost in a cost allocation study. For instance, the January 2020 storm day caused many schools and businesses to close and with the population staying at home, residential load was higher than it otherwise would have been. While a winter storm or a polar vortex is the type of problem that the system capacity needs to accommodate, planning system capacity generally contemplates a state where all customers using the system (in other words, schools and businesses would be open). Moreover, it is desirable that the results of cost allocation study should be stable and not be subject to extreme weather events.[7]

46. The events of 2020 and 2023 are demonstrating that it is no longer reasonable to depend on the system peak occurring in December and that the cost allocation results will not necessarily be stable based on a single coincident peak. For this reason, Chymko Consulting revised the measure of coincident peak, from a single winter peak to the average of three coincident peaks in January, February, and December. Compared to using the February 2023 system peak, the impact of using three months is advantageous to the residential rate class and detrimental to general service and lighting. This is because there were more daylight hours in February (compared to December) and some businesses are less than full capacity during extreme weather events. However, the traditional method of using single system peak would also mean the opposite in some years (i.e. general service and lighting benefit while residential is worse off), depending upon the occurrence of an extreme weather event. Thus, Chymko expects the impact to be neutral over the long run.

47. Updated load data reflects higher usage by the Residential class, which is attributed to increased use of electric heat. For the farm group, studies prior to 2020 assumed Farms followed a residential-like behaviour because there was no other information as to how Farms consumed on an hourly basis and Residential and Farm kWh sales trended higher in the

[7] For this reason, the 2020 study disregarded the peak set by the January winter storm and instead used the second-highest peak from December 2020.

winter. Since then, load research is demonstrating that farms consume differently. Though Farm monthly kWh sales are higher during the winter months, hourly usage is more level, meaning that usage is occurring in the off-peak hours, too. This higher load factor means that Farms are not contributing as much to the winter system peaks. On the contrary, Farms' highest peak hours for the year occur in October and November, when the volume of potatoes in storage is highest.

Non-Coincident Peak Demand (NCP)

48. Non-coincident peak demand (NCP) represents the peak demand for each rate class without regard for when the peak occurs for other rate classes. Therefore, the sum of all rate class NCPs is (by definition) equal to or greater than the system peak. This type of allocator is typically paired with demand-related costs associated with more localized distribution facilities. NCP is widely recognized as an appropriate allocator for components of the distribution system that must be designed and built to handle local peak demand situations that do not necessarily correspond to the overall system peak.

49. Distribution network functions classified as demand-related are allocated based on non-coincident peak demand. As facilities become more localized, they are more likely to serve one rate class and the needs of specific local customers play a more important role in network design. Individual customers served by a distribution feeder are still diverse, but less so than in a bulk transmission system that services a greater number and a broader mix of customers. Thus, local distribution customers are more likely to peak at the same time compared to a random collection of residential, commercial, and industrial customers. Given that local distribution facilities are more likely to serve one rate class, an allocation based on non-coincident rate class peak demand is appropriate. The calculation of non-coincident peak demand reflects diversity within a rate class, but not between rate classes.

50. For the same reasons outlined above for moving away from a single coincident peak, this study averages the three highest peaks for each class. We expect this will help facilitate stability in cost allocation results by muting the influence of any one extreme weather event.

Energy Use

51. An energy allocator is calculated from rate class kWh sales, grossed-up for losses. This allocator is used for power supply classified as energy-related, but is not otherwise used for the other wires-related functions.

52. As per the updated load data, Residential energy sales (relative to total sales) rose by five percentage points from the 2020 level. The utility has noted increased use of electric heat, which may explain this increase.

Number of Sites

53. The number of sites within each rate class is used to allocate site-related costs. Depending upon the function to be allocated, adjustments are required. For instance, the allocation of

the secondary lines function should exclude distribution sites that are just served at the primary voltage. Another adjustment is necessary for lighting fixtures and other unmetered points of delivery, which are high in number but the addition of one more fixture should not cause distribution cost to increase as much as the addition of one more Residential customer, for example.[8]

54. Furthermore, site counts are sometimes weighted if the per-site cost is known to differ between rate classes and neither a demand nor an energy-based allocation is a reasonable alternative. This situation often occurs when several factors either directly or indirectly affect the per-site cost and the net impact is material. This is a generally accepted cost allocation practice and in its cost allocation model, CCL weights the site-based allocations of functions such as service lines, meter assets, meter reading, billing, and remittance & collection.

55. While the functions for service connection and late payment revenue are classified as site-related, this is mainly for completeness. This revenue is directly assigned to rate classes according the same proportions as it was collected.

56. The share of sites considered Residential rose by two percentage points, while all others fell in relatively equal shares.

[8] In this study, CCL discounted the number of lighting fixtures and unmetered points of delivery by a factor of 0.40. CCL selected 0.40 such that the allocated secondary distribution voltage cost per fixture is approximately one fifth of a Residential customer.

Summary of Allocators

Table 7
Summary of 2023 Allocators

	Coincident Peak[9] (kW)	Coincident Peak - Firm (kW)	Non-Coincident Peak[10] [11] (kW)	Energy Including Losses[9] (MWh)	Sites
Residential	185,944	185,944	195,630	789,322	66,464
Residential (S)	3,950	3,950	6,602	28,129	7,737
Farm	9,196	9,196	11,744	51,488	517
General Service	67,948	67,349	73,343	432,454	7,906
General Service (S)	23	23	3,057	10,718	1,642
Small Industrial	22,069	22,069	25,327	98,190	285
Large Industrial	19,061	4,645	9,133	174,214	7
Lights	1,054	1,054	1,052	4,200	5,087
Unmetered	379	379	372	2,748	296
Total	309,623	294,608	326,259	1,591,463	89,940

4.3 RESULT

57. MECL's allocated revenue requirement is shown in detail in Appendix A while a simplified version is shown in Table 8 below.

Table 8
Allocated 2023 MECL Revenue Requirement ($,000)

	Operating Expenses	Capital Expenses	Gross Revenue Require-ment	OATT Revenue	Other Revenue	Net Revenue Require-ment
Residential	96,690	43,983	140,673	(1,637)	(2,129)	136,907
Residential (S)	3,712	2,962	6,674	(35)	(135)	6,504
Farm	5,434	1,600	7,035	(81)	(54)	6,900
General Service	44,484	13,030	57,514	(598)	(458)	56,458
General Service (S)	1,119	838	1,957	(0)	(35)	1,922
Small Industrial	10,891	3,325	14,216	(194)	(118)	13,904
Large Industrial	14,805	2,282	17,086	(168)	(53)	16,866
Lights	1,040	2,462	3,502	(9)	(66)	3,427
Unmetered	339	130	468	(3)	(4)	461
Total	178,513	70,613	249,126	(2,725)	(3,051)	243,349

58. Again, results are consistent with prior studies and differences from the 2020 study are largely caused by (1) how MECL's revenue requirement and customer base have evolved

[9] Calculated at input voltage.
[10] Calculated at primary voltage.
[11] Excludes transmission only customers and transmission losses.

since 2020, and (2) the impact of the updated load data. A comparison appears below in Table 9, and explanations regarding changes in MECL's customer base follow below.

Table 9
Allocated MECL Revenue Requirement

	Total Revenue Requirement		Excluding Power Supply	
	2023	2020	2023	2020
Residential	56%	55%	64%	63%
Residential (S)	3%	2%	4%	5%
Farm	3%	3%	2%	2%
General Service	23%	25%	17%	19%
General Service (S)	1%	1%	1%	1%
Small Industrial	6%	6%	5%	4%
Large Industrial	7%	7%	2%	2%
Lights	1%	1%	3%	4%
Unmetered	0%	0%	0%	0%
Total	100%	100%	100%	100%

Residential

59. As the rate class that consumes the most energy in absolute terms, Residential continues to be allocated the largest share of revenue requirement. This share continues to increase as energy sales and peak demand also increase at a faster rate than the number of customers. CCL understands that electric heating has increased in popularity in the last several years, which might account for the higher sales per household.

60. Many new homes are installing both resistive and heat pump installations, with the resistive heat sources intended to operate only during the coldest times of the year. Annual system peaks typically occur between mid-December and mid-January, during extended cold snaps. Holiday lighting is on, and many of the installed heat pumps are supplemented with resistive heat. The utility believes this has been the main contributing factor to observed higher system peaks.

61. Though Residential is allocated a larger share of revenue requirement, higher sales also mean more revenue. In terms of how this would affect any rate rebalancing, the revenue-to-cost ratio increased by one percentage point.

Residential (Seasonal)

62. The Residential Seasonal rate class's share of revenue requirement slightly increased from 2020. There was a slight reduction in share of sites, although the number of Seasonal Residential sites increased. This difference is most likely due to the comparatively faster growth of the Residential rate class.

63. The Residential Seasonal share of coincident peak increased and the share of energy sales also increased from 2020 numbers, which means that Residential Seasonal is allocated more

cost. Revenue also increases, but at a slower rate, and the revenue-to-cost ratio decreases by six-percentage points, from ninety-four per cent in 2020 to eighty-eight per cent in 2023.

Farm

64. In previous studies, prior to 2020, little was known about the behaviour of farms during system peak, and so the default assumption was to assume they behaved similarly to Residential customers. Load research showed that farms are associated with a higher load factor than assumed prior to 2020, which resulted in fewer expenses allocated to farms. Revenue did not change to the same degree as previous studies, and so the revenue-to-cost ratio improves as a result.

General Service

65. Compared to 2020, the General Service share of peak demand decreased by all measures (i.e. coincident, non-coincident, and 3-peaks), as well as the share of sales. Fewer costs are allocated to General Service and even though revenue also decreased, revenue did not change to the same degree. Because allocated cost fell at a faster rate than revenue, the revenue-to-cost ratio is higher than it was in 2020.

General Service (Seasonal)

66. Usage patterns of Seasonal General Service changed from 2020. The number of sites decreased, and so too did total energy sales. However, usage per customer still increased by more than 150 kWh per month and this usage was more skewed toward peak hours. This means that the class share of non-coincident demand increased. Revenue per customer increased as well, and at a faster rate than allocated cost per customer, which made the revenue to cost ratio increase. The seasonal classes tend to have relatively small sample sets, therefore creating the appearance of large fluctuations in the data.

Small Industrial

67. Even though the Small Industrial class decreased by three customers since 2020, the share of coincident peak demand is a percentage point higher and non-coincident peak demand a half percentage point higher. This is not necessarily a change in behaviour and more likely the indirect impact of better measuring the behaviour of other customer classes. Small Industrial is not part of the utility's load research program, and so the Small Industrial peak is inferred by subtracting the usage of all other rate classes from total deliveries to the distribution system. As the load research program expands and there is a more accurate measurement of how other rate classes behave during peak hours, this indirectly improves the accuracy of estimating small industrial's usage.

68. The class share of allocated costs decreased from 2020, but revenue declined to a greater degree, likely because one of the highest-use customers moved to large industrial. This reduced the revenue to cost ratio by about thirteen per centage points.

Large Industrial

69. The Large Industrial rate class grew by one customer from 2020 and the rate class share of coincident peak demand also increased. Large Industrial customers are metered on an hourly basis and no assumptions are required to measure their usage during system peak. Usage per customer declined and so too did total sales.

70. Overall, the rate class share of allocated cost decreased, and so too the percent of total revenue collected from the Large Industrial class. Revenue decreased at a slower rate than allocated cost and the revenue-to-cost ratio improved one percentage point compared to 2020.

Lights

71. Conversion to LED streetlights means lower energy usage and reduced power supply cost when compared with the high-pressure sodium (HPS) lights. The LED conversion program has gradually decreased the number of HPS fixtures, but the total number of fixtures also increased, meaning that the percentage of HPS fixtures is decreasing at a faster rate. However, this does not mean a lower cost for lights overall. Revenue requirement recovers the cost of financing infrastructure, operating costs, and maintenance costs, none of which vary by the amount of energy delivered. While lighting's allocated share of cost is virtually the same as it was 2020, revenue per fixture is lower and Lights' revenue-to-cost ratio falls to sixty-six per cent.

CONCLUSIONS

72. CCL's 2023 Cost Allocation Study is based on MECL's 2023 Statement of Earnings. To use these results as a yardstick for the next rate proposal, which would propose to generate a different level of revenue, it is necessary to express the allocated net revenue requirement as a percentage share. This adjustment is shown in Table 10.

Table 10
Allocated 2023 Net Revenue Requirement from Rates

	Net Revenue Requirement ($,000)	Per cent Share
Residential	136,907	56.3%
Residential (S)	6,504	2.7%
Farm	6,900	2.8%
General Service	56,458	23.2%
General Service (S)	1,922	0.8%
Small Industrial	13,904	5.7%
Large Industrial	16,866	6.9%
Lights	3,427	1.4%
Unmetered	461	0.2%
Total	243,349	100.0%

73. Allocated cost in Table 10 is only one yardstick or guideline for designing future rates. Other rate design considerations are equally important and one such consideration is the current structure and level of rates. If the desired change is too significant and would cause rate shock (for example, an increase greater than ten per cent of the total bill), then it may be necessary to adopt additional strategies to implement change gradually. One such indicator of the possibility of rate shock is the revenue-to-cost ratio. Table 11 below calculates revenue-to-cost ratios on current rates as well as providing similarly calculated revenue-to-cost ratios from the 2020 study.

Table 11 Allocated 2023 Net Revenue Requirement from Rates				
	Revenue Collected	Allocated Cost	Revenue-to-Cost Ratio (2023)	Revenue-to-Cost Ratio (2020)
Residential	52.7%	56.3%	94%	93%
Residential (S)	2.4%	2.7%	88%	94%
Farm	2.6%	2.8%	90%	87%
General Service	28.2%	23.2%	122%	118%
General Service (S)	0.9%	0.8%	108%	103%
Small Industrial	5.5%	5.7%	96%	109%
Large Industrial	6.7%	6.9%	97%	96%
Lights	0.9%	1.4%	66%	79%
Unmetered	0.2%	0.2%	104%	106%
Total	100.0%	100.0%	100%	100%

74. Given that the objective of a cost allocation study is to fairly allocate revenue requirement to rate classes on a cost causation basis, a ratio below 100 per cent in Table 11 indicates that (all else equal) rate revenues should be raised for that rate class. Similarly, a ratio above 100 per cent indicates that current rate revenues are above cost and should (all else equal) be lowered.

75. What is generally accepted to be a reasonable revenue-to-cost ratio will vary among Canadian provinces and regulators. For MECL's specific circumstances, CCL considers 100 per cent to be a long-term objective, but variances in any given year would be expected and reasonable. Actual rate impacts will depend upon MECL's rate design proposal, and MECL's proposal will need to make such other considerations such as rate shock, or whether an overall general rate increase is required.

76. Moreover, one must consider that rates are set prospectively and that normal forecast variances in cost, load, and revenue will mean that the intended revenue-to-cost ratio will rarely be achieved. Pending further rate design analysis, it may be necessary to compromise revenue-to-cost ratio objectives in the short run to mitigate rate shock for one or more rate classes or even subsets of customers within rate classes. In this situation, a short to medium term objective of transitioning customer rates toward a revenue-to-cost ratio between 90 per cent and 110 per cent may be more reasonable, with a long-term goal of bringing the revenue-to-cost ratios within 95 per cent to 105 per cent, as directed by the Commission.

77. The Residential revenue-to-cost ratio increased from 2020 to 2023. A greater share of revenue requirement is allocated to Residential, but sales did not increase as quickly meaning lower revenue and overall, the revenue-to-cost ratio increased by one percentage point.

78. The updated load data showed that the revenue-to-cost ratio for Farm customers is not as low as previously thought. Load research indicated that Farm customers contribute less to the system peak than CCL calculated in 2020, resulting in fewer demand-related costs allocated to Farm and the revenue-to-cost ratio increases.

79. The revenue-to-cost ratio for the Small Industrial rate class has decreased from 109 per cent to 96 per cent since 2020. This was because the share of revenue collected fell at a faster

rate than the allocated costs. The current revenue-to-cost ratio is now within MECL's desired target range of 95 to 105 per cent.

80. Unit cost is another output from the cost allocation study with potential use for rate design. Unit cost is calculated by dividing billing units into allocated cost for each rate class. In Table 12 below, CCL divides billing demand (i.e., peak demand on the customers' bills) into allocated demand-related cost and number of bills into allocated site-related cost.

Table 12
Unit Cost Results for Consideration in Rate Design

	Demand-Related ($/kW/Mo Billing Demand)	Site-Related ($/Bill/Mo)
Residential	N/A	32.13
Residential (S)	N/A	55.20
Farm	N/A	32.67
General Service	16.03	39.85
General Service (S)	15.09	79.73
Small Industrial	17.68	45.69
Large Industrial	8.11	314.67
Lights	N/A	755.45
Unmetered	77.17	76.95
Total	N/A	4.80

81. Site-related unit cost gives some indication for an appropriate monthly service charge. Given that the service line, meter, and billing costs are all considered site-related, a monthly service charge equal to unit cost would at least ensure the utility is recovering the localized fixed costs from every customer regardless of their consumption. One such application is the Seasonal rate, which requires just as much local distribution infrastructure to serve but is billed for only half the year. From a cost-causation perspective, it would be fair for the Seasonal rate class to have a higher monthly service charge to ensure these local infrastructure costs are recovered from each site.[12]

82. Like the site-related unit cost, the demand-related unit cost in Table 12 is calculated as the demand-related cost divided by the kilowatts billed to customers in that rate class. This only applies to rate classes that are metered and billed for peak demand and unit cost also provides useful information for a potential demand charge. Demand-related costs are predominantly related to reserve power supply, transmission, and primary voltage distribution and flowing through the demand-related unit cost in the monthly demand charge helps communicate to these customers the value of reducing peak demand.

Final Remarks

83. The overall purpose of a cost allocation study is to develop a benchmark to guide rate design. Rates that reflect the full cost of electric utility service are generally accepted as a worthwhile

[12] Note that there is an offsetting effect in which Seasonal rate classes are allocated fewer demand-related costs because they contribute little to system peak by virtue of being less active in the winter.

objective, subject to other considerations. MECL's existing rate structure is in place, in part, because MECL was legislated from 1994 to 2004 to operate under price cap regulation based on the New Brunswick tariff. Customer acceptance is an important consideration in rate design and the longevity of the existing structure may make some changes, regardless of their merit, more difficult to accept. It is for this reason that cost allocation results alone should not be the determining factor for rates. The revenue-to-cost ratios in Table 11 indicate that some rates might need to change significantly. As per MECL's Rate Design Application, currently on Docket UE22503 before the Commission, MECL is proposing to rebalance rates gradually and in stages. This will also afford future opportunities to update the cost allocation results and confirm directionally how far rate rebalancing should proceed.

APPENDIX A: CLASSIFYING DISTRIBUTION INFRASTRUCTURE

84. While the cost allocation process is consistent across utilities, outcomes vary because the functionalization, classification and allocation decisions depend on the specific operations, configuration, and infrastructure of each utility. And because cost allocation results typically impact rates, utilities are often called upon by regulators and customer groups to explain their cost allocation assumptions and decisions.

85. One often contentious issue is how to classify the cost of distribution infrastructure. There can be controversy about classification decisions because several factors affect cost, some of which are not necessarily tied to how customers use the distribution system. For instance, a planning engineer might report that the biggest factors affecting the costs of constructing a high voltage distribution line are things such as the width of the right-of-way and proximity to population, roads, and buildings. These factors have little to do with how customers use the system. Nevertheless, cost allocation studies generally accept that the cost of a high voltage distribution line is at least partially a function of peak demand because, all else equal, it will cost more to install higher load capacity infrastructure.

86. On the other hand, distribution infrastructure is not typically classified as *entirely* demand related. At some point, the utility will need to extend and expand the high voltage distribution line, not because of peak demand, but to serve customers in a new location. Thus, there is a consensus that distribution infrastructure costs are partially demand-related and partially site-related.[13] The controversy then is usually over how much should be demand and site related. To this end, James C. Bonbright[14] is often quoted in arguments to support a specific answer – some have even suggested that Bonbright advocates for all distribution costs to be considered demand related.[15] However, Bonbright states that his work focuses on 'the basic criteria of reasonable rates rather than on the many problems of application and administration.'[16] In other words, Bonbright does not endorse any specific classification of distribution costs, and utilities must still rationalize the classification of distribution infrastructure costs.[17]

[13] Note that while it is common to use the term "customer-related" in a cost allocation study, Chymko Consulting prefers to use the term "site-related." The latter term places emphases on the infrastructure and the physical delivery points on the distribution system, the cost of which is the focus of a cost allocation study. One customer might represent multiple delivery points, and the point of such a study is to attribute cost to all points of delivery.
[14] Bonbright, J. C., Danielson, A., & Kamerschen, D. (1988). *Principles of Public Utility Rates* (Second ed.). Arlington, VA, United States: Public Utilities Reports, Inc., pp. 491-492.
[15] Whited, M., Havumaki, B., & Takasugi, A. (2022). Review of Maritime Electric's Proposed Rate Changes. Cambridge, MA, United States: Synapse Energy Economics, Inc., p. 21.
[16] Bonbright, J. C. (1961). *Principles of Public Utility Rates* (First ed.). New York, NY, United States: Columbia University Press., p. vii.
[17] Bonbright only acknowledges that there is a distribution classification dilemma because there is no statistical reason to classify these shared costs as being either customer or demand related. The authors attempted a cross-sectional

87. In May of 2022, Synapse Energy Economics, Inc. (Synapse) completed a comparison of ten North American electric distribution utilities to Maritime Electric to evaluate Maritime Electric's classification method.[18] There is no need to repeat Synapse's work. The comparison is interesting but not necessarily instructive since it does not justify why each utility was selected for comparison when others could be suitable comparators. It is additionally difficult to compare how utilities classify distribution infrastructure due to differences in how they functionalize revenue requirement, customer density, and their proportions of core customers (i.e., a comparison of Toronto Hydro and Maritime Electric is of limited value). In this case, it is helpful to instead review and compare the different classification approaches to determine which is most appropriate for Maritime Electric.

88. This appendix presents a more fulsome explanation of the issue, along with the advantages and disadvantages of differing methods in how they attempt to attribute cost to customer classes. In short, the issue is never conclusively resolved because there are imperfections associated with every choice. Thus, the solution proposed by Chymko is to weigh the various options and select a method that is explainable to customers, practical to implement, and produces a result that is intuitively reasonable. To do otherwise and pursue perfection, when imperfection is a feature of every policy choice, leads to regulatory uncertainty if the issue is re-litigated every tariff application, needlessly introducing volatility and uncertainty in customer rates.

Methods of Classification

89. There are several methods for determining what portion of the distribution system ought to be classified as demand and site related. A method usually starts with an underlying rationale or theory because the cost allocation study is often used to justify rates. If the reasoning is not believable or understandable to a layperson, this undermines the credibility of the rates themselves. The method also needs to have practical application because a theoretical explanation has little value if it requires data or information that does not exist.

90. We therefore discuss four different methods and their relative merits.

- Method 1: Minimum Plant

91. A distribution system is designed to meet the expected peak demand for the network of customers it connects, but how might it compare to a distribution system designed to only

study of multiple utilities to determine if they could find a connection between the customer base size and total cost and did not find a meaningful relationship. This is not necessarily surprising because of the challenges of controlling every other factor that affects cost and because the study (as described) appeared to compare existing utilities as they existed in that moment in time. If a utility's service area remains fixed, the addition of one more customer is unlikely to affect distribution costs. For this reason, the authors suggest that a more relevant cost causation factor is density, or the number of customers served for a given area. This implies that some utility costs should be allocated and recovered from rate classes based on some measure of density. Bonbright goes on to say that density is a more relevant cost factor than the number of customers or peak demand, but using this measure would cause rates to vary across communities in violation of "a generally accepted tradition." Utilities and regulators are therefore still left to decide what factors will influence the classification of distribution infrastructure costs.

[18] Whited, M., Havumaki, B., & Takasugi, A. (2022). Review of Maritime Electric's Proposed Rate Changes. Cambridge, MA, United States: Synapse Energy Economics, Inc., pp. 21-24.

serve a minimum load? If such a system existed, it would represent the lowest cost of connecting all customers and there is an arguable point that this is what should be classified as being site related. In effect, this is the cost of entry to become a utility customer and so all costs incurred above the minimum system must be to satisfy demand. Thus, the difference between the actual system and the minimum system is what is needed to satisfy demand and is demand related.

92. One way to go about quantifying the minimum system is to devise a cost estimate of the infrastructure needed to satisfy a minimum load, hence the name: minimum plant. Ideally, the minimum plant method imagines a system that satisfies the minimal cost required to connect all sites on a network. It identifies the minimum size poles, conductors, cable, and transformers that are currently installed by the utility. The method then classifies distribution infrastructure as demand and site related by quantifying the costs of a minimum system compared to the as-built network. In other words, if the estimated cost of a minimum system is 40 percent of the estimated cost of the as-built system then 40 percent of distribution infrastructure is classified as site related.

93. However, defining this 'minimum' is not without some subjective judgement. The minimum system, for instance, could be one sufficient to power a 10-watt LED light bulb for each customer. If earnestly costed out, the minimum plant to build such a system would still be material. After all, the utility would need to employ planning engineers and procure electrical conductor, poles, transformers, and meters. It would also need to procure easements, rights-of-way, construct civil engineering works for supporting buildings, and hire construction crews. All these costs for the minimum system would then be attributed to rate classes based on the number of customers since all customers are receiving similar benefits from these costs.

94. One criticism of the minimum plant method is that despite all this effort to scope out a minimum system, it could carry *some* load (i.e., 10 watts) and therefore some element of demand is still captured within the portion deemed to be site related. However, it is arguable whether a minimum system that carries no load is a fair comparison to the as-built system. For instance, a conductor that is not capable of carrying any load is not really a conductor. This begs the question as to what one is comparing the cost of a conductor to, because this no longer appears to be an electric distribution system. By reducing load to zero and eliminating infrastructure, the exercise is no longer comparing a minimum system to the actual system, counter to the initial premise. The objective, after all, is to estimate the cost of meeting a minimum need and then to apportion that expense to all customers.

95. The advantage of the minimum plant method is that it is based on an intuitive logic that can be explained at a high level without requiring intimate technical knowledge. All customers equally share the cost of connecting to the network, but only for the minimal level of service (i.e., to power a light bulb). The minimum system is analogous to a membership fee and all additional costs are shared based on peak demand.

96. The disadvantage of the minimum plant method is that the results highly depend on estimated distribution infrastructure costs. Unfortunately, accurate, reliable, and

representative data is challenging to acquire. Before the adoption of sophisticated asset management and geographic information systems (GIS), utilities did not typically retain records of original installed cost for each type of asset. In this case, the utility must develop proxy estimations of either original or replacement cost.

97. Original cost may be estimated from a sampling of original construction records. Beside the administrative burden of collecting enough records to be considered statistically significant, construction records might not necessarily break down costs into enough detail to be useable. Replacement cost could be estimated from a sampling of recent construction records (and adjusting for inflation) or through current contractor quotes. In this case, estimates may vary depending on whether the cost is based on greenfield or replacing existing facilities. Whereas the former assumes construction costs in a new neighbourhood, prior to the construction of houses and roads, the latter assumes construction costs in an established neighbourhood and includes reclamation costs.

98. Beyond this administrative burden, a theoretical minimum plant requires engineering and an amount of data and effort that may be unreasonable for most utilities to obtain. In developing this theoretical minimum plant, the utility must account for the same engineering and construction conditions and constraints that would apply to the as-built system. For comparison to the as-built system, which can deliver peak capacity according to customer demand, the minimum system would need to be designed to physically deliver a pre-defined minimum amount of electricity (e.g., enough to power a light bulb) to each customer. The resulting minimum system would likely contemplate a range of infrastructure that depends upon voltage, distance, and customer density. The drawback of a detailed and comprehensively defined minimum system is a very high burden on administrative, financial, and engineering resources to design a viable network that will never be built. The practical trade off is to make simplifying assumptions regarding construction techniques, labour practices, and any other factor that may have influenced the development of the as-built system. There are short cuts that make compromises to simplify this process, but this may result in extrapolating too much data.

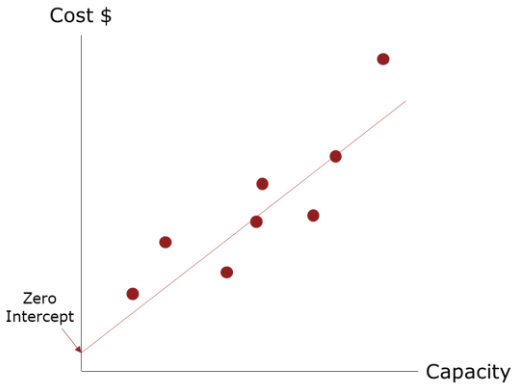
99. One way to simplify this process is to engineer the theoretical minimum system for a sample of the network rather then for its entirety. For example, the utility could engineer the minimum system required to power a single lightbulb in each site for a small neighbourhood and then extrapolate that data across the broader system. Implementing the minimum plant method this way has a smaller administrative, financial, and engineering burden and cost. However, finding the minimum plant for part of the network, and then applying it to the entire network may have some additional challenges. Mainly, one neighbourhood will not be representative of the entire network. There will always be parts of the network that have significantly different characteristics than the sample and it is not necessarily fair to treat the whole system as though it is all like the sample. One could get around this issue by including more sample neighbourhoods, but this increases the administrative burden. Furthermore, adding more samples for the purpose of improving the results only proves that the ideal results come from using the whole system as a sample. Since we have already stated that using the entire network as the sample is unfeasible, this brings us back to looking for a

short-cut that simplifies the administrative burden that comes with trying to sample the whole system. One such option is the zero-intercept method.

- Method 2: Zero-Intercept

100. The zero-intercept method classifies distribution infrastructure as demand and site related based on the statistically estimated cost of a minimum system using theoretical zero-load infrastructure. Whereas the minimum plant method relies on the cost of the most inexpensive distribution assets, the zero-intercept method relies on the statistically estimated cost of theoretical zero-load infrastructure. This requires the use of statistical regression techniques to extrapolate a linear relationship between the capacity of infrastructure and its cost, based on the utility's construction data. In simple terms, one can plot all observations of capacity and cost on a chart, and draw a straight line between them, and extrapolate what cost would be if capacity is zero. What is considered site related is determined by where the line crosses the vertical axis, as illustrated in Figure 2.

Figure 2: Zero Intercept Method



101. In this sense, zero-intercept is an attempt to overcome the practical challenges of minimum plant. It still seeks to estimate the cost of the minimum system but avoids the unreasonable administrative burden on engineering resources to design a system that will never be built. Instead, the minimum system is extrapolated through statistical regression of historical construction projects. This is the advantage of the zero-intercept method: it is practical to the extent that it can use data that already exists. Nevertheless, the zero-intercept method follows the same intuitive logic of the minimum plant method, where the cost of the minimum system is theoretically the cost that all customers share for connecting to the network and nothing more.

102. Given that the method relies heavily on statistical inference, it is also fair to evaluate the merits of the method using statistical measures. A simple tool familiar to most analytical professionals is the R-squared statistic. The R-squared statistic measures how well the best-fit line represents the sampled data points. For instance, an R-squared of 80 percent indicates that the regression line drawn between the data points explains 80 percent of the relationship between demand and cost. However, this statistic is potentially misleading because the R-squared statistic only considers the relationship for the data points used in the study. The sample of data points represent whatever historical data is available, which introduces a bias because it is usually only recent construction projects, not a random sample. It would be rare and unusual for a utility to archive data on every construction project ever undertaken, and so the data that is available is skewed based on what the utility's construction crews focused on that year.

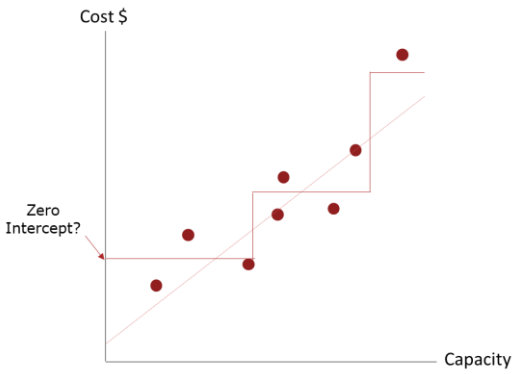
103. This is where a second statistical test, the F-statistic, is useful. The F-statistic tests a notion that the result can be attributed to randomness (the null hypothesis) and is used to calculate the p-value, which represents whether similar results could occur under the null hypothesis; failing the test means that the result has some statistical credibility. Such tests are framed with probabilistic certainty. For instance, rejecting the null hypothesis with 99 percent confidence means that there is a 1 percent chance of being wrong. In Chymko's experience with the zero-intercept analysis, we either:

- Conclude there is not enough data to be able to reject the null hypothesis. In other words, we are unable to conclusively say that the best fit line is not a random result.

- Rely on field estimate guidelines (e.g. installed conductor will cost $X per km), which produce statistically significant results. This is misleading because the field estimates themselves were chosen from recent experience for the purpose of being accurate on average, which means disregarding outliers. Thus, the data already fits a trend line because the data was chosen to in the first place.

104. In part, this issue is due to a lack of data, but the shortcoming is also more fundamental. This is the assumption there is linear relationship between the capacity of infrastructure and cost. In practice, a utility professional knows there is a step relationship between cost and capacity, not a linear relationship. This is because there is a cost incurred to construct and maintain infrastructure before the first kWh is consumed and additional infrastructure is not needed until a specific capacity need is reached. Capacity is not perfectly scalable for every equal increment in peak demand. Instead, the utility increases capacity to a certain level that it expects to maintain for years before more capacity is required.

Figure 3: A Non-Linear Functional Form



105. Illustrated in Figure 3: A Non-Linear Functional Form, the relationship between capacity and cost is more complicated and requires considerably more study that the utility usually cannot afford due to the additional administrative to collect the data. Furthermore, more study leads to the same drawbacks of the minimum plant method whereby the most accurate results are those that come from studying and analyzing each minute detail of the entire system. For these reasons, despite its limitations, many utilities will still opt for the use of the zero-intercept method for its administrative ease and logical results that are understandable and explainable.

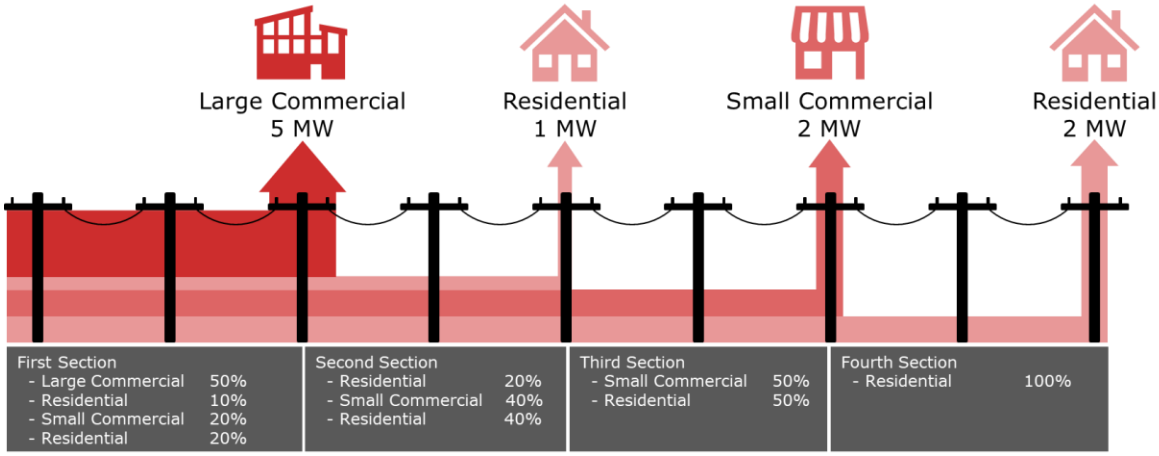
- Method 3: Micro Analysis

106. The micro analysis method relies on new data sources from contemporary asset management software systems, system planning software, customer information systems (CIS), and geographical information systems (GIS), all tied together to paint a more precise picture of who uses which distribution facilities. Such sources of information did not exist when Bonbright conceived of *Principles of Public Utility Rates*. In broad strokes, this technique uses asset management systems to identify each asset or facility, GIS to determine which distribution delivery points are downstream of that facility, and CIS to identify customers and their respective rate classes associated with each delivery point. Bringing all this information together, the utility gains a sense of who uses each part of the electricity network and wherever possible, directly assigns facilities to the rate classes they solely serve. Ultimately, most infrastructure is still shared and used by more than one rate class, so on a case-by-case basis, each facility is allocated to rate classes that use it.

107. The comparable component analysis method (CAM), used by FortisAlberta Inc., was described by its regulator as providing a far more precise allocation of costs than what is typically found using either a minimum plant or zero-intercept classification method.[19] In Alberta, the electric utility EPCOR Distribution & Transmission Inc. also uses a similar method. Eastward Energy Inc. a gas utility in Nova Scotia, is also proposing a similar method that relies on hydraulic modelling to simulate where the gas flows on a peak winter day.

108. For an established utility with hundreds of transformers, poles, and kilometers of conductor, this process involves thousands of decisions to either attribute an asset to one rate class or allocate between multiple rate classes. Additionally, and given that the specific composition of individual customers served will vary with each electrical facility, the allocation percentage to each rate class will differ every time there is an allocation decision. Figure 3 illustrates.

Figure 4: Micro-Analysis, Illustrated



[19] FortisAlberta Inc. "Appendix H: review of Component Analysis Method (CAM) Model," (Exhibit 25916-XX0015, Alberta Utilities Commission eFiling System, 2020), paras. 6-7.

109. In a traditional cost allocation study, the classification step is necessary and important to help guide which type of allocator to use (e.g., demand or customer in this scenario for electric distribution infrastructure). With the detailed, micro-analysis, however, the objective is to first identify which facilities are directly attributable to a rate class and then to allocate the rest, usually based on demand. In some sense, direct attribution to a group of customers in a class is customer-related because the utility would no longer be incurring cost if the facilities were retired after customers were to exit the system. However, this is not entirely the same as the original minimum plant thought-exercise where one attempts to quantify the base level of cost necessary to serve the customers before entertaining any extra cost to serve demand. In this case, the cost attributed to a group of customers includes both the theoretical customer and demand components of infrastructure.

110. It is for this reason that classification becomes less meaningful through this micro analysis. Infrastructure costs are attributed to each rate class in thousands of calculations and summed by rate class to create an allocator for operating costs, depreciation, interest, and return relating to that infrastructure. There is then typically no attempt to sum costs by a decision or assumption (e.g., direct assigned, 60:40 allocation between two rate classes, 40:30:30 allocation between three rate classes, etc.), much less by classification.

111. The benefit of this method is that it does not necessarily require an unreasonable incremental amount of time and effort by design engineers because that effort was a sunk cost. In other words, the time and effort of utility professionals was already spent to populate the GIS, asset management, and customer databases. At no point does this exercise attempt to theorize the cost of a parallel minimum system, it simply attempts to leverage the information in existing corporate management systems to attribute infrastructure to rate classes. Of course, the key assumption here is that the utility already justified an investment in GIS, asset management, and customer databases. This is not necessarily the case because GIS and asset management systems are relatively new and not all utilities have deployed such systems. Furthermore, this type of analysis still requires a substantial effort to initiate and complete.

112. The fundamental challenge with this method is that it lacks transparency. It requires the regulator and customers to trust that the utility's calculations, assumptions, and the sum of all those decisions, are accurate and not just precise. This is not an insurmountable problem, per se. The regulatory framework often depends upon the utility to provide correct and reliable information in summary form. For example, it is possible to review and debate the recommendations of a depreciation study without listing every asset and verifying the original cost of each asset. Typically, the utility is expected to describe what the study entailed in detail, disclose material assumptions and decision points, and respond to questions posed by the regulator and stakeholders. Provided that the utility can provide confidence that the inputs, the assumptions, and the process were all reasonable, there is usually some accommodation to accept that the outcome is therefore reasonable.

- Method 4: Synapse's Basic Customer

113. Synapse describes a fourth classification method it calls the 'Basic Customer' approach. Chymko is unfamiliar with this method because it is not used in Canada to our knowledge.

114. Although the Synapse report calls this the 'Basic Customer' method, it appears to Chymko that this is not so much a 'method' as it is a decision. This is because Synapse does not posit a theory about how to fairly measure use of the system and there is no accompanying analysis. Instead, Basic Customer appears to be a policy decision to classify 100 percent of primary lines, secondary lines, and transformers as demand related. Doing so results in fewer costs associated with primary lines, secondary lines, and transformers being attributed to high-count customer rate classes (such as residential).[20] The benefit of this method is that it can be implemented immediately because it does not require analysis or study. However, the fact that it does not depend on a rationale, analysis, or study is also the drawback.

115. Classifying primary lines, secondary lines, and transformers as entirely demand related does not make intuitive sense if the goal is to fairly attribute shared network cost to all customers. Imagine, for instance, a hypothetical rate class with zero demand. In practical terms, similar customers in a rate class tend to cluster together (e.g., a neighbourhood of residences, a commercial avenue, etc.) and the utility builds electrical infrastructure to service clusters of customers. Under Basic Customer, this hypothetical zero-demand rate class would not be attributed any infrastructure costs for primary lines, secondary lines, and transformers even if they are physically connected to the network. This is not intuitive because there is a known cost (construction, civil engineering) for connecting sites to the network and customers receive the benefits of the network before they even consume one kWh of energy. Additionally, expanding service to a new area to add more customers to the network requires additional costs for installing transformers as well as primary and secondary lines. Basic Customer does not attribute any of these costs to the hypothetical zero-demand rate class. Because the rate class exists in this hypothetical example, the implication is that they desire utility service. However, utility service would be impossible without primary lines, secondary lines, and transformers. For this reason, we therefore conclude it is an unfair and unreasonable outcome that this rate class is attributed zero cost.

116. In this discussion, Chymko is careful to note the distinction between cost attribution (the cost allocation study) and cost recovery (rate design). If for some public policy reason, the regulator desired that any rate class should pay less than attributed cost, this is potentially a valid policy debate. The point made here is that the purpose of a cost allocation study is to provide a benchmark upon which one can make policy decisions regarding rates. Skewing the benchmark to drive a desired outcome transfers what would have been a wider policy debate into a more specialized, less accessible forum of a technical study and in the process, undermines the purpose of having a benchmark in the first place.

[20] Whited, Havumaki, & Takasugi, 2022, pp. 22-25.

Conclusion

117. There is no single correct classification method applicable to all situations. The issue is never conclusively resolved because there are drawbacks associated with every choice and more importantly, the drawbacks are either muted or accentuated based on each utility's specific situation. This means that the choice for every utility might be different depending on what data is available and the resources it is able to dedicate to the issue. Illustrated below, some methods have a stronger rationale and are therefore easier to communicate and justify to the regulator and customer. However, just because a method might have a strong rationale does not necessarily mean it is easy to implement. Minimum plant has a very strong rationale that is conceptually simple to explain, but it is not sensible to direct all resources toward designing and costing a hypothetical distribution system that will never be built. One must make compromises, and in the case of the minimum plant method, simplifications introduce biases (e.g., in selecting what data sample to use) that incrementally undermine the credibility of the result and its ability to represent the original theory.

Table 13
Comparing Classification Methods

Method	Rationale	Effort
Minimum System	High	Medium-High
Zero Intercept	Medium	Medium
Micro Analysis	High	High
Basic Customer	Low	Low

118. This again serves to illustrate that a cost allocation study is one piece of information that guides rate making. It allows utilities and regulators to understand the costs attributed to each rate class so they may determine an appropriate cost recovery through rates. Different factors affect cost, some of which are indirectly tied to how customers use the system. Other times, the connection might be very tenuous or nonexistent. For instance, a planning engineer might report that the biggest factors affecting the costs of constructing a high voltage distribution line are things such as the width of the right-of-way and proximity to population, roads, and buildings. These factors have little to do with how customers use the system. Nevertheless, attributing cost based on how customers measurably use the system is ultimately the point of this exercise, so many recognized and legitimate factors affecting cost are treated as fixed and unchanging.

Applying Research

119. With the aim of learning how the above classification methods could be applied to Maritime Electric, the utility's personnel obtained sufficient data to calculate the zero intercept for transformers and primary lines. Similar information was not available for secondary lines, but the conclusions drawn for transformers and primary lines are nevertheless informative.

Transformers

120. Maritime Electric obtained the procurement cost of transformers from three points in time: 2004-05, 2014-15, and 2019/2022 (leaving out Covid years). The utility typically procures transformers multiple times during the year, anywhere between 64 and 121 different days. This data set included a total of 435 observations and the average cost per transformer was $6,578. The zero-intercept method is a statistical regression, and for a first attempt, Chymko Consulting calculated the best-fit line with cost on the vertical axis and transformer capacity on the horizontal axis.

Table 14
Regression, Cost of Transformers as Function of MVA and Single/Three-Phase

	coefficient	std. error	t-ratio	p-value
const	2,803.04	340.56	8.231	2.21E-15
SizekVA	25.41	0.96	26.5	1.16E-92
Mean dependent var	6577.569	S.D. dependent var		10434.41
Sum squared resid	1.80E+10	S.E. of regression		6451.792
R-squared	0.618563	Adjusted R-squared		0.617682
F(1, 433)	702.1801	P-value(F)		1.16E-92
Log-likelihood	−4432.105	Akaike criterion		8868.21
Schwarz criterion	8876.361	Hannan-Quinn		8871.427

121. Many statistical measures are provided in Table 14, but the basic result is that the coefficient "SizeKVA" indicates that the cost of a transformer increases by $25.4069 for every kVA of additional capacity. The zero-intercept method concerns itself with the cost of a theoretical zero kVA transformer, which is where the regression line intersects the vertical axis. This is the coefficient "const" in Table 14, or $2,803.04.

122. An important statistic for evaluating the coefficients is the p-value, which quantifies the whether the observed trend is statistically significant. A p-value represents the probability that the calculated coefficient is the product of random chance, that there is no relationship between the two sets of data (the null-hypothesis). For example, a p-value of 0.05 indicates that one can reject the null hypothesis with a certainty of 95 percent, or 19 times out of 20. In this case, the null hypothesis is rejected with a high degree of certainty because the p-value is very small (e.g. the p-value of "const" is 2.21×10^{-15}).[21]

123. The other statistic worth mentioning in Table 14 is "R-Squared," which is a measure of how well the best fit line predicts the relationship between the 435 observations of transformer size and cost. In this case, the R-Squared is 0.618563, which means that the two coefficients predict 62 percent of transformer cost.

124. There are, of course, many other factors that could explain transformer cost and some of these factors were available in the dataset that Maritime Electric collected. Specifically, the data set indicated whether the transformer is pole or pad-mounted and or whether it is single

[21] It is important to recognize that rejecting the null hypothesis does not conclusively say that transformer size *causes* cost. One other possibility is that both transformer size *and* cost are equally affected by an unknown third factor.

or three-phase. Chymko Consulting therefore expanded the regression equation to include this information by creating dummy variables. The first one, "isPad" is equal to zero if the transformer is pole-mounted and one if the transformer is pad mounted. Similarly, "isThreePhase" is zero if the transformer is single phase and one if three phase. This revised regression equation appears below in Table 15.

Table 15
Regression, Cost of Transformers as Function of MVA and Single/Three-Phase

	coefficient	std. error	t-ratio	p-value
const	1,945.44	329.15	5.910470822	6.94E-09
MVA	17.59	1.19	14.75880176	3.44E-40
isPad	3,595.46	1,009.14	3.56288082	0.000407758
IsThreePhase	6,290.72	1,306.93	4.813356532	2.06E-06
Mean dependent var	6577.569195	S.D. dependent var		10434.40928
Sum squared resid	14740244427	S.E. of regression		5848.08542
R-squared	0.688054144	Adjusted R-squared		0.685882827
F(3, 431)	316.8833421	P-value(F)		1.30E-108
Log-likelihood	-4388.362289	Akaike criterion		8784.724579
Schwarz criterion	8801.025963	Hannan-Quinn		8791.15849

125. Besides noting that the p-value of all four coefficients are all very small (and therefore statistically significant), adding this information to the regression equation considerably improves the predictive power of the best fit line. With these three pieces of information, the R-Squared of the equation improves to 69 percent.

126. As it applies to the practical application of the zero-intercept method, the addition of two more variables complicates the original diagram shown in Figure 2. This equation suggests that the zero intercept depends on whether the transformer is pole or pad mounted, and the transformer is single or three phase.

- If the transformer is pole mounted (isPad=0) and single phase (isThreePhase=0), then the cost of a zero-capacity transformer is $1,945.44, which is almost $900 less than predicted in Table 14.
- If the transformer is pad mounted (isPad=1) and single phase (isThreePhase=0), then the cost of a zero-capacity transformer is $5,540.90.
- If the transformer is pad mounted (isPad=1) and three phase (isThreePhase=1), then the cost of a zero-capacity transformer is $11,831.62.

127. In other words, the zero intercept depends on more than capacity.

128. One final piece of information in the data set is the year of purchase. We tested this by creating adding additional dummy variables based on the year. Many factors can change between years, inflationary pressures being one of them. The elegance of a dummy variable based on the year would not only capture inflation, but also any other structural changes that

affect cost.[22] Experimenting with additional functional forms that included a dummy variable for years, Chymko Consulting concluded that the procurement year is indeed statistically significant, particularly when one includes engineering and supervision overheads and construction interest.

129. Applying the zero-intercept regression equation, Maritime Electric then calculated the replacement cost for all transformers in service as of November 2022, inclusive of overheads and construction interest.[23] The replacement cost and zero-capacity cost appears below.

Table 16
Replacement and Zero-Capacity Cost of Transformers
In-Service as of November 2022

kVA	Number in Service	Replacement Cost ($)	Zero-Intercept Cost ($)
10	9,009	36,863,152	29,490,215
15	10,917	48,068,657	35,735,895
25	7,433	40,611,819	24,331,310
37	3,490	20,998,425	11,424,226
50	2,722	28,728,413	8,910,241
75	1,461	17,804,426	4,782,462
100	129	2,907,642	2,035,336
150	96	3,599,766	2,636,534
167	85	2,321,712	2,334,431
225	39	1,658,561	1,071,092
300	223	11,048,634	6,124,449
500	161	9,558,535	4,421,688
750	65	4,276,423	1,785,153
1,000	29	2,987,654	796,453
1,500	24	3,069,263	659,134
2,000	7	1,130,809	192,247
2,500	11	2,143,174	302,103
Total	35,901	237,777,067	137,032,970

130. Using the totals of the two right-most columns, customer-related portion of transformers is 58 percent ($137.0 million divided by $237.9 million).

131. The asset management system can only provide a snapshot of how many transformers are in service as of the query, and because this information is not regularly required by Maritime Electric, the utility extrapolated transformers in-service for each of the years studied. The same calculation as Table 13 applies, and the zero-intercept customer-related portion of transformers is as follows:

[22] Hypothetical examples include new manufacturing processes, new manufacturers or manufacturing hubs, import tariffs, material shortages, and transportation cost.
[23] For 75 percent of transformers in service, replacement cost is known because the utility procured a similar transformer in 2022. For the remaining 25 percent, Maritime Electric estimated replacement cost for using the zero-intercept regression line. The remaining 25 percent consists mainly of 10 kVA pole mounted transformers. The utility did not purchase any of these in 2022.

Table 17 Zero-Intercept Results by Year	
Year	Site related Portion (%)
2004	63
2005	60
2014	53
2015	55
2019	54
2022	58

132. In repeating this exercise for all six years of sampled data, the site related portion of transformers varies between 53 and 63 percent. Notably, the current assumption is 40 percent. Since one of the principles of rate design is stability, and for the sake of continuity, we recommend that Maritime Electric maintain this assumption.

133. Using the same data, one can also calculate the customer proportion using a rudimentary minimum plant approach. In Table 16, there are 35,901 transformers, and that figure multiplied by the lowest per-transformer cost in Table 16 is $146.9 million. This is a minimum system and divided by replacement cost of $237.8 million in Table 16 is 62 percent site related. Again, the result is not substantially different from the current assumption and there appears to be little justification to change.

Primary Lines

134. Transformers are procured, constructed, and recorded in discrete units. This is not the case for electrical lines, which are the sum of many components over varying lengths. This means that Maritime Electric's records cannot produce historical costs in a form that is immediately useful for a zero-intercept analysis. As an alternative, Maritime Electric used 2022 charge-out rates to estimate the construction of one span of primary line. This estimate includes labour (foreperson, technician, indirect and direct overheads, and a line truck) and materials (conductor, 40-foot poles, crossarms, v-braces, pole top pins, insulator pins, and a neutral bracket). The utility calculated the total construction cost for one span, then divided it by the typical length of a span to arrive at a cost per kilometre.

135. There are six different line configurations used in Maritime Electric's system. These configurations vary based on conductor specifications (ampacity, weight, and strength), and whether they are single or three-phase. These variables also determine the megavolt amp (MVA) rating of 7.2 kV line. Each configuration also spans a different distance; so, Maritime Electric calculated the per-km cost of each configuration. Producing the following data set:

Table 18 Primary Lines Cost per Kilometre 2022 Charge-Out Rates					
Primary conductor	Current Rating (Amp)	7.2 kVA Line Rating (MVA)	Average Span (metres)	Cost per Span ($)	Cost per Km ($)
#4 ACSR	140	1.01	75.4	1,274	16,895
#2 ACSR	180	1.30	75.4	1,318	17,475
2/0 ACSR	270	1.94	75.4	1,418	18,795
4/0 ACSR	340	2.45	75.4	1,539	20,405
#4 ACSR	140	3.02	56.3	1,936	34,421
#2 ACSR	180	3.89	56.3	2,001	35,581
2/0 ACSR	270	5.83	56.3	2,113	37,561
4/0 ACSR	340	7.34	42.6	2,169	50,958
477 MCM ASC	639	13.80	42.6	2,442	57,355

136. With this data set, Chymko Consulting calculated a regression equation as follows.

Table 19 Regression, Cost of Primary Lines as Function of MVA				
	coefficient	std. error	t-ratio	p-value
const	16,864.80	3,251.52	5.187	0.0013
MVA	3,391.83	549.45	6.173	0.0005
Mean dependent var	3.22E+04	S.D. dependent var		14998.47
Sum squared resid	2.79E+08	S.E. of regression		6316.355
R-squared	0.844816	Adjusted R-squared		0.822647
F(1, 7)	38.10774	P-value(F)		0.000457
Log-likelihood	90.39761	Akaike criterion		184.7952
Schwarz criterion	185.1897	Hannan-Quinn		183.944

137. In Table 19, the coefficient "MVA" indicates that the per-metre cost of a primary line increases by $3,391.83 per kilometre for every MVA of additional capacity. The coefficient "const" is the cost of a zero-MVA line, which is $16,864.80. Both coefficients are also statistically significant with a reasonably high level of certainty; the highest p-value is for the coefficient "const" at 0.0013, which means that the probability there is no relationship is about one tenth of one percent. Finally, the R-Squared is 0.844816, meaning that the model explains 84 percent of primary line cost.

138. Other factors can explain cost and the Maritime Electric data set indicated whether the primary line is single or three-phase. Chymko Consulting therefore expanded the regression equation to include a dummy variable "isThreePhase," which is zero for a single-phase line and one for a three-phase line. This revised regression equation appears below in Table 20.

Table 20 Regression, Cost of Primary Lines as Function of MVA and Single/Three-Phase				
	coefficient	std. error	t-ratio	p-value
const	14,624.60	1,675.92	8.726	0.0001
MVA	2,250.79	362.56	6.208	0.0008
IsThreePhase	13,294.50	2,795.91	4.755	0.0031
Mean dependent var	32160.66	S.D. dependent var		14998.47
Sum squared resid	58568773	S.E. of regression		3124.334
R-squared	0.967455	Adjusted R-squared		0.956607
F(2, 6)	89.18053	P-value(F)		0.000034
Log-likelihood	83.36864	Akaike criterion		172.7373
Schwarz criterion	173.329	Hannan-Quinn		171.4605

139. Adding a distinction between single and three phase lines improves the explanatory power of the regression line, as measured by the R-Squared statistic.[24] When the line is single-phase line ("isThreePhase"=0), Table 20 indicates that the zero-capacity cost is $14,624.60 per kilometre. When the line is three-phase, however, the zero-capacity cost is $13,294.50 per kilometre *more* for a total of $27,919.10 per kilometre.

140. Using the zero-intercept regression equation, one can calculate the replacement cost for primary lines in service as of November 2022. The replacement cost and zero-capacity cost appear below.

Table 21 Replacement and Zero-Capacity Cost of Primary Lines Using 2022 Charge-Out Rates			
Primary Conductor	km in Service[25]	Replacement Cost ($,000)	Zero-Intercept Cost ($,000)
#4 ACSR	1,718	29,025	25,125
#2 ACSR	761	13,302	11,132
2/0 ACSR	548	10,306	8,019
4/0 ACSR	103	2,103	1,507
#4 ACSR	173	5,966	4,839
#2 ACSR	269	9,576	7,514
2/0 ACSR	426	16,004	11,896
4/0 ACSR	120	6,098	3,341
477 MCM ASC	326	18,703	9,104
Total	4,445	111,081	82,476

141. Using the totals of the two right-most columns, customer-related portion of primary lines is 74 percent (=$82.5 million / $111.1 million).

142. Using the same data, one can also calculate the customer proportion using a rudimentary minimum plant approach. There are 4,445 km of primary lines and multiplied by the lowest

[24] Although the explanatory power of this regression model appears very satisfactory, a cautionary note is that this is based on costing estimates that are chosen because they fit an expected trend. This is first noted on page 35.
[25] As of 2023.

per-metre cost in Table 18 is $75.1 million. Thus, a minimum system calculation $75.1 divided by $111.1, or 68 percent site related.

143. Maritime Electric's current classification assumption for the primary lines is 50 percent site related. However, Synapse advocated in May 2022 that primary lines should be zero percent site related. With the benefit of Maritime Electric data, there is no evidence to reduce the classification of primary lines below 50 percent.

APPENDIX B: DETAILED SCHEDULES

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Prepared by Chymko Consulting
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Calgary, AB
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(403) 781-7691
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Summary of Cost Allocation Results										
Revenue Requirement ($,000)										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
Revenue Collected	128,201	5,734	6,215	68,780	2,078	13,423	16,336	2,245	478	243,491
less Rate of Return Adjustment	0	0	0	0	0	0	0	0	0	0
add Weather Normalization	204	10	10	84	3	21	25	5	1	363
Base Revenue, Comparable for 202	128,405	5,743	6,226	68,864	2,081	13,444	16,362	2,250	479	243,854
Revenue Share	53%	2%	3%	28%	1%	6%	7%	1%	0%	100%
Allocated Cost (net of Other Reven	136,907	6,504	6,900	56,458	1,922	13,904	16,866	3,427	461	243,349
Allocated Share	56%	3%	3%	23%	1%	6%	7%	1%	0%	100%
Revenue to Cost Ratio (Current)	94 %	88 %	90 %	122 %	108 %	96 %	97 %	66 %	104 %	100 %
Revenue to Cost Ratio (2020)	93 %	94 %	87 %	118 %	103 %	109 %	96 %	79 %	106 %	100 %
Unit Cost										
Demand Related ($/kW/Mo Billing	N/A	N/A	N/A	16.03	15.09	17.68	8.11	N/A	77.17	0.00
Site Related ($/Bill/Mo)	32.13	55.20	32.67	39.85	79.73	45.69	314.67	755.45	76.95	4.80

Schedule 1.1										
Unit Cost Summary										
Full Revenue Requirement (¢/kWh Sales)										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
Operating Expenses										
Energy Costs	11.42	10.41	10.78	10.45	8.86	11.23	8.87	11.72	10.31	10.80
ECAM Adjustment	(0.61)	(0.57)	(0.59)	(0.57)	(0.50)	(0.61)	(0.49)	(0.62)	(0.56)	(0.58)
Net Energy Costs	10.81	9.84	10.19	9.88	8.36	10.63	8.38	11.10	9.75	10.21
Distribution	0.81	1.72	0.41	0.38	1.26	0.43	0.08	7.65	0.70	0.61
Transmission	0.15	0.09	0.11	0.10	0.00	0.14	0.07	0.16	0.09	0.12
Transmission and Distribution -	0.25	0.47	0.14	0.12	0.30	0.15	0.03	1.66	0.22	0.19
Transmission - OATT	0.02	0.01	0.02	0.02	0.00	0.02	0.01	0.03	0.01	0.02
General	1.24	2.18	0.57	0.57	1.36	0.59	0.22	6.16	2.55	0.91
Total Operating Expenses	13.29	14.31	11.44	11.06	11.28	11.97	8.79	26.75	13.31	12.07
Amortization										
Amortization Other	0.04	0.05	0.02	0.02	0.03	0.03	0.01	0.12	0.04	0.03
Amortization - CTGS	0.15	0.14	0.14	0.14	0.12	0.15	0.13	0.15	0.14	0.14
Amortization Plant And Equipme	2.33	4.68	1.22	1.21	3.64	1.32	0.45	26.81	1.97	1.83
Total Amortization	2.52	4.86	1.39	1.37	3.79	1.49	0.59	27.09	2.14	2.00
Total Operating Income	15.80	19.17	12.83	12.43	15.07	13.47	9.38	53.84	15.45	14.07
Financing Expenses										
Long-Term Debt	1.27	2.35	0.71	0.67	1.67	0.78	0.27	13.02	1.06	1.00
Short-Term Debt	0.11	0.21	0.06	0.06	0.15	0.07	0.02	1.18	0.10	0.09
Interest Charged To Constructio	(0.07)	(0.12)	(0.04)	(0.04)	(0.09)	(0.04)	(0.01)	(0.69)	(0.06)	(0.05)
Interest Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00
Amortization of Financing Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00
Total Financing Expenses	1.32	2.45	0.74	0.70	1.74	0.81	0.29	13.56	1.11	1.04
Earnings before Income Taxes	17.12	21.62	13.57	13.13	16.81	14.27	9.66	67.39	16.56	15.11
Income Taxes	0.69	1.28	0.39	0.37	0.91	0.42	0.15	7.09	0.58	0.54
Net Earnings	1.53	2.83	0.86	0.81	2.01	0.93	0.33	15.67	1.28	1.20
Gross Revenue Requirement	19.34	25.73	14.81	14.31	19.74	15.63	10.14	90.14	18.41	16.85
OATT Revenue	(0.22)	(0.13)	(0.17)	(0.15)	(0.00)	(0.21)	(0.10)	(0.24)	(0.13)	(0.18)
Other Revenue	(0.29)	(0.52)	(0.11)	(0.11)	(0.35)	(0.13)	(0.03)	(1.71)	(0.17)	(0.21)
Net Revenue Requirement	18.82	25.08	14.53	14.04	19.39	15.29	10.01	88.20	18.11	16.46

Schedule 1.1										
Unit Cost Summary										
Demand Related Revenue Requirement ($/kW/Mo Billing Demand)										
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	Small Industrial	Large Industrial	Lights	Unmetered	
Operating Expenses										
Energy Costs	N/A	N/A	N/A	6.46	0.22	7.00	2.55	N/A	32.20	
ECAM Adjustment	N/A	N/A	N/A	(0.29)	(0.01)	(0.32)	(0.07)	N/A	(1.47)	
Net Energy Costs	0.00	0.00	0.00	6.16	0.22	6.68	2.48	0.00	30.73	
Distribution	N/A	N/A	N/A	1.02	2.14	1.15	0.42	N/A	4.71	
Transmission	N/A	N/A	N/A	0.37	0.01	0.40	0.37	N/A	1.85	
Transmission and Distribution -	N/A	N/A	N/A	0.38	0.68	0.43	0.15	N/A	1.79	
Transmission - OATT	N/A	N/A	N/A	0.06	0.00	0.07	0.06	N/A	0.30	
General	N/A	N/A	N/A	1.27	1.48	1.40	0.80	N/A	6.04	
Total Operating Expenses	N/A	N/A	N/A	9.27	4.52	10.13	4.28	N/A	45.42	
Amortization										
Amortization Other	N/A	N/A	N/A	0.05	0.04	0.05	0.03	N/A	0.24	
Amortization - CTGS	N/A	N/A	N/A	0.06	0.00	0.07	0.06	N/A	0.32	
Amortization Plant And Equipme	N/A	N/A	N/A	2.82	4.38	3.14	1.67	N/A	13.23	
Total Amortization	N/A	N/A	N/A	2.93	4.41	3.26	1.77	N/A	13.79	
Total Operating Income	N/A	N/A	N/A	12.20	8.94	13.40	6.05	N/A	59.20	
Financing Expenses										
Long-Term Debt	N/A	N/A	N/A	1.66	2.35	1.84	0.98	N/A	7.83	
Short-Term Debt	N/A	N/A	N/A	0.15	0.21	0.17	0.09	N/A	0.71	
Interest Charged To Constructi	N/A	N/A	N/A	(0.09)	(0.12)	(0.10)	(0.05)	N/A	(0.41)	
Interest Income	N/A	N/A	N/A	0.00	0.00	0.00	0.00	N/A	0.01	
Amortization of Financing Costs	N/A	N/A	N/A	0.00	0.00	0.00	0.00	N/A	0.01	
Total Financing Expenses	N/A	N/A	N/A	1.72	2.44	1.91	1.02	N/A	8.11	
Earnings before Income Taxes	N/A	N/A	N/A	2.90	4.11	3.22	1.72	N/A	13.68	
Income Taxes	N/A	N/A	N/A	0.90	1.28	1.00	0.54	N/A	4.26	
Net Earnings	N/A	N/A	N/A	2.00	2.83	2.22	1.18	N/A	9.42	
Gross Revenue Requirement	N/A	N/A	N/A	16.82	15.48	18.53	8.79	N/A	80.99	
OATT Revenue	N/A	N/A	N/A	(0.57)	(0.01)	(0.61)	(0.56)	N/A	(2.81)	
Other Revenue	N/A	N/A	N/A	(0.22)	(0.38)	(0.24)	(0.12)	N/A	(1.01)	
Net Revenue Requirement	N/A	N/A	N/A	16.03	15.09	17.68	8.11	N/A	77.17	

Schedule 1.1										
Unit Cost Summary										
Energy Related Revenue Requirement (¢/kWh)										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
Operating Expenses										
Energy Costs	8.83	8.82	8.82	8.75	8.79	8.78	8.42	8.79	8.79	8.76
ECAM Adjustment	(0.50)	(0.50)	(0.50)	(0.49)	(0.49)	(0.49)	(0.47)	(0.49)	(0.49)	(0.49)
Net Energy Costs	8.33	8.33	8.32	8.26	8.30	8.29	7.94	8.30	8.30	8.26
Distribution	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission and Distribution -	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission - OATT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
General	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.08	0.08	0.08
Total Operating Expenses	8.41	8.41	8.41	8.34	8.38	8.37	8.02	8.38	8.38	8.35
Amortization										
Amortization Other	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Amortization - CTGS	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Amortization Plant And Equipme	0.15	0.15	0.15	0.15	0.15	0.15	0.14	0.15	0.15	0.15
Total Amortization	0.28	0.28	0.28	0.28	0.28	0.28	0.27	0.28	0.28	0.28
Total Operating Income	8.70	8.69	8.69	8.62	8.66	8.65	8.29	8.66	8.66	8.63
Financing Expenses										
Long-Term Debt	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Short-Term Debt	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Interest Charged To Constructio	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Interest Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amortization of Financing Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Financing Expenses	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.11	0.11	0.11
Earnings before Income Taxes	0.18	0.18	0.18	0.18	0.18	0.18	0.17	0.18	0.18	0.18
Income Taxes	0.06	0.06	0.06	0.05	0.06	0.06	0.05	0.06	0.06	0.05
Net Earnings	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Gross Revenue Requirement	9.16	9.15	9.15	9.08	9.12	9.11	8.73	9.12	9.12	9.08
OATT Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Revenue	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
Net Revenue Requirement	9.15	9.14	9.14	9.07	9.11	9.10	8.72	9.11	9.11	9.07

Schedule 1.1										
Unit Cost Summary										
Site Related Revenue Requirement ($/Bill)										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
Operating Expenses										
Energy Costs	0.12	0.20	0.12	0.12	0.24	0.12	0.11	1.94	0.23	0.02
ECAM Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Energy Costs	0.12	0.20	0.12	0.12	0.24	0.12	0.11	1.94	0.23	0.02
Distribution	3.73	6.52	3.83	4.41	9.00	5.53	25.41	75.26	6.54	0.55
Transmission	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission and Distribution -	0.96	1.63	0.96	0.96	1.90	0.96	0.90	15.63	1.85	0.14
Transmission - OATT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
General	6.08	8.24	6.02	6.66	10.39	7.08	52.95	57.90	30.18	0.84
Total Operating Expenses	10.88	16.59	10.92	12.15	21.53	13.68	79.36	150.74	38.79	1.54
Amortization										
Amortization Other	0.08	0.12	0.08	0.10	0.17	0.11	0.71	1.00	0.25	0.01
Amortization - CTGS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amortization Plant And Equipme	9.83	17.39	10.31	13.50	27.72	18.82	126.15	265.37	16.56	1.51
Total Amortization	9.91	17.51	10.39	13.59	27.88	18.92	126.86	266.37	16.81	1.52
Total Operating Income	20.80	34.10	21.32	25.74	49.41	32.60	206.22	417.12	55.61	3.06
Financing Expenses										
Long-Term Debt	4.71	8.32	4.90	5.77	11.87	7.93	40.40	127.32	8.21	0.71
Short-Term Debt	0.43	0.75	0.44	0.52	1.08	0.72	3.66	11.54	0.74	0.06
Interest Charged To Constructio	(0.25)	(0.44)	(0.26)	(0.30)	(0.63)	(0.42)	(2.13)	(6.73)	(0.43)	(0.04)
Interest Income	0.01	0.01	0.01	0.01	0.02	0.01	0.07	0.21	0.01	0.00
Amortization of Financing Costs	0.01	0.01	0.01	0.01	0.02	0.01	0.07	0.21	0.01	0.00
Total Financing Expenses	4.91	8.66	5.11	6.00	12.36	8.26	42.06	132.57	8.55	0.74
Earnings before Income Taxes	25.70	42.76	26.42	31.75	61.77	40.86	248.29	549.68	64.16	3.80
Income Taxes	2.57	4.53	2.67	3.14	6.46	4.32	21.99	69.32	4.47	0.39
Net Earnings	5.67	10.01	5.90	6.94	14.28	9.54	48.61	153.20	9.88	0.86
Gross Revenue Requirement	33.94	57.30	34.99	41.83	82.51	54.72	318.89	772.20	78.51	5.05
OATT Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Revenue	(1.80)	(2.10)	(2.32)	(1.98)	(2.78)	(9.03)	(4.22)	(16.75)	(1.56)	(0.25)
Net Revenue Requirement	32.13	55.20	32.67	39.85	79.73	45.69	314.67	755.45	76.95	4.80

Schedule 1.2										
Unit Cost by Function										
Full Revenue Requirement (¢/kWh Sales)										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	1.03	0.96	0.99	0.96	0.85	1.02	0.89	1.04	0.95	0.99
Purchased Power	10.04	9.26	9.57	9.31	8.10	9.91	7.94	10.13	9.21	9.55
Transmission	1.48	0.88	1.12	0.98	0.01	1.40	0.65	1.57	0.86	1.21
Substations	0.62	0.37	0.47	0.41	0.01	0.59	0.08	0.66	0.36	0.49
Primary Lines	2.17	4.84	1.04	0.92	3.29	1.05	0.20	18.17	2.06	1.60
Transformers	1.47	2.94	0.82	0.69	2.13	0.86	0.16	10.34	1.29	1.11
Secondary Lines	0.76	1.68	0.36	0.32	1.15	0.37	0.07	6.32	0.72	0.56
Service Lines	0.72	2.77	0.10	0.17	1.73	0.08	0.00	7.05	0.63	0.49
Meter Assets	0.19	0.63	0.02	0.21	1.76	0.03	0.01	0.00	0.00	0.18
Meter Reading	0.16	0.31	0.02	0.03	0.15	0.01	0.00	0.00	0.00	0.10
Billing	0.12	0.22	0.01	0.03	0.11	0.00	0.00	0.10	1.93	0.07
Remittance & Collection	0.09	0.18	0.01	0.02	0.09	0.00	0.00	0.11	0.12	0.06
Uncollectibles & Damage Claims	0.05	0.15	0.01	0.01	0.08	0.00	0.00	0.00	0.00	0.03
Service Connections	(0.03)	(0.08)	(0.00)	(0.00)	(0.04)	(0.00)	0.00	(0.00)	(0.01)	(0.02)
Late Payments	(0.06)	(0.06)	(0.02)	(0.02)	(0.05)	(0.03)	0.00	(0.03)	(0.01)	(0.04)
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.67	0.00	0.09
Total	18.81	25.07	14.52	14.04	19.38	15.28	10.01	88.13	18.11	16.45
Demand Related Revenue Requirement ($/kW/Mo Billing Demand)										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	0.00	0.00	0.00	0.44	0.01	0.48	0.44	0.00	2.19	1.26
Purchased Power	0.00	0.00	0.00	4.82	0.10	5.23	1.17	0.00	24.08	13.15
Transmission	0.00	0.00	0.00	3.72	0.08	4.00	3.67	0.00	18.42	10.57
Substations	0.00	0.00	0.00	1.57	0.03	1.69	0.43	0.00	7.77	4.26
Primary Lines	0.00	0.00	0.00	2.52	6.82	2.88	1.10	0.00	11.33	6.99
Transformers	0.00	0.00	0.00	2.09	5.67	2.40	0.92	0.00	9.43	5.81
Secondary Lines	0.00	0.00	0.00	0.88	2.37	1.00	0.38	0.00	3.94	2.43
Service Lines	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meter Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meter Reading	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Billing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remittance & Collection	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Uncollectibles & Damage Claims	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Service Connections	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Late Payments	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	0.00	0.00	0.00	16.03	15.09	17.68	8.11	0.00	77.17	44.47

Schedule 1.2										
Unit Cost by Function										
Energy Related Revenue Requirement (¢/kWh)										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	0.85	0.85	0.85	0.85	0.85	0.85	0.81	0.85	0.85	0.85
Purchased Power	8.12	8.11	8.11	8.05	8.09	8.08	7.74	8.08	8.08	8.05
Transmission	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Substations	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Primary Lines	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transformers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Secondary Lines	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Service Lines	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meter Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Meter Reading	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Billing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remittance & Collection	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Uncollectibles & Damage Claims	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Service Connections	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Late Payments	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	8.97	8.97	8.96	8.89	8.94	8.93	8.55	8.93	8.93	8.90
Site Related Revenue Requirement ($/Bill)										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Purchased Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Substations	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Primary Lines	10.95	18.64	10.95	10.95	21.73	10.95	10.95	178.69	21.10	294.91
Transformers	6.07	10.34	6.07	6.07	12.05	6.07	5.20	99.06	11.70	162.62
Secondary Lines	3.81	6.49	3.81	3.81	7.56	3.81	3.26	62.18	7.34	102.07
Service Lines	6.58	13.20	7.75	7.30	17.32	20.22	73.52	73.29	8.65	227.83
Meter Assets	1.77	3.01	1.77	8.89	17.64	8.89	186.61	0.00	0.00	228.56
Meter Reading	1.47	1.47	1.47	1.47	1.47	1.47	7.37	0.00	0.00	16.22
Billing	1.07	1.07	1.07	1.07	1.07	1.07	26.69	1.07	26.69	60.85
Remittance & Collection	0.86	0.86	0.86	0.86	0.86	0.86	0.86	1.17	1.66	8.88
Uncollectibles & Damage Claims	0.42	0.72	0.42	0.42	0.84	0.00	0.00	0.00	0.00	2.83
Service Connections	(0.30)	(0.36)	(0.04)	(0.20)	(0.39)	(0.07)	0.00	(0.03)	(0.10)	(1.48)
Late Payments	(0.58)	(0.28)	(1.48)	(0.82)	(0.49)	(7.62)	0.00	(0.31)	(0.14)	(11.73)
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	339.68	0.00	339.68
Total	32.11	55.16	32.65	39.82	79.67	45.65	314.47	754.81	76.91	1,431.23

Schedule 1.3										
Allocated Revenue Requirement ($,000)										
Full Revenue Requirement										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
Operating Expenses										
Energy Costs	83,113	2,700	5,121	42,022	878	10,221	14,943	456	262	159,717
ECAM Adjustment	(4,470)	(147)	(278)	(2,289)	(49)	(551)	(819)	(24)	(14)	(8,641)
Net Energy Costs	78,643	2,553	4,843	39,733	829	9,670	14,125	431	248	151,076
Distribution	5,903	446	193	1,516	125	391	137	297	18	9,025
Transmission	1,078	23	53	394	0	128	111	6	2	1,795
Transmission and Distribution -	1,854	121	67	496	30	140	44	64	6	2,822
Transmission - OATT	176	4	9	64	0	21	18	1	0	293
General	9,036	565	270	2,281	135	541	370	240	65	13,502
Total Operating Expenses	96,690	3,712	5,434	44,484	1,119	10,891	14,805	1,040	339	178,513
Amortization										
Amortization Other	264	12	12	92	3	25	23	5	1	436
Amortization - CTGS	1,091	36	68	564	12	135	219	6	4	2,134
Amortization Plant And Equipme	16,950	1,214	579	4,851	361	1,200	753	1,042	50	27,001
Total Amortization	18,305	1,262	659	5,507	376	1,360	995	1,053	55	29,572
Total Operating Income	114,995	4,974	6,093	49,991	1,495	12,250	15,800	2,093	393	208,085
Financing Expenses										
Long-Term Debt	9,224	611	338	2,702	166	706	462	506	27	14,742
Short-Term Debt	836	55	31	245	15	64	42	46	2	1,337
Interest Charged To Constructio	(487)	(32)	(18)	(143)	(9)	(37)	(24)	(27)	(1)	(779)
Interest Income	(31)	(2)	(1)	(9)	(1)	(2)	(2)	(2)	(0)	(49)
Amortization of Financing Costs	16	1	1	5	0	1	1	1	0	25
Total Financing Expenses	9,558	633	350	2,800	172	732	479	525	28	15,276
Earnings before Income Taxes	16,120	1,067	591	4,723	290	1,234	808	885	47	25,765
Income Taxes	5,022	332	184	1,471	90	384	252	276	15	8,026
Net Earnings	11,099	735	407	3,252	200	850	556	609	33	17,739
Gross Revenue Requirement	140,673	6,674	7,035	57,514	1,957	14,216	17,086	3,502	468	249,126
OATT Revenue	(1,637)	(35)	(81)	(598)	(0)	(194)	(168)	(9)	(3)	(2,725)
Other Revenue	(2,129)	(135)	(54)	(458)	(35)	(118)	(53)	(66)	(4)	(3,051)
Net Revenue Requirement	136,907	6,504	6,900	56,458	1,922	13,904	16,866	3,427	461	243,349

Schedule 1.3										
Allocated Revenue Requirement ($,000)										
Demand Related Revenue Requirement										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
Operating Expenses										
Energy Costs	18,778	400	930	6,815	4	2,230	765	106	38	30,066
ECAM Adjustment	(858)	(18)	(42)	(311)	(0)	(102)	(21)	(5)	(2)	(1,360)
Net Energy Costs	17,920	382	887	6,505	4	2,128	743	102	37	28,707
Distribution	2,892	89	166	1,078	35	367	127	16	6	4,776
Transmission	1,078	23	53	394	0	128	111	6	2	1,795
Transmission and Distribution -	1,090	32	61	405	11	137	44	6	2	1,789
Transmission - OATT	176	4	9	64	0	21	18	1	0	293
General	3,621	96	195	1,338	24	446	240	20	7	5,988
Total Operating Expenses	26,778	625	1,372	9,783	73	3,227	1,283	150	54	43,347
Amortization										
Amortization Other	140	3	7	52	1	17	10	1	0	231
Amortization - CTGS	186	4	9	68	0	22	19	1	0	310
Interest Income	8,018	227	444	2,973	71	1,000	502	44	16	13,295
Total Amortization	8,344	234	461	3,092	72	1,039	531	46	16	13,837
Total Operating Income	35,123	860	1,833	12,876	145	4,266	1,815	196	70	57,184
Financing Expenses										
Long-Term Debt	4,725	131	259	1,750	38	587	295	26	9	7,821
Short-Term Debt	428	12	24	159	3	53	27	2	1	709
Interest Charged To Constructio	(250)	(7)	(14)	(92)	(2)	(31)	(16)	(1)	(0)	(413)
Interest Income	(16)	(0)	(1)	(6)	(0)	(2)	(1)	(0)	(0)	(26)
Amortization of Financing Costs	8	0	0	3	0	1	0	0	0	13
Total Financing Expenses	4,897	135	269	1,813	40	608	306	27	10	8,104
Earnings before Income Taxes	8,259	228	453	3,058	67	1,026	516	46	16	13,668
Income Taxes	2,573	71	141	953	21	320	161	14	5	4,258
Net Earnings	5,686	157	312	2,105	46	706	355	31	11	9,411
Gross Revenue Requirement	48,278	1,223	2,555	17,747	251	5,900	2,637	269	96	78,957
OATT Revenue	(1,637)	(35)	(81)	(598)	(0)	(194)	(168)	(9)	(3)	(2,725)
Other Revenue	(618)	(18)	(35)	(230)	(6)	(78)	(36)	(3)	(1)	(1,025)
Net Revenue Requirement	46,023	1,171	2,439	16,919	245	5,629	2,433	256	92	75,207

Schedule 1.3										
Allocated Revenue Requirement ($,000)										
Energy Related Revenue Requirement										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
Operating Expenses										
Energy Costs	64,239	2,289	4,190	35,196	872	7,991	14,179	342	224	129,522
ECAM Adjustment	(3,611)	(129)	(236)	(1,979)	(49)	(449)	(797)	(19)	(13)	(7,282)
Net Energy Costs	60,628	2,161	3,955	33,217	823	7,542	13,381	323	211	122,240
Distribution	36	1	2	20	0	4	8	0	0	73
Transmission	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0
General	568	20	37	311	8	71	125	3	2	1,145
Total Operating Expenses	61,232	2,182	3,994	33,548	831	7,617	13,515	326	213	123,458
Amortization										
Amortization Other	57	2	4	32	1	7	13	0	0	116
Amortization - CTGS	905	32	59	496	12	113	200	5	3	1,824
Amortization Plant And Equipme	1,091	39	71	598	15	136	241	6	4	2,200
Total Amortization	2,053	73	134	1,125	28	255	453	11	7	4,140
Total Operating Income	63,285	2,255	4,128	34,673	859	7,872	13,968	337	220	127,598
Financing Expenses										
Long-Term Debt	741	26	48	406	10	92	163	4	3	1,493
Short-Term Debt	67	2	4	37	1	8	15	0	0	135
Interest Charged To Constructio	(39)	(1)	(3)	(21)	(1)	(5)	(9)	(0)	(0)	(79)
Interest Income	(2)	(0)	(0)	(1)	(0)	(0)	(1)	(0)	(0)	(5)
Amortization of Financing Costs	1	0	0	1	0	0	0	0	0	3
Total Financing Expenses	767	27	50	420	10	95	169	4	3	1,547
Earnings before Income Taxes	1,294	46	84	709	18	161	286	7	5	2,609
Income Taxes	403	14	26	221	5	50	89	2	1	813
Net Earnings	891	32	58	488	12	111	197	5	3	1,797
Gross Revenue Requirement	65,347	2,329	4,263	35,802	887	8,129	14,423	348	227	131,754
OATT Revenue	0	0	0	0	0	0	0	0	0	0
Other Revenue	(73)	(3)	(5)	(40)	(1)	(9)	(16)	(0)	(0)	(148)
Net Revenue Requirement	65,273	2,326	4,258	35,762	886	8,120	14,407	347	227	131,607

Schedule 1.3										
Allocated Revenue Requirement ($,000)										
Site Related Revenue Requirement										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
Operating Expenses										
Energy Costs	95	11	1	11	2	0	0	7	0	129
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	95	11	1	11	2	0	0	7	0	129
Distribution	2,975	356	24	419	89	19	2	281	12	4,176
Transmission	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	764	89	6	91	19	3	0	58	3	1,033
Transmission - OATT	0	0	0	0	0	0	0	0	0	0
General	4,846	449	37	632	103	24	4	217	56	6,369
Total Operating Expenses	8,680	905	68	1,153	214	47	7	564	71	11,707
Amortization										
Amortization Other	66	7	1	9	2	0	0	4	0	89
Amortization - CTGS	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	7,841	948	64	1,280	275	64	11	992	31	11,507
Total Amortization	7,908	955	64	1,290	277	65	11	996	31	11,596
Total Operating Income	16,587	1,859	132	2,442	490	111	17	1,560	102	23,303
Financing Expenses										
Long-Term Debt	3,758	453	30	547	118	27	3	476	15	5,428
Short-Term Debt	341	41	3	50	11	2	0	43	1	492
Interest Charged To Constructio	(199)	(24)	(2)	(29)	(6)	(1)	(0)	(25)	(1)	(287)
Interest Income	(12)	(2)	(0)	(2)	(0)	(0)	(0)	(2)	(0)	(18)
Amortization of Financing Costs	6	1	0	1	0	0	0	1	0	9
Total Financing Expenses	3,894	470	32	567	122	28	4	493	16	5,625
Earnings before Income Taxes	6,567	792	53	956	206	47	6	832	26	9,487
Income Taxes	2,046	247	17	298	64	15	2	259	8	2,955
Net Earnings	4,522	546	37	658	142	33	4	573	18	6,532
Gross Revenue Requirement	27,048	3,122	217	3,965	818	187	27	2,886	145	38,414
OATT Revenue	0	0	0	0	0	0	0	0	0	0
Other Revenue	(1,438)	(114)	(14)	(188)	(28)	(31)	(0)	(63)	(3)	(1,879)
Net Revenue Requirement	25,610	3,007	203	3,777	791	156	26	2,823	142	36,535

Schedule 1.4										
Allocated Revenue Requirement ($,000)										
Full Revenue Requirement										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	7,490	249	468	3,870	84	924	1,502	40	24	14,653
Purchased Power	73,097	2,403	4,547	37,442	804	9,013	13,386	394	234	141,320
Transmission	10,736	228	531	3,923	1	1,274	1,101	61	22	17,877
Substations	4,532	96	224	1,656	1	538	129	26	9	7,211
Primary Lines	15,816	1,256	493	3,695	326	955	332	706	52	23,631
Transformers	10,732	762	391	2,784	212	783	275	402	33	16,375
Secondary Lines	5,503	437	172	1,286	114	332	115	246	18	8,222
Service Lines	5,247	720	48	692	172	69	6	274	16	7,244
Meter Assets	1,408	164	11	843	175	30	16	0	0	2,647
Meter Reading	1,176	80	9	140	15	5	1	0	0	1,426
Billing	851	58	7	101	11	4	2	4	49	1,087
Remittance & Collection	688	47	5	82	9	3	0	4	3	842
Uncollectibles & Damage Claims	337	39	3	40	8	0	0	0	0	428
Service Connections	(242)	(19)	(0)	(19)	(4)	(0)	0	(0)	(0)	(284)
Late Payments	(466)	(15)	(9)	(78)	(5)	(26)	0	(1)	(0)	(601)
Lighting	0	0	0	0	0	0	0	1,270	0	1,270
Total	136,907	6,504	6,900	56,458	1,922	13,904	16,866	3,427	461	243,349
Demand Related Revenue Requirement										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	1,279	27	63	467	0	152	131	7	3	2,130
Purchased Power	14,034	298	694	5,083	2	1,666	351	80	29	22,236
Transmission	10,736	228	531	3,923	1	1,274	1,101	61	22	17,877
Substations	4,532	96	224	1,656	1	538	129	26	9	7,211
Primary Lines	7,085	239	425	2,656	111	917	331	38	13	11,816
Transformers	5,891	199	354	2,209	92	763	275	32	11	9,825
Secondary Lines	2,465	83	148	924	39	319	115	13	5	4,111
Service Lines	0	0	0	0	0	0	0	0	0	0
Meter Assets	0	0	0	0	0	0	0	0	0	0
Meter Reading	0	0	0	0	0	0	0	0	0	0
Billing	0	0	0	0	0	0	0	0	0	0
Remittance & Collection	0	0	0	0	0	0	0	0	0	0
Uncollectibles & Damage Claims	0	0	0	0	0	0	0	0	0	0
Service Connections	0	0	0	0	0	0	0	0	0	0
Late Payments	0	0	0	0	0	0	0	0	0	0
Lighting	0	0	0	0	0	0	0	0	0	0
Total	46,023	1,171	2,439	16,919	245	5,629	2,433	256	92	75,207

Schedule 1.4										
Allocated Revenue Requirement ($,000)										
Energy Related Revenue Requirement										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	6,211	221	405	3,403	84	773	1,371	33	22	12,523
Purchased Power	59,062	2,105	3,853	32,359	802	7,347	13,036	314	206	119,084
Transmission	0	0	0	0	0	0	0	0	0	0
Substations	0	0	0	0	0	0	0	0	0	0
Primary Lines	0	0	0	0	0	0	0	0	0	0
Transformers	0	0	0	0	0	0	0	0	0	0
Secondary Lines	0	0	0	0	0	0	0	0	0	0
Service Lines	0	0	0	0	0	0	0	0	0	0
Meter Assets	0	0	0	0	0	0	0	0	0	0
Meter Reading	0	0	0	0	0	0	0	0	0	0
Billing	0	0	0	0	0	0	0	0	0	0
Remittance & Collection	0	0	0	0	0	0	0	0	0	0
Uncollectibles & Damage Claims	0	0	0	0	0	0	0	0	0	0
Service Connections	0	0	0	0	0	0	0	0	0	0
Late Payments	0	0	0	0	0	0	0	0	0	0
Lighting	0	0	0	0	0	0	0	0	0	0
Total	65,273	2,326	4,258	35,762	886	8,120	14,407	347	227	131,607
Site Related Revenue Requirement										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0
Transmission	0	0	0	0	0	0	0	0	0	0
Substations	0	0	0	0	0	0	0	0	0	0
Primary Lines	8,731	1,016	68	1,039	216	37	1	668	39	11,816
Transformers	4,840	563	38	576	120	21	0	370	22	6,550
Secondary Lines	3,038	354	24	361	75	13	0	233	14	4,111
Service Lines	5,247	720	48	692	172	69	6	274	16	7,244
Meter Assets	1,408	164	11	843	175	30	16	0	0	2,647
Meter Reading	1,176	80	9	140	15	5	1	0	0	1,426
Billing	851	58	7	101	11	4	2	4	49	1,087
Remittance & Collection	688	47	5	82	9	3	0	4	3	842
Uncollectibles & Damage Claims	337	39	3	40	8	0	0	0	0	428
Service Connections	(242)	(19)	(0)	(19)	(4)	(0)	0	(0)	(0)	(284)
Late Payments	(466)	(15)	(9)	(78)	(5)	(26)	0	(1)	(0)	(601)
Lighting	0	0	0	0	0	0	0	1,270	0	1,270
Total	25,610	3,007	203	3,777	791	156	26	2,823	142	36,535

Schedule 2.0										
Allocators by Function										
Allocators										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	51.1 %	1.7 %	3.2 %	26.4 %	0.6 %	6.3 %	10.3 %	0.3 %	0.2 %	100.0 %
Purchased Power	51.7 %	1.7 %	3.2 %	26.5 %	0.6 %	6.4 %	9.5 %	0.3 %	0.2 %	100.0 %
Transmission	60.1 %	1.3 %	3.0 %	21.9 %	0.0 %	7.1 %	6.2 %	0.3 %	0.1 %	100.0 %
Substations	62.8 %	1.3 %	3.1 %	23.0 %	0.0 %	7.5 %	1.8 %	0.4 %	0.1 %	100.0 %
Primary Lines	66.9 %	5.3 %	2.1 %	15.6 %	1.4 %	4.0 %	1.4 %	3.0 %	0.2 %	100.0 %
Transformers	65.5 %	4.7 %	2.4 %	17.0 %	1.3 %	4.8 %	1.7 %	2.5 %	0.2 %	100.0 %
Secondary Lines	66.9 %	5.3 %	2.1 %	15.6 %	1.4 %	4.0 %	1.4 %	3.0 %	0.2 %	100.0 %
Service Lines	72.4 %	9.9 %	0.7 %	9.6 %	2.4 %	1.0 %	0.1 %	3.8 %	0.2 %	100.0 %
Meter Assets	53.2 %	6.2 %	0.4 %	31.8 %	6.6 %	1.1 %	0.6 %	0.0 %	0.0 %	100.0 %
Meter Reading	82.5 %	5.6 %	0.6 %	9.8 %	1.0 %	0.4 %	0.0 %	0.0 %	0.0 %	100.0 %
Billing	78.3 %	5.4 %	0.6 %	9.3 %	1.0 %	0.3 %	0.2 %	0.4 %	4.5 %	100.0 %
Remittance & Collection	81.8 %	5.6 %	0.6 %	9.7 %	1.0 %	0.4 %	0.0 %	0.5 %	0.4 %	100.0 %
Uncollectibles & Damage Claims	78.9 %	9.2 %	0.6 %	9.4 %	1.9 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Service Connections	85.0 %	6.8 %	0.1 %	6.6 %	1.4 %	0.1 %	0.0 %	0.0 %	0.1 %	100.0 %
Late Payments	77.5 %	2.5 %	1.5 %	13.0 %	0.8 %	4.3 %	0.0 %	0.2 %	0.0 %	100.0 %
Lighting	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %	0.0 %	100.0 %
Demand Allocators, Isolated (%)										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	60.1 %	1.3 %	3.0 %	21.9 %	0.0 %	7.1 %	6.2 %	0.3 %	0.1 %	100.0 %
Purchased Power	63.1 %	1.3 %	3.1 %	22.9 %	0.0 %	7.5 %	1.6 %	0.4 %	0.1 %	100.0 %
Transmission	60.1 %	1.3 %	3.0 %	21.9 %	0.0 %	7.1 %	6.2 %	0.3 %	0.1 %	100.0 %
Substations	62.8 %	1.3 %	3.1 %	23.0 %	0.0 %	7.5 %	1.8 %	0.4 %	0.1 %	100.0 %
Primary Lines	60.0 %	2.0 %	3.6 %	22.5 %	0.9 %	7.8 %	2.8 %	0.3 %	0.1 %	100.0 %
Transformers	60.0 %	2.0 %	3.6 %	22.5 %	0.9 %	7.8 %	2.8 %	0.3 %	0.1 %	100.0 %
Secondary Lines	60.0 %	2.0 %	3.6 %	22.5 %	0.9 %	7.8 %	2.8 %	0.3 %	0.1 %	100.0 %
Service Lines	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Assets	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Reading	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Billing	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Remittance & Collection	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Uncollectibles & Damage Claims	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Connections	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Late Payments	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Lighting	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %

Schedule 2.0										
Allocators by Function										
Energy Allocators, Isolated (%)										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	49.6 %	1.8 %	3.2 %	27.2 %	0.7 %	6.2 %	10.9 %	0.3 %	0.2 %	100.0 %
Purchased Power	49.6 %	1.8 %	3.2 %	27.2 %	0.7 %	6.2 %	10.9 %	0.3 %	0.2 %	100.0 %
Transmission	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Substations	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Primary Lines	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Transformers	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Secondary Lines	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Lines	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Assets	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Reading	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Billing	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Remittance & Collection	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Uncollectibles & Damage Claims	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Connections	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Late Payments	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Lighting	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Site Allocators, Isolated (%)										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
Generation	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Purchased Power	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Transmission	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Substations	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Primary Lines	73.9 %	8.6 %	0.6 %	8.8 %	1.8 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %
Transformers	73.9 %	8.6 %	0.6 %	8.8 %	1.8 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %
Secondary Lines	73.9 %	8.6 %	0.6 %	8.8 %	1.8 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %
Service Lines	72.4 %	9.9 %	0.7 %	9.6 %	2.4 %	1.0 %	0.1 %	3.8 %	0.2 %	100.0 %
Meter Assets	53.2 %	6.2 %	0.4 %	31.8 %	6.6 %	1.1 %	0.6 %	0.0 %	0.0 %	100.0 %
Meter Reading	82.5 %	5.6 %	0.6 %	9.8 %	1.0 %	0.4 %	0.0 %	0.0 %	0.0 %	100.0 %
Billing	78.3 %	5.4 %	0.6 %	9.3 %	1.0 %	0.3 %	0.2 %	0.4 %	4.5 %	100.0 %
Remittance & Collection	81.8 %	5.6 %	0.6 %	9.7 %	1.0 %	0.4 %	0.0 %	0.5 %	0.4 %	100.0 %
Uncollectibles & Damage Claims	78.9 %	9.2 %	0.6 %	9.4 %	1.9 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Service Connections	85.0 %	6.8 %	0.1 %	6.6 %	1.4 %	0.1 %	0.0 %	0.0 %	0.1 %	100.0 %
Late Payments	77.5 %	2.5 %	1.5 %	13.0 %	0.8 %	4.3 %	0.0 %	0.2 %	0.0 %	100.0 %
Lighting	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %	0.0 %	100.0 %

Schedule 2.1										
Allocators										
Allocators										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
1CP - Input	64.5 %	1.2 %	2.2 %	19.6 %	0.0 %	6.5 %	5.5 %	0.3 %	0.1 %	100.0 %
1CP - Input Firm	67.5 %	1.3 %	2.3 %	20.4 %	0.0 %	6.8 %	1.3 %	0.3 %	0.1 %	100.0 %
1CP - Transmission	64.5 %	1.2 %	2.2 %	19.6 %	0.0 %	6.5 %	5.5 %	0.3 %	0.1 %	100.0 %
1CP - Distribution Primary	67.3 %	1.3 %	2.3 %	20.5 %	0.0 %	6.8 %	1.4 %	0.3 %	0.1 %	100.0 %
3CP - Input	60.1 %	1.3 %	3.0 %	21.9 %	0.0 %	7.1 %	6.2 %	0.3 %	0.1 %	100.0 %
3CP - Input Firm	63.1 %	1.3 %	3.1 %	22.9 %	0.0 %	7.5 %	1.6 %	0.4 %	0.1 %	100.0 %
3CP - Transmission	60.1 %	1.3 %	3.0 %	21.9 %	0.0 %	7.1 %	6.2 %	0.3 %	0.1 %	100.0 %
3CP - Distribution Primary	62.8 %	1.3 %	3.1 %	23.0 %	0.0 %	7.5 %	1.8 %	0.4 %	0.1 %	100.0 %
NCP - Distribution Primary	61.9 %	2.0 %	3.3 %	20.8 %	1.1 %	7.8 %	2.7 %	0.3 %	0.1 %	100.0 %
NCP - Distribution Secondary	61.9 %	2.0 %	3.3 %	20.8 %	1.1 %	7.8 %	2.7 %	0.3 %	0.1 %	100.0 %
3NCP - Distribution Primary	60.0 %	2.0 %	3.6 %	22.5 %	0.9 %	7.8 %	2.8 %	0.3 %	0.1 %	100.0 %
3NCP - Distribution Secondary	60.0 %	2.0 %	3.6 %	22.5 %	0.9 %	7.8 %	2.8 %	0.3 %	0.1 %	100.0 %
Energy - Input	49.6 %	1.8 %	3.2 %	27.2 %	0.7 %	6.2 %	10.9 %	0.3 %	0.2 %	100.0 %
Sites	73.9 %	8.6 %	0.6 %	8.8 %	1.8 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %
Sites - Distribution Primary	73.9 %	8.6 %	0.6 %	8.8 %	1.8 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %
Sites - Distribution Secondary	73.9 %	8.6 %	0.6 %	8.8 %	1.8 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %
Sites - Mass Market	78.9 %	9.2 %	0.6 %	9.4 %	1.9 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Service Lines	72.4 %	9.9 %	0.7 %	9.6 %	2.4 %	1.0 %	0.1 %	3.8 %	0.2 %	100.0 %
Meter Assets	53.2 %	6.2 %	0.4 %	31.8 %	6.6 %	1.1 %	0.6 %	0.0 %	0.0 %	100.0 %
Meter Reading	82.5 %	5.6 %	0.6 %	9.8 %	1.0 %	0.4 %	0.0 %	0.0 %	0.0 %	100.0 %
Billing	78.3 %	5.4 %	0.6 %	9.3 %	1.0 %	0.3 %	0.2 %	0.4 %	4.5 %	100.0 %
Remittance & Collection	81.8 %	5.6 %	0.6 %	9.7 %	1.0 %	0.4 %	0.0 %	0.5 %	0.4 %	100.0 %
Service Connection Revenue	85.0 %	6.8 %	0.1 %	6.6 %	1.4 %	0.1 %	0.0 %	0.0 %	0.1 %	100.0 %
Penalty Revenue	77.5 %	2.5 %	1.5 %	13.0 %	0.8 %	4.3 %	0.0 %	0.2 %	0.0 %	100.0 %
Lighting Direct Assign	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %	0.0 %	100.0 %
MECL Generation	51.1 %	1.7 %	3.2 %	26.4 %	0.6 %	6.3 %	10.3 %	0.3 %	0.2 %	100.0 %
MECL Purchases	51.7 %	1.7 %	3.2 %	26.5 %	0.6 %	6.4 %	9.5 %	0.3 %	0.2 %	100.0 %
Primary System	66.9 %	5.3 %	2.1 %	15.6 %	1.4 %	4.0 %	1.4 %	3.0 %	0.2 %	100.0 %
Distribution Transformers	65.5 %	4.7 %	2.4 %	17.0 %	1.3 %	4.8 %	1.7 %	2.5 %	0.2 %	100.0 %
Secondary System	66.9 %	5.3 %	2.1 %	15.6 %	1.4 %	4.0 %	1.4 %	3.0 %	0.2 %	100.0 %

Schedule 2.1										
Allocators										
Demand Allocators, Isolated (%)										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
1CP - Input	64.5 %	1.2 %	2.2 %	19.6 %	0.0 %	6.5 %	5.5 %	0.3 %	0.1 %	100.0 %
1CP - Input Firm	67.5 %	1.3 %	2.3 %	20.4 %	0.0 %	6.8 %	1.3 %	0.3 %	0.1 %	100.0 %
1CP - Transmission	64.5 %	1.2 %	2.2 %	19.6 %	0.0 %	6.5 %	5.5 %	0.3 %	0.1 %	100.0 %
1CP - Distribution Primary	67.3 %	1.3 %	2.3 %	20.5 %	0.0 %	6.8 %	1.4 %	0.3 %	0.1 %	100.0 %
3CP - Input	60.1 %	1.3 %	3.0 %	21.9 %	0.0 %	7.1 %	6.2 %	0.3 %	0.1 %	100.0 %
3CP - Input Firm	63.1 %	1.3 %	3.1 %	22.9 %	0.0 %	7.5 %	1.6 %	0.4 %	0.1 %	100.0 %
3CP - Transmission	60.1 %	1.3 %	3.0 %	21.9 %	0.0 %	7.1 %	6.2 %	0.3 %	0.1 %	100.0 %
3CP - Distribution Primary	62.8 %	1.3 %	3.1 %	23.0 %	0.0 %	7.5 %	1.8 %	0.4 %	0.1 %	100.0 %
NCP - Distribution Primary	61.9 %	2.0 %	3.3 %	20.8 %	1.1 %	7.8 %	2.7 %	0.3 %	0.1 %	100.0 %
NCP - Distribution Secondary	61.9 %	2.0 %	3.3 %	20.8 %	1.1 %	7.8 %	2.7 %	0.3 %	0.1 %	100.0 %
3NCP - Distribution Primary	60.0 %	2.0 %	3.6 %	22.5 %	0.9 %	7.8 %	2.8 %	0.3 %	0.1 %	100.0 %
3NCP - Distribution Secondary	60.0 %	2.0 %	3.6 %	22.5 %	0.9 %	7.8 %	2.8 %	0.3 %	0.1 %	100.0 %
Energy - Input	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites - Distribution Secondary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites - Mass Market	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Lines	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Assets	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Reading	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Billing	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Remittance & Collection	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Connection Revenue	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Penalty Revenue	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Lighting Direct Assign	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
MECL Generation	60.1 %	1.3 %	3.0 %	21.9 %	0.0 %	7.1 %	6.2 %	0.3 %	0.1 %	100.0 %
MECL Purchases	63.1 %	1.3 %	3.1 %	22.9 %	0.0 %	7.5 %	1.6 %	0.4 %	0.1 %	100.0 %
Primary System	60.0 %	2.0 %	3.6 %	22.5 %	0.9 %	7.8 %	2.8 %	0.3 %	0.1 %	100.0 %
Distribution Transformers	60.0 %	2.0 %	3.6 %	22.5 %	0.9 %	7.8 %	2.8 %	0.3 %	0.1 %	100.0 %
Secondary System	60.0 %	2.0 %	3.6 %	22.5 %	0.9 %	7.8 %	2.8 %	0.3 %	0.1 %	100.0 %

Schedule 2.1										
Allocators										
Energy Allocators, Isolated (%)										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
1CP - Input	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
1CP - Input Firm	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
1CP - Transmission	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
1CP - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
3CP - Input	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
3CP - Input Firm	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
3CP - Transmission	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
3CP - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
NCP - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
NCP - Distribution Secondary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
3NCP - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
3NCP - Distribution Secondary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Energy - Input	49.6 %	1.8 %	3.2 %	27.2 %	0.7 %	6.2 %	10.9 %	0.3 %	0.2 %	100.0 %
Sites	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites - Distribution Secondary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites - Mass Market	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Lines	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Assets	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Meter Reading	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Billing	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Remittance & Collection	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Service Connection Revenue	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Penalty Revenue	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Lighting Direct Assign	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
MECL Generation	49.6 %	1.8 %	3.2 %	27.2 %	0.7 %	6.2 %	10.9 %	0.3 %	0.2 %	100.0 %
MECL Purchases	49.6 %	1.8 %	3.2 %	27.2 %	0.7 %	6.2 %	10.9 %	0.3 %	0.2 %	100.0 %
Primary System	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Distribution Transformers	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Secondary System	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %

Schedule 2.1										
Allocators										
Site Allocators, Isolated (%)										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
1CP - Input	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
1CP - Input Firm	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
1CP - Transmission	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
1CP - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
3CP - Input	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
3CP - Input Firm	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
3CP - Transmission	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
3CP - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
NCP - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
NCP - Distribution Secondary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
3NCP - Distribution Primary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
3NCP - Distribution Secondary	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Energy - Input	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Sites	73.9 %	8.6 %	0.6 %	8.8 %	1.8 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %
Sites - Distribution Primary	73.9 %	8.6 %	0.6 %	8.8 %	1.8 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %
Sites - Distribution Secondary	73.9 %	8.6 %	0.6 %	8.8 %	1.8 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %
Sites - Mass Market	78.9 %	9.2 %	0.6 %	9.4 %	1.9 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Service Lines	72.4 %	9.9 %	0.7 %	9.6 %	2.4 %	1.0 %	0.1 %	3.8 %	0.2 %	100.0 %
Meter Assets	53.2 %	6.2 %	0.4 %	31.8 %	6.6 %	1.1 %	0.6 %	0.0 %	0.0 %	100.0 %
Meter Reading	82.5 %	5.6 %	0.6 %	9.8 %	1.0 %	0.4 %	0.0 %	0.0 %	0.0 %	100.0 %
Billing	78.3 %	5.4 %	0.6 %	9.3 %	1.0 %	0.3 %	0.2 %	0.4 %	4.5 %	100.0 %
Remittance & Collection	81.8 %	5.6 %	0.6 %	9.7 %	1.0 %	0.4 %	0.0 %	0.5 %	0.4 %	100.0 %
Service Connection Revenue	85.0 %	6.8 %	0.1 %	6.6 %	1.4 %	0.1 %	0.0 %	0.0 %	0.1 %	100.0 %
Penalty Revenue	77.5 %	2.5 %	1.5 %	13.0 %	0.8 %	4.3 %	0.0 %	0.2 %	0.0 %	100.0 %
Lighting Direct Assign	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %	0.0 %	100.0 %
MECL Generation	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
MECL Purchases	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %
Primary System	73.9 %	8.6 %	0.6 %	8.8 %	1.8 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %
Distribution Transformers	73.9 %	8.6 %	0.6 %	8.8 %	1.8 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %
Secondary System	73.9 %	8.6 %	0.6 %	8.8 %	1.8 %	0.3 %	0.0 %	5.7 %	0.3 %	100.0 %

Schedule 2.2										
Allocator Assumptions (2023)										
Site Allocator Weighting Assumptions										
	Residential	Residential (S)	Farm	General Service 1	General Service 1 (S)	Small Industrial	Large Industrial	Lights	Unmetered	Total
Service Lines	424	500	500	470	562	1,304	4,739	289	289	9,078
Meter Assets	51	51	51	257	257	257	5,388	0	0	6,311
Meter Reading	12	7	12	12	6	12	60	0	0	121
Billing	12	7	12	12	6	12	300	1	300	662
Remittance & Collection	12	7	12	12	6	12	12	1	12	86
Lighting & Unmetered Equivalence								0.4	0.4	
Base Allocators										
	Residential	Residential (S)	Farm	General Service 1	General Service 1	Small Industrial	Large Industrial	Lights	Unmetered	Total
1CP - Input (kW)	231,276	4,314	7,922	70,414	29	23,441	19,618	1,073	376	358,463
1CP - Input Firm (kW)	231,276	4,314	7,922	69,760	29	23,441	4,584	1,073	376	342,775
1CP - Transmission (kW)	226,921	4,233	7,773	69,088	29	23,000	19,249	1,053	369	351,713
1CP - Distribution Primary (kW)	226,921	4,233	7,773	69,088	29	23,000	4,794	1,053	369	337,258
3CP - Input (kW)	185,944	3,950	9,196	67,948	23	22,069	19,061	1,054	379	309,623
3CP - Input Firm (kW)	185,944	3,950	9,196	67,349	23	22,069	4,645	1,054	379	294,608
3CP - Transmission (kW)	182,443	3,875	9,023	66,668	22	21,653	18,702	1,034	372	303,792
3CP - Distribution Primary (kW)	182,443	3,875	9,023	66,668	22	21,653	5,210	1,034	372	290,300
NCP - Distribution Primary (kW)	226,921	7,500	12,087	76,112	3,851	28,761	9,837	1,055	375	366,498
NCP - Distribution Secondary (kW)	214,115	7,077	11,405	71,817	3,633	27,138	9,282	996	353	345,815
3NCP - Distribution Primary (kW)	195,630	6,602	11,744	73,343	3,057	25,327	9,133	1,052	372	326,259
3NCP - Distribution Secondary (kW	184,590	6,229	11,081	69,204	2,885	23,897	8,617	993	351	307,847
Energy - Input (MWh)	789,322	28,129	51,488	432,454	10,718	98,190	174,214	4,200	2,748	1,591,463
Sites	66,464	7,737	517	7,906	1,642	285	7	5,087	296	89,940
Sites - Distribution Primary	66,464	7,737	517	7,906	1,642	285	7	5,087	296	89,940
Sites - Distribution Secondary	66,464	7,737	517	7,906	1,642	285	6	5,087	296	89,939
Sites - Mass Market	66,464	7,737	517	7,906	1,642	0	0	0	0	84,265
Service Lines ($,000)	28,184	3,866	258	3,719	923	371	33	1,472	86	38,913
Meter Assets ($,000)	3,389	394	26	2,028	421	73	38	0	0	6,369
Meter Reading (Weighted Sites x 1	798	55	6	95	10	3	0	0	0	967
Billing (Weighted Sites x 1000)	798	55	6	95	10	3	2	4	46	1,018
Remittance & Collection (Weighted	798	55	6	95	10	3	0	5	4	975
Service Connection Revenue ($,00	398	32	0	31	6	0	0	0	0	468
Penalty Revenue ($,000)	483	16	10	81	5	27	0	1	0	623
Lighting Direct Assign	0	0	0	0	0	0	0	1	0	1
Sales Data										
Billing Demand (kW * 12 Months)	N/A	N/A	N/A	1,055,231	16,239	318,412	299,987	N/A	1,188	1,691,057
Peak metered demand	N/A	N/A	N/A	1,055,231	16,239	316,084	294,031	N/A	N/A	1,681,584
Sales (MWh)	727,754	25,945	47,511	402,135	9,918	90,978	168,491	3,888	2,544	1,479,164
Average Bills per Month	66,464	7,737	517	7,906	1,642	285	7	3,740	154	88,451
Revenue ($,000)	128,201	5,734	6,215	68,780	2,078	13,423	16,336	2,245	478	243,491
Lighting & Unmetered Fixtures								12,718	740	

Schedule 2.4					
Classification Assumptions					
Allocator	Demand Related	Energy Related	Site Related	Total	
1CP - Input	100 %	0 %	0 %	100 %	
1CP - Input Firm	100 %	0 %	0 %	100 %	
1CP - Transmission	100 %	0 %	0 %	100 %	
1CP - Distribution Primary	100 %	0 %	0 %	100 %	
3CP - Input	100 %	0 %	0 %	100 %	
3CP - Input Firm	100 %	0 %	0 %	100 %	
3CP - Transmission	100 %	0 %	0 %	100 %	
3CP - Distribution Primary	100 %	0 %	0 %	100 %	
NCP - Distribution Primary	100 %	0 %	0 %	100 %	
NCP - Distribution Secondary	100 %	0 %	0 %	100 %	
3NCP - Distribution Primary	100 %	0 %	0 %	100 %	
3NCP - Distribution Secondary	100 %	0 %	0 %	100 %	
Energy - Input	0 %	100 %	0 %	100 %	
Sites	0 %	0 %	100 %	100 %	
Sites - Distribution Primary	0 %	0 %	100 %	100 %	
Sites - Distribution Secondary	0 %	0 %	100 %	100 %	
Sites - Mass Market	0 %	0 %	100 %	100 %	
Service Lines	0 %	0 %	100 %	100 %	
Meter Assets	0 %	0 %	100 %	100 %	
Meter Reading	0 %	0 %	100 %	100 %	
Billing	0 %	0 %	100 %	100 %	
Remittance & Collection	0 %	0 %	100 %	100 %	
Service Connection Revenue	0 %	0 %	100 %	100 %	
Penalty Revenue	0 %	0 %	100 %	100 %	
Lighting Direct Assign	0 %	0 %	100 %	100 %	
MECL Generation	15 %	85 %	0 %	100 %	
MECL Purchases	16 %	84 %	0 %	100 %	
Primary System	50 %	0 %	50 %	100 %	
Distribution Transformers	60 %	0 %	40 %	100 %	
Secondary System	50 %	0 %	50 %	100 %	
Blended Allocator Assumptions					
	MECL Generation	MECL Purchases	Primary System	Distribution Transformers	Secondary System
1CP - Input					
1CP - Input Firm					
1CP - Transmission					
1CP - Distribution Primary					
3CP - Input	15 %				
3CP - Input Firm		16 %			
3CP - Transmission					
3CP - Distribution Primary					
NCP - Distribution Primary					
NCP - Distribution Secondary					
3NCP - Distribution Primary			50 %		
3NCP - Distribution Secondary				60 %	50 %
Energy - Input	85 %	84 %			

Schedule 2.4					
Classification Assumptions					
Sites					
Sites - Distribution Primary			50 %		
Sites - Distribution Secondary				40 %	50 %
Total	100 %	100 %	100 %	100 %	100 %

Schedule 2.5	
Allocator by Function Assumptions	
Function	Allocator
Generation	MECL Generation
Purchased Power	MECL Purchases
Transmission	3CP - Transmission
Substations	3CP - Distribution Primary
Primary Lines	Primary System
Transformers	Distribution Transformers
Secondary Lines	Secondary System
Service Lines	Service Lines
Meter Assets	Meter Assets
Meter Reading	Meter Reading
Billing	Billing
Remittance & Collection	Remittance & Collection
Uncollectibles & Damage Claims	Sites - Mass Market
Service Connections	Service Connection Revenue
Late Payments	Penalty Revenue
Lighting	Lighting Direct Assign

Schedule 3.0																	
Functionalized Revenue Requirement, Summary																	
Revenue Requirement ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	5,266	148,366	5,534	275	92	92	92	0	0	0	0	0	0	0	0	0	159,717
ECAM Adjustment	0	(8,641)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(8,641)
Net Energy Costs	5,266	139,725	5,534	275	92	92	92	0	0	0	0	0	0	0	0	0	151,076
Distribution	85	0	85	983	3,504	2,250	1,187	626	231	0	0	0	0	0	0	74	9,025
Transmission	0	0	1,795	0	0	0	0	0	0	0	0	0	0	0	0	0	1,795
Transmission and Distribution -	0	0	0	615	1,129	701	376	0	0	0	0	0	0	0	0	0	2,822
Transmission - OATT	0	0	293	0	0	0	0	0	0	0	0	0	0	0	0	0	293
General	1,062	282	2,310	948	1,934	1,954	782	394	223	1,218	992	751	403	160	16	73	13,502
Total Operating Expenses	6,413	140,007	10,017	2,822	6,659	4,998	2,437	1,020	453	1,218	992	751	403	160	16	147	178,513
Amortization																	
Amortization Other	34	103	122	27	40	54	17	2	5	21	6	1	1	1	1	1	436
Amortization - CTGS Reserve V	2,134	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,134
Amortization Plant And Equipme	2,498	77	3,941	1,439	6,699	5,058	2,311	2,964	1,254	137	52	34	10	10	4	511	27,001
Total Amortization	4,667	180	4,062	1,467	6,739	5,113	2,328	2,966	1,260	159	59	35	11	11	5	511	29,572
Total Operating Income	11,080	140,186	14,079	4,289	13,399	10,110	4,765	3,986	1,713	1,377	1,051	786	414	171	21	659	208,085
Financing Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt	1,331	422	2,430	1,088	3,951	2,333	1,334	1,213	348	18	14	21	5	5	0	228	14,742
Short-Term Debt	121	38	220	99	358	212	121	110	32	2	1	2	0	0	0	21	1,337
Interest Charged To Constructio	(70)	(22)	(128)	(58)	(209)	(123)	(71)	(64)	(18)	(1)	(1)	(1)	(0)	(0)	(0)	(12)	(779)
Interest Income	(4)	(1)	(8)	(4)	(13)	(8)	(4)	(4)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(49)
Amortization of Financing Costs	2	1	4	2	7	4	2	2	1	0	0	0	0	0	0	0	25
Total Financing Expenses	1,379	438	2,518	1,128	4,094	2,418	1,383	1,257	361	19	14	22	5	5	0	236	15,276
Earnings before Income Taxes	2,326	738	4,246	1,902	6,906	4,078	2,332	2,121	608	32	24	36	9	8	1	398	25,765
Income Taxes	724	230	1,323	592	2,151	1,270	726	661	189	10	7	11	3	3	0	124	8,026
Net Earnings	1,601	508	2,924	1,310	4,755	2,808	1,606	1,460	419	22	16	25	6	6	1	274	17,739
Gross Revenue Requirement	14,785	141,362	20,843	7,319	24,399	16,606	8,480	7,364	2,682	1,427	1,088	844	428	184	22	1,293	249,126
OATT Revenue	0	0	(2,725)	0	0	0	0	0	0	0	0	0	0	0	0	0	(2,725)
Other Revenue	(132)	(42)	(240)	(108)	(768)	(231)	(258)	(120)	(34)	(2)	(1)	(2)	(0)	(468)	(623)	(23)	(3,051)
Net Revenue Requirement	14,653	141,320	17,877	7,211	23,631	16,375	8,222	7,244	2,647	1,426	1,087	842	428	(284)	(601)	1,270	243,349

Schedule 3.0																	
Functionalized Revenue Requirement, Summary																	
Revenue Requirement, Demand Related ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	766	23,345	5,534	275	46	55	46	0	0	0	0	0	0	0	0	0	30,066
ECAM Adjustment	0	(1,360)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,360)
Net Energy Costs	766	21,985	5,534	275	46	55	46	0	0	0	0	0	0	0	0	0	28,707
Distribution	12	0	85	983	1,752	1,350	594	0	0	0	0	0	0	0	0	0	4,776
Transmission	0	0	1,795	0	0	0	0	0	0	0	0	0	0	0	0	0	1,795
Transmission and Distribution -	0	0	0	615	565	421	188	0	0	0	0	0	0	0	0	0	1,789
Transmission - OATT	0	0	293	0	0	0	0	0	0	0	0	0	0	0	0	0	293
General	154	44	2,310	948	967	1,173	391	0	0	0	0	0	0	0	0	0	5,988
Total Operating Expenses	932	22,029	10,017	2,822	3,330	2,999	1,219	0	0	0	0	0	0	0	0	0	43,347
Amortization																	
Amortization Other	5	16	122	27	20	33	9	0	0	0	0	0	0	0	0	0	231
Amortization - CTGS Reserve V	310	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	310
Amortization Plant And Equipme	363	12	3,941	1,439	3,350	3,035	1,155	0	0	0	0	0	0	0	0	0	13,295
Total Amortization	678	28	4,062	1,467	3,370	3,068	1,164	0	0	0	0	0	0	0	0	0	13,837
Total Operating Income	1,611	22,058	14,079	4,289	6,699	6,066	2,383	0	0	0	0	0	0	0	0	0	57,184
Financing Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt	193	66	2,430	1,088	1,976	1,400	667	0	0	0	0	0	0	0	0	0	7,821
Short-Term Debt	18	6	220	99	179	127	60	0	0	0	0	0	0	0	0	0	709
Interest Charged To Constructio	(10)	(4)	(128)	(58)	(104)	(74)	(35)	0	0	0	0	0	0	0	0	0	(413)
Interest Income	(1)	(0)	(8)	(4)	(7)	(5)	(2)	0	0	0	0	0	0	0	0	0	(26)
Amortization of Financing Costs	0	0	4	2	3	2	1	0	0	0	0	0	0	0	0	0	13
Total Financing Expenses	200	69	2,518	1,128	2,047	1,451	691	0	0	0	0	0	0	0	0	0	8,104
Earnings before Income Taxes	338	116	4,246	1,902	3,453	2,447	1,166	0	0	0	0	0	0	0	0	0	13,668
Income Taxes	105	36	1,323	592	1,076	762	363	0	0	0	0	0	0	0	0	0	4,258
Net Earnings	233	80	2,924	1,310	2,377	1,685	803	0	0	0	0	0	0	0	0	0	9,411
Gross Revenue Requirement	2,149	22,243	20,843	7,319	12,199	9,964	4,240	0	0	0	0	0	0	0	0	0	78,957
OATT Revenue	0	0	(2,725)	0	0	0	0	0	0	0	0	0	0	0	0	0	(2,725)
Other Revenue	(19)	(7)	(240)	(108)	(384)	(138)	(129)	0	0	0	0	0	0	0	0	0	(1,025)
Net Revenue Requirement	2,130	22,236	17,877	7,211	11,816	9,825	4,111	0	0	0	0	0	0	0	0	0	75,207

Schedule 3.0																	
Functionalized Revenue Requirement, Summary																	
Revenue Requirement, Energy Related ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	4,501	125,021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	129,522
ECAM Adjustment	0	(7,282)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(7,282)
Net Energy Costs	4,501	117,740	0	0	0	0	0	0	0	0	0	0	0	0	0	0	122,240
Distribution	73	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	73
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	908	237	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,145
Total Operating Expenses	5,481	117,977	0	0	0	0	0	0	0	0	0	0	0	0	0	0	123,458
Amortization																	
Amortization Other	29	87	0	0	0	0	0	0	0	0	0	0	0	0	0	0	116
Amortization - CTGS Reserve V	1,824	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,824
Amortization Plant And Equipme	2,135	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,200
Total Amortization	3,988	151	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4,140
Total Operating Income	9,469	118,129	0	0	0	0	0	0	0	0	0	0	0	0	0	0	127,598
Financing Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt	1,137	356	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,493
Short-Term Debt	103	32	0	0	0	0	0	0	0	0	0	0	0	0	0	0	135
Interest Charged To Constructio	(60)	(19)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(79)
Interest Income	(4)	(1)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(5)
Amortization of Financing Costs	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
Total Financing Expenses	1,178	369	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,547
Earnings before Income Taxes	1,988	622	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,609
Income Taxes	619	194	0	0	0	0	0	0	0	0	0	0	0	0	0	0	813
Net Earnings	1,368	428	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,797
Gross Revenue Requirement	12,635	119,119	0	0	0	0	0	0	0	0	0	0	0	0	0	0	131,754
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	(112)	(35)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(148)
Net Revenue Requirement	12,523	119,084	0	0	0	0	0	0	0	0	0	0	0	0	0	0	131,607

Schedule 3.0																	
Functionalized Revenue Requirement, Summary																	
Revenue Requirement, Site Related ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	0	0	0	0	46	37	46	0	0	0	0	0	0	0	0	0	129
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	0	0	0	0	46	37	46	0	0	0	0	0	0	0	0	0	129
Distribution	0	0	0	0	1,752	900	594	626	231	0	0	0	0	0	0	74	4,176
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	565	281	188	0	0	0	0	0	0	0	0	0	1,033
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	967	782	391	394	223	1,218	992	751	403	160	16	73	6,369
Total Operating Expenses	0	0	0	0	3,330	1,999	1,219	1,020	453	1,218	992	751	403	160	16	147	11,707
Amortization																	
Amortization Other	0	0	0	0	20	22	9	2	5	21	6	1	1	1	1	1	89
Amortization - CTGS Reserve V	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	3,350	2,023	1,155	2,964	1,254	137	52	34	10	10	4	511	11,507
Total Amortization	0	0	0	0	3,370	2,045	1,164	2,966	1,260	159	59	35	11	11	5	511	11,596
Total Operating Income	0	0	0	0	6,699	4,044	2,383	3,986	1,713	1,377	1,051	786	414	171	21	659	23,303
Financing Expenses		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Long-Term Debt	0	0	0	0	1,976	933	667	1,213	348	18	14	21	5	5	0	228	5,428
Short-Term Debt	0	0	0	0	179	85	60	110	32	2	1	2	0	0	0	21	492
Interest Charged To Constructi	0	0	0	0	(104)	(49)	(35)	(64)	(18)	(1)	(1)	(1)	(0)	(0)	(0)	(12)	(287)
Interest Income	0	0	0	0	(7)	(3)	(2)	(4)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(18)
Amortization of Financing Costs	0	0	0	0	3	2	1	2	1	0	0	0	0	0	0	0	9
Total Financing Expenses	0	0	0	0	2,047	967	691	1,257	361	19	14	22	5	5	0	236	5,625
Earnings before Income Taxes	0	0	0	0	3,453	1,631	1,166	2,121	608	32	24	36	9	8	1	398	9,487
Income Taxes	0	0	0	0	1,076	508	363	661	189	10	7	11	3	3	0	124	2,955
Net Earnings	0	0	0	0	2,377	1,123	803	1,460	419	22	16	25	6	6	1	274	6,532
Gross Revenue Requirement	0	0	0	0	12,199	6,642	4,240	7,364	2,682	1,427	1,088	844	428	184	22	1,293	38,414
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	(384)	(92)	(129)	(120)	(34)	(2)	(1)	(2)	(0)	(468)	(623)	(23)	(1,879)
Net Revenue Requirement	0	0	0	0	11,816	6,550	4,111	7,244	2,647	1,426	1,087	842	428	(284)	(601)	1,270	36,535

Schedule 3.1																	
Functionalized Revenue Requirement																	
Direct Assigned ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	4,792	148,182	4,559	0	0	0	0	0	0	0	0	0	0	0	0	0	157,533
ECAM Adjustment	0	(8,641)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(8,641)
Net Energy Costs	4,792	139,541	4,559	0	0	0	0	0	0	0	0	0	0	0	0	0	148,892
Distribution	0	0	0	285	0	829	0	0	231	0	0	0	0	0	0	0	1,345
Transmission	0	0	1,795	0	0	0	0	0	0	0	0	0	0	0	0	0	1,795
Transmission and Distribution -	0	0	0	306	0	0	0	0	0	0	0	0	0	0	0	0	306
Transmission - OATT	0	0	293	0	0	0	0	0	0	0	0	0	0	0	0	0	293
General	0	0	0	0	0	0	0	0	0	491	542	0	158	0	0	0	1,191
Total Operating Expenses	4,792	139,541	6,647	591	0	829	0	0	231	491	542	0	158	0	0	0	153,822
Amortization																	
Amortization Other	0	93	0	0	0	0	0	0	0	0	0	0	0	0	0	0	93
Amortization - CTGS Reserve V	2,134	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,134
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	2,134	93	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,228
Total Operating Income	6,926	139,635	6,647	591	0	829	0	0	231	491	542	0	158	0	0	0	156,050
Financing Expenses																	
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Income	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	6,926	139,635	6,647	591	0	829	0	0	231	491	542	0	158	0	0	0	156,050
OATT Revenue	0	0	(2,725)	0	0	0	0	0	0	0	0	0	0	0	0	0	(2,725)
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	(468)	(623)	0	(1,091)
Net Revenue Requirement	6,926	139,635	3,921	591	0	829	0	0	231	491	542	0	158	(468)	(623)	0	152,233

Schedule 3.1																	
Functionalized Revenue Requirement																	
For Allocation (First)																	
	ECC	SCADA	Environmental	Primary & Secondary	Call Center	Labour	Customer Service	Finance Labour	Head Office	T&D Plant	Right of Way Amortization	Distribution Lines	Distribution Network	Total Plant			Total
Operating Expenses																	
Energy Costs	1,102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,102
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	1,102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,102
Distribution	0	340	0	0	0	0	0	0	0	0	0	2,347	4,994	0	0	0	7,681
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	2,516	0	0	0	2,516
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	1,107	6,741	426	758	225	882	0	0	0	85	0	0	10,224
Total Operating Expenses	1,102	340	0	0	1,107	6,741	426	758	225	882	0	2,347	7,510	85	0	0	21,523
Amortization																	
Amortization Other	0	0	0	0	0	281	0	0	0	0	62	0	0	0	0	0	343
Amortization - CTGS Reserve V	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	281	0	0	0	0	62	0	0	0	0	0	343
Total Operating Income	1,102	340	0	0	1,107	7,022	426	758	225	882	62	2,347	7,510	85	0	0	21,866
Financing Expenses																	
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Income	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	1,102	340	0	0	1,107	7,022	426	758	225	882	62	2,347	7,510	85	0	0	21,866
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	(502)	0	0	0	0	0	0	0	0	0	0	0	0	(502)
Net Revenue Requirement	1,102	340	0	(502)	1,107	7,022	426	758	225	882	62	2,347	7,510	85	0	0	21,364

Schedule 3.1																	
Functionalized Revenue Requirement																	
For Allocation (Second)																	
	Amortization	G&T Rate Base	Rate Base Excluding WC	Rate Base													Total
Operating Expenses																	
Energy Costs	0	1,082	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,082
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	0	1,082	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,082
Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	2,086	0	0	0	0	0	0	0	0	0	0	0	0	0	2,086
Total Operating Expenses	0	1,082	2,086	0	0	0	0	0	0	0	0	0	0	0	0	0	3,168
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization - CTGS Reserve V	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	27,001	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	27,001
Total Amortization	27,001	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	27,001
Total Operating Income	27,001	1,082	2,086	0	0	0	0	0	0	0	0	0	0	0	0	0	30,169
Financing Expenses																	
Long-Term Debt	0	0	0	14,742	0	0	0	0	0	0	0	0	0	0	0	0	14,742
Short-Term Debt	0	0	0	1,337	0	0	0	0	0	0	0	0	0	0	0	0	1,337
Interest Charged To Constructio	0	0	0	(779)	0	0	0	0	0	0	0	0	0	0	0	0	(779)
Interest Income	0	0	0	(49)	0	0	0	0	0	0	0	0	0	0	0	0	(49)
Amortization of Financing Costs	0	0	0	25	0	0	0	0	0	0	0	0	0	0	0	0	25
Total Financing Expenses	0	0	0	15,276	0	0	0	0	0	0	0	0	0	0	0	0	15,276
Earnings before Income Taxes	0	0	0	25,765	0	0	0	0	0	0	0	0	0	0	0	0	25,765
Income Taxes	0	0	0	8,026	0	0	0	0	0	0	0	0	0	0	0	0	8,026
Net Earnings	0	0	0	17,739	0	0	0	0	0	0	0	0	0	0	0	0	17,739
Gross Revenue Requirement	27,001	1,082	2,086	41,041	0	0	0	0	0	0	0	0	0	0	0	0	71,210
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	(1,458)	0	0	0	0	0	0	0	0	0	0	0	0	(1,458)
Net Revenue Requirement	27,001	1,082	2,086	39,583	0	0	0	0	0	0	0	0	0	0	0	0	69,752

Schedule 3.1																	
Functionalized Revenue Requirement																	
Required Allocation Factors																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Environmental	50.0 %	0.0 %	0.0 %	2.1 %	0.0 %	47.9 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Primary & Secondary	0.0 %	0.0 %	0.0 %	0.0 %	75.0 %	0.0 %	25.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Call Center	0.0 %	0.0 %	5.0 %	0.0 %	3.3 %	3.3 %	3.3 %	0.0 %	0.0 %	5.0 %	20.0 %	40.0 %	10.0 %	10.0 %	0.0 %	0.0 %	100.0 %
Labour	12.1 %	3.4 %	22.6 %	9.7 %	13.6 %	18.9 %	5.9 %	0.6 %	1.9 %	7.6 %	2.3 %	0.2 %	0.2 %	0.2 %	0.2 %	0.3 %	100.0 %
Customer Service	0.0 %	0.0 %	2.8 %	0.0 %	1.8 %	1.8 %	1.8 %	0.0 %	0.0 %	27.8 %	11.0 %	22.0 %	25.5 %	5.5 %	0.0 %	0.0 %	100.0 %
Finance Labour	4.9 %	1.3 %	17.7 %	6.9 %	16.5 %	14.6 %	6.0 %	5.7 %	1.8 %	3.1 %	0.8 %	20.0 %	0.0 %	0.0 %	0.0 %	0.7 %	100.0 %
Head Office	4.9 %	1.4 %	14.6 %	5.2 %	11.4 %	11.8 %	5.2 %	2.6 %	1.2 %	5.0 %	8.9 %	19.3 %	4.1 %	4.1 %	0.1 %	0.4 %	100.0 %
T&D Plant	0.0 %	0.0 %	21.1 %	8.0 %	27.0 %	16.8 %	9.1 %	13.5 %	2.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.6 %	100.0 %
Right of Way Amortization	0.0 %	0.0 %	93.7 %	0.0 %	3.2 %	2.0 %	1.1 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Lines	0.0 %	0.0 %	0.0 %	0.0 %	52.6 %	0.0 %	17.5 %	26.7 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	3.2 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	12.3 %	44.9 %	27.9 %	15.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Total Plant	8.4 %	0.1 %	18.9 %	7.5 %	24.6 %	16.1 %	8.4 %	11.5 %	2.5 %	0.2 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	1.4 %	100.0 %
Amortization	9.3 %	0.3 %	14.6 %	5.3 %	24.8 %	18.7 %	8.6 %	11.0 %	4.6 %	0.5 %	0.2 %	0.1 %	0.0 %	0.0 %	0.0 %	1.9 %	100.0 %
G&T Rate Base	35.4 %	0.0 %	64.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Rate Base Excluding WC	9.1 %	1.8 %	16.6 %	7.5 %	27.1 %	16.0 %	9.2 %	8.3 %	2.4 %	0.1 %	0.1 %	0.1 %	0.0 %	0.0 %	0.0 %	1.6 %	100.0 %
Rate Base	9.0 %	2.9 %	16.5 %	7.4 %	26.8 %	15.8 %	9.1 %	8.2 %	2.4 %	0.1 %	0.1 %	0.1 %	0.0 %	0.0 %	0.0 %	1.5 %	100.0 %

Schedule 3.1																	
Functionalized Revenue Requirement																	
First Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	92	184	275	275	92	92	92	0	0	0	0	0	0	0	0	0	1,102
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	92	184	275	275	92	92	92	0	0	0	0	0	0	0	0	0	1,102
Distribution	85	0	85	699	3,504	1,421	1,187	626	0	0	0	0	0	0	0	74	7,681
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	309	1,129	701	376	0	0	0	0	0	0	0	0	0	2,516
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	872	245	1,963	793	1,368	1,620	591	220	173	724	448	748	244	159	16	40	10,224
Total Operating Expenses	1,049	429	2,323	2,076	6,093	3,834	2,246	846	173	724	448	748	244	159	16	115	21,523
Amortization																	
Amortization Other	34	10	122	27	40	54	17	2	5	21	6	1	1	1	1	1	343
Amortization - CTGS Reserve V	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	34	10	122	27	40	54	17	2	5	21	6	1	1	1	1	1	343
Total Operating Income	1,083	438	2,445	2,103	6,133	3,888	2,263	848	178	745	454	748	245	160	17	115	21,866
Financing Expenses																	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Income	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	1,083	438	2,445	2,103	6,133	3,888	2,263	848	178	745	454	748	245	160	17	115	21,866
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	(377)	0	(126)	0	0	0	0	0	0	0	0	0	(502)
Net Revenue Requirement	1,083	438	2,445	2,103	5,756	3,888	2,138	848	178	745	454	748	245	160	17	115	21,364

Schedule 3.1																	
Functionalized Revenue Requirement																	
Second Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	383	0	699	0	0	0	0	0	0	0	0	0	0	0	0	0	1,082
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	383	0	699	0	0	0	0	0	0	0	0	0	0	0	0	0	1,082
Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	190	37	347	156	566	334	191	174	50	2	2	3	1	1	0	33	2,086
Total Operating Expenses	573	37	1,046	156	566	334	191	174	50	2	2	3	1	1	0	33	3,168
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization - CTGS Reserve V	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	2,498	77	3,941	1,439	6,699	5,058	2,311	2,964	1,254	137	52	34	10	10	4	511	27,001
Total Amortization	2,498	77	3,941	1,439	6,699	5,058	2,311	2,964	1,254	137	52	34	10	15	4	515	27,001
Total Operating Income	3,071	114	4,987	1,595	7,265	5,392	2,502	3,138	1,304	140	54	37	11	15	4	548	30,169
Financing Expenses																	
Long-Term Debt	1,331	422	2,430	1,088	3,951	2,333	1,334	1,213	348	18	14	21	5	5	0	228	14,742
Short-Term Debt	121	38	220	99	358	212	121	110	32	2	1	2	0	0	0	21	1,337
Interest Charged To Constructio	(70)	(22)	(128)	(58)	(209)	(123)	(71)	(64)	(18)	(1)	(1)	(1)	(0)	(0)	(0)	(12)	(779)
Interest Income	(4)	(1)	(8)	(4)	(13)	(8)	(4)	(4)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(49)
Amortization of Financing Costs	2	1	4	2	7	4	2	2	1	0	0	0	0	0	0	0	25
Total Financing Expenses	1,379	438	2,518	1,128	4,094	2,418	1,383	1,257	361	19	14	22	5	5	0	237	15,276
Earnings before Income Taxes	2,326	738	4,246	1,902	6,906	4,078	2,332	2,121	608	32	24	36	9	8	1	398	25,765
Income Taxes	724	230	1,323	592	2,151	1,270	726	661	189	10	7	11	3	3	0	124	8,026
Net Earnings	1,601	508	2,924	1,310	4,755	2,808	1,606	1,460	419	22	16	25	6	6	1	274	17,739
Gross Revenue Requirement	6,776	1,289	11,751	4,625	18,266	11,888	6,216	6,516	2,273	191	92	95	25	24	5	1,178	71,210
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	(132)	(42)	(240)	(108)	(391)	(231)	(132)	(120)	(34)	(2)	(1)	(2)	(0)	(0)	(0)	(23)	(1,458)
Net Revenue Requirement	6,644	1,247	11,511	4,517	17,875	11,657	6,084	6,396	2,238	189	91	93	24	24	5	1,161	69,752

Schedule 3.1																	
Functionalized Revenue Requirement																	
Total																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	5,266	148,366	5,534	275	92	92	92	0	0	0	0	0	0	0	0	0	159,717
ECAM Adjustment	0	(8,641)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(8,641)
Net Energy Costs	5,266	139,725	5,534	275	92	92	92	0	0	0	0	0	0	0	0	0	151,076
Distribution	85	0	85	983	3,504	2,250	1,187	626	231	0	0	0	0	0	0	74	9,025
Transmission	0	0	1,795	0	0	0	0	0	0	0	0	0	0	0	0	0	1,795
Transmission and Distribution -	0	0	0	615	1,129	701	376	0	0	0	0	0	0	0	0	0	2,822
Transmission - OATT	0	0	293	0	0	0	0	0	0	0	0	0	0	0	0	0	293
General	1,062	282	2,310	948	1,934	1,954	782	394	223	1,218	992	751	403	160	16	73	13,502
Total Operating Expenses	6,413	140,007	10,017	2,822	6,659	4,998	2,437	1,020	453	1,218	992	751	403	160	16	147	178,513
Amortization																	
Amortization Other	34	103	122	27	40	54	17	2	5	21	6	1	1	1	1	1	436
Amortization - CTGS Reserve V	2,134	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,134
Amortization Plant And Equipme	2,498	77	3,941	1,439	6,699	5,058	2,311	2,964	1,254	137	52	34	10	10	4	511	27,001
Total Amortization	4,667	180	4,062	1,467	6,739	5,113	2,328	2,966	1,260	159	59	35	11	11	5	511	29,572
Total Operating Income	11,080	140,186	14,079	4,289	13,399	10,110	4,765	3,986	1,713	1,377	1,051	786	414	171	21	659	208,085
Financing Expenses																	
Long-Term Debt	1,331	422	2,430	1,088	3,951	2,333	1,334	1,213	348	18	14	21	5	5	0	228	14,742
Short-Term Debt	121	38	220	99	358	212	121	110	32	2	1	2	0	0	0	21	1,337
Interest Charged To Constructio	(70)	(22)	(128)	(58)	(209)	(123)	(71)	(64)	(18)	(1)	(1)	(1)	(0)	(0)	(0)	(12)	(779)
Interest Income	(4)	(1)	(8)	(4)	(13)	(8)	(4)	(4)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(49)
Amortization of Financing Costs	2	1	4	2	7	4	2	2	1	0	0	0	0	0	0	0	25
Total Financing Expenses	1,379	438	2,518	1,128	4,094	2,418	1,383	1,257	361	19	14	22	5	5	0	236	15,276
Earnings before Income Taxes	2,326	738	4,246	1,902	6,906	4,078	2,332	2,121	608	32	24	36	9	8	1	398	25,765
Income Taxes	724	230	1,323	592	2,151	1,270	726	661	189	10	7	11	3	3	0	124	8,026
Net Earnings	1,601	508	2,924	1,310	4,755	2,808	1,606	1,460	419	22	16	25	6	6	1	274	17,739
Gross Revenue Requirement	14,785	141,362	20,843	7,319	24,399	16,606	8,480	7,364	2,682	1,427	1,088	844	428	184	22	1,293	249,126
OATT Revenue	0	0	(2,725)	0	0	0	0	0	0	0	0	0	0	0	0	0	(2,725)
Other Revenue	(132)	(42)	(240)	(108)	(768)	(231)	(258)	(120)	(34)	(2)	(1)	(2)	(0)	(468)	(623)	(23)	(3,051)
Net Revenue Requirement	14,653	141,320	17,877	7,211	23,631	16,375	8,222	7,244	2,647	1,426	1,087	842	428	(284)	(601)	1,270	243,349

Schedule 3.2																	
Functionalized Labour																	
Direct Assigned ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	507	0	33	0	0	0	0	0	0	0	0	0	0	0	0	0	540
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	507	0	33	0	0	0	0	0	0	0	0	0	0	0	0	0	540
Distribution	0	0	0	43	0	551	0	0	92	0	0	0	0	0	0	0	686
Transmission	0	0	583	0	0	0	0	0	0	0	0	0	0	0	0	0	583
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	288	0	0	0	0	0	0	0	0	0	0	0	0	0	288
General	0	0	0	0	0	0	0	0	0	401	110	0	0	0	0	0	512
Total Operating Expenses	507	0	904	43	0	551	0	0	92	401	110	0	0	0	0	0	2,609
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization - CTGS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	507	0	904	43	0	551	0	0	92	401	110	0	0	0	0	0	2,609
Financing Expenses																	
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Income	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	507	0	904	43	0	551	0	0	92	401	110	0	0	0	0	0	2,609
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	507	0	904	43	0	551	0	0	92	401	110	0	0	0	0	0	2,609

Schedule 3.2																	
Functionalized Labour																	
For Allocation																	
	ECC	SCADA	T&D Plant	Distribution Lines	Distribution	Finance Labour											Total
Operating Expenses																	
Energy Costs	1,040	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,040
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	1,040	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,040
Distribution	0	198	0	78	1,286	0	0	0	0	0	0	0	0	0	0	0	1,562
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	0	205	0	0	0	0	0	0	0	0	0	0	205
Total Operating Expenses	1,040	198	0	78	1,286	205	0	0	0	0	0	0	0	0	0	0	2,807
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization - CTGS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	1,040	198	0	78	1,286	205	0	0	0	0	0	0	0	0	0	0	2,807
Financing Expenses																	
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Income	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	1,040	198	0	78	1,286	205	0	0	0	0	0	0	0	0	0	0	2,807
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	1,040	198	0	78	1,286	205	0	0	0	0	0	0	0	0	0	0	2,807
Required Allocation Factors																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
T&D Plant	0.0 %	0.0 %	21.1 %	8.0 %	27.0 %	16.8 %	9.1 %	13.5 %	2.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.6 %	100.0 %
Distribution Lines	0.0 %	0.0 %	0.0 %	0.0 %	52.6 %	0.0 %	17.5 %	26.7 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	3.2 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	12.3 %	44.9 %	27.9 %	15.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Finance Labour	6.3 %	6.3 %	6.3 %	6.3 %	6.3 %	6.3 %	6.3 %	6.3 %	6.3 %	6.3 %	6.3 %	6.3 %	6.3 %	6.3 %	6.3 %	6.3 %	100.0 %

Schedule 3.2																	
Functionalized Labour																	
First Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	87	173	260	260	87	87	87	0	0	0	0	0	0	0	0	0	1,040
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	87	173	260	260	87	87	87	0	0	0	0	0	0	0	0	0	1,040
Distribution	49	0	49	207	635	375	223	21	0	0	0	0	0	0	0	2	1,562
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	136	173	310	468	722	462	309	21	0	0	0	0	0	0	0	2	2,603
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization - CTGS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	136	173	310	468	722	462	309	21	0	0	0	0	0	0	0	2	2,603
Financing Expenses																	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Income	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	136	173	310	468	722	462	309	21	0	0	0	0	0	0	0	2	2,603
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	136	173	310	468	722	462	309	21	0	0	0	0	0	0	0	2	2,603
Second Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	205
Total Operating Expenses	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	205
Amortization																	

Schedule 3.2																	
Functionalized Labour																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization - CTGS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	205
Financing Expenses																	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Income	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	205
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	205

Schedule 3.2																	
Functionalized Labour																	
Total																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	594	173	293	260	87	87	87	0	0	0	0	0	0	0	0	0	1,580
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	594	173	293	260	87	87	87	0	0	0	0	0	0	0	0	0	1,580
Distribution	49	0	49	251	635	926	223	21	92	0	0	0	0	0	0	2	2,248
Transmission	0	0	583	0	0	0	0	0	0	0	0	0	0	0	0	0	583
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	288	0	0	0	0	0	0	0	0	0	0	0	0	0	288
General	13	13	13	13	13	13	13	13	13	414	123	13	13	13	13	13	716
Total Operating Expenses	656	186	1,227	524	734	1,026	322	34	104	414	123	13	13	13	13	15	5,416
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization - CTGS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	656	186	1,227	524	734	1,026	322	34	104	414	123	13	13	13	13	15	5,416
Financing Expenses																	
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Income	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	656	186	1,227	524	734	1,026	322	34	104	414	123	13	13	13	13	15	5,416
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	656	186	1,227	524	734	1,026	322	34	104	414	123	13	13	13	13	15	5,416

Schedule 3.3																	
Functionalized Vehicle																	
Direct Assigned ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	27	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	29
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	27	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	29
Distribution	0	0	0	4	0	120	0	0	16	0	0	0	0	0	0	0	140
Transmission	0	0	77	0	0	0	0	0	0	0	0	0	0	0	0	0	77
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	27	0	80	4	0	120	0	0	16	0	0	0	0	0	0	0	246
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization - CTGS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	27	0	80	4	0	120	0	0	16	0	0	0	0	0	0	0	246
Financing Expenses																	
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Income	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	27	0	80	4	0	120	0	0	16	0	0	0	0	0	0	0	246
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	27	0	80	4	0	120	0	0	16	0	0	0	0	0	0	0	246

Schedule 3.3																	
Functionalized Vehicle																	
For Allocation																	
	ECC	SCADA	T&D Plant	Distribution Lines	Distribution												Total
Operating Expenses																	
Energy Costs	23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	23
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	23
Distribution	0	19	0	15	202	0	0	0	0	0	0	0	0	0	0	0	236
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	23	19	0	15	202	0	0	0	0	0	0	0	0	0	0	0	260
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization - CTGS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	23	19	0	15	202	0	0	0	0	0	0	0	0	0	0	0	260
Financing Expenses																	
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Income	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	23	19	0	15	202	0	0	0	0	0	0	0	0	0	0	0	260
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	23	19	0	15	202	0	0	0	0	0	0	0	0	0	0	0	260
Required Allocation Factors																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
T&D Plant	0.0 %	0.0 %	21.1 %	8.0 %	27.0 %	16.8 %	9.1 %	13.5 %	2.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.6 %	100.0 %
Distribution Lines	0.0 %	0.0 %	0.0 %	0.0 %	52.6 %	0.0 %	17.5 %	26.7 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	3.2 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	12.3 %	44.9 %	27.9 %	15.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %

Schedule 3.3																	
Functionalized Vehicle																	
Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	2	4	6	6	2	2	2	0	0	0	0	0	0	0	0	0	23
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	2	4	6	6	2	2	2	0	0	0	0	0	0	0	0	0	23
Distribution	5	0	5	30	100	58	34	4	0	0	0	0	0	0	0	0	236
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	7	4	11	35	102	60	36	4	0	0	0	0	0	0	0	0	260
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization - CTGS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	7	4	11	35	102	60	36	4	0	0	0	0	0	0	0	0	260
Financing Expenses																	0
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Income	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	7	4	11	35	102	60	36	4	0	0	0	0	0	0	0	0	260
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	7	4	11	35	102	60	36	4	0	0	0	0	0	0	0	0	260

Schedule 3.3																	
Functionalized Vehicle																	
Total																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Operating Expenses																	
Energy Costs	29	4	8	6	2	2	2	0	0	0	0	0	0	0	0	0	53
ECAM Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Energy Costs	29	4	8	6	2	2	2	0	0	0	0	0	0	0	0	0	
Distribution	5	0	5	33	100	177	34	4	16	0	0	0	0	0	0	0	376
Transmission	0	0	77	0	0	0	0	0	0	0	0	0	0	0	0	0	77
Transmission and Distribution -	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission - OATT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	34	4	90	39	102	179	36	4	16	0	0	0	0	0	0	0	
Amortization																	
Amortization Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization - CTGS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization Plant And Equipme	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Income	34	4	90	39	102	179	36	4	16	0	0	0	0	0	0	0	506
Financing Expenses																	
Long-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short-Term Debt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Charged To Constructio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Income	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Financing Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Earnings before Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Earnings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Revenue Requirement	34	4	90	39	102	179	36	4	16	0	0	0	0	0	0	0	506
OATT Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Revenue Requirement	34	4	90	39	102	179	36	4	16	0	0	0	0	0	0	0	506

Schedule 3.4																	
Functionalized Rate Base																	
Direct Assigned ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	32,212	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	32,212
Transmission & Distribution																	
Substations	0	0	985	4,278	0	0	0	0	0	0	0	0	0	0	0	0	5,263
Lines and Line Transformers	0	0	58,405	0	0	75,710	0	44,322	0	0	0	0	0	0	0	0	178,437
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	12,313	0	0	0	0	0	0	0	12,313
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8,177	8,177
Total Transmission & Distrib	0	0	59,390	4,278	0	75,710	0	44,322	12,313	0	0	0	0	0	0	8,177	204,191
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	32,212	0	59,390	4,278	0	75,710	0	44,322	12,313	0	0	0	0	0	0	8,177	236,403
Contributions - Net	0	0	(10,289)	0	0	0	0	0	0	0	0	0	0	0	0	0	(10,289)
Future Income Taxes																	
Fixed Assets Recovery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECAM	0	(3,618)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(3,618)
Deferred Charges	(361)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(361)
Employee Future Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Liability	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Asset	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tax Adjustments for CAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Future Income Taxes	(361)	(3,618)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(3,979)
Deferred Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd pre-2004 costs recover	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd post-2003 costs recove	0	11,671	0	0	0	0	0	0	0	0	0	0	0	0	0	0	11,671
Regulatory Liability - OPEB & EMP I	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Asset - Weather Norma	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Asset - CTGS	9,605	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9,605
Regulatory Asset - RORA/Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Assets																	
Right of Ways	0	0	2,801	0	0	0	0	0	0	0	0	0	0	0	0	0	2,801
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	2,801	0	0	0	0	0	0	0	0	0	0	0	0	0	2,801
Deferred Charge	1,165	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,165
Working Capital																	0
Inventory	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross operating expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income taxes paid	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Working Capital	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	42,621	8,053	51,902	4,278	0	75,710	0	44,322	12,313	0	0	0	0	0	0	8,177	247,377

Schedule 3.4																	
Functionalized Rate Base																	
For Allocation	First Allocation											Second Al	Third Allocation				
	Substations 1841 Account	ECC	SCADA	Primary & Secondary	Distribution Facilities	Distribution Lines	Distribution Network	Transportation	Labour	Head Office	Contributions Related Distribution Plant	Net Plant	Rate Base Excluding WC	O&M			Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	56,032	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	56,032
Lines and Line Transformers	0	0	0	176,054	0	0	7,176	0	0	0	0	0	0	0	0	0	183,230
SCADA and Communications	0	0	6,426	0	0	0	0	0	0	0	0	0	0	0	0	0	6,426
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	56,032	0	6,426	176,054	0	0	7,176	0	0	0	0	0	0	0	0	0	245,688
Administrative & General	0	1,198	0	0	0	0	7,416	9,051	7,872	3,544	0	0	0	0	0	0	29,081
Gross Fixed Assets	56,032	1,198	6,426	176,054	0	0	14,592	9,051	7,872	3,544	0	0	0	0	0	0	274,769
Contributions - Net	0	0	0	0	(319)	0	0	0	0	0	(15,207)	0	0	0	0	0	(15,527)
Future Income Taxes																	
Fixed Assets Recovery	0	0	0	0	0	0	0	0	0	0	0	(48,310)	0	0	0	0	(48,310)
ECAM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Charges	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Employee Future Benefits	0	0	0	0	0	0	0	0	1,968	0	0	0	0	0	0	0	1,968
DSM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Liability	0	0	0	0	0	0	0	0	0	0	0	207	0	0	0	0	207
Future Income Tax Asset	0	0	0	0	0	0	0	0	0	0	0	29,780	0	0	0	0	29,780
Other	0	0	0	0	0	0	0	0	0	0	0	(12,269)	0	0	0	0	(12,269)
Tax Adjustments for CAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Future Income Taxes	0	0	0	0	0	0	0	0	1,968	0	0	(30,592)	0	0	0	0	(28,624)
Deferred Financing Costs	0	0	0	0	0	0	0	0	0	0	0	1,490	0	0	0	0	1,490
Unrecoverd pre-2004 costs recover	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd post-2003 costs recove	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Liability - OPEB & EMP I	0	0	0	0	0	0	0	0	(5,343)	0	0	0	0	0	0	0	(5,343)
Regulatory Asset - Weather Norma	0	0	0	0	0	0	0	0	0	0	0	3,559	0	0	0	0	3,559
Regulatory Asset - CTGS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Asset - RORA/Revenue	0	0	0	0	0	0	0	0	0	0	0	1,020	0	0	0	0	1,020
Intangible Assets																	
Right of Ways	0	0	0	0	198	0	0	0	0	0	0	0	0	0	0	0	198
Software	0	0	0	0	0	0	0	0	1,022	0	0	0	0	0	0	0	1,022
Total Intangible Assets	0	0	0	0	198	0	0	0	1,022	0	0	0	0	0	0	0	1,220
Deferred Charge	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Working Capital																	0
Inventory	0	0	0	0	0	2,926	0	0	0	0	0	0	0	0	0	0	2,926
Gross operating expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	6,890	0	0	6,890
Income taxes paid	0	0	0	0	0	0	0	0	0	0	0	0	89	0	0	0	89
Total Working Capital	0	0	0	0	0	2,926	0	0	0	0	0	0	89	6,890	0	0	9,904
Total	56,032	1,198	6,426	176,054	(121)	2,926	14,592	9,051	5,518	3,544	(15,207)	(24,524)	89	6,890	0	0	242,467

Schedule 3.4																	
Functionalized Rate Base																	
Required Allocation Factors																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Substations 1841 Account	0.0 %	0.0 %	49.0 %	51.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Primary & Secondary	0.0 %	0.0 %	0.0 %	0.0 %	75.0 %	0.0 %	25.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Facilities	0.0 %	0.0 %	0.0 %	0.0 %	51.2 %	31.8 %	17.1 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Lines	0.0 %	0.0 %	0.0 %	0.0 %	52.6 %	0.0 %	17.5 %	26.7 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	3.2 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	12.3 %	44.9 %	27.9 %	15.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Transportation	6.7 %	0.8 %	17.9 %	7.7 %	20.2 %	35.5 %	7.2 %	0.8 %	3.2 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.1 %	100.0 %
Labour	12.1 %	3.4 %	22.6 %	9.7 %	13.6 %	18.9 %	5.9 %	0.6 %	1.9 %	7.6 %	2.3 %	0.2 %	0.2 %	0.2 %	0.2 %	0.3 %	100.0 %
Head Office	4.9 %	1.4 %	14.6 %	5.2 %	11.4 %	11.8 %	5.2 %	2.6 %	1.2 %	5.0 %	8.9 %	19.3 %	4.1 %	4.1 %	0.1 %	0.4 %	100.0 %
Contributions Related Distribution I	0.0 %	0.0 %	0.0 %	0.0 %	38.1 %	23.7 %	12.7 %	19.3 %	3.9 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	2.3 %	100.0 %
Net Plant	7.3 %	0.1 %	17.5 %	7.8 %	28.0 %	16.8 %	9.4 %	8.5 %	2.5 %	0.2 %	0.1 %	0.1 %	0.0 %	0.0 %	0.0 %	1.6 %	100.0 %
Rate Base Excluding WC	9.1 %	1.8 %	16.6 %	7.5 %	27.1 %	16.0 %	9.2 %	8.3 %	2.4 %	0.1 %	0.1 %	0.1 %	0.0 %	0.0 %	0.0 %	1.6 %	100.0 %
O&M	3.3 %	79.8 %	5.1 %	1.5 %	3.5 %	2.7 %	1.3 %	0.5 %	0.2 %	0.7 %	0.6 %	0.4 %	0.2 %	0.1 %	0.0 %	0.1 %	100.0 %

Schedule 3.4																	
Functionalized Rate Base																	
First Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	27,456	28,576	0	0	0	0	0	0	0	0	0	0	0	0	56,032
Lines and Line Transformers	0	0	0	882	135,261	2,001	45,087	0	0	0	0	0	0	0	0	0	183,230
SCADA and Communications	1,606	0	1,606	1,606	535	535	535	0	0	0	0	0	0	0	0	0	6,426
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	1,606	0	29,062	31,065	135,796	2,536	45,622	0	0	0	0	0	0	0	0	0	245,688
Administrative & General	1,830	588	4,216	2,854	6,724	7,284	2,515	213	488	781	494	702	163	163	21	44	29,081
Gross Fixed Assets	3,436	588	33,279	33,918	142,520	9,820	48,137	213	488	781	494	702	163	163	21	44	274,769
Contributions - Net	0	0	0	0	(5,957)	(3,700)	(1,986)	(2,937)	(599)	0	0	0	0	0	0	(348)	(15,527)
Future Income Taxes																	
Fixed Assets Recovery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECAM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Charges	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Employee Future Benefits	238	68	446	190	267	373	117	12	38	151	45	5	5	5	5	6	1,968
DSM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Liability	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Asset	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tax Adjustments for CAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Future Income Taxes	238	68	446	190	267	373	117	12	38	151	45	5	5	5	5	6	1,968
Deferred Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd pre-2004 costs recover	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd post-2003 costs recove	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Liability - OPEB & EMP I	(647)	(184)	(1,210)	(516)	(724)	(1,012)	(318)	(33)	(103)	(409)	(121)	(13)	(13)	(13)	(13)	(15)	(5,343)
Regulatory Asset - Weather Norma	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Asset - CTGS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Asset - RORA/Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Assets																	
Right of Ways	0	0	0	0	101	63	34	0	0	0	0	0	0	0	0	0	198
Software	124	35	231	99	139	193	61	6	20	78	23	2	2	2	2	3	1,022
Total Intangible Assets	124	35	231	99	240	256	95	6	20	78	23	2	2	2	2	3	1,220
Deferred Charge	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Working Capital																	
Inventory	0	0	0	0	1,540	0	513	780	0	0	0	0	0	0	0	93	2,926
Gross operating expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income taxes paid	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Working Capital	0	0	0	0	1,540	0	513	780	0	0	0	0	0	0	0	93	2,926
Total	3,151	507	32,746	33,691	137,885	5,737	46,558	(1,958)	(156)	601	440	696	158	158	16	(218)	260,012

Schedule 3.4																	
Functionalized Rate Base																	
Second Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contributions - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Taxes																	
Fixed Assets Recovery	(3,531)	(62)	(8,432)	(3,780)	(13,505)	(8,103)	(4,565)	(4,107)	(1,207)	(85)	(51)	(70)	(16)	(16)	(2)	(777)	(48,310)
ECAM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Charges	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Employee Future Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Liability	15	0	36	16	58	35	20	18	5	0	0	0	0	0	0	3	207
Future Income Tax Asset	2,177	38	5,198	2,330	8,325	4,995	2,814	2,532	744	52	31	43	10	10	1	479	29,780
Other	(897)	(16)	(2,141)	(960)	(3,430)	(2,058)	(1,159)	(1,043)	(306)	(22)	(13)	(18)	(4)	(4)	(1)	(197)	(12,269)
Tax Adjustments for CAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Future Income Taxes	(2,236)	(39)	(5,339)	(2,394)	(8,552)	(5,131)	(2,891)	(2,601)	(764)	(54)	(32)	(44)	(10)	(10)	(1)	(492)	(30,592)
Deferred Financing Costs	109	2	260	117	417	250	141	127	37	3	2	2	1	1	0	24	1,490
Unrecoverd pre-2004 costs recover	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd post-2003 costs recove	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Liability - OPEB & EMP I	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Asset - Weather Norma	260	5	621	278	995	597	336	303	89	6	4	5	1	1	0	57	3,559
Regulatory Asset - CTGS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Asset - RORA/Revenue	75	1	178	80	285	171	96	87	25	2	1	1	0	0	0	16	1,020
Intangible Assets																	
Right of Ways	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Charge	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Working Capital																	
Inventory	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross operating expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income taxes paid	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Working Capital	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	(1,793)	(31)	(4,280)	(1,919)	(6,856)	(4,114)	(2,317)	(2,085)	(612)	(43)	(26)	(35)	(8)	(8)	(1)	(395)	(24,524)

Schedule 3.4																	
Functionalized Rate Base																	
Third Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Contributions - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Taxes																	
Fixed Assets Recovery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ECAM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Charges	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Employee Future Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Liability	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Asset	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tax Adjustments for CAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Future Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Financing Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd pre-2004 costs recover	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd post-2003 costs recove	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Liability - OPEB & EMP I	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Asset - Weather Norma	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Asset - CTGS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Asset - RORA/Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Assets																	
Right of Ways	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Charge	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Working Capital																	
Inventory	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross operating expenses	229	5,500	352	105	239	183	88	33	16	48	39	29	16	6	1	4	6,890
Income taxes paid	8	2	15	7	24	14	8	7	2	0	0	0	0	0	0	1	89
Total Working Capital	238	5,501	367	111	264	197	96	41	18	48	39	30	16	6	1	6	6,979
Total	238	5,501	367	111	264	197	96	41	18	48	39	30	16	6	1	6	6,979

Schedule 3.4																	
Functionalized Rate Base																	
Total																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	32,212	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	32,212
Transmission & Distribution																	
Substations	0	0	28,441	32,855	0	0	0	0	0	0	0	0	0	0	0	0	61,296
Lines and Line Transformers	0	0	58,405	882	135,261	77,711	45,087	44,322	0	0	0	0	0	0	0	0	361,667
SCADA and Communications	1,606	0	1,606	1,606	535	535	535	0	0	0	0	0	0	0	0	0	6,426
Meters	0	0	0	0	0	0	0	0	12,313	0	0	0	0	0	0	0	12,313
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8,177	8,177
Total Transmission & Distrib	1,606	0	88,452	35,343	135,796	78,246	45,622	44,322	12,313	0	0	0	0	0	0	8,177	449,879
Administrative & General	1,830	588	4,216	2,854	6,724	7,284	2,515	213	488	781	494	702	163	163	21	44	29,081
Gross Fixed Assets	35,648	588	92,668	38,197	142,520	85,531	48,137	44,535	12,802	781	494	702	163	163	21	8,221	511,172
Contributions - Net	0	0	(10,289)	0	(5,957)	(3,700)	(1,986)	(2,937)	(599)	0	0	0	0	0	0	(348)	(25,816)
Future Income Taxes																	0
Fixed Assets Recovery	(3,531)	(62)	(8,432)	(3,780)	(13,505)	(8,103)	(4,565)	(4,107)	(1,207)	(85)	(51)	(70)	(16)	(16)	(2)	(777)	(48,310)
ECAM	0	(3,618)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(3,618)
Deferred Charges	(361)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(361)
Employee Future Benefits	238	68	446	190	267	373	117	12	38	151	45	5	5	5	5	6	1,968
DSM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Income Tax Liability	15	0	36	16	58	35	20	18	5	0	0	0	0	0	0	3	207
Future Income Tax Asset	2,177	38	5,198	2,330	8,325	4,995	2,814	2,532	744	52	31	43	10	10	1	479	29,780
Other	(897)	(16)	(2,141)	(960)	(3,430)	(2,058)	(1,159)	(1,043)	(306)	(22)	(13)	(18)	(4)	(4)	(1)	(197)	(12,269)
Tax Adjustments for CAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Future Income Taxes	(2,359)	(3,589)	(4,894)	(2,204)	(8,285)	(4,759)	(2,774)	(2,589)	(726)	97	12	(39)	(6)	(6)	3	(487)	(32,604)
Deferred Financing Costs	109	2	260	117	417	250	141	127	37	3	2	2	1	1	0	24	1,490
Unrecoverd pre-2004 costs recover	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unrecoverd post-2003 costs recove	0	11,671	0	0	0	0	0	0	0	0	0	0	0	0	0	0	11,671
Regulatory Liability - OPEB & EMP I	(647)	(184)	(1,210)	(516)	(724)	(1,012)	(318)	(33)	(103)	(409)	(121)	(13)	(13)	(13)	(13)	(15)	(5,343)
Regulatory Asset - Weather Norma	260	5	621	278	995	597	336	303	89	6	4	5	1	1	0	57	3,559
Regulatory Asset - CTGS	9,605	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9,605
Regulatory Asset - RORA/Revenue	75	1	178	80	285	171	96	87	25	2	1	1	0	0	0	16	1,020
Intangible Assets																	
Right of Ways	0	0	2,801	0	101	63	34	0	0	0	0	0	0	0	0	0	2,999
Software	124	35	231	99	139	193	61	6	20	78	23	2	2	2	2	3	1,022
Total Intangible Assets	124	35	3,032	99	240	256	95	6	20	78	23	2	2	2	2	3	4,021
Deferred Charge	1,165	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,165
Working Capital																	0
Inventory	0	0	0	0	1,540	0	513	780	0	0	0	0	0	0	0	93	2,926
Gross operating expenses	229	5,500	352	105	239	183	88	33	16	48	39	29	16	6	1	4	6,890
Income taxes paid	8	2	15	7	24	14	8	7	2	0	0	0	0	0	0	1	89
Total Working Capital	238	5,501	367	111	1,803	197	610	821	18	48	39	30	16	6	1	98	9,904
Total	44,217	14,030	80,735	36,162	131,293	77,531	44,337	40,320	11,563	606	454	691	165	156	15	7,570	489,844

Schedule 3.5																	
Functionalized Contributions Related Distribution Plant																	
Direct Assigned ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	0	0	109,702	0	89,591	0	0	0	0	0	0	0	0	199,293
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	18,278	0	0	0	0	0	0	0	18,278
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10,623	10,623
Total Transmission & Distrib	0	0	0	0	0	109,702	0	89,591	18,278	0	0	0	0	0	0	10,623	228,194
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	0	0	0	0	0	109,702	0	89,591	18,278	0	0	0	0	0	0	10,623	228,194
Intangible Assets																	
Right of Ways	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	109,702	0	89,591	18,278	0	0	0	0	0	0	10,623	228,194
For Allocation																	
	Primary &	Distribution															Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	235,466	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	235,466
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	235,466	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	235,466
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	235,466	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	235,466
Intangible Assets																	
Right of Ways	0	282	0	0	0	0	0	0	0	0	0	0	0	0	0	0	282
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	282	0	0	0	0	0	0	0	0	0	0	0	0	0	0	282
Total	235,466	282	0	0	0	0	0	0	0	0	0	0	0	0	0	0	235,748
Required Allocation Factors																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Primary & Secondary	0.0 %	0.0 %	0.0 %	0.0 %	75.0 %	0.0 %	25.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Facilities	0.0 %	0.0 %	0.0 %	0.0 %	51.2 %	31.8 %	17.1 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %

Schedule 3.5																	
Functionalized Contributions Related Distribution Plant																	
Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	0	176,600	0	58,867	0	0	0	0	0	0	0	0	0	235,466
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	0	0	0	0	176,600	0	58,867	0	0	0	0	0	0	0	0	0	235,466
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	0	0	0	0	176,600	0	58,867	0	0	0	0	0	0	0	0	0	235,466
Intangible Assets																	
Right of Ways	0	0	0	0	144	90	48	0	0	0	0	0	0	0	0	0	282
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	144	90	48	0	0	0	0	0	0	0	0	0	282
Total	0	0	0	0	176,744	90	58,915	0	0	0	0	0	0	0	0	0	235,748
Total																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	0	176,600	109,702	58,867	89,591	0	0	0	0	0	0	0	0	434,759
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	18,278	0	0	0	0	0	0	0	18,278
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10,623	10,623
Total Transmission & Distrib	0	0	0	0	176,600	109,702	58,867	89,591	18,278	0	0	0	0	0	0	10,623	463,660
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	0	0	0	0	176,600	109,702	58,867	89,591	18,278	0	0	0	0	0	0	10,623	463,660
Intangible Assets																	
Right of Ways	0	0	0	0	144	90	48	0	0	0	0	0	0	0	0	0	282
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	144	90	48	0	0	0	0	0	0	0	0	0	282
Total	0	0	0	0	176,744	109,792	58,915	89,591	18,278	0	0	0	0	0	0	10,623	463,942

Schedule 3.6																	
Functionalized Amortization																	
Direct Assigned ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	2,010	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,010
Transmission & Distribution																	
Substations	0	0	0	146	0	0	0	0	0	0	0	0	0	0	0	0	146
Lines and Line Transformers	0	0	2,948	0	0	4,389	0	3,146	0	0	0	0	0	0	0	0	10,483
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	1,224	0	0	0	0	0	0	0	1,224
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	529	529
Total Transmission & Distrib	0	0	2,948	146	0	4,389	0	3,146	1,224	0	0	0	0	0	0	529	12,381
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	2,010	0	2,948	146	0	4,389	0	3,146	1,224	0	0	0	0	0	0	529	14,390
Contributions - Net	0	0	(578)	0	0	0	0	0	0	0	0	0	0	0	0	0	(578)
Total	2,010	0	2,370	146	0	4,389	0	3,146	1,224	0	0	0	0	0	0	529	13,813
For Allocation																	
	Substations 1841 Account	ECC	SCADA	Primary & Secondary	Distribution Facilities	Distribution Lines	Distribution Network	Transportation	Labour	Head Office	Contributions Related Distribution Plant						Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	1,530	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,530
Lines and Line Transformers	0	0	0	8,528	0	0	0	0	0	0	0	0	0	0	0	0	8,528
SCADA and Communications	0	0	775	0	0	0	0	0	0	0	0	0	0	0	0	0	775
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	1,530	0	775	8,528	0	0	0	0	0	0	0	0	0	0	0	0	10,832
Administrative & General	0	44	0	0	0	0	378	1,175	1,693	158	0	0	0	0	0	0	3,448
Gross Fixed Assets	1,530	44	775	8,528	0	0	378	1,175	1,693	158	0	0	0	0	0	0	14,280
Contributions - Net	0	0	0	0	(24)	0	0	0	0	0	(1,067)	0	0	0	0	0	(1,091)
Total	1,530	44	775	8,528	(24)	0	378	1,175	1,693	158	(1,067)	0	0	0	0	0	13,189

Schedule 3.6																	
Functionalized Amortization																	
Required Allocation Factors																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Substations 1841 Account	0.0 %	0.0 %	49.0 %	51.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Primary & Secondary	0.0 %	0.0 %	0.0 %	0.0 %	75.0 %	0.0 %	25.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Facilities	0.0 %	0.0 %	0.0 %	0.0 %	51.2 %	31.8 %	17.1 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Lines	0.0 %	0.0 %	0.0 %	0.0 %	52.6 %	0.0 %	17.5 %	26.7 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	3.2 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	12.3 %	44.9 %	27.9 %	15.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Transportation	6.7 %	0.8 %	17.9 %	7.7 %	20.2 %	35.5 %	7.2 %	0.8 %	3.2 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.1 %	100.0 %
Labour	12.1 %	3.4 %	22.6 %	9.7 %	13.6 %	18.9 %	5.9 %	0.6 %	1.9 %	7.6 %	2.3 %	0.2 %	0.2 %	0.2 %	0.2 %	0.3 %	100.0 %
Head Office	4.9 %	1.4 %	14.6 %	5.2 %	11.4 %	11.8 %	5.2 %	2.6 %	1.2 %	5.0 %	8.9 %	19.3 %	4.1 %	4.1 %	0.1 %	0.4 %	100.0 %
Contributions Related Distribution I	0.0 %	0.0 %	0.0 %	0.0 %	38.1 %	23.7 %	12.7 %	19.3 %	3.9 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	2.3 %	100.0 %
First Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	750	780	0	0	0	0	0	0	0	0	0	0	0	0	1,530
Lines and Line Transformers	0	0	0	0	6,396	0	2,132	0	0	0	0	0	0	0	0	0	8,528
SCADA and Communications	194	0	194	194	65	65	65	0	0	0	0	0	0	0	0	0	775
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	194	0	943	974	6,460	65	2,196	0	0	0	0	0	0	0	0	0	10,832
Administrative & General	295	77	627	320	658	865	254	24	73	137	52	34	10	10	4	6	3,448
Gross Fixed Assets	488	77	1,570	1,294	7,118	929	2,450	24	73	137	52	34	10	10	4	6	14,280
Contributions - Net	0	0	0	0	(419)	(260)	(140)	(206)	(42)	0	0	0	0	0	0	(24)	(1,091)
Total	488	77	1,570	1,294	6,699	669	2,311	(182)	31	137	52	34	10	10	4	(18)	13,189

Schedule 3.6																	
Functionalized Amortization																	
Total																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	2,010	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,010
Transmission & Distribution																	
Substations	0	0	750	926	0	0	0	0	0	0	0	0	0	0	0	0	1,675
Lines and Line Transformers	0	0	2,948	0	6,396	4,389	2,132	3,146	0	0	0	0	0	0	0	0	19,010
SCADA and Communications	194	0	194	194	65	65	65	0	0	0	0	0	0	0	0	0	775
Meters	0	0	0	0	0	0	0	0	1,224	0	0	0	0	0	0	0	1,224
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	529	529
Total Transmission & Distrib	194	0	3,891	1,119	6,460	4,454	2,196	3,146	1,224	0	0	0	0	0	0	529	23,213
Administrative & General	295	77	627	320	658	865	254	24	73	137	52	34	10	10	4	6	3,448
Gross Fixed Assets	2,498	77	4,518	1,439	7,118	5,319	2,450	3,170	1,296	137	52	34	10	10	4	535	28,670
Contributions - Net	0	0	(578)	0	(419)	(260)	(140)	(206)	(42)	0	0	0	0	0	0	(24)	(1,669)
Total	2,498	77	3,941	1,439	6,699	5,058	2,311	2,964	1,254	137	52	34	10	10	4	511	27,001

Schedule 4.0																	
Functionalized Gross Plant																	
Direct Assigned ($,000)																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	57,957	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	57,957
Transmission & Distribution																	
Substations	0	0	998	4,834	0	0	0	0	0	0	0	0	0	0	0	0	5,833
Lines and Line Transformers	0	0	87,799	0	0	109,702	0	89,591	0	0	0	0	0	0	0	0	287,092
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	18,278	0	0	0	0	0	0	0	18,278
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10,623	10,623
Total Transmission & Distrib	0	0	88,798	4,834	0	109,702	0	89,591	18,278	0	0	0	0	0	0	10,623	321,826
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	57,957	0	88,798	4,834	0	109,702	0	89,591	18,278	0	0	0	0	0	0	10,623	379,783
Intangible Assets																	
Right of Ways	0	0	4,543	0	0	0	0	0	0	0	0	0	0	0	0	0	4,543
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	4,543	0	0	0	0	0	0	0	0	0	0	0	0	0	4,543
Total	57,957	0	93,341	4,834	0	109,702	0	89,591	18,278	0	0	0	0	0	0	10,623	384,326
For Allocation	First Allocation				Second Al	Third Allocation											
	Substations 1841 Account	ECC	SCADA	Primary & Secondar...	Distribution Facilities	Distribution Network	Transportation	Labour	Head Office								Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	85,394	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	85,394
Lines and Line Transformers	0	0	0	235,466	0	7,176	0	0	0	0	0	0	0	0	0	0	242,642
SCADA and Communications	0	0	17,353	0	0	0	0	0	0	0	0	0	0	0	0	0	17,353
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	85,394	0	17,353	235,466	0	7,176	0	0	0	0	0	0	0	0	0	0	345,389
Administrative & General	0	1,377	0	0	0	9,699	17,054	12,088	6,349	0	0	0	0	0	0	0	46,568
Gross Fixed Assets	85,394	1,377	17,353	235,466	0	16,875	17,054	12,088	6,349	0	0	0	0	0	0	0	391,957
Intangible Assets																	
Right of Ways	0	0	0	0	282	0	0	0	0	0	0	0	0	0	0	0	282
Software	0	0	0	0	0	0	0	2,688	0	0	0	0	0	0	0	0	2,688
Total Intangible Assets	0	0	0	0	282	0	0	2,688	0	0	0	0	0	0	0	0	2,970
Total	85,394	1,377	17,353	235,466	282	16,875	17,054	14,776	6,349	0	0	0	0	0	0	0	394,927

Schedule 4.0																	
Functionalized Gross Plant																	
Required Allocation Factors																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Substations 1841 Account	0.0 %	0.0 %	49.0 %	51.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Primary & Secondary	0.0 %	0.0 %	0.0 %	0.0 %	75.0 %	0.0 %	25.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Facilities	0.0 %	0.0 %	0.0 %	0.0 %	51.2 %	31.8 %	17.1 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	12.3 %	44.9 %	27.9 %	15.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Transportation	6.7 %	0.8 %	17.9 %	7.7 %	20.2 %	35.5 %	7.2 %	0.8 %	3.2 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.1 %	100.0 %
Labour	12.1 %	3.4 %	22.6 %	9.7 %	13.6 %	18.9 %	5.9 %	0.6 %	1.9 %	7.6 %	2.3 %	0.2 %	0.2 %	0.2 %	0.2 %	0.3 %	100.0 %
Head Office	4.9 %	1.4 %	14.6 %	5.2 %	11.4 %	11.8 %	5.2 %	2.6 %	1.2 %	5.0 %	8.9 %	19.3 %	4.1 %	4.1 %	0.1 %	0.4 %	100.0 %
First Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	41,843	43,551	0	0	0	0	0	0	0	0	0	0	0	0	85,394
Lines and Line Transformers	0	0	0	0	176,600	0	58,867	0	0	0	0	0	0	0	0	0	235,466
SCADA and Communications	4,338	0	4,338	4,338	1,446	1,446	1,446	0	0	0	0	0	0	0	0	0	17,353
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	4,338	0	46,181	47,889	178,046	1,446	60,313	0	0	0	0	0	0	0	0	0	338,213
Administrative & General	115	230	344	344	115	115	115	0	0	0	0	0	0	0	0	0	1,377
Gross Fixed Assets	4,453	230	46,526	48,234	178,160	1,561	60,427	0	0	0	0	0	0	0	0	0	339,590
Intangible Assets																	
Right of Ways	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	4,453	230	46,526	48,234	178,160	1,561	60,427	0	0	0	0	0	0	0	0	0	339,590

Schedule 4.0																	
Functionalized Gross Plant																	
Second Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Administrative & General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gross Fixed Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Assets																	
Right of Ways	0	0	0	0	144	90	48	0	0	0	0	0	0	0	0	0	282
Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Intangible Assets	0	0	0	0	144	90	48	0	0	0	0	0	0	0	0	0	282
Total	0	0	0	0	144	90	48	0	0	0	0	0	0	0	0	0	282
Third Allocation																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission & Distribution																	
Substations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lines and Line Transformers	0	0	0	882	3,220	2,001	1,073	0	0	0	0	0	0	0	0	0	7,176
SCADA and Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission & Distrib	0	0	0	882	3,220	2,001	1,073	0	0	0	0	0	0	0	0	0	7,176
Administrative & General	2,911	633	6,711	4,006	10,154	11,788	3,730	375	863	1,245	839	1,253	288	288	34	74	45,191
Gross Fixed Assets	2,911	633	6,711	4,887	13,375	13,788	4,804	375	863	1,245	839	1,253	288	288	34	74	52,367
Intangible Assets																	
Right of Ways	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Software	326	92	609	260	365	509	160	17	52	206	61	6	6	6	6	8	2,688
Total Intangible Assets	326	92	609	260	365	509	160	17	52	206	61	6	6	6	6	8	2,688
Total	3,237	726	7,319	5,147	13,739	14,297	4,964	392	915	1,450	900	1,259	294	294	40	82	55,055

Schedule 4.0																	
Functionalized Gross Plant																	
Total																	
	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Fixed Assets																	
Production	57,957	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	57,957
Transmission & Distribution																	
Substations	0	0	42,842	48,385	0	0	0	0	0	0	0	0	0	0	0	0	91,227
Lines and Line Transformers	0	0	87,799	882	179,820	111,703	59,940	89,591	0	0	0	0	0	0	0	0	529,735
SCADA and Communications	4,338	0	4,338	4,338	1,446	1,446	1,446	0	0	0	0	0	0	0	0	0	17,353
Meters	0	0	0	0	0	0	0	0	18,278	0	0	0	0	0	0	0	18,278
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10,623	10,623
Total Transmission & Distrib	4,338	0	134,979	53,605	181,266	113,149	61,386	89,591	18,278	0	0	0	0	0	0	10,623	667,215
Administrative & General	3,026	863	7,055	4,350	10,269	11,902	3,845	375	863	1,245	839	1,253	288	288	34	74	46,568
Gross Fixed Assets	65,321	863	142,034	57,955	191,535	125,051	65,231	89,966	19,141	1,245	839	1,253	288	288	34	10,697	771,740
Intangible Assets																	
Right of Ways	0	0	4,543	0	144	90	48	0	0	0	0	0	0	0	0	0	4,825
Software	326	92	609	260	365	509	160	17	52	206	61	6	6	6	6	8	2,688
Total Intangible Assets	326	92	5,152	260	509	599	208	17	52	206	61	6	6	6	6	8	7,514
Total	65,647	955	147,186	58,215	192,044	125,650	65,439	89,983	19,193	1,450	900	1,259	294	294	40	10,705	779,253

Schedule 4.1	
Revenue Requirement Summary	
Operating Expenses	($,000)
Energy Costs	159,717
ECAM Adjustment	(8,641)
Net Energy Costs	151,076
Distribution	9,025
Transmission	1,795
Transmission and Distribution -	2,822
Transmission - OATT	293
General	13,502
Total Operating Expenses	178,513
Amortization	
Amortization Other	436
Amortization - CTGS Reserve V	2,134
Amortization Plant And Equipme	27,001
Total Amortization	29,572
Total Operating Income	208,085
Financing Expenses	
Long-Term Debt	14,742
Short-Term Debt	1,337
Interest Charged To Constructi	(779)
Interest Income	(49)
Amortization of Financing Costs	25
Total Financing Expenses	15,276
Earnings before Income Taxes	25,765
Income Taxes	8,026
Net Earnings	17,739
Gross Revenue Requirement	249,126
OATT Revenue	(2,725)
Other Revenue	(3,051)
Net Revenue Requirement	243,349

Schedule 4.2				
2023 Rate Base ($,000)				
	Open	Close	Mid Year	Basis for Functionalization
Fixed Assets				
Production	28,791	35,633	32,212	Detailed Analysis
Transmission & Distribution				
Substations	57,689	64,903	61,296	Detailed Analysis
Lines and Line Transformers	344,430	378,904	361,667	Detailed Analysis
SCADA and Communications	6,588	6,264	6,426	Detailed Analysis
Meters	12,586	12,041	12,313	Detailed Analysis
Street & Private Area Lights	7,839	8,516	8,177	Detailed Analysis
Total Transmission & Distrib	429,131	470,627	449,879	
Administrative & General	27,728	30,434	29,081	Detailed Analysis
Net Fixed Assets	485,650	536,694	511,172	
Contributions - Net	(24,828)	(26,803)	(25,816)	Detailed Analysis
Future Income Taxes				
Fixed Assets Recovery	(47,849)	(48,770)	(48,310)	Net Plant
ECAM	(3,613)	(3,623)	(3,618)	Purchased Power
Deferred Charges	(376)	(347)	(361)	Generation
Employee Future Benefits	1,922	2,014	1,968	Labour
DSM	0	0	0	Purchased Power
Future Income Tax Liability	413	0	207	Net Plant
Future Income Tax Asset	31,376	28,184	29,780	Net Plant
Other	(11,848)	(12,690)	(12,269)	Net Plant
Tax Adjustments for CAR	0	0	0	Net Plant
Total Future Income Taxes	(29,976)	(35,231)	(32,604)	Net Plant
Deferred Financing Costs	1,235	1,746	1,490	Net Plant
Unrecoverd pre-2004 costs recover	0	0	0	Purchased Power
Unrecoverd post-2003 costs recove	11,655	11,686	11,671	Purchased Power
Regulatory Liability - OPEB & EMP I	(5,276)	(5,411)	(5,343)	Labour
Regulatory Asset - Weather Norma	3,236	3,881	3,559	Net Plant
Regulatory Asset - CTGS	10,672	8,538	9,605	Generation
Regulatory Asset - RORA/Revenue	2,038	1	1,020	Net Plant
Intangible Assets				
Right of Ways	3,007	2,992	2,999	Detailed Analysis
Software	1,056	987	1,022	Detailed Analysis
Total Intangible Assets	4,063	3,979	4,021	
Deferred Charge	1,212	1,119	1,165	Generation
Working Capital				
Inventory	2,304	3,548	2,926	Distribution Lines
Gross operating expenses	6,639	7,140	6,890	O&M
Income taxes paid	88	90	89	Rate Base Excluding WC
Total Working Capital	9,030	10,778	9,904	
Rate Base	468,712	510,977	489,844	

Schedule 5.0																	
Functional Allocator Summary																	
Percent (%)																	
Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Exogenous Allocators																	
Substations 1841 Account	0.0 %	0.0 %	49.0 %	51.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Primary & Secondary	0.0 %	0.0 %	0.0 %	0.0 %	75.0 %	0.0 %	25.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Call Center	0.0 %	0.0 %	5.0 %	0.0 %	3.3 %	3.3 %	3.3 %	0.0 %	0.0 %	5.0 %	20.0 %	40.0 %	10.0 %	10.0 %	0.0 %	0.0 %	100.0 %
ECC	8.3 %	16.7 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
SCADA	25.0 %	0.0 %	25.0 %	25.0 %	8.3 %	8.3 %	8.3 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Allocators Based on Fixed Assets																	
Environmental	50.0 %	0.0 %	0.0 %	2.1 %	0.0 %	47.9 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
T&D Transformers	0.0 %	0.0 %	0.9 %	4.2 %	0.0 %	95.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Distribution Facilities	0.0 %	0.0 %	0.0 %	0.0 %	51.2 %	31.8 %	17.1 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Right of Way Amortization	0.0 %	0.0 %	93.7 %	0.0 %	3.2 %	2.0 %	1.1 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Engineering	0.7 %	0.0 %	21.0 %	8.0 %	26.8 %	16.7 %	9.1 %	13.4 %	2.7 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.6 %	100.0 %
Procurement	0.0 %	0.0 %	20.9 %	7.5 %	27.3 %	17.0 %	9.1 %	13.8 %	2.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.6 %	100.0 %
Distribution Lines	0.0 %	0.0 %	0.0 %	0.0 %	52.6 %	0.0 %	17.5 %	26.7 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	3.2 %	100.0 %
Distribution Network	0.0 %	0.0 %	0.0 %	12.3 %	44.9 %	27.9 %	15.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
T&D Plant	0.0 %	0.0 %	21.1 %	8.0 %	27.0 %	16.8 %	9.1 %	13.5 %	2.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.6 %	100.0 %
Total Plant	8.4 %	0.1 %	18.9 %	7.5 %	24.6 %	16.1 %	8.4 %	11.5 %	2.5 %	0.2 %	0.1 %	0.2 %	0.0 %	0.0 %	0.0 %	1.4 %	100.0 %
Contributions Related Distributi	0.0 %	0.0 %	0.0 %	0.0 %	38.1 %	23.7 %	12.7 %	19.3 %	3.9 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	2.3 %	100.0 %
Amortization	9.3 %	0.3 %	14.6 %	5.3 %	24.8 %	18.7 %	8.6 %	11.0 %	4.6 %	0.5 %	0.2 %	0.1 %	0.0 %	0.0 %	0.0 %	1.9 %	100.0 %
Net Plant	7.3 %	0.1 %	17.5 %	7.8 %	28.0 %	16.8 %	9.4 %	8.5 %	2.5 %	0.2 %	0.1 %	0.1 %	0.0 %	0.0 %	0.0 %	1.6 %	100.0 %
Rate Base Excluding WC	9.1 %	1.8 %	16.6 %	7.5 %	27.1 %	16.0 %	9.2 %	8.3 %	2.4 %	0.1 %	0.1 %	0.1 %	0.0 %	0.0 %	0.0 %	1.6 %	100.0 %
G&T Rate Base	35.4 %	0.0 %	64.6 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Rate Base	9.0 %	2.9 %	16.5 %	7.4 %	26.8 %	15.8 %	9.1 %	8.2 %	2.4 %	0.1 %	0.1 %	0.1 %	0.0 %	0.0 %	0.0 %	1.5 %	100.0 %
Allocators Based on O&M																	
Transportation	6.7 %	0.8 %	17.9 %	7.7 %	20.2 %	35.5 %	7.2 %	0.8 %	3.2 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.1 %	100.0 %
Non-Finance Labour	12.3 %	3.3 %	23.3 %	9.8 %	13.8 %	19.4 %	5.9 %	0.4 %	1.8 %	7.7 %	2.1 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Labour	12.1 %	3.4 %	22.6 %	9.7 %	13.6 %	18.9 %	5.9 %	0.6 %	1.9 %	7.6 %	2.3 %	0.2 %	0.2 %	0.2 %	0.2 %	0.3 %	100.0 %
O&M	3.3 %	79.8 %	5.1 %	1.5 %	3.5 %	2.7 %	1.3 %	0.5 %	0.2 %	0.7 %	0.6 %	0.4 %	0.2 %	0.1 %	0.0 %	0.1 %	100.0 %
Blended Allocators																	
Finance Labour	4.9 %	1.3 %	17.7 %	6.9 %	16.5 %	14.6 %	6.0 %	5.7 %	1.8 %	3.1 %	0.8 %	20.0 %	0.0 %	0.0 %	0.0 %	0.7 %	100.0 %
Customer Service	0.0 %	0.0 %	2.8 %	0.0 %	1.8 %	1.8 %	1.8 %	0.0 %	0.0 %	27.8 %	11.0 %	22.0 %	25.5 %	5.5 %	0.0 %	0.0 %	100.0 %
Head Office	4.9 %	1.4 %	14.6 %	5.2 %	11.4 %	11.8 %	5.2 %	2.6 %	1.2 %	5.0 %	8.9 %	19.3 %	4.1 %	4.1 %	0.1 %	0.4 %	100.0 %

Schedule 5.1																	
Functional Allocator Worksheet																	
Exogenous Allocators																	
Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Substations 1841 Account	0	0	49	51	0	0	0	0	0	0	0	0	0	0	0	0	100
Primary & Secondary	0	0	0	0	75	0	25	0	0	0	0	0	0	0	0	0	100
Call Center	0	0	5	0	3	3	3	0	0	5	20	40	10	10	0	0	100
ECC	8	17	25	25	8	8	8	0	0	0	0	0	0	0	0	0	100
SCADA	25	0	25	25	8	8	8	0	0	0	0	0	0	0	0	0	100

Schedule 5.1																	
Functional Allocator Worksheet																	
Allocators Based on Fixed Assets ($,000)																	
Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Environmental																	0
Wires	0	0	0	4,824	0	109,702	0	0	0	0	0	0	0	0	0	0	114,527
Generation	114,527																114,527
Total	114,527	0	0	4,824	0	109,702	0	0	0	0	0	0	0	0	0	0	229,053
T&D Transformers																	
Substations			998	4,834													5,833
Lines and Line Transformers						109,702											109,702
Total	0	0	998	4,834	0	109,702	0	0	0	0	0	0	0	0	0	0	115,535
Distribution Facilities																	
Substations					0	0	0										0
Lines and Line Transformers					176,600	109,702	58,867										345,169
Total	0	0	0	0	176,600	109,702	58,867	0	0	0	0	0	0	0	0	0	345,169
Right of Way Amortization																	
Transmission Component			100.0 %														58
Distribution Component					51.2 %	31.8 %	17.1 %										4
Total	0	0	58	0	2	1	1	0	0	0	0	0	0	0	0	0	62
Engineering																	
Total Transmission & Distributio	4,338	0	134,979	52,724	178,046	111,148	60,313	89,591	18,278	0	0	0	0	0	0	10,623	660,039
Administrative & General	115	230	344	344	115	115	115	0	0	0	0	0	0	0	0	0	1,377
Right of Ways	0	0	4,543	0	144	90	48	0	0	0	0	0	0	0	0	0	4,825
Total	4,453	230	139,867	53,068	178,305	111,353	60,475	89,591	18,278	0	0	0	0	0	0	10,623	666,241
Procurement																	
Substations	0	0	42,842	48,385	0	0	0	0	0	0	0	0	0	0	0	0	91,227
Lines and Line Transformers	0	0	87,799	0	176,600	109,702	58,867	89,591	0	0	0	0	0	0	0	0	522,559
Meters	0	0	0	0	0	0	0	0	18,278	0	0	0	0	0	0	0	18,278
Street & Private Area Lights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10,623	10,623
Right of Ways	0	0	4,543	0	144	90	48	0	0	0	0	0	0	0	0	0	4,825
Total	0	0	135,184	48,385	176,744	109,792	58,915	89,591	18,278	0	0	0	0	0	0	10,623	647,512
Distribution Lines					176,744		58,915	89,591								10,623	335,872
Distribution Network				48,385	176,744	109,792	58,915										393,836
T&D Plant			139,867	53,068	178,305	111,353	60,475	89,591	18,278	0	0	0	0	0	0	10,623	661,559
Total Plant	65,647	955	147,186	58,215	192,044	125,650	65,439	89,983	19,193	1,450	900	1,259	294	294	40	10,705	779,253
Contributions Related Distribution I	0	0	0	0	176,744	109,792	58,915	89,591	18,278	0	0	0	0	0	0	10,623	463,942
Amortization	2,498	77	3,941	1,439	6,699	5,058	2,311	2,964	1,254	137	52	34	10	10	4	511	27,001
Net Plant																	
Gross Fixed Assets	35,648	588	92,668	38,197	142,520	85,531	48,137	44,535	12,802	781	494	702	163	163	21	8,221	511,172
Contributions - Net	0	0	(10,289)	0	(5,957)	(3,700)	(1,986)	(2,937)	(599)	0	0	0	0	0	0	(348)	(25,816)
Total Intangible Assets	124	35	3,032	99	240	256	95	6	20	78	23	2	2	2	2	3	4,021
Total	35,772	623	85,412	38,296	136,804	82,087	46,246	41,605	12,222	859	517	704	166	166	24	7,876	489,377
Rate Base Excluding WC	43,980	8,529	80,367	36,050	131,030	77,334	44,241	40,279	11,545	558	415	661	149	149	15	7,564	482,866
G&T Rate Base	44,217		80,735														124,952
Rate Base	44,217	14,030	80,735	36,162	131,293	77,531	44,337	40,320	11,563	606	454	691	165	156	15	7,570	489,844

Schedule 5.1																	
Functional Allocator Worksheet																	
Allocators Based on O&M ($,000)																	
Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Transportation	34	4	90	39	102	179	36	4	16	0	0	0	0	0	0	0	506
Non Finance Labour	643	173	1,214	511	722	1,013	309	21	92	401	110	0	0	0	0	2	5,212
Labour	656	186	1,227	524	734	1,026	322	34	104	414	123	13	13	13	13	15	5,416
O&M	5,840	139,970	8,970	2,667	6,093	4,663	2,246	846	403	1,215	990	748	403	159	16	115	175,345

Schedule 5.2																	
Functional Allocator Worksheet, Blended Allocators (2023)																	
Finance Labour																	
FTEs by Function																	
Customer Payments	1.0	Remittance & Collection															
Collection	0.0	Remittance & Collection															
Purchasing	1.0	Procurement															
Payroll	1.0	Labour															
Accounts Receivable (Non-Elect	1.0	Labour															
Accounts Payable	1.0	Procurement															
Total	5.0																
Weighting																	
Allocator	Weight																
Remittance & Collection	20 %																
Procurement	40 %																
Labour	40 %																
Total	100 %																
Allocator Components																	
Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Remittance & Collection												100.0 %					100.0 %
Procurement	0.0 %	0.0 %	20.9 %	7.5 %	27.3 %	17.0 %	9.1 %	13.8 %	2.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.6 %	100.0 %
Non-Finance Labour	12.3 %	3.3 %	23.3 %	9.8 %	13.8 %	19.4 %	5.9 %	0.4 %	1.8 %	7.7 %	2.1 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	100.0 %
Finance Labour	4.9 %	1.3 %	17.7 %	6.9 %	16.5 %	14.6 %	6.0 %	5.7 %	1.8 %	3.1 %	0.8 %	20.0 %	0.0 %	0.0 %	0.0 %	0.7 %	100.0 %
Customer Service																	
Weighting																	
Call Centre	55 %																
Uncollectibles & Damage Claims	20 %																
Meter Reading	25 %																
Total	100 %																

Schedule 5.2																	
Functional Allocator Worksheet, Blended Allocators (2023)																	
Allocator Components																	
Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Call Center	0.0 %	0.0 %	5.0 %	0.0 %	3.3 %	3.3 %	3.3 %	0.0 %	0.0 %	5.0 %	20.0 %	40.0 %	10.0 %	10.0 %	0.0 %	0.0 %	100.0 %
Uncollectibles & Damage Claims													100.0 %				100.0 %
Meter Reading										100.0 %							100.0 %
Average	0.0 %	0.0 %	2.8 %	0.0 %	1.8 %	1.8 %	1.8 %	0.0 %	0.0 %	27.8 %	11.0 %	22.0 %	25.5 %	5.5 %	0.0 %	0.0 %	100.0 %
Head Office																	
Allocation of Head Office Floor Space																	
Function	Floor	Occupancy	Allocator														
Customer Service	1	100 %	Call Center														
Customer Service	2	100 %	Call Center														
Engineering	3	33 %	Engineering														
Information Technology	3	67 %	Labour														
Finance	4	80 %	Finance Labour														
Procurement	4	20 %	Procurement														
Executive	5	100 %	Labour														
Weighting																	
Allocator	Weight																
Call Center	40 %																
Finance Labour	16 %																
Engineering	7 %																
Procurement	4 %																
Labour	33 %																
Total	100 %																
Allocator Components																	
Functional Allocator	Generation	Purchased Power	Transmission	Substations	Primary Lines	Transformers	Secondary Lines	Service Lines	Meter Assets	Meter Reading	Billing	Remittance & Collection	Uncollectibles & Damage Claims	Service Connections	Late Payments	Lighting	Total
Call Center	0.0 %	0.0 %	5.0 %	0.0 %	3.3 %	3.3 %	3.3 %	0.0 %	0.0 %	5.0 %	20.0 %	40.0 %	10.0 %	10.0 %	0.0 %	0.0 %	100.0 %
Finance Labour	4.9 %	1.3 %	17.7 %	6.9 %	16.5 %	14.6 %	6.0 %	5.7 %	1.8 %	3.1 %	0.8 %	20.0 %	0.0 %	0.0 %	0.0 %	0.7 %	100.0 %
Engineering	0.7 %	0.0 %	21.0 %	8.0 %	26.8 %	16.7 %	9.1 %	13.4 %	2.7 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.6 %	100.0 %
Procurement	0.0 %	0.0 %	20.9 %	7.5 %	27.3 %	17.0 %	9.1 %	13.8 %	2.8 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	1.6 %	100.0 %
Labour	12.1 %	3.4 %	22.6 %	9.7 %	13.6 %	18.9 %	5.9 %	0.6 %	1.9 %	7.6 %	2.3 %	0.2 %	0.2 %	0.2 %	0.2 %	0.3 %	100.0 %
Average	4.9 %	1.4 %	14.6 %	5.2 %	11.4 %	11.8 %	5.2 %	2.6 %	1.2 %	5.0 %	8.9 %	19.3 %	4.1 %	4.1 %	0.1 %	0.4 %	100.0 %

Schedule 6.0								
Revenue Requirement 2023								
Account	Description	2023 Trial Balance	Power Supply Demand Related	Labour Related	Vehicle Related	O&M Reporting	Functionalization Method	Power Supply Demand Related (%)
7000	NB Power Assured	62,358	0	0	0	Energy Costs	Purchased Power	0 %
7002	NB Power Capacity	11,772,330	#######	0	0	Energy Costs	Purchased Power	100 %
7007	Wind Energy	17,005,155	3,911,186	0	0	Energy Costs	Purchased Power	23 %
7008	Other Energy	3,440,970	0	0	0	Energy Costs	Purchased Power	0 %
7020	Lepreau Fuel	857,031	0	0	0	Energy Costs	Purchased Power	0 %
7021	Lepreau Cost of Carrying Fuel	156,322	0	0	0	Energy Costs	Purchased Power	0 %
7023	Lepreau Cost of Capital	10,280,858	2,570,215	0	0	Energy Costs	Purchased Power	25 %
7025	Lepreau O&M & Indirect	11,731,572	2,932,893	0	0	Energy Costs	Purchased Power	25 %
7027	Lepreau Decommissioning Charge	1,995,577	498,894	0	0	Energy Costs	Purchased Power	25 %
7029	Lepreau Guarantee Fee	420,205	105,051	0	0	Energy Costs	Purchased Power	25 %
7031	Lepreau Inventory Common Stock	41,077	10,269	0	0	Energy Costs	Purchased Power	25 %
7040	O&M Murray Corner	199,034	0	0	0	Energy Costs	Transmission	N/A
7041	O&M Memramcook	175,464	0	0	0	Energy Costs	Transmission	N/A
7042	Breaker Rental NB Power	183,878	0	0	0	Energy Costs	Transmission	N/A
7043	Reserve 10 Minute Non Spinning	254,446	254,446	0	0	Energy Costs	Purchased Power	100 %
7044	Reserve 30 Minute Non Spinning	206,106	206,106	0	0	Energy Costs	Purchased Power	100 %
7046	NB Power Secure	1,875,379	0	0	0	Energy Costs	Purchased Power	0 %
7049	Capacity Other	(84,450)	(84,450)	0	0	Energy Costs	Purchased Power	100 %
7050	NB Power Firm	85,823,732	0	0	0	Energy Costs	Purchased Power	0 %
7051	NB Power Firm 2	2,579,389	0	0	0	Energy Costs	Purchased Power	0 %
7053	Imbalance Energy	(1,785,808)	0	0	0	Energy Costs	Purchased Power	0 %
7054	Imbalance Premium	556,517	0	0	0	Energy Costs	Purchased Power	0 %
7055	COS Energy Purchase	0	0	0	0	Energy Costs	Purchased Power	100 %
7056	E-Tagging and Scheduling	15,160	0	0	0	Energy Costs	Purchased Power	0 %
7057	Cost of Energy for Sales	(189,222)	0	0	0	Energy Costs	Purchased Power	0 %
7058	IPL Transmission Sch 1, 2, 7	1,167,710	1,167,710	0	0	Energy Costs	Purchased Power	100 %
7090	ECAM Recovery	(8,641,284)	0	0	0	ECAM Adjustment	Purchased Power	0 %
7102	CTGS Build and Serv	0	0	0	0	Energy Costs	Generation	100 %
7103	CTGS Maintenance	0	0	0	0	Energy Costs	Generation	100 %
7105	CTGS Operating	0	0	0	0	Energy Costs	Generation	100 %
7116	CTGS Superintendence	0	0	0	0	Energy Costs	Generation	100 %
7117	CTGS Generation Fuel Bunker	7,171	7,171	0	0	Energy Costs	Generation	100 %
7150	ECC Operations	1,101,838	0	1,040,244	23,370	Energy Costs	ECC	N/A
7180	Training	3,735	0	0	0	Energy Costs	G&T Rate Base	N/A
7202	BGS CT Building and Services	6,532	6,532	17	0	Energy Costs	Generation	100 %
7209	BGS CT Operating	37,378	37,378	30,543	1,317	Energy Costs	Generation	100 %
7210	BGS CT Maintenance	273,329	273,329	251,462	9,877	Energy Costs	Generation	100 %
7216	BGS CT Superintendance	12,726	12,726	12,726	0	Energy Costs	Generation	100 %
7217	BGS CT Fuel - Diesel	420,815	0	0	0	Energy Costs	Generation	0 %
7302	CTGS CT Building and Services	241,491	241,491	63,345	10,754	Energy Costs	Generation	100 %
7303	CTGS CT Maint	122,412	122,412	109,541	4,066	Energy Costs	Generation	100 %
7305	CTGS CT Operating	33,035	33,035	13,700	161	Energy Costs	Generation	100 %
7316	CTGS CT Superintendance	31,502	31,502	25,823	757	Energy Costs	Generation	100 %
7317	CTGS CT Fuel - Diesel	586,870	0	0	0	Energy Costs	Generation	0 %
7350	Insurance	822,556	0	0	0	Energy Costs	G&T Rate Base	N/A
7355	Prop Taxes	255,601	0	0	0	Energy Costs	G&T Rate Base	N/A
7400	Loan Payment Cable Interconnection Fina	3,018,324	0	0	0	Energy Costs	Generation	N/A
7415	MICF Gov Misc Lab & Exp	4,000,839	0	32,702	2,263	Energy Costs	Transmission	N/A
7450	Mech Maint BUDGET	0	0	0	0	Energy Costs	T&D Plant	N/A

Schedule 6.0								
Revenue Requirement 2023								
7510	OATT	292,618	0	288,438	0	Transmission - OATT	Transmission	N/A
7741	Maint Sub, Build, Prop	284,650	0	43,215	3,614	Distribution	Substations	N/A
7745	Maint ROW Line Clearing	2,346,644	0	78,453	15,223	Distribution	Distribution Lines	N/A
7748	Maint Lines	2,155,781	0	829,603	153,359	Distribution	Distribution Network	N/A
7750	Maint Line Devices	87,818	0	31,432	3,504	Distribution	Distribution Network	N/A
7751	Maint Trans	829,483	0	551,129	119,634	Distribution	Transformers	N/A
7754	Maint street lights	79,443	0	64,870	14,453	Distribution	Distribution Network	N/A
7755	Maint UG system	84,858	0	70,133	14,606	Distribution	Distribution Network	N/A
7756	Maint UG service lines	0	0	0	0	Distribution	Distribution Network	N/A
7758	Maint Meters	230,530	0	91,533	16,390	Distribution	Meter Assets	N/A
7760	Communication	223,413	0	118,249	12,180	Distribution	SCADA	N/A
7763	Scada	116,537	0	79,669	7,307	Distribution	SCADA	N/A
7765	Eng	382,828	0	290,033	15,779	Distribution	Distribution Network	N/A
7768	Misc labor and expense	2,203,247	0	0	0	Distribution	Distribution Network	N/A
7780	Training	131,870	0	0	0	Transmission and Distribution - Other	Distribution Network	N/A
7841	Maint sub equip	81,390	0	58,633	6,666	Transmission	Transmission	N/A
7845	Maint ROW Line Clearing	549,234	0	21,049	0	Transmission	Transmission	N/A
7848	Maint Trans Lines	887,966	0	250,020	47,814	Transmission	Transmission	N/A
7850	Maint line devices	73,929	0	66,895	6,947	Transmission	Transmission	N/A
7865	Eng	202,516	0	186,562	15,955	Transmission	Transmission	N/A
7950	Insurance	306,267	0	0	0	Transmission and Distribution - Other	Substations	N/A
7955	Prop Taxes	2,384,260	0	0	0	Transmission and Distribution - Other	Distribution Network	N/A
8000	Super	418,527	0	N/A	N/A	General	Customer service	N/A
8020	CSS	1,107,392	0	N/A	N/A	General	Call Center	N/A
8030	Meter Reading	491,235	0	401,463	N/A	General	Meter Reading	N/A
8040	Training	7,499	0	N/A	N/A	General	Customer service	N/A
8055	Claims	12,461	0	N/A	N/A	General	Uncollectibles & Damage Claims	N/A
8060	Collections	(35,124)	0	N/A	N/A	General	Uncollectibles & Damage Claims	N/A
8065	Uncollectible	180,671	0	N/A	N/A	General	Uncollectibles & Damage Claims	N/A
8100	Super	476,310	0	N/A	N/A	General	Finance Labour	N/A
8110	Admin	812,413	0	314,846	N/A	General	Finance Labour	N/A
Adjustment for cost allocation purposes								
8110	Admin	(541,926)	0	(110,196)	N/A	General	Finance Labour	N/A
8110	Admin	541,926	0	110,196	N/A	General	Billing	N/A
Net adjustment		0	0	0				
8130	Aud, Tax & Prof Services	10,070	0	N/A	N/A	General	Rate Base Excluding WC	N/A
8140	Training	11,404	0	N/A	N/A	General	Finance Labour	N/A
8200	Super	515,894	0	N/A	N/A	General	Labour	N/A
8210	Operational Costs	246,148	0	N/A	N/A	General	Labour	N/A
8240	Training	19,103	0	N/A	N/A	General	Labour	N/A
8300	Super	498	0	N/A	N/A	General	T&D Plant	N/A
8340	Training	2,247	0	N/A	N/A	General	T&D Plant	N/A
8345	HO Prop Exp	224,924	0	N/A	N/A	General	Head Office	N/A
8350	WRSC Prop Exp	705,131	0	N/A	N/A	General	T&D Plant	N/A
8360	East Prop Exp	53,624	0	N/A	N/A	General	T&D Plant	N/A
8365	West Prop Exp	80,329	0	N/A	N/A	General	T&D Plant	N/A
8370	Sub Prop	40,643	0	N/A	N/A	General	T&D Plant	N/A
8400	Super	758,918	0	N/A	N/A	General	Rate Base Excluding WC	N/A
8415	Donations	140,199	0	N/A	N/A	General	Labour	N/A
8440	Training	1,346	0	N/A	N/A	General	Rate Base Excluding WC	N/A
8500	Super	439,896	0	N/A	N/A	General	Rate Base Excluding WC	N/A
8510	Regulation	866,718	0	N/A	N/A	General	Rate Base Excluding WC	N/A

Schedule 6.0								
Revenue Requirement 2023								
8540	Training	9,077	0	N/A	N/A	General	Rate Base Excluding WC	N/A
8600	Super	3,651,118	0	N/A	N/A	General	Labour	N/A
8602	Insurance	84,846	0	N/A	N/A	General	Total Plant	N/A
8603	Legal	114,428	0	N/A	N/A	General	Labour	N/A
8605	Future Benefits	269,658	0	N/A	N/A	General	Labour	N/A
8606	Supplementary Retirement Pensi	165,311	0	N/A	N/A	General	Labour	N/A
8607	Prop Taxes	237,915	0	N/A	N/A	General	Labour	N/A
8613	Directors' Fees	511,423	0	N/A	N/A	General	Labour	N/A
8614	Gen Admin	208,043	0	N/A	N/A	General	Labour	N/A
8615	Gen Admin - Parent	639,000	0	N/A	N/A	General	Labour	N/A
8620	Environmental	3,047	0	N/A	N/A	General	Labour	N/A
8640	Training	19,340	0	N/A	N/A	General	Labour	N/A
6603	Interest During Const (Equity)	(313,424)	0	N/A	N/A	Interest Charged To Construction	Rate Base	N/A
6604	Interest During Const (Debt)	(465,535)	0	N/A	N/A	Interest Charged To Construction	Rate Base	N/A
6611	Interest Income Misc	(48,812)	0	N/A	N/A	Interest Income	Rate Base	N/A
9000	Interest 2051 3.397%	1,358,800	0	N/A	N/A	Long-Term Debt	Rate Base	N/A
9002	Interest 2031 8.92%	1,790,896	0	N/A	N/A	Long-Term Debt	Rate Base	N/A
9003	Interest 2027 8.625%	1,293,750	0	N/A	N/A	Long-Term Debt	Rate Base	N/A
9004	Interest 2038 6.054%	3,632,400	0	N/A	N/A	Long-Term Debt	Rate Base	N/A
9005	Interest 2058 4.148%	1,659,200	0	N/A	N/A	Long-Term Debt	Rate Base	N/A
9006	Interest 2061 4.915%	1,462,800	0	N/A	N/A	Long-Term Debt	Rate Base	N/A
9007	Interest 2053 5.203%	934,402	0	N/A	N/A	Long-Term Debt	Rate Base	N/A
9008	Interest 2025 7.57%	1,135,500	0	N/A	N/A	Long-Term Debt	Rate Base	N/A
9009	Interest 2061 4.915%	1,474,500	0	N/A	N/A	Long-Term Debt	Rate Base	N/A
9100	Other Interest	1,336,713	0	N/A	N/A	Short-Term Debt	Rate Base	N/A
9200	Amortization Finance Costs Tem	24,888	0	N/A	N/A	Amortization of Financing Costs	Rate Base	N/A
9400	Amortization	27,001,358	0	N/A	N/A	Amortization Plant And Equipment	Amortization	N/A
9412	Amortization CTGS reserve variance	2,134,453	0	N/A	N/A	Amortization - CTGS Reserve Variance	Generation	N/A
9415	Amortization - Lepreau Writedo	93,400	0	N/A	N/A	Amortization Other	Purchased Power	N/A
9425	Amortization - Developed Softw	280,940	0	N/A	N/A	Amortization Other	Labour	N/A
9427	Amortization - ROW and Easemen	62,072	0	N/A	N/A	Amortization Other	Right of Way Amortization	N/A
9600	Income Tax	2,770,526	0	N/A	N/A	Income Taxes	Rate Base	N/A
9602	Future Income Tax Expense	5,255,346	0	N/A	N/A	Income Taxes	Rate Base	N/A
Total Net Earnings		17,738,776	0	N/A	N/A	Net Earnings	Rate Base	N/A
6241	Service Connections	(467,914)	0	N/A	N/A	Other Revenue	Service Connections	N/A
6260	Late Payment Charges	(623,171)	0	N/A	N/A	Other Revenue	Late Payments	N/A
6605	Misc Revenue	(491,584)	0	N/A	N/A	Other Revenue	Primary & Secondary	N/A
6606	Accrued Revenue Adjustment	(1,457,840)	0	N/A	N/A	Other Revenue	Rate Base	N/A
Pole Revenue		(10,914)	0	N/A	N/A	Other Revenue	Primary & Secondary	N/A
7500	Transmission Access	10,744,185	0	N/A	N/A	OATT Revenue	Transmission	N/A
7502	Scheduling Service	287,552	0	N/A	N/A	OATT Revenue	Transmission	N/A
7503	Wind Regulation and Load Follo	34,640	0	N/A	N/A	OATT Revenue	Transmission	N/A
7504	Reactive Supply and Voltage Co	262,202	0	N/A	N/A	OATT Revenue	Transmission	N/A
7505	Energy Imbalance OATT	435,075	0	N/A	N/A	OATT Revenue	Transmission	N/A
7508	Non-Capital Support Charge	66,373	0	N/A	N/A	OATT Revenue	Transmission	N/A
6340	Transmission Access	########	0	N/A	N/A	OATT Revenue	Transmission	N/A
6342	Scheduling Service	(364,536)	0	N/A	N/A	OATT Revenue	Transmission	N/A
6343	Regulation and Load Following	(34,639)	0	N/A	N/A	OATT Revenue	Transmission	N/A
6344	Reactive Supply and Voltage Co	(318,618)	0	N/A	N/A	OATT Revenue	Transmission	N/A
6345	Energy Imbalance OATT	(437,766)	0	N/A	N/A	OATT Revenue	Transmission	N/A
6347	Residual Uplift	9,821	0	N/A	N/A	OATT Revenue	Transmission	N/A
6348	Non-Capital Support Charge	(289,108)	0	N/A	N/A	OATT Revenue	Transmission	N/A

Schedule 6.1														
Plant In Service 2023														
		Fixed Assets			Accumulated Amortization			WIP			Net	Annual		
Account	Name	Open	Close	Year	Open	Close	Year	Open	Close	Year	Fixed Assets	Amortization	Presentation Header	Basis for Functionalization
1101	Prod Power Plant Land	2,261,810	2,261,810	2,261,810	0	0	0	0	0	0	2,261,810	0	Production	Generation
1102	Prod Power Plant Build & Structure	310,364	5,992,700	3,151,532	(134,977)	(871,923)	(503,450)	304,082	(0)	152,041	3,502,941	101,479	Production	Generation
1103	Prod Pumphouse Elect Equip	0	0	0	225,849	225,849	225,849	0	0	0	(225,849)	0	Production	Generation
1104	Prod Pumphouse Mech Equip	0	0	0	(22,559)	(22,559)	(22,559)	0	0	0	22,559	0	Production	Generation
1105	Prod Boiler Plant Equip	(0)	(0)	(0)	4,066,984	3,937,973	4,002,478	(0)	(0)	(0)	(4,002,478)	(0)	Production	Generation
1107	Prod Turbine & Aux Equip	(28,440)	0	(14,220)	4,187,763	4,101,847	4,144,805	(0)	(0)	(0)	(4,159,025)	(2,052)	Production	Generation
1109	Gas Turbine & Aux Equip	37,109,600	37,600,204	37,354,902	8,977,457	9,305,073	9,141,265	338,409	0	169,205	28,044,432	986,169	Production	Generation
1113	Prod Elect Equip Plant & Yard	0	0	0	453,302	453,302	453,302	0	0	0	(453,302)	0	Production	Generation
1115	Prod Misc Power Plant Equip	0	0	0	313,443	313,443	313,443	0	0	0	(313,443)	0	Production	Generation
1135	Prod Shop Equip	0	0	0	607	607	607	0	0	0	(607)	0	Production	Generation
1139	Prod River Pumphouse Build	0	0	0	(7,327)	(7,327)	(7,327)	0	0	0	7,327	0	Production	Generation
1201	Prod Borden Power Plant Land	43,567	43,567	43,567	0	0	0	0	0	0	43,567	0	Production	Generation
1202	Prod Borden Build & Structures	821,494	856,959	839,227	219,263	266,680	242,971	0	(0)	(0)	596,255	47,416	Production	Generation
1209	Prod Borden Gas Turbine & Aux Eq	13,669,920	13,918,259	13,794,090	6,638,100	7,490,575	7,064,338	6,920	0	3,460	6,726,292	852,475	Production	Generation
1215	Prod Borden Misc Equip	320,116	328,012	324,064	209,447	228,404	218,925	0	0	0	105,139	18,958	Production	Generation
1301	ECC Land	20,470	20,470	20,470	0	0	0	0	0	0	20,470	0	Administrative & General	ECC
1315	Prod ECC Misc Power Plant Equip	201,817	201,817	201,817	142,914	148,121	145,518	0	0	0	56,300	5,207	Production	Generation
1355	ECC UG Cables	0	0	0	0	0	0	0	0	0	0	0	Production	Generation
1379	ECC Build	1,315,401	1,397,982	1,356,691	155,563	199,249	177,406	3,361	0	1,681	1,177,605	43,685	Administrative & General	ECC
1740	Dist Substation Land	4,506	4,506	4,506	0	0	0	0	0	0	4,506	0	Substations	Substations
1741	Dist Substation Equip Build & Struc	4,656,554	4,992,092	4,824,323	520,788	590,918	555,853	(0)	29	15	4,268,455	145,694	Substations	Substations
1744	Dist Land	5,467	5,467	5,467	0	0	0	0	0	0	5,467	0	Substations	Substations
1748	Dist OH Conductors	123,519,202	131,600,441	127,559,821	30,918,348	28,212,959	29,565,653	3,710	5,649	4,679	97,989,489	4,490,008	Lines and Line Transformers	Primary & Secondary
1749	Dist Poles & Fixtures	89,918,960	96,177,321	93,048,140	24,783,782	23,692,994	24,238,388	(0)	79,912	39,956	68,769,796	3,571,514	Lines and Line Transformers	Primary & Secondary
1750	Dist Line Control Devices	10,390,479	10,421,741	10,406,110	3,586,796	3,943,050	3,764,923	(0)	(0)	(0)	6,641,187	366,295	Lines and Line Transformers	Primary & Secondary
1751	Dist Tranformers	86,872,434	98,619,381	92,745,907	28,631,447	31,574,914	30,103,180	(15)	(15)	(15)	62,642,742	3,542,894	Lines and Line Transformers	Transformers
1752	Dist Transformer Installations	16,386,622	17,526,383	16,956,503	3,530,257	4,248,041	3,889,149	(0)	(0)	(0)	13,067,354	846,129	Lines and Line Transformers	Transformers
1753	Dist Service Lines	84,609,098	90,256,037	87,432,567	42,493,502	45,434,807	43,964,155	(0)	(0)	(0)	43,468,413	3,103,856	Lines and Line Transformers	Service Lines
1754	Dist Street & Yard Lights	9,629,331	10,309,297	9,969,314	1,739,255	1,731,069	1,735,162	(0)	(0)	(0)	8,234,152	517,407	Street & Private Area Lights	Lighting
1755	Dist UG Conductors	4,330,951	4,573,150	4,452,050	1,749,132	1,848,858	1,798,995	0	0	0	2,653,056	99,726	Lines and Line Transformers	Primary & Secondary
1756	Dist UG Service Lines	2,144,074	2,172,205	2,158,140	1,282,925	1,325,225	1,304,075	0	0	0	854,065	42,300	Lines and Line Transformers	Service Lines
1757	Dist UG System Street Lights	653,789	653,789	653,789	705,246	716,492	710,869	0	0	0	(57,080)	11,245	Street & Private Area Lights	Lighting
1758	Dist Meters	16,221,658	16,511,150	16,366,404	6,269,278	7,275,006	6,772,142	(0)	(0)	(0)	9,594,262	1,080,183	Meters	Meter Assets
1759	Dist Meter Installations	1,771,718	2,050,983	1,911,351	(861,611)	(754,073)	(807,842)	0	0	0	2,719,193	143,351	Meters	Meter Assets
1760	Dist Communications System	15,158,556	15,608,246	15,383,401	8,781,589	9,475,380	9,128,485	(0)	(0)	(0)	6,254,917	693,791	SCADA and Communications	SCADA
1761	Dist Eng Test & Survey Equip	10,900	10,707	10,804	(339,599)	(339,097)	(339,348)	0	0	0	350,152	739	Administrative & General	Distribution Network
1762	Dist Tools & Stores Equip	1,547,472	1,769,508	1,658,490	681,152	767,170	724,161	0	0	0	934,329	113,441	Administrative & General	Distribution Network
1763	Supervisory Scada System	1,969,367	1,969,367	1,969,367	1,757,920	1,838,664	1,798,292	0	0	0	171,075	80,744	SCADA and Communications	SCADA
1777	Dist General Property Land	329,731	329,731	329,731	0	0	0	0	0	0	329,731	0	Administrative & General	Head Office
1778	Dist General Prop Build Office	5,705,460	6,333,560	6,019,510	2,673,282	2,829,538	2,751,410	0	107,095	53,548	3,214,552	158,098	Administrative & General	Head Office
1779	Dist General Property Build District	7,874,759	8,185,504	8,030,131	1,808,157	1,988,678	1,898,417	0	0	0	6,131,714	264,191	Administrative & General	Distribution Network
1780	Office Equip	251,267	595,913	423,590	50,892	111,827	81,360	0	2,853	1,427	340,804	65,984	Administrative & General	Labour
1781	Transportation Equip	16,441,087	17,666,575	17,053,831	7,510,710	8,495,841	8,003,276	0	0	0	9,050,556	1,175,009	Administrative & General	Transportation
1784	Computer Hardware	3,029,505	3,503,008	3,266,257	983,582	1,455,843	1,219,712	594,757	61,774	328,265	1,718,279	821,784	Administrative & General	Labour
1785	Computer Software	7,042,279	9,754,076	8,398,178	1,623,181	2,063,361	1,843,271	95,486	1,388,760	742,123	5,812,784	805,047	Administrative & General	Labour
1786	Marketing & Transition	0	0	0	0	0	0	0	0	0	0	0	Administrative & General	Labour
1840	Trans Substation Land	565,767	565,767	565,767	0	0	0	26,675	0	13,338	552,430	0	Substations	Transmission
1841	Trans Substation Equip, Build & St	79,868,556	90,919,995	85,394,275	22,198,941	23,366,911	22,782,926	5,098,303	8,059,728	6,579,015	56,032,334	1,529,675	Substations	Substations 1841 Account
1842	Road & Trails	73,263	73,263	73,263	21,083	22,460	21,772	73,263	0	36,632	14,860	1,377	Lines and Line Transformers	Transmission
1844	Trans Land	432,597	432,597	432,597	0	0	0	0	0	0	432,597	0	Substations	Transmission
1846	Road & Trails	0	0	0	(0)	(0)	(0)	(73,263)	0	(36,632)	36,632	0	Lines and Line Transformers	Transmission
1847	Trans Towers	878,834	878,834	878,834	804,953	822,705	813,829	0	0	0	65,005	17,752	Lines and Line Transformers	Transmission
1848	Trans OH Conductors	56,539,317	57,559,514	57,049,415	18,796,366	18,374,166	18,585,266	0	7,204	3,602	38,460,547	1,796,943	Lines and Line Transformers	Transmission
1849	Trans Poles & Fixtures	26,618,980	27,097,002	26,857,991	8,575,976	9,365,508	8,970,742	0	26,500	13,250	17,873,999	1,044,260	Lines and Line Transformers	Transmission
1850	Trans Line Control Devices	2,721,233	2,827,225	2,774,229	944,451	1,027,723	986,087	0	0	0	1,788,141	87,388	Lines and Line Transformers	Transmission
1855	Trans UG Cables	0	0	0	0	0	0	0	0	0	0	0	Lines and Line Transformers	Transmission
1877	Trans General Property Land	165,586	165,586	165,586	0	0	0	0	0	0	165,586	0	Lines and Line Transformers	Transmission
Subtotal PPE		734,385,479	794,741,698	764,563,589	247,647,612	257,276,255	252,461,934	6,471,688	9,739,488	8,105,588	503,996,067	28,670,165		
3200	Material & Supply Line Hardwar	5,383,637	8,968,492	7,176,065	0	0	0	0	0	0	7,176,065	0	Lines and Line Transformers	Distribution Network
3205	PST Material & Supply Line Har	0	0	0	0	0	0	0	0	0	0	0	Lines and Line Transformers	Distribution Network
3210	COGP Line Hardware	0	0	0	0	0	0	0	0	0	0	0	Lines and Line Transformers	Distribution Network
3212	COGP LH Price Variance	0	0	0	0	0	0	0	0	0	0	0	Lines and Line Transformers	Distribution Network
3215	COGP Other	0	0	0	0	0	0	0	0	0	0	0	Lines and Line Transformers	Distribution Network
3217	COGP Other Price Variance	0	0	0	0	0	0	0	0	0	0	0	Lines and Line Transformers	Distribution Network
3220	Material Quantity Variance	0	0	0	0	0	0	0	0	0	0	0	Lines and Line Transformers	Distribution Network
3305	HRLY Clearing	0	0	0	0	0	0	0	0	0	0	0	Lines and Line Transformers	Distribution Network
Subtotal Inventory		5,383,637	8,968,492	7,176,065	0	0	0	0	0	0	7,176,065	0		
WIP Adjustment		0	0	0	0	0	0	0	0	0	(0)	0	Lines and Line Transformers	Distribution Network
Total Fixed Assets		739,769,117	803,710,190	771,739,653	247,647,612	257,276,255	252,461,934	6,471,688	9,739,488	8,105,588	511,172,132	28,670,165		

Schedule 6.2							
Contributions & Intangible Assets (2023)							
Contributions		Gross					
Account	Name	Open	Close	Change	lid Year		
4500	Contributions - New Services	27,633,145	30,593,274	2,960,130	29,113,209		
4503	Contributions - Extensions	573,341	573,341	0	573,341		
4510	Refundable Contributions	383,238	359,680	(23,559)	371,459		
4505	Contributions - Other	16,408,452	16,409,526	1,074	16,408,989		
4500	Contributions - EV Chargers	350,530	350,530	0	350,530		
Total Gross		45,348,706	48,286,351	2,937,645	46,817,529		
		Accumulated Amortization					
		Open	Close	Change	lid Year	Basis for Functionalization	
4501	Amortization Contributions	14,670,324	15,031,308	360,984	14,850,816	Contributions Related Distribution Plant	
4501	Amortization Contributions	5,831,178	6,408,775	577,596	6,119,976	Transmission	
4501	Amortization Contributions	19,118	43,270	24,152	31,194	Distribution Facilities	
Total Accumulated Amortization		20,520,620	21,483,353	962,732	21,001,986		
	Retirements not appearing on I/S			706,075		Contributions Related Distribution Plant	
		Total Net					
		Open	Close	Change	lid Year	Basis for Functionalization	
	Distribution	13,919,400	16,494,986	2,575,586	15,207,193	Contributions Related Distribution Plant	
	Transmission	10,577,274	10,000,752	(576,523)	10,289,013	Transmission	
	EV Chargers	331,412	307,260	(24,152)	319,336	Distribution Facilities	
	Total Net	24,828,086	26,802,998	1,974,912	25,815,542		
Intangible		Gross					
Account	Name	Open	Close	Change	lid Year	Presentation Header	Basis for Functionalization
3580	ROW Distribution	282,000	282,000	0	282,000	Right of Ways	Distribution Facilities
3580	ROW Transmission	4,519,693	4,566,642	46,949	4,543,168	Right of Ways	Transmission
3585	CIS and EPS	2,683,013	2,693,829	10,816	2,688,421	Software	Labour
Total Gross		7,484,706	7,542,471	57,765	7,513,588		
		Accumulated Amortization					
Account	Name	Open	Close	Change	lid Year	Presentation Header	Basis for Functionalization
3582	ROW Distribution	82,034	85,954	3,920	83,994	Right of Ways	Distribution Facilities
3582	ROW Transmission	1,712,930	1,771,083	58,153	1,742,007	Right of Ways	Transmission
3586	CIS and EPS	1,627,154	1,706,686	79,532	1,666,920		
Total Accumulated Amortization		3,422,118	3,563,723	141,605	3,492,920		
		Total Net					
Account	Name	Open	Close	Change	lid Year	Presentation Header	Basis for Functionalization
3580	ROW Distribution	199,966	196,046	(3,920)	198,006	Right of Ways	Distribution Facilities
3580	ROW Transmission	2,806,763	2,795,559	(11,203)	2,801,161	Right of Ways	Transmission
3585	CIS and EPS	1,055,859	987,143	(68,716)	1,021,501	Software	Labour
Total Net		4,062,588	3,978,748	(83,839)	4,020,668		

Schedule 6.3	
Standard Lists	
Rate Classes	Allocators
Residential	1CP - Input
Residential (S)	1CP - Input Firm
Farm	1CP - Transmission
General Service 1	1CP - Distribution Primary
General Service 1 (S)	3CP - Input
Small Industrial	3CP - Input Firm
Large Industrial	3CP - Transmission
Lights	3CP - Distribution Primary
Unmetered	NCP - Distribution Primary
	NCP - Distribution Secondary
Functions	3NCP - Distribution Primary
Generation	3NCP - Distribution Secondary
Purchased Power	Energy - Input
Transmission	Sites
Substations	Sites - Distribution Primary
Primary Lines	Sites - Distribution Secondary
Transformers	Sites - Mass Market
Secondary Lines	Service Lines
Service Lines	Meter Assets
Meter Assets	Meter Reading
Meter Reading	Billing
Billing	Remittance & Collection
Remittance & Collection	Service Connection Revenue
Uncollectibles & Damage Claims	Penalty Revenue
Service Connections	Lighting Direct Assign
Late Payments	MECL Generation
Lighting	MECL Purchases
	Primary System
	Distribution Transformers
	Secondary System