EPCOR Electricity Distribution Ontario Inc.

Cost of Service Application
EB-2022-0028
May 27, 2022

Exhibit 1 – Administrative Documents

PROVIDING MORE

Contents

CERTIFICATION OF EVIDENCE

The undersigned, being EPCOR Electricity Distribution Ontario Inc. ("EEDO") Chief Executive Officer, Susannah Robinson hereby certifies for and on behalf of EPCOR Electricity Distribution Ontario Inc that:

1. I am a senior officer of EPCOR Electricity Distribution Ontario Inc.

2. This certificate is given pursuant to Chapter 1 of the Ontario Energy Board's (the "Board") Filing Requirements for Filing Requirements For Electricity Distribution Rate Applications dated December 16, 2021; and

3. The evidence submitted in support of EEDO's Application for rates effective on January 1, 2023 filed with the Board is accurate, consistent and complete to the best of my knowledge.

4. The distributor has processes and internal controls in place for the preparation, review, verification and oversight of the account balances being disposed.

5. The distributor has not deviated from the Small Utility Filing Requirements (Dec. 16, 2021 version).

6. The documents filed in support of EEDO's above referenced application do not include any personal information (as that phrase is defined in the Freedom of Information and Protection of Privacy Act), that is not otherwise redacted in accordance with rule 9A of the OEB's Rules of Practice and Procedure.

DATED this 27th day of May, 2022.

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Susannah Robinson
Chief Executive Officer
EPCOR Electricity Distribution Ontario Inc.

1.0 Administrative Documents

1.2 Application Summary & Overview

EPCOR Electricity Distribution Ontario Inc. ("EEDO") is pleased to present its Cost of Service application for rates effective January 1, 2023. This application consists of the following Exhibits and Excel models as evidence to support this application.

- Exhibit 1: Administrative Documents
- Exhibit 2: Rate Base and Distribution System Plan
- Exhibit 3: Customer and Load Forecast
- Exhibit 4: Operating Expenses
- Exhibit 5: Cost of Capital and Capital Structure
- Exhibit 6: Revenue Requirement and Revenue Deficiency/Sufficiency
- Exhibit 7: Cost Allocation
- Exhibit 8: Rate Design
- Exhibit 9: Deferral and Variance Accounts

- EEDO_2023 Benchmarking Forecast Model.
- EEDO_2023 Cost Allocation Model
- EEDO_2023 Test Year Income Tax PILs Work Form
- EEDO_2023 Revenue Requirement Work Form
- EEDO_2023 RTSR Work Form
- EEDO_2023 Load Forecast Model
- EEDO_2023 LRAMVA Workform
- EEDO_2023 DVA Continuity Schedule
- EEDO_2023 COS Checklist
- EEDO_2023 Filing Requirements Chapter 2 Appendixes
- EEDO_2023 Filing Requirements Chapter 5 Appendix
- EEDO_2023 Demand Data Model
- EEDO_2023 GA Analysis Workform
- EEDO_2023 Tariff Schedule & Bill Impact Model

All documents have been submitted to the OEB via the RESS on-line portal. The application along with all supporting evidence will also be posted on the utility's website and customers informed of the filing via social media and bill notification once the application is accepted by the Ontario Energy Board (OEB).

1.2.1 Application Summary

The applicant is EPCOR Electricity Distribution Ontario Inc. ("EEDO"), an electricity distribution company owned by EPCOR Utilities Inc. ("EUI"), based out of Edmonton, Alberta. In decision and order EB-2017-0373/0374, the Ontario Energy Board approved the sale of the shares of Collus PowerStream Corp. to EPCOR Utilities Inc. with the sale formally closing on October 1, 2018.

EUI other Ontario operations include EPCOR Natural Gas Limited Partnership, located with operations centres in Aylmer and Kincardine, provided natural gas to a growing customer market..

For the purpose of this application, the LDC is referred to as "EEDO" consistently. The corporation remains the same corporate entity before and after the sale of its shares, with the only change being an amendment to the name.

EEDO serves approximately 18,500 mostly residential and commercial electricity customers in the Towns of Collingwood, Stayner, Creemore and the village of Thornbury. EPCOR, an Ontario corporation with operations centre located in Collingwood, Ontario, carries on the business of owning and operating electricity distribution facilities under Electricity Distribution License ED-2002-0518.

EEDO last appeared before the OEB with a cost of service rebasing application for 2013 rates in the EB-2012-0116 proceeding. In decision and order EB-2017-0373/0374, the Ontario Energy Board approved a deferral of the rate rebasing period for five years from the October 1, 2018 date of closing of the sale of the shares of the company to EPCOR.

Since the finalization of the Share Purchase agreement, EEDO has invested nearly $12M in capital infrastructure in the communities it serves and has transitioned from a locally owned LDC to become a trusted community partner, strong corporate citizen while continuing to reliably provide power.

EEDO is able to leverage the benefits of a financially strong, established company to provide added benefits to a local LDC through improved standards and processes, oversight, health and safety and technology. In preparation of this application, EEDO not only engaged directly with customers for input on strategic priorities, but also took into account what we learn on a daily basis while talking to our customers.

This application is the curation of customer & employee engagement, health and safety prioritization, operational excellence and continuous improvement.

EEDO continues to prioritize electricity distribution investment for both customer growth and life cycle replacement work, while preparing for the future technologies as part of this application.

- 45% of the distribution revenue that EEDO collects from customers will be invested directly in capital to improve and upgrade the grid (which is an increase from 29% previously)
- 30% will be used to safely operate and maintain the existing infrastructure
- 25% will be used to implement and monitor health and safety programs, meet billing & regulatory obligations and infrastructure financing and accounting requirements

As it has been ten years since the previous filing, there are multiple factors which have contributed to changes in revenue requirements, including customer growth, inflation, aging infrastructure, financing and operating costs along with increased health and safety, regulatory and equipment standards that EEDO is expected to meet or exceed.

The following sections provide additional detail on the key elements of this application along with reference to where further detail and explanation can be located.

1.2.2 Revenue Requirement

Refer to Exhibit 6 – Revenue Requirement for further detail and analysis.

EEDO is proposing a service revenue requirement for the 2023 Test Year of $10,208,496. The revenue requirement reflects an increase of $3,448,043 or 51% from the $6,760,453 approved in 2013 (EB-2012-0116). This represents an annual increase of approximately 4%. Customer impacts have been mitigated as there has also been a 17% increase in customer count and an 11% increase in projected consumption over the 10 year period.

Table 1.2-1 below highlights the main drivers of revenue requirement and the change from the previous cost of service application.

Table 1.2-1

Summary of Changes in Revenue ($)

	Driver	A **2013 Board Approved**	B **2023 Test Year**	C **Variance**	D **Total % Change**	E **Annual % Change**
1	OM&A Expenses	4,585,160	6,530,315	1,945,155	42%	4%
2	Depreciation	940,212	1,688,100	747,888	80%	6%
3	Taxes/Other Expenses	67,958	25,600	-42,358	-62%	-9%
4	Deemed Interest Expense	461,552	778,865	317,313	69%	5%
5	Return on Equity (ROE)	705,571	1,185,616	480,045	68%	5%
6	**Service Revenue Requirement**	**6,760,453**	**10,208,496**	**3,448,043**	**51%**	**4%**
7	Revenue Offsets	-480,405	-792,010	-311,605	65%	5%
8	**Base Revenue Requirement**	**6,280,048**	**9,416,486**	**3,136,438**	**50%**	**4%**

The increase is driven by an increase of $1,945,155 in OM&A costs which reflect general inflation of approximatly16%[1], an increase in customers serviced of approximately 17%. The increase in depreciation is driven by an increase in the proposed rate base of $14,583,922 (additional asset investment driven by customer growth, aging infrastructure and cost inflation, offset by a decrease

[1] Cumulative of inflation factors for incentive rate setting under price cap IR 2011 – 2020, using 1.5% for 2020.

in working capital). The decrease in income taxes reflects tax loss carryforwards that EEDO is anticipating to utilize in 2023. The increase in cost of capital is increase in ratebase offset by a lower weighted average cost of capital.

As EEDO's projected distribution revenue requirement is below $10M, a materiality threshold of $10,000 has been used to explain variances throughout this application.

1.2.3 Load Forecast Summary

Refer to Exhibit 3 – Customer and Load Forecast for further detail and analysis.

EEDO engaged Elenchus Research Associates ("Elenchus") to complete the 2023 Test Year load forecast. Elenchus provided forecasts by rate class for: consumption and demand (if applicable); and the number of customers and connections. The sales and energy forecast utilized actual data from January 2012 to December 2021. Forecasts were provided both with and without the impact arising from Conservation and Demand Management ("CDM") programs.

EEDO's load forecast relies on a multivariate regression methodology for weather-sensitive classes: Residential, GS<50 kW, and GS>50 kW. Monthly consumption, is used as the dependent variable in the multivariate regressions. Independent variables considered for each class model are are as follows:

- Weather
  - Heating Degree Days ("HDD") and Cooling Degree Days ("CDD")
- Economic
  - Gross Domestic Product ("GDP")
  - Employment levels measured by Full Time Equivalents ("FTEs")
- Time Trend
  - Monthly trend variable incrementing by 1 each month. The value begins at 1 in January 2012 and reaches 144 in December 2023
- Calendar Binary
  - 12 monthly binary variables equal to 1 in the month associated with the observation and 0 in all other months

- Seasonal Binary
  - Spring binary variable equal to 1 in March, April, and May and 0 in all other months
  - Fall binary variable equal to 1 in September, October, and November and 0 in all other months
  - Shoulder binary variable equal to 1 in the Spring and Fall months and 0 in all other months
- Number of Days
  - The number of days in the month
  - The number of "Peak Days" (non-holiday weekdays) in the month
- Number of Customers
- Other
  - COVID binary and COVID/Degree Day interaction variables
  - Binary 2012 variable covering the first 6 months of 2012

The load forecast approved in EEDO's last Cost of Service application (EB-2012-0116), was based on a methodology which modeled total purchases and allocated forecast purchases to rate classes. EEDO has more detailed consumption data than was available prior to the 2013 Cost of Service so the methodology has evolved to forecast metered consumption separately for each rate class.

The forecasted change in mid-year customer count from 2013-2023 is detailed below in Table 1.2-2.

Table 1.2-2 - Load Forecast Summary

	Rate Class	A 2013 Board Approved	B 2023 Test Year	C Variance	D % Change
Customer/Connection Count					
1	Residential	14,233	17,012	2,779	20%
2	GS < 50 kW	1,717	1,833	116	7%
3	GS > 50 kW	117	127	10	8%
4	Street Light	3,045	3,318	273	9%
5	USL	30	30	0	0%
6	**Total**	**19,142**	**22,319**	**3,177**	**17%**
kWh					
7	Residential	117,956,589	137,646,072	19,689,483	17%
8	GS < 50 kW	47,173,865	44,991,441	-2,182,424	-5%
9	GS > 50 kW	116,404,810	131,924,542	15,519,732	13%
10	Street Light	2,165,737	1,242,766	-922,971	-43%
11	USL	403,504	396,233	-7,271	-2%
12	**Total**	**284,104,505**	**316,201,055**	**32,096,550**	**11%**
kW from Applicable Classes					
13	GS > 50 kW	342,409	325,120	-17,289	-5%
14	Street Light	6,285	3,496	-2,789	-44%
15	**Total**	**348,694**	**328,616**	**-20,078**	**-6%**

1.2.4 Rate Base and Distribution System Plan (DSP)

Refer to Exhibit 2 – Rate Base for further detail and analysis.

EEDO's Distribution System Plan documents EEDO's asset management processes and capital expenditure plan for the 2023-2027 period that responds to our customer vision for a cost effective, responsive and reliable electricity service delivered through a resilient system that can continue to meet climate change impacts. To support this customer driven vision, EEDO has developed a plan that renews its assets, improves system performance through technology & innovation and betters the customer experience from connection to outage management.

Major drivers of the DSP include:

System Renewal: Based on a health condition assessment, EEDO will replace poorly conditioned pole lines, municipal station equipment and power delivery equipment in order to maintain the expected level of reliability. The condition assessment is more cost effective than simply basing on asset age.

Outage Management: Despite EEDO's best efforts to maintain a reliable system, the service is still subject to unplanned outages from events like storms where trees fall onto power lines causing a faulted condition. Customer feedback during these outages and through its recent survey has demonstrated a desire to resolve these outages faster, and to provide more timely information.

To improve system reliability, EEDO plans to deploy smart devices such as line sensors and remotely controllable switches to more quickly locate a fault and remotely restore customers. This is a more cost effective and safe response as it will reduce the amount of time spent in the field searching for the fault.

Customer Experience: While EEDO's online outage map provides information where customers can retrieve real time information around where an outage is and when it may be restored, EEDO plans to implement solutions whereby outage information is pushed to customers in real time. The communication may be in the form of text or email, whereby the customer will be able to respond with any information they may have such as pictures of failed electrical equipment.

System Performance: Customer feedback has indicated that our customers want to continue to participate in the opportunities surrounding distributed energy resources such as electric vehicle integration and distributed renewable energy. To prepare for this grid evolution, EEDO has been implementing grid technology solutions such as a digital model of our system that permits for advanced analytics. This technology will be essential to maintain safety and reliability with the complexities introduced by EV charging behaviours and exported energy from batteries and solar PV.

To further support this, EEDO has developed a plan to continue to upgrade, modify and keep secure these grid technology solutions in order to maintain pace with the growing distributed energy resources.

EEDO's application includes a forecasted rate base of $34,226,778 for the 2023 Test Year. This represents an increase of $14,583,925 from the $19,642,856 thousand approved rate base in the previous rate application. The following table details the derivation of respective rate bases.

Table 1.2-3 - Summary of Changes in Rate Base ($000's)

		A **2013 Test**	B **2023 Test**	C **Variance $**	D **Variance %**
1					
2	Opening Balance, January 1	15,254	29,877	14,623	96%
3	Closing Balance, December 31	15,857	32,333	16,475	104%
4	**Net Fixed Assets (average)**	15,556	**31,105**	**15,549**	**100%**
5					
6	Controllable Expenses	4,585	6,556	1,971	43%
7	Cost of Power	29,473	35,066	5,593	19%
8	Working Capital Base	34,059	41,622	7,563	22%
9	Working Capital Rate %	12.0%	7.5%	-4.5%	-38%
10	**Working Capital Allowance**	4,087	**3,122**	**(965)**	**-24%**
11					
12	**Total Rate Base**	19,643	**34,227**	**14,584**	**74%**

(Source: Exhibit 2, Section 2.1.1)

EEDO is proposing a capital plan for the 2023 Test Year of $4,295,838. This is a $2,322,630 increase from the $1,973,208 thousand capital plan previously approved for 2013. Proposed Expenditures by type, including System Access, System Renewal, System Service and General Plant are as in Table 1.2-4 below. The Distribution System Plan included in Exhibit 2 provides additional details on EEDO's proposed capital plan.

Table 1.2-4

Proposed 2023 Test Year Capital Expenditures and 2013 Board Approved ($)

		A	B	C	D	E
	Category	**2013 Board Approved**	**2023 Test Year**	**Change**		**Annualized % Change**
				$	**Percent**	
1	System Access	75,500	601,079	525,579	696%	23%
2	System Renewal	1,475,708	2,066,743	591,035	40%	3%
3	System Service	40,000	1,372,616	1,332,616	3332%	42%
4	General Plant	382,000	255,400	-126,600	-33%	-4%
5	**Total**	**1,973,208**	**4,295,838**	**2,322,630**	**118%**	**8%**

(Source: Exhibit 2, Distribution System Plan)

1.2.5 Operations, Maintenance and Administration Expense (OM&A)

Refer to Exhibit 4 – Operating Expenses for further detail and analysis.

EEDO's 2023 Test Year OM&A costs are forecast to be $6,530,315, which represents an increase of $1,945,155 from its' 2013 Board Approved amount, or equivalent to an increase at an annualized rate of 3.6%.

Table 1.2-5 Proposed 2023 Test Year Capital Expenditures and 2013 Board Approved ($)

Description	2013 OEB Approved	2023 Test Year	Variance	Annualized % Change
Operations & Maintenance	2,073,000	2,617,272	544,272	2.6%
Billing & Collecting	993,862	1,109,304	151,465	1.1%
Community Relations	138,000	188,553	50,553	3.2%
General & Administrative	1,380,298	2,615,186	1,234,888	6.6%
Total	**4,585,160**	**6,530,315**	**1,945,155**	**3.6%**

(Source: Exhibit 4, Section 4.2.1)

EEDO's OM&A costs and employee structure have varied in the 10 year period between filings. Broadly speaking, the overall increase from 2013 to 2018 can be attributed to several factors including:

- the loss of ability to charge employee costs to the town of Collingwood for administrative services no longer being provided;
- an increase in operations FTEs to keep up with increasing community growth partially offset by
- increased employee time and charges to capital as EEDO focused more employee time on capital work.

2019 General & Administrative costs increased relative to 2018 due to having a full year of shared services being provided from EPCOR affiliates.

2020 Operations & Maintenance costs increased relative to 2019 due to higher labour costs as a result of lower time spent on capital projects primarily due to additional operational time (including overtime) being required related to several storms in the year, lower labour vacancies, and increased contractor costs for substation maintenance.

2021 OM&A decreased relative to 2020 due to higher amounts of employee time spent on capital projects primarily due to completing planning activities late in 2020 and early in 2021 to allow capital work to commence earlier in 2021 as well as having more historically normal weather in 2021 (adverse weather in 2020 resulted in more time being spent on operating activities), partially offset by higher contractor costs as a result of a high point in tree trimming cycle activity. Shared services costs from affiliates were lower due to an allocation error as noted in section 4.4.2.

EEDO believes that the proposed costs for the 2023 Test Year reflects the minimum cost required to operate the utility in a manner that provides the level of service expected by customers while maintaining safe, reliable, and efficient operations. EEDO will continue to seek cost savings and efficiencies to minimize the impacts to ratepayers. The proposed OM&A costs for the 2023 Test Year are aligned with EEDO's expectations for annual costs going forward.

1.2.6 Cost of Capital

Refer to Exhibit 5 – Cost of Capital and Capital Structure for further detail and analysis.

EEDO has submitted cost of capital evidence in Exhibit 5 of this Application consistent with the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* issued December 11, 2009 (the "2009 Report") as well as the Board's direction on the cost of capital for 2022 filings in its letter dated October 28, 2021.[2] No deviations from the Board's cost of capital methodology are contemplated.

Table 1.2.6-1 below identifies the weighted average cost of capital proposed for the 2023 Test Year as well as the rates of return respective of short-term debt and equity. EEDO understands that these rates will be updated once the 2023 cost of capital parameters are issued by the Board. EEDO's long term debt has been calculated based on actual third party debt issuances along with affiliate debt, which has been calculated a top-down internal credit analysis.

Table 1.2-6

Weighted Average Cost of Capital

	Capital Component	A **Ratio**	B **Cost Rate**	C **Return Component (WACC)**
1	Equity	40%	8.66%	3.46%
2	Long-term Debt	56%	3.98%	2.23%
3	Short-term Debt	4%	1.17%	0.05%
4	**Total**	**100%**		**5.74%**

[2] https://www.oeb.ca/sites/default/files/OEB-Ltr-2022-Cost-of-Capital-Update-20211028.pdf

1.2.7 Cost Allocation and Rate Design

Refer to Exhibit 7 – Cost Allocation for further detail and analysis.

EEDO has used the 2022 version of the cost allocation study model and submitted the cost allocation study to reflect 2023 Test Year costs, customer numbers and demand values. The 2023 demand values are based on the weather normalized load forecast used to design rates.

The Board has established what it considered to be the appropriate ranges of revenue to cost ratios which are summarized in Table 7.3-1 below. In addition, Table 7.3-2 also provides EEDO's revenue to cost ratios from the 2013 Cost of Service application, the updated 2023 cost allocation study and the proposed 2023 to 2027 ratios.

The 2023 cost allocation study indicates the revenue to cost ratio for the Street Light and Unmetered Scattered Load classes are outside the Board's acceptable range. For 2023, it is proposed that the ratio for Street Light be decreased to the maximum value of the Board's acceptable range. To maintain revenue neutrality, EEDO proposes to increase revenues from USL and General Service > 50 kW, the two classes with the lowest Revenue to Cost Ratios. The revenue to cost ratios of the General Service > 50 kW and USL classes are within the target range and remain the lowest revenue to cost ratios after the revenue reallocation from Street Light.

Table 1.2-7
Revenue to Cost Ratios

Rate Class	2012 Board Approved	2023 Cost Allocation Study	2023-2027 Proposed Ratios	OEB Target Min to Max	
Residential	101.90%	98.67%	99.22%	85%	115%
GS < 50 kW	94.10%	103.43%	103.43%	80%	120%
GS > 50 kW	95.90%	92.43%	99.22%	80%	120%
Street Light	120.00%	278.61%	120.00%	80%	120%
USL	120.00%	82.67%	99.22%	80%	120%

(Source: Exhibit 7.3 Revenue to Cost Ratios)

1.2.8 Deferral and Variance Accounts

Refer to Exhibit 9 – Deferral & Variance Accounts for further detail and analysis.

EEDO proposes to dispose of a debit of $1,446,929 related to Group 1 RSVA accounts, debit of $916,731 related to Group 2 Variance/Deferral Accounts and a debit of $185,830 of LRAMVA recoveries. This includes carrying charges up to and including December 31, 2022.

Table 1.2-8

DVA Allocations

Rate Class	Group 1 (RPP& Non-RPP)	Group 1 (Non-RPP Only)	Group 2	LRAMVA	Total
Residential	$722,545	($7,335)	$271,929	$0	**$987,139**
GS<50kW	$238,808	($24,659)	$130,047	$74,406	**$418,602**
GS>50kW	$706,437	($173,227)	$517,597	$30,730	**$1,081,537**
Street Lighting	$6,632	($4,385)	($4,208)	$80,806	**$78,855**
USL	$2,115	($1)	$1,367	($122)	**$3,359**
Total	**$1,676,537**	**($209,607)**	**$916,732**	**$185,830**	**$2,569,492**

EEDO is proposing to recover the Group 1 and Group 2 DVA and LRAMVA balances over 24 months due to :

- The change in timing of its rate effective date from May 1 to Jan 1, as previously approved 2020 balances will continue to be applied until May 1, 2023, and;

- The long accumulation of Group 2 balances accounts as EEDO has not rebased since 2013 or completed any supplemental applications to dispose of Group 2 accounts.

EEDO has followed the OEB's guidance as provided by the OEB's Electricity Distributor's Disposition of Variance Accounts Reporting Requirements Report and has not made any adjustments to DVA balances that were previously approved by the Board on a final basis in previous Cost of Service and/or IRM proceedings.

EEDO is requesting two additional Group 2 deferral accounts as part of this application:

- Non-Utility Billing Variance Account ("NBDA"); and
- Recovery of Income Taxes Deferral Account ("RITDA").

EEDO is requesting discontinuation of the following Group 2 DVAs:

Table 1.2-9

DVA Accounts to be Discontinued

Account	Name
1508	Deferred IFRS Transition Costs
1508	Pole Attachment Revenue Variance
1508	Retail Service Charge Incremental Revenue
1508	Other Regulatory Assets - Icon F&G Meter Disposal
1508	Other Regulatory Assets - OEB Cost Assessment Variance
1508	Other Regulatory Assets - Energy East Consultation Costs
1508	Other Regulatory Assets - LPP Variance
1531	REG Capital Deferral Account
1532	REG Capital OM&A Account
1534	Smart Grid Capital Deferral Account
1555	Smart Grid Capital Deferral - Stranded Meters
1557	Meter Cost Deferral Account (MIST Meters)

1.2.9 Bill Impacts

Refer to Exhibit 8 – Rate Design for further detail and analysis.

Residential

- On January 1, 2023 a typical Residential customer using 750 kWh per month will see an increase of $7.40 (20%) in the distribution component of their bill. The total delivery component will increase by $6.73 (14%). The total monthly bill is expected to increase by $6.43 (5%).
- This average residential bill will decrease on May 1, 2023 by approximately $3.55 as certain rate riders related to the previous IRM filing (EB-2021-0020) will expire This will result in a $2.88 (2%) variance compared to existing May 1, 2022 rates. This is due to change of implementation date from the previous May 1 to January 1.

GS<50kW

- On January 1, 2023 a typical GS<50kW customer using 2000 kWh per month will see an increase of $20.76 (25%) in the distribution component of their bill. The total delivery component will increase by $19.22 (18%). The total monthly bill is expected to increase by $18.37 (6%).
- This average GS<50kW bill will decrease on May 1, 2023 by approximately $13.44 as certain rate riders related to the previous IRM filing (EB-2021-0020) will expire This will result in a $4.93 (2%) increase compared to existing May 1, 2022 rates. This is due to change of implementation date from the previous May 1 to January 1.

GS>50kW

- On January 1, 2023 a typical GS>50kW customer using 86,000 kWh and a peak demand of 250kW per month will see an increase of $721.28 (40%) in the distribution component of their bill. The total delivery component will increase by $663.20 (22%). The total monthly bill is expected to increase by $636.59 (4%).
- This average GS>50kW bill will decrease on May 1, 2023 by approximately $728.07 as certain rate riders related to the previous IRM filing (EB-2021-0020) will expire This will

result in a $91.49 (1%) decrease compared to existing May 1, 2022 rates. This is due to change of implementation date from the previous May 1 to January 1.

Street Lighting

- On January 1, 2023 a typical Street Lighting customer using 15,000 kWh with 1000 connections per month will see a decrease of $1,905.74 (27%) in the distribution component of their bill. The total delivery component will decrease by $1,923.38 (26%). The total monthly bill is expected to decrease by $2,193.10 (21%).

- This average Street Lighting bill will decrease on May 1, 2023 by approximately $1,556.54 as certain rate riders related to the previous IRM filing (EB-2021-0020) will expire (specifically the LRAMVA recovery). This will result in a favourable $3,749.67 (36%) decrease compared to existing May 1, 2022 rates. This is due to change of implementation date from the previous May 1 to January 1.

Unmetered Scattered Load (USL)

- On January 1, 2023 a typical USL customer using 150 kWh will see an increase of $1.43 (28%) in the distribution component of their bill. The total delivery component will increase by $1.32 (19%). The total monthly bill is expected to decrease by $1.26 (6%).

- This average USL bill will decrease on May 1, 2023 by approximately $0.69 as certain rate riders related to the previous IRM filing (EB-2021-0020) will expire. This will result in a $0.57 (3%) increase compared to existing May 1, 2022 rates. This is due to change of implementation date from the previous May 1 to January 1.

Table 1.2-10: Customer Bill Impacts per Rate Class

	May-22	Jan-23	Variance (vs. May 22)		May-23	Variance (vs. May 22)	
Residential	$124.73	$131.16	$6.43	5%	$127.61	$2.88	2%
GS <50	$311.94	$330.31	$18.37	6%	$316.87	$4.93	2%
GS >50	$14,634.21	$15,270.80	$636.59	4%	$14,542.73	($91.49)	-1%
Street Light	$10,441.42	$8,248.32	($2,193.10)	-21%	$6,691.75	($3,749.67)	-36%
USL	$22.29	$23.55	$1.26	6%	$22.86	$0.57	3%

1.2.10 Business Planning Assumptions & Business Plan

EEDO has developed business plan that considers customer needs, aligns with public policy, supports operational effectiveness and efficiency and prioritizes financial performance as a utility. The Distribution System Plan (DSP) is the foundational input into the business plan providing the next five years of utility investment priorities. These investments are required to ensure that EEDO will achieve its business plan objectives and the performance measures set by both the OEB and EPCOR itself.

A critical input into the business plan is customer feedback. EEDO has carried out various customer engagements since acquiring the utility in October of 2018. Our customers have told us that their priorities include improved reliability, increased resilience to climate change, and grid modernization. While there is general support for increased investment in these areas, our customers have also told us that they are sensitive to rates.

In response to customer feedback, EEDO has developed a five year investment plan that will prepare our wire and station assets to be able to withstand an increasingly volatile climate that impacts system reliability through severe wind storms and other inclement weather. The plan includes investments in smart devices that will speed EPCOR's ability to fault locate, isolate and restore customers faster. Finally, there will be projects undertaken to upgrade our management systems to improve customer service including increased outage communication, an improved customer portal and Green Button access while setting the conditions for greater customer participation in the form of DER integration through increased real time data access and system integration .

Ministry of Energy (MOE) policy has encouraged LDCs to pursue consolidation opportunities in order to achieve cost synergies among LDCs. EEDO has pursued a business plan to achieve this objective by realizing synergies between our natural gas and electricity LDCs in Ontario. This has both resulted in cost savings for our customers and the ability to implement operational solutions driving innovation, efficiencies and safety through collaboration and shared services.

The planning assumptions and approaches used to develop both the strategic direction of EEDO and its DSP are the following:

a) EEDO's load service requirement will continue to grow at approximately 2% per annum.

b) EEDO may have to build a new municipal station during this 5 year period if certain developments materialize. EEDO's system capacity is sufficient at this point for known developments and 2% load growth so the plan does not include building additional capacity pre-emptively to avoid over building the system. However, such an expansion may be required if additional growth occurs on an actual basis.

c) Before EEDO builds new capacity, it will consider the impact of DER penetration as well as non-wires alternatives that are expected to be more available over the next 5 years.

d) EEDO's customers will continue to adopt DER technology including electric vehicles which will require a modernized and updated grid management system.

e) EEDO will continue to invest into SmartMap as its grid management system grounded in an electrically connected GIS system model.

f) EEDO will need to determine a strategy to address its operations facility capacity limitations within this 5 year period. Options being considered are a purchase of its existing leased accommodations, building and owning a satellite building, or being relieved of its lease agreement with the Town of Collingwood in order to build a new facility.

g) EEDO will continue to be impacted by climate change which will challenge service reliability and resiliency. This will require a continuance of its pole line renewal program to harden the system against severe weather as well as adding smart devices to be improve trouble response times when such events occur.

h) Further integration into EPCOR Distribution & Transmissions Inc's (EDTI) system control center will set the conditions for improved grid management. This is beneficial to our customer base because it will help enable customer driven participation through DER integration.

i) Cyber security will continue to be a growing risk requiring increased investment and system hardening.

j) EEDO will invest in customer engagement tools to improve customer communications during outages.

Each year, EEDO develops an operational plan with a five year outlook. The primary purpose of this plan is to develop goals and measures for both the upcoming year and over the five year period in order to measure our progress against these goals. Planning covers the five focus areas of:

- Health Safety and Environment,
- People,
- Operational Excellence,
- Customer and Stakeholder, and
- Shareholder.

EEDO has included its 2022 operating plan as part of this submission. Achieving this plan will not only help EEDO achieve its regulated scorecard metrics, while continuing to engage with customers and other key stakeholders to plan for the future.

EEDO's first priority is our employee's health and safety. This is the foundational piece to achieving a successful business outcome. This requires a competently trained workforce who believe in the safety first culture. A growing emphasis needs to be placed on Environment, Social and Governance (ESG) metrics which translates to public safety and engagement Re-establishing our culture coming out of the COVID-19 pandemic will be critical in establishing an engaged and innovative work force. Operational excellence describes the way we do things and how we can innovate and continuously improve. These pieces build the foundation to provide value to our customers and stakeholders. It is critical to continue to identify opportunities to engage with customers, to not only ensure that safe and reliable power is provided, but to improve customer service, customer experience while expanding opportunities to connect to the grid through distributed energy resources and evolving technology.

Focus Area: Health Safety and Environment

Vision: Everyone goes home every night heathy

Goals	Performance Measures	
	2022 Measure	5 Year Outlook
Become a procedurally based operation	EEDO references procedures within 100% of Safe Work Plans Tool Developed that makes access to procedures easier when in the field	Any work completed is procedurally based where procedures have been trained on and employees have been deemed competent prior to use
Focus on compliance and competency training status	Training compliance is >90% Zero compliance violations to ESA	Leading indicator reporting culture created and corrective actions are tracked and reviewed regularly
Establish ESG goals in our planning processes	Meet PCB 2022 compliance commitments Implement Green Button	Engage municipalities on contributing to net-zero targets
Develop confidence in the ERS system to report and continuously learn from safety risk	Near misses/hazard IDs > 84 across Ontario Inspections/Observations > 192 across Ontario	Employee and contractor TRIF consistently < 1.00 Leading indicator reporting culture created and corrective actions are tracked and reviewed regularly

Focus Area: People

Vision: Knowledgeable, Capable, Actively Engaged and Inclusive

Goals	Performance Measures	
	2022 Measure	**5 Year Outlook**
Demonstrate we listen to our people and deliver on our commitments	Engagement Committees continue to be a source of joint action	Engagement in the top decile
Smarter use of existing and shared resources	Meeting time to work time ratio for front line kept at < 10% IT tools implemented to combat burnout (ex: virtual collaboration options)	Backup for each position identified and trained to cover off There is never a gap of service due to resource availability
Re-establish EPCOR Ontario culture post pandemic	Successful reintegration and transition to hybrid work culture Seasonal celebrations have engaged participation Low employee turnover rate Pulse engagement survey results	Employees feel supported and comfortable with their work family environment where life challenges can be managed Impact from mental health managed from a short & long term disability perspective
Educate Ontario team on the attributes to diversity and Inclusion	All APfRs have individual goals related to D&I Two D&I workshops held in Ontario	Diversity & Inclusion becomes table stakes in all planning and decision making

Focus Area: Operational Excellence

Vision: Innovative Strides to Continuously Improve

Goals	Performance Measures	
	2022 Measure	5 Year Outlook
Implement optimal capital program delivery model	Meet DSP targets	DSP capital plan is reviewed and updated every year based on asset planning process, and DSP is achieved annually
	Process for capital program governance implemented including a lessons learned process following project completion	Controllable Cost per customer grows at < 2%
	Carry-over capital reduced to <10% of program	IRP developed for and EEDO
	Overspend on capital program <10%	Strong OEB scorecard and benchmarking results for EEDO
	Controllable Cost per customer < $285	
Implement technology road maps for SCADA, GIS, IT/OT and billing	Meet 2022 road map milestones	EEDO are viewed as being ahead of the curve with system and customer technology
Improved emergency preparedness and cyber threat	Mock emergencies drilled in both EEDO	All employees comfortable with Emergency Response protocols
	Meet 2021 cyber security framework requirements	Operation fully compliant to OEB cyber security framework
Implement a shared resources/work strategy for Operations and Engineering	Further integration into EDTI system control	Internal competence exceeds contactor value for core work. Competitive work contracted out to aligned partners

Focus Area: Customer and Stakeholders

Vision: Awareness & Engagement in our role as partner in the utilization of the distribution grid

Goals	Performance Measures	
	2022 Measure	5 Year Outlook
Improved customer experience	Customer focus groups created to solicit feedback (ex. Commercial, social media users) SAIDI < 0.46 (OEB target) Exceed calls answered within 30 sec OEB target	Improved system reliability, resilience and integrity
Define the role we play in the utility of the future	Apply for and participate on select industry work groups	Three innovative modernization customer projects implemented in Ontario (ex: battery energy storage, EV integration)
Improved EPCOR brand in our area of operations of who we are and what we do	Outage communication process refreshed Customer engagement strategy developed and implemented	Customer expectations around communication consistently met or exceeded EPCOR regularly participates in community outreach events

Focus Area: Shareholder Value

Vision: Position the operation for growth while delivering safe and reliable essential services

Goals	Performance Measures	
	2022 Measure	5 Year Outlook
Continue to grow organically in all of our operating areas	Support EV transition activities in EEDO Meet or be below operational expense budgets	3% YOY income growth
Meet all regulatory filing obligations	EEDO RRR and scorecard filings meet deadlines	Strong alignment between budget, rate filings, and DSP

1.3 Administration

1.3.1 Primary Contact for Application

The Applicant's primary EPCOR contact and address for this Application is as follows:

Tim Hesselink
Senior Manager, Regulatory Affairs
EPCOR Electricity Distribution Ontario Inc.
43 Stewart Road
Collingwood, Ontario L9Y 4M7

Telephone:(705) 445-1800 ext. 2274
E-Mail:thesselink@epcor.com

1.3.2 Legal Representation for Application

The Applicant's internal counsel is as follows:

Daniela O'Callaghan
Legal Counsel
EPCOR Utilities Inc.
2000 – 10423 101 Street NW
Edmonton, Alberta T5H 0E8

Telephone:(780) 412-4081
E-Mail:docallaghan@epcor.com

The Applicant's external counsel is as follows:

Richard King
Osler, Hoskin & Harcourt LLP
100 King Street West
1 First Canadian Place
Suite 6200, PO Box 50
Toronto, ON M5X 1B8

Telephone:(416) 862-6626
Fax:(416) 862-6666
E-Mail:rking@osler.com

1.3.3 Applicant's Internet and Social Media Addresses

EPCOR will make a copy of this Application available at the following internet address:

https://www.epcor.com/account-billing/rate-applications/Pages/default.aspx

Confirmation that EEDO has filed an Application and details as to where it can be accessed will also be communicated to customers via a statement included in customers' bills.

EEDO's general website address is as follows:

https://www.epcor.com/Pages/Home.aspx?mylocation=collingwood_ontario

1.3.4 Publication of Notice of Hearing

EEDO is proposing that notices related to this Application appear in the Collingwood Connection newspaper. The Collingwood Connection is an unpaid local publication with an average circulation of approximately 12,000 per week. It is also available online at:

https://www.simcoe.com/collingwood-on/.

1.3.5 Form of Hearing

EEDO requests that, pursuant to Section 34.01 of the OEB's Rules of Practice and Procedure, this proceeding be conducted by way of written hearing. At this time EEDO has made allotments in its budget assuming a written hearing. Should the Board decide to proceed with an oral hearing in this matter, EEDO will respectfully request to amend the forecast to incorporate the incremental consultant, intervenor, OEB costs and legal fees, as well as travel and other expenses related with attendance at and preparation for an oral hearing.

In addition, if the Board determines it will hold an oral hearing EEDO will provide the names of appropriate witnesses (and their curriculum vitae) prior to such oral hearing.

1.3.6 Customer Impacts

This application will impact all customers in EEDO's service territory.

1.3.7 Requested Effective Date - Alignment with Fiscal Year

EEDO currently has a distribution rate annual implementation date of May 1. EEDO requests that the Board implement its Rate Order effective January 1, 2023, allowing rates to be aligned with the fiscal year[3]. In the event that the OEB is not able to provide a Decision and Rate Order in time for EEDO to implement its rates effective January 1, 2023, EEDO requests that the OEB declare EEDO's current rates interim effective January 1, 2023 and approve rate riders to recover any change between current and approved revenue between the implementation date of the OEB's 2023 Rate Order and January 1, 2023.

1.3.8 Methodology Changes

EEDO has included the following methodology changes in this Application:

- Subsequent to EEDO's previous cost of service application for the 2013 year, EEDO converted its financial reporting framework from Canadian GAAP (CGAAP) to IFRS with a transition date of January 1, 2014. As detailed in Appendix 2-Y, there are no material differences in the 2023 revenue requirement between CGAAP and MIFRS.
- In 2020, EEDO converted all billing to a calendar month cycle. Previously residential and GS<50kW customers will billed on a cyclical basis of 28/35 days throughout the month.
- EEDO is proposing a change in the rate implementation effective date from May to January 1 as noted in the section above.

The projections for the 2018 Test Year were prepared in accordance with EEDO's budget process and all processes are in compliance with policies, directives and rules and guidelines from the Ontario Energy Board and other regulators.

[3] Consistent with Chapter 2A Filing Requirements for Electricity Distribution Rate Applications, Section 2.0.6

1.3.9 OEB Directions from Previous Decision or Orders

In EEDO's last cost of service proceeding (EB-2012-0116), the Board included a directive as set out below.

The Board finds that carrying charges should be recorded monthly on the opening principal balance in this deferral account at the Board's prescribed rates. However, the Board finds that it is premature to determine whether the stranded FG meter assets ultimately will attract carrying charges.

The Board notes that in approving the settlement agreement, the extent of its approval regarding this component was limited to the establishment of the deferral account to track the NBV of the stranded assets until such time that the extent of the issue with the FG meters is known. The Board notes that the disposition of Account 1508, Other Regulatory Assets, Subaccount Stranded Assets NBV will be considered at a later date, either in a Collus PowerStream proceeding, or as part of a larger generic proceeding. On disposition of the balance of Account 1508, Other Regulatory Assets, Sub-account Stranded Assets NBV, the account balance will be subject to a review of Collus' costs by the Board or Board findings arising from a generic proceeding, if such a proceeding were to occur. At that time the Board will also consider the disposition of the accumulated interest charges[4].

EEDO is unaware if the generic proceeding referenced above took place and has included the balance in this account, plus carrying charges as part of the Group 2 deferral and variance account request for disposition as evidenced further in Exhibit 9. At this point, carrying charges have been included based on the guidance provided above.

At the date of this submission, EEDO is not aware of any additional Board Directives from any previous Board Decisions and/or Orders that require addressing in this Application.

[4] Collus PowerStream Rate Order, October 24, 2013 page 3 of 17

1.3.10 Conditions of Service

EEDO's current version of its Conditions of Service can be found on its website:

https://www.epcor.com/products-services/power/Pages/conditions-of-service.aspx

EEDO's Conditions of Service were last updated in April 2019 which addressed changes as a result of the OEB's review of customer service rules (EB-2017-0183).

EEDO's Conditions of Service were previously updated in 2014, where they were harmonized as part of a utility collaborative exercise while EEDO was a member of the Cornerstone Hydro Electric Concepts (CHEC). This revision required OEB approval.

EEDO anticipates making adjustments to its conditions of service in 2022 to accommodate recent amendments to the Distribution System Code, but they have not been completed at the time of the filing of this application regarding:

- DER Connections- EB-2021-0117 - effective October 1, 2022
- Net Metering - EB-2022-0152 - effective July 1, 2022

EEDO does not anticipate that these amendments will have a large customer impact.

1.3.11 Conditions of Service Confirmation

EEDO confirms that there are no rates or charges listed in the Conditions of Service or other policies and regulations that are not included in EEDO's rate schedules.

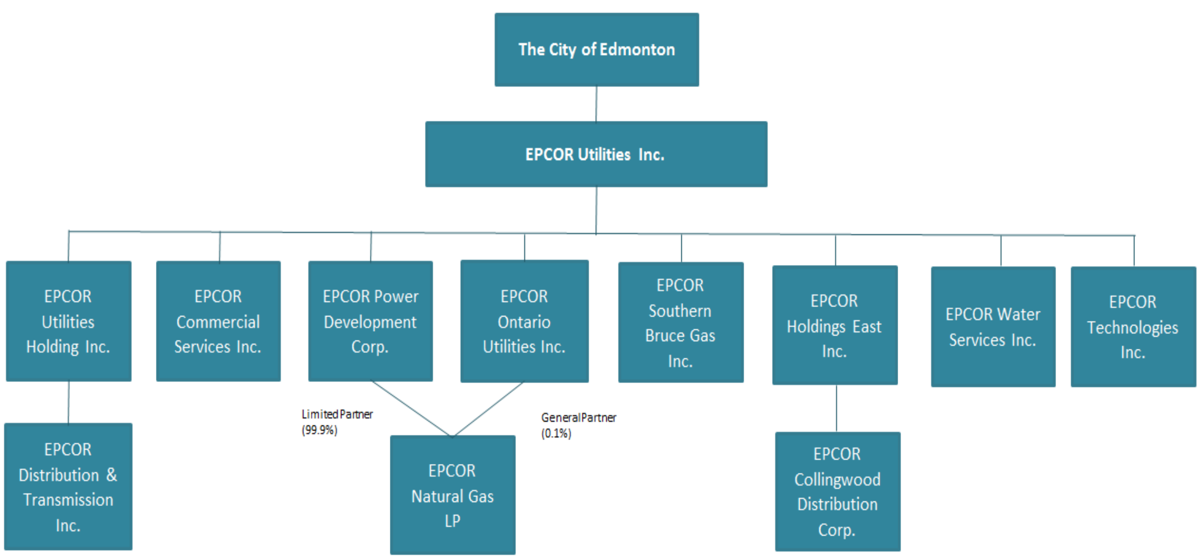
1.3.12 Organizational Structure

EEDO is owned by EPCOR Utilities Inc.(EUI), based out of Edmonton, Alberta. In decision and order EB-2017-0373/0374, the Ontario Energy Board approved the sale of the shares of Collus PowerStream Corp. to EPCOR Utilities Inc. with the sale formally closing on October 1, 2018.

EPCOR Utilities Inc. was incorporated as Edmonton Power Corporation pursuant to the Business Corporations Act (Alberta) on August 28, 1995. On May 8, 1996, Edmonton Power Corporation changed its name to EPCOR Utilities Inc. and, on May 26, 1999, the Corporation amended its Articles of Incorporation to delete the provision restricting the Corporation from offering its securities to the public. The City of Edmonton (the City or the Shareholder) is the sole common shareholder of the Corporation.

Figure 1.3-1

Simplified EPCOR Organizational Chart



EEDO's Board is represented by Directors who are two senior employees of EUI, along with one Director who is independent of EUI. This composite meet the requirements of Section 2.1.2 of the Affiliate Relationships Code for Electricity Distributors and Transmitters.

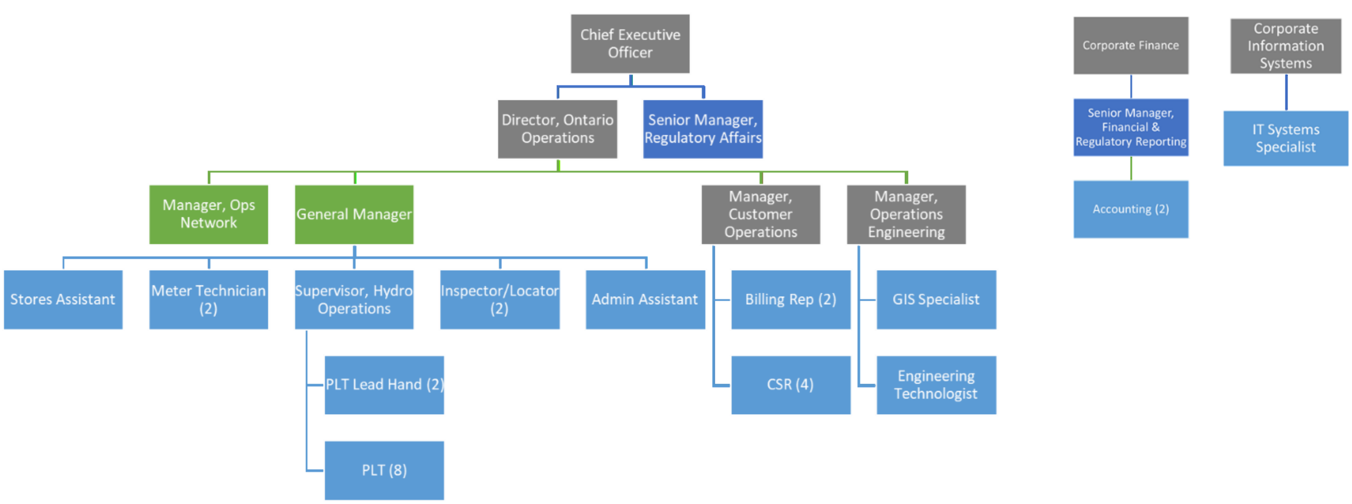
EEDO does not currently have any changes in corporate or operational structure, including any changes in legal organization and control planned

EEDO employs 32 people to ensure the safe and reliable operations of the distribution system. This includes, 10 Powerline Technicians, 2 Metering Technicians, 2 Inspector/Locators, Finance & Administration (Billing, Collections, Customer Service, Accounting, GIS, Engineering) and supporting management.

Further, EEDO also relies on third party consultants and contractors for the maintenance of the distribution system and assistance with meeting regulatory requirements.

Figure 1.3-2

EEDO Organizational Structure



As a member of the EPCOR group of corporations, one of the advantages for EEDO is that it can access and leverage expertise across EPCOR's entities through a shared services model. EEDO has structured its business operations to reasonably and prudently take advantage of economies of scale and scope through the appropriate use of corporate and affiliate services. As such, EEDO receives certain shared services from and is expected to provide certain services to, other members of the EPCOR group.

Further detail and analysis can be found in Exhibit 4.4.1 – Workforce Planning and Exhibit 4.4.2 Share Services and Corporate Cost Allocation.

1.3.13 Requested Approvals and Accounting Orders

EEDO hereby applies to the Ontario Energy Board (the "Board" or the "OEB"), pursuant to section 78 of the Ontario Energy Board Act, 1998 as amended (the "OEB Act") for an Order or Orders approving its proposed electricity distribution rates and other charges, effective January 1, 2023

i. Approval of EEDO's forecasted 2023 Test Year service revenue requirement of $10,208,496 and base revenue requirement of $9,416,686.

ii. Approval to charge distribution rates effective January 1, 2023 to recover a base revenue requirement and revenue deficiency, as detailed in the Revenue Requirement Workform and discussed in Exhibit 6, through applying the proposed rates as set out in the Tariff Schedule & Bill Impact model and Exhibit 8.

iii. Approval of the Distribution System Plan as outlined in Exhibit 2.

iv. Approval of revised Low Voltage Rates as proposed in Exhibit 8.

v. Approval for an adjustment to the Retail Transmission Service Rates approved in the Applicant's 2022 IRM application (EB-2020-0021) as proposed in Exhibit 8.

vi. Approval to continue to charge Wholesale Market Services, Capacity-Based Recovery and Rural Rate Protection charges as approved by the OEB and detailed in Exhibit 8.

vii. Approval to continue the specific Service Charges and Transformer Allowance as previously approved by the OEB and as detailed in Exhibit 8.

viii. Approval of the proposed Loss Factor as detailed in Exhibit 8 and calculated in Chapter 2 Filing Requirements Appendix worksheet App2-R Loss Factors.

ix. Approval of the Rate Riders for a 24-month disposition of the Group 1 Deferral and Variance account balances as at December 31, 2021 along with the projected carrying charges in accordance with the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR – July 31, 2009) as detailed in Exhibit 9.

x. Approval of the Rate Riders for a 24-month disposition of the Group 2 Deferral and Variance account balances as at December 31, 2021 along with the projected carrying charges in accordance with the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR – July 31, 2009) as detailed in Exhibit 9.

xi. EEDO is proposing the following deferral and variance accounts be closed and discontinued from use:

1. 1508-Deferred IFRS Transition Costs
2. 1508-Pole Attachment Revenue Variance
3. 1508-Retail Service Charge Incremental Revenue
4. 1508-Customer Choice Initiative Costs
5. 1508-Other Regulatory Assets - Icon F&G Meter Disposal
6. 1508-Other Regulatory Assets - OEB Cost Assessment Variance
7. 1508-Other Regulatory Assets - Energy East Consultation Costs
8. 1508-Other Regulatory Assets - LPP Variance
9. 1531-REG Capital Deferral Account

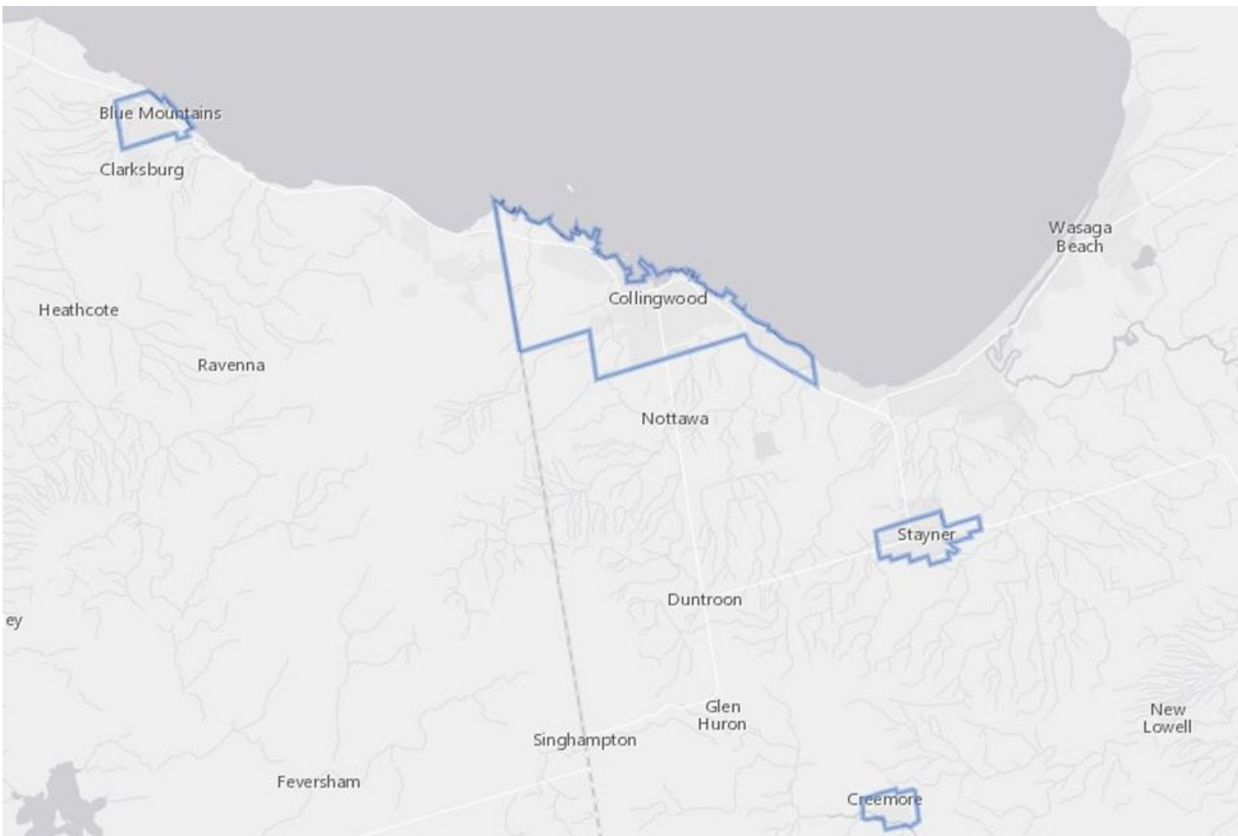
10. 1532-REG Capital OM&A Account
11. 1534-Smart Grid Capital Deferral Account
12. 1555-Smart Grid Capital Deferral - Stranded Meters
13. 1557-Meter Cost Deferral Account (MIST Meters)

xii. EEDO is proposing the following deferral and variance accounts be established and the associated draft accounting orders be approved:

1. Non-Utility Billing Variance Account ("NBDA");
2. Recovery of Income Taxes Deferral Account ("RITDA").

1.4 Distribution System Overview

EEDO is an embedded distributor within Hydro One's service territory and is connected to the grid through Hydro One's Transmission Station feeders. EEDO serves approximately 19,000 mostly residential and commercial electricity customers four communities in Simcoe & Grey Counties: Collingwood, Stayner and Creemore (part of Clearview Township) and Thornbury (part of The Town of the Blue Mountains). EEDO's operations centre is located in Collingwood.



The Town of Collingwood functions as the major commercial centre for northwest Simcoe County and northeast Grey County. It has been identified as a Primary Settlement Area in the Province's Places to Grow Act. The municipality has experienced a significant shift toward tourist-related service industries since the closure of the Collingwood Steamship Lines (CSL) shipbuilding operation in 1986. Other key large manufacturing losses, specifically affecting electricity demand, include the loss of large electricity users such as Magna and Collingwood Ethanol. Today, Collingwood is a major tourist destination for the Greater Toronto Area (GTA). Collingwood is considered a regional hub for recreation, health care, commercial services and various types of employment. It is a prime tourist destination for both summer and winter recreational activities.

Stayner, Creemore and Thornbury are smaller communities with a mix of residential and light general service customers. EEDO is responsible for maintaining distribution and infrastructure assets deployed over 45 square kilometers (including 362 kilometers of overhead lines and underground lines)

EEDO has not had any transmission or high voltage assets deemed by the OEB as distribution assets and there are not any such assets that EEDO is seeking approval for in this application.

1.5 Customer Engagement

Since acquiring the utility in 2018, EEDO has worked to communicate and engage with customers in its distribution area to ensure that customer service and capital investment is prudent, appropriate and aligns with community interests and priorities.

EEDO engages customers and stakeholders in a variety of ways, tailoring engagement to the needs of the topic and the community. It engages with customers and communicates about education, safety, system reliability, billing and its community presence. EEDO is committed to open, transparent communication and consultation with customers through multiple channels and initiatives.

EEDO uses a variety of channels, touchpoints, tools and tactics, as appropriate, to connect with customers and stakeholders, including bill inserts, print advertisements, news media, website updates, surveys and charitable community investments.

The following are examples of the types of customer engagements EEDO has undertaken (additional detail and examples can be found in Table 1-10, following) :

- In advance of planned outages, EEDO notifies customers through advertisements in the local newspaper, phone calls to commercial customers, door hangers where possible, postings on our website and social media.

- Unplanned outages result in the most frequent opportunity to engage with customers. EEDO notifies customers of unplanned outages through the outage map on its website, as well as through interactions on social media. Customer feedback received during these outages assists with refinement of our communication preferences and priorities.

- EEDO conducts customer satisfaction surveys on a periodic basis as part of the balanced Electricity Distributor Scorecard (EDS) and other reporting and regulatory requirements for the OEB. EEDO reviews the survey results to determine if adjustments to corporate programs and strategies are warranted. For surveys performed in 2019 and 2021, EEDO retained RedHead Media Solutions Inc. to conduct the biannual survey and received customer satisfaction index scores of 73% (2019) and 74% (2021) respectively. The final reports from the two most recent surveys have been included as appendixes in this Exhibit.

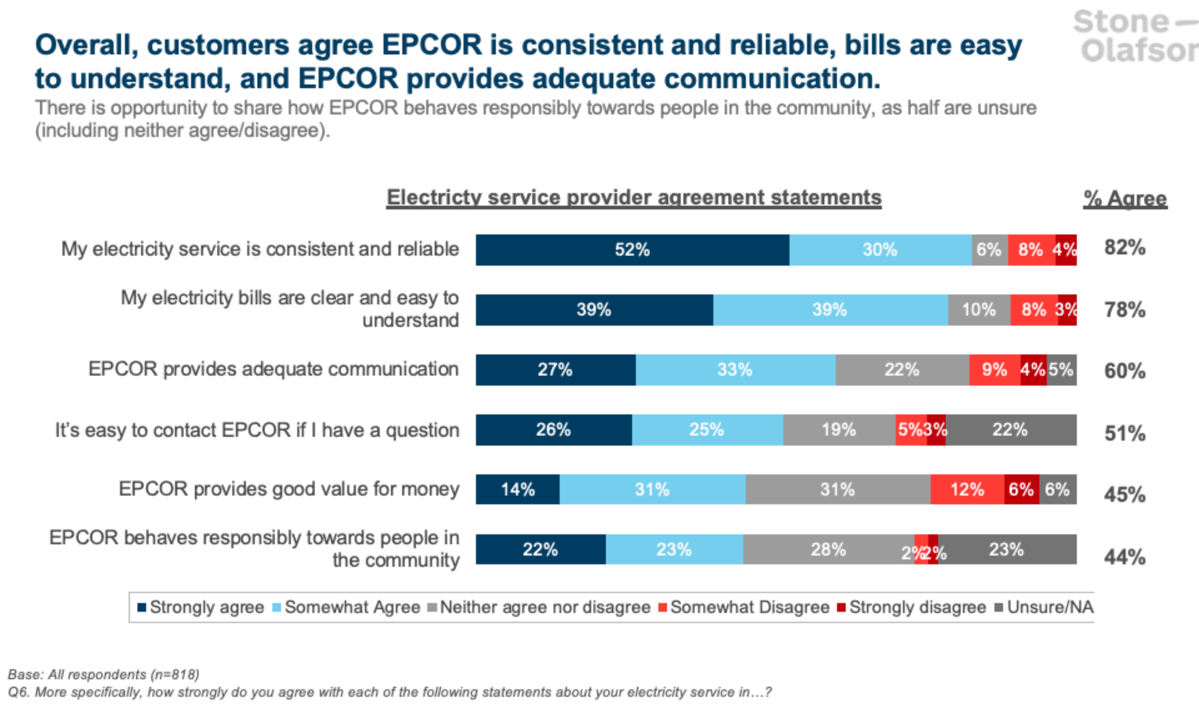
Distribution System Plan Customer Engagement

In developing the DSP included in this application, EEDO undertook a survey to gather feedback from customers in all rate classes. EEDO retained Stone Olafson, a third party research company, to administer the survey in Q4 2021. The survey canvassed a number of key areas including customer satisfaction and priorities related to customer's electricity service. This information was used to determine the level of ratepayer support for EEDO's planned investment position in the DSP that is designed to maintain existing service levels. There were 818 residential and commercial respondents to this survey, providing a margin of error +/- 3.4% 19 times out of 20. The survey participation for this survey was double the number of respondents to the biannual customer service survey required to meet OEB requirements.

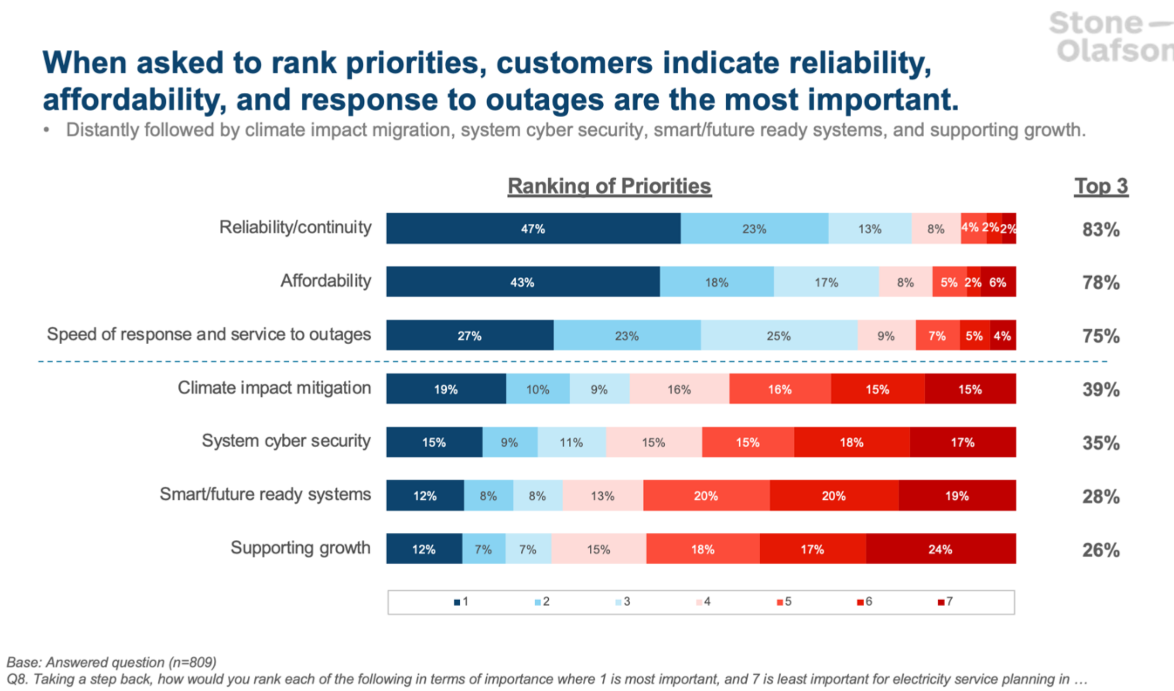
Key findings of the public consultation conducted in 2021, as noted above, are as follows:

There is a high level of awareness that EEDO is responsible for electricity distribution in the community, with 89% unaided, and 95% aided awareness. Customers, therefore, know who to contact with concerns and opinions. The majority (67%) are satisfied with EEDO service, with 16% dissatisfied. Primary reasons for dissatisfaction are service interruptions and cost.

Overall, the vast majority agree EEDO service is consistent, reliable and billing is clear and easy to understand.



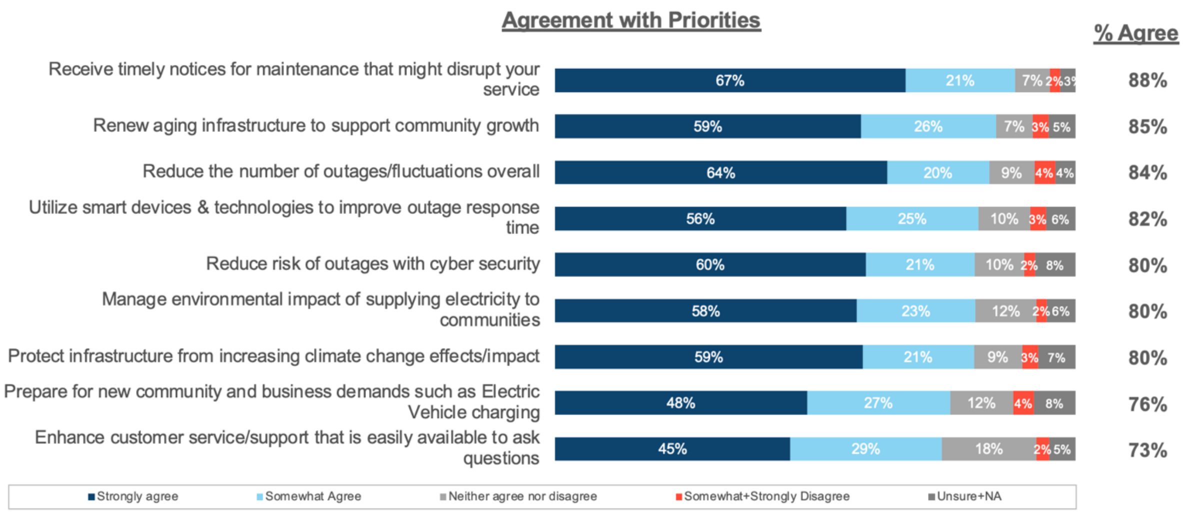
When asked to rank priorities for EEDO, reliability, affordability and fast response times are the top three. These align with EEDO's investment priorities of renewing infrastructure, utilizing smart devices and enhancing grid technology that will help reduce outages, improve communication and make the system more efficient, as outlined in the DSP.



When presented with the proposed planning priorities, there was a high level of agreement among all customers. In fact, the majority of proposed planning initiatives exceeded 50% 'strong agreement.' Customers' top priorities, as noted below, support the DSP objectives of deploying smart devices to help improve response times and communication during outages. In addition, respondents support EEDO's initiatives to upgrade grid technologies to maintain pace with the growing renewable distributed energy resources, such as electric vehicles integration.

Overall customers agree that the proposed priorities are the right ones for EPCOR to address – the majority having more than 50% *strong* agreement.

- Specifically, timely notices for maintenance, renew aging infrastructure, reducing outages, and utilizing smart devices.



Base: All respondents (n=818) Q7. following is a list of considerations that operators look at when supplying electricity to communities. We would like to understand how strongly you agree with each of the following priorities:

Interpreting these questions together, we see that the community is engaged and supportive of strategies that will not only support continuity of service today but also in technology, security and planning for the future.

While cost was ranked second most important to their concerns overall, the majority of community members see this as a contextual decision. When given the option to reduce costs with slight risk to service, maintain status quo or invest slightly more than today for slight improvement, 94% would maintain status quo or higher, with 61% definitively support investing in future improvements. Residential customers were the most supportive of investing and commercial customers just lightly less.

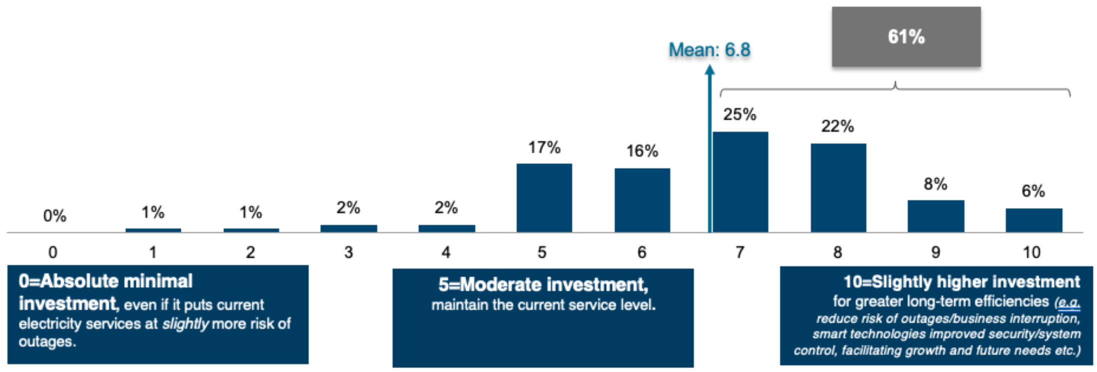
Customer consultation showed that respondents' priorities align with the DSP investment plan priorities with respect to current and future electricity services.

Stone—Olafson

To avoid risk, customers are willing to invest more in these services to allow for longer-term benefits and efficiencies, with very few calling for minimal investments.

Those most likely to be willing to invest are older (55+), believe current rates are fair, male, have no children at home, retired, and have a household income of over $100,000/annually.

Personal Position on Investment Scale



All respondents excluding those who answered "Unsure" (n=734)
Looking ahead to the next several years, in principal, where would you position yourself on the following investment scale?

Table 1.5-1 - Summary of Customer Engagement Activities (Chapter 2 Appendix2-AC_Customer Engagement)

Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
Community Engagement - Town of Collingwood Advisory Committee	This committee provides an ongoing opportunity to discuss community issues relevant to both EEDO and the Town of Collingwood in an effort to educate and discuss industry and local topics	New agendas and topics are brought forward each meeting depending on current events and changes. Action items are determined based on the item. Some actions include rate updates, pandemic response and pandemic measures, capital planning and community event education and alignment.
Community Engagement - Community Events	EEDO engages in sponsorships as a way to build its brand in its service territory. This helps to increase awareness of the services EEDO provides so customers know who to contact for electricity services and assistance. In addition, EEDO uses these opportunities to educate customers on how they can stay safe around utility infrastructure. EEDO and its employees also participate and volunteer in the community and contribute to not-for-profit and charitable organizations, particularly those that align with EEDO's social, environmental and governance values.	EEDO supports the communities where its employees live and work. Some examples of community initiatives it has supported include: Collingwood Collegiate Institute Student Scholarship, local minor baseball, local junior hockey, Downtown Business Improvement Area events, Georgian Triangle Humane Society and Santa Claus Parades, as well as conservation events as community fairs and businesses. EEDO employees also participate in an annual United Way fundraising campaign with EEDO matching employee contributions to support the local chapter of the organization.
Community Engagement - EPCOR Heart + Soul Fund	Through EPCOR's Heart + Soul Fund, just under $30,000 has been invested into 10 organizations that focus on delivering artus, culture, charitable and mental health supports. The Heart + Soul Fund will continue into 2022.	In 2020, EPCOR launched the Heart + Soul Fund to help arts, culture and non-profit sectors impacted by the COVID-19 pandemic. For the past two years, EPCOR has supported local programming that helps organizations build resiliency, uplifts our communities and enables them to continuing to do what they do best: bringing the heart and soul to the communities we serve.
Customer Education - Bill Inserts, Bill Messaging	Bill inserts and messaging provides an opportunity for customers to be made aware of changes in the industry that could impact them. This can include rate changes, pricing optionality, health and safety, conservation and low income support. The regulatory environment is complex and this medium provides an opportunity to proactively inform customers of changes that could impact them.	Every EEDO customer is billed monthly. As such, this continues to be a good avenue to reach all customers. Periodic billing inserts provide current rate information and other important safety considerations. EEDO prepares a communication plan annually to schedule important customer communications allowing for flexibility to address industry changes.
Customer Education - Electrical Safety Awareness & Training	Education and Safety - There is a need for elementary students to understand electrical system hazards	EEDO coordinated in-person safety programs for elementary schools in our service territory to help educate and inform students

Customer Engagement - Surveys Biennial Customer Satisfaction Survey - Residential and Small Business customers	EEDO has engaged RedHead Media to conduct biennial Customer Satisfaction Surveys since 2016 (previously Utility Pulse). The primary objective of the survey is to provide information that supports discussions about improving customer care for residential and small commercial customers. Each response/score is an important indicator/influencer of to determine priorities of investment and staff education. EEDO's Overall Customer Satisfaction Scores has shown continuous improvement: 2016-2017 - 72% of customers are overall satisfied with EEDO's performance and services; 2018-2019 - 73% 2020-2021 - 74% While the results remain positive and demonstrate moderate continuous improvement, areas of customer concern include: reliability, increased communication, customer interaction.	In addition to the reliability concerns address in the Distribution System Plan, EEDO continues to invest and implement ways to improve the customer experience: Outage map: Using SmartMap technology, EEDO launched an outage map that customers can access online to see planned and unplanned outages. Where possible, EEDO will update the map with restoration time and relevant updates. This tool provides customers with a consistent location to look for updates and to help determine the scale of outages. Improved digital experience: EEDO has converted several intake forms from paper to digital available on our website (new service connections/move forms, account applications etc...) Customer Connect: While EEDO's legacy customer portal is expected to be replaced in 2022 to allow for an improved digital experience, the current portal 'Customer Connect' allows customers to access historical data billing information to help address conservation and efficiency options. While Customer Connect has been a helpful tool, an upgrade will allow for easier access and reduce the number of calls and emails from customers as they get setup. UtiliSmart Energy Manager Tool: In advance of the Green Button implementation, EEDO offers the UtiliSmart Energy Manager tool to C&I customers to track, validate and export consumption and demand data in detail. Green Button: EEDO is on track to meet the Ministry of Energy's November 2023 timing for implementation of the Green Button standard to allow customers improved access to account data. Web re-platform: EEDO is undertaking an overhaul of its current website to transfer to an updated platform

Customer Engagement - Surveys Biennial Public Awareness of Safety Survey	Since 2015, EEDO has engaged RedHead Media to conduct its bi-annual survey to assess public awareness of the dangers/risks associated with electricity. The survey compiles data to measure the level of awareness of key electrical safety precautions among the public within the electricity distributor's service territory. Results are based on a telephone survey (Random Digit Dialing) among 400 Members of the General Public,18 years of age or older, within the LDC's geographic service territory. The 2020 survey results show many respondents have good knowledge or have received some information pertaining to the 6 core measurement questions. EEDO's Public Safety Awareness Index Score is 83%.	EEDO follows strict safety measurements making safety to our customers and community its number one priority. Responding to emergency services is also a critical part of its role with customers. EEDO responds immediately to customer concerns of downed power lines, open utility transformers, vehicle accidents involving power equipment and unplanned outages. EEDO educates customers on homeowner responsibilities and safety around utility infrastructure using various communication channels including billing inserts, social media, digital media, local newspapers, radio, events and school presentations. In addition, EEDO participates in public awareness days, such as Emergency Preparedness Week, Fire Prevention Week and Dig Safe Month to increase customer awareness on the importance of safety practices.
Customer Engagement - Surveys In anticipation of this Cost of Service rate application, EEDO conducted an additional customer survey inviting Residential, Small Business and Industrial & Commercial customers to provide feedback to help identify and align priorities to be used in the distribution system plan.	Included questions concerning satisfaction, The specific objectives are to: • Identify overarching and most sensitive areas of how we perform that matters most • Gather feedback on existing or proposed broad areas of performance • Early analysis of rate sensitivity • What to do with the information: Data will inform your decisions on initial prioritization of projects and consideration of performance measures (weighting and categories) A copy of this report has been included in Exhibit 2	Based on the survey, the top "high priority" statements for investment prioritization are: 1. Timely notices for maintenance (communication) 2. Renewing aging infrastructure 3. Reducing outages 4. Utilizing smart devices EEDO customers are in agreement that to avoid risk they support EPCOR investing in these services for longer-term benefits and efficiencies. At minimum, they want to maintain status quo, though more agree with a slight increase in rates if it means improving reliability. EEDO has used this feedback to help shape its DSP and 5-year capital investment plan.

Customer Service - In-Office open to the public Before closing to the public due to the COVID-19 pandemic, EEDO's office was open 5 days a week during business hours where customers could telephone, e-mail or visit and speak to a knowledgeable LDC representative on a variety of topics	a) Front Counter Engagement b) Technical Engagement c) Bill query support - consumption analysis d) Account setup and configuration e) Bill payments f) Customer/developer initiated expansion and construction Knowledgeable customer service representatives engage with EEDO customers on a daily basis through a number of direct customer service interactions – by telephone, email, mail, and face-to-face. Although EEDO continues to identify opportunities to shift services to on-line services, EEDO has been open to provide in person accessible customer service. EEDO averages approximately 15,000 customer calls annually.	Consumer concerns and issues are dealt with immediately by knowledgeable Customer Service Representatives (CSR) over the phone and in-person. Queries regarding service lay-out requests, power outage or partial power are discussed with the Operations Staff. CSR's assist consumers with queries such as understanding the bill and reviewing electricity usage queries. For example, CSR's can print interval data for a specified period and present to customers information showing when their consumption appears irregular (high/low). This assists customers in understanding TOU periods and rates. EEDO management hold weekly team meetings with CSR staff to inform them of changes in the industry and also participate in utility collaborative meetings to further discuss changes and share best practices.
Customer Service - In-Office - Pandemic Response On March 17 2020, EEDO closed its office due to the COVID-19 pandemic and public health guidelines. Customers, contractors and suppliers were not allowed to enter the LDC's building.	In its pandemic response, EEDO closed its doors to the public but shifted to accommodate changes in customer interactions (from in person to increased calls). EEDO has received approximately 1900 additional calls in 2020 and 2021 (13% increase) but has continued to maintain call answered percentages above OEB industry targets. While EEDO continues to receive increased phone calls, customers want to be able to access services on-line and on their own schedule in order to address account changes, bill inquiries and changes in the industry. - Online self-serve option for managing your account and usage; and, - Online self-serve options for requesting services.	As the office remains closed, EEDO has prioritized call answer performance as a customer service target to ensure that staff remain available to address customer concerns and provide options for bill payments, financial support and payment arrangements. Further information regarding improved digital and self-service can be found in the Biennial Customer Satisfaction Survey - Residential and Small Business customers section above

Customer Support - Financial Assistance Programs a) Low-Income Emergency Assistance Program (LEAP) b) Ontario Electricity Support Program (c) Affordability Fund Trust (AFT) (d) COVID-19 Emergency Assistance Program (CEAP) (e) COVID-19 Emergency Assistance Program - Small Business (CEAP-SB)	EEDO provides support through the United Way with the province's Low-income Energy Assistance Program (LEAP). These emergency financial assistance programs are designed to help low-income customers who have difficulty making their electricity bill payments. EEDO actively promotes the Ontario Electricity Support Program (OESP) to customers through bill notifications and email/telephone correspondence. EEDO promoted the Affordability Fund Trust program (2018-2021) assisting approximately 70 customers. Promotion is through social media, bill inserts and EEDO's website. EEDO has promoted the COVID-19 Emergency Assistance Program (CEAP) through social media, EEDO's website as well as mentioning the program to customers when they telephone or e-mail.	EEDO continues to promote financial assistance programs that are available to assist low-income customers through social media, the LDC's website, telephone calls and e-mails as well as bill inserts
Conservation - Participation in conservation programs - Business	Customers have provided clear feedback that they need clear, and up to date, information on the ever-changing conservation programs and initiatives available	While EEDO administered Conservation First Framework and the Save on Energy programs, EEDO was active in its local community through promotion and education of business customers to determine their needs, as well as the programs available for them to participate. Including; energy conservation and the value it provides customers. EEDO remained ahead of the CFF targets. Support was offered to assist customers, identify projects, complete program applications, and implement energy conservation projects.
Customer Collaboration - Customer Demand Work	Customer require new services, service upgrades, increased transformation, service new developments including subdivisions	EEDO will continue to maintain this service, provide digital options for project intake and working with customers to address supply chain issues (i.e. transformers) and low cost installation (through alternate bids)
Customer Collaboration - Engineering Customer Engagement Activities	Engineering staff regularly consult with, listen to and engage customers regarding specific projects such as pole replacements or padmount transformer locations, generation installation and new connections. EEDO also attends the Town of Collingwood development	Some specific examples of customer preference affecting project outcomes: 1. MicroFit Contract management and net metering setup 2. A customer has engaged EPCOR regarding a hydro pole that requires relocation from legacy installation on private property. to accommodate the construction of a deck by customer

	meetings to ensure we are updated on future expansion and growth.	3. A customer has approached EPCOR regarding the relocation one of our an anchor that is located on private property.
Customer Collaboration - Commercial & Industrial consumer interaction - DER	Large customers are looking to implement emerging DER technologies in order to reduce peak demand and save energy. EEDO works with these customers to help efficiently complete projects and navigate the emerging regulatory landscape and technical requirements.	As the regulatory framework evolves through the integration of distributed energy resources, EEDO continues to work with customers on new and emerging technology projects and build internal processes in order to improve project timing. As an embedded distributor, EEDO acts as a liaison between the customer and Hydro One to help navigate requirements and configuration. EEDO has supported the implementation of two large battery energy storage system (BESS) projects in its distribution area that are creating the ability to curtail approximately 7.5MW of demand during peak hours.
Collaboration - Regional Planning Engagements/Hydro One	EEDO regularly participates in: a) IESO regional planning meetings b) Hydro One planning meetings	These meetings provide opportunity to bring forward customer feedback and LDC concerns regarding growth and expansion to ensure any upstream requirements are communicated.

1.6 Performance Management

On March 5, 2014, the Board issued its report on "Performance Measurement for Electricity Distributors: A Scorecard Approach." The report set out the Board's policies on the measures that are to be used to assess a distributor's effectiveness and improvement in achieving customer focus, operational efficiencies, public policy responsiveness, and financial performance to the benefit of existing and future customers.

1.6.1 OEB Scorecard

EEDO maintains copies of its OEB scorecards on its website for public review and which can be accessed on distributor's website:

https://www.epcor.com/products-services/power/Pages/electricity-distributor-scorecard.aspx

1.6.2 Pacific Economics Group (PEG) Forecasting Model

EEDO has included the Pacific Economics Group (PEG) forecasting excel model for the test year which provides a forecast of its efficiency assessment for the purposes of providing the OEB with a directional indication of efficiency. The 2022 version (posted September 21, 2021) was used as the 2023 version was not yet published. (EEDO_2023 Benchmarking Forecast Model).

The workbook results in a stretch factor cohort of 2, for both the 2022 Bridge and 2023 Test years, which is consistent with historical performance. EEDO has been assigned the second cohort since 2016, where it had previously been assigned cohort 3:

Table 1.6-1 Historical Inflationary Increases and Stretch Factor

	2014 IRM	2015 IRM	2016 IRM	2017 IRM	2018 IRM	2019 IRM	2020 IRM	2021 IRM	2022 IRM
Inflationary Increase	1.70%	1.60%	2.10%	1.90%	1.20%	1.50%	2.00%	2.20%	3.30%
Stretch Factor	0.30%	0.30%	0.30%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%
Net Increase	**1.40%**	**1.30%**	**1.80%**	**1.75%**	**1.05%**	**1.35%**	**1.85%**	**2.05%**	**3.15%**

Table 1.6-2 Summary of Cost Benchmarking Results

Cost Benchmarking Summary	2020 (History)	2022 (Bridge)	2023 (Test Year)
Actual Total Cost	11,059,984	11,888,284	12,497,588
Predicted Total Cost	12,196,412	13,543,486	14,079,706
Difference	(1,136,428)	(1,655,202)	(1,582,118)
Percentage Difference (Cost Performance)	**-9.8%**	**-13.0%**	**-11.9%**
Three-Year Average Performance			-11.6%
Stretch Factor Cohort			
Annual Result	**3**	**2**	**2**
Three Year Average			2

EEDO has used the results obtained from the PEG model to inform the business plan and application by using the result as a consistency measure of performance compared to expected results. EEDO has been in Cohort II since 2017 and is expected to remain based on the model. As stated in section 1.2.10, EEDO has a target of a >2% increase in controllable customer cost as a performance improvement target.

1.6.3 Activity and Product Based Benchmarking (APB)

On February 25, 2022, the Ontario Energy Board (OEB) announced changes to certain unit cost metric calculations within the Activity and Program-based Benchmarking (APB) framework to help drive utility performance and support efficiencies in the regulatory process.

Using these improved calculations along with the results of a limited data survey, OEB staff has updated all the unit cost results for fiscal 2018, 2019, and 2020 in a new Report to the Ontario Energy Board – Activities and Program Benchmarking: 2020 Results[5]. The project's consultant, Pacific Economics Group Research LLC, has also updated all of the econometric model results to incorporate new data and align with the 2018 to 2020 time period.

As noted in Chapter 2 of the OEB's filing requirements for electricity distribution rate applications, distributors submitting 2023 Cost of Service rate applications must review the most current APB results and discuss their performance for each program.

Table 1.6-3 – APB Summary

	A	B	C	D	E	F
	Item	**Cost ($1,000)**	**Scale**	**Unit Cost ($/Cust)**	**Ontario Average**	**Average?**
1	Billing O&M	499	18	28	36	Below
2	Metering O&M	459	18	26	20	Above
3	Vegetation Management O&M	147	5	28	35	Below
4	Lines O&M	720	373	1,929	1,814	Above
5	Stations O&M	118	6	19,659	68,109	Below
6	Poles Towers O&M	89	5	17	11	Above
7	Stations CAPEX	-	6	-	223,325	Below
8	Poles, Towers CAPEX	1,626	151	11,439	7,523	Above
9	Lines Transformers CAPEX	213	59	4,036	10,970	Below
10	Meters CAPEX	120	18	7	13	Below

EEDO notes that 2018-2020 average amounts have been lower than the Ontario average for seven out of the ten categories currently being measured by the APB Program. EEDO does not have any specific remedial actions to take as a result of this information, but will continue to monitor and better understand measures. As there are many differences between LDC's (customer count/geography/historical capital investment levels etc..), EEDO plans to use future APB results as a ranking benchmark to influence future planning.

[5] https://www.oeb.ca/sites/default/files/APB-PEG-Report-2020-Results.pdf

1.7 Facilitating Innovation

EEDO has made prior investments into grid technologies that have established the base for further modernization and innovation. EEDO has implemented a GIS to inventory its assets and form the basis of an electrically connected model that can be used as an outage management tool and a distribution management tool. The tool that EEDO uses is Utilismart's SmartMap s/w. EEDO's SCADA system and AMI network is integrated into SmartMap making it a powerful real time and planning tool.

These management systems permit for EEDO to carry out various advanced grid functionality such as:

a. Outage management by aggregating last gasp AMI signals to determine the area impacted. This aids is fault location and isolation.
b. Outage communication to customers through the on line outage map that atomically identifies the area out of power through the aggregation of AMI signals.
c. Asset loading studies by aggregating AMI data upstream to distribution transformers and station equipment, and combining this with station SCADA.
d. Switching simulations to understand planned outage impacts, and options for restoring unplanned outages.

EEDO has integrated SmartMap and SCADA into EDTI's system control center. This is a 24/7 resourced control room with highly trained operators who can assist EEDO's operations with outage management. EEDO intends to further integrate into system control enabling operators to ping AMI meters and actuate remotely operated switches in order to fault isolate and restore customers much faster than having to roll a trouble truck after hours.

SmartMap's use as a management tool will provide increased real time visibility into the grid allowing EEDO to optimize its loading. This will become increasingly more important with the integration of EV charging load and DER generation coming back onto the grid. With AMI integrated into Smartmap, and Smartmap integrated into system control, the operators will be able to simulate and switch the system in real time as peak loading may move around system now due to EV loading, DER diversity, battery loading, During the next five years it will be necessary for EEDO to update its GIS desktop software to remain current with the support from its vendor ESRI. EEDO must also replace the underlying "Geometric Network "data model with Esri's "Utility Network" model (UN). The data model defines the "back end" database structure and ArcGIS Pro software is the "front end" where the data is displayed and manipulated. The Utility Network (UN) model offers a digital representation of the network systems that is more accurate, more useful and more reliable than the legacy, antiquated Geometric Network model. The data model migration to UN will modernize GIS utility maintenance and functionality, will deliver the full value of the ArcGIS platform, and can result in increased operational efficiency and safety.

EEDO also intends to invest into the use of mobile apps for field operational efficiencies. An example of mobile applications in the field include the ability to complete digital safe work plans reducing the need for paper. Digital storage of safe work plans also permits for greater data analysis of hazards identified and can be trended. EEDO also has plans to move away from its paper based work management process to a more digitally based system.

EEDO has recently been selected as a delivery organization for NRCan grant funding towards electric vehicle charging infrastructure. This is expected to result in an investment in EV infrastructure into our operating areas. This will provide EEDO an opportunity to use its grid tools such as SmartMap to study the impacts of increased loading from EV charging. This may provide the opportunity for the piloting of load management tools to ensure assets are not overloaded and deteriorate at a faster rate.

EEDO also intends to invest in better customer engagement methods. Over the last five year period, an outage map was introduced that maps out an area currently impacted by an outage. This is a customer pull strategy requiring the customer to visit the map for information on estimated time of restoration. EEDO plans to implement a customer push strategy where outage information is sent via txt or email to customers proactively for planned or unplanned outages.

1.8 Financial Information

EEDO has included the audited 2019-2021 financial statements in this exhibit (Exhibit 1, Tab 2, Appendix B).

Additional information regarding its parent company, EPCOR Utilities Inc. can be found on SEDAR. SEDAR is the official site that provides access to most public securities documents and information filed by issuers with the thirteen provincial and territorial securities regulatory authorities ("Canadian Securities Administrators" or "CSA") in the SEDAR filing system.

https://sedar.com/DisplayProfile.do?lang=EN&issuerType=03&issuerNo=00012250

EEDO does not have any specific rating agency reports or prospectuses, etc. for recent and planned public issuances.

EEDO remains an corporation, registered in the province of Ontario. There have not been changes to the corporations tax status, nor are there any planned changes.

EEDO has one specific accounting order:

Deferral Account to Record Regulatory Expense Deferral Account; - 1508 Other Regulatory Assets, Sub-account Stranded Assets. The purpose of the deferral account is to record the cost of smart meters net of their accumulated depreciation (i.e. “NBV”) for meters that must be removed from service before the end of their expected service life and replaced with new meters. A copy of this accounting order is included in the Exhibit 9 appendixes.

EEDO has not departed from this order and the remainder of EEDO’s deferral account practices are based on generic orders and the Accounting Procedures Handbook.

EEDO provides billing service to the Town of Collingwood for water and wastewater as a non-distribution businesses and confirms that the accounting treatment it has used has segregated all of these activities from its rate-regulated activities.

Subsequent to EEDO's previous cost of service application for the 2013 year, EEDO converted its financial reporting framework from Canadian GAAP (CGAAP) to IFRS with a transition date of January 1, 2014.

1.9 Distributor Consolidation

EUI acquired EEDO via a Share Purchase Agreement with the Town of Collingwood, which was approved by the OEB on August 30, 2018. The sale closed October 1, 2018. (EB2017-0373/0374). The OEB determined that the proposed transactions met the "no harm" test and therefore the OEB approved the transactions.

The OEB also approved the Applicants' related requests for:

- A 1% rate reduction to base residential distribution rates (exclusive of rate riders) relative to those established through CollusLDC's 2018 rate setting process (EB- 2017-0034).
- A deferral of the rate rebasing period of CollusLDC for five years from the date of closing of the proposed transactions.
- Approval to continue to track costs in the deferral and variance accounts currently approved for CollusLDC and to seek disposition of their balances at a future date.
- EPCOR shall file its Distribution System Plan for Collus PowerStream Corporation as a prerequisite to any Incremental Capital Module application

EPCOR continues to look to expand its footprint in the province of Ontario and globally for areas of investment within both the regulated and non-regulated environments. In addition to EEDO, EPCOR owns and operates EPCOR Natural Gas Limited Partnership ("ENGLP"), a regulated natural gas utility with operations in both Aylmer and Kincardine. ENGLP has also recently been the successful proponent of further natural gas expansion in Brockton.

As further explained in Exhibit 4, EPCOR/EEDO is working to build an Ontario based business model to allow for efficiencies and savings through shared services in the province. This would help enable additional utility expansion and acquisition through a mature business operation and on-boarding program.

Appendix A - Historical Customer Service Surveys

2021 EPCOR Customer Satisfaction Survey

Introduction and Summary

Thank you for selecting Redhead Media Solutions Inc. for this important project for EPCOR. We appreciate your confidence in us to provide you with data on Customer Satisfaction that provides both a current snapshot and can be used to compare with previous surveys in 2017, 2019 and among other LDCs that we work with.

It is our goal to always be improving our deliverables and provide value to our clients. To supplement this report, we have also included a stand-alone section on comparable data and verbatims for question G15 (open comments) in spreadsheet format. The methodology guide, as well as residential and general service questionnaires are also included as appendices B, C and D for your reference.

Should there be any specific data or breakouts that you require we would be happy to provide them. Please contact us to discuss how we can assist you and ensure you are getting the most from this project.

Sincerely,

Graydon Smith
President

Introduction and Summary

Redhead Media Solutions Inc. (Redhead), partnering with ADVANIS for data collection and reporting, has been retained (via an RFP process by Cornerstone Hydro Electric Concepts Inc. - CHEC) to conduct a 2021 Customer Satisfaction Survey for EPCOR. This survey is a required part of an LDC's Balanced Scorecard and other reporting and regulatory requirements for the Ontario Energy Board (OEB).

The complete group of participating CHEC LDCs are as follows:

- Centre Wellington Hydro
- EPCOR
- ERTH Power
- Grimsby Power
- Lakefront Utilities
- Lakeland Power Distribution
- Niagara-on-the-Lake Hydro
- Orangeville Hydro
- Ottawa River Power
- Renfrew Hydro
- Rideau St. Lawrence Distribution
- Tillsonburg Hydro
- Wasaga Distribution
- Wellington North Power

REDHEAD MEDIA SOLUTIONS INC

Introduction and Summary

This final report contains data specifically for EPCOR.

The survey is comprised of 402 randomly selected interviews of EPCOR customers among the low volume customer base (residential customers and general service under 50kW customers; GS<50kW). Residential customers were asked to confirm that they receive an electricity or hydro bill from EPCOR and that they are the primary payer of that bill or share the responsibility.

GS<50kW customers were also asked to confirm they receive an electricity or hydro bill from EPCOR, and additionally to confirm that the person who manages the organization's electricity bill was the one to complete the interview. The sample frame is stratified on region (where applicable) and consumption quartiles by rate class in accordance with the "Survey Implementation Requirements" on page 4 of the "EDA/Innovative Customer Satisfaction Scorecard: Methodology & Survey Implementation Guide" which is contained in Appendix B of this report.

The objective of the survey is to provide an Overall Customer Satisfaction index score for EPCOR. This is a calculated aggregate value based on responses of to 9 core measures in the survey instrument. In some cases, additional questions were asked but not included in the calculation of the Customer Satisfaction Index Score.

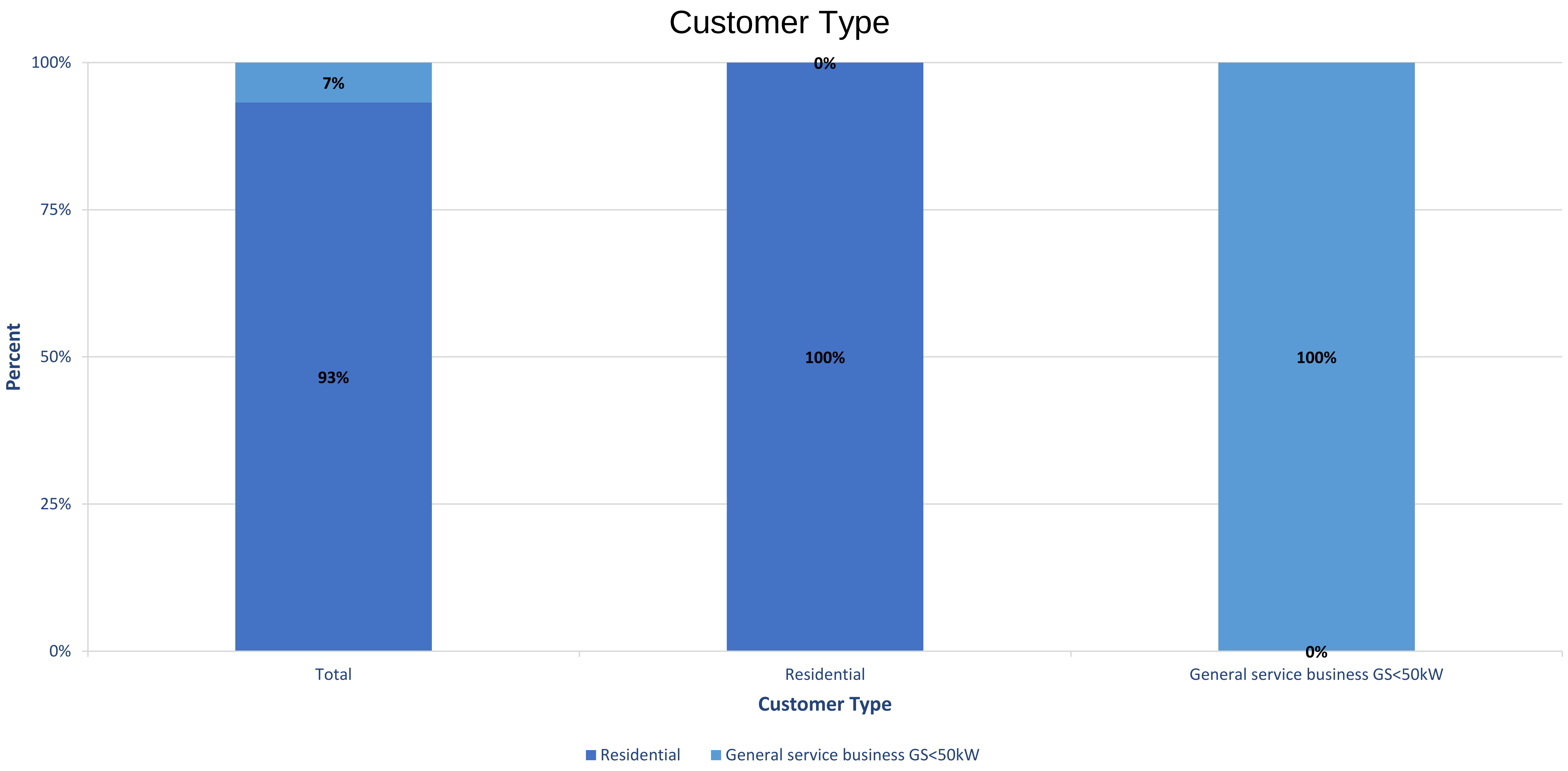
EPCOR's 2021 Customer Satisfaction Index Score is 74%, This is a 1% increase over the 2019 score (73%) and 5% less than the average of all LDCs (79%).

This falls within a very tight spectrum of index scores we processed for all LDCs that participated in the 2019 survey via Redhead. When the confidence interval is applied to all index scores, there is significant overlap between LDCs which underlines the statistical similarity of performance and satisfaction among participants. Statistically, EPCOR is similar to all but one other LDC surveyed.

The following report contains graphic data and tables for all core questions as well as any additional questions supplied by the LDC, which were asked after the core questions were completed.

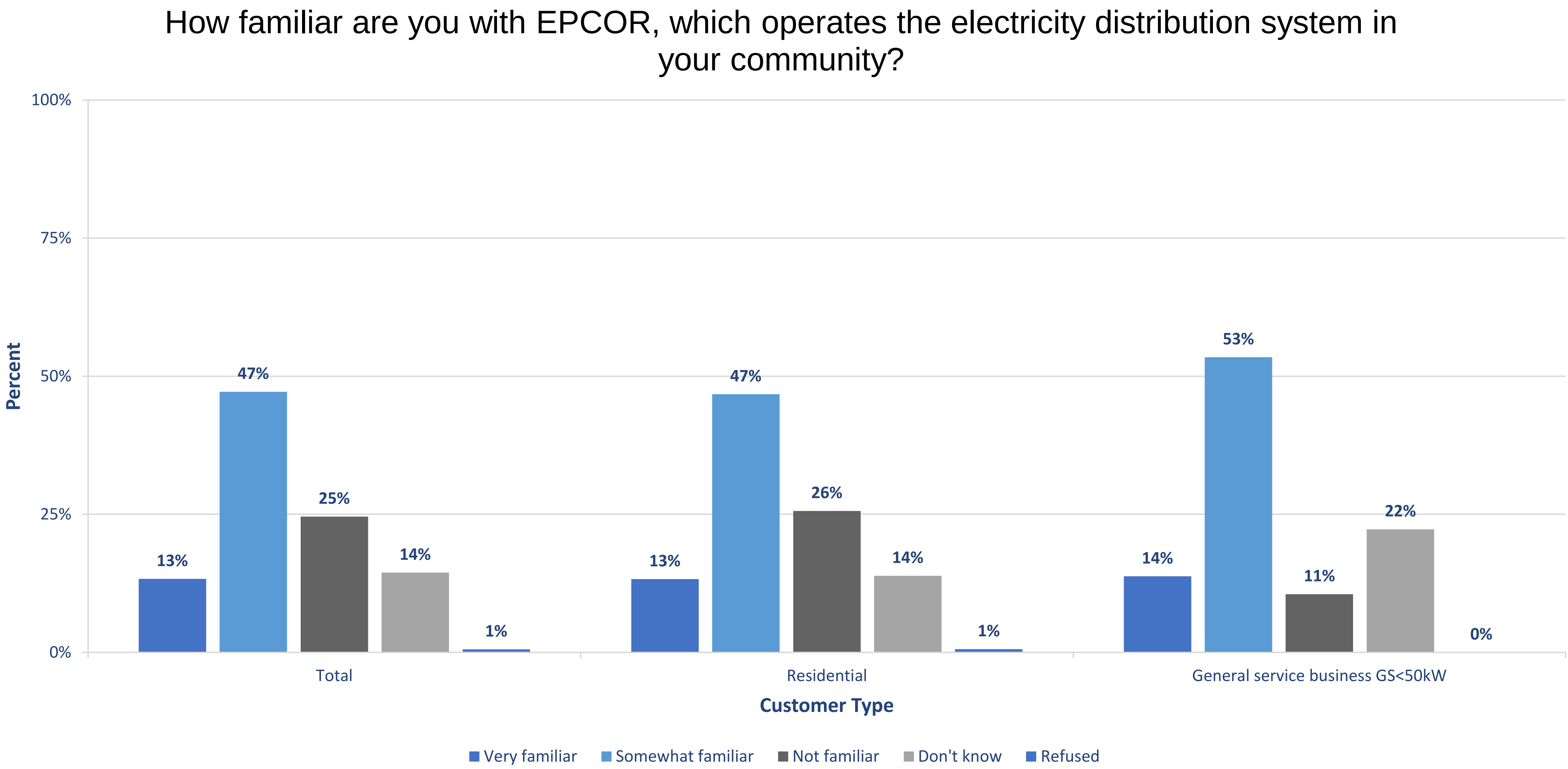
Question scoring and index methodologies were prescribed by the EDA/Innovative. As such, there has been limited additional analysis provided beyond the direction provided to meet the reporting guidelines. Should you wish further analysis of the data please contact our office to discuss.

PARTICIPANT INFORMATION



REDHEAD MEDIA SOLUTIONS INC

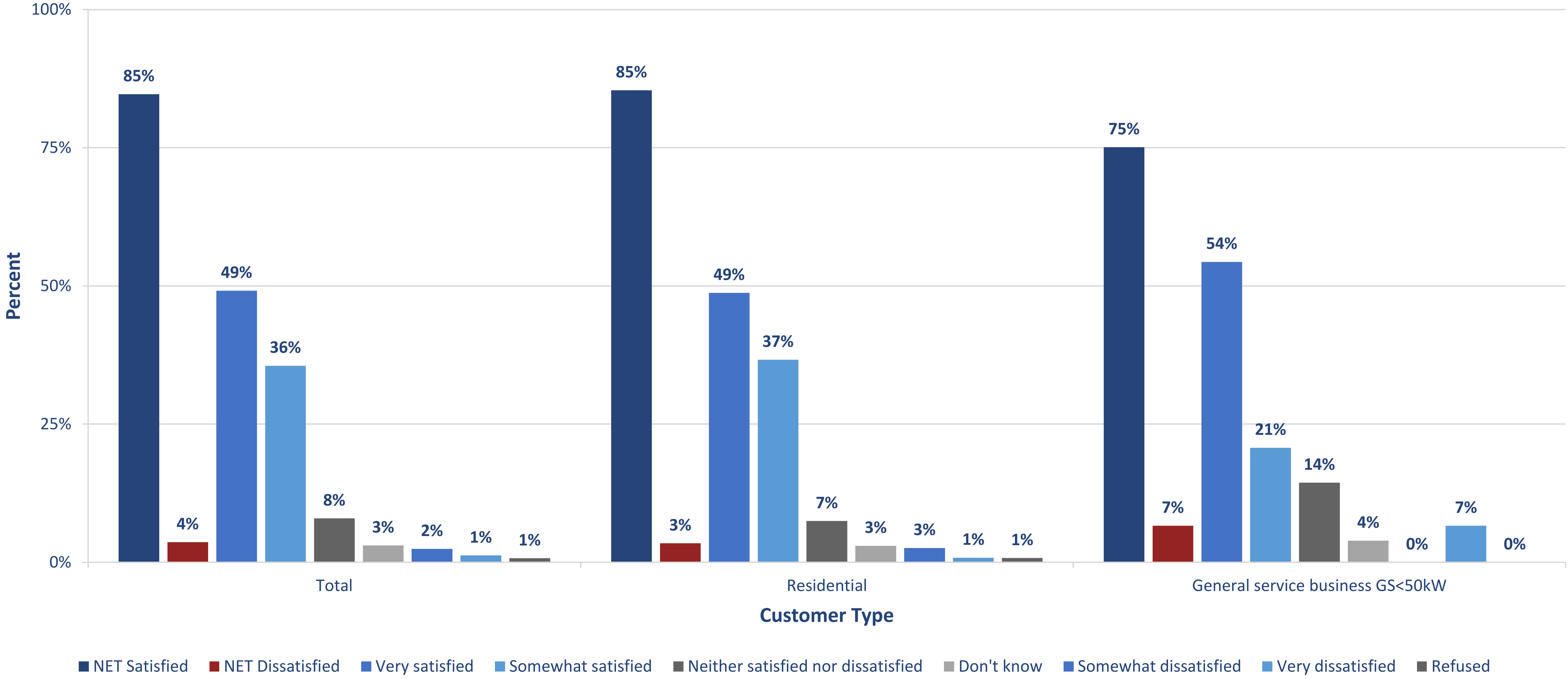
QUESTIONS/DATA



Source: Redhead Media Solutions/Advanis telephone random customer survey, January 15-February 25, 2021, n=402, accurate 4.8 percentage points plus or minus, 19 times out of 20.

REDHEAD MEDIA SOLUTIONS INC

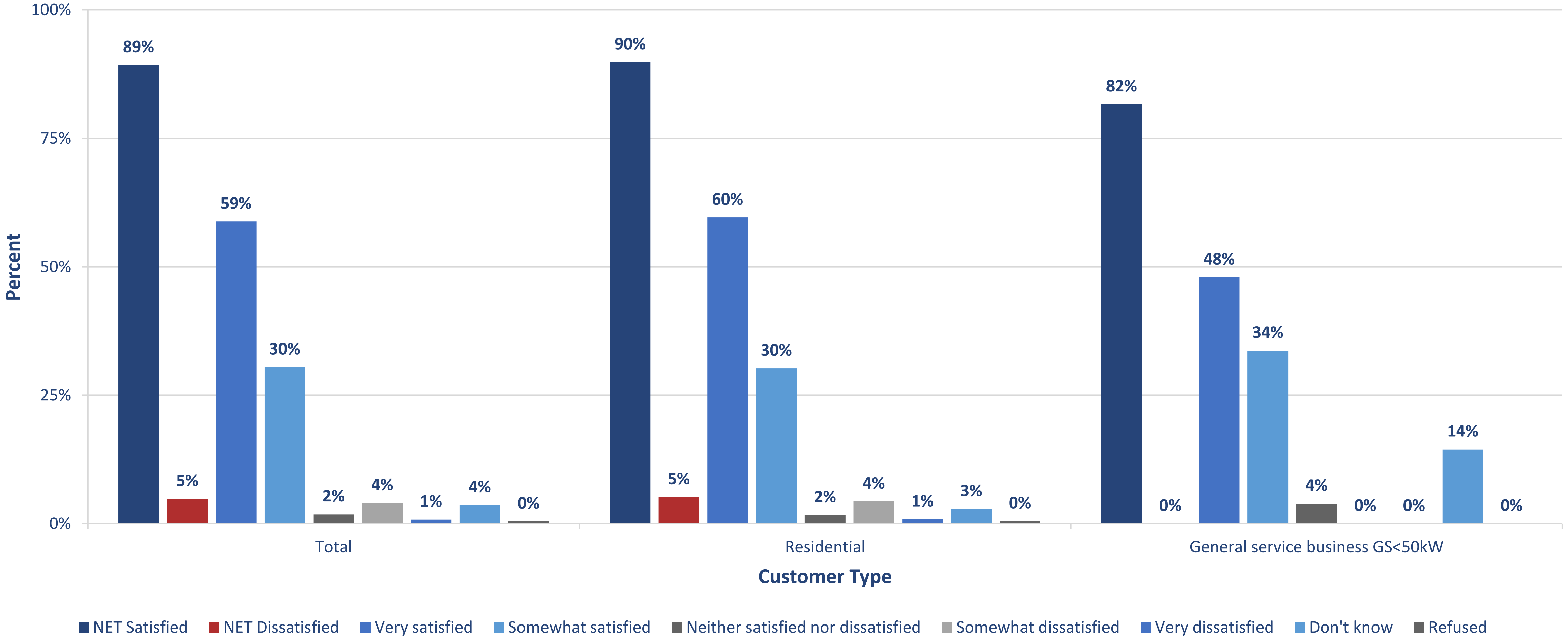
Thinking specifically about the services provided to you and your community by EPCOR, overall, how satisfied are you with the services that you receive from EPCOR?



Source: Redhead Media Solutions/Advanis telephone random customer survey, January 15-February 25, 2021, n=402, accurate 4.8 percentage points plus or minus, 19 times out of 20.

REDHEAD MEDIA SOLUTIONS INC

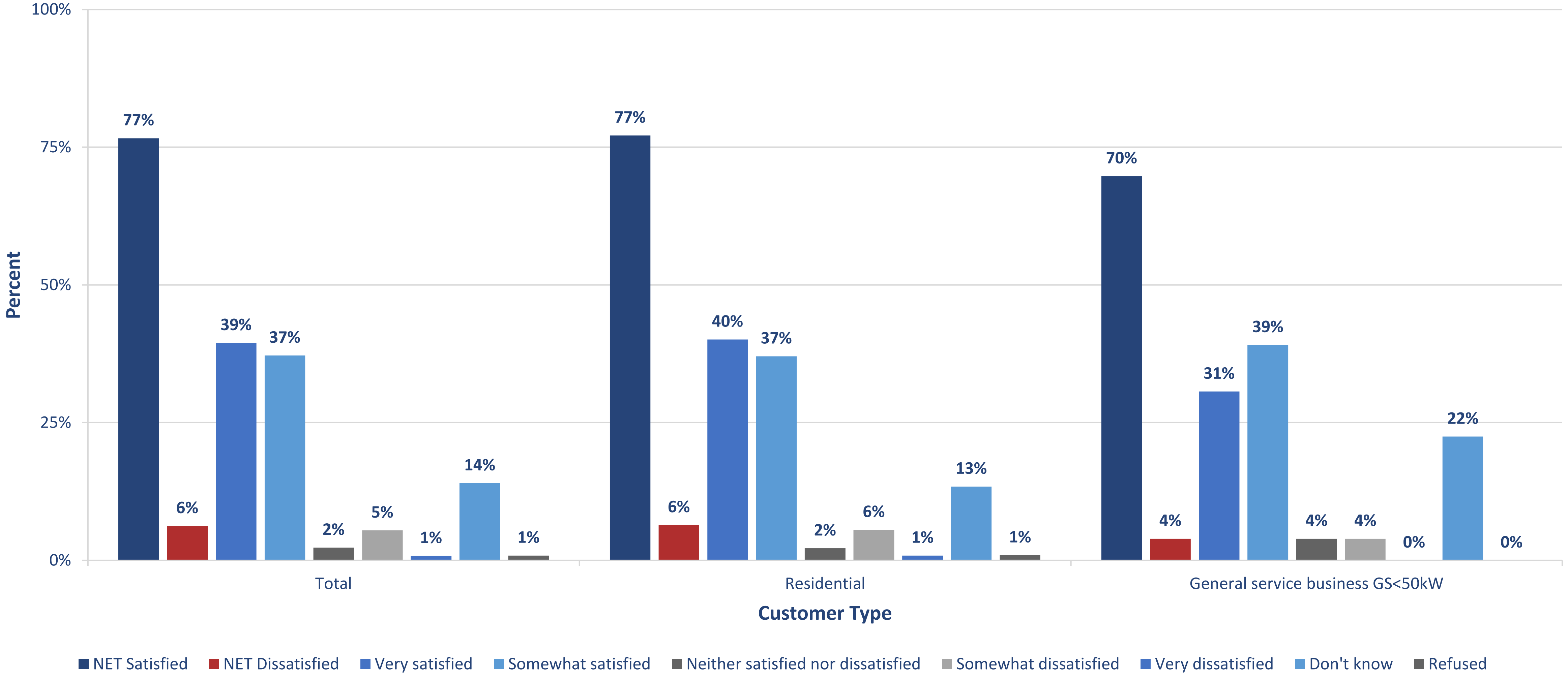
The reliability of your electricity service – as judged by the number of power outages you experience: How satisfied are you with the electrical service that you receive from EPCOR based on...?



Source: Redhead Media Solutions/Advanis telephone random customer survey, January 15-February 25, 2021, n=402, accurate 4.8 percentage points plus or minus, 19 times out of 20.

REDHEAD MEDIA SOLUTIONS INC

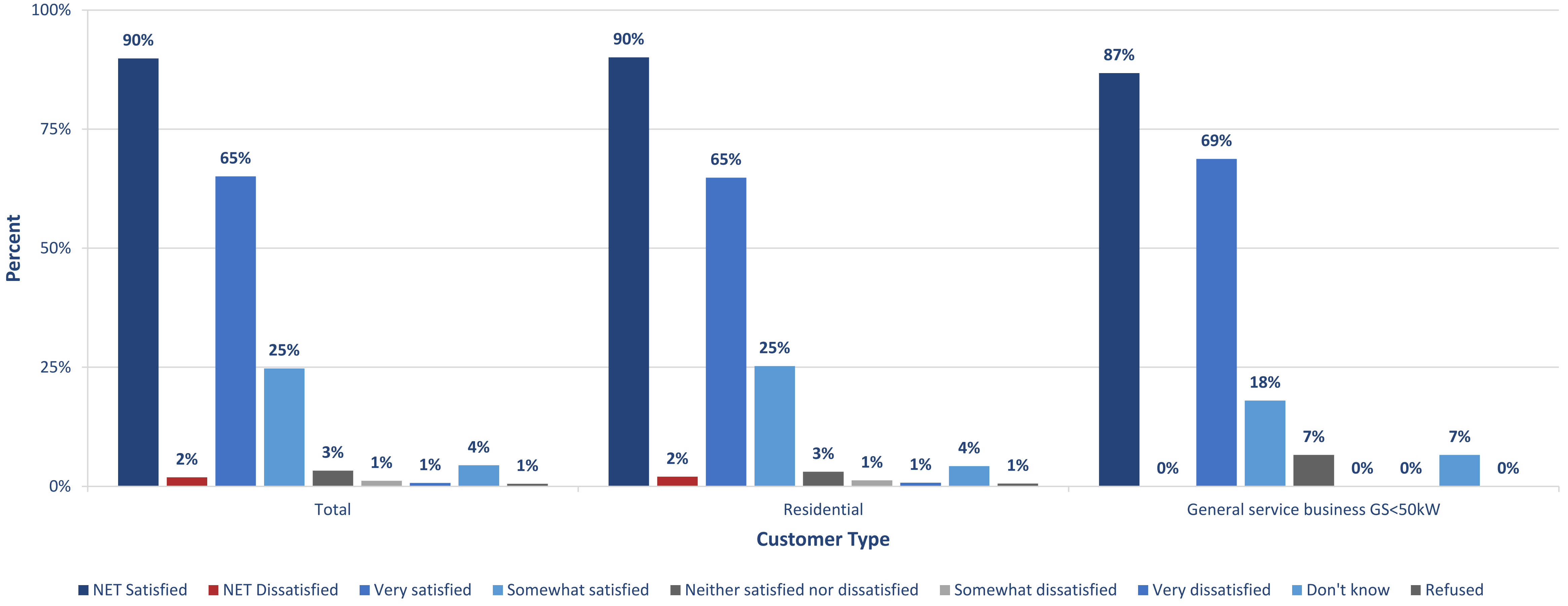
The amount of time it takes to restore power when power outages occur: How satisfied are you with the electrical service that you receive from EPCOR based on...?



Source: Redhead Media Solutions/Advanis telephone random customer survey, January 15-February 25, 2021, n=402, accurate 4.8 percentage points plus or minus, 19 times out of 20.

REDHEAD MEDIA SOLUTIONS INC

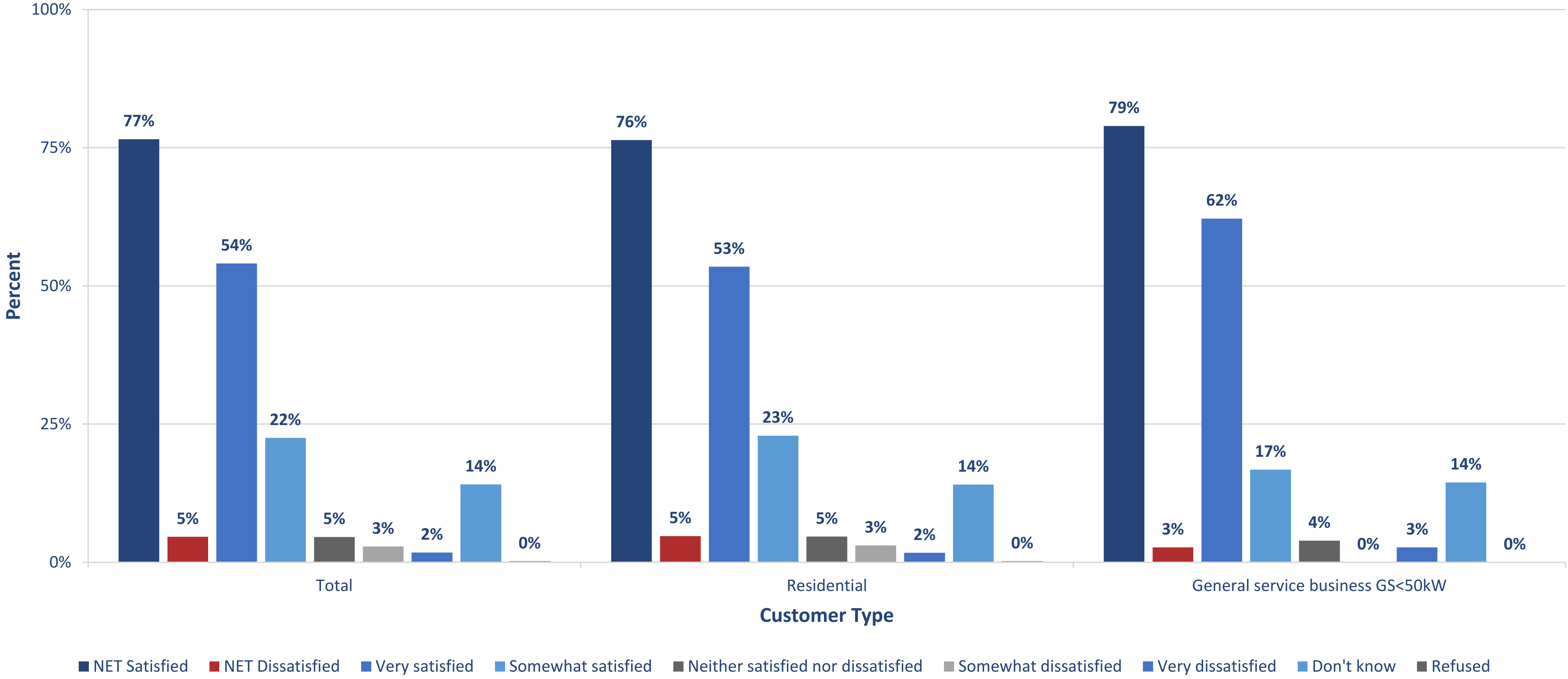
The quality of the power delivered to you as judged by the absence of voltage fluctuations that can result in [flickering/dimming of lights OR have an affect on equipment]: How satisfied are you with the electrical service that you receive from EPCOR based on...?



Source: Redhead Media Solutions/Advanis telephone random customer survey, January 15-February 25, 2021, n=402, accurate 4.8 percentage points plus or minus, 19 times out of 20.

REDHEAD MEDIA SOLUTIONS INC

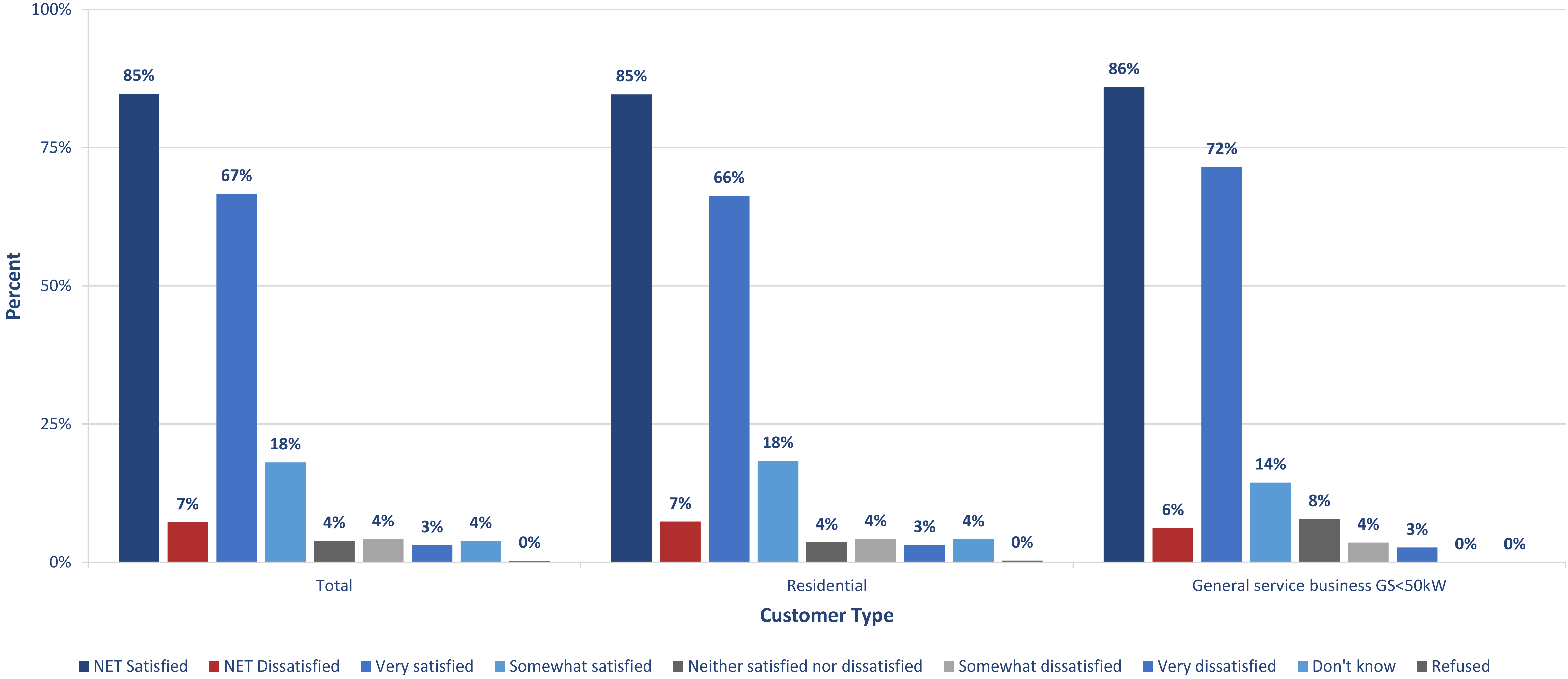
Providing accurate bills: How satisfied are you with the bills that you receive from EPCOR based on them...?



Source: Redhead Media Solutions/Advanis telephone random customer survey, January 15-February 25, 2021, n=402, accurate 4.8 percentage points plus or minus, 19 times out of 20.

REDHEAD MEDIA SOLUTIONS INC

Providing convenient options to both receive and pay your bills: How satisfied are you with the bills that you receive from EPCOR based on them...?



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REDHEAD MEDIA SOLUTIONS INC

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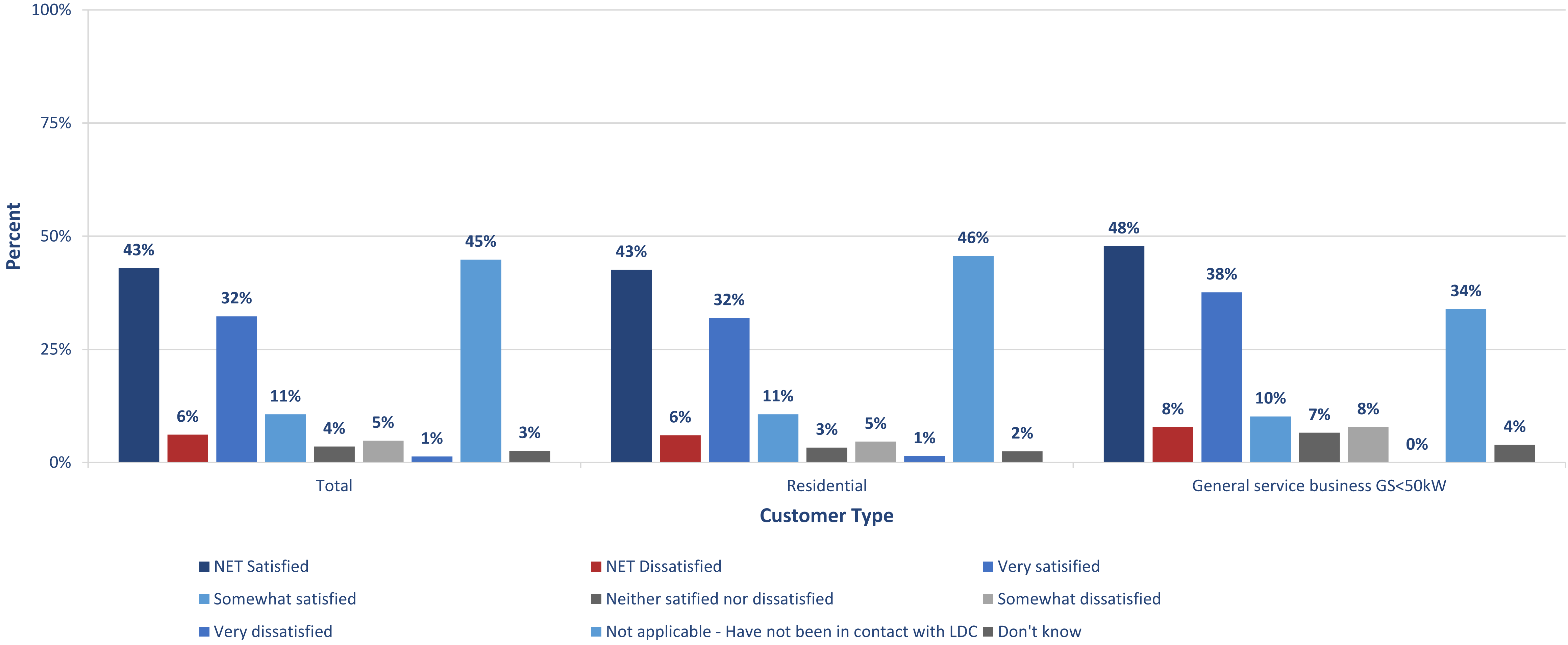

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 15-February 25, 2021, n=402, accurate 4.8 percentage points plus or minus, 19 times out of 20.

REDHEAD MEDIA SOLUTIONS INC

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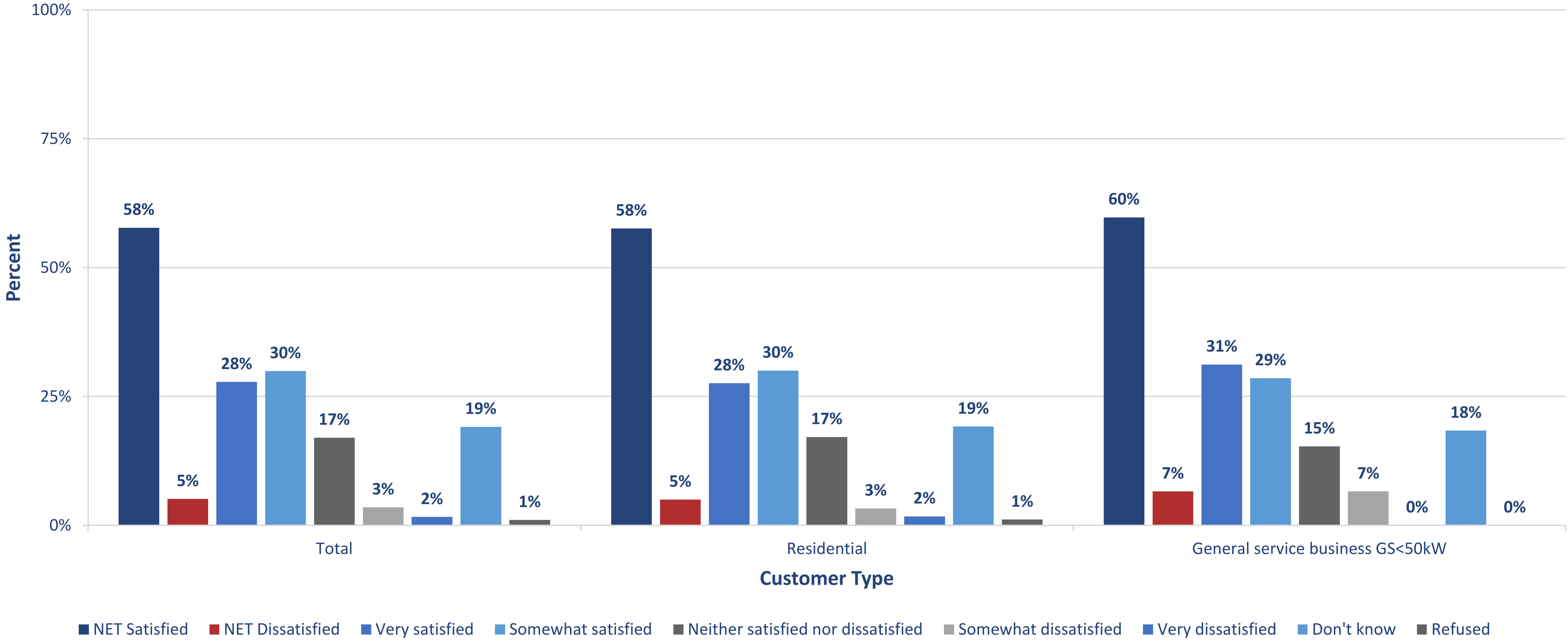
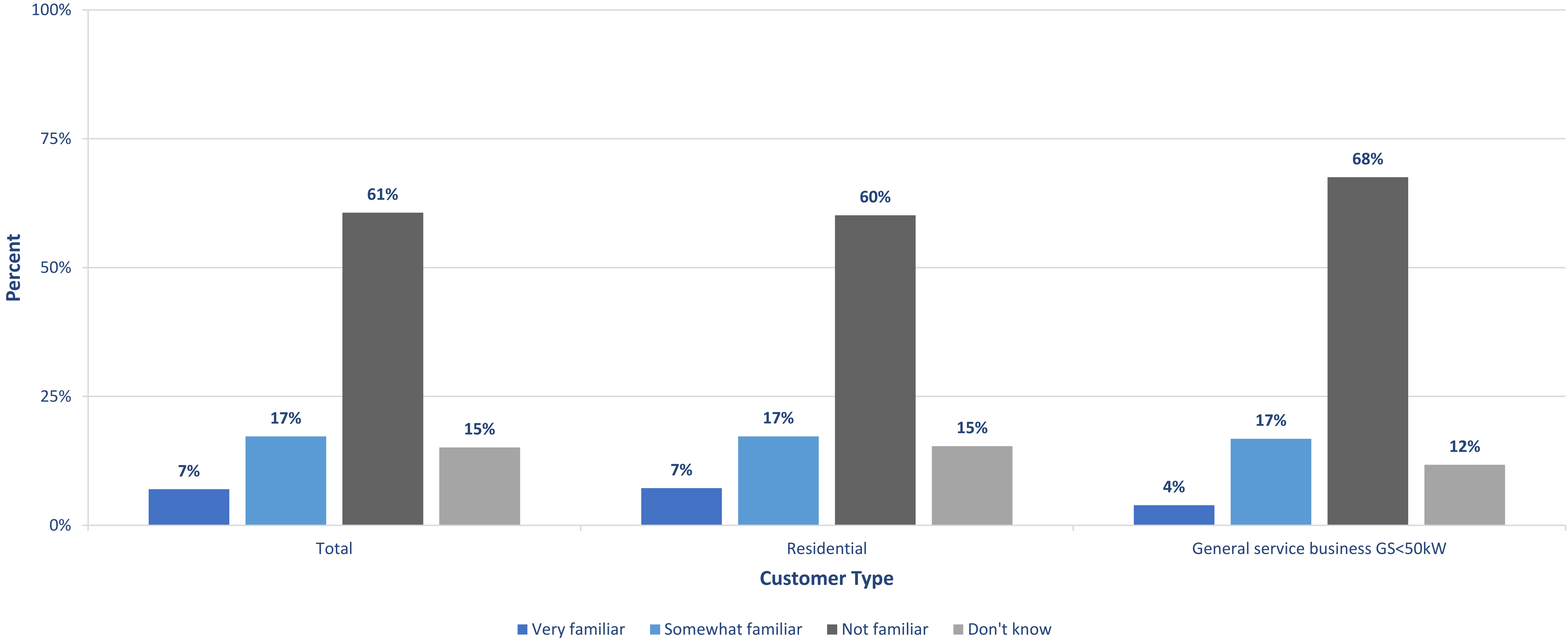


Source: Redhead Media Solutions/Advanis telephone random customer survey, January 15-February 25, 2021, n=402, accurate 4.8 percentage points plus or minus, 19 times out of 20.

REDHEAD MEDIA SOLUTIONS INC

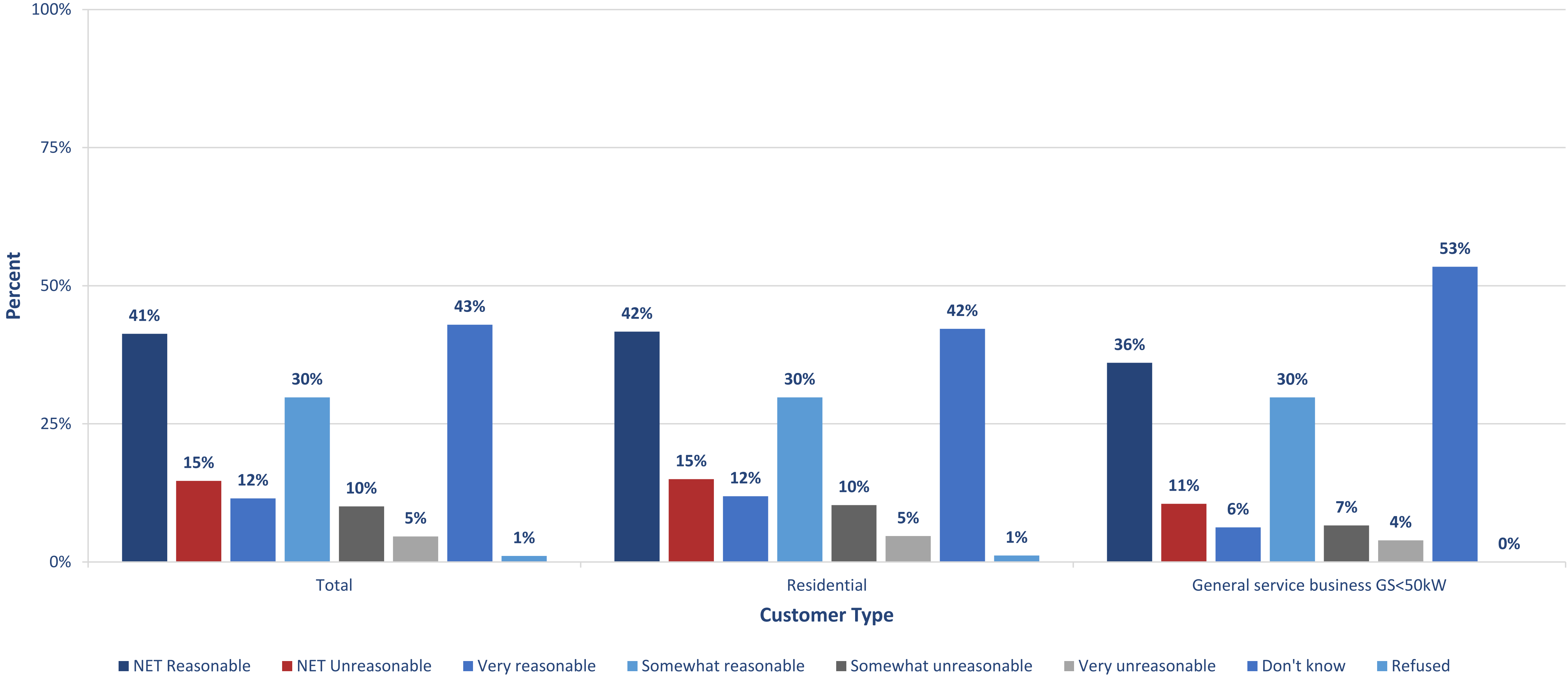
How familiar are you with the percentage of your electricity bill that went to EPCOR? So, NOT the portions allocated to power generation companies, transmission companies, the provincial government and regulatory agencies.



Source: Redhead Media Solutions/Advanis telephone random customer survey, January 15-February 25, 2021, n=402, accurate 4.8 percentage points plus or minus, 19 times out of 20.

REDHEAD MEDIA SOLUTIONS INC

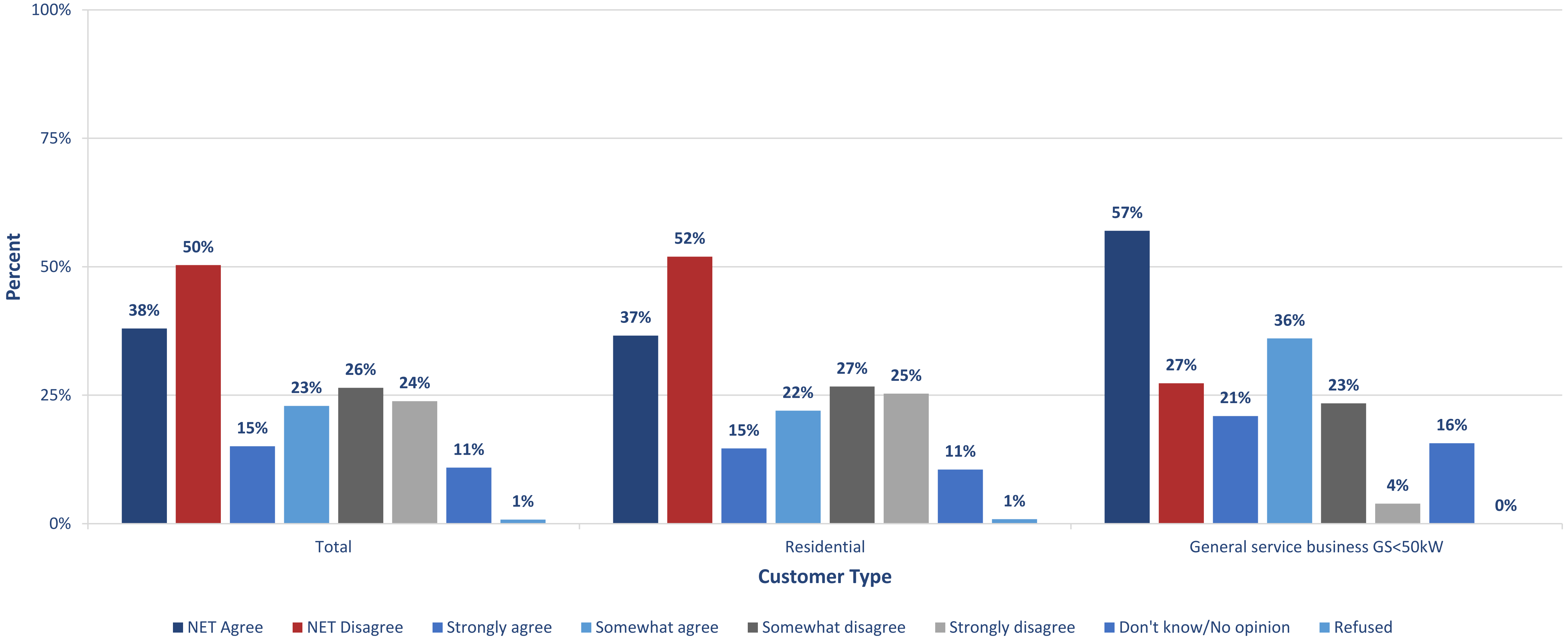
Do you feel that the percentage of your total electricity bill that you pay to EPCOR for the services they provide is...?



Source: Redhead Media Solutions/Advanis telephone random customer survey, January 15-February 25, 2021, n=402, accurate 4.8 percentage points plus or minus, 19 times out of 20.

REDHEAD MEDIA SOLUTIONS INC

The cost of my electricity bill has a major impact [on personal finances OR bottom line of organization]: To what extent do you agree with the following statements regarding the electricity system in Ontario?



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REDHEAD MEDIA SOLUTIONS INC

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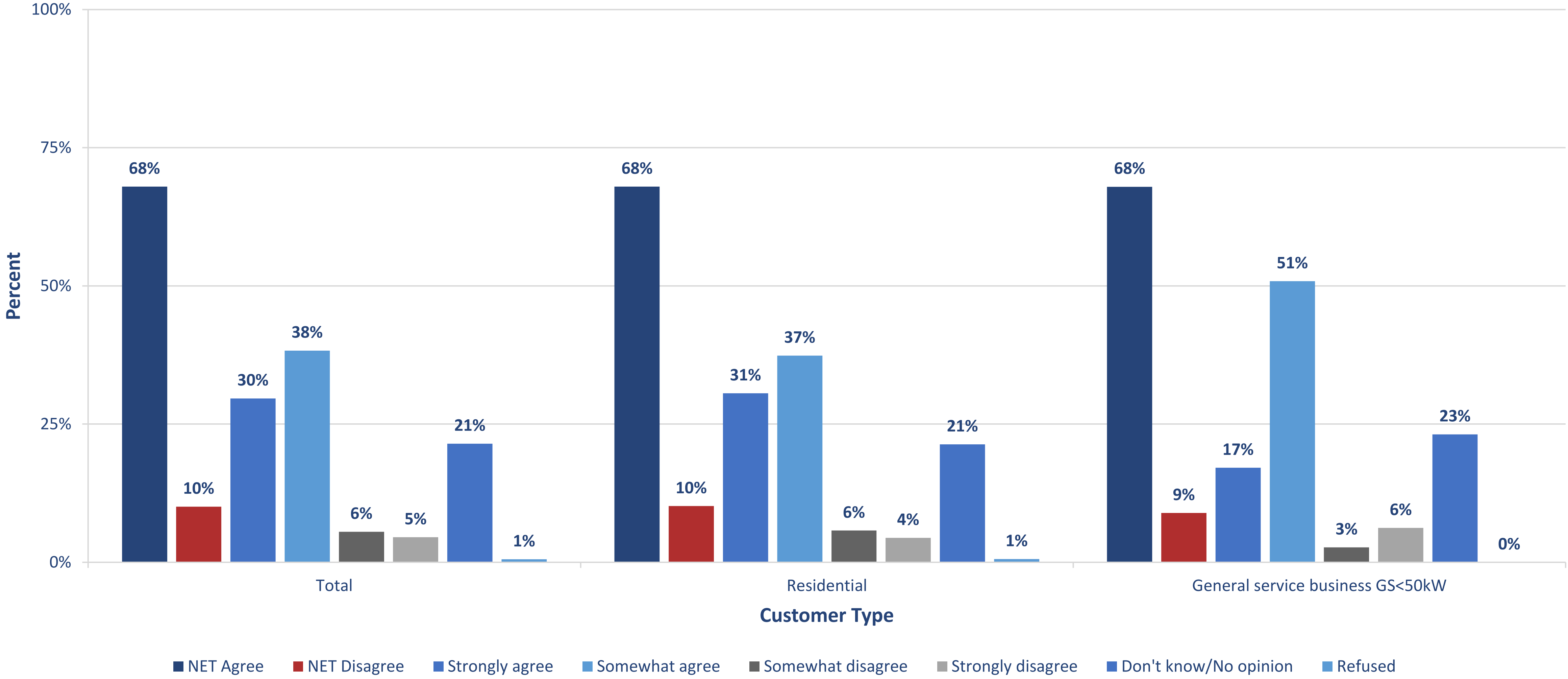


Source: Redhead Media Solutions/Advanis telephone random customer survey, January 15-February 25, 2021, n=402, accurate 4.8 percentage points plus or minus, 19 times out of 20.

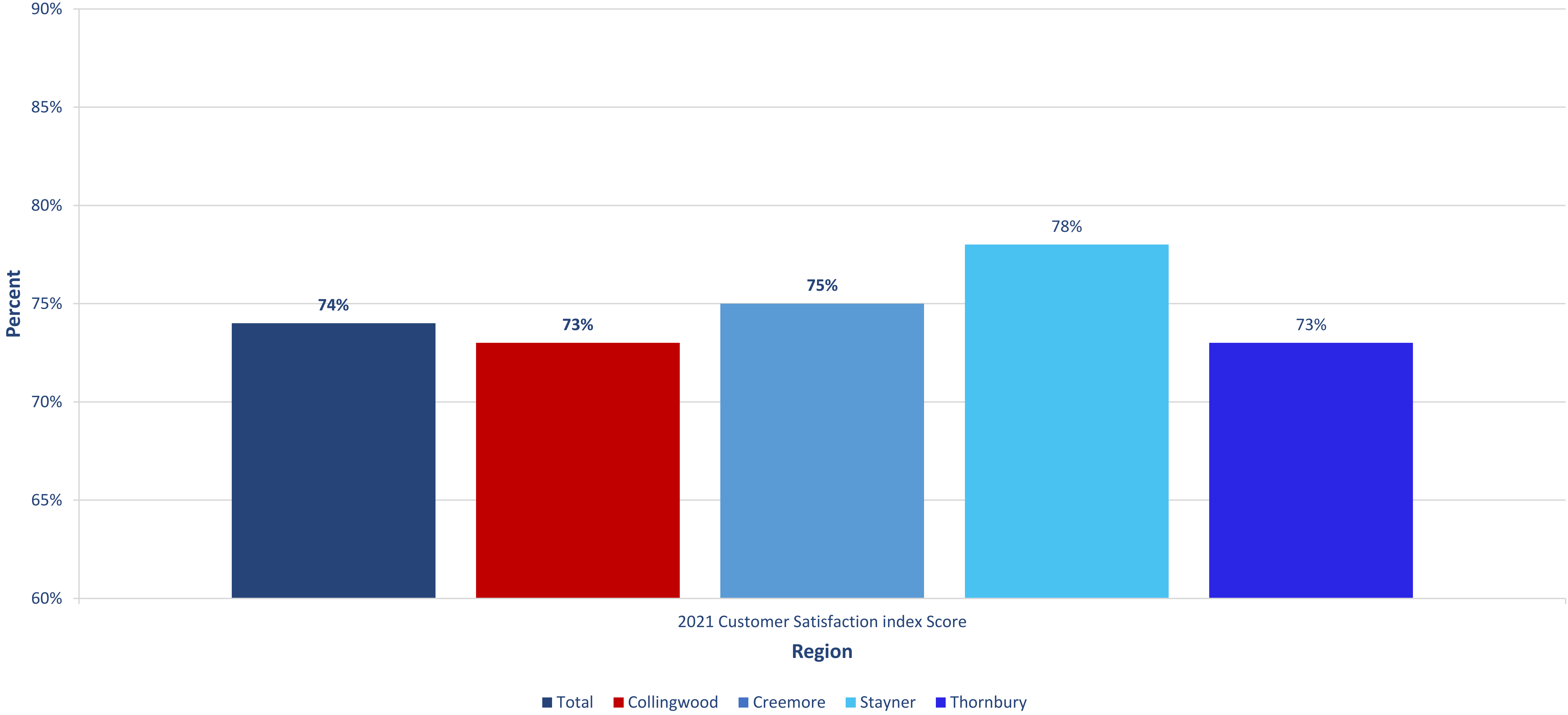
REDHEAD MEDIA SOLUTIONS INC

CUSTOMER SATISFACTION INDEX

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 15-February 25, 2021, n=402, accurate 4.8 percentage points plus or minus, 19 times out of 20.

REDHEAD MEDIA SOLUTIONS INC

2021 Customer Satisfaction Index Score by Region

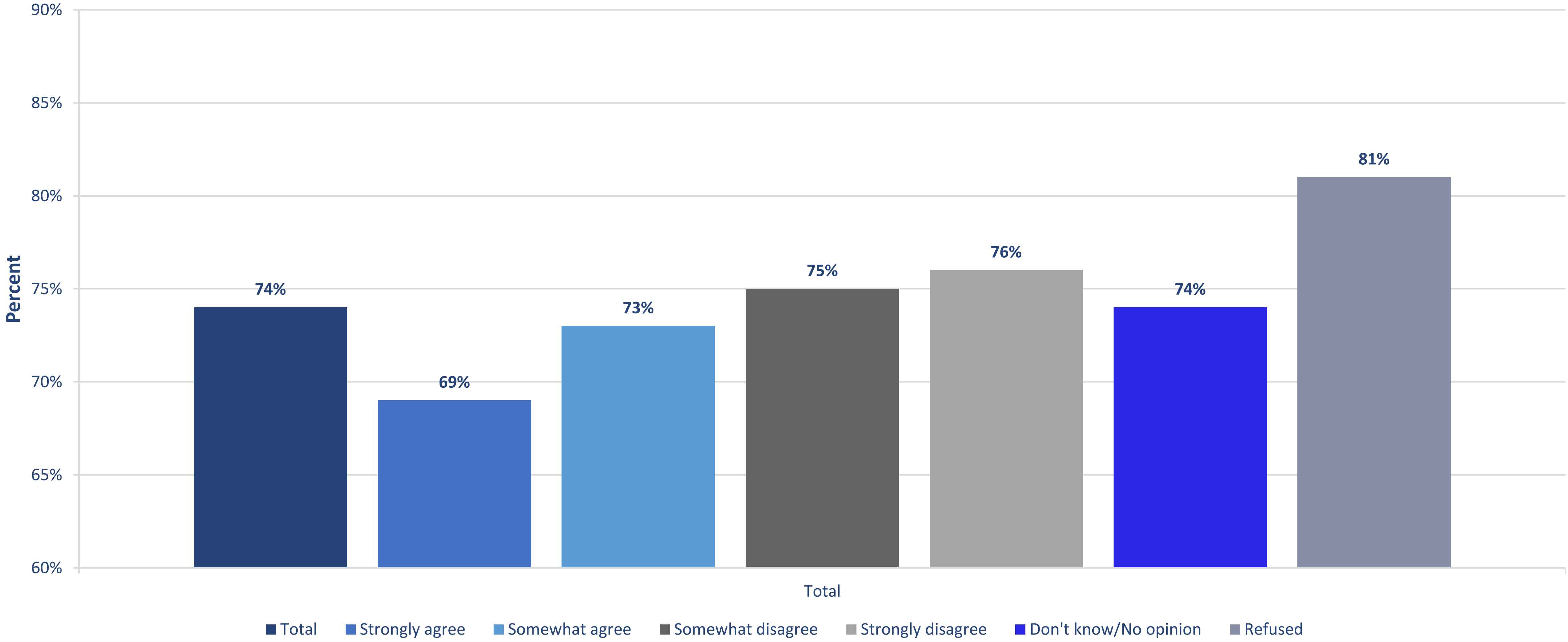


Source: Redhead Media Solutions/Advanis telephone random customer survey, January 15-February 25, 2021, n=402, accurate 4.8 percentage points plus or minus, 19 times out of 20.

REDHEAD MEDIA SOLUTIONS INC

Customer Satisfaction Index by the following statement:

The cost of my electricity bill has a major impact on [my personal finances/bottom line]

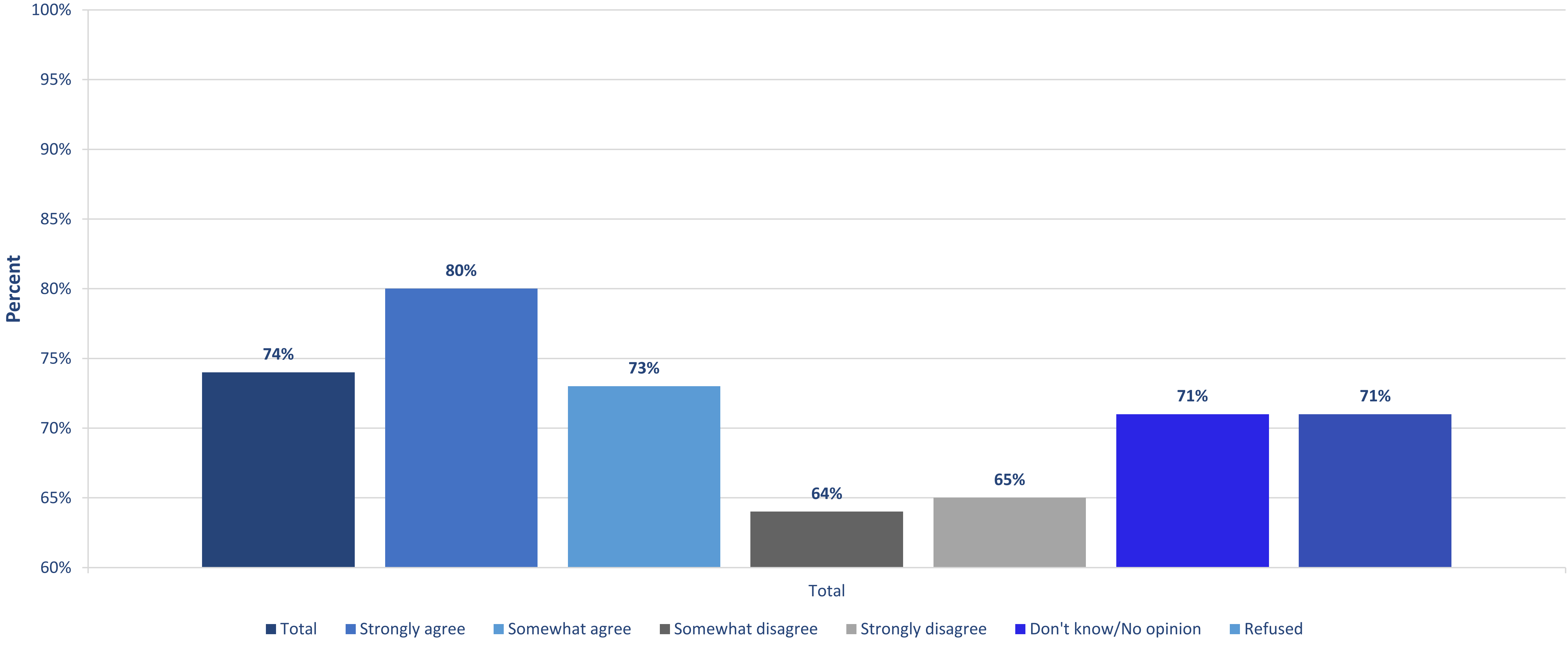


Source: Redhead Media Solutions/Advanis telephone random customer survey, January 15-February 25, 2021, n=402, accurate 4.8 percentage points plus or minus, 19 times out of 20.

REDHEAD MEDIA SOLUTIONS INC

Customer Satisfaction Index by the following statement:

Customers are well served by the electricity system in Ontario



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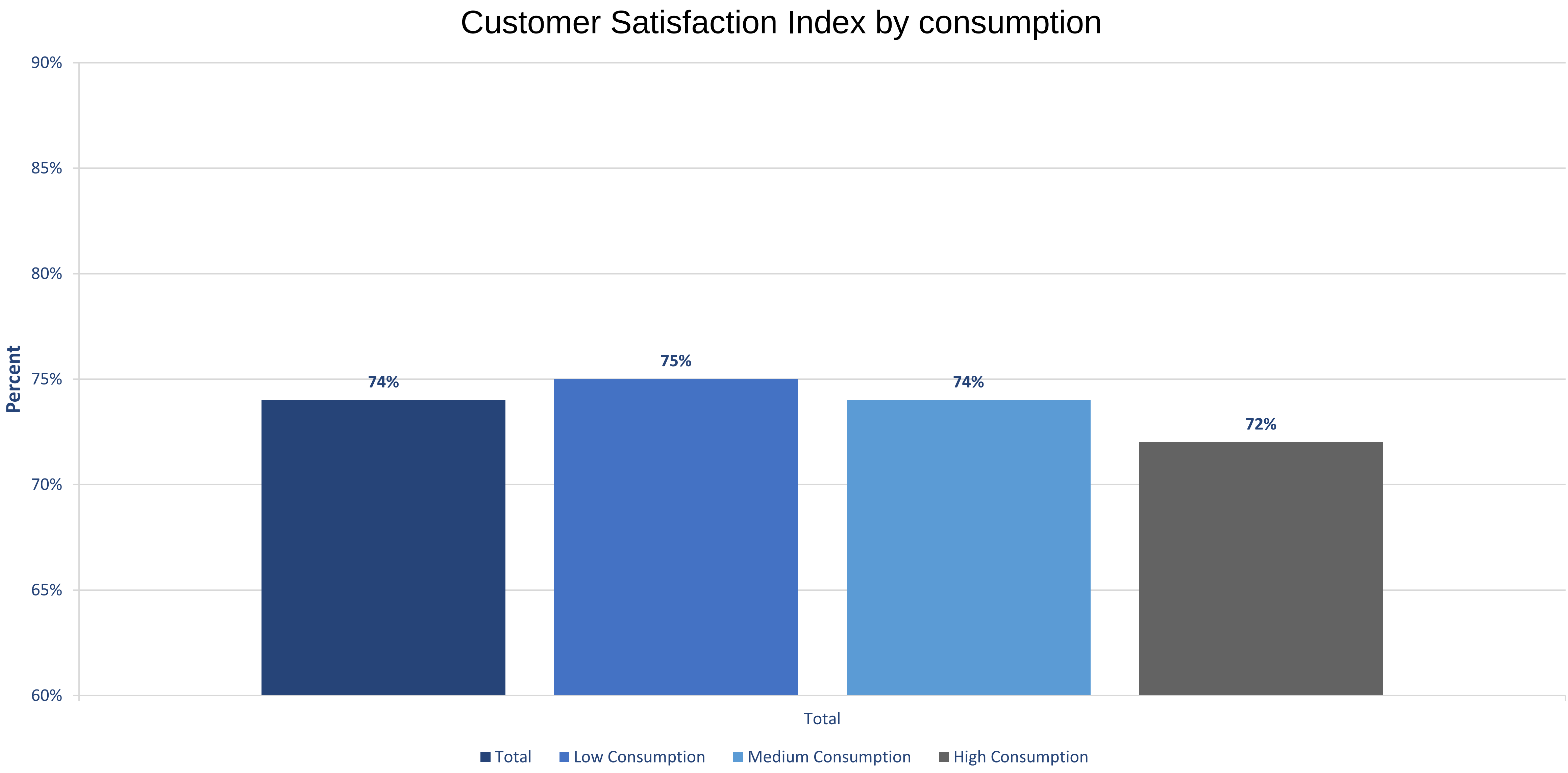
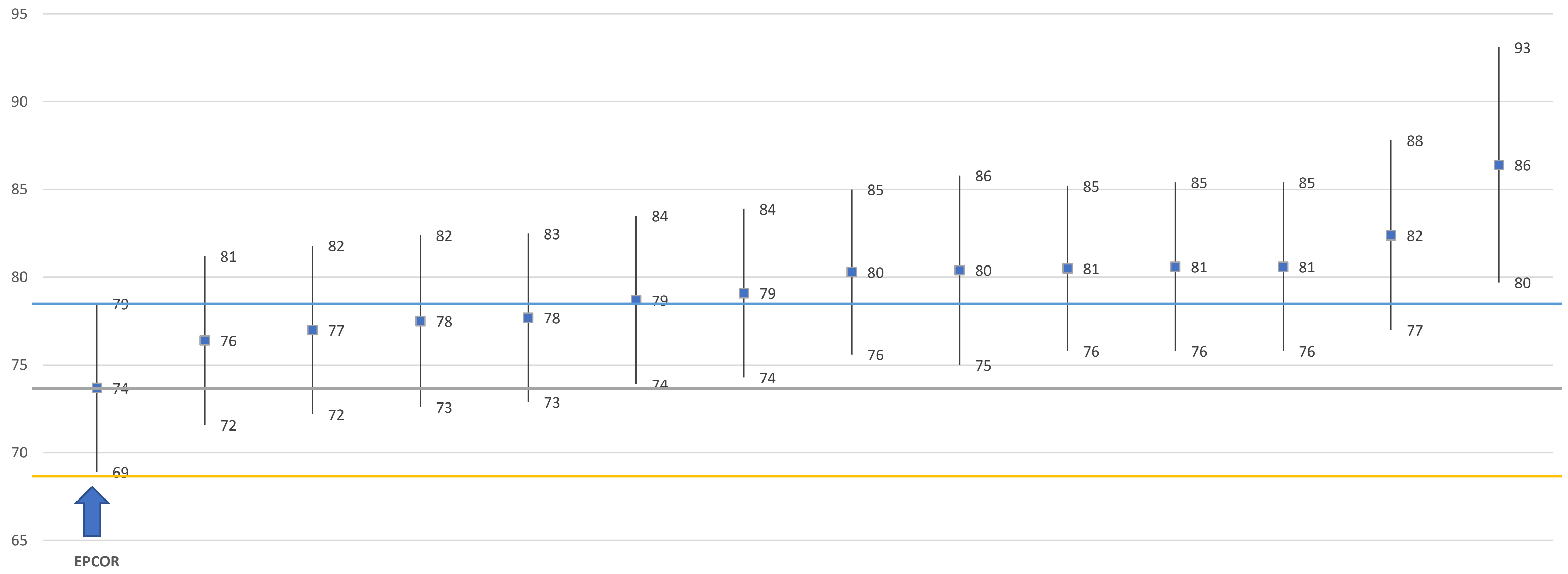
REDHEAD MEDIA SOLUTIONS INC



Source: Redhead Media Solutions/Advanis telephone random customer survey, January 15-February 25, 2021, n=402, accurate 4.8 percentage points plus or minus, 19 times out of 20.

REDHEAD MEDIA SOLUTIONS INC

Customer Satisfaction Index Score Comparison to External LDCs
Upper and Lower Bound

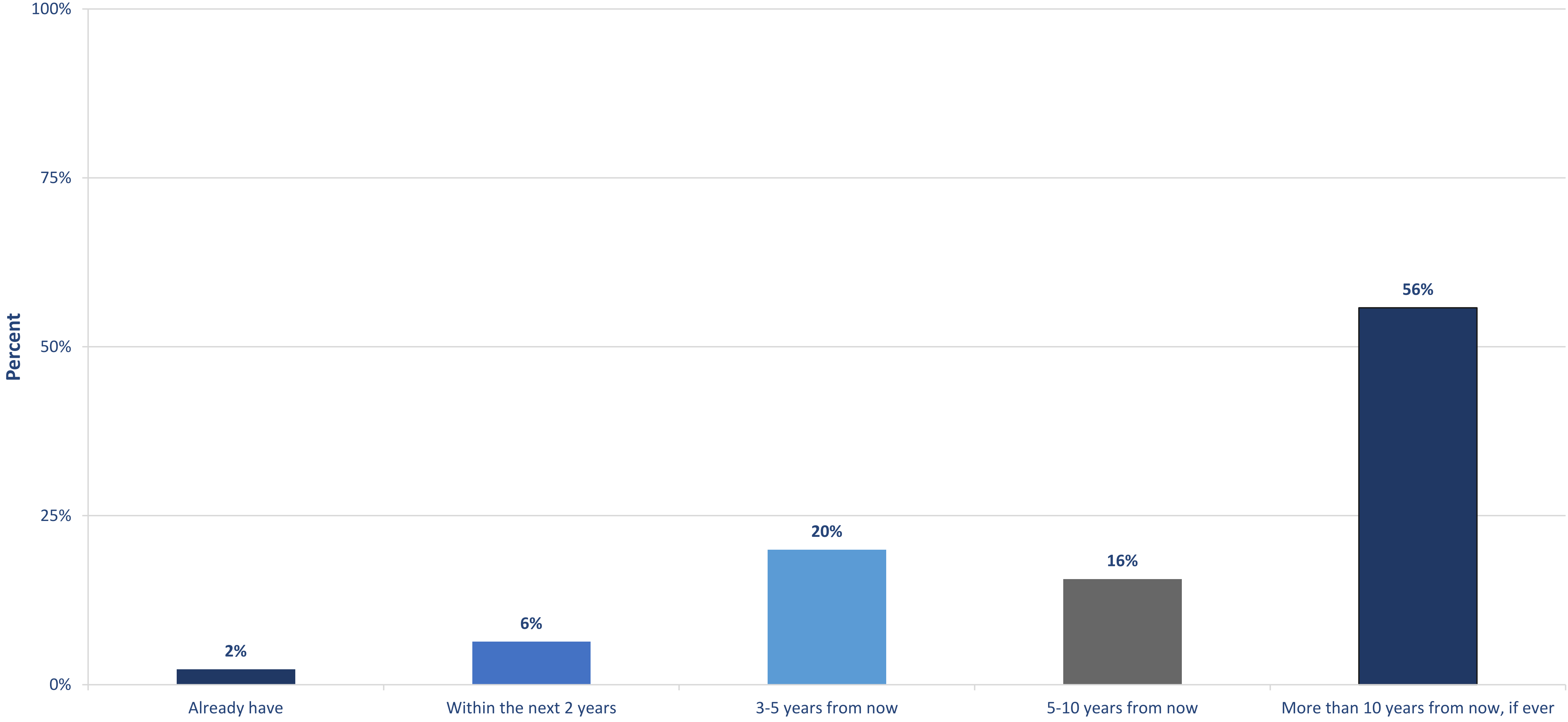


- The lines denote EPCOR's upper and lower bound based on the CSI Score.
- Almost all LDCs confidence intervals overlap, similar to 2019.
- EPCOR overlaps with all LDCs, indicating statistical uniformity.

REDHEAD MEDIA SOLUTIONS INC

CUSTOM QUESTIONS

When do you anticipate purchasing your first electric vehicle?



Source: Redhead Media Solutions/Advanis telephone random customer survey, January 15-February 25, 2021, n=402, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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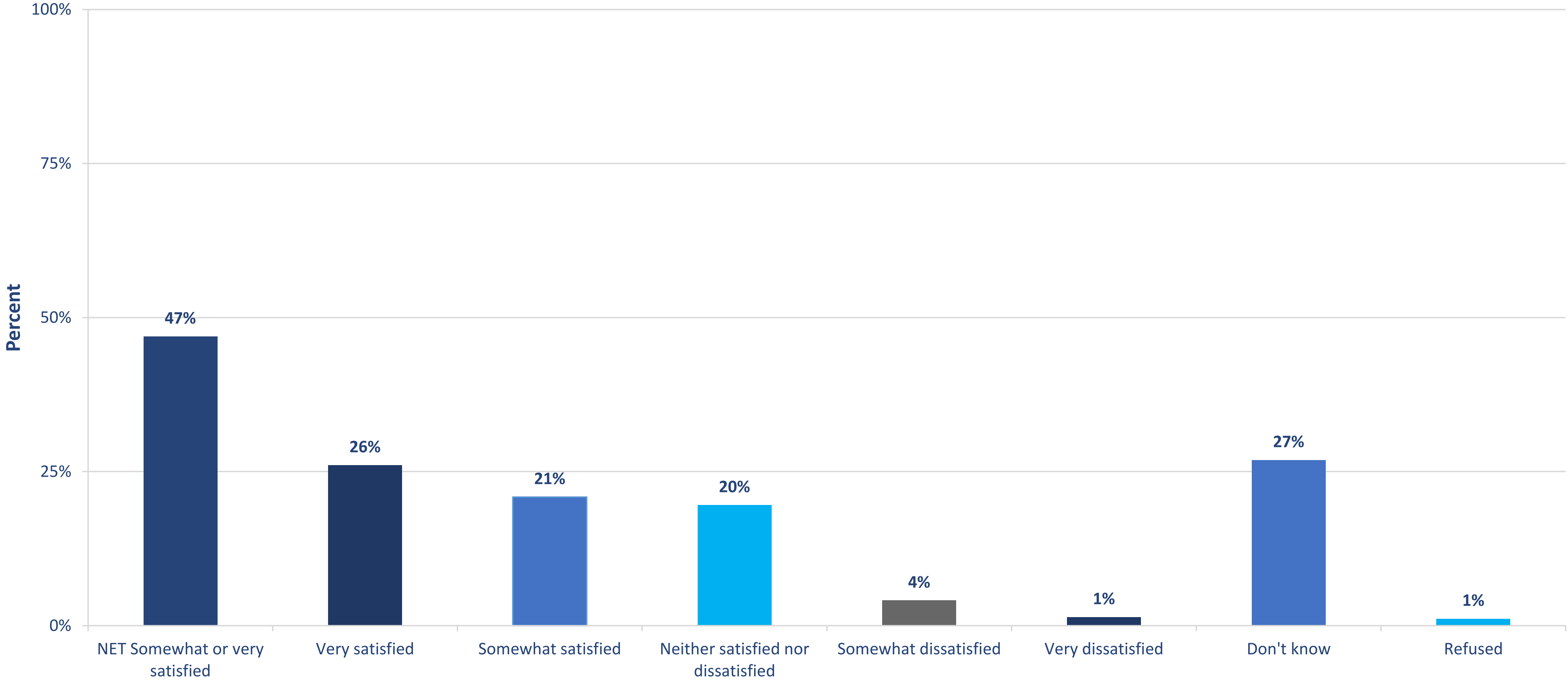
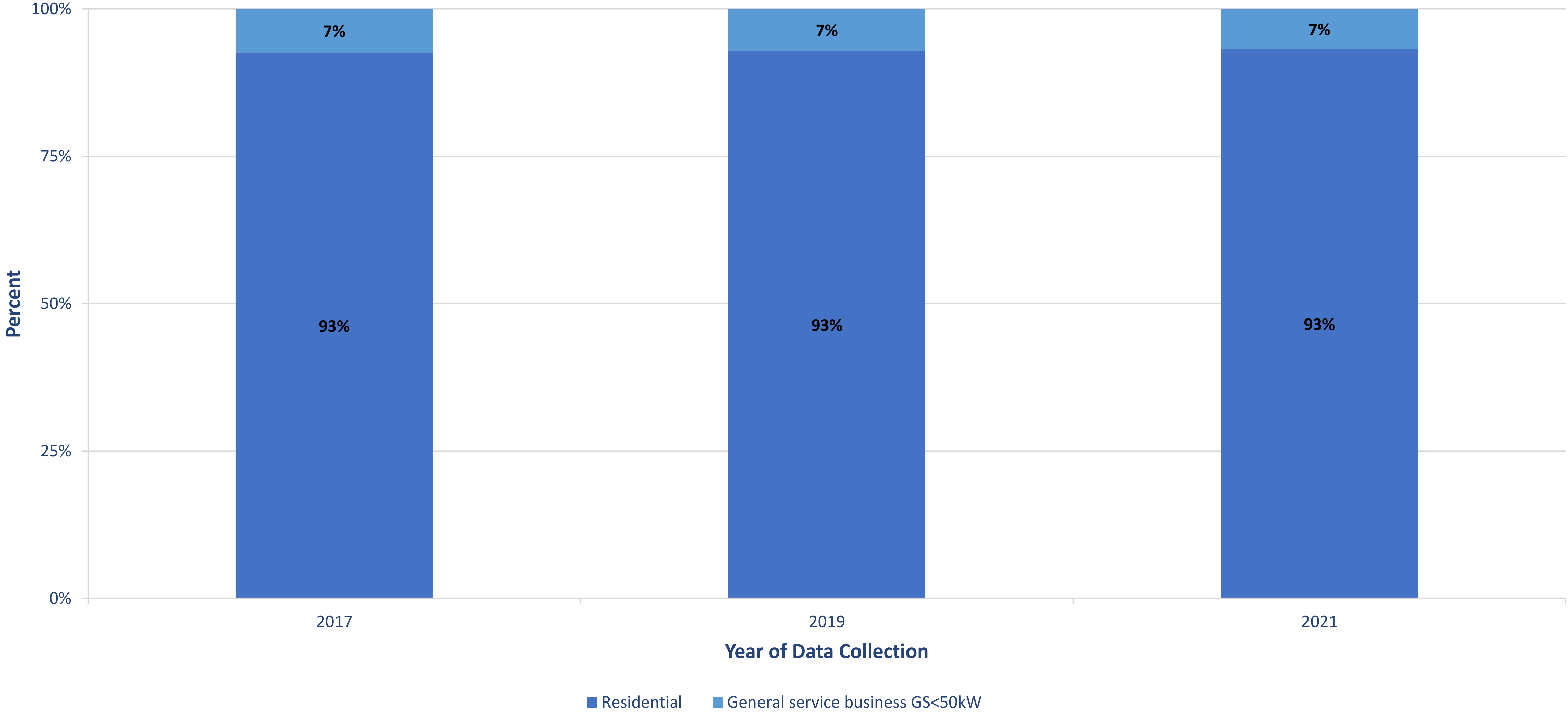
Thinking about how long it takes for EPCOR to respond to requests for service, are you...?



Source: Redhead Media Solutions/Advanis telephone random customer survey, January 15-February 25, 2021, n=402, accurate 4.8 percentage points plus or minus, 19 times out of 20.

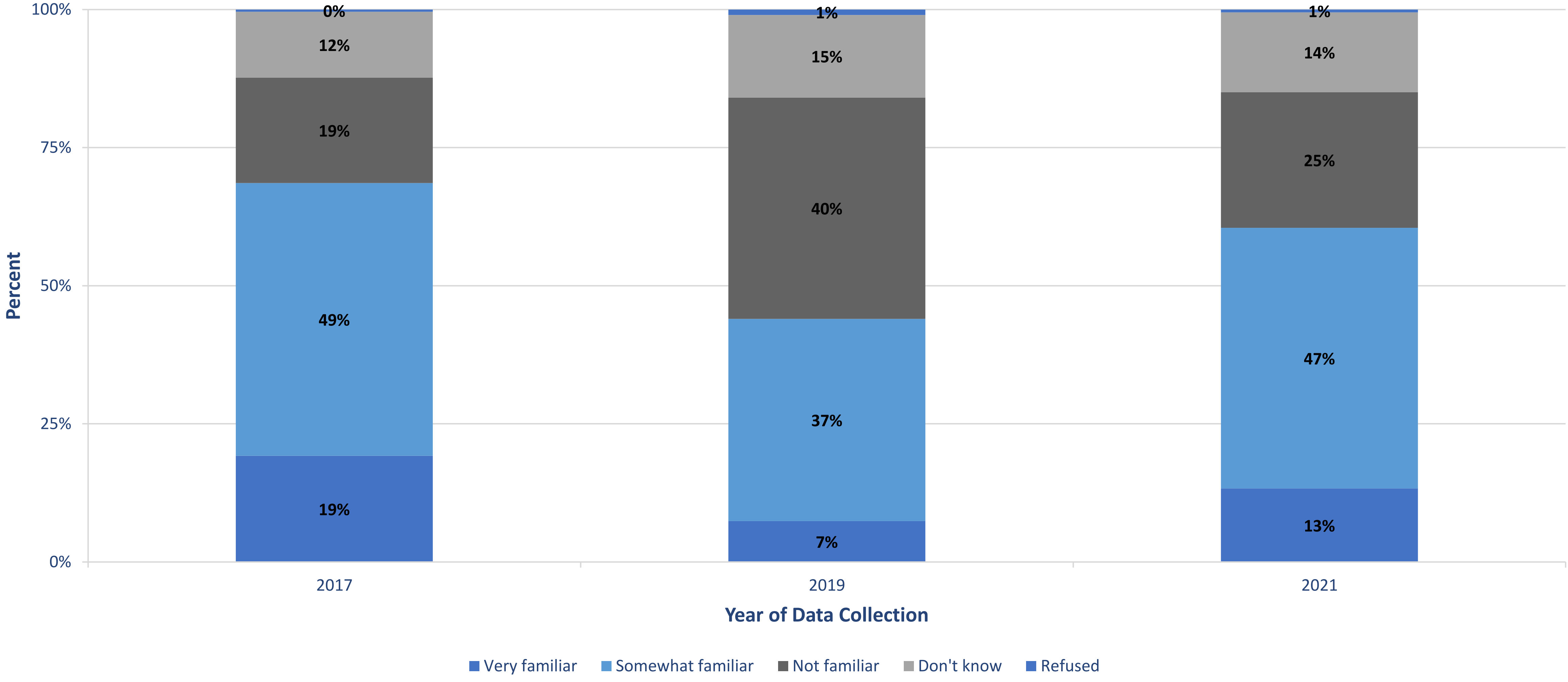
CORE COMPARATIVE DATA 2017-2021

Customer Type



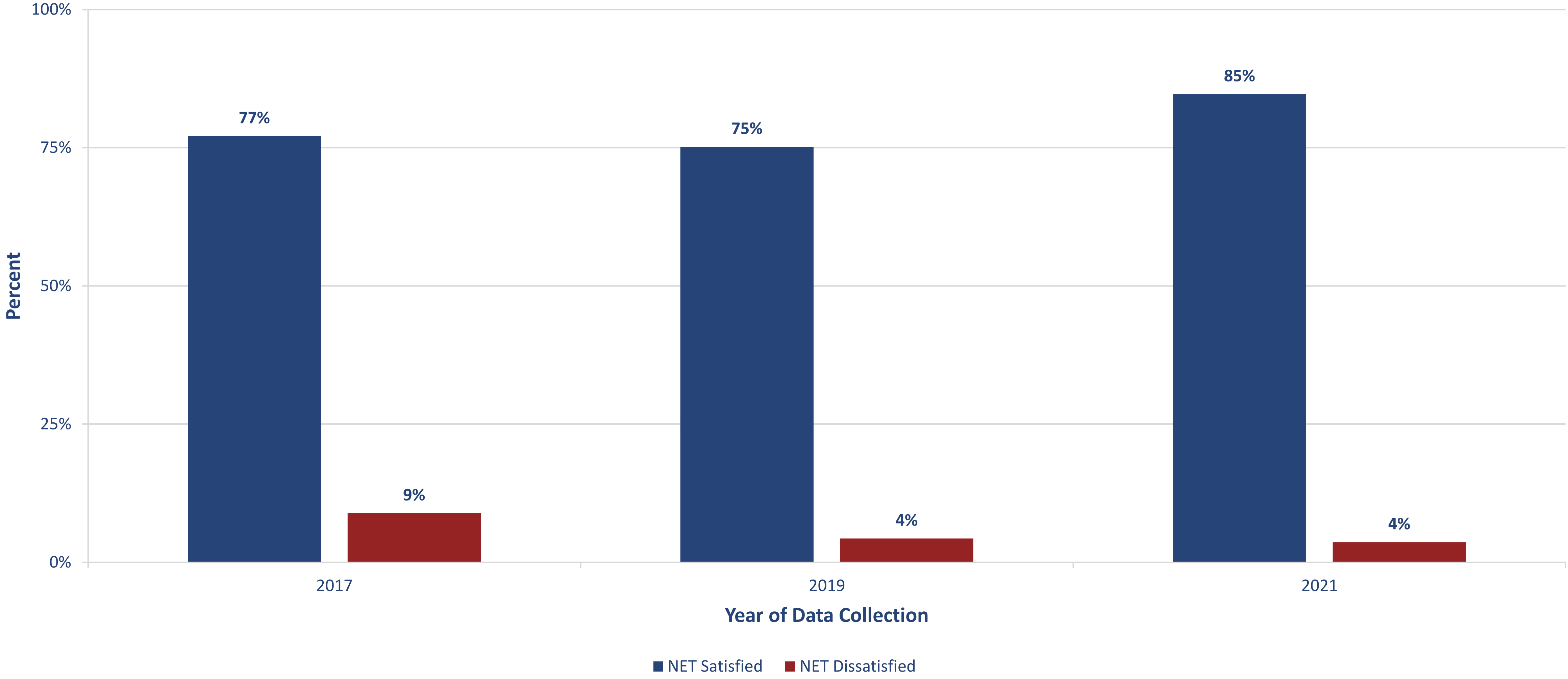
REDHEAD MEDIA SOLUTIONS INC

How familiar are you with EPCOR, which operates the electricity distribution system in your community?

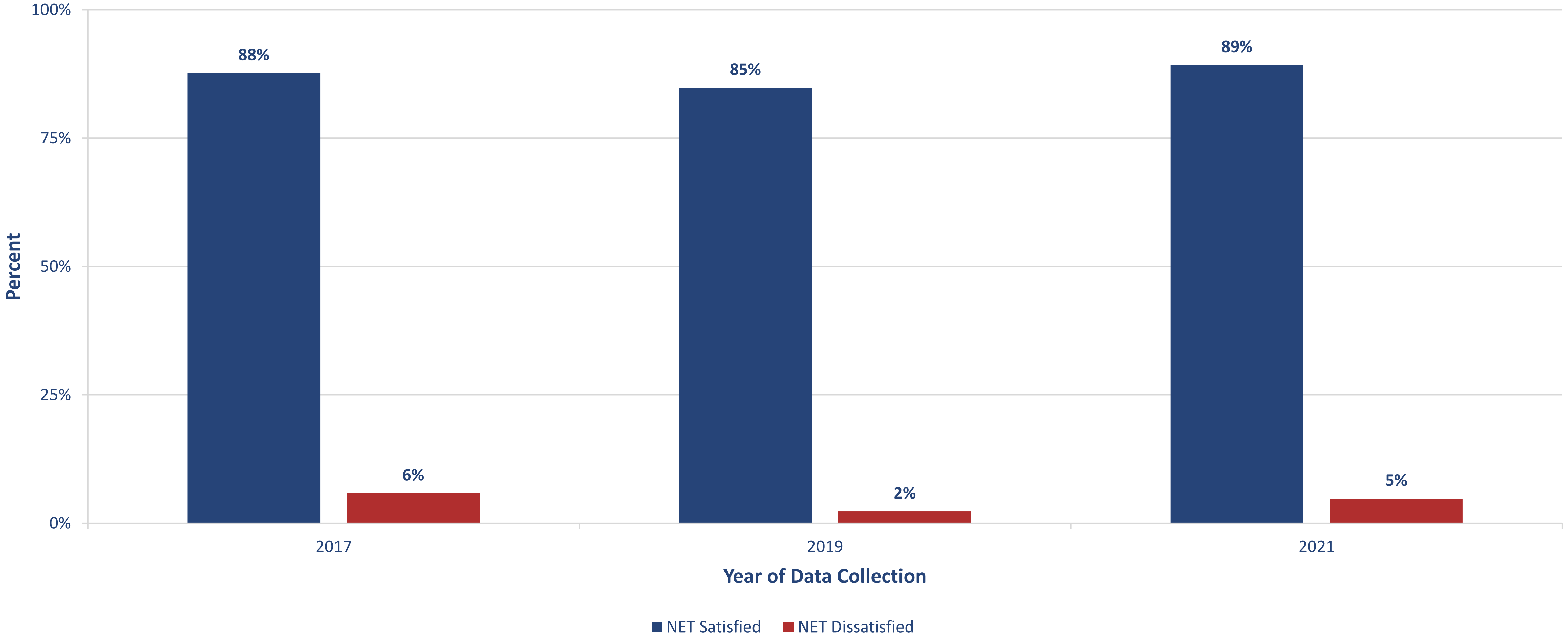


REDHEAD MEDIA SOLUTIONS INC

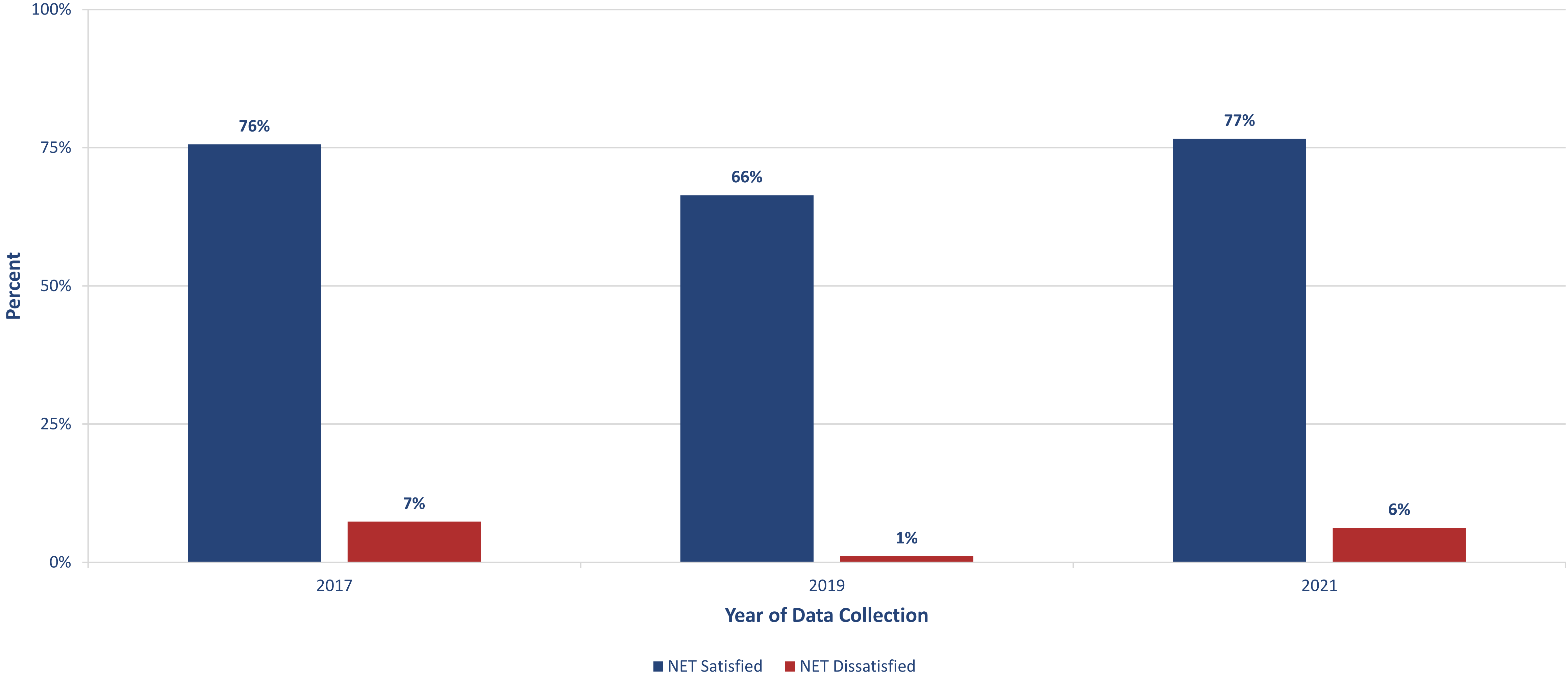
Thinking specifically about the services provided to you and your community by EPCOR, overall, how satisfied are you with the services that you receive from EPCOR?



The reliability of your electricity service – as judged by the number of power outages you experience: How satisfied are you with the electrical service that you receive from EPCOR based on...?



The amount of time it takes to restore power when power outages occur: How satisfied are you with the electrical service that you receive from EPCOR based on...?



REDHEAD MEDIA SOLUTIONS INC

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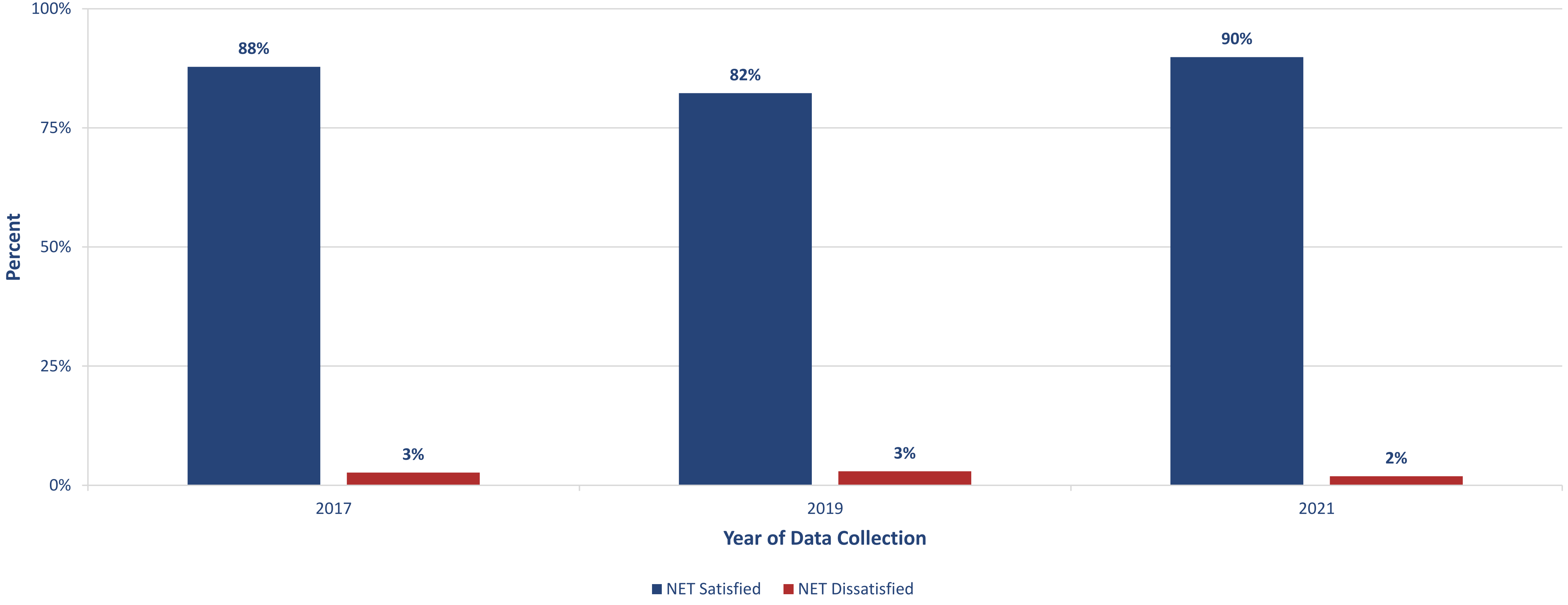

REDHEAD MEDIA SOLUTIONS INC

Providing accurate bills: How satisfied are you with the bills that you receive from EPCOR based on them...?

REDHEAD MEDIA SOLUTIONS INC

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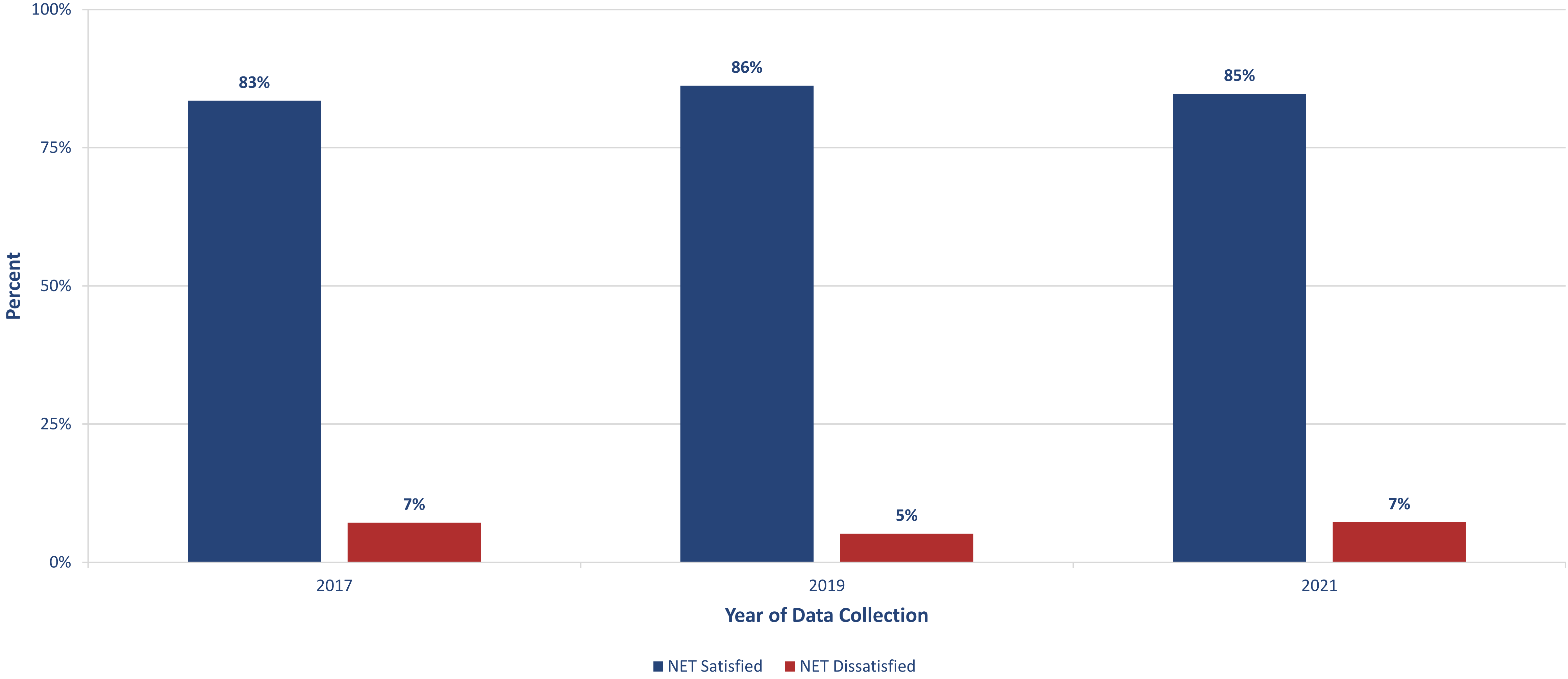

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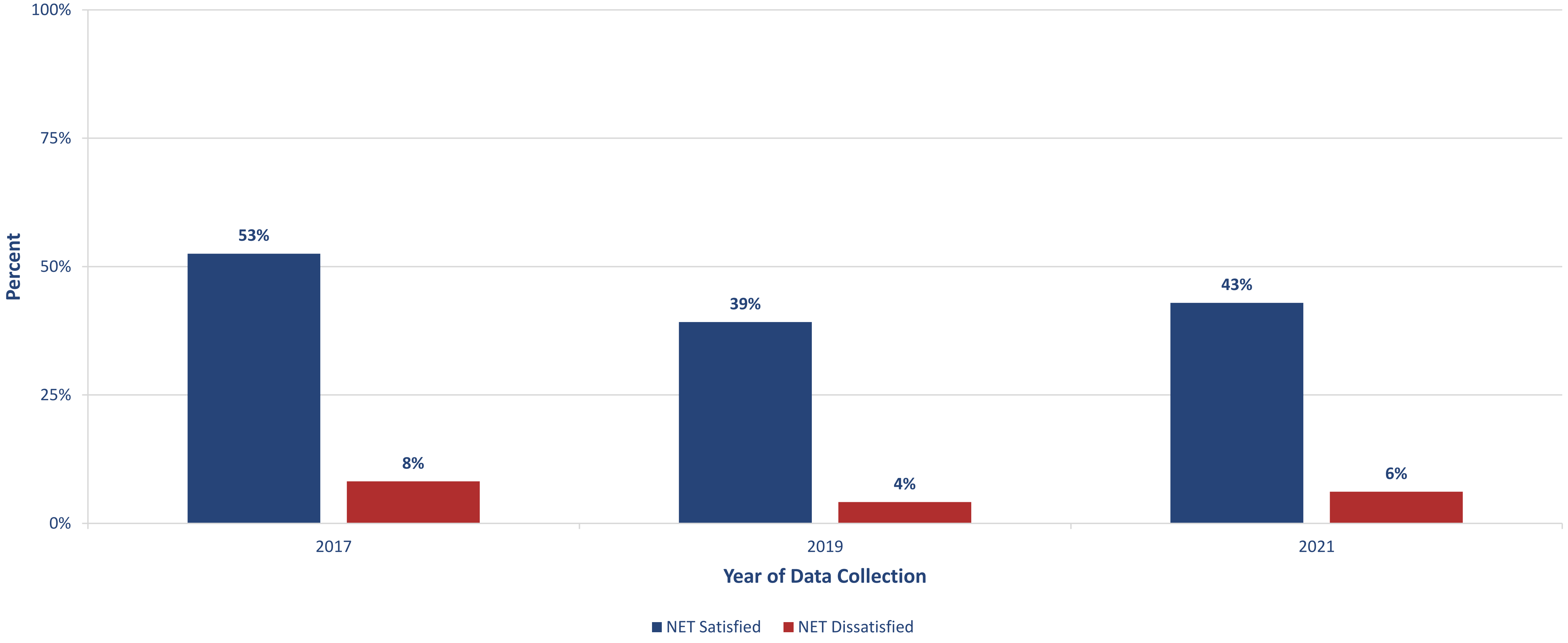

REDHEAD MEDIA SOLUTIONS INC

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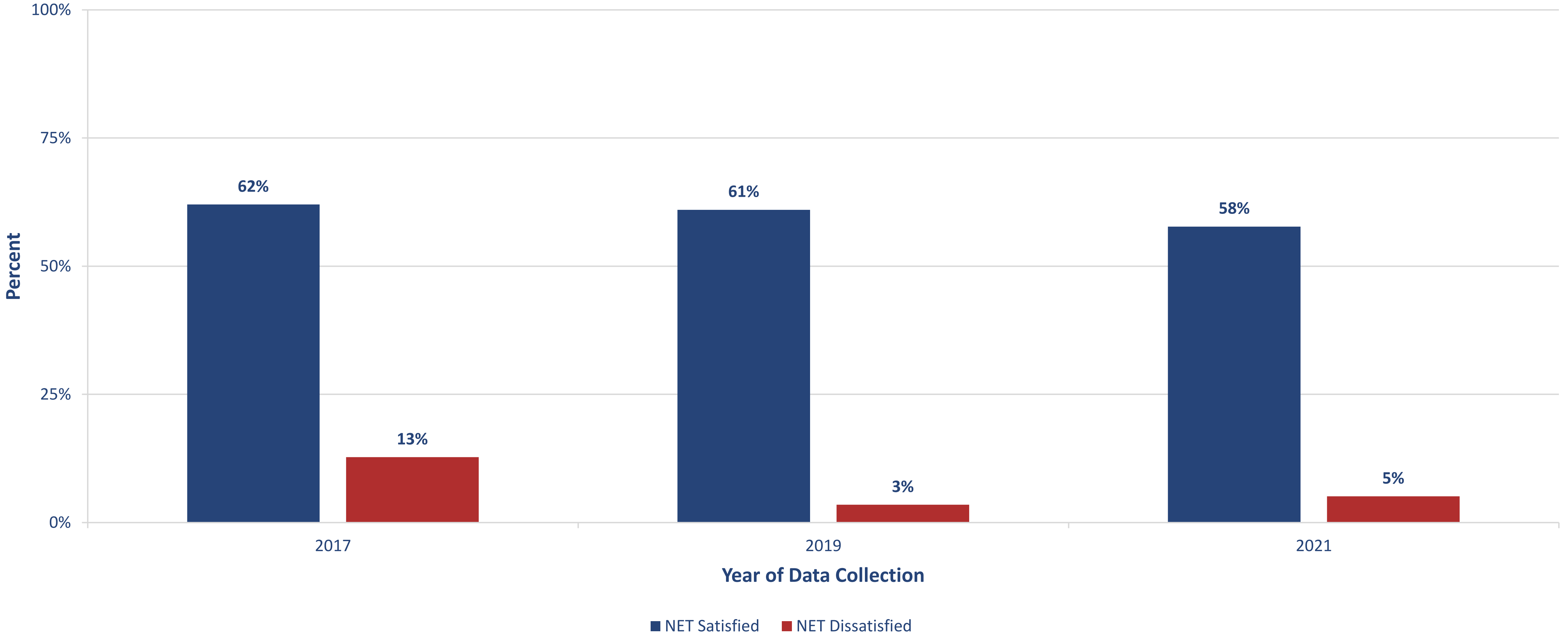

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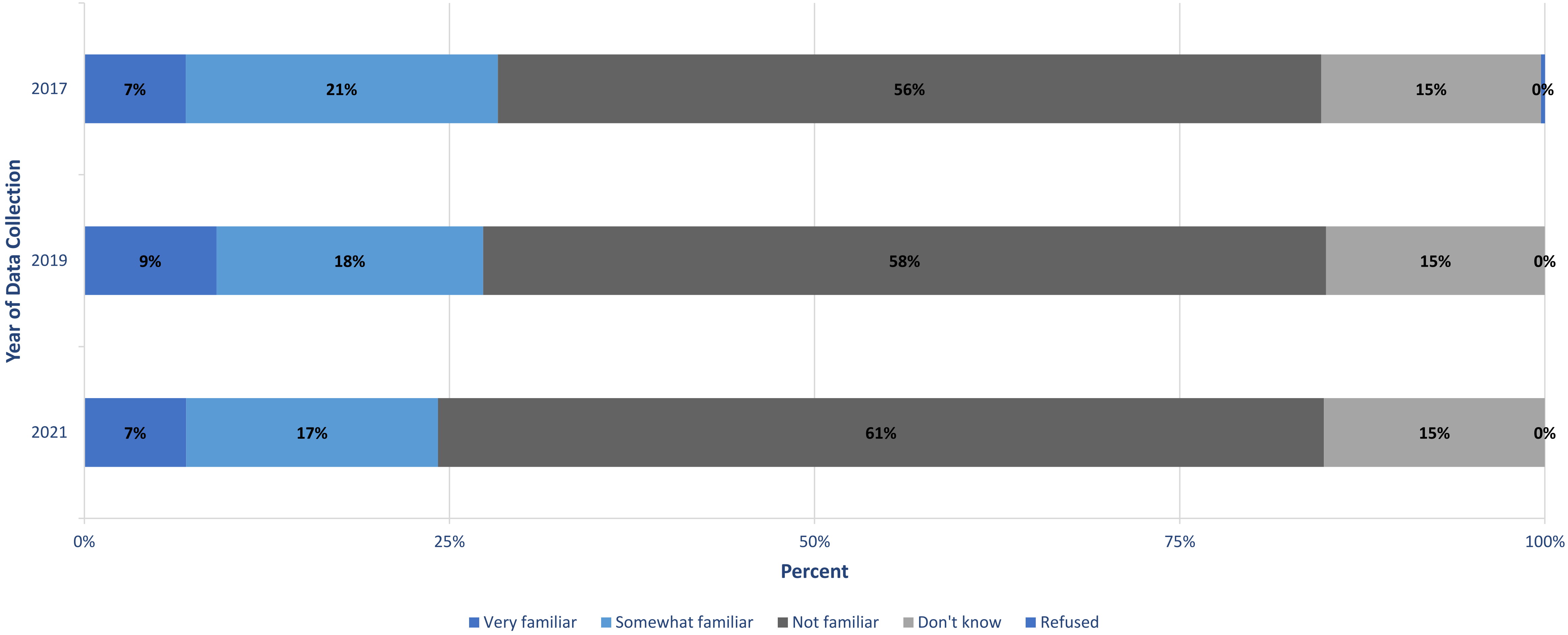
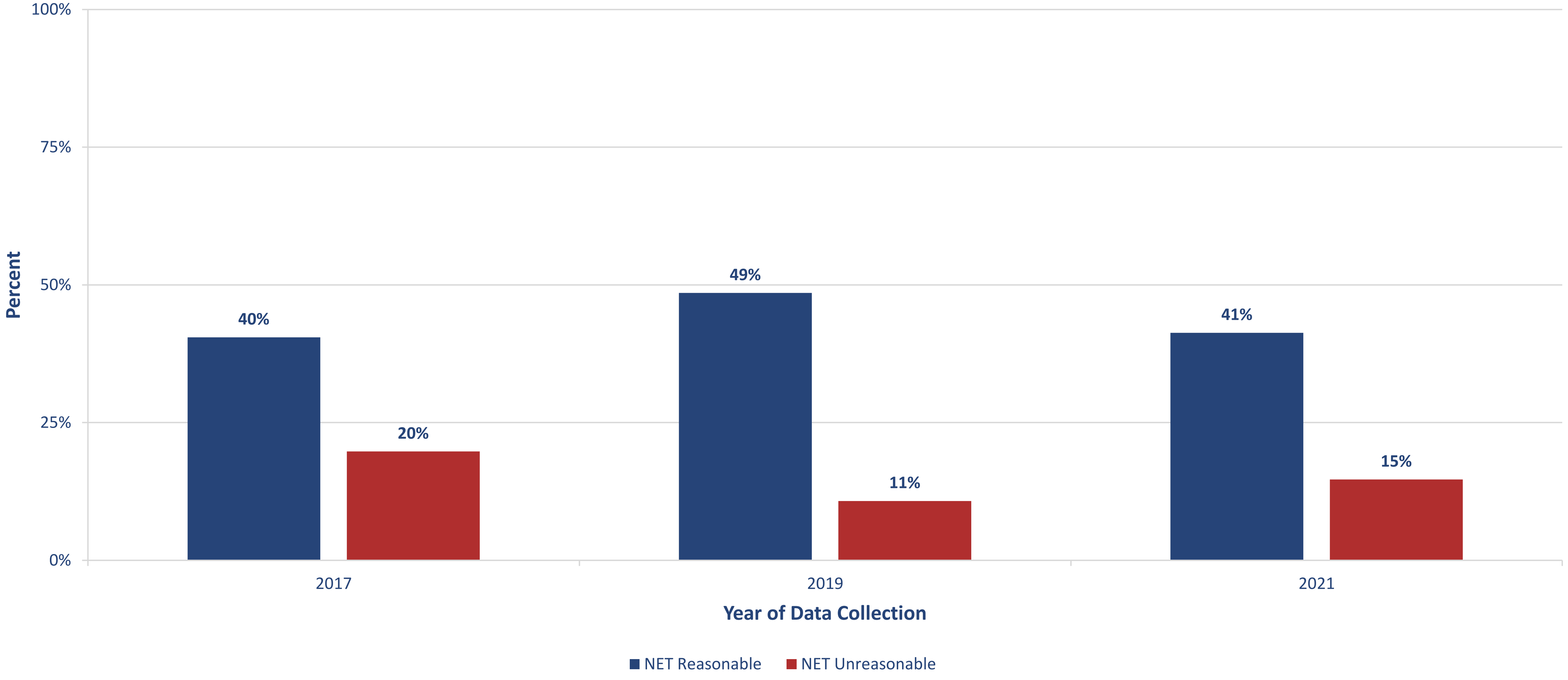
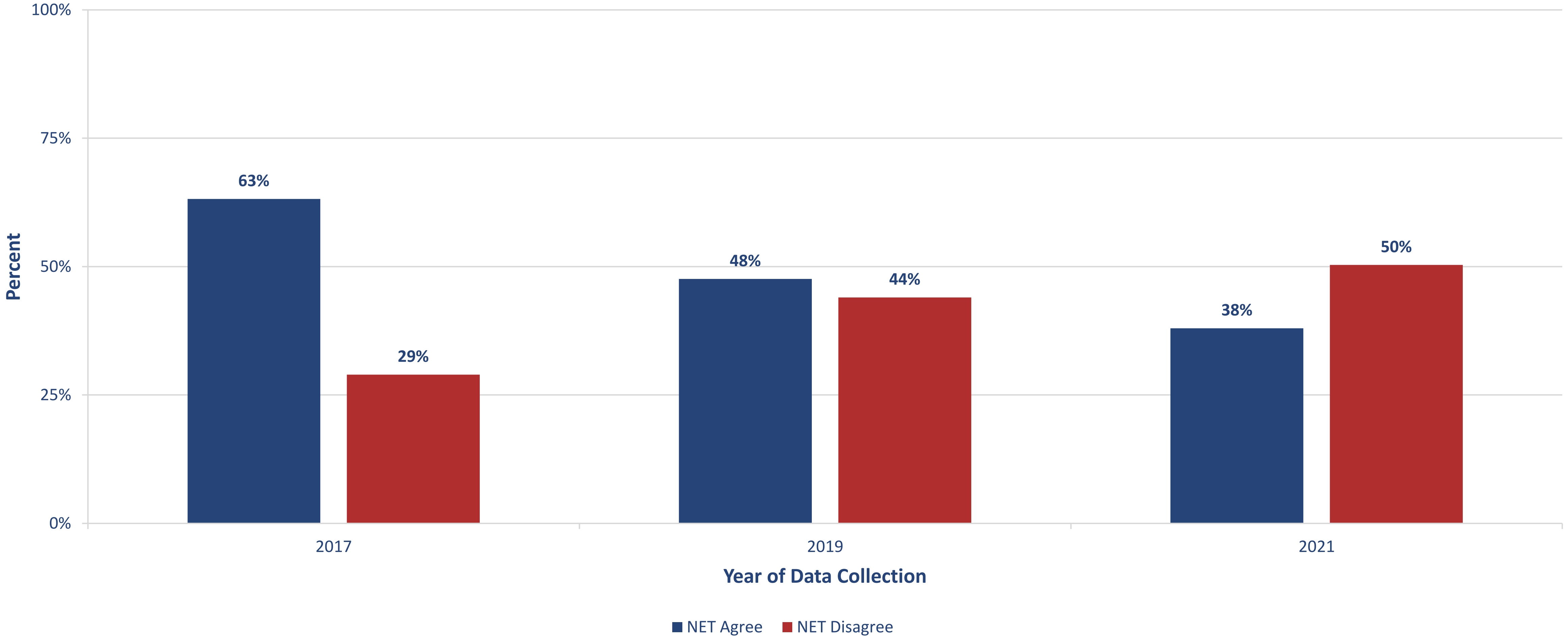


Do you feel that the percentage of your total electricity bill that you pay to EPCOR for the services they provide is...?



REDHEAD INC
MEDIA SOLUTIONS

The cost of my electricity bill has a major impact [on personal finances OR bottom line of organization]: To what extent do you agree with the following statements regarding the electricity system in Ontario?



REDHEAD MEDIA SOLUTIONS INC

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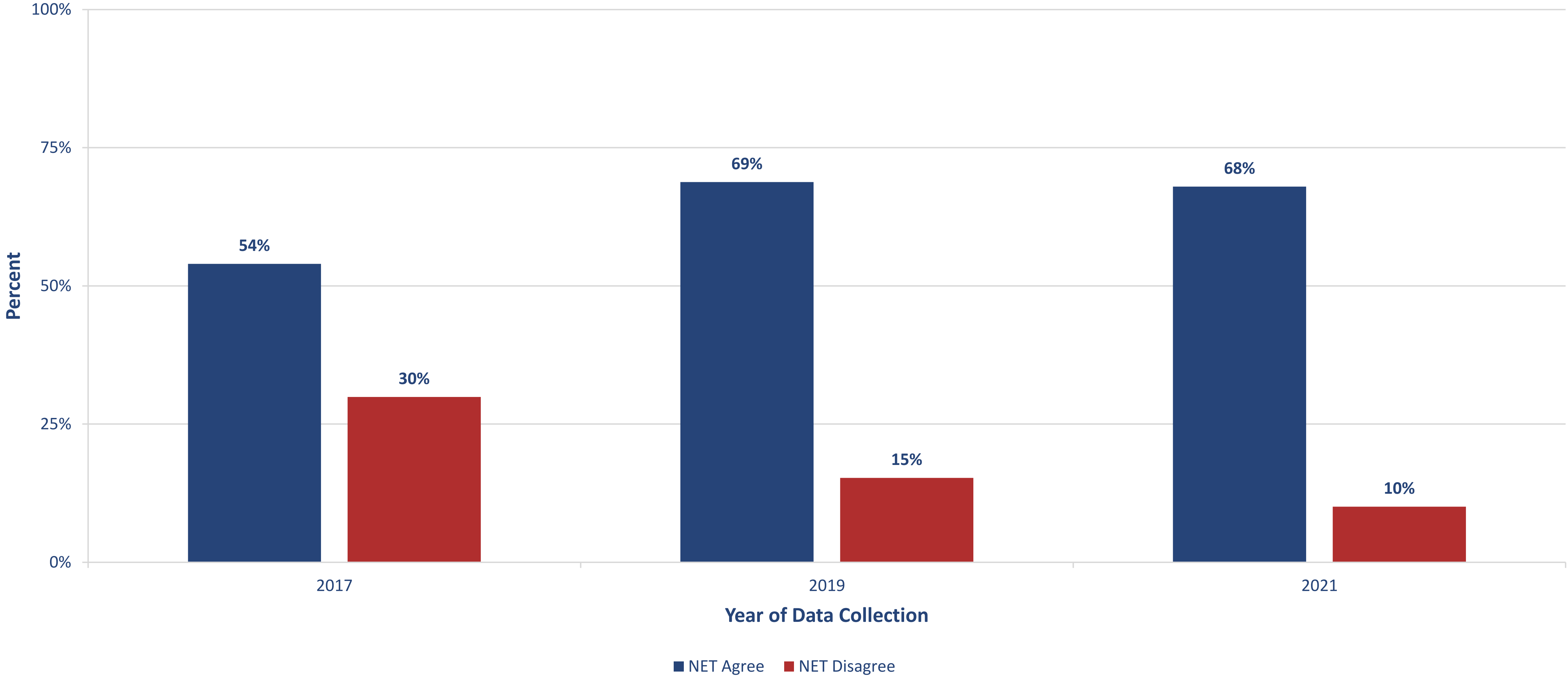
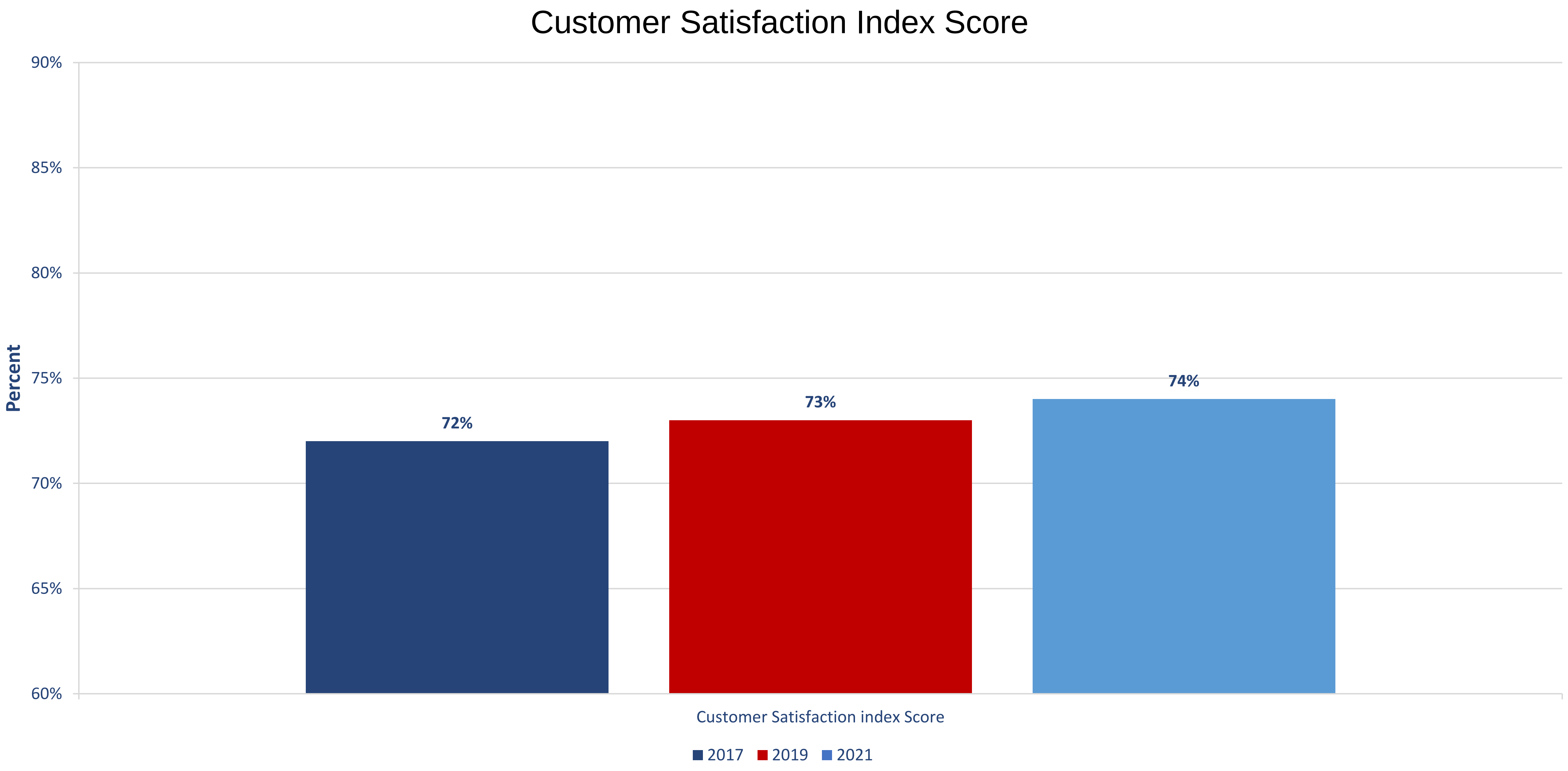


REDHEAD MEDIA SOLUTIONS INC



REDHEAD INC
MEDIA SOLUTIONS

METHODOLOGY

REDHEAD MEDIA SOLUTIONS INC

Methodology Summary

Commissioned by	EPCOR Inc.
Sample size	402 randomly selected customers
Margin of error	±4.8 percentage points, 19 times out of 20
Survey mode	Random telephone survey of customer base, CATI data collection
Survey sample	Residential and GS <50kWh customer lists provided by EPCOR
Time of calling	4PM-9PM Weekdays, 10AM-5PM Saturdays, scheduled callbacks
In-field dates	January 15-February 25, 2021
Language	English only
Survey author	Innovative Research/Electricity Distributors Association
Question Order	Report shown in order
Question Wording	Questions shown in report as asked
Survey Company	Redhead Media Solutions Inc/Advanis

REDHEAD MEDIA SOLUTIONS INC

Methodology Details

Target Respondents

The respondents of the survey were Ontario residents who are the primary bill payer or share the responsibility if residential or the person in-charge of managing the electricity bill at the organization if general service, and who resided within one of EPCOR's service territory(ies). Service territories were determined based on customer lists provided by EPCOR.

Sample Size and Statistical Reliability

The final total completed surveys by LDC, and the associated margin of error for each, are shown below.

All margins of error are shown at a 95% confidence level.

- E.g., the margin of error associated with a sample size of 400 for a large (infinite) population is ±4.9 percentage points, 19 times out of 20.

Since EPCOR has a finite population, we used the specific population sizes (i.e., the number of samples records received from EPCOR) in the calculation of margin of error. Doing so is more accurate, and results in a narrower margin of error than if we simply assumed large (infinite) population for each.

Sample sizes were set according to the *LDC Customer Satisfaction Survey: Methodology & Survey Implementation Guide*, prepared for the Electrical Distributors Association (April 19, 2016 revision):

Where possible, sample size of n=400.
Distributors with 3000 to 4999 customers (residential + GS<50), n=300
Distributors with <3000 customers (residential + GS<50), n=200

Methodology Details

Sampling Methodology

Redhead was provided sample lists from EPCOR. Customer lists included all basic information required such as name, telephone number, region (where applicable), customer type (residential or GS<50), LDC fee, Annual or Monthly consumption values. Redhead then calculated which quartile group each resident belonged to by evenly dividing them into four groups within each region and customer type. These quartiles were calculated based on annual consumption value.

To minimize low response:

- Sample was loaded in batches to ensure the sample was fully utilized before moving onto fresh sample records;
- Calls were made between the hours of 4pm and 9pm ET; and
- Call backs were scheduled and honored between the hours of 9am and 9pm ET.

Sample Cleaning

Redhead cleaned the customer lists individually once received from each LDC to ensure the customer list counts reflected actual individual records that could be called. The following steps were taken during sample cleaning.

- All records with no phone numbers were removed.
- All phone numbers were checked to see if they were valid numbers (i.e. 10 digits, all numerical, etc.) and any bad cases were removed.
- When duplicates were detected based on phone number, the average of the consumption value was calculated and kept for one consolidated record. All others were removed.
- Residential and GS<50KW were separated into their own lists to be loaded and managed separately in the calling system.

Regions within each customer list were given a numerical value to be used for calling quotas.

Methodology Details

Questionnaire

The survey instrument was provided by the Electricity Distributors Association (EDA) developed in conjunction with Innovative Research. The survey consisted of an introduction, overall satisfaction, power quality and reliability, billing and payment, customer service experience, communications, price, optional deeper dive questions, and final personal finance / sector mood measures. Additional questions were provided individually by EPCOR. These questions are not required as part of the survey and, as outlined in the methodology guideline, were asked after all the standard and required questions.

Data Collection

Computer aided telephone interviews (CATI) were conducted from January 15-February 25, 2021.

Quality Control

- Advanis, on behalf of Redhead, trained the interviewers to understand the study's objectives;
- Detailed call records are kept by the automated CATI system, and are supplemented by output files to SPSS for productivity analysis (i.e., not subject to human error);
- The survey was soft launched in LDCs that had the most available sample, and the data was then checked before calling began in full for EPCOR;
- 100% of all surveys are digitally recorded for potential review (see next bullet);
- Advanis' Quality Assurance team listened to the actual recordings of five percent of completed surveys and compared the responses to those entered by the interviewer to ensure that responses from respondents are properly recorded;
- Team Supervisors conduct regular more formal evaluations with each interviewer, in addition to nightly monitoring of each interviewer on their team;
- Project Managers closely monitored the progress of data collection, including call record dispositions;
- All SPSS code is reviewed by a more senior researcher;
- All Report Builder output is reviewed by a more senior researcher; and
- All values in the report are reviewed by another team member to ensure accuracy.

Methodology Details

Analysis of Findings & Data Weighting

Results were weighted to match the proportion of low volume rate class records as provided to Redhead after cleaning of the sample file. Where a region flag was also provided, results were weighted to the low volume rate class within each region and regions were weighted proportionately to one another based on the customer base as provided in the cleaned sample file.

The Customer Satisfaction index scores have been highlighted and were calculated as described below, based on instructions in the Survey Methodology Guidelines. The "response values" referenced in the description below were also determined and provided by the survey authors.

Data analysis and cross-tabulation have been conducted using SPSS and Report Builder software.

This **index score** is calculated using the following process:

Step 1: Weight data to n=400 with each low volume rate class proportionate to its share of LDC customer base.

Step 2: Rescale the index score variables onto the 0 to 1 scale as indicated by the response values detailed below.

Step 3: The average result of the questions asked for each OEB topic and the overall satisfaction score will be added together[3].

	B5
+	[C6+C7+C8] divided by 3
+	[D9+D10] divided by 2
+	**E11**
+	**F12**
+	**G14**
=	**Total cumulative scores**

Step 4: The total cumulative score from Step 2 will be divided by 6 to generate the **Customer Satisfaction Index Score** (bound between 0-1).

The chart on the following page illustrates how the **Customer Satisfaction Index Score** will be calculated.

As noted above, LDCs without a region flag were weighted to their low volume rate class proportion based on the cleaned sample file. LDCs with a region flag were weighted to their low volume rate class proportion within each region based on the cleaned sample file, and then regions were weighted proportionately to one another based on the customer base as provided in the cleaned sample file.

Specific values of the number of sample records, estimated population proportions, and final weighted sample counts within EPCOR are provided below. The sum of the regional population proportions within an LDC may not equal 100% due to rounding.

REDHEAD MEDIA SOLUTIONS INC

Methodology Tables

Margin of error

LDC	Customer Records from LDC	Completed Surveys	Sample Size as % of Customer list	Margin of Error @ 95% confidence level
EPCOR	13,639	402	2.95%	+/- 4.8%

Sample weighting

EPCOR Electricity Distribution Ontario						
Regions Flagged in Sample	Low Volume Rate Class	Clean, Deduplicated Sample Received	Rate Class Proportion	Estimated Customer Proportion	Weighted Sample Count	Unweighted Sample Count
Collingwood	Residential	9,892	94%	77%	292	270
	General Service < 50 kW	652	6%		19	18
Creemore	Residential	425	90%	3%	13	17
	General Service < 50 kW	49	10%		1	2
Stayner	Residential	1,292	91%	10%	38	53
	General Service < 50 kW	125	9%		4	5
Thornbury	Residential	1,105	92%	9%	33	34
	General Service < 50 kW	99	8%		3	3
TOTAL	**Residential**	**12,714**	**93%**	**100%**	**375**	**374**
	General Service < 50 kW	**925**	**7%**		**27**	**28**
					402	**402**

REDHEAD INC
MEDIA SOLUTIONS

Thank You

We greatly appreciate working on this important project for EPCOR and hope we have met or exceeded your expectations.

We are happy to present this data to your staff or Board members upon request. If you wish to do so, please contact us for an appointment.

We look forward to working with you on future projects, including the Electricity Safety Awareness Survey later in 2021. Please note if you have any other projects that we may be able to help you with, don’t hesitate to be in touch.

Graydon Smith - President
Redhead Media Solution Inc.
505 Hwy 118 W.
Suite 416
Bracebridge, ON
P1L 2G7

EPCOR

REDHEAD
MEDIA SOLUTIONS INC

2019 Customer Satisfaction Survey Final Report

For EPCOR

By Redhead Media Solutions Inc.

April 15, 2019

Introduction and Summary

Thank you for selecting Redhead Media Solutions Inc. for this important project for EPCOR. We appreciate your confidence in us to provide you with data on Customer Satisfaction that can now be used to compare with the previous survey in 2017 and among other LDCs.

We have restructured our reporting to you this year, replacing the traditional single report with tables and transitioning to a more robust and informative graphics based style that gives you the ability to see differences "at a glance" as opposed to simply comparing numbers. To supplement this report, we have also included the full set of 2019 tables, comparative 2017/2019 tables and comments for question G15 (open comments) in spreadsheet format, allowing you easy access to the data we have generated. You can find this as part of the email we sent labelled "Appendix A". The methodology guide, as well as residential and general service questionnaires are also included as appendices B, C and D for your reference.

Should there be any specific data or breakouts that you require, please contact us to discuss.

Graydon Smith
President

Introduction and Summary

Redhead Media Solutions Inc. (Redhead), partnering with ADVANIS for data collection and reporting, has been retained (via an RFP process by Cornerstone Hydro Electric Concepts Inc. - CHEC) to conduct a 2019 Customer Satisfaction Survey for EPCOR. This survey is a required part of an LDC's Balanced Scorecard and other reporting and regulatory requirements for the Ontario Energy Board (OEB).

The complete group of participating CHEC LDCs are as follows:

- Centre Wellington Hydro
- EPCOR
- Grimsby Power
- Lakefront Utilities
- Lakeland Power Distribution
- Niagara-on-the-Lake Hydro
- Orangeville Hydro
- Ottawa River Power
- Renfrew Hydro
- Rideau St. Lawrence Distribution
- Tillsonburg Hydro
- Wasaga Distribution
- Wellington North Power

Additionally, Redhead also provided services for this project outside the CHEC group of LDCs.

Introduction and Summary

This final report contains data specifically for EPCOR.

The survey is comprised of approximately 400 randomly selected interviews of EPCOR customers among the low volume customer base (residential customers and general service under 50kW customers; GS<50kW). Residential customers were asked to confirm that they receive an electricity or hydro bill from EPCOR and that they are the primary payer of that bill, or share the responsibility.

GS<50kW customers were also asked to confirm they receive an electricity or hydro bill from EPCOR, and additionally to confirm that the person who manages the organization's electricity bill was the one to complete the interview. The sample frame is stratified on region (where applicable) and consumption quartiles by rate class in accordance with the "Survey Implementation Requirements" on page 4 of the "EDA/Innovative Customer Satisfaction Scorecard: Methodology & Survey Implementation Guide" which is contained in Appendix B of this report.

The objective of the survey is to provide an Overall Customer Satisfaction index score for EPCOR. This is a calculated aggregate value based on responses of to 9 core measures in the survey instrument. In some cases, additional questions were asked but not included in the calculation of the Customer Satisfaction Index Score.

EPCOR's 2019 Customer Satisfaction Index Score is 73.0%, This is a 1.2% increase over the 2017 score (71.8%) and 6.4% less than the mean average of all CHEC LDCs (79.4%).

This falls within a very tight spectrum of index scores we processed for all LDCs that participated in the 2019 survey via Redhead. When the confidence interval is applied to all index scores, there is significant overlap between LDCs which underlines the statistical similarity of performance and satisfaction among participants. Statistically, EPCOR is similar to all but one other LDC surveyed.

The following report contains graphic data and tables for all prescribed questions as well as year-over-year comparative data (internal) and comparative scoring data (external). Additional data is available in the attached spreadsheet sheets and tables. (Appendix A)

Question scoring and index methodologies were prescribed by the EDA/Innovative. As such, there has been limited additional analysis provided beyond the direction provided to meet the reporting guidelines. Should you wish further analysis of the data please contact our office to discuss.

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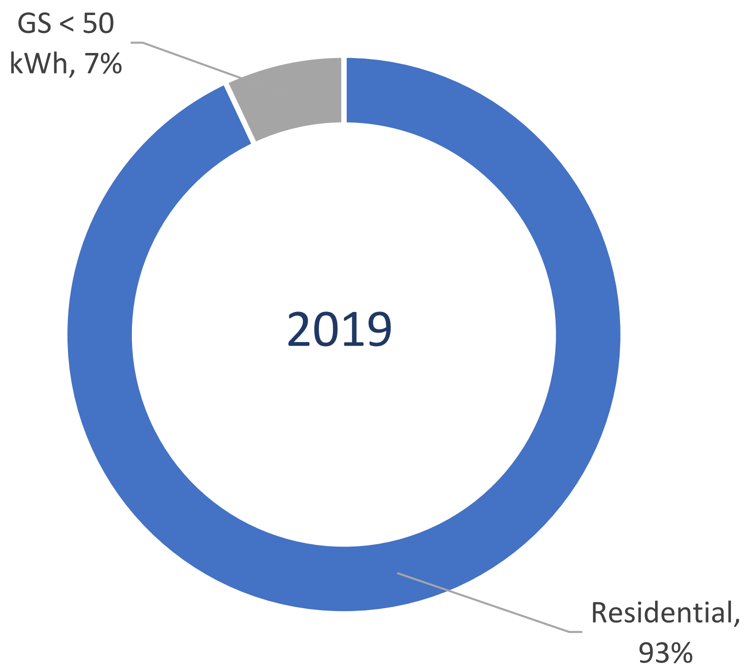
Customer Type: Low Volume Rate Class



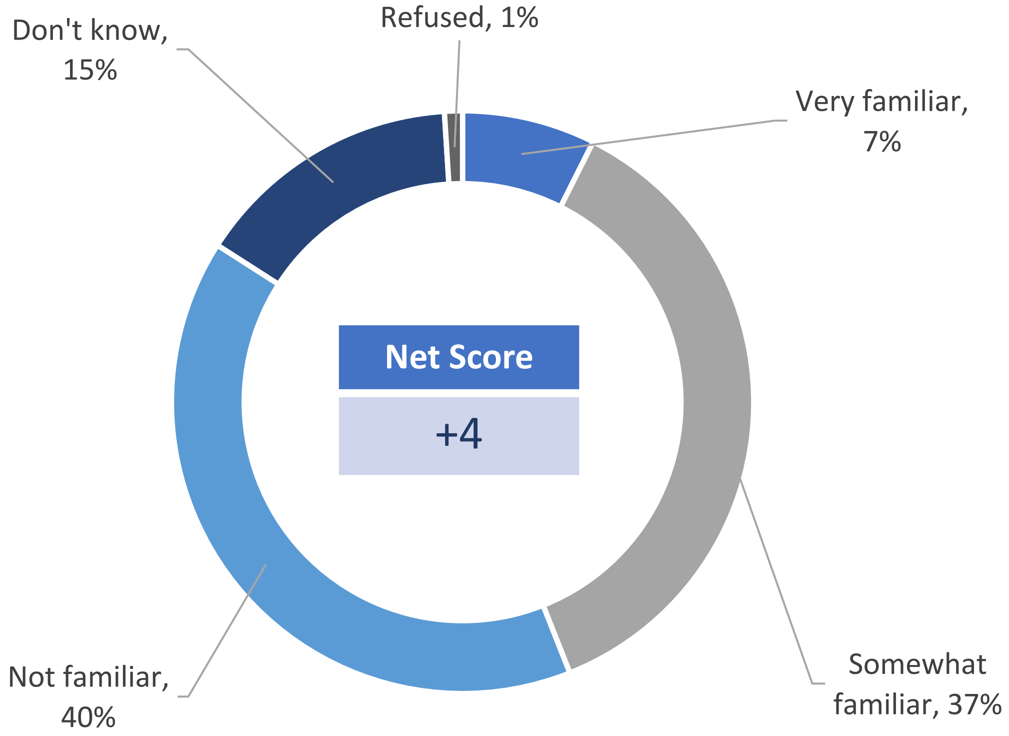
	Total	Residential	General service business GS<50kWh
Base: Total answering	400	371	29
Residential	93%	100%	0%
General service business GS<50kWh	7%	0%	100%

*Note: Charts and tables may not add up to 100% due to rounding

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 7, 2019, n=400, accurate 4.8 percentage points plus or minus, 19 times out of 20.

REDHEAD MEDIA SOLUTIONS INC

B4: How familiar are you with EPCOR, which operates the electricity distribution system in your community?



	Total	Residential	General service business GS<50kWh
Base: Total answering	400	371	29
Very familiar	7%	7%	8%
Somewhat familiar	37%	36%	39%
Not familiar	40%	40%	37%
Don't know	15%	15%	13%
Refused	1%	1%	4%

*Note: Charts and tables may not add up to 100% due to rounding

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 7, 2019, n=400, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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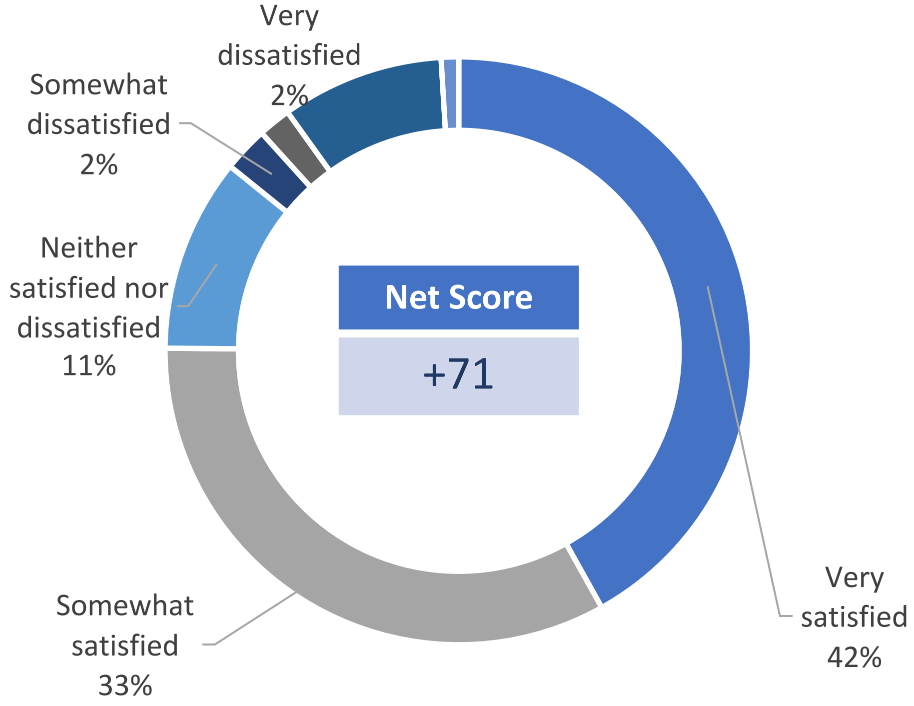
B5: Thinking specifically about the services provided to you and your community by EPCOR, overall, how satisfied are you with the services that you receive from EPCOR?

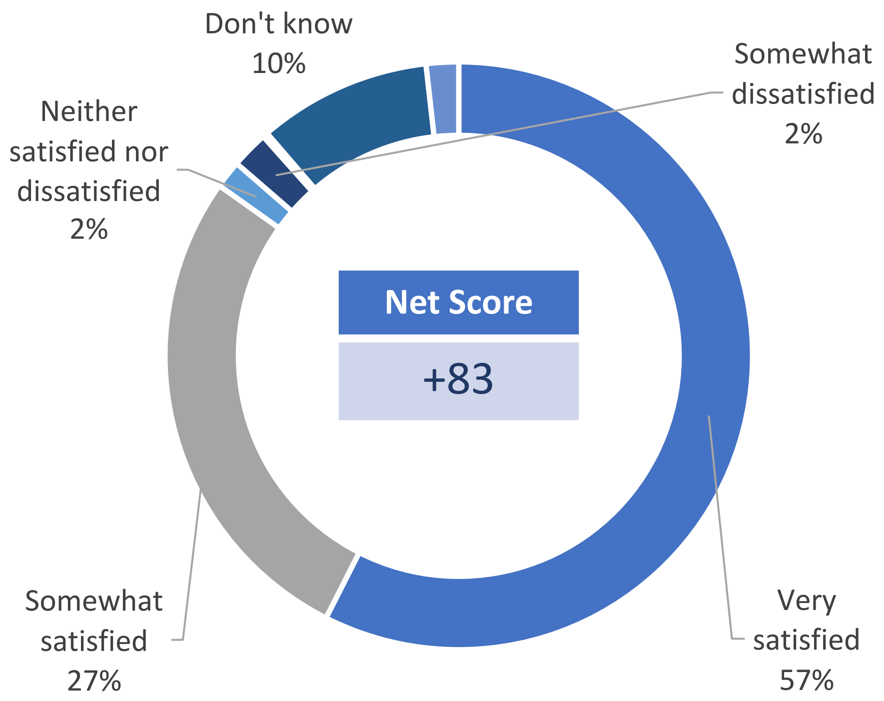


	Total	Residential	General service business GS<50kWh
Base: Total Answering	400	371	29
Very satisfied	42%	42%	45%
Somewhat satisfied	33%	32%	45%
Neither satisfied nor dissatisfied	11%	11%	3%
Somewhat dissatisfied	2%	2%	4%
Very dissatisfied	2%	2%	0%
Don't know	9%	9%	4%
Refused	1%	1%	0%

*Note: Charts and tables may not add up to 100% due to rounding

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 7, 2019, n=400, accurate 4.8 percentage points plus or minus, 19 times out of 20.

C6: Satisfaction with the reliability of your electricity service – as judged by the number of outages you experience.



*Note: Charts and tables may not add up to 100% due to rounding

	Total	Residential	General service business GS<50kWh
Base: Total Answering	400	371	29
Very satisfied	57%	58%	55%
Somewhat satisfied	27%	27%	36%
Neither satisfied nor dissatisfied	2%	2%	0%
Somewhat dissatisfied	2%	2%	0%
Very dissatisfied	0%	0%	0%
Don't know	10%	10%	6%
Refused	2%	2%	3%

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 7, 2019, n=400, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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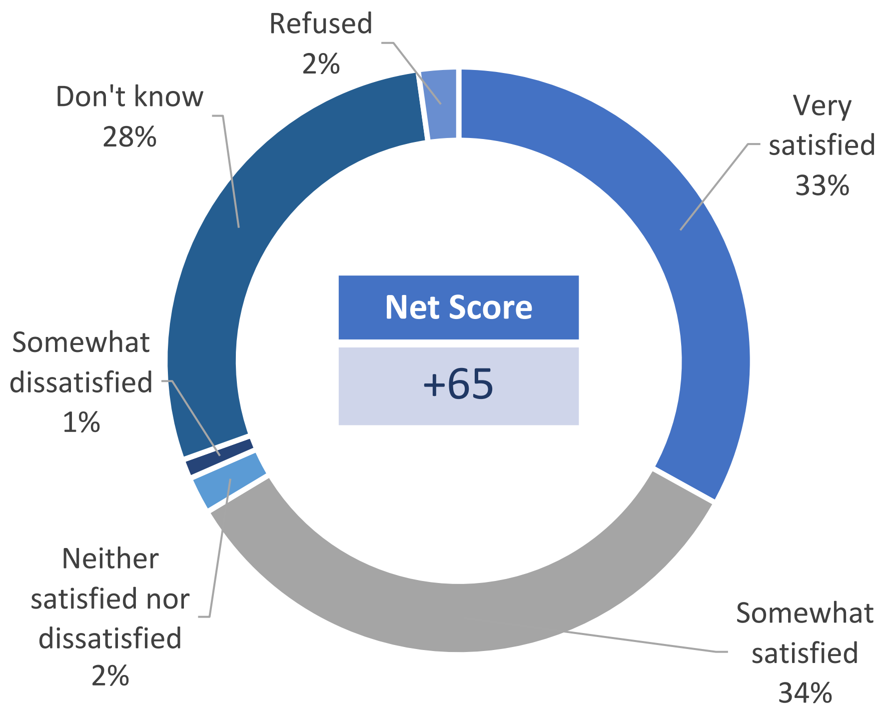
C7: Satisfaction with the amount of time it takes when outages occur.



	Total	Residential	General service business GS<50kWh
Base: Total Answering	400	371	29
Very satisfied	33%	34%	25%
Somewhat satisfied	34%	33%	42%
Neither satisfied nor dissatisfied	2%	2%	0%
Somewhat dissatisfied	1%	1%	0%
Very dissatisfied	0%	0%	0%
Don't know	28%	28%	30%
Refused	2%	2%	3%

*Note: Charts and tables may not add up to 100% due to rounding

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 7, 2019, n=400, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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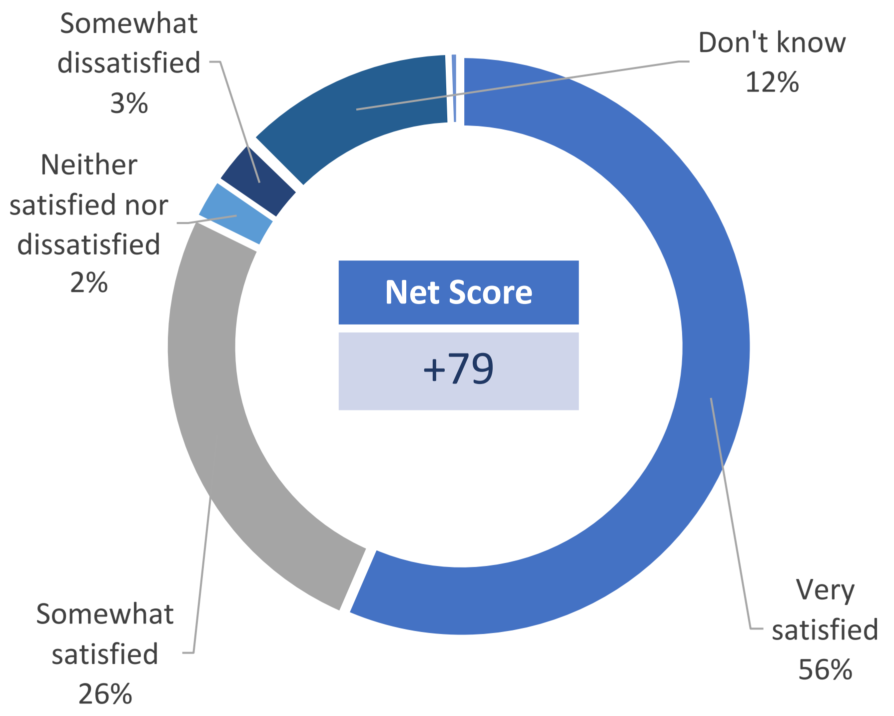
C8: Satisfaction with the quality of power delivered to you as judged by the absence of voltage fluctuations that can result in the flickering or diming of lights or may affect your equipment.



	Total	Residential	General service business GS<50kWh
Base: Total Answering	400	371	29
Very satisfied	56%	57%	54%
Somewhat satisfied	26%	25%	37%
Neither satisfied nor dissatisfied	2%	2%	0%
Somewhat dissatisfied	3%	3%	0%
Very dissatisfied	0%	0%	0%
Don't know	12%	12%	9%
Refused	1%	1%	0%

*Note: Charts and tables may not add up to 100% due to rounding

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 7, 2019, n=400, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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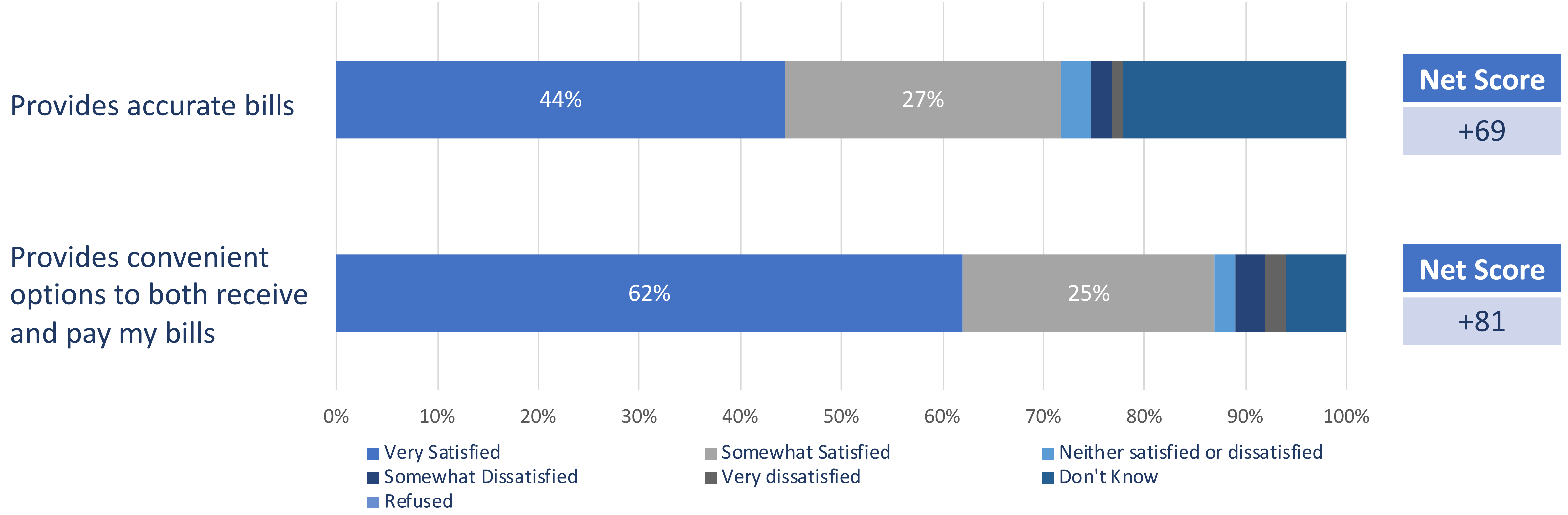
D9/D10: For each of the following statements about the bills that you receive from EPCOR, please tell me how satisfied you are…



*Note: Charts and tables may not add up to 100% due to rounding

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 7, 2019, n=400, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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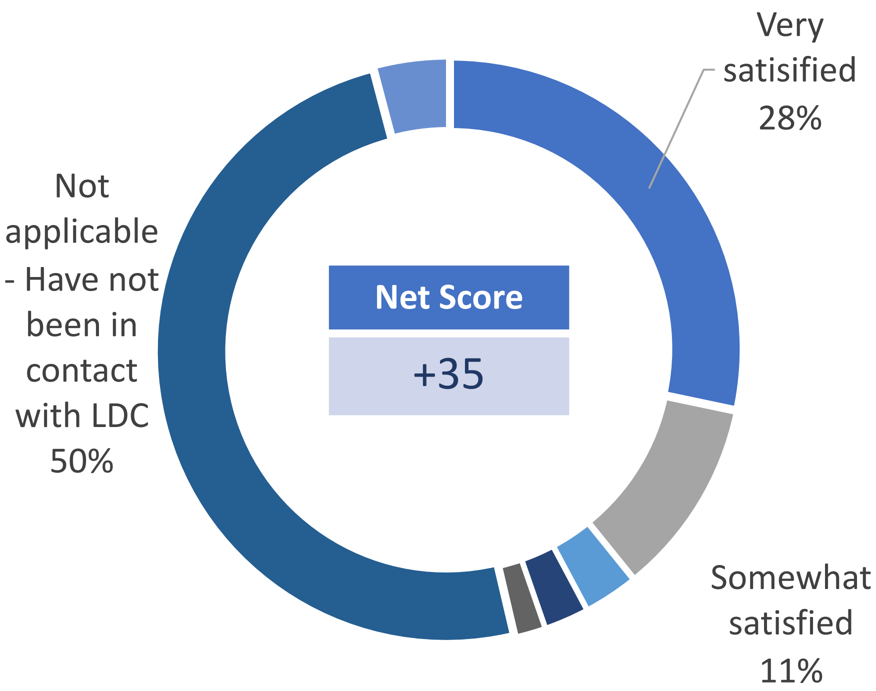
E11: Overall, how satisfied are you with the customer service provided by EPCOR



	Total	Residential	General service business GS<50kWh
Base: Total Answering	400	371	29
Very satisfied	28%	27%	44%
Somewhat satisfied	11%	11%	11%
Neither satisfied nor dissatisfied	3%	3%	0%
Somewhat dissatisfied	2%	3%	0%
Very dissatisfied	2%	2%	0%
Not applicable - Have not been in contact with LDC	50%	50%	45%
Don't know	4%	4%	0%

*Note: Charts and tables may not add up to 100% due to rounding

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 7, 2019, n=400, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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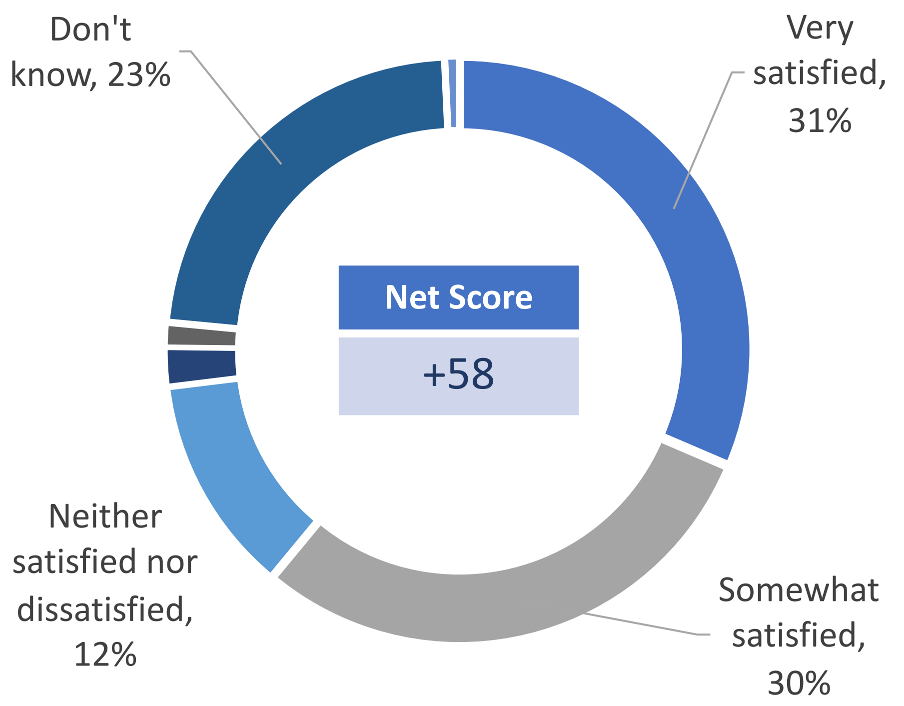
F12: Overall, how satisfied are you with the communications that you receive from EPCOR related specifically to your electrical service?



	Total	Residential	General service business GS<50kWh
Base: Total Answering	400	371	29
Very satisfied	31%	32%	20%
Somewhat satisfied	30%	29%	32%
Neither satisfied nor dissatisfied	12%	13%	4%
Somewhat dissatisfied	2%	2%	0%
Very dissatisfied	1%	1%	2%
Don't know	23%	22%	39%
Refused	1%	1%	3%

*Note: Charts and tables may not add up to 100% due to rounding

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 7, 2019, n=400, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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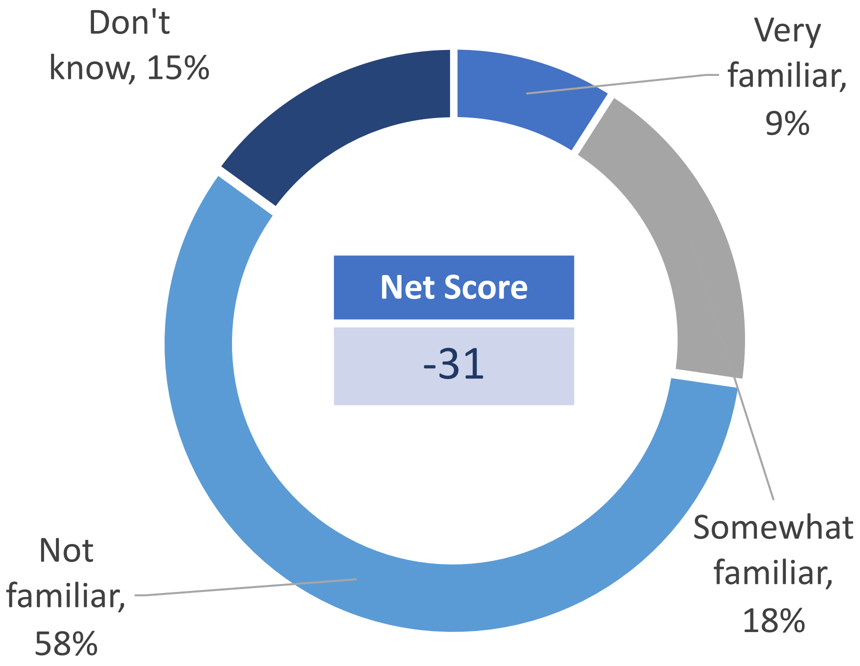
G13: Before this survey, how familiar with you with the percentage of your (household/organization)'s electricity bill that went to EPCOR?



	Total	Residential	General service business GS<50kWh
Base: Total Answering	400	371	29
Very familiar	9%	9%	10%
Somewhat familiar	18%	19%	6%
Not familiar	58%	57%	69%
Don't know	15%	15%	15%

*Note: Charts and tables may not add up to 100% due to rounding

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 7, 2019, n=400, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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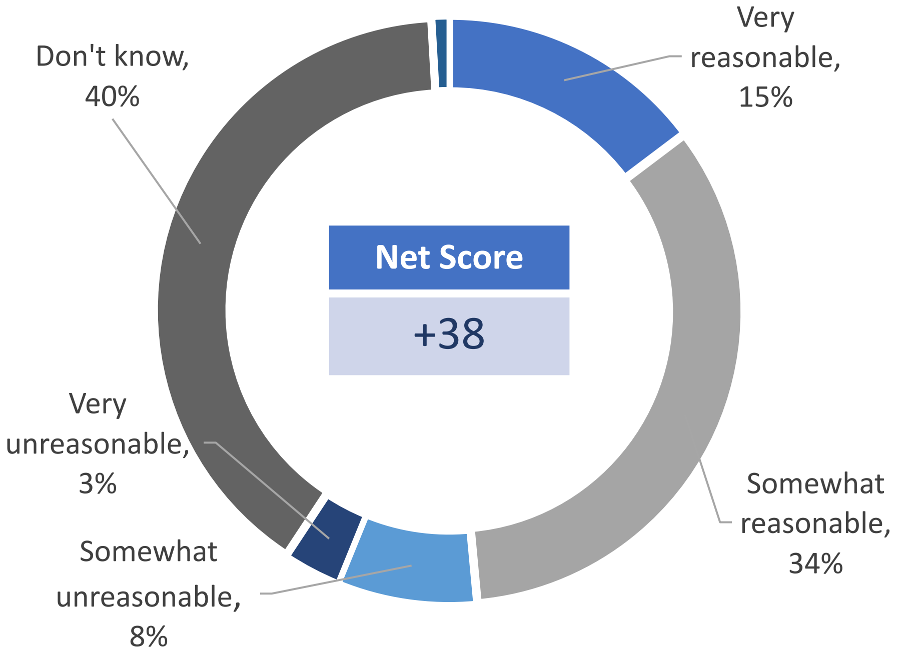
G14: Do you feel that the percentage of your (household/organizations)'s total electricity bill that you pay to EPCOR for the services they provide is…?



	Total	Residential	General service business GS<50kWh
Base: Total Answering	400	371	29
Very reasonable	15%	15%	6%
Somewhat reasonable	34%	34%	35%
Somewhat unreasonable	8%	8%	5%
Very unreasonable	3%	3%	0%
Don't know	40%	39%	51%
Refused	1%	1%	2%

*Note: Charts and tables may not add up to 100% due to rounding

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 7, 2019, n=400, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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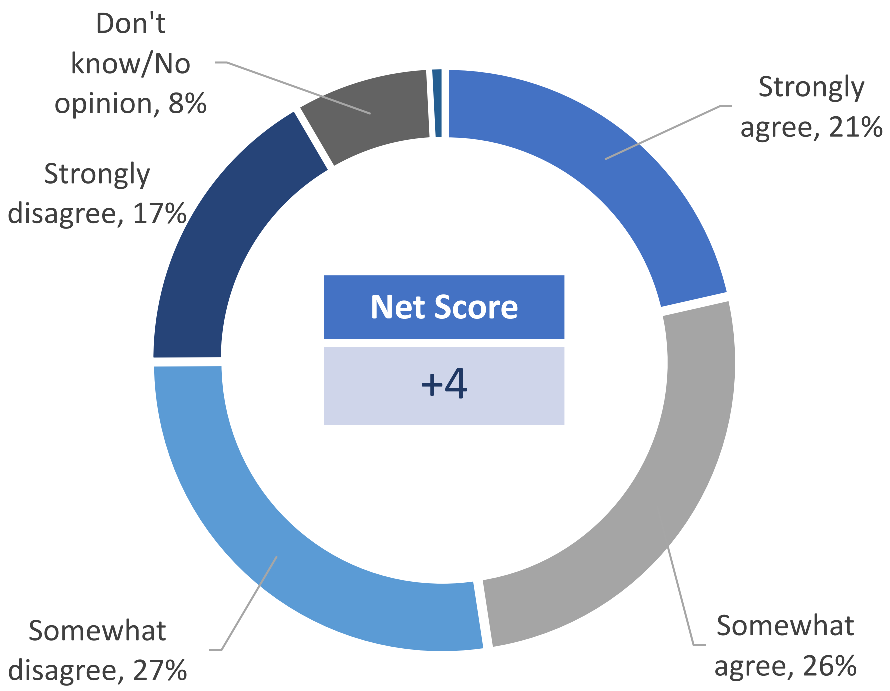
H16: The cost of my electricity bill has a major impact on (my finances and requires I do without some other important priorities)/(on the bottom line of my organization and results in some important spending priorities and investments being put off.



	Total	Residential	General service business GS<50kWh
Base: Total Answering	400	371	29
Strongly agree	21%	21%	34%
Somewhat agree	26%	26%	30%
Somewhat disagree	27%	27%	26%
Strongly disagree	17%	18%	4%
Don't know/No opinion	8%	8%	6%
Refused	1%	1%	0%

*Note: Charts and tables may not add up to 100% due to rounding

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 7, 2019, n=400, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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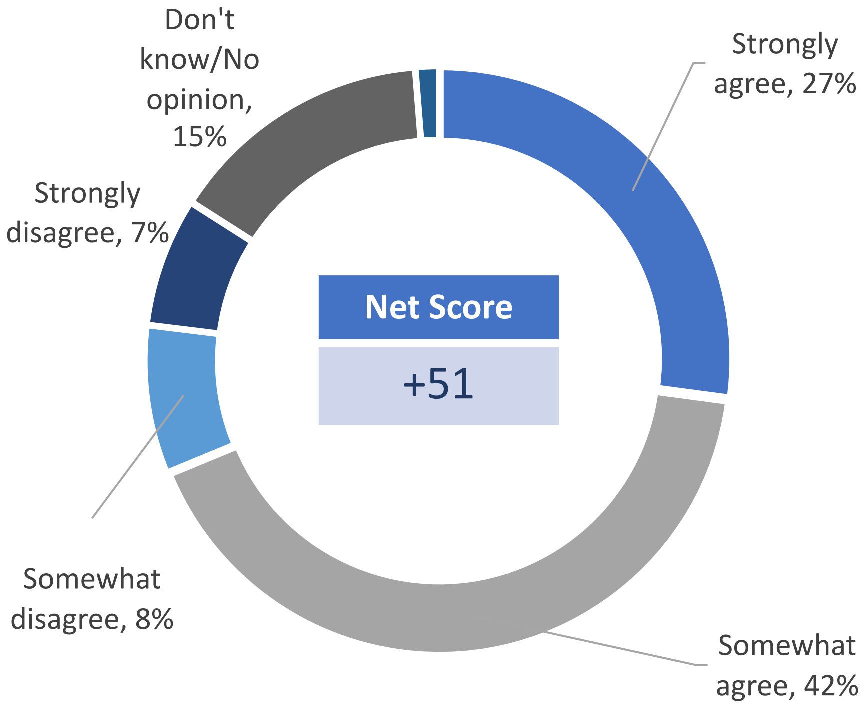
H17: Customers are well served by the electricity system in Ontario.



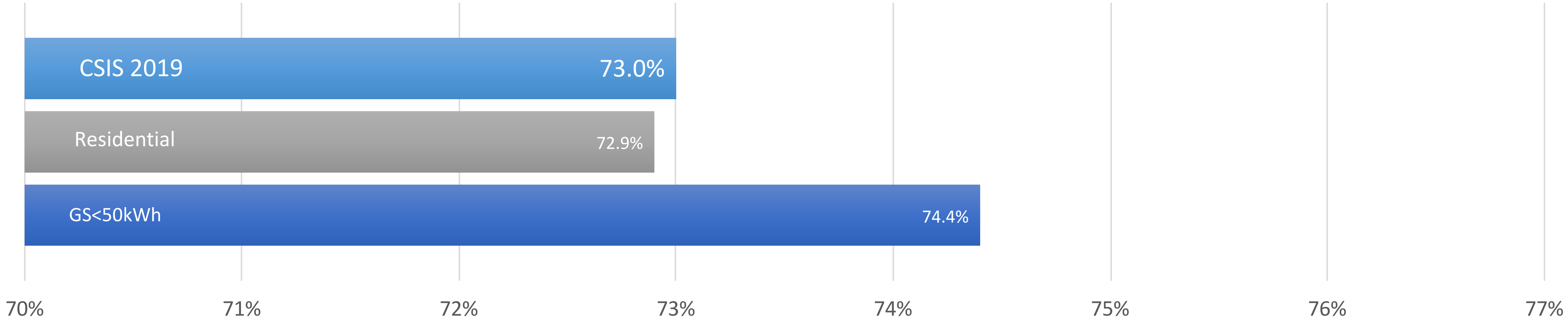
	Total	Residential	General service business GS<50kWh
Base: Total Answering	400	371	29
Strongly agree	27%	27%	34%
Somewhat agree	42%	42%	33%
Somewhat disagree	8%	8%	10%
Strongly disagree	7%	7%	6%
Don't know/No opinion	15%	15%	11%
Refused	1%	1%	6%

*Note: Charts and tables may not add up to 100% due to rounding

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 7, 2019, n=400, accurate 4.8 percentage points plus or minus, 19 times out of 20.

REDHEAD INC MEDIA SOLUTIONS

Customer Satisfaction Index Score



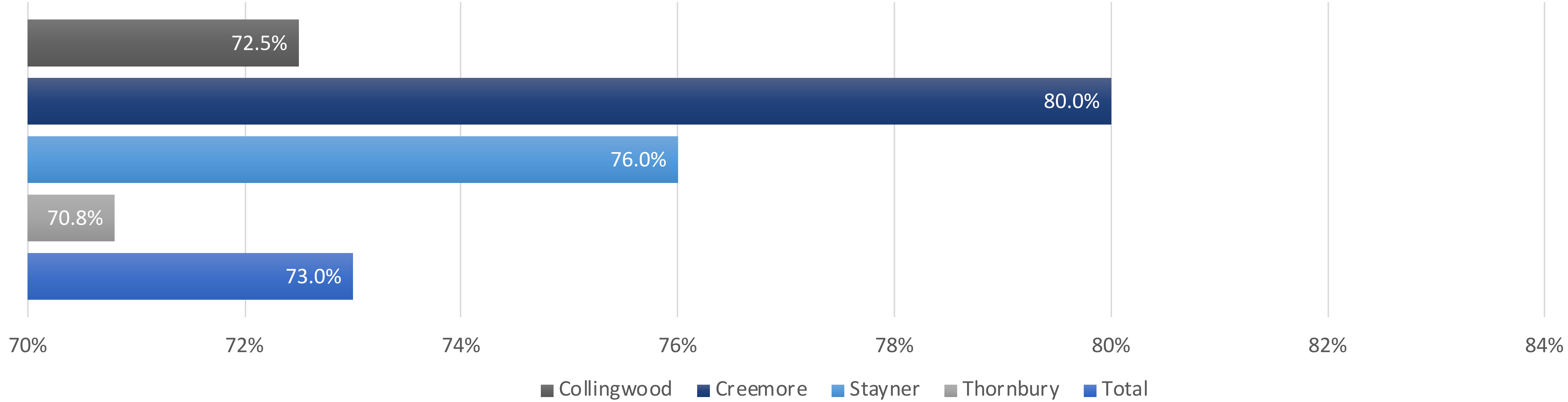
	Total	Residential	General service business GS<50kWh
Base: Total Answering	400	371	29
Customer Satisfaction index score	73.0%	72.9%	74.4%

*Note: Charts and tables may not add up to 100% due to rounding

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 7, 2019, n=400, accurate 4.8 percentage points plus or minus, 19 times out of 20.

REDHEAD INC MEDIA SOLUTIONS

Customer Satisfaction Index Score by region



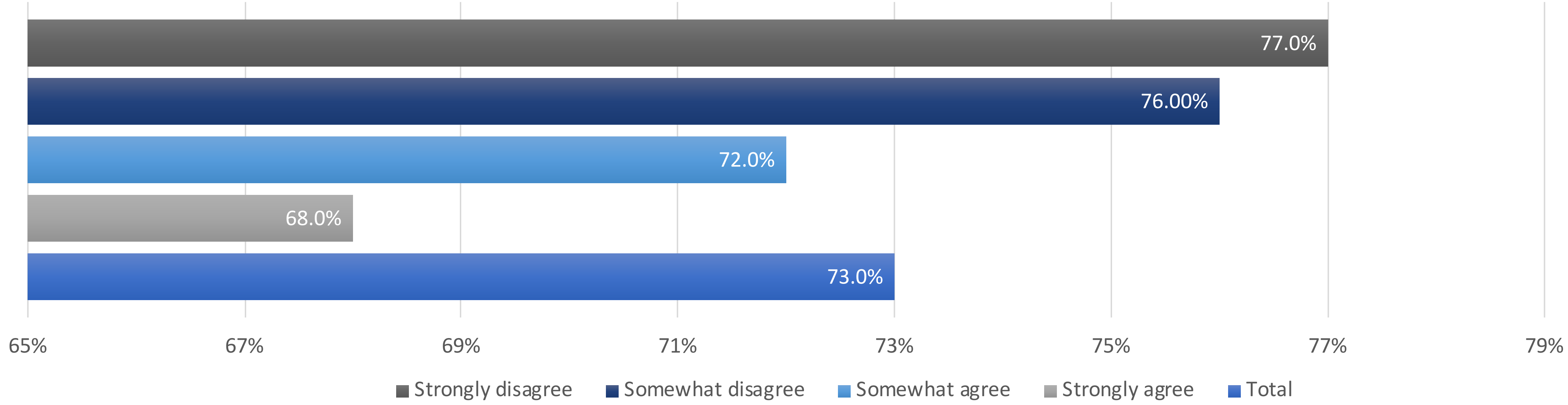
	Total	Collingwood	Creemore	Stayner	Thornbury
Base: Total Answering	400	288	19	58	35
Customer Satisfaction index score	73.0%	72.5%	80.0%	76.0%	70.8%

*Note: Charts and tables may not add up to 100% due to rounding

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 11, 2019, n=401, accurate 4.7 percentage points plus or minus, 19 times out of 20.

REDHEAD MEDIA SOLUTIONS INC

Customer Satisfaction Index Score by reply to question H16 (Electricity bill impact on finances)



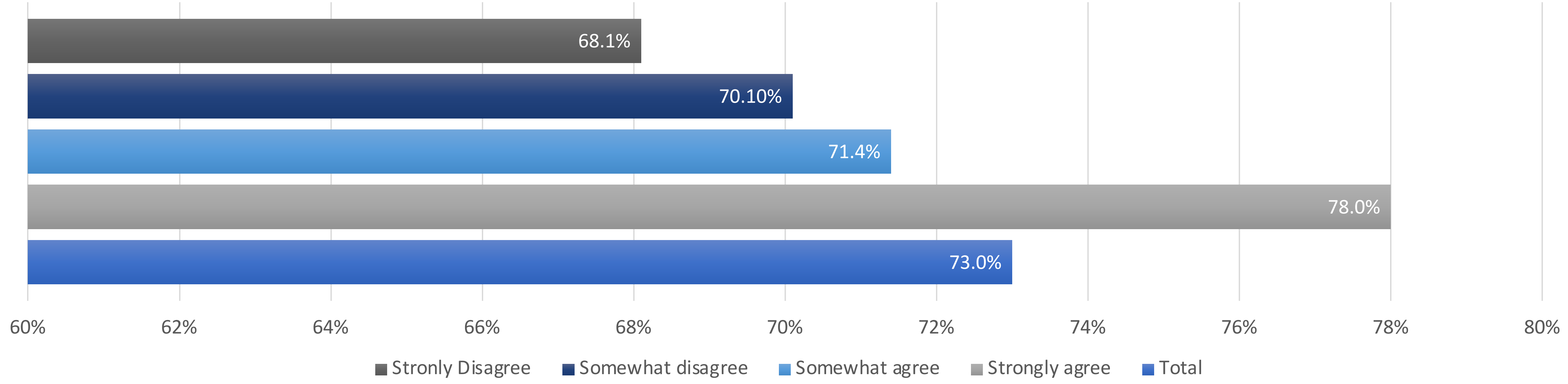
	Total	Strongly agree	Somewhat agree	Somewhat disagree	Strongly disagree
Base: Total Answering	400	85	105	110	66
Customer Satisfaction index score	73.0%	68.0%	72.0%	76.0%	77.0%

*Note: Charts and tables may not add up to 100% due to rounding

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 7, 2019, n=400, accurate 4.8 percentage points plus or minus, 19 times out of 20.

REDHEAD MEDIA SOLUTIONS INC

Customer Satisfaction Index Score by reply to question H17 (Well served by electricity system)



	Total	Strongly agree	Somewhat agree	Somewhat disagree	Strongly disagree
Base: Total Answering	400	108	165	33	28
Customer Satisfaction index score	73.0%	78.0%	71.4%	70.1%	68.1%

*Note: Charts and tables may not add up to 100% due to rounding

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 7, 2019, n=400, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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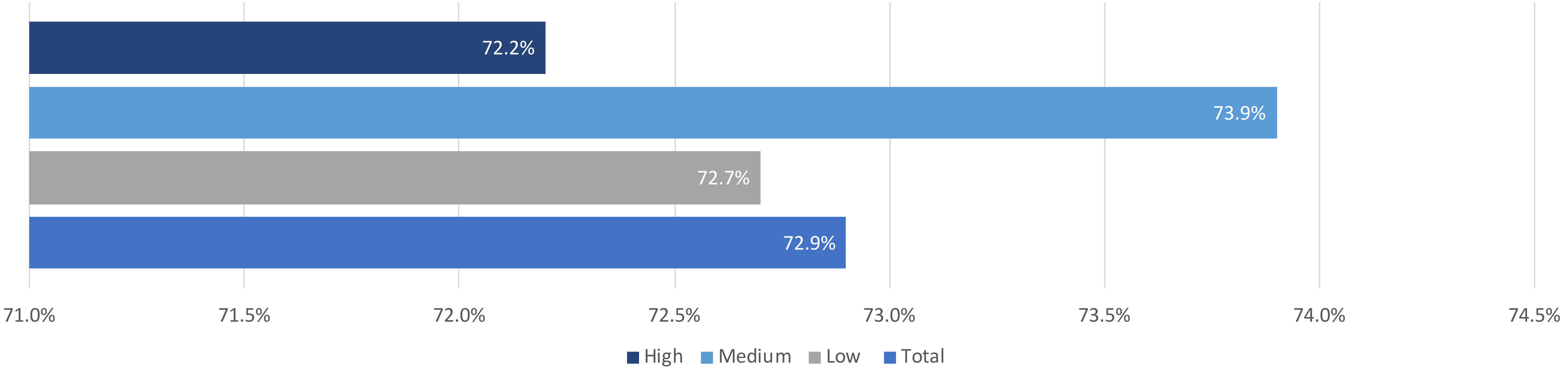
Customer Satisfaction Index Score by consumption tranches (residential)

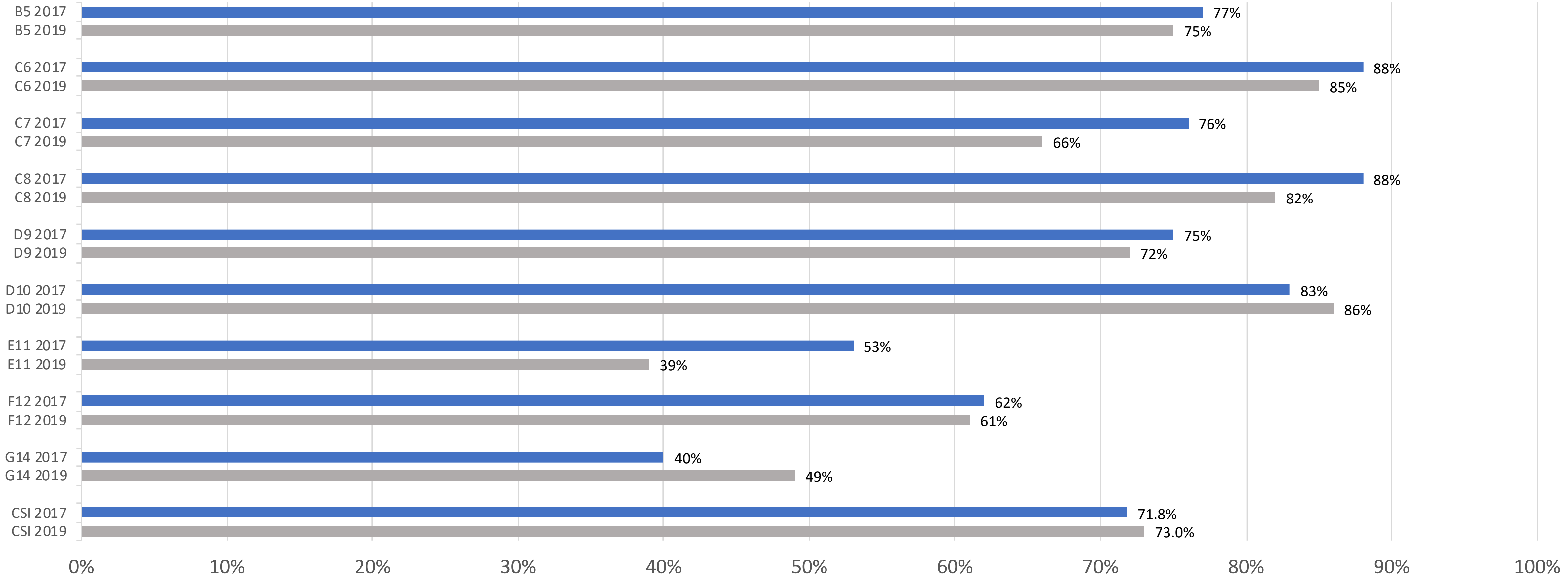


	Total	Low consumption	Medium consumption	High consumption
Base: Residential customers	371	142	105	124
Customer Satisfaction index score	72.9%	72.7%	73.9%	72.2%

*Note: Charts and tables may not add up to 100% due to rounding

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 7, 2019, n=371.

Comparative Data – Core CSI Questions 2017/2019
Net Satisfied Response



*Note: Charts and tables may not add up to 100% due to rounding

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 7, 2019, n=400, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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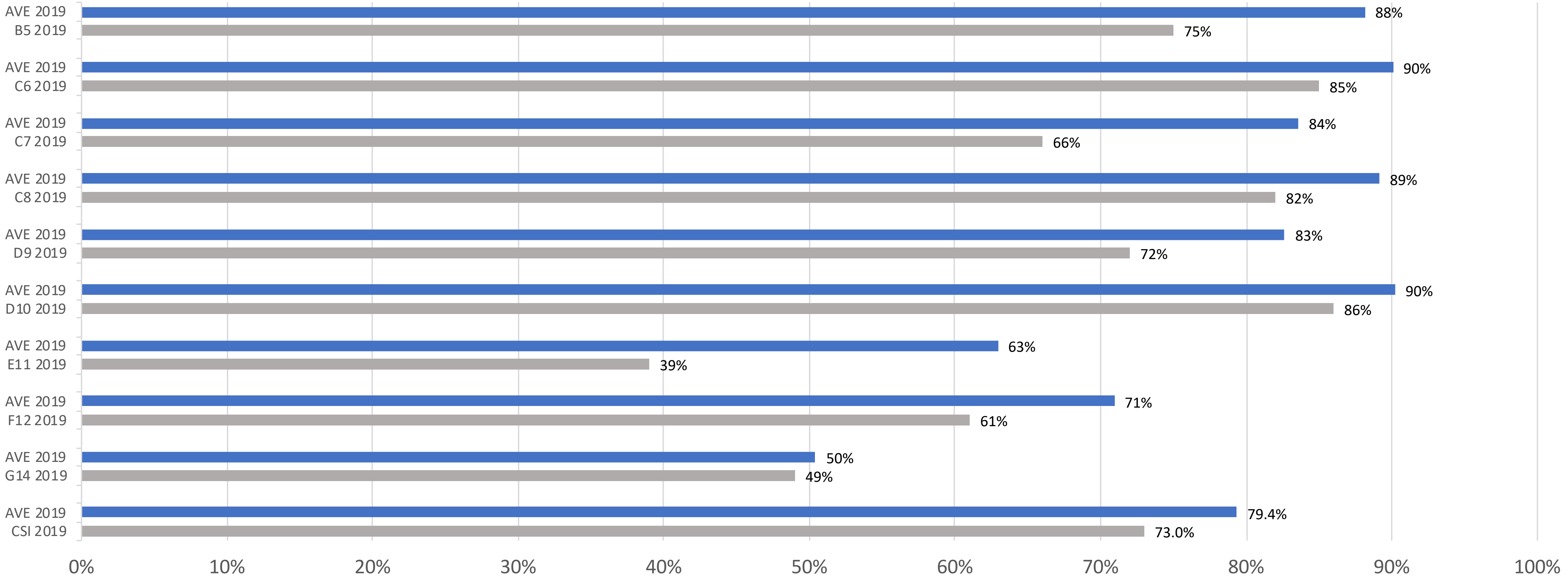
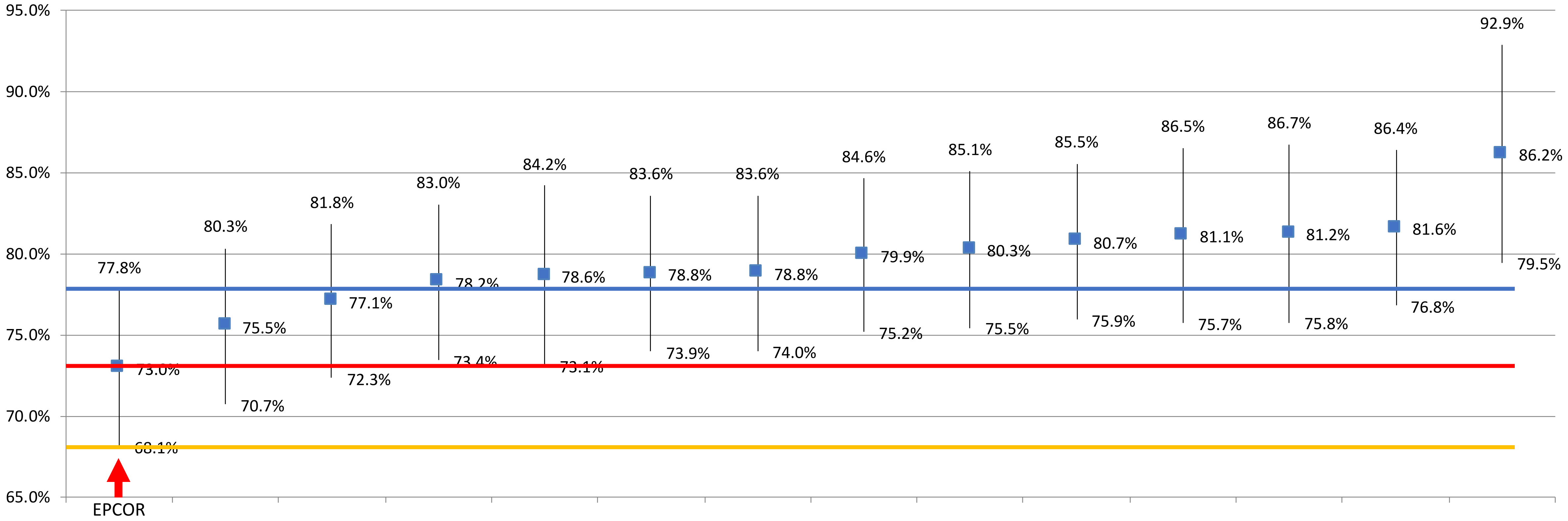
Comparative Data – Core CSI Questions Participant Ave/EPCOR Net Satisfied Response



*Note: Charts and tables may not add up to 100% due to rounding

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 7, 2019, n=400, accurate 4.8 percentage points plus or minus, 19 times out of 20.

Customer Satisfaction Index Score Comparison
Upper and Lower Bound



- The lines denote EPCOR's upper and lower bound based on the CSI Score.
- Almost all LDCs confidence intervals overlap, similar to 2017.
- EPCOR overlaps with all but the highest scoring LDC, which indicates a statistical similarity with most.

Source: Redhead Media Solutions/Advanis telephone random customer survey, January 8-Febuary 7, 2019, n=400, accurate 4.8 percentage points plus or minus, 19 times out of 20.

REDHEAD INC MEDIA SOLUTIONS

Methodology Summary

Commissioned by	EPCOR Inc.
Sample size	400 randomly selected customers
Margin of error	±4.8 percentage points, 19 times out of 20
Survey mode	Random telephone survey of customer base, CATI data collection
Survey sample	Residential and GS <50kWh customer lists provided by EPCOR
Time of calling	4PM-9PM Weekdays, 10AM-5PM Saturdays, scheduled callbacks
In-field dates	January 8-February 8, 2019
Language	English only
Survey author	Innovative Research/Electricity Distributors Association
Question Order	Report shown in order
Question Wording	Questions shown in report as asked
Survey Company	Redhead Media Solutions Inc/Advanis

REDHEAD MEDIA SOLUTIONS INC

Methodology Details

Target Respondents

The respondents of the survey were Ontario residents who are the primary bill payer or share the responsibility if residential or the person in-charge of managing the electricity bill at the organization if general service, and who resided within one of EPCOR's service territory(ies). Service territories were determined based on customer lists provided by EPCOR.

Sample Size and Statistical Reliability

The final total completed surveys by LDC, and the associated margin of error for each, are shown below.

All margins of error are shown at a 95% confidence level.

- E.g., the margin of error associated with a sample size of 400 for a large (infinite) population is ±4.9 percentage points, 19 times out of 20.

Since EPCOR has a finite population, we used the specific population sizes (i.e., the number of samples records received from EPCOR) in the calculation of margin of error. Doing so is more accurate, and results in a narrower margin of error than if we simply assumed large (infinite) population for each.

Sample sizes were set according to the *LDC Customer Satisfaction Survey: Methodology & Survey Implementation Guide*, prepared for the Electrical Distributors Association (April 19, 2016 revision):

Where possible, sample size of n=400.
Distributors with 3000 to 4999 customers (residential + GS<50), n=300
Distributors with <3000 customers (residential + GS<50), n=200

Methodology Details

Sampling Methodology

Redhead was provided sample lists from EPCOR. Customer lists included all basic information required such as name, telephone number, region (where applicable), customer type (residential or GS<50), LDC fee, Annual or Monthly consumption values. Redhead then calculated which quartile group each resident belonged to by evenly dividing them into four groups within each region and customer type. These quartiles were calculated based on annual consumption value.

To minimize low response:

- Sample was loaded in batches to ensure the sample was fully utilized before moving onto fresh sample records;
- Calls were made between the hours of 4pm and 9pm ET; and
- Call backs were scheduled and honored between the hours of 9am and 9pm ET.

Sample Cleaning

Redhead cleaned the customer lists individually once received from each LDC to ensure the customer list counts reflected actual individual records that could be called. The following steps were taken during sample cleaning.

- All records with no phone numbers were removed.
- All phone numbers were checked to see if they were valid numbers (i.e. 10 digits, all numerical, etc.) and any bad cases were removed.
- When duplicates were detected based on phone number, the average of the consumption value was calculated and kept for one consolidated record. All others were removed.
- Residential and GS<50KW were separated into their own lists to be loaded and managed separately in the calling system.

Regions within each customer list were given a numerical value to be used for calling quotas.

Methodology Details

Questionnaire

The survey instrument was provided by the Electricity Distributors Association (EDA) developed in conjunction with Innovative Research. The survey consisted of an introduction, overall satisfaction, power quality and reliability, billing and payment, customer service experience, communications, price, optional deeper dive questions, and final personal finance / sector mood measures. Additional questions were provided individually by EPCOR. These questions are not required as part of the survey and, as outlined in the methodology guideline, were asked after all the standard and required questions.

Data Collection

Computer aided telephone interviews (CATI) were conducted from January 8-February 8, 2019.

Quality Control

- Advanis, on behalf of Redhead, trained the interviewers to understand the study's objectives;
- Detailed call records are kept by the automated CATI system, and are supplemented by output files to SPSS for productivity analysis (i.e., not subject to human error);
- The survey was soft launched in LDCs that had the most available sample, and the data was then checked before calling began in full for EPCOR;
- 100% of all surveys are digitally recorded for potential review (see next bullet);
- Advanis' Quality Assurance team listened to the actual recordings of five percent of completed surveys and compared the responses to those entered by the interviewer to ensure that responses from respondents are properly recorded;
- Team Supervisors conduct regular more formal evaluations with each interviewer, in addition to nightly monitoring of each interviewer on their team;
- Project Managers closely monitored the progress of data collection, including call record dispositions;
- All SPSS code is reviewed by a more senior researcher;
- All Report Builder output is reviewed by a more senior researcher; and
- All values in the report are reviewed by another team member to ensure accuracy.

Methodology Details

Analysis of Findings & Data Weighting

Results were weighted to match the proportion of low volume rate class records as provided to Redhead after cleaning of the sample file. Where a region flag was also provided, results were weighted to the low volume rate class within each region and regions were weighted proportionately to one another based on the customer base as provided in the cleaned sample file.

The Customer Satisfaction index scores have been highlighted and were calculated as described below, based on instructions in the Survey Methodology Guidelines. The "response values" referenced in the description below were also determined and provided by the survey authors.

Data analysis and cross-tabulation have been conducted using SPSS and Report Builder software.

This **index score** is calculated using the following process:

Step 1: Weight data to n=400 with each low volume rate class proportionate to its share of LDC customer base.

Step 2: Rescale the index score variables onto the 0 to 1 scale as indicated by the response values detailed below.

Step 3: The average result of the questions asked for each OEB topic and the overall satisfaction score will be added together[3].

	B5
+	**[C6+C7+C8]** divided by 3
+	**[D9+D10]** divided by 2
+	**E11**
+	**F12**
+	**G14**
=	**Total cumulative scores**

Step 4: The total cumulative score from Step 2 will be divided by 6 to generate the **Customer Satisfaction Index Score** (bound between 0-1).

The chart on the following page illustrates how the **Customer Satisfaction Index Score** will be calculated.

As noted above, LDCs without a region flag were weighted to their low volume rate class proportion based on the cleaned sample file. LDCs with a region flag were weighted to their low volume rate class proportion within each region based on the cleaned sample file, and then regions were weighted proportionately to one another based on the customer base as provided in the cleaned sample file.

Specific values of the number of sample records, estimated population proportions, and final weighted sample counts within EPCOR are provided below. The sum of the regional population proportions within an LDC may not equal 100% due to rounding.

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Methodology Tables

Margin of error

LDC	Customer Records from LDC	Completed Surveys	Sample Size as % of Customer list	Margin of Error @ 95% confidence level
EPCOR	12582	400	3.18%	+/- 4.8%

Sample Weighting

EPCOR						
Regions Flagged in Sample	Low Volume Rate Class	Sample Received	Rate Class Proportion	Estimated Population Proportion	Weighted Sample Count	Unweighted Sample Count
Collingwood	Residential	9,146	94%	72%	291	269
	General Service < 50 kW	634	6%		20	19
Creemore	Residential	410	90%	4%	13	17
	General Service < 50 kW	46	10%		1	2
Stayner	Residential	1088	91%	15%	35	53
	General Service < 50 kW	111	9%		4	5
Thornbury	Residential	1049	91%	9%	33	32
	General Service < 50 kW	98	9%		3	3
TOTAL	Residential	11,693	93%	100%	372	371
	General Service < 50 kW	889	7%		28	29
					400	400

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Thank You

We greatly appreciate working on this important project for EPCOR and hope we have met or exceeded your expectations.

We are happy to present this data to your staff or Board members upon request. If you wish to do so, please contact us for an appointment.

We look forward to working with you on future projects, including the Electricity Safety Awareness Survey later in 2019. Please note if you have any other projects that we may be able to help you with, don't hesitate to be in touch.

Graydon Smith - President
Redhead Media Solution Inc.
505 Hwy 118 W.
Suite 416
Bracebridge, ON
P1L 2G7

Appendix B – Financial Statements

Financial Statements of

EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.

Years ended December 31, 2021 and 2020

Independent Auditor's Report

Financial Statements:

Tel: 519-432-5534
Fax: 519-432-6544
www.bdo.ca

BDO Canada LLP
633 Colborne St., Suite 230
London ON N6B 2V3

INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of EPCOR Utilities Inc.:

Opinion

We have audited the financial statements of EPCOR Electricity Distribution Ontario Inc. (the Entity), which comprise the statement of financial position as at December 31, 2021, and the statement of comprehensive income, statement of changes in equity and statement of cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2021, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditor's Responsibility for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Chartered Professional Accountants, Licensed Public Accountants
London, Ontario
April 7, 2022

EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.

Statements of Comprehensive Income
(In Canadian dollars)

Years ended December 31, 2021 and 2020

	2021	2020
Revenues (Note 6)	$ 48,331,501	$ 51,231,264
Operating expenses:		
Cost of power purchased	38,611,271	43,853,252
Depreciation and amortization (Note 26)	1,418,939	1,331,425
Billing and collecting (Note 34)	1,159,037	1,296,411
Operations and maintenance (Note 34)	2,461,747	2,785,780
General and administrative (Note 34)	2,186,394	2,137,588
Other recoverable expenses (Note 34)	806,880	825,081
Loss on disposal of property, plant and equipment	-	75,154
Donations and Low-Income Energy Assistance Program (Note 34)	8,614	9,769
	46,652,882	52,314,460
Operating income (loss)	1,678,619	(1,083,196)
Finance expenses (Note 24)	(784,107)	(821,286)
Income/(Loss) before income taxes and net regulatory movements	894,512	(1,904,482)
Income tax expense/(recovery) (Note 8)	235,378	(154,494)
Income/(Loss) before net regulatory movements	659,134	(1,749,988)
Net movement on regulatory deferral accounts (Note 12)	(435,179)	1,530,716
Net income/(loss) and regulatory movements	223,955	(219,272)
Other comprehensive income: item that will not be reclassified to net income and regulatory movements		
Re-measurement of defined benefit pension plan	-	-
Comprehensive income/(loss)	$ 223,955	$ (219,272)

The accompanying notes are an integral part of these financial statements.

EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.

Statements of Financial Position
(In Canadian dollars)

December 31, 2021 and 2020

	2021	2020
ASSETS		
Current assets:		
Cash	$ -	$ 10,404
Trade and other receivables (Note 7)	8,328,332	8,315,872
Inventories	984,364	666,065
Payments in lieu of taxes receivable	-	92,803
Prepaid expenses	117,329	128,710
	9,430,025	9,213,854
Non-current assets:		
Deferred tax assets (Note 8)	447,253	678,115
Property, plant and equipment (Note 9)	33,166,468	30,351,733
Intangibles (Note 10)	908,420	893,557
Right of use assets (Note 11)	1,160,526	1,332,456
Total assets	45,112,692	42,469,715
Regulatory deferrals (Note 12)	4,538,104	4,826,965
TOTAL ASSETS AND REGULATORY DEFERRALS	$ 49,650,796	$ 47,296,680
LIABILITIES AND EQUITY		
Current liabilities:		
Trade and other payables (Note 14)	$ 4,968,772	$ 4,831,204
Loans and borrowings (Note 13)	484,456	501,822
Customer deposits and credits (Note 15)	1,621,179	1,682,413
Deferred revenue (Note 16)	150,794	126,857
Lease liabilities (Note 17)	155,294	145,252
	7,380,495	7,287,548
Non-current liabilities:		
Deferred revenue (Note 16)	6,113,326	5,592,166
Lease liabilities (Note 17)	1,113,520	1,268,815
Loans and borrowings (Note 13)	18,236,856	16,721,312
Employee future benefits (Note 18)	885,798	876,311
Total liabilities	33,729,995	31,746,152
Equity:		
Share capital (Note 21)	5,101,340	5,101,340
Miscellaneous paid in capital (Note 22)	9,466,014	9,466,014
Retained earnings	1,075,249	851,294
Accumulated other comprehensive deficit	(164,939)	(164,939)
Total equity	15,477,664	15,253,709
Total liabilities and equity	49,207,659	46,999,861
Regulatory deferrals (Note 12)	443,137	296,819
TOTAL LIABILITIES, EQUITY AND REGULATORY DEFERRALS	$ 49,650,796	$ 47,296,680

Approved on behalf of the Board,

Stuart Lee
Director

John Elford,
Director

The accompanying notes are an integral part of these financial statements.

EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.

Statements of Changes in Equity
(In Canadian dollars)

December 31, 2021 and 2020

	Share Capital	Miscellaneous Paid In Capital	Accumulated Other Comprehensive Deficit	Retained Earnings	Total
Balance January 1, 2020	$ 5,101,340	$ 5,466,014	$ (164,939)	$ 1,070,566	$ 11,472,981
Net loss and regulatory movement	-	-	-	(219,272)	(219,272)
Shareholder contributions	-	4,000,000	-	-	4,000,000
Balance December 31, 2020	$ 5,101,340	$ 9,466,014	$ (164,939)	$ 851,294	$ 15,253,709
Net income and regulatory movement	-	-	-	223,955	223,955
Balance December 31, 2021	$ 5,101,340	$ 9,466,014	$ (164,939)	$ 1,075,249	$ 15,477,664

The accompanying notes are an integral part of these financial statements.

EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.

Statements of Cash Flows
(In Canadian dollars)

Years ended December 31, 2021 and 2020

	2020	2019
Cash flows from operating activities:		
Comprehensive income (loss)	$ 223,955	$ (219,272)
Reconciliation of comprehensive loss to cash from (used in) operating activities:		
Depreciation and amortization (Note 26)	1,418,939	1,331,425
Vehicle depreciation, allocated to other accts (Note 26)	270,572	249,028
Loss on disposal of property, plant and equipment	-	75,154
Gain on disposal of property, plant and equipment	(9,272)	(11,936)
Cash contributions received (Note 16)	642,312	575,614
Deferred revenue recognized (Note 16)	(145,047)	(121,960)
Income tax expense (recovery) (Note 8)	235,378	(154,494)
Income tax refunds	88,287	-
Finance expenses (Note 24)	784,107	821,286
Interest paid	(758,136)	(808,863)
Interest received	-	15,343
	2,751,095	1,751,325
Change in non-cash working capital balances (Note 29)	168,546	469,439
Net cash flows from operating activities	2,919,641	2,222,764
Cash flows from (used in) investing activities:		
Acquisition and construction of property, plant and equipment (Note 9)	(4,227,924)	(3,820,656)
Acquisition of computer software (Note 10)	(71,423)	(5,385)
Proceeds on disposal of property, plant and equipment	9,272	52,466
Changes in non-cash investing working capital (Note 29)	7,105	(171,934)
	(4,282,970)	(3,945,509)
Cash flows from (used in) financing activities:		
Net issuance (repayment) of short-term debt net (Note 32)	(26,293)	(5,154,549)
Proceeds from issuance of long-term debt (Note 32)	2,000,000	2,020,000
Repayments of long-term debt (Note 32)	(475,529)	(466,943)
Repayments of lease liability (Note 32)	(145,253)	(133,973)
Shareholder contributions received (Note 22)	-	4,000,000
	1,352,925	264,535
Decrease in cash during the year	(10,404)	(1,460,210)
Cash, beginning of year	10,404	1,470,614
Cash, end of year	$ -	$ 10,404

1. Description of business

(a) Nature of operations

EPCOR Electricity Distribution Ontario Inc. (the "Company" or EPCOR) was incorporated on April 13, 2000, under the Business Corporations Act (Ontario), and is wholly owned by its ultimate parent EPCOR Utilities Inc., a corporation incorporated under the laws of the province of Alberta. The address of the Company's office and principal place of business is 43 Stewart Road, Collingwood, Ontario, Canada.

The principal activity of the Company is to distribute electricity to approximately 18,000 customers in the service area of Collingwood, Thornbury, Stayner, and Creemore in the Province of Ontario, under licenses issued by the Ontario Energy Board ("OEB"). The Company is regulated under the OEB and adjustments to the distribution rates require OEB approval.

(b) Rate regulation

The Company, as an electricity distributor, is both licensed and regulated by the OEB, which has a legislative mandate to oversee various aspects of the electricity industry. The OEB exercises statutory authority through setting or approving all rates charged by the Company and establishing standards of service for the Company's customers. The OEB has broad powers relating to licensing, standards of conduct and service and the regulation of rates charged by the Company and other electricity distributors in Ontario. The Ontario government enacted the Energy Competition Act, 1998, to introduce competition to the Ontario energy market. Rates are set by the OEB on an annual basis for May 1 to April 30.

Regulatory risk is the risk that the Province and its regulator, the OEB, could establish a regulatory regime that imposes conditions that restrict the electricity distribution business from achieving an acceptable rate of return that permits financial sustainability of its operations including the recovery of expenses incurred for the benefit of other market participants in the electricity industry such as transition costs and other regulatory assets. All requests for changes in electricity distribution charges require the approval of the OEB.

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect distribution rates and other permitted recoveries in the future. The Company is subject to a cost of service regulatory mechanism under which the OEB establishes the revenues required (i) to recover the forecast operating costs, including amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. As actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

2. Basis of presentation

(a) Statement of compliance

These financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and Interpretations of the International Financial Reporting Interpretations Committee (IFRIC), and effective on December 31, 2021 and 2020. These financial statements were approved and authorized for issue by the Board of Directors on April 7, 2022.

(b) Basis of measurement

The Company's financial statements are prepared on the historical cost basis.

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is also the corporation's functional currency, and all values are rounded to the nearest dollar, unless otherwise indicated.

3. Significant accounting policies

The accounting policies set out below have been applied consistently to all years presented in these financial statements unless otherwise indicated.

(a) Changes in significant accounting policies

The Company has adopted amendments to various accounting standards effective January 1, 2021, which did not have a significant impact on these financial statements.

(b) Regulatory deferral accounts

Regulatory deferral account debit balances represent future revenues associated with certain costs incurred in the current year or in prior year(s) that are expected to be recovered from consumers in future years through the rate-setting process. Regulatory deferral account credit balances are associated with the collection of certain revenues earned in the current year or in prior year(s), which are expected to be returned to consumers in future years through the rate-setting process. Regulatory deferral account balances can arise from differences in amounts collected from customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred by the Company in the wholesale market administered by the Independent Electricity System Operator (the "IESO") after May 1, 2002. These amounts have been accumulated pursuant to regulation underlying the Electricity Act (the "EA") and deferred in anticipation of their future recovery or expense in electricity distribution service charges.

Explanation of recognized amounts

Regulatory deferral account balances are recognized and measured initially and subsequently at cost. They are assessed for impairment on the same basis as other non-financial assets as described below.

Management continually assesses the likelihood of recovery of regulatory deferral accounts. If recovery through future rates were no longer considered probable, the amounts would be charged to the results of operations in the year that the assessment is made.

(c) Revenue recognition

The Company recognizes revenue when it transfers control over a promised good or service, a performance obligation under the contract, to a customer and where the Company is entitled to consideration as a result of completion of the performance obligation. Revenue is comprised of the sale and distribution of electricity, pole use rental, collection and other customer charges, contributions in aid of construction and other miscellaneous revenues.

Sale and distribution of electricity

The Company is licensed by the OEB to distribute electricity. As a licensed distributor, the Company is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Company is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Company ultimately collects these amounts from customers. The Company has determined that they are acting as a principal for the electricity distribution and, therefore, have presented the electricity revenues on a gross basis.

The contracts with customers for the supply of electricity consists of perpetual contracts that are effective until terminated by the customer or Company. The Company distributes electricity, which is a distinct service that is simultaneously received and consumed by the customers. Performance obligations are satisfied, over time using the output method for recognition of revenue for the metered units of electricity consumed. Electricity revenue is measured in consumption based on kWh consumed or on peak demand, which is a measurable unit of consumption. Revenue from the sale and distribution of electricity is recognized on an accrual basis, including unbilled revenues accrued in respect of electricity delivered but not yet billed. Payments are due within 30 days of billing.

Other

Other revenues, which include revenues from pole use rental, collection charges and other miscellaneous revenues are recognized at the time services are provided. Where the Company has an ongoing obligation to provide

3. Significant accounting policies (continued)

services, revenues are recognized as the service is performed and amounts billed in advance are recognized as deferred revenue.

(d) Non-derivative financial instruments

Financial assets are identified and classified based on the business model used by the Company for managing those financial assets, as one of the following: at amortized cost, at fair value through other comprehensive income, or at fair value through profit or loss. Financial liabilities are classified as measured at fair value through profit or loss at amortized cost.

Financial assets and financial liabilities are presented on a net basis when the Company has a legally enforceable right to offset the recognized amounts and intends to settle on a net basis or to realize the asset and settle the liability simultaneously.

At amortized cost

Cash, accounts receivable and unbilled energy revenue are classified as financial assets at amortized cost. These financial assets are recognized initially at fair value plus directly attributable transaction costs, if any. After initial recognition, they are measured at amortized cost when they are held for collection of cash flows, where those cash flows solely represent payments of principal and interest using the effective interest rate method less any impairment. The effective interest rate method calculates the amortized cost of a financial asset and allocates the finance income over the term of the financial asset using an effective interest rate. The effective interest rate is the rate that discounts estimated future cash receipts through the expected life of the financial asset, or a shorter period when appropriate, to the gross carrying amount of the financial asset.

The Company's accounts payable and accruals, customer deposits and credits, and short and long-term debt are classified as financial liabilities at amortized cost and recognized on the date at which the Company becomes a party to the contractual arrangement. Financial liabilities are derecognized when the contractual obligations are discharged, cancelled or expire. Financial liabilities are initially recognized at fair value including discounts and premiums, plus directly attributable transaction costs, such as issue expenses, if any. Subsequently, these liabilities are measured at amortized cost using the effective interest rate method.

At fair value through other comprehensive income

Financial assets that are held for collection of contractual cash flows and for selling, where the assets' cash flows solely represent payments of principal and interest, are classified as financial assets at fair value through other comprehensive income. These financial assets are initially recognized at fair value and directly attributable transaction costs. Subsequent to initial recognition, these financial assets are measured at fair value with unrealized gains and losses recognized in other comprehensive income, except for the recognition of impairment losses, reversal of impairment losses, interest income and foreign exchange gains and losses, which are recognized in net income. On de-recognition of the financial asset, the cumulative gain or loss previously recognized in other comprehensive income is reclassified to net income. Interest income from these financial assets is recognized as other income using the effective interest rate method.

At fair value through profit or loss

Financial instruments at fair value through profit or loss include instruments that are designated as financial instruments at fair value through profit or loss or those financial instruments that do not meet the criteria for classification under any other category. Upon initial recognition, directly attributable transaction costs are recognized in net income as incurred. Changes in fair value of financial instruments measured at fair value through profit or loss are recognized in net income.

3. Significant accounting policies (continued)

(e) Cash

Cash and bank includes cash on hand, deposits held on demand with financial institutions, other short-term, highly liquid investments with original maturities of three months or less that are readily convertible to known amounts of cash and subject to an insignificant risk of change in value.

(f) Customer deposits

Customers may be required to post security to obtain electricity or other services, which are refundable. Where the security posted is in the form of cash, these amounts are recorded in the accounts as deposits. Deposits to be refunded to customers within the next fiscal year are classified as a current liability.

(g) Inventories

Cost of inventory is comprised of direct materials, which typically consists of distribution assets not deemed as major spares, unless purchased for specific capital projects in process or as spare units. Costs, after deducting rebates and discounts, are assigned to individual items of inventory on the basis of weighted average cost. Decommissioned assets that are transferred to inventory are tested for impairment once they are removed from service and placed in inventory. Inventory is recognized at the lower of cost and net realizable value, which is the estimated selling price in the ordinary course of business less the estimated costs of completion and the estimated costs necessary to make the sale.

(h) Leases

At the inception of a contract, the Company determines whether a contract is, or contains a lease. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

As a lessee

On initial identification of a lease contract, the Company recognizes a right-of-use (ROU) asset and a lease liability at the commencement of the lease contract. The lease liability is initially measured at the present value of the future unavoidable lease payments under the contract, discounted using the interest rate implicit in the lease contract. Where the implicit rate cannot be readily determined, the Company uses the incremental borrowing rate of the legal entity entering into the lease contract. Lease payments include fixed payments including in-substance fixed payments less any lease incentives receivable, variable lease payments that depend on an index or a rate, the exercise price of a purchase option or optional renewal period that the Company is reasonably certain to exercise and penalties for early termination of a lease contract unless the Company is reasonably certain not to terminate early. Subsequently, the lease liability is measured at amortized cost, using the effective interest method. The lease liability is re-measured to reflect any reassessments or lease modifications. Lease payments are allocated between the principal repayment of the lease liability and finance expense. The finance expense on the lease liability is charged to net income over the term of the lease contract to produce a constant periodic rate of interest on the remaining balance of the lease liability for each period.

The ROU asset is initially measured at cost, which includes the initial lease liability, any lease payments made at or before commencement date less any lease incentives received, any initial direct costs and restoration costs. The ROU assets are depreciated on a straight-line basis over the shorter of the respective asset's useful life and the remaining term of the lease contract. The ROU assets are subsequently re-measured to reflect any reassessments or lease modifications. At each reporting date, ROU assets are reviewed for indications of impairment. In case it is determined that indications of impairment exist, the recoverable amount is estimated for ROU assets, which is the greater of value in use and fair value the Company expects to recover from sub-lease of the asset.

The Company has elected not to recognize ROU assets and lease liabilities for lease contracts where the total term of the respective lease contract is less than or equal to 12 months or for low value lease contracts. The Company recognizes the payments relating to such leases (including principal and interest associated with these leases) as an expense on a straight-line basis over the lease term. These payments are presented within other administrative expense in net income.

3. Significant accounting policies (continued)

(i) Property, plant and equipment

Property, plant and equipment (PP&E) are recognized at cost, net of accumulated depreciation and accumulated impairment, if any, being the purchase price and directly attributable cost of acquisition or construction required to bring the asset to the location and condition necessary to be capable of operating in the manner intended by the Company, including eligible borrowing costs.

Depreciation of PP&E is recorded in the statement of comprehensive income on a straight-line basis over the estimated useful life of the related asset. Half of a year's amortization is taken for the first year, regardless of when the property was actually put into service during the year. The estimated useful lives, residual values and amortization methods are reviewed at the end of each annual reporting period, with the effect of any changes in estimate being accounted for on a prospective basis. The estimated useful lives for the current and comparative years are:

Buildings	50 years
Distribution stations	20 - 45 years
Distribution lines	40 - 60 years
Distribution transformers	40 years
Distribution services	40 years
Meters	15 years
Vehicles	5 - 8 years
Equipment	3 - 15 years

Work-in-Progress assets are not depreciated until the project is complete and ready for use.

Major spares such as spare transformers and other items kept as standby/back up equipment are accounted for as PP&E since they support the Company’s distribution system reliability. These are included in work-in-progress (Note 9) and not depreciated.

Gains or losses on disposal of an item of property, plant and equipment are determined by comparing the net proceeds from disposal with the carrying amount of the asset, and are included in the statement of comprehensive income when the asset is disposed. When an item of property, plant and equipment with related contributions in aid of construction is disposed, the remaining contributions are recognized in full in the statement of comprehensive income.

(j) Borrowing costs

The Company capitalizes interest expenses and other finance charges directly relating to the acquisition, construction or production of assets that take a substantial period of time to get ready for its intended use. Capitalization commences when expenditures are being incurred, borrowing costs are being incurred and activities that are necessary to prepare the asset for its intended use or sale are in progress. Capitalization will be suspended during periods in which active development is interrupted. Capitalization will cease when substantially all of the activities necessary to prepare the asset for its intended use or sale are complete.

3. Significant accounting policies (continued)

(k) Intangible assets

Paid Capital Contributions include amounts paid by the corporation for capital expenditures under a Capital Cost Recovery Agreement. The contribution is measured at cost less accumulated amortization and accumulated impairment losses. They are not amortized until put into use.

Computer software that is acquired or developed by the Company, including software that is not integral to the functionality of equipment purchased, which has finite useful lives, is measured at cost less accumulated amortization and accumulated impairment losses.

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, other than goodwill, from the date that they are available for use. Half of a year's amortization is taken for the first year in service. Amortization methods and useful lives of all intangible assets are reviewed at the end of each annual reporting period. The estimated useful lives for the current and comparative years are:

Paid Capital Contributions	45 years
Computer software	5 years

Goodwill represents the cost of acquired local distribution companies in Stayner, Creemore and Thornbury in excess of fair value of the net identifiable assets purchased. Goodwill is measured at cost and is not amortized.

(l) Deferred revenue

Certain assets may be contributed by customers or be constructed using non-refundable cash contributions from customers. Non-refundable customer contributions, which are used to provide ongoing goods or services to these customers are recorded as deferred revenue. The deferred revenue is initially recorded at the fair value of contributed assets, or the amount of cash contributions received, and is recognized as revenue on a straight-line basis over the estimated life of the contract with the customers. Where contracts with customers are perpetual, the related contributed asset will be used to provide ongoing goods or services to customers and as such the estimated life of the contract with the customers is estimated to be equivalent to the economical useful life of the asset to which the contribution relates.

Certain assets may be contributed by developers or be acquired or constructed using non-refundable cash contributions from developers. Non-refundable developer contributions that result in the Company having an on-going obligation to provide goods or services with respect to the assets acquired or constructed are recorded as deferred revenue, at the fair value of the contributed assets or the amount of cash contribution received, and are recognized as revenue on a straight-line basis over the estimated economic useful lives of the assets to which the contribution relates.

(m) Impairment of financial assets

The Company uses the “expected credit loss” (ECL) model for calculating impairment and recognizes ECL as a loss allowance for financial assets measured at amortized cost.

For trade receivables without significant financing component, the Company applies the simplified approach and uses a provision matrix, which is based on the Company’s historical credit loss experience, current market conditions and forward looking information, to estimate and recognize the lifetime ECL. Trade and other receivables that are not assessed for impairment individually are assessed for impairment on a collective basis taking into consideration the unique risk factors associated with each customer group.

(n) Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognized as a finance expense over the estimated period until settlement of the obligation.

3. Significant accounting policies (continued)

(o) Impairment of non-financial assets

The carrying amounts of the Company's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. Non-financial assets include PP&E, intangible assets and goodwill. For PP&E and intangible assets with definite useful lives, the recoverable amount is estimated when an indication of impairment exists. For goodwill and intangible assets that have indefinite useful lives or that are not yet available for use, the recoverable amount is estimated at least once each year.

The recoverable amount of an asset or cash-generating unit (CGU) is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using an after-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. For the purpose of impairment testing, assets that cannot be tested individually are tested as a CGU. CGU's are the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. For the purposes of goodwill impairment testing, goodwill acquired in a business combination is allocated to the CGU, or the group of CGUs, that is expected to benefit from the synergies of the combination. This allocation is subject to an operating segment ceiling test and reflects the lowest level at which that goodwill is monitored for internal reporting purposes.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in comprehensive income. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units, and then to reduce the carrying amount of the assets in the unit or the group of units on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other non-financial assets, impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a fundamental change, since the date of impairment, which may improve the financial performance of the non-financial asset. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(p) Employee future benefits

Pension plan

The employees of the Company participate in the Ontario Municipal Employees Retirement System ("OMERS"). The Company also contributes to the OMERS plan on behalf of its employees. The plan has a defined benefit option at retirement available to employees, which specifies the amount of the retirement benefit plan to be received by the employees based on length of service and rates of pay. However, the plan is accounted for as a defined contribution plan as insufficient information is available to account for the plan as a defined benefit plan. The Company is only one of a number of employers that participates in the plan and the financial information provided to the Company on the basis of the contractual agreements is insufficient to measure the Company's proportionate share in the plan assets and liabilities on defined benefit accounting requirements. The contribution payable in exchange for services rendered during a period is recognized as an expense during that period.

Post employment medical and life insurance plan

A defined benefit plan is a post-employment benefit plan other than a defined contribution plan. The Company's net obligation on behalf of its retired employees' unfunded, extended medical and dental benefits is calculated by estimating the amount of future benefits that are expected to be paid out discounted to determine its present value. Any unrecognized past service costs are deducted.

The calculation is performed by a qualified actuary using the projected unit credit method every third year or when there are significant changes to workforce. When the calculation results in a benefit to the Company, the recognized asset is limited to the total of any unrecognized past service costs and the present value of economic benefits available in the form of any future refunds from the plan or reductions in future contributions to the plan. An economic benefit is available to the Company if it is realizable during the life of the plan, or on settlement of the plan liabilities.

Defined benefit obligations are measured using the projected unit credit method discounted to its present value using yields available on high quality corporate bonds that have maturity dates approximating the terms of the liabilities.

3. Significant accounting policies (continued)

Remeasurements of the defined benefit obligation are recognized in other comprehensive income. The remeasurements include actuarial gains and losses.

Service costs are recognized in operating expenses and include current and past service costs as well as gains and losses on curtailments.

Net interest expense is recognized in finance costs and is calculated by applying the discount rate used to measure the defined benefit obligation at the beginning of the annual period to the balance of the net defined benefit obligation, considering the effects of benefit payments during the period. Gains or losses arising from changes to defined benefits or plan curtailment are recognized immediately in the statement of comprehensive income. Settlements of defined benefit plans are recognized in the period in which the settlement occurs.

Other employee benefits

Short-term employee benefit obligations are measured on an undiscounted basis and are expensed as the related service is provided. A liability for short-term employee benefits is recognized for the amount expected to be paid if the Company has a legal or constructive obligation to pay this amount as a result of past service provided by the employee and the obligation can be estimated reliably.

(q) Payments in lieu of taxes payable

Tax status

The corporation is a Municipal Electricity Utility (“MEU”) for purposes of the payments in lieu of taxes (“PILs”) regime contained in the Electricity Act, 1998. As a MEU, the Company is exempt from tax under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario).

Under the Electricity Act, 1998, the Company is required to make, for each taxation year, PILs to Ontario Electricity Financial Corporation ("OEFC"), commencing October 1, 2001. These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

Current and deferred tax

Provision in lieu of taxes ("PILs") is comprised of current and deferred tax. Current tax and deferred tax are recognized in net income except to the extent that it relates to items recognized directly in Other Comprehensive Income.

Current PILs are recognized on the taxable income or loss for the current year plus any adjustment in respect of previous years. Current PILs are determined using tax rates and tax laws that have been enacted or substantively enacted by the year-end date.

Deferred tax assets and liabilities are recognized where the carrying amount of an asset or liability differs from its tax base. The amount of the deferred tax asset or liability is measured at the amount expected to be recovered from or paid to the taxation authorities. This amount is determined using tax rates and tax laws that have been enacted or substantively enacted by the year-end date and are expected to apply when the liabilities/(assets) are settled/(recovered).

Recognition of deferred tax assets for unused tax losses, tax credits and deductible temporary differences is restricted to those instances where it is probable that future taxable profit will be available against which the deferred tax asset can be utilized.

At the end of each reporting period, the Company reassesses both recognized and unrecognized deferred tax assets. The Company recognizes a previously unrecognized deferred tax asset to the extent that it has become probable that future taxable profit will allow the deferred tax asset to be recovered.

3. Significant accounting policies (continued)

(r) Standards and interpretations not yet applied

A number of new standards, amendments to standards and interpretations of standards have been issued by the IASB and the IFRIC, the application of which is effective for periods beginning on or after January 1, 2022. The Company does not expect the implementation of these new accounting pronouncements to have a significant impact on its accounting policies.

4. Use of judgments and estimates

The preparation of the Company's financial statements in accordance with IFRS requires management to make judgments in the application of accounting policies, and estimates and assumptions that affect the reported amounts of income, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities.

(a) Judgments

Information about critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements are included in notes:

Note 3(h) - Leases
Note 3(i) - Property, plant and equipment

(b) Estimates

The Company reviews its estimates and assumptions on an ongoing basis, uses the most current information available and exercises careful judgment in making these estimates and assumptions. Adjustments to previous estimates, which may be material, are recorded in the period in which they become known. Actual results may differ from these estimates. Assumptions and uncertainties that have a significant risk of resulting in a material adjustment within the next financial year include:

Employee future benefits
The cost of post-employment medical and insurance benefits are determined using actuarial valuations. An actuarial valuation involves making various assumptions. Due to the complexity of the valuation, the underlying assumptions and its long-term nature, post employment medical and insurance benefits are highly sensitive to changes in these assumptions. All assumptions are reviewed at each reporting date. See Note 18 Employee Future Benefits.

Payments in lieu of taxes payable and deferred taxes
The Company is required to make payments in lieu of tax calculated on the same basis as income taxes on taxable income earned and capital taxes. Significant judgment is required in determining the provision for income taxes and deferred taxes. There are many transactions and calculations undertaken during the ordinary course of business for which the ultimate tax determination is uncertain. The Company recognizes liabilities for anticipated tax audit issues based on the Company's current understanding of the tax law. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the current and deferred tax provisions in the period in which such determination is made.

Accounts receivable impairment
In determining the expected credit loss allowance, the Company considers historical credit loss experience for accounts receivable, current market conditions and the future expectations, to estimate and recognize the lifetime expected credit loss.

Estimate of useful life of assets
The estimates and assumptions made to determine the useful life of property, plant and equipment and certain intangibles are determined by management at the time the asset is acquired and reviewed annually for appropriateness based on industry standards, historical experience, and technological obsolescence.

Regulatory estimates
Certain estimates are necessary given that the regulatory environment in which the Company operates often requires amounts to be recorded at estimated values until finalization and adjustment, pursuant to subsequent OEB regulatory proceedings or decisions.

(In Canadian dollars unless otherwise indicated)

4. Use of judgments and estimates (continued)

Unbilled energy revenue
Unbilled energy revenue is based on an assessment of electricity distribution services supplied to customers between the date of the last meter reading and the period ending date. The Company applies judgmental to the measurement of the estimated consumption and the valuation of that consumption.

Fair value measurement
Certain accounting measures such as determining asset impairments and recording financial assets and liabilities use various valuation techniques to determine fair value. Estimates of fair value may be based on readily determinable market values or depreciable replacement cost or discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate.

5. Novel coronavirus

In March 2020, the global outbreak of the novel coronavirus (COVID-19) was declared a pandemic by the World Health Organization and continues to disrupt business activities including supply chains around the world. In order to manage the impacts of the outbreak, local governmental authorities in Alberta have regularly been monitoring and responding to the emerging situation with maintaining certain travel and business related restrictions. Since the beginning of the pandemic, the Company has been operating under its business continuity plan to ensure safety of its employees and customers. In view of the uncertainty caused by the continued persistence of virus infections, the Company has deferred its plans for re-integration of the employees back to their permanent work locations. The Company is closely monitoring the situation (including advisories from the local governments), and planning to cautiously phase-in the reintegration of its employees back to their permanent work locations when considered safe to do so.

Since the majority of the Company's operations consist of the provision of essential utility services, the Company has not experienced any significant impact of COVID-19 on its operations and financial results except for a decline in services to commercial customers mainly due to business closures resulting from government imposed restrictions, which has largely been offset by an increase in services to residential customers. Overall, the COVID -19 pandemic did not result in any material impact on the financial results of the Company for the years ended December 31, 2021 and 2020.

6. Revenues

	2021	2020
Sale of energy	$ 37,728,278	$ 41,819,872
Distribution revenue	9,112,646	8,028,188
Deferred revenue recognized (Note 16)	145,047	121,960
Other revenue	1,345,530	1,261,244
	$ 48,331,501	$ 51,231,264

Revenue from contracts with customers expected to be recognized in future periods related to performance obligations that are unsatisfied or partially satisfied at the reporting date are as follows:

	2022	2023	2024	2025	2026	2027 and thereafter	Total
Contributions received from customers and developers	$ 150,794	$ 150,794	$ 150,794	$ 150,794	$ 150,794	$ 5,510,150	$ 6,264,120

(In Canadian dollars unless otherwise indicated)

6. Revenues (continued)

As at December 31, 2021, the Company had deferred revenue recorded in the statements of financial position related to contributions in aid of construction received from customers and developers. Revenue will be recognized in future periods related to this balance, as described in note 3(l), over periods ranging between 40-50 years.

7. Trade and other receivables

		2021		2020
Trade receivables	$	4,533,396	$	5,059,031
Accrued revenues		3,797,572		3,320,754
EPCOR Electricity Solutions Ontario Inc., a company under common control		105,727		105,727
EPCOR Collingwood Energy Inc., a company under common control		(100)		(100)
Long-term Investment - UCS (Note 19)		100		100
Gross accounts receivable		8,436,695		8,485,512
Expected credit loss allowance (Notes 25 and 31)		108,363		169,640
Net accounts receivable	$	8,328,332	$	8,315,872

Accounts receivable include $1,015,481 (December 31, 2020 - $1,199,462) for water and sewer billings.

Details of the aging of accounts receivable and analysis of the changes in the ECL allowance are provided in Note 31.

8. Payments in lieu of corporate taxes

(a) The significant components of the provision for payments in lieu of taxes recognized in net income are as follows:

		2021		2020
Current tax				
Based on current year taxable income	$	-	$	-
Adjustments for over / under provision in prior periods		4,516		(3,878)
	$	4,516	$	(3,878)
Deferred tax				
Origination and reversal of temporary differences		122,638		(145,335)
Adjustments for over / under provision in prior periods		108,224		(5,281)
	$	230,862	$	(150,616)
	$	235,378	$	(154,494)

(In Canadian dollars unless otherwise indicated)

8. **Payments in lieu of corporate taxes (continued)**

Statutory Canadian federal and provincial tax rates for the current year comprise 15% (2020 - 15%) for federal corporate tax and 11.5% (2020 - 11.5%) for corporate tax in Ontario. The PILs expense varies from amounts, which would be computed by applying the Company's combined statutory income tax rate as follows:

		2021		2020
Total income (loss) and other comprehensive income (loss)	$	223,955	$	(219,272)
Plus current and deferred income taxes		235,378		(154,494)
Net income (loss) before income taxes		459,333		(373,766)
Statutory Canadian federal and provincial tax rate		26.50%		26.50%
Provision for PILs at statutory rate		121,723		(99,048)
Increase (decrease) in income tax resulting from:				
Interest and penalties on taxes		-		-
Meals and entertainment		915		188
Items in property, plant and equipment		-		(46,475)
Miscellaneous other		-		-
Prior year provision adjustment		112,740		(9,159)
Total provision	$	235,378	$	(154,494)
Effective tax rate		51.24%		41.33%

(b) The movement in the deferred tax asset is as follows:

		2021		2020
Opening balance	$	678,115	$	527,499
Recognized in net income		(230,862)		150,616
Recognized in other comprehensive income		-		-
Closing balance	$	447,253	$	678,115

Deferred tax assets (liabilities) are attributable to the following:

		2021		2020
Employee future benefits	$	236,564	$	232,222
Property, plant and equipment		(2,164,602)		(1,723,784)
Intangibles		(88,016)		(87,565)
Right of use assets		(307,539)		(353,101)
Goodwill		(73,327)		(73,327)
Deferred revenues		1,659,992		1,515,541
Lease liabilities		336,236		374,728
Non-capital losses carryforward		847,945		793,401
Net deferred tax asset	$	447,253	$	678,115

The utilization of this tax asset is dependent on future taxable profits in excess of profits arising from the reversal of existing taxable temporary differences. The Company believes that this asset should be recognized as it will be recovered through future services.

(In Canadian dollars unless otherwise indicated)

9. Property, plant and equipment

		Land and Buildings	Distribution Equipment	Vehicles	Other Equipment	Work-in Progress	Total
Cost							
Balance, beginning of 2021	$	755,197	$31,027,916	$ 2,742,962	$ 1,461,518	$ 1,813,049	$37,800,642
Additions		-	-	-	-	4,275,756	4,275,756
Transfers into service		-	3,140,722	-	122,053	(3,262,775)	-
Disposals		-	-	-	-	-	-
Balance, end of 2021		755,197	34,168,638	2,742,962	1,583,571	2,826,029	42,076,398
Accumulated depreciation							
Balance, beginning of 2021	$	65,229	$ 5,329,974	$ 1,439,743	$ 613,963	$ -	$ 7,448,909
Depreciation		9,243	1,010,910	270,572	170,296	-	1,461,021
Disposals		-	-	-	-	-	-
Balance, end of 2021		74,472	6,340,884	1,710,315	784,259	-	8,909,930
Net Book Value, end of 2021	$	680,725	$27,827,754	$ 1,032,647	$ 799,313	$ 2,826,029	$33,166,468

		Land and Buildings	Distribution Equipment	Vehicles	Other Equipment	Work-in Progress	Total
Cost							
Balance, beginning of 2020	$	755,197	$27,374,234	$ 2,353,936	$ 1,479,747	$ 1,731,440	$33,694,554
Additions		-	-	-	-	4,331,153	4,331,153
Transfers into service		-	3,722,746	463,574	63,224	(4,249,544)	-
Disposals		-	(69,064)	(74,548)	(81,453)	-	(255,065)
Balance, end of 2020		755,197	31,027,916	2,742,962	1,461,518	1,813,049	37,800,642
Accumulated depreciation							
Balance, beginning of 2020	$	55,986	$ 4,420,337	$ 1,200,034	$ 409,372	$ -	$ 6,206,139
Depreciation		9,243	932,281	249,028	161,599	-	1,352,151
Disposals		-	(22,644)	(9,319)	(77,418)	-	(109,381)
Balance, end of 2020		65,229	5,329,974	1,439,743	613,963	-	7,448,909
Net Book Value, end of 2020	$	689,968	$25,697,942	$ 1,303,219	$ 847,555	$ 1,813,049	$30,351,733

During the year the corporation purchased PP&E with cash totaling $4,227,924 (2020 - $3,820,656) and received contributed capital of $47,832 (2020 - $510,497).

There were no borrowing costs capitalized during the years ended December 31, 2021 and December 31, 2020.

There are no security charges over the Company's property, plant and equipment.

The Company has considered the increase in expenses as an indicator of impairment and therefore has determined the recoverable amount for its property, plant and equipment. The recoverable amount exceeded the carrying amount based on forecast cash flows. The cash flow forecasts are based on budgets for the next 5 years, with an assumed growth rate thereafter. The cash flows were probability weighted based on a positive case of 20% and a negative case of 20%. The calculation includes a growth rate of 1.8%, which is the average long-term growth rate for the Company's industry. The cash flows were discounted at a pre-tax discount rate of 3.9%, which is the weighted average cost of capital for the Company's industry. The discount rate was tested for sensitivity at +/-0.20%, and the recoverable amount remained above the carrying value.

(In Canadian dollars unless otherwise indicated)

10. Intangibles

	Paid Capital Contributions	Software	Goodwill	Total
Cost				
Balance, beginning of 2021	$ 553,415	$ 298,897	$ 276,704	$ 1,129,016
Additions	-	71,423	-	71,423
Balance, end of 2021	553,415	370,320	276,704	1,200,439
Accumulated amortization				
Balance, beginning of 2021	$ 43,043	$ 192,416	$ -	$ 235,459
Amortization	12,298	44,262	-	56,560
Balance, end of 2021	55,341	236,678	-	292,019
Net Book Value, end of 2021	$ 498,074	$ 133,642	$ 276,704	$ 908,420
Cost				
Balance, beginning of 2020	$ 553,415	$ 293,512	$ 276,704	$ 1,123,631
Additions	-	5,385	-	5,385
Balance, end of 2020	553,415	298,897	276,704	1,129,016
Accumulated amortization				
Balance, beginning of 2020	$ 30,745	$ 148,341	$ -	$ 179,086
Amortization	12,298	44,075	-	56,373
Balance, end of 2020	43,043	192,416	-	235,459
Net Book Value, end of 2020	$ 510,372	$ 106,481	$ 276,704	$ 893,557

There are no security charges over the Company’s intangible assets.

For purposes of impairment testing, goodwill acquired through business combination has been allocated to a single CGU, the Company. The most recent review of goodwill was performed in the fourth quarter. Management reviewed conditions since the last review was performed and determined that no circumstances occurred since then to require a revision to the assumptions used in the value in use calculations.

The recoverable amount of the CGU was determined using a discounted cash flow analysis. Forecasted cash flows reflect revenues consistent with OEB methodology of allowing a fair return on prudently placed capital that is recoverable through customer rates. Operating costs reflect historical costs of running the business, adjusted for inflation, and capital-spending forecasts reflect system integrity and capacity needs of utility infrastructure.

Key assumptions used in value-in-use calculations

The future cash flows of the underlying businesses are relatively stable since they relate primarily to ongoing electricity distribution in a rate-regulated environment. In the case of CGUs operating under a rate-regulated environment, revenues are set by the regulators to cover operating costs and to earn a return on the rate base, which is set at the regulator’s approved weighted average cost of capital for the underlying utility.

The calculation of value in use for the CGU is most sensitive to the following assumption:

(In Canadian dollars unless otherwise indicated)

10. Intangibles (continued)

Discount rates

The after-tax discount rates used were 3.9% (2020 – 4.0%), which were estimated based on the weighted average cost of capital for the CGU.

11. Right of use assets

		2021		2020
Cost				
January 1	$	1,676,316	$	1,676,316
Additions		-		-
December 31		1,676,316		1,676,316
Accumulated amortization				
January 1	$	343,860	$	171,930
Amortization		171,930		171,930
December 31		515,790		343,860
Net book value				
December 31	$	1,160,526	$	1,332,456

12. Regulatory deferral accounts

All amounts deferred as regulatory deferral account debit balances are subject to approval by the OEB. As such, amounts subject to deferral could be altered by the regulators. Remaining recovery periods are those expected and the actual recovery or settlement periods could differ based on OEB approval. Where no recovery period is noted, the deferral amount will be applied for disposition at the time of the next Cost of Service Application to the OEB, which will be for January 1, 2023 rates. The recovery period will be determined by the OEB at that time.

Due to previous, existing or expected future regulatory articles or decisions, the Company has the following amounts expected to be recovered from customers (returned to customers) in future periods and as such regulatory deferral account balances are comprised of:

(In Canadian dollars unless otherwise indicated)

12. Regulatory deferral accounts (continued)

	2020	Disposition May 2021	Balances Arising in the Period	Recovery	2021
Regulatory deferral debits:					
Stranded assets	$ 561,827	$ -	$ 2,921	$ -	**$** 564,748
OEB Cost assessment variance	177,959	-	33,596	-	211,555
Energy East consultation costs	2,467	-	13	-	2,480
IFRS transition costs	213,926	-	1,078	-	215,004
Late payment penalty settlement	(2,217)	-	-	-	(2,217)
COVID-19 costs and foregone revenue	147,739	-	(10,791)	(72,311)	64,637
Green Energy Renewable Connection	32,067	-	7,229	-	39,296
Stranded meters	10,135	-	21	-	10,156
Smart Grid	5,012	-	25	-	5,037
MIST Meters	242,184	-	11,532	-	253,716
MIST Meters Capitalized for IFRS	(201,191)	-	-	-	(201,191)
PILs tax variance - Ontario SBD	37,910	-	199	-	38,109
LRAMVA	105,587	(107,144)	96,812	-	97,255
RARA approved May 1, 2018, 2 yr	65,604	-	121	17,079	82,804
RARA approved May 1, 2019, 1 yr	19,127	-	10	-	19,137
RARA approved May 1, 2020, 1 yr	628,258	-	1,542	(568,504)	61,296
RARA approved May 1, 2021, 1 yr	-	1,036,078	2,716	(699,510)	339,284
Retail settlement variances	2,754,146	(928,934)	895,521	-	2,720,733
Miscellaneous deferred debits	24,425	-	(8,160)	-	16,265
	$ 4,826,965	$ -	$ 1,034,385	$ (1,323,246)	$ 4,538,104
Regulatory deferral credits:					
Pole attachment revenue variance	283,251	-	138,397	-	421,648
Retail service charge revenue variance	13,568	-	7,921	-	21,489
	$ 296,819	$ -	$ 146,318	$ -	$ 443,137
Net regulatory asset	$ 4,530,146	$ -	$ 888,066	$ (1,323,246)	**$** 4,094,967

(In Canadian dollars unless otherwise indicated)

12. Regulatory deferral accounts (continued)

Carrying charges are calculated monthly on the opening balance of the applicable variance account using the prescribed interest rate set by the OEB. During the period, the corporation recorded a net debit balance of $23,144 (2020 - $46,567) to the above regulatory accounts for carrying charges and the related net credit balance is included in net movement on regulatory deferral accounts. The prescribed interest rate history is as follows:

	Q1	Q2	Q3	Q4
2021 OEB quarterly prescribed interest rates	0.57%	0.57%	0.57%	0.57%
2020 OEB quarterly prescribed interest rates	2.18%	2.18%	0.57%	0.57%

Stranded assets

The purpose of this other regulatory deferral account is to record the cost of Sensus ICON model F and model G smart meters net of their accumulated amortization that must be removed from service prematurely before the end of their expected service life and replaced with new meters. These meters are exhibiting communication issues that are causing severe operational issues and are unable to meet new requirements such as data encryption. No amortization expense is recorded on these meters after they have been removed from service. Carrying charges are recorded monthly on the opening principal balance. A total of 4,631 units were replaced between June 2013 and December 31, 2015 at an actual removed net book value of $512,493.

OEB cost assessment variance

On February 9, 2016, the Board established this deferral account to record material differences between the quarterly OEB cost assessments currently built into rates and the cost assessments that will result from the application of the new Cost Assessment Model.

Energy east consultation costs

On June 13, 2014, the Board established this deferral account to record the Energy East Pipeline Project consultation costs.

IFRS transition costs

The corporation uses this deferral account to record one-time administrative incremental IFRS transition costs, which are not already approved and included for recovery in distribution rates and the associated carrying charges.

Late payment penalty ("LPP") settlement

On July 22, 2010, the Ontario Superior Court of Justice approved a settlement of the LPP Class Action. As its share of this settlement, the corporation was required to pay $46,486 on June 30, 2011 to charity to assist low-income electricity users. The corporation received approval from the OEB to recover this amount from ratepayers over a one-year period, starting May 1, 2011.

COVID-19 costs and foregone revenue

On March 20, 2020, the OEB established a regulatory account to track any incremental costs and lost revenues related to the COVID-19 pandemic and the associated carrying charges.

Green energy renewable connection

Under the Green Energy and Green Economy Act, electricity distributors are required to facilitate the connection of renewable energy sources to their systems and to undertake activities that will lead to a smart grid. The OEB has authorized deferral accounts to record the associated costs and related carrying charges.

Stranded meters

This account includes the NBV of stranded mechanical meters, which have been replaced by smart meters, plus carrying charges and less rate rider recoveries beginning October 1, 2013 and ending April 30, 2015.

12. Regulatory Deferral Accounts (continued)

Smart grid

Investments related to smart grid demonstration projects and investments undertaken as part of a project to accommodate renewable generation are recorded in the capital deferral account. Operating expenses directly related to smart grid development activities are recorded in the operating deferral account. Both of these deferral accounts attract applicable carrying charges.

MIST (metering inside the settlement timeframe) meters

This meter cost deferral account has been established for the tracking of incremental capital, operating costs and carrying charges related to the Distribution System Code amendment requiring distributors to install interval meters (i.e. MIST meters) on any installation that is forecast by the distributor to have a monthly average peak demand during a calendar year of over 50kW. The physical meters portion of this account meet the IAS 16 Property, Plant and Equipment ("PP&E") requirements and therefore have been reclassified to PPE.

Payments in lieu of taxes ("PILs") variances - Ontario small business deduction (SBD)

The PILs variance relates to the differences that have resulted from a legislative or regulatory change to the tax rates or rules assumed in the rate adjustment model.

Effective for taxation years ending after May 1, 2014, Canadian Controlled Private Corporations with taxable capital of $15 million or more are no longer eligible for the Ontario Small Business Deduction, which is a preferential corporate income tax rate of 4.5% instead of 11.5% on the first $500,000 of active business income. The Board requires any tax changes to be shared equally between ratepayers and the shareholder. The tax change began to be incorporated into the Incentive Regulation Mechanism ("IRM") process starting with effective rates May 1, 2016 and forward.

Lost revenue adjustment mechanism variance account (“LRAMVA”)

This variance account captures the difference between results of actual, verified impacts of authorized CDM activities undertaken and the level of CDM program activities included in the distributor’s load forecast and therefore embedded into rates.

Regulatory asset recovery accounts ("RARA")

The RARA is comprised of the cumulative balances of regulatory assets and regulatory liabilities approved for disposition by the OEB, reduced by amounts settled with customers through billing of approved disposition rate riders. The RARA is subject to carrying charges following the OEB prescribed methodology and rates. The number of years over which the recovery has been approved has been noted in the preceding schedule.

Retail settlement variance accounts ("RSVA")

RSVAs are comprised of the variances between amounts charged by the corporation to its customers, based on regulated rates, and the corresponding cost of non-competitive electricity service incurred by the corporation. The settlement variances relate primarily to service charges, non-competitive electricity charges and the global adjustment. Accordingly, the corporation has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. The balance for settlement variances continues to be calculated and attracts carrying charges in accordance with the OEB’s direction.

Low Voltage Variance

This account is included in Retail Settlement Variances and is used to record the variances arising from low voltage transactions that are not part of the electricity wholesale market.

Notes to Financial Statements (expressed in CDN$)

12. Regulatory deferral accounts (continued)

Miscellaneous deferred debits

This account includes expenses incurred in the expansion of the service area for Stayner, Creemore, and Thornbury, which will benefit future periods and are carried forward and charged to amortization expense over a twenty-five year period ending December 31, 2024.

Pole attachment revenue variance

The OEB set a new province-wide pole attachment charge effective January 1, 2019, adjusted annually for inflation. The new charge applies to all local distribution companies (LDCs) that have not received OEB approval for a distributor-specific charge. The excess incremental revenue is recorded in a variance account, with the accumulated balance ultimately refunded to ratepayers in the LDC's next cost-based rate application.

Regulatory deferral accounts adjustment

The entry required to translate the accounting records from regulatory reporting to IFRS was as follows:

	2021	2020
Statement of Comprehensive Income:		
Decrease/(Increase) in the sale of energy	$ 57,885	$ (174,325)
Increase in the cost of power purchased	825,108	2,207,706
Increase in distribution revenue	(1,227,316)	(520,573)
Increase in other revenue	(144,270)	(141,059)
Increase in operating expenses	38,428	120,561
Decrease in interest expense	(4,250)	(7,607)
Decrease in interest revenue	27,394	54,174
Increase in depreciation	15,138	12,722
Decrease in amortization of deferred charges	(8,160)	(8,160)
Statement of Financial Position:		
Increase in property, plant and equipment	150,421	163,144
Decrease to regulatory deferral accounts	(201,191)	(201,191)
Decrease in retained earnings	35,632	25,324
Net movement on regulatory deferral accounts	(435,179)	1,530,716
Decrease in retained earnings	4,530,146	2,999,430
	$ 4,094,967	$ 4,530,146

(In Canadian dollars unless otherwise indicated)

13. Loans and borrowings

	2021	2020
EPCOR Utilities Inc. - prime rate 2.45% (2020 – 2.45%), due monthly, January 31, 2022	$ -	$ 26,293
The Corporation of The Town of Collingwood		
Assignment of Infrastructure Ontario Debentures, secured by a general security agreement on all assets and real property		
4.67% fixed rate, $100,000 principal repayable semi-annually plus interest in October and April, due April 2025	$ 700,000	$ 900,000
3.84% fixed rate, $32,700 principal and interest repayable monthly, due September 2037	4,631,999	4,842,130
4.58% fixed rate, $3,563 principal and interest repayable monthly, due December 2043	594,313	609,711
2.76% fixed rate, $25,000 principal repayable semi-annually plus interest in October and April, due April 2035	675,000	725,000
EPCOR Utilities Inc. - unsecured related party promissory notes		
4.30% fixed rate, interest only payable semi-annually June and December, due December 2048	8,100,000	8,100,000
2.88% fixed rate, interest only payable semi-annually June and December, due December 2050	2,020,000	2,020,000
3.41% fixed rate, interest only payable semi-annually June and December, due December 2051	2,000,000	-
	18,721,311	17,223,134
Current portion of long-term debt	484,456	501,822
	$ 18,236,856	$ 16,721,312

The Company has combined the short-term debt and long-term debt note for presentation purposes.

14. Trade and other payables

	2021	2020
Accounts payable - energy purchases	$ 2,910,095	$ 2,945,677
Trade payables	825,764	702,910
Town of Collingwood - Water and Wastewater	923,317	915,532
Affordability Fund Trust	3,347	9,449
HST Payable	7,884	56,148
Short-term incentive plan	158,081	87,222
Payroll liabilities	85,095	59,616
Accrued interest on long-term debt	55,189	54,650
	$ 4,968,772	$ 4,831,204

(In Canadian dollars unless otherwise indicated)

15. Customer deposits and credits

	2021	2020
Customer deposits	$ 361,511	$ 392,599
Construction work deposits	709,882	581,603
Customer credit balances in trade receivables	549,786	708,211
	$ 1,621,179	$ 1,682,413

16. Deferred revenue

	2021	2020
Balance, beginning of year	$ 5,719,023	$ 4,754,872
Contributions received[1]	690,144	1,086,111
Revenue recognized	(145,047)	(121,960)
Balance, end of year	$ 6,264,120	$ 5,719,023
Less: current portion	150,794	126,857
	$ 6,113,326	$ 5,592,166

[1] Contributions received include cash contributions of $642,312 (2020 - $575,614) and non-cash contributions of $47,832 (2020 - $510,497)

17. Lease liabilities

The change in lease liabilities during the year were as follows:

	2021	2020
Balance, beginning of year	$ 1,414,067	$ 1,548,040
Payments during the year	(145,253)	(133,973)
Balance, end of year	$ 1,268,814	$ 1,414,067

Approximate future payments by the Company with respect to its lease liabilities are as follows:

	2021	2020
Within one year	$ 207,481	$ 203,412
After one year but not more than five years	872,257	855,154
More than five years	404,318	628,902
Unrecognized finance expense	(215,241)	(273,401)
	$ 1,268,814	$ 1,414,067

The lease liability consists of the Company's lease for land and building office and warehouse space in Collingwood, Ontario, Canada as the Company's head office. The agreement, which became effective in the fourth quarter of 2018, has an initial lease term of 25 years, expiring in the fourth quarter of 2043. The agreement also provides for early termination of the lease after nine years, with a one-year notice. As it is likely that the Company will exercise its rights on the agreement, the term of the lease has been determined to be 10 years.

There are no variable lease payments not included in the measurement of liabilities.

18. Employee future benefits

(a) Pension Plan

The employees of the Company participate in the Ontario Municipal Employees Retirement System ("OMERS"). Although the plan has a defined retirement benefit plan for employees, the related obligation of the corporation cannot be identified. The OMERS plan has several unrelated participating municipalities and costs are not specifically attributed to each participant.

The plan specifies the amount of the retirement benefit to be received by employees based on the length of service and rates of pay. The plan is financed by equal contributions from participating employers and employees, and by the investment earnings of the fund. The employer portion of amounts paid to OMERS during the year was $318,387 (2020 - $312,877). The contributions were made for current service and these have been recognized in net income.

Each year, an independent actuary determines the funding status of OMERS Primary Pension Plan by comparing the actuarial value of invested assets to the estimated present value of all pension benefits that members have earned to date. The most recent actuarial valuation of the Plan was conducted at December 31, 2021. The results of this valuation disclosed total actuarial liabilities of $120.8 (2020 - $113.1) billion in respect of benefits accrued for service with actuarial assets at that date of $117.7 (2020 - $109.8) billion, indicating a going concern actuarial deficit of $3.1 (2020 - $3.2) billion. Because OMERS is a multi-employer plan, any pension plan surpluses or deficits are a joint responsibility of Ontario municipal organizations and their employees. As a result, the Company does not recognize any share of the OMERS pension surplus or deficit.

The contribution rates for normal retirement age 65 members were 9.0% (2020 - 9.0%) for employees earning up to $61,600 (2020 - $58,700) and 14.6% (2020 - 14.6%) thereafter.

(b) Post employment medical and life insurance plan

The Company provides certain unfunded health, dental and life insurance benefits on behalf of its retired employees. All employees who retire from the Company are eligible for post-retirement life insurance benefits. In addition, employees age 55 or older with a minimum of 25 years of active service are eligible for extended health, dental, and vision benefits until they turn 65.

These benefits are provided through a group defined benefit plan. The Company has reported its share of the defined benefit costs and related liabilities, as calculated by an actuary, in these financial statements. The accrued benefit liability and the expense for the years ended December 31, 2021 and 2020 were based on results and assumptions determined by actuarial valuation as at December 31, 2019.

The plan is exposed to a number of risks, including interest rate risk on the discount rate used, longevity risk for changes in the estimation of mortality rates of current and former employees, and health care cost risk for increases in the costs of providing health, dental and life insurance benefits.

Benefits for employees on long-term disability

The Company provides continued contributions for health, dental and life insurance benefits on behalf of its employees while on disability leave.

(In Canadian dollars unless otherwise indicated)

18. Employee future benefits (continued)

(b) Post employment medical and life insurance plan continued

Information about the group unfunded defined benefit plan as a whole and changes in the present value of the unfunded defined benefit obligation and the accrued benefit liability are as follows:

	2021	2020
Defined benefit obligation, beginning of the year	$ 876,311	$ 880,722
Amounts recognized in net income:		
Current service cost - retirees	41,215	39,592
Current service cost - disability	-	(6,000)
Interest cost on obligation	25,432	25,292
	66,647	58,884
Amounts recognized in other comprehensive income:		
Actuarial loss from financial assumption	-	-
Actuarial gain/loss from adjustments (experience)	-	-
	-	-
Benefit payments	(57,160)	(63,295)
Defined benefit obligation, end of the year	$ 885,798	$ 876,311

Actuarial assumptions are as follows:

	2021	2020
Discount rate	3.00%	3.00%
Rate of compensation increase	3.50%	3.50%
Health benefits costs escalation	4.70%	4.40%
Dental benefits costs escalation	4.90%	4.70%
Retirement age	59 yrs	59 yrs

Sensitivity analysis:

The approximate effect on the defined benefit obligation if the main actuarial assumptions underlying the valuation increased or decreased by:

	2021	2020
Medical and dental benefits costs escalation:		
1% increase	$ 36,400	$ 36,400
1% decrease	$ (31,100)	$ (31,100)
Discount rate:		
1% increase	$ (121,500)	$ (121,500)
1% decrease	$ 162,900	$ 162,900

(In Canadian dollars unless otherwise indicated)

19. Commitments

Utility Collaborative Services Inc. ("UCS")

The Company has the right to redeem its shares in UCS by retraction upon the following terms:

(a) notice of such retraction shall be given 120 days prior to the effective date;

(b) and a retraction fee shall be paid equal to the previous three years' worth of the average purchases from UCS for services or products; or in alternative to paying such fees, the Company may elect in writing to provide three years' written notice of the retraction, provided that the Company continues to receive services at the same or greater average volume as those received at the time the notice was given.

As at December 31, 2021 the obligation to UCS includes 2022 to 2024 fees of approximately $230,000 per year, $690,000 total.

EPCOR Utilities Inc.

Annual commitments for the purchase of general administrative and operation services from EPCOR and its subsidiaries are estimated at $1,467,781.

20. Liability insurance

The Company belongs to the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE"). MEARIE is a self-insurance plan that pools the risks of all of its members. Any losses experienced by MEARIE are shared amongst its members. As at December 31, 2021, the Company has not been made aware of any assessments for losses. Insurance premiums charged to each member consist of a levy per thousand of dollars of service revenue subject to a credit or surcharge based on each member's claims experience.

21. Share capital

Authorized shares

Unlimited number of voting common shares without nominal or par value.

Issued shares

		2021	2020
5,101,340	Common shares	$ 5,101,340	$ 5,101,340

(In Canadian dollars unless otherwise indicated)

22. Miscellaneous paid In capital

Collingwood Public Utilities Commission was restructured November 1, 2000. The Ontario Government enacted the Energy Competition Act, 1998 which introduced competition to the Ontario electricity market. Net electricity distribution assets and liabilities of the original Collingwood Public Utilities Commission of $9,777,524 were transferred to the newly created Company on November 1, 2000, with off-setting credits from a promissory note of $1,710,170, common shares of $5,101,340 and miscellaneous paid in capital of $2,966,014 recorded.

On October 31, 2019, the shareholder contributed $2,500,000 to the miscellaneous paid in capital. On January 31, 2020 and October 31, 2020, the shareholder contributed an additional $2,000,000 respectively.

	2021	2020
Miscellaneous Paid in Capital	$ 9,466,014	$ 9,466,014

23. Credit facilities

Letter of Credit ("LOC") - Independent Electricity System Operator (IESO)

As at December 31, 2021, the Company's ultimate parent issued a $2,326,160 (2020 - $2,326,160) letter of credit for a standby letter of credit that was provided to the IESO to mitigate the risk of default on energy payments. The IESO can draw on the letter of credit if the Company defaults on its payment.

The Company is charged a monthly fee related to the letter of credit. For the year ended December 31, 2021 the fee incurred was $9,122 (2020 - $16,096).

Parental Guarantee - Town of Collingwood

The Company's parent provided a guarantee to the Town of Collingwood for the assumed Infrastructure Ontario loans of $6,686,479, which is currently still in place. The Company is charged a monthly fee related to the parental guarantee. For the year ended December 31, 2021 the fee incurred was $11,933 (2020 - $9,390).

24. Finance expenses

	2021	2020
Interest earned on bank account	$ -	$ (15,343)
Net interest on employee future benefits	25,432	25,292
Interest on customer deposits	1,547	6,706
Letter of Credit fees - IESO	9,122	16,096
Letter of Guarantee fees - Town of Collingwood	11,933	9,390
Interest on short-term debt	3,781	77,269
Interest on long-term debt	675,996	639,260
Corporate tax late payment penalty	1,383	-
Interest on lease obligation	54,913	62,616
	$ 784,107	$ 821,286

(In Canadian dollars unless otherwise indicated)

25. Bad debt expense (recovery)

		2021		2020
Write-offs	$	79,914	$	65,995
Recoveries		(35,322)		(20,912)
Opening allowance		(169,640)		(134,011)
Closing allowance		108,363		169,640
	$	(16,685)	$	80,712

26. Depreciation and amortization

		2021		2020
Property, plant and equipment	$	1,461,022	$	1,352,150
Right of use assets		171,930		171,930
Less vehicle depreciation, burdened to other accounts		(270,572)		(249,028)
		1,362,380		1,275,052
Capital contributions paid		12,298		12,298
Software		44,261		44,075
Deferred charges		8,160		8,160
		1,427,099		1,339,585
Less net regulatory movement related to deferred charges		(8,160)		(8,160)
	$	1,418,939	$	1,331,425

(In Canadian dollars unless otherwise indicated)

27. Related party balances and transactions

The Company is indirectly 100% owned by EPCOR Utilities Inc., which is in turn 100% owned by the City of Edmonton. The Company provides operations management, maintenance, repair, engineering services, system control and general plant services to EPCOR and its subsidiaries and purchases services from EPCOR and its subsidiaries relating to operational and inventory management, administration, maintenance, repair, utilities, facilities, general plant use, employee costs, executive oversight, legal, finance, treasury, audit, human resources, procurement, and information technology services pursuant to service agreements. Transactions between the Company and its related parties are in the normal course of operations, and are generally based on normal commercial rates, as approved by regulation.

The following summarizes the Company's related party transactions with EPCOR and its subsidiaries:

		2021		2020
Statements of Comprehensive Income:				
Administrative and Information technology service revenue (a)	$	179,841	$	175,249
Staff cost and employee benefit expense (b)	$	2,859,536	$	3,281,164
Interest expense (c)	$	434,498	$	456,161
Shared corporate services (d)	$	1,145,688	$	1,244,844
Statements of Financial Position:				
Property, plant and equipment purchases (e)	$	10,647	$	6,726
Shareholder contribution - Miscellaneous paid in capital (f)	$	-	$	4,000,000

The following summarizes the Company's related party balances with EPCOR and its subsidiaries:

		2021		2020
Statements of Financial Position:				
Trade and other receivables (g)	$	163,037	$	155,296
Trade and other payables (h)	$	191,954	$	127,658
Short-term debt (i)	$	-	$	26,293
Long-term debt (i)	$	12,120,000	$	10,120,000

(a) Relates to recoveries of various services provided to EPCOR.
(b) Relates to staff costs and employee benefits expenses paid by EPCOR on behalf of the Company. The comparative figure (not previously disclosed) has been included to conform with current year disclosure.
(c) Relates to interest expense on short-term and long-term notes payable to EPCOR as well as guarantee and letter of credit fees.
(d) Relates to expenditures for administrative services provided by EPCOR.
(e) Relates to expenditures for information services projects.
(f) Relates to contributions of paid in capital by EPCOR.
(g) Relates to accounts receivable due from EPCOR and its subsidiaries related to various services provided by the Company.
(h) Relates to accounts payable for administration of services, accrued interest on long-term notes payable to EPCOR, and accrual for employee benefits. The comparative figure has been restated to conform with current year disclosure.
(i) Relates to short-term and long-term notes payable to EPCOR.

(In Canadian dollars unless otherwise indicated)

28. Financial instruments

Classification

The classification of the Company's financial instruments at December 31, 2021 and 2020 are summarized as follows:

	Classification			
	Fair value through profit or loss	Fair value through other comprehensive income	Amortized cost	Fair value hierarchy
Measured at amortized cost				
Cash and cash equivalents			X	Level 1
Trade and other receivables			X	Level 3
Trade and other payables			X	Level 3
Loans and borrowings			X	Level 2
Customer deposits/credits			X	Level 3

Fair value

The carrying amounts of cash, trade and other receivables, trade and other payables and certain other liabilities (including customer deposits) approximate their fair values due to the short-term nature of these instruments.

The carrying amounts and fair values of the Company's remaining financial instruments measured at amortized cost are as follows:

	2021		2020	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Loans and borrowings (Note 13)	$ 18,721,311	$ 20,555,234	$ 17,196,841	$ 20,700,944

Fair value hierarchy
The financial instruments of the Company have been disclosed at fair value using a fair value hierarchy. A Level 1 valuation is determined by unadjusted quoted prices in active markets for identical assets or liabilities. A Level 2 valuation is based upon inputs other than quoted prices included in Level 1 that are observable for the instruments either directly or indirectly. A Level 3 valuation for the assets and liabilities are not based on observable market data.

Loans and borrowings

Short-term debt is measured at amortized cost and the carrying value approximates the fair value due to the short-term nature of these financial instruments.

The fair value of the Company's long-term debt is based on determining a current yield for the Company's debt as at December 31, 2021 and December 31, 2020. This yield is based on an estimated credit spread for the Company over the yields of long-term Government of Canada bonds for Canadian dollar loans that have similar maturities to the Company's debt.

(In Canadian dollars unless otherwise indicated)

29. Net change in non-cash working capital balances

The net change in non-cash working capital balances consists of:

		2021		2020
Trade and other receivables	$	(12,460)	$	1,250,391
Inventories		(318,299)		(133,196)
Prepaid expenses		11,381		41,590
Trade and other payables		137,029		118,818
Customer deposits and credits		(61,234)		580,321
Employee future benefits		(15,945)		(29,703)
Payments in lieu of corporate taxes paid		-		-
Net (increase) decrease in regulatory deferrals		435,179		(1,530,716)
Changes in non-cash working capital	$	175,651	$	297,505
Operating activities	$	168,546	$	469,439
Investing activities		7,105		(171,934)
	$	168,546	$	297,505

30. Capital management

The Company's primary objectives when managing capital are to safeguard the ability to continue as a going concern, pay dividends to its shareholder in accordance with the Company's dividend policy, and maintain an investment grade credit rating. The Company manages its capital structure in a manner consistent with the risk characteristics of the underlying assets and in accordance with OEB regulatory decisions. This overall objective and policy for managing capital remained unchanged in the current year from the prior year.

The Company manages capital through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and reviewing monthly financial results. The Company matches the maturity profiles of financial assets and liabilities to identify financing requirements to help ensure an adequate amount of liquidity.

The Company considers its capital structure to consist of long-term and short-term debt net of cash and shareholder's equity. The following table represents the Company's total capital:

		2021		2020
Loans and borrowings (including current portion) (Notes 13)	$	18,721,311	$	17,170,548
Cash		-		(10,404)
Net debt		18,721,311		17,160,144
Total equity		15,477,664		15,253,709
Total Capital	$	34,198,975	$	32,413,853

To manage or adjust its capital structure, the Company can issue new debt, repay existing debt or issue or redeem common units.

31. Financial risk management

Overview

As part of its operations, the Company carries out transactions that expose it to financial risks such as credit, liquidity and market risks. The following is a discussion of risks and related mitigation strategies that have been identified by the Company for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks identified.

Market risk

Market risk is the risk that changes in market prices, such as foreign exchange rates, commodity prices, and interest rates will affect the Company's net earnings or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits.

The Company does not have any direct exposure to foreign currency exchange rate risk or commodity price risk. The Company had no forward exchange rate contracts or commodity price contracts in place as at or during the year ended December 31, 2021.

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. Note 18 describes the interest rate risk associated with Employee Future Benefits. The Company is also exposed to interest rate fluctuations on its cash and short-term debt. The Company is protected from interest rate fluctuations on long-term debt for Infrastructure Ontario and EPCOR Utilities Inc., which bear fixed rates of interest. As at December 31, 2021, if interest rates had been 1% lower or higher with all other variables held constant, net income for the year would not have been impacted materially.

Credit risk

Credit risk is the risk that one party to a financial instrument will cause a loss for the other party by failing to pay for its obligation. The maximum credit exposure is limited to the carrying amount of cash, accounts receivable, and unbilled energy revenue presented on the statement of financial position.

The COVID-19 outbreak and resulting measures introduced by various governments and municipalities have resulted in economic slowdown. The economic slowdown together with measures by various governments preventing utility companies from disconnecting customers for non-payment and allowing certain utility customers to defer payments of their utility bills for a limited period, have increased the credit risk of the Company.

The Company limits its exposure to credit loss by placing its cash with a high credit quality financial institution. The Company maintains cash with one major financial institution. Eligible deposits per financial institution are insured to a maximum basic insurance level of $100,000, including principal and interest by the Canada Deposit Insurance Corporation.

The Company is exposed to credit risk related to accounts receivable and unbilled energy revenue arising from its day-to-day electricity and service revenue. Exposure to credit risk is limited due to the Company's large and diverse customer base. The corporation has approximately 18,000 customers, the majority of which are residential. No single customer accounts for revenue in excess of 10% of total revenue. The corporation limits its credit risk by collecting deposits, purchasing commercial account credit insurance, following collection policies, monitoring accounts receivable aging, and utilizing collection agencies. The Ontario Energy Board has prescribed certain rules for the collection of deposits from customers and the application of collection procedures. The corporation does not have any material accounts receivable balances greater than 90 days outstanding. The corporation believes that its accounts receivable represent a low credit risk.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in net income. The provision is based on account age and customer standing. Subsequent recoveries of receivables previously provisioned are credited to net income. (Note 25)

(In Canadian dollars unless otherwise indicated)

31. Financial Risk Management (continued)

The Company, in view of the COVID-19 pandemic and related economic impacts including the temporary deferral of customer payments, has adjusted the provision to account for higher level of potential customer defaults. The adjustment has resulted in recording no additional provision (2020 – $20,712) for the year ended December 31, 2021. Given the high degree of volatility caused by the COVID-19 outbreak, the estimates and judgments made by management in the preparation of the allowance are subject to a higher degree of estimation uncertainty compared to previous years. The Company continues to monitor the situation, including information related to realized credit losses from customers and further pronouncements from governments and regulators, and if required, will adjust the allowance in future periods. In response to COVID-19 the OEB issued an accounting order on March 25, 2020 allowing electricity distributors to track incremental bad debt expenses and subsequently apply for recovery as well as other incremental costs and foregone revenue.

The value of accounts receivable, by age, and the related expected credit loss allowance are presented in the following table. Unbilled energy revenue is considered all current. Receivables greater than 30 days are considered past due.

	2021	2020
Under 30 days	$ 7,865,964	$ 7,610,331
30 to 60 days	121,303	135,787
61 to 90 days	67,240	114,016
Over 90 days	382,188	625,378
	8,436,695	8,485,512
Expected credit loss allowance	108,363	169,640
Total accounts receivable	$ 8,328,332	$ 8,315,872

(In Canadian dollars unless otherwise indicated)

31. Financial risk management (continued)

Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. The Company's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions without incurring unacceptable losses or risking harm to the corporation's reputation. The Company's exposure is reduced by cash generated from operations and credit facility capacity with the ultimate parent company EPCOR Utilities Inc. The Company engages in borrowing to meet financing needs that exceed cash from operations. Exposure to such risks is significantly reduced through close monitoring of cash flows and budgeting. Liquidity risks associated with financial commitments are as follows:

	2022	2023	2024	2025	2026	2027 and thereafter	Total contractual cash flows
Trade and other payables[(a)]	$4,913,583	$ -	$ -	$ -	$ -	$ -	$ 4,913,583
Customer Deposits/credits	1,621,179	-	-	-	-	-	1,621,179
Lease liability	155,294	165,831	176,884	188,477	200,632	381,696	1,268,814
Loans and borrowings	484,456	493,736	503,385	513,416	523,846	16,202,473	18,721,312
Interest payments on loans and borrowings	724,010	704,010	683,723	662,890	648,752	11,793,727	15,217,112
	$ 7,898,522	$1,363,577	$1,363,992	$1,364,783	$1,373,230	$ 28,377,896	$ 41,742,000

(a) Excluding accrued interest on short-term debt of $55,189 (2020 - $54,650).

The Company's undiscounted cash flow requirements and contractual maturities in the next twelve months of $7,898,522 will be funded from operating cash flows and additional loans and borrowings.

32. Changes in liabilities arising from financing activities

	2020	Proceeds	Repayment	Other	2021
Accrued interest*	$ 54,650	$ -	$ -	$ 539	$ 55,189
Lease liabilities	1,414,067	-	(145,253)	-	1,268,814
Short-term debt	26,293	17,018,652	(17,044,945)	-	-
Long-term debt	17,196,841	2,000,000	(475,529)	-	18,721,312

* Accrued interest is included within trade and other payables

33. Judicial inquiry

The Company received a summons for the Town of Collingwood Judicial Inquiry dated June 29, 2018. The corporation was required to produce all documents related to the inquiry concerning the 50% share sale of Collingwood Utility Services Corp. to PowerStream Inc. The Town of Collingwood Judicial Inquiry is an independent inquiry established pursuant to section 274(1) of the Municipal Act 2001, pursuant to a majority vote of the Council of the Town of Collingwood. The inquiry concluded its public hearings on December 2, 2019. The report was released on November 3, 2020.

The corporation incurred legal expense or legal expense reimbursements to others related to the judicial inquiry of $182,866 (2020 - $61,268) during the year.

(In Canadian dollars unless otherwise indicated)

34. Operating expenses

	2021	2020
Labour	$ 2,859,536	$ 3,281,164
Shared corporate services	1,160,542	1,244,844
Contractor and consultants	1,089,019	1,122,380
Vehicle expenses	418,107	371,943
Vehicle burden allocation	(347,570)	(280,658)
Stock, materials, clothing and equipment	303,168	306,167
Office, printing, postage	249,463	239,935
Regulatory	196,829	75,114
Legal	186,447	61,268
Insurance	144,093	143,146
Licences, memberships and dues	86,731	137,116
Rent and storage	77,521	69,686
Telephone and utilities	57,799	61,709
Training and recognition	56,256	49,538
Audit	39,220	41,610
Advertising, donations and promotion	30,626	12,501
Property taxes	18,388	18,716
Travel, meals and entertainment	12,613	12,331
Foreign exchange loss	569	5,407
Bad debts (recoveries) (Note 25)	(16,685)	80,712
	$ 6,622,672	$ 7,054,629
Represented by:		
Billing and collecting	1,159,037	1,296,411
Operations and maintenance	2,461,747	2,785,780
General and administrative	2,186,394	2,137,588
Other recoverable expenses	806,880	825,081
Donations and Low-Income Energy Assistance Program	8,614	9,769
	$ 6,622,672	$ 7,054,629

35. Comparative figures

Some of the comparative figures have been reclassified to conform to the current year's presentation.

Financial Statements of

EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.

Years ended December 31, 2020 and 2019

EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.
Financial Statements

Years ended December 31, 2020 and 2019

Independent Auditor's Report

Financial Statements:

Tel: 519-432-5534
Fax: 519-432-6544
www.bdo.ca

BDO Canada LLP
633 Colborne St., Suite 230
London ON N6B 2V3

INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of EPCOR Utilities Inc.:

Opinion

We have audited the financial statements of EPCOR Electricity Distribution Ontario Inc. (the Entity), which comprise the statement of financial position as at December 31, 2020, and the statement of comprehensive income, statement of changes in equity and statement of cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2020, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditor's Responsibility for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Chartered Professional Accountants, Licensed Public Accountants
London, Ontario
April 15, 2021

EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.

Statements of Comprehensive Income
(expressed in Canadian dollars)

Years ended December 31, 2020 and 2019

	2020	2019
Revenues (Note 6)	**$ 51,231,264**	$ 46,090,281
Expenses		
Cost of power purchased	**43,853,252**	36,981,897
Depreciation and amortization (Note 27)	**1,331,425**	1,215,642
Billing and collecting (Note 35)	**1,296,411**	1,232,700
Operations and maintenance (Note 35)	**2,785,780**	2,278,270
General and administrative (Note 35)	**2,137,588**	3,076,554
Other recoverable expenses (Note 35)	**825,081**	769,866
Loss on disposal of property, plant and equipment	**75,154**	7,755
Donations and Low-Income Energy Assistance Program (Note 35)	**9,769**	11,832
	52,314,460	45,574,516
Income (loss) from operations	**(1,083,196)**	515,765
Finance expenses (Note 25)	**(821,286)**	(863,893)
Loss before income taxes and net regulatory movements	**(1,904,482)**	(348,128)
Income tax recovery (Note 8)	**(154,494)**	(211,290)
Loss before net regulatory movements	**(1,749,988)**	(136,838)
Net movement on regulatory deferral accounts (Note 12)	**1,530,716**	(361,928)
Net loss and regulatory movements	**(219,272)**	(498,766)
Other comprehensive loss: items that will not be reclassified to profit or loss, net of income tax		
Remeasurement of defined benefit pension plan	**-**	(37,263)
Total comprehensive loss	**$ (219,272)**	$ (536,029)

The accompanying notes are an integral part of these financial statements.

EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.

Statements of Financial Position
(expressed in Canadian dollars)

December 31, 2020 and 2019

		2020		2019
Assets				
Current assets				
Cash	**$**	**10,404**	$	1,470,614
Trade and other receivables (Note 7)		**8,315,872**		9,566,263
Inventories		**666,065**		532,869
Payments in lieu of taxes receivable		**92,803**		88,925
Prepaid expenses		**128,710**		170,300
		9,213,854		11,828,971
Deferred tax assets (Note 8)		**678,115**		527,499
Property, plant and equipment (Note 9)		**30,351,733**		27,488,415
Intangibles (Note 10)		**893,557**		944,545
Right of use assets (Note 11)		**1,332,456**		1,504,386
Total Assets		**42,469,715**		42,293,816
Regulatory deferrals (Note 12)		**4,826,965**		3,129,027
Total Assets and Regulatory Deferrals	**$**	**47,296,680**	$	45,422,843
Liabilities and Shareholder's Equity				
Current liabilities				
Short-term debt (Note 13)	**$**	**26,293**	$	5,180,842
Trade and other payables (Note 14)		**4,831,204**		4,709,913
Customer deposits and credits (Note 15)		**1,682,413**		1,102,092
Deferred revenue (Note 16)		**126,857**		121,960
Current portion of lease liabilities (Note 17)		**145,252**		135,683
Current portion of long-term debt (Note 18)		**475,529**		466,944
		7,287,548		11,717,434
Deferred revenue (Note 16)		**5,592,166**		4,632,912
Lease liabilities (Note 17)		**1,268,815**		1,412,357
Long-term debt (Note 18)		**16,721,312**		15,176,840
Employee future benefits (Note 19)		**876,311**		880,722
Total Liabilities		**31,746,152**		33,820,265
Shareholder's equity				
Share capital (Note 22)		**5,101,340**		5,101,340
Miscellaneous paid in capital (Note 23)		**9,466,014**		5,466,014
Retained earnings		**851,294**		1,070,566
Accumulated other comprehensive deficit		**(164,939)**		(164,939)
Total Shareholder's Equity		**15,253,709**		11,472,981
Total Liabilities and Shareholder's Equity		**46,999,861**		45,293,246
Regulatory deferrals (Note 12)		**296,819**		129,597
Total Liabilities, Equity and Regulatory Deferrals	**$**	**47,296,680**	$	45,422,843

Approved on behalf of the Board:

____________________ Stuart Lee, Chair   ____________________ Steven Stanley, Director

The accompanying notes are an integral part of these financial statements.

EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.

Statements of Changes in Equity
(expressed in Canadian dollars)

December 31, 2020 and 2019

	Share Capital	Miscellaneous Paid In Capital	Accumulated Other Comprehensive Deficit	Retained Earnings	Total
Balance January 1, 2019	**$ 5,101,340**	**$ 2,966,014**	**$ (127,676)**	**$ 1,569,332**	**$ 9,509,010**
Net loss and regulatory movement	-	-	-	(498,766)	(498,766)
Other comprehensive loss	-	-	(37,263)	-	(37,263)
Shareholder contributions	-	2,500,000	-	-	2,500,000
Balance December 31, 2019	**$ 5,101,340**	**$ 5,466,014**	**$ (164,939)**	**$ 1,070,566**	**$ 11,472,981**
Net loss and regulatory movement	-	-	-	(219,272)	(219,272)
Shareholder contributions	-	4,000,000	-	-	4,000,000
Balance December 31, 2020	**$ 5,101,340**	**$ 9,466,014**	**$ (164,939)**	**$ 851,294**	**$ 15,253,709**

The accompanying notes are an integral part of these financial statements.

EPCOR ELECTRICITY DISTRIBUTION ONTARIO INC.

Statements of Cash Flows
(expressed in Canadian dollars)

Years ended December 31, 2020 and 2019

		2020		2019
Cash flows from operating activities				
Comprehensive loss	**$**	**(219,272)**	$	(536,029)
Reconciliation of net income to cash from (used in) operating activities:				
Depreciation and amortization(Note 27)		**1,331,425**		1,215,642
Vehicle depreciation, allocated to other accts (Note 27)		**249,028**		232,366
Loss on disposal of property, plant and equipment		**75,154**		7,755
Gain on disposal of property, plant and equipment		**(11,936)**		(106,781)
Cash contributions received (Note 16)		**575,614**		811,666
Deferred revenue recognized (Note 16)		**(121,960)**		(102,382)
Income taxes (Note 8)		**(154,494)**		(224,725)
Finance expenses (Note 25)		**821,286**		863,893
Interest paid		**(808,863)**		(913,352)
Interest received		**15,343**		65,738
		1,751,325		1,313,791
Net change in non-cash working capital balances (Note 30)		**297,505**		(2,136,792)
Net cash flows from operating activities		**2,048,830**		(823,001)
Cash flows from investing activities				
Purchase of property, plant and equipment (Note 9)		**(3,820,656)**		(4,746,777)
Purchase of computer software (Note 10)		**(5,385)**		(123,652)
Proceeds on disposal of property, plant and equipment		**52,466**		106,780
		(3,773,575)		(4,763,649)
Cash flows from financing activities				
Proceeds (repayment) of short-term debt net (Note 33)		**(5,154,549)**		4,389,122
Proceeds of long-term debt (Note 33)		**2,020,000**		-
Repayments of long-term debt (Note 33)		**(466,943)**		(458,685)
Repayments of lease liability (Note 33)		**(133,973)**		(128,276)
Shareholder contributions received (Note 23)		**4,000,000**		2,500,000
		264,535		6,302,161
(Decrease) increase in cash during the year		**(1,460,210)**		715,511
Cash, beginning of year		**1,470,614**		755,103
Cash, end of year	**$**	**10,404**	$	1,470,614

The accompanying notes are an integral part of these financial statements.

1. Corporate Information

(a) Nature of Operations

EPCOR Electricity Distribution Ontario Inc. (the "Company" or EPCOR) was incorporated on April 13, 2000, under the Business Corporations Act (Ontario), and is wholly owned by its ultimate parent EPCOR Utilities Inc., a corporation incorporated under the laws of the province of Alberta. The address of the Company's office and principal place of business is 43 Stewart Road, Collingwood, Ontario, Canada.

The principal activity of the Company is to distribute electricity to approximately 18,000 customers in the service area of Collingwood, Thornbury, Stayner, and Creemore in the Province of Ontario, under licences issued by the Ontario Energy Board ("OEB"). The Company is regulated under the OEB and adjustments to the distribution rates require OEB approval.

(b) Rate Regulation

The Company, as an electricity distributor, is both licensed and regulated by the OEB which has a legislative mandate to oversee various aspects of the electricity industry. The OEB exercises statutory authority through setting or approving all rates charged by the Company and establishing standards of service for the Company's customers. The OEB has broad powers relating to licensing, standards of conduct and service and the regulation of rates charged by the Company and other electricity distributors in Ontario. The Ontario government enacted the Energy Competition Act, 1998, to introduce competition to the Ontario energy market. Rates are set by the OEB on an annual basis for May 1 to April 30.

Regulatory Risk

Regulatory risk is the risk that the Province and its regulator, the OEB, could establish a regulatory regime that imposes conditions that restrict the electricity distribution business from achieving an acceptable rate of return that permits financial sustainability of its operations including the recovery of expenses incurred for the benefit of other market participants in the electricity industry such as transition costs and other regulatory assets. All requests for changes in electricity distribution charges require the approval of the OEB.

Recovery Risk

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect distribution rates and other permitted recoveries in the future. The Company is subject to a cost of service regulatory mechanism under which the OEB establishes the revenues required (i) to recover the forecast operating costs, including amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. As actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

2. Basis of Preparation

(a) Statement of Compliance

These financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and Interpretations of the International Financial Reporting Interpretations Committee (IFRIC), and effective on December 31, 2020 and 2019. These financial statements were approved and authorized for issue by the Board of Directors on April 15, 2021.

(b) Basis of Measurement

The Company's financial statements are prepared on the historical cost basis.

(c) Functional and Presentation Currency

These financial statements are presented in Canadian dollars, which is also the corporation's functional currency, and all values are rounded to the nearest dollar, unless otherwise indicated.

3. Significant Accounting Policies

The accounting policies set out below have been applied consistently to all years presented in these financial statements unless otherwise indicated.

Changes in Significant Accounting Policies

The Company has adopted amendments to various accounting standards effective January 1, 2020, which did not have a significant impact on these financial statements.

(a) Regulatory Deferral Accounts

Regulatory deferral account debit balances represent future revenues associated with certain costs incurred in the current year or in prior year(s), that are expected to be recovered from consumers in future years through the rate-setting process. Regulatory deferral account credit balances are associated with the collection of certain revenues earned in the current year or in prior year(s), that are expected to be returned to consumers in future years through the rate-setting process. Regulatory deferral account balances can arise from differences in amounts collected from customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred by the Company in the wholesale market administered by the Independent Electricity System Operator (the "IESO") after May 1, 2002. These amounts have been accumulated pursuant to regulation underlying the Electricity Act (the "EA") and deferred in anticipation of their future recovery or expense in electricity distribution service charges.

Explanation of recognized amounts

Regulatory deferral account balances are recognized and measured initially and subsequently at cost. They are assessed for impairment on the same basis as other non-financial assets as described below.

Management continually assesses the likelihood of recovery of regulatory deferral accounts. If recovery through future rates is no longer considered probable, the amounts would be charged to the results of operations in the year that the assessment is made.

(b) Revenue Recognition

The Company recognizes revenue when it transfers control over a promised good or service, a performance obligation under the contract, to a customer and where the Company is entitled to consideration as a result of completion of the performance obligation. Revenue is comprised of the sale and distribution of electricity, pole use rental, collection and other customer charges, contributions in aid of construction and other miscellaneous revenues.

Sale and distribution of electricity

The Company is licensed by the OEB to distribute electricity. As a licensed distributor, the Company is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Company is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Company ultimately collects these amounts from customers. The Company has determined that they are acting as a principal for the electricity distribution and, therefore, have presented the electricity revenues on a gross basis.

The contracts with customers for the supply of electricity consists of perpetual contracts that are effective until terminated by the customer or Company. The Company distributes electricity which is a distinct service that is simultaneously received and consumed by the customers. Performance obligations are satisfied, over time using the output method for recognition of revenue for the metered units of electricity consumed. Electricity revenue is measured in consumption based on kWh consumed or on peak demand, which is a measurable unit of consumption. Revenue from the sale and distribution of electricity is recognized on an accrual basis, including unbilled revenues accrued in respect of electricity delivered but not yet billed. Payments are due within 30 days of billing.

Other

Other revenues, which include revenues from pole use rental, collection charges and other miscellaneous revenues are recognized at the time services are provided. Where the Company has an ongoing obligation to provide services, revenues are recognized as the service is performed and amounts billed in advance are recognized as deferred revenue.

3. Significant Accounting Policies Continued

(c) Non-derivative Financial Instruments

Financial assets are identified and classified based on the business model used by the Company for managing those financial assets, as one of the following: at amortized cost, at fair value through other comprehensive income, or at fair value through profit or loss. Prior to January 1, 2018, financial assets were identified and classified as one of the following: measured at fair value through profit or loss, loans and receivables, or available-for-sale financial assets. Non-derivative financial assets that were not classified in any of the above categories were designated as available-for-sale financial assets. Financial liabilities continue to be classified as measured at fair value through profit or loss or at amortized cost, as there is no change in classification of financial liabilities under IFRS 9.

Financial assets and financial liabilities are presented on a net basis when the Company has a legally enforceable right to offset the recognized amounts and intends to settle on a net basis or to realize the asset and settle the liability simultaneously.

At amortized cost

Cash, accounts receivable and unbilled energy revenue are classified as financial assets at amortized cost. These financial assets are recognized initially at fair value plus directly attributable transaction costs, if any. After initial recognition, they are measured at amortized cost when they are held for collection of cash flows, where those cash flows solely represent payments of principal and interest using the effective interest rate method less any impairment. The effective interest rate method calculates the amortized cost of a financial asset and allocates the finance income over the term of the financial asset using an effective interest rate. The effective interest rate is the rate that discounts estimated future cash receipts through the expected life of the financial asset, or a shorter period when appropriate, to the gross carrying amount of the financial asset.

The Company’s accounts payable and accruals, customer deposits and credits, and short and long-term debt are classified as financial liabilities at amortized cost and recognized on the date at which the Company becomes a party to the contractual arrangement. Financial liabilities are derecognized when the contractual obligations are discharged, cancelled or expire. Financial liabilities are initially recognized at fair value including discounts and premiums, plus directly attributable transaction costs, such as issue expenses, if any. Subsequently, these liabilities are measured at amortized cost using the effective interest rate method.

At fair value through other comprehensive income

Financial assets that are held for collection of contractual cash flows and for selling, where the assets’ cash flows solely represent payments of principal and interest, are classified as financial assets at fair value through other comprehensive income. These financial assets are initially recognized at fair value plus directly attributable transaction costs. Subsequent to initial recognition, these financial assets are measured at fair value with unrealized gains and losses recognized in other comprehensive income, except for the recognition of impairment losses, reversal of impairment losses, interest income and foreign exchange gains and losses, which are recognized in net income. On de-recognition of the financial asset, the cumulative gain or loss previously recognized in other comprehensive income is reclassified to net income. Interest income from these financial assets is recognized as other income using the effective interest rate method.

At fair value through profit or loss

Financial instruments at fair value through profit or loss include instruments that are designated as financial instruments at fair value through profit or loss or those financial instruments that do not meet the criteria for classification under any other category. Upon initial recognition, directly attributable transaction costs are recognized in net income as incurred. Changes in fair value of financial instruments measured at fair value through profit or loss are recognized in net income.

3. Significant Accounting Policies Continued

(d) Cash

Cash and bank includes cash on hand, deposits held on demand with financial institutions, other short-term, highly liquid investments with original maturities of three months or less that are readily convertible to known amounts of cash and subject to an insignificant risk of change in value.

(e) Customer Deposits

Customers may be required to post security to obtain electricity or other services, which are refundable. Where the security posted is in the form of cash, these amounts are recorded in the accounts as deposits. Deposits to be refunded to customers within the next fiscal year are classified as a current liability.

(f) Inventories

Cost of inventory is comprised of direct materials, which typically consists of distribution assets not deemed as major spares, unless purchased for specific capital projects in process or as spare units. Costs, after deducting rebates and discounts, are assigned to individual items of inventory on the basis of weighted average cost. Decommissioned assets that are transferred to inventory are tested for impairment once they are removed from service and placed in inventory. Inventory is recognized at the lower of cost and net realizable value, which is the estimated selling price in the ordinary course of business less the estimated costs of completion and the estimated costs necessary to make the sale.

(g) Leases

At the inception of a contract, the Company determines whether a contract is, or contains a lease. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

As a lessee

On initial identification of a lease contract, the Company recognizes a right-of-use (ROU) asset and a lease liability at the commencement of the lease contract. The lease liability is initially measured at the present value of the future unavoidable lease payments under the contract, discounted using the interest rate implicit in the lease contract. Where the implicit rate cannot be readily determined, the Company uses the incremental borrowing rate of the legal entity entering into the lease contract. Lease payments include fixed payments including in-substance fixed payments less any lease incentives receivable, variable lease payments that depend on an index or a rate, the exercise price of a purchase option or optional renewal period that the Company is reasonably certain to exercise and penalties for early termination of a lease contract unless the Company is reasonably certain not to terminate early. Subsequently, the lease liability is measured at amortized cost, using the effective interest method. The lease liability is re-measured to reflect any reassessments or lease modifications. Lease payments are allocated between the principal repayment of the lease liability and finance expense. The finance expense on the lease liability is charged to net income over the term of the lease contract to produce a constant periodic rate of interest on the remaining balance of the lease liability for each period.

The ROU asset is initially measured at cost which includes the initial lease liability, any lease payments made at or before commencement date less any lease incentives received, any initial direct costs and restoration costs. The ROU assets are depreciated on a straight-line basis over the shorter of the respective asset's useful life and the remaining term of the lease contract. The ROU assets are subsequently re-measured to reflect any reassessments or lease modifications. At each reporting date, ROU assets are reviewed for indications of impairment. In case it is determined that indications of impairment exist, the recoverable amount is estimated for ROU assets, which is the greater of value in use and fair value the Company expects to recover from sub-lease of the asset.

The Company has elected not to recognize ROU assets and lease liabilities for lease contracts where the total term of the respective lease contract is less than or equal to 12 months or for low value lease contracts. The Company recognizes the payments relating to such leases (including principal and interest associated with these leases) as an expense on a straight-line basis over the lease term. These payments are presented within other administrative expense in net income.

3. Significant Accounting Policies Continued

(h) Property, Plant and Equipment

Property, plant and equipment (PP&E) are recognized at cost, net of accumulated depreciation and accumulated impairment, if any, being the purchase price and directly attributable cost of acquisition or construction required to bring the asset to the location and condition necessary to be capable of operating in the manner intended by the Company, including eligible borrowing costs.

Depreciation of PP&E is recorded in the statement of comprehensive income on a straight-line basis over the estimated useful life of the related asset. Half of a year's amortization is taken for the first year, regardless of when the property was actually put into service during the year. The estimated useful lives, residual values and amortization methods are reviewed at the end of each annual reporting period, with the effect of any changes in estimate being accounted for on a prospective basis. The estimated useful lives for the current and comparative years are:

Buildings	50 years
Distribution stations	20 - 45 years
Distribution lines	40 - 60 years
Distribution transformers	40 years
Distribution services	40 years
Meters	15 years
Vehicles	5 - 8 years
Equipment	3 - 15 years

Work-in-Progress assets are not depreciated until the project is complete and ready for use.

Major spares such as spare transformers and other items kept as standby/back up equipment are accounted for as PP&E since they support the Company’s distribution system reliability. These are included in work-in-progress (Note 9) and not depreciated.

Gains or losses on disposal of an item of property, plant and equipment are determined by comparing the net proceeds from disposal with the carrying amount of the asset, and are included in the statement of comprehensive income when the asset is disposed. When an item of property, plant and equipment with related contributions in aid of construction is disposed, the remaining contributions are recognized in full in the statement of comprehensive income.

(i) Borrowing Costs

The Company capitalizes interest expenses and other finance charges directly relating to the acquisition, construction or production of assets that take a substantial period of time to get ready for its intended use. Capitalization commences when expenditures are being incurred, borrowing costs are being incurred and activities that are necessary to prepare the asset for its intended use or sale are in progress. Capitalization will be suspended during periods in which active development is interrupted. Capitalization will cease when substantially all of the activities necessary to prepare the asset for its intended use or sale are complete.

3. Significant Accounting Policies Continued

(j) Intangible Assets

Paid Capital Contributions include amounts paid by the corporation for capital expenditures under a Capital Cost Recovery Agreement. The contribution is measured at cost less accumulated amortization and accumulated impairment losses. They are not amortized until put into use.

Computer software that is acquired or developed by the Company, including software that is not integral to the functionality of equipment purchased, which has finite useful lives, is measured at cost less accumulated amortization and accumulated impairment losses.

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, other than goodwill, from the date that they are available for use. Half of a year's amortization is taken for the first year in service. Amortization methods and useful lives of all intangible assets are reviewed at the end of each annual reporting period. The estimated useful lives for the current and comparative years are:

Paid Capital Contributions	45 years
Computer software	5 years

Goodwill represents the cost of acquired local distribution companies in Stayner, Creemore and Thornbury in excess of fair value of the net identifiable assets purchased. Goodwill is measured at cost and is not amortized.

(k) Deferred Revenue

Certain assets may be contributed by customers or be constructed using non-refundable cash contributions from customers. Non-refundable customer contributions which are used to provide ongoing goods or services to these customers are recorded as deferred revenue. The deferred revenue is initially recorded at the fair value of contributed assets, or the amount of cash contributions received, and is recognized as revenue on a straight-line basis over the estimated life of the contract with the customers. Where contracts with customers are perpetual, the related contributed asset will be used to provide ongoing goods or services to customers and as such the estimated life of the contract with the customers is estimated to be equivalent to the economical useful life of the asset to which the contribution relates.

Certain assets may be contributed by developers or be acquired or constructed using non-refundable cash contributions from developers. Non-refundable developer contributions that result in the Company having an on-going obligation to provide goods or services with respect to the assets acquired or constructed are recorded as deferred revenue, at the fair value of the contributed assets or the amount of cash contribution received, and are recognized as revenue on a straight-line basis over the estimated economic useful lives of the assets to which the contribution relates.

(l) Impairment of financial assets

The Company uses the “expected credit loss” (ECL) model for calculating impairment and recognizes ECL as a loss allowance for financial assets measured at amortized cost.

For trade receivables without significant financing component, the Company applies the simplified approach and uses a provision matrix, which is based on the Company’s historical credit loss experience, current market conditions and forward looking information, to estimate and recognize the lifetime ECL. Trade and other receivables that are not assessed for impairment individually are assessed for impairment on a collective basis taking into consideration the unique risk factors associated with each customer group.

(m) Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognized as a finance expense over the estimated period until settlement of the obligation.

3. Significant Accounting Policies Continued

(n) Impairment of non-financial assets

The carrying amounts of the Company's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. Non-financial assets include PP&E, intangible assets and goodwill. For PP&E and intangible assets with definite useful lives, the recoverable amount is estimated when an indication of impairment exists. For goodwill and intangible assets that have indefinite useful lives or that are not yet available for use, the recoverable amount is estimated at least once each year.

The recoverable amount of an asset or cash-generating unit (CGU) is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using an after-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. For the purpose of impairment testing, assets that cannot be tested individually are tested as a CGU. CGU's are the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. For the purposes of goodwill impairment testing, goodwill acquired in a business combination is allocated to the CGU, or the group of CGUs, that is expected to benefit from the synergies of the combination. This allocation is subject to an operating segment ceiling test and reflects the lowest level at which that goodwill is monitored for internal reporting purposes.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in comprehensive income. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units, and then to reduce the carrying amount of the assets in the unit or the group of units on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other non-financial assets, impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a fundamental change, since the date of impairment, which may improve the financial performance of the non-financial asset. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(o) Employee Future Benefits

Pension plan

The employees of the Company participate in the Ontario Municipal Employees Retirement System ("OMERS"). The Company also makes contributions to the OMERS plan on behalf of its employees. The plan has a defined benefit option at retirement available to employees, which specifies the amount of the retirement benefit plan to be received by the employees based on length of service and rates of pay. However, the plan is accounted for as a defined contribution plan as insufficient information is available to account for the plan as a defined benefit plan. The Company is only one of a number of employers that participates in the plan and the financial information provided to the Company on the basis of the contractual agreements is insufficient to measure the Company's proportionate share in the plan assets and liabilities on defined benefit accounting requirements. The contribution payable in exchange for services rendered during a period is recognized as an expense during that period.

Post employment medical and life insurance plan

A defined benefit plan is a post-employment benefit plan other than a defined contribution plan. The Company's net obligation on behalf of its retired employees' unfunded, extended medical and dental benefits is calculated by estimating the amount of future benefits that are expected to be paid out discounted to determine its present value. Any unrecognized past service costs are deducted.

The calculation is performed by a qualified actuary using the projected unit credit method every third year or when there are significant changes to workforce. When the calculation results in a benefit to the Company, the recognized asset is limited to the total of any unrecognized past service costs and the present value of economic benefits available in the form of any future refunds from the plan or reductions in future contributions to the plan. An economic benefit is available to the Company if it is realizable during the life of the plan, or on settlement of the plan liabilities.

Defined benefit obligations are measured using the projected unit credit method discounted to its present value using yields available on high quality corporate bonds that have maturity dates approximating the terms of the liabilities.

Remeasurements of the defined benefit obligation are recognized in other comprehensive income. The remeasurements include actuarial gains and losses.

3. Significant Accounting Policies Continued

(o) Employee Future Benefits Continued

Service costs are recognized in operating expenses and include current and past service costs as well as gains and losses on curtailments.

Net interest expense is recognized in finance costs and is calculated by applying the discount rate used to measure the defined benefit obligation at the beginning of the annual period to the balance of the net defined benefit obligation, considering the effects of benefit payments during the period. Gains or losses arising from changes to defined benefits or plan curtailment are recognized immediately in the statement of comprehensive income. Settlements of defined benefit plans are recognized in the period in which the settlement occurs.

Other employee benefits

Short-term employee benefit obligations are measured on an undiscounted basis and are expensed as the related service is provided. A liability for short-term employee benefits is recognized for the amount expected to be paid if the Company has a legal or constructive obligation to pay this amount as a result of past service provided by the employee and the obligation can be estimated reliably.

(p) Payments in Lieu of Taxes Payable

Tax status

The corporation is a Municipal Electricity Utility (“MEU”) for purposes of the payments in lieu of taxes (“PILs”) regime contained in the Electricity Act, 1998. As a MEU, the Company is exempt from tax under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario).

Under the Electricity Act, 1998, the Company is required to make, for each taxation year, PILs to Ontario Electricity Financial Corporation ("OEFC"), commencing October 1, 2001. These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

Current and deferred tax

Provision in lieu of taxes ("PILs") is comprised of current and deferred tax. Current tax and deferred tax are recognized in net income except to the extent that it relates to items recognized directly in Other Comprehensive Income.

Current PILs are recognized on the taxable income or loss for the current year plus any adjustment in respect of previous years. Current PILs are determined using tax rates and tax laws that have been enacted or substantively enacted by the year-end date.

Deferred tax assets and liabilities are recognized where the carrying amount of an asset or liability differs from its tax base. The amount of the deferred tax asset or liability is measured at the amount expected to be recovered from or paid to the taxation authorities. This amount is determined using tax rates and tax laws that have been enacted or substantively enacted by the year-end date and are expected to apply when the liabilities/(assets) are settled/(recovered).

Recognition of deferred tax assets for unused tax losses, tax credits and deductible temporary differences is restricted to those instances where it is probable that future taxable profit will be available against which the deferred tax asset can be utilized.

At the end of each reporting period, the Company reassesses both recognized and unrecognized deferred tax assets. The Company recognizes a previously unrecognized deferred tax asset to the extent that it has become probable that future taxable profit will allow the deferred tax asset to be recovered.

(q) Standards and Interpretations Not Yet Applied

A number of new standards, amendments to standards and interpretations of standards have been issued by the IASB and the IFRIC, the application of which is effective for periods beginning on or after January 1, 2021. The Company does not expect the implementation of these new accounting pronouncements to have a significant impact on its accounting policies.

4. Use of Judgments and Estimates

The preparation of the Company's financial statements in accordance with IFRS requires management to make judgments in the application of accounting policies, and estimates and assumptions that affect the reported amounts of income, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities.

(a) Judgments

Information about critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements are included in notes:

Note 3(g) - Leases
Note 3(h) - Property, plant and equipment

(b) Estimates

The Company reviews its estimates and assumptions on an ongoing basis, uses the most current information available and exercises careful judgment in making these estimates and assumptions. Adjustments to previous estimates, which may be material, are recorded in the period in which they become known. Actual results may differ from these estimates. Assumptions and uncertainties that have a significant risk of resulting in a material adjustment within the next financial year include:

Employee future benefits
The cost of post employment medical and insurance benefits are determined using actuarial valuations. An actuarial valuation involves making various assumptions. Due to the complexity of the valuation, the underlying assumptions and its long-term nature, post employment medical and insurance benefits are highly sensitive to changes in these assumptions. All assumptions are reviewed at each reporting date. See Note 19 Employee Future Benefits.

Payments in Lieu of Taxes Payable and Deferred Taxes
The Company is required to make payments in lieu of tax calculated on the same basis as income taxes on taxable income earned and capital taxes. Significant judgment is required in determining the provision for income taxes and deferred taxes. There are many transactions and calculations undertaken during the ordinary course of business for which the ultimate tax determination is uncertain. The Company recognizes liabilities for anticipated tax audit issues based on the Company's current understanding of the tax law. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the current and deferred tax provisions in the period in which such determination is made.

Accounts Receivable Impairment
In determining the expected credit loss allowance, the Company considers historical credit loss experience for accounts receivable, current market conditions and the future expectations, to estimate and recognize the lifetime expected credit loss.

Estimate of Useful Life of Assets
The estimates and assumptions made to determine the useful life of property, plant and equipment and certain intangibles are determined by management at the time the asset is acquired and reviewed annually for appropriateness based on industry standards, historical experience, and technological obsolescence.

Regulatory Estimates
Certain estimates are necessary given that the regulatory environment in which the Company operates often requires amounts to be recorded at estimated values until finalization and adjustment, pursuant to subsequent OEB regulatory proceedings or decisions.

Unbilled Energy Revenue
Unbilled energy revenue is based on an assessment of electricity distribution services supplied to customers between the date of the last meter reading and the period ending date. The Company applies judgemental to the measurement of the estimated consumption and the valuation of that consumption.

Fair value measurement
Certain accounting measures such as determining asset impairments and recording financial assets and liabilities use various valuation techniques to determine fair value. Estimates of fair value may be based on readily determinable market values or depreciable replacement cost or discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate.

Notes to Financial Statements (expressed in CDN$)

5. Novel Coronavirus

In March 2020, the global outbreak of the novel coronavirus (COVID-19) was declared a pandemic by the World Health Organization. In response to the outbreak, governmental authorities globally introduced various recommendations and measures to try to limit spread of the pandemic, including non-essential business closures, quarantines, travel restrictions, self-isolation, social and physical distancing and shelter-in-place. These measures caused disruptions to businesses globally resulting in an economic slowdown. While the majority of the Company's operations consist of the provision of essential utility services, the Company experienced a decline in the sale of electricity to its commercial customers, which was largely offset by increase in sales to residential and multi-residential customers, as well as additional costs incurred to mitigate risks of the outbreak. During the year ended December 31, 2020, the COVID-19 pandemic did not result in any material impact on the financial results of the Company.

In Ontario, the spread of COVID-19 showed signs of slowing down in the second and third quarters of the year, and most of the restrictions were gradually lifted by the provincial governments. However, in the fourth quarter of the year, the number of COVID-19 cases started to rise and the federal and provincial governments imposed restrictions again. Any prolonged restrictions could disrupt business activities, which could negatively affect one or more factors that are essential for maintaining regular operations of the Company including, but not limited to, availability of employees for delivery of services, availability of supplies and equipment for operations and planned construction of plants and other assets. The ultimate duration and magnitude of the impact on the economy and consequential financial effect on the Company, is unknown at this time.

6. Revenues

	2020	2019
Sale of energy	**$ 41,819,872**	$ 36,232,007
Distribution revenue	**8,028,188**	8,414,526
Deferred revenue recognized (Note 16)	**121,960**	102,382
Other revenue	**1,261,244**	1,341,366
	$ 51,231,264	$ 46,090,281

The Company has reclassified the prior year other recoverable expenses of $769,866 from a net against other revenue to a separate line item in operating expenses, which more accurately represents total revenues and total expenses.

Revenue from contracts with customers expected to be recognized in future periods related to performance obligations that are unsatisfied or partially satisfied at the reporting date are as follows:

	2021	2022	2023	2024	2025	2026 and thereafter	Total
Contributions received from customers and developers	$ 126,857	$ 126,857	$ 126,857	$ 126,857	$ 126,857	$ 5,084,738	$ 5,719,023

As at December 31, 2020, the Company had deferred revenue recorded in the statements of financial position related to contributions in aid of construction received from customers and developers. Revenue will be recognized in future periods related to this balance, as described in note 3(k), over periods ranging between 40-50 years.

Notes to Financial Statements (expressed in CDN$)

7. Trade and Other Receivables

		2020		2019
Trade receivables	$	5,059,031	$	4,952,363
Accrued revenues		3,320,754		4,642,184
EPCOR Electricity Solutions Ontario Inc., a company under common control		105,727		105,727
EPCOR Collingwood Energy Inc., a company under common control		(100)		(100)
Long-term Investment - UCS (Note 20)		100		100
Gross accounts receivable		8,485,512		9,700,274
Expected credit loss allowance (Notes 26 and 32)		169,640		134,011
	$	8,315,872	$	9,566,263

Accounts receivable include $1,199,462 (December 31, 2019 - $1,204,476) for water and sewer billings.

Details of the aging of accounts receivable and analysis of the changes in the ECL allowance are provided in Note 32.

The Company has combined the prior year unbilled energy revenue with trade and other receivables and reclassified HST receivable to trade and other payables for presentation purposes.

8. Payments in Lieu of Corporate Taxes

(a) The significant components of the provision for payments in lieu of taxes recognized in net income are as follows:

		2020		2019
Current tax				
Based on current year taxable income	$	-	$	1,521
Adjustments for over / under provision in prior periods		(3,878)		-
	$	(3,878)	$	1,521
Deferred tax				
Origination and reversal of temporary differences		(145,335)		(212,811)
Adjustments for over / under provision in prior periods		(5,281)		-
	$	(150,616)	$	(212,811)
	$	(154,494)	$	(211,290)

The significant components of the tax effect of the amount recognized in other comprehensive income are as follows:

		2020		2019
Deferred tax				
Remeasurement of defined benefit plan	$	-	$	(13,435)

Notes to Financial Statements (expressed in CDN$)

8. Payments in Lieu of Corporate Taxes (Continued)

Statutory Canadian federal and provincial tax rates for the current year comprise 15% (2019 - 15%) for federal corporate tax and 11.5% (2019 - 11.5%) for corporate tax in Ontario. The PILs expense varies from amounts which would be computed by applying the Company's combined statutory income tax rate as follows:

	2020	2019
Total loss and other comprehensive loss	$ **(219,272)**	$ (536,029)
Plus current and deferred income taxes	**(154,494)**	(224,725)
Net loss before income taxes	**(373,766)**	(760,754)
Statutory Canadian federal and provincial tax rate	**26.50%**	26.50%
Provision for PILs at statutory rate	**(99,048)**	(201,600)
Increase (decrease) in income tax resulting from:		
Interest and penalties on taxes	**-**	786
Meals and entertainment	**188**	1,940
Items in property, plant and equipment	**(46,475)**	(29,858)
Miscellaneous other	**-**	4,007
Prior year provision adjustment	**(9,159)**	-
Total provision	$ **(154,494)**	$ (224,725)
Effective tax rate	**41.33%**	29.54%

(b) The movement in the deferred tax asset is as follows:

	2020	2019
Opening balance	$ **527,499**	$ 301,253
Recognized in net income	**150,616**	212,811
Recognized in other comprehensive income	**-**	13,435
Closing balance	$ **678,115**	$ 527,499

Deferred tax assets (liabilities) are attributable to the following:

	2020	2019
Employee future benefits	$ **232,222**	$ 233,390
Property, plant and equipment	**(1,723,784)**	(1,254,042)
Intangibles	**(87,565)**	(79,747)
Property under lease	**(353,101)**	(398,662)
Goodwill	**(73,327)**	(73,327)
Deferred revenues	**1,515,541**	1,260,042
Lease obligation	**374,728**	410,231
Loss carryforward	**793,401**	429,614
	$ **678,115**	$ 527,499

The utilization of this tax asset is dependent on future taxable profits in excess of profits arising from the reversal of existing taxable temporary differences. The Company believes that this asset should be recognized as it will be recovered through future services.

Notes to Financial Statements (expressed in CDN$)

9. Property, Plant and Equipment

	Land and Buildings	Distribution Equipment	Vehicles	Other Equipment	Work-in Progress	Total
Cost						
January 1, 2019	$ 755,197	$25,076,960	$ 1,833,631	$ 743,850	$ 693,329	$29,102,967
Additions	-	-	-	-	4,746,777	4,746,777
Transfers into service	-	2,318,787	653,982	735,897	(3,708,666)	-
Disposals	-	(21,513)	(133,677)	-	-	(155,190)
December 31, 2019	755,197	27,374,234	2,353,936	1,479,747	1,731,440	33,694,554
Additions	-	-	-	-	4,331,153	4,331,153
Transfers into service	-	3,722,746	463,574	63,224	(4,249,544)	-
Disposals	-	(69,064)	(74,548)	(81,453)	-	(225,065)
December 31, 2020	$ 755,197	$31,027,916	$ 2,742,962	$ 1,461,518	$ 1,813,049	$37,800,642
Accumulated Depreciation						
January 1, 2019	$ 46,743	$ 3,568,182	$ 1,101,346	$ 409,372	$ -	$ 5,125,643
Depreciation	9,243	865,912	232,365	120,410	-	1,227,930
Disposals	-	(13,757)	(133,677)	-	-	(147,434)
December 31, 2019	55,986	4,420,337	1,200,034	529,782	-	6,206,139
Depreciation	9,243	932,281	249,028	161,599	-	1,352,151
Disposals	-	(22,644)	(9,319)	(77,418)	-	(109,381)
December 31, 2020	$ 65,229	$ 5,329,974	$ 1,439,743	$ 613,963	$ -	$ 7,448,909
Net Book Value						
December 31, 2019	$ 699,211	$22,953,897	$ 1,153,902	$ 949,965	$ 1,731,440	$27,488,415
December 31, 2020	$ 689,968	$25,697,942	$ 1,303,219	$ 847,555	$ 1,813,049	$30,351,733

During the year the corporation purchased PP&E with cash totalling $3,820,656 (2019 - $4,746,777) and received contributed capital of $510,497 (2019 - $NIL).

The Company has considered the increase in expenses as an indicator of impairment and therefore has determined the recoverable amount for its property, plant and equipment. The recoverable amount exceeded the carrying amount based on forecast cash flows. The cash flow forecasts are based on budgets for the next 5 years, with an assumed growth rate thereafter. The cash flows were probability weighted based on a positive case of 20% and a negative case of 20%. The calculation includes a growth rate of 1.8%, which is the average long-term growth rate for the Company's industry. The cash flows were discounted at a pre-tax discount rate of 3.96% which is the weighted average cost of capital for the Company's industry. The discount rate was tested for sensitivity at +/-0.20%, and the recoverable amount remained above the carrying value.

Notes to Financial Statements (expressed in CDN$)

10. Intangibles

	Paid Capital Contributions	Software	Goodwill	Total
Cost				
January 1, 2019	$ 553,415	$ 169,860	$ 276,704	$ 999,979
Additions	-	123,652	-	123,652
December 31, 2019	553,415	293,512	276,704	1,123,631
Additions	-	5,385	-	5,385
December 31, 2020	$ 553,415	$ 298,897	$ 276,704	$ 1,129,016
Accumulated Amortization				
January 1, 2019	$ 18,447	$ 112,491	$ -	$ 130,938
Amortization	12,298	35,850	-	48,148
December 31, 2019	30,745	148,341	-	179,086
Amortization	12,298	44,075	-	56,373
December 31, 2020	$ 43,043	$ 192,416	$ -	$ 235,459
Net Book Value				
December 31, 2019	$ 522,670	$ 145,171	$ 276,704	$ 944,545
December 31, 2020	$ 510,372	$ 106,481	$ 276,704	$ 893,557

11. Right of Use Assets

	2020	2019
Cost		
January 1	$ 1,676,316	$ -
Additions	-	1,676,316
December 31	1,676,316	1,676,316
Accumulated Amortization		
January 1	$ 171,930	$ -
Amortization	171,930	171,930
December 31	343,860	171,930
Carrying Amounts		
December 31	$ 1,332,456	$ 1,504,386

Notes to Financial Statements (expressed in CDN$)

12. Regulatory Deferral Accounts

All amounts deferred as regulatory deferral account debit balances are subject to approval by the OEB. As such, amounts subject to deferral could be altered by the regulators. Remaining recovery periods are those expected and the actual recovery or settlement periods could differ based on OEB approval. Where no recovery period is noted, the deferral amount will be applied for disposition at the time of the next Cost of Service Application to the OEB, which will be for May 1, 2023 rates. The recovery period will be determined by the OEB at that time.

Due to previous, existing or expected future regulatory articles or decisions, the Company has the following amounts expected to be recovered from customers (returned to customers) in future periods and as such regulatory deferral account balances are comprised of:

	2019	Disposition May 2020	Balances Arising in the Period	Recovery	2020
Regulatory deferral debits:					
Stranded assets	$ 554,815	$ -	$ 7,012	$ -	**$ 561,827**
OEB Cost assessment variance	140,966	-	36,993	-	**177,959**
Energy East consultation costs	2,435	-	32	-	**2,467**
IFRS transition costs	211,337	-	2,589	-	**213,926**
Late payment penalty settlement	(2,217)	-	-	-	**(2,217)**
COVID-19 costs and foregone revenue	-	-	147,739	-	**147,739**
Green Energy Renewable Connection	25,013	-	7,054	-	**32,067**
Stranded meters	10,085	-	50	-	**10,135**
Smart Grid	4,950	-	62	-	**5,012**
MIST Meters	229,163	-	13,021	-	**242,184**
MIST Meters Capitalized for IFRS	(201,191)	-	-	-	**(201,191)**
PILs tax variance - Ontario SBD	37,431	-	479	-	**37,910**
LRAMVA	312,630	(289,166)	84,123	-	**107,587**
RARA approved May 1, 2018, 2 yr	392,747	-	1,933	(329,076)	**65,604**
RARA approved May 1, 2019, 1 yr	221,626	-	1,070	(203,569)	**19,127**
RARA approved May 1, 2020, 1 yr	-	743,073	4,584	(119,399)	**628,258**
Retail settlement variances	1,156,652	(453,907)	2,051,401	-	**2,754,146**
Miscellaneous deferred debits	32,585	-	(8,160)	-	**24,425**
	$ 3,129,027	$ -	$ 2,349,982	$ (652,044)	**$ 4,826,965**
Regulatory deferral credits:					
Pole attachment revenue variance	124,387	-	158,864	-	**283,251**
Retail service charge revenue variance	5,210	-	8,358	-	**13,568**
	$ 129,597	$ -	$ 167,222	$ -	**$ 296,819**
Net regulatory asset	$ 2,999,430	$ -	$ 2,182,760	$ (652,044)	**$ 4,530,146**

Notes to Financial Statements (expressed in CDN$)

12. Regulatory Deferral Accounts Continued

Carrying charges are calculated monthly on the opening balance of the applicable variance account using the prescribed interest rate set by the OEB. During the period, the corporation recorded a net debit balance of $46,567 (2019 - $75,483) to the above regulatory accounts for carrying charges and the related net credit balance is included in net movement on regulatory deferral accounts. The prescribed interest rate history is as follows:

	Q1	Q2	Q3	Q4
2020 OEB quarterly prescribed interest rates	2.18 %	2.18 %	0.57 %	0.57 %
2019 OEB quarterly prescribed interest rates	2.45 %	2.18 %	2.18 %	2.18 %

Stranded Assets

The purpose of this other regulatory deferral account is to record the cost of Sensus ICON model F and model G smart meters net of their accumulated amortization that must be removed from service prematurely before the end of their expected service life and replaced with new meters. These meters are exhibiting communication issues that are causing severe operational issues and are unable to meet new requirements such as data encryption. No amortization expense is recorded on these meters after they have been removed from service. Carrying charges are recorded monthly on the opening principal balance. A total of 4,631 units were replaced between June 2013 and December 31, 2015 at an actual removed net book value of $512,493.

OEB Cost Assessment Variance

On February 9, 2016, the Board established this deferral account to record material differences between the quarterly OEB cost assessments currently built into rates and the cost assessments that will result from the application of the new Cost Assessment Model.

Energy East Consultation Costs

On June 13, 2014, the Board established this deferral account to record the Energy East Pipeline Project consultation costs.

IFRS Transition Costs

The corporation uses this deferral account to record one-time administrative incremental IFRS transition costs, which are not already approved and included for recovery in distribution rates and the associated carrying charges.

Late Payment Penalty ("LPP") Settlement

On July 22, 2010, the Ontario Superior Court of Justice approved a settlement of the LPP Class Action. As its share of this settlement, the corporation was required to pay $46,486 on June 30, 2011 to charity to assist low income electricity users. The corporation received approval from the OEB to recover this amount from ratepayers over a one-year period, starting May 1, 2011.

COVID-19 Costs and Foregone Revenue

On March 20, 2020 the OEB established a regulatory account to track any incremental costs and lost revenues related to the COVID-19 pandemic and the associated carrying charges.

Green Energy Renewable Connection

Under the Green Energy and Green Economy Act, electricity distributors are required to facilitate the connection of renewable energy sources to their systems and to undertake activities that will lead to a smart grid. The OEB has authorized deferral accounts to record the associated costs and related carrying charges.

Stranded Meters

This account includes the NBV of stranded mechanical meters, which have been replaced by smart meters, plus carrying charges and less rate rider recoveries beginning October 1, 2013 and ending April 30, 2015.

12. Regulatory Deferral Accounts Continued

Smart Grid

Investments related to smart grid demonstration projects and investments undertaken as part of a project to accommodate renewable generation are recorded in the capital deferral account. Operating expenses directly related to smart grid development activities are recorded in the operating deferral account. Both of these deferral accounts attract applicable carrying charges.

MIST (Metering Inside the Settlement Timeframe) Meters

This meter cost deferral account has been established for the tracking of incremental capital, operating costs, and carrying charges related to the Distribution System Code amendment requiring distributors to install interval meters (i.e. MIST meters) on any installation that is forecast by the distributor to have a monthly average peak demand during a calendar year of over 50kW. The physical meters portion of this account meet the IAS 16 Property, Plant and Equipment ("PP&E") requirements and therefore have been reclassified to PPE.

Payments in Lieu of Taxes ("PILs") Variances - Ontario Small Business Deduction (SBD)

The PILs variance relates to the differences that have resulted from a legislative or regulatory change to the tax rates or rules assumed in the rate adjustment model.

Effective for taxation years ending after May 1, 2014, Canadian Controlled Private Corporations with taxable capital of $15 million or more are no longer eligible for the Ontario Small Business Deduction, which is a preferential corporate income tax rate of 4.5% instead of 11.5% on the first $500,000 of active business income. The Board requires any tax changes to be shared equally between ratepayers and the shareholder. The tax change began to be incorporated into the Incentive Regulation Mechanism ("IRM") process starting with effective rates May 1, 2016 and forward.

Lost Revenue Adjustment Mechanism Variance Account (“LRAMVA”)

This variance account captures the difference between results of actual, verified impacts of authorized CDM activities undertaken and the level of CDM program activities included in the distributor’s load forecast and therefore embedded into rates.

Regulatory Asset Recovery Accounts ("RARA")

The RARA is comprised of the cumulative balances of regulatory assets and regulatory liabilities approved for disposition by the OEB, reduced by amounts settled with customers through billing of approved disposition rate riders. The RARA is subject to carrying charges following the OEB prescribed methodology and rates. The number of years over which the recovery has been approved has been noted in the preceding schedule.

Retail Settlement Variance Accounts ("RSVA")

RSVAs are comprised of the variances between amounts charged by the corporation to its customers, based on regulated rates, and the corresponding cost of non-competitive electricity service incurred by the corporation. The settlement variances relate primarily to service charges, non-competitive electricity charges and the global adjustment. Accordingly, the corporation has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. The balance for settlement variances continues to be calculated and attracts carrying charges in accordance with the OEB’s direction.

Low Voltage Variance

This account is included in Retail Settlement Variances and is used to record the variances arising from low voltage transactions that are not part of the electricity wholesale market.

Notes to Financial Statements (expressed in CDN$)

12. Regulatory Deferral Accounts Continued

Miscellaneous Deferred Debits

This account includes expenses incurred in the expansion of the service area for Stayner, Creemore, and Thornbury, which will benefit future periods and are carried forward and charged to amortization expense over a twenty-five year period ending December 31, 2024.

Pole Attachment Revenue Variance

The OEB set a new province-wide pole attachment charge effective January 1, 2019, adjusted annually for inflation. The new charge applies to all local distribution companies (LDCs) that have not received OEB approval for a distributor-specific charge. The excess incremental revenue is recorded in a variance account, with the accumulated balance ultimately refunded to ratepayers in the LDC's next cost-based rate application.

Regulatory Deferral Accounts Adjustment

The entry required to translate the accounting records from regulatory reporting to IFRS was as follows:

	2020	2019
Statement of Comprehensive Income:		
Increase in the sale of energy	**$ (174,325)**	$ (106,822)
Increase in the cost of power purchased	**2,207,706**	856,712
Increase in distribution revenue	**(520,573)**	(1,114,110)
Increase in other revenue	**(141,059)**	(136,271)
Increase in operating expenses	**120,561**	71,240
Decrease in interest expense	**(7,607)**	(17,244)
Decrease in interest revenue	**54,174**	92,727
Increase in depreciation	**12,722**	12,722
Decrease in amortization of deferred charges	**(8,160)**	(8,160)
Statement of Financial Position:		
Increase in property, plant and equipment	**163,144**	175,867
Decrease to regulatory deferral accounts	**(201,191)**	(201,191)
Decrease in retained earnings	**25,324**	12,602
Net movement on regulatory deferral accounts	**1,530,716**	(361,928)
Decrease in retained earnings	**2,999,430**	3,361,358
	$ 4,530,146	$ 2,999,430

Notes to Financial Statements (expressed in CDN$)

13. Short-Term Debt

	2020	2019
EPCOR Utilities Inc. - prime rate 2.45% (2019 - 3.95%), due monthly, January 31, 2021	**$ 26,293**	$ 5,180,842

14. Trade and other payables

	2020	2019
Accounts payable - energy purchases	**$ 2,945,677**	$ 2,791,470
Trade payables	**702,910**	612,915
Town of Collingwood - Water and Wastewater	**915,532**	1,081,734
Affordability Fund Trust	**9,449**	27,683
HST Payable	**56,148**	28,386
Short-term incentive plan	**87,222**	43,389
Payroll liabilities	**59,616**	72,160
Accrued interest on long-term debt	**54,650**	52,176
	$ 4,831,204	$ 4,709,913

15. Customer Deposits and Credits

	2020	2019
Customer deposits	**$ 392,599**	$ 444,952
Construction work deposits	**581,603**	151,302
Customer credit balances in trade receivables	**708,211**	505,838
	$ 1,682,413	$ 1,102,092

16. Deferred Revenue

	2020	2019
Balance, beginning of year	**$ 4,754,872**	$ 4,045,588
Contributions received[1]	**1,086,111**	811,666
Revenue recognized	**(121,960)**	(102,382)
Balance, end of year	**$ 5,719,023**	$ 4,754,872
Less: current portion	**126,857**	121,960
	$ 5,592,166	$ 4,632,912

[1] Contributions received include cash contributions of $575,614 (2019 - $811,666) and non-cash contributions of $510,497 (2019 - $NIL).

Notes to Financial Statements (expressed in CDN$)

17. Lease Liabilities

	2020	2019
The Corporation of The Town of Collingwood - Administration building lease	**$ 1,414,067**	$ 1,548,040
Current portion of lease liability	**145,252**	135,683
	$ 1,268,815	$ 1,412,357

Approximate future payments by the Company with respect to its lease liabilities are as follows:

	2020	2019
Within one year	**$ 203,412**	$ 197,714
After one year but not more than five years	**855,154**	838,386
More than five years	**628,902**	849,082
Unrecognized finance expense	**(273,401)**	(337,142)
	$ 1,414,067	$ 1,548,040

18. Long-Term Debt

	2020	2019
The Corporation of The Town of Collingwood		
Assignment of Infrastructure Ontario Debentures, secured by a general security agreement on all assets and real property		
4.67% fixed rate, $100,000 principal repayable semi-annually plus interest in October and April, due April 2025	**$ 900,000**	$ 1,100,000
3.84% fixed rate, $32,700 principal and interest repayable monthly, due September 2037	**4,842,130**	5,044,357
4.58% fixed rate, $3,563 principal and interest repayable monthly, due December 2043	**609,711**	624,427
2.76% fixed rate, $25,000 principal repayable semi-annually plus interest in October and April, due April 2035	**725,000**	775,000
EPCOR Utilities Inc. - unsecured related party promissory notes		
4.30% fixed rate, interest only payable semi-annually June and December, due December 2048	**8,100,000**	8,100,000
2.88% fixed rate, interest only payable semi-annually June and December, due December 2050	**2,020,000**	-
	17,196,841	15,643,784
Current portion of long-term debt	**475,529**	466,944
	$ 16,721,312	$ 15,176,840

19. Employee Future Benefits

(a) Pension Plan

The employees of the Company participate in the Ontario Municipal Employees Retirement System ("OMERS"). Although the plan has a defined retirement benefit plan for employees, the related obligation of the corporation cannot be identified. The OMERS plan has several unrelated participating municipalities and costs are not specifically attributed to each participant.

The plan specifies the amount of the retirement benefit to be received by employees based on the length of service and rates of pay. The plan is financed by equal contributions from participating employers and employees, and by the investment earnings of the fund. The employer portion of amounts paid to OMERS during the year was $312,877 (2019 - $273,513). The contributions were made for current service and these have been recognized in net income.

Each year, an independent actuary determines the funding status of OMERS Primary Pension Plan by comparing the actuarial value of invested assets to the estimated present value of all pension benefits that members have earned to date. The most recent actuarial valuation of the Plan was conducted at December 31, 2020. The results of this valuation disclosed total actuarial liabilities of $113.1 (2019 - $107.7) billion in respect of benefits accrued for service with actuarial assets at that date of $109.8 (2019 - $104.3) billion, indicating a going concern actuarial deficit of $3.2 (2019 - $3.4) billion. Because OMERS is a multi-employer plan, any pension plan surpluses or deficits are a joint responsibility of Ontario municipal organizations and their employees. As a result, the Company does not recognize any share of the OMERS pension surplus or deficit.

The contribution rates for normal retirement age 65 members were 9.0% (2019 - 9.0%) for employees earning up to $58,700 (2019 - $57,400) and 14.6% (2019 - 14.6%) thereafter.

(b) Post employment medical and life insurance plan

The Company provides certain unfunded health, dental and life insurance benefits on behalf of its retired employees. All employees who retire from the Company are eligible for post-retirement life insurance benefits. In addition, employees age 55 or older with a minimum of 25 years of active service are eligible for extended health, dental, and vision benefits until they turn 65.

These benefits are provided through a group defined benefit plan. The Company has reported its share of the defined benefit costs and related liabilities, as calculated by an actuary, in these financial statements. The accrued benefit liability and the expense for the years ended December 31, 2020 and 2019 were based on results and assumptions determined by actuarial valuation as at December 31, 2019.

The plan is exposed to a number of risks, including interest rate risk on the discount rate used, longevity risk for changes in the estimation of mortality rates of current and former employees, and health care cost risk for increases in the costs of providing health, dental and life insurance benefits.

Benefits for employees on long-term disability

The Company provides continued contributions for health, dental and life insurance benefits on behalf of its employees while on disability leave.

Notes to Financial Statements (expressed in CDN$)

19. Employee Future Benefits Continued

(b) Post employment medical and life insurance plan continued

Information about the group unfunded defined benefit plan as a whole and changes in the present value of the unfunded defined benefit obligation and the accrued benefit liability are as follows:

		2020		2019
Defined benefit obligation, beginning of the year	**$**	**880,722**	$	845,464
Amounts recognized in net income:				
Current service cost - retirees		**39,592**		25,071
Current service cost - disability		**(6,000)**		6,000
Interest cost on obligation		**25,292**		31,453
		58,884		62,524
Amounts recognized in other comprehensive income:				
Actuarial loss from financial assumption		**-**		36,298
Actuarial gain/loss from adjustments (experience)		**-**		14,400
		-		50,698
Benefit payments		**(63,295)**		(77,964)
Defined benefit obligation, end of the year	**$**	**876,311**	$	880,722

Actuarial assumptions are as follows:

	2020	2019
Discount rate	**3.00 %**	3.00 %
Rate of compensation increase	**3.50 %**	3.50 %
Health benefits costs escalation	**4.40 %**	5.30 %
Dental benefits costs escalation	**4.70 %**	4.50 %
Retirement age	**59 yrs**	59 yrs

Sensitivity analysis:

The approximate effect on the defined benefit obligation if the main actuarial assumptions underlying the valuation increased or decreased by:

		2020		2019
Medical and dental benefits costs escalation:				
1% increase	**$**	**36,400**	$	36,400
1% decrease	**$**	**(31,100)**	$	(31,100)
Discount rate:				
1% increase	**$**	**(121,500)**	$	(121,500)
1% decrease	**$**	**162,900**	$	162,900

Notes to Financial Statements (expressed in CDN$)

20. Commitments

Utility Collaborative Services Inc. ("UCS")

The Company has the right to redeem its shares in UCS by retraction upon the following terms:

(a) notice of such retraction shall be given 120 days prior to the effective date;

(b) and a retraction fee shall be paid equal to the previous three years' worth of the average purchases from UCS for services or products; or in alternative to paying such fees, the Company may elect in writing to provide three years' written notice of the retraction, provided that the Company continues to receive services at the same or greater average volume as those received at the time the notice was given.

As at December 31, 2020 the obligation to UCS includes 2021 to 2023 fees of approximately $237,000 per year, $712,000 total.

EPCOR Utilities Inc.

Annual commitments for the purchase of general administrative and operation services from EPCOR and its subsidiaries are estimated at $1,244,844.

21. Liability Insurance

The Company belongs to the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE"). MEARIE is a self-insurance plan that pools the risks of all of its members. Any losses experienced by MEARIE are shared amongst its members. As at December 31, 2020, the Company has not been made aware of any assessments for losses. Insurance premiums charged to each member consist of a levy per thousand of dollars of service revenue subject to a credit or surcharge based on each member's claims experience.

22. Share Capital

Authorized shares

Unlimited number of voting common shares without nominal or par value.

Issued shares

		2020	2019
5,101,340	Common shares	**$ 5,101,340**	$ 5,101,340

23. Miscellaneous Paid In Capital

Collingwood Public Utilities Commission was restructured November 1, 2000. The Ontario Government enacted the Energy Competition Act, 1998 which introduced competition to the Ontario electricity market. Net electricity distribution assets and liabilities of the original Collingwood Public Utilities Commission of $9,777,524 were transferred to the newly created Company on November 1, 2000, with off-setting credits from a promissory note of $1,710,170, common shares of $5,101,340 and miscellaneous paid in capital of $2,966,014 recorded.

On October 31, 2019, the shareholder contributed $2,500,000 to the miscellaneous paid in capital. On January 31, 2020 and October 31, 2020, the shareholder contributed an additional $2,000,000 respectively.

	2020	2019
Miscellaneous Paid in Capital	**$ 9,466,014**	$ 5,466,014

Notes to Financial Statements (expressed in CDN$)

24. Credit Facilities

Letter of Credit ("LOC") - Independent Electricity System Operator (IESO)

As at December 31, 2020, the Company's ultimate parent issued a $2,326,160 (2019 - $2,326,160) letter of credit for a standby letter of credit that was provided to the IESO to mitigate the risk of default on energy payments. The IESO can draw on the letter of credit if the Company defaults on its payment.

The Company is charged a monthly fee related to the letter of credit. For the year ended December 31, 2020 the fee incurred was $16,096 (2019 - $13,039).

Parental Guarantee - Town of Collingwood

The Company's ultimate parent provided a parental guarantee to the Town of Collingwood for the Share Purchase Agreement of $25,360,000, which was cancelled August 31, 2019 upon completion of the transaction obligations. The Company's parent also provided a guarantee to the Town of Collingwood for the assumed Infrastructure Ontario loans of $6,686,479, which is currently still in place. The Company is charged a monthly fee related to the parental guarantee. For the year ended December 31, 2020 the fee incurred was $9,390 (2019 - $30,528).

25. Finance Expenses

	2020	2019
Interest earned on bank account	**$ (15,343)**	$ (65,738)
Net interest on employee future benefits	**25,292**	31,453
Interest on customer deposits	**6,706**	8,523
Letter of Credit fees - IESO	**16,096**	13,039
Letter of Guarantee fees - Town of Collingwood	**9,390**	30,528
Interest on short-term debt	**77,269**	136,539
Interest on long-term debt	**639,260**	642,224
Corporate tax late payment penalty	**-**	2,963
Interest on lease obligation	**62,616**	64,362
	$ 821,286	$ 863,893

26. Bad Debt Expense

	2020	2019
Write-offs	**$ 65,995**	$ 73,966
Recoveries	**(20,912)**	(27,041)
Opening allowance	**(134,011)**	(132,046)
Closing allowance	**169,640**	134,011
	$ 80,712	$ 48,890

Notes to Financial Statements (expressed in CDN$)

27. Depreciation and Amortization

		2020		2019
Property, plant and equipment	**$**	**1,352,150**	$	1,227,930
Lease liabilities		**171,930**		171,930
Less vehicle depreciation, burdened to other accounts		**(249,028)**		(232,366)
		1,275,052		1,167,494
Capital contributions paid		**12,298**		12,298
Software		**44,075**		35,850
Deferred charges		**8,160**		8,160
		1,339,585		1,223,802
Less net regulatory movement related to deferred charges		**(8,160)**		(8,160)
	$	**1,331,425**	$	1,215,642

28. Related Party Balances and Transactions

The Company is indirectly 100% owned by EPCOR Utilities Inc., which is in turn 100% owned by the City of Edmonton. The Company provides operations management, maintenance, repair, engineering services, system control and general plant services to EPCOR and its subsidiaries and purchases services from EPCOR and its subsidiaries relating to operational and inventory management, administration, maintenance, repair, utilities, facilities, general plant use, employee costs, executive oversight, legal, finance, treasury, audit, human resources, procurement, and information technology services pursuant to service agreements. Transactions between the Company and its related parties are in the normal course of operations, and are generally based on normal commercial rates, as approved by regulation.

The following summarizes the Company's related party transactions with EPCOR and its subsidiaries:

		2020		2019
Statements of Comprehensive Income:				
Administrative and Information technology service revenue	$	175,249	$	138,290
Interest expense	$	456,161	$	530,087
Shared corporate services	$	1,244,844	$	1,106,009
Statements of Financial Position:				
Property, plant and equipment purchases	$	6,726	$	258,339
Shareholder contribution - Miscellaneous paid in capital	$	4,000,000	$	2,500,000

The following summarizes the Company's related party balances with EPCOR and its subsidiaries:

Statements of Financial Position:				
Trade and other receivables	$	155,296	$	244,950
Trade and other payables	$	40,436	$	137,805
Short-term debt	$	26,293	$	5,180,842
Long-term debt	$	10,120,000	$	8,100,000

Notes to Financial Statements (expressed in CDN$)

29. Financial Instruments

Fair value

The carrying amounts of cash, trade and other receivables, trade and other payables and certain other liabilities (including customer deposits) approximate their fair values due to the short-term nature of these instruments.

The carrying amounts and fair values of the Company's remaining financial instruments measured at amortized cost are as follows:

	2020		2019	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Long-term debt (Note 18)	**$ 17,196,841**	**$ 20,700,944**	$ 15,643,784	$ 15,643,784

Loans and borrowings

Short-term debt is measured at amortized cost and the carrying value approximates the fair value due to the short-term nature of these financial instruments.

The fair value of the Company's long-term debt is based on determining a current yield for the Company's debt as at December 31, 2020 and December 31, 2019. This yield is based on an estimated credit spread for the Company over the yields of long-term Government of Canada bonds for Canadian dollar loans that have similar maturities to the Company's debt. The estimated credit spread is based on the Company's indicative spread as published by independent financial institutions.

30. Net Change in Non-cash Working Capital Balances

The net change in non-cash working capital balances consists of:

	2020	2019
Trade and other receivables	**$ 1,250,391**	$ (742,647)
Inventories	**(133,196)**	8,624
Prepaid expenses	**41,590**	73,785
Trade and other payables	**118,818**	(1,602,031)
Customer deposits and credits	**580,321**	(67,324)
Employee future benefits	**(29,703)**	3,805
Payments in lieu of corporate taxes paid	**-**	(172,932)
Net (increase) decrease in regulatory deferrals	**(1,530,716)**	361,928
	$ 297,505	$ (2,136,792)

Notes to Financial Statements (expressed in CDN$)

31. Capital Management

The Company's primary objectives when managing capital are to safeguard the ability to continue as a going concern, pay dividends to its shareholder in accordance with the Company's dividend policy, and maintain an investment grade credit rating. The Company manages its capital structure in a manner consistent with the risk characteristics of the underlying assets and in accordance with OEB regulatory decisions. This overall objective and policy for managing capital remained unchanged in the current year from the prior year.

The Company manages capital through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and reviewing monthly financial results. The Company matches the maturity profiles of financial assets and liabilities to identify financing requirements to help ensure an adequate amount of liquidity.

The Company considers its capital structure to consist of long-term and short-term debt net of cash and shareholder's equity. The following table represents the Company's total capital:

	2020	2019
Loans and borrowings (including current portion) (Notes 13 & 18)	**$ 17,223,134**	$ 20,824,626
Cash	**(10,404)**	(1,470,614)
Net debt	**17,212,730**	19,354,012
Total equity	**15,253,709**	11,472,981
Total Capital	**$ 32,466,439**	$ 30,826,993

To manage or adjust its capital structure, the Company can issue new debt, repay existing debt or issue or redeem common units.

32. Financial Risk Management

Overview

As part of its operations, the Company carries out transactions that expose it to financial risks such as credit, liquidity and market risks. The following is a discussion of risks and related mitigation strategies that have been identified by the Company for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks identified.

Market risk

Market risk is the risk that changes in market prices, such as foreign exchange rates, commodity prices, and interest rates will affect the Company's net earnings or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits.

The Company does not have any direct exposure to foreign currency exchange rate risk or commodity price risk. The Company had no forward exchange rate contracts or commodity price contracts in place as at or during the year ended December 31, 2020.

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. Note 19 describes the interest rate risk associated with Employee Future Benefits. The Company is also exposed to interest rate fluctuations on its cash and short-term debt. The Company is protected from interest rate fluctuations on long-term debt for Infrastructure Ontario and EPCOR Utilities Inc., which bear fixed rates of interest. As at December 31, 2020, if interest rates had been 1% lower or higher with all other variables held constant, net income for the year would not have been impacted materially.

Notes to Financial Statements (expressed in CDN$)

32. Financial Risk Management Continued

Credit risk

Credit risk is the risk that one party to a financial instrument will cause a loss for the other party by failing to pay for its obligation. The maximum credit exposure is limited to the carrying amount of cash, accounts receivable, and unbilled energy revenue presented on the statement of financial position.

The COVID-19 outbreak and resulting measures introduced by various governments and municipalities have resulted in economic slowdown. The economic slowdown together with measures by various governments preventing utility companies from disconnecting customers for non-payment and allowing certain utility customers to defer payments of their utility bills for a limited period, have increased the credit risk of the Company.

The Company limits its exposure to credit loss by placing its cash with a high credit quality financial institution. The Company maintains cash with one major financial institution. Eligible deposits per financial institution are insured to a maximum basic insurance level of $100,000, including principal and interest by the Canada Deposit Insurance Corporation.

The Company is exposed to credit risk related to accounts receivable and unbilled energy revenue arising from its day-to-day electricity and service revenue. Exposure to credit risk is limited due to the Company's large and diverse customer base. The corporation has approximately 18,000 customers, the majority of which are residential. No single customer accounts for revenue in excess of 10% of total revenue. The corporation limits its credit risk by collecting deposits, purchasing commercial account credit insurance, following collection policies, monitoring accounts receivable aging, and utilizing collection agencies. The Ontario Energy Board has prescribed certain rules for the collection of deposits from customers and the application of collection procedures. The corporation does not have any material accounts receivable balances greater than 90 days outstanding. The corporation believes that its accounts receivable represent a low credit risk.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in net income. The provision is based on account age and customer standing. Subsequent recoveries of receivables previously provisioned are credited to net income. (Note 26)

The Company, in view of the COVID-19 pandemic and related economic impacts including the temporary deferral of customer payments, has adjusted the provision to account for higher level of potential customer defaults. The adjustment has resulted in recording an additional provision of $20,712 for the year ended December 31, 2020. Given the high degree of volatility caused by the COVID-19 outbreak, the estimates and judgments made by management in the preparation of the allowance are subject to a higher degree of estimation uncertainty compared to previous years. The Company continues to monitor the situation, including information related to realized credit losses from customers and further pronouncements from governments and regulators, and if required, will make adjustments to the allowance in future periods. In response to COVID-19 the OEB issued an accounting order on March 25, 2020 allowing electricity distributors to track incremental bad debt expenses and subsequently apply for recovery as well as other incremental costs and foregone revenue.

The value of accounts receivable, by age, and the related expected credit loss allowance are presented in the following table. Unbilled energy revenue is considered all current. Receivables greater than 30 days are considered past due.

	2020	2019
Under 30 days	**$ 7,610,331**	$ 9,117,357
30 to 60 days	**135,787**	143,144
61 to 90 days	**114,016**	50,076
Over 90 days	**625,378**	389,697
	8,485,512	9,700,274
Expected credit loss allowance	**169,640**	134,011
Total accounts receivable	**$ 8,315,872**	$ 9,566,263

Notes to Financial Statements (expressed in CDN$)

32. Financial Risk Management Continued

Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. The Company's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions without incurring unacceptable losses or risking harm to the corporation's reputation. The Company's exposure is reduced by cash generated from operations and credit facility capacity with the ultimate parent company EPCOR Utilities Inc. The Company engages in borrowing to meet financing needs that exceed cash from operations. Exposure to such risks is significantly reduced through close monitoring of cash flows and budgeting. Liquidity risks associated with financial commitments are as follows:

	0 - 3 mo	3 mo - 1 yr	1 - 5 yr	Thereafter	Total
Short-term debt	$ 26,293	$ -	$ -	$ -	$ 26,293
Accounts payable[(a)]	4,776,554	-	-	-	4,776,554
Customer deposits/credits	-	1,682,413	-	-	1,682,413
Lease liability	36,313	108,939	686,487	582,328	1,414,067
Long-term debt	55,564	419,965	1,894,993	14,826,319	17,196,841
Interest payments	67,765	666,004	2,671,107	10,729,987	14,134,863
Total	$ 4,962,489	$ 2,877,321	$ 5,252,587	$ 26,138,634	$ 39,231,031

(a) Excluding accrued interest on short-term debt of $54,650 (2019 - $52,176).

The Company's undiscounted cash flow requirements and contractual maturities in the next twelve months of $4,962,489 will be funded from operating cash flows and additional loans and borrowings.

33. Summary of Changes in Liabilities Arising from Financing Activities

	2019	Proceeds	Repayment	Other	**2020**
Accrued interest*	$ 52,176	$ -	$ -	$ 2,474	$ 54,650
Lease liabilities	1,548,040	-	(133,973)	-	1,414,067
Short-term debt	5,180,842	58,858,953	(64,013,502)	-	26,293
Long-Term debt	15,643,784	(2,020,000)	(466,943)	-	17,196,841

* Accrued interest is included within trade and other payables

34. Judicial Inquiry

The Company received a summons for the Town of Collingwood Judicial Inquiry dated June 29, 2018. The corporation was required to produce all documents related to the inquiry concerning the 50% share sale of Collingwood Utility Services Corp. to PowerStream Inc. The Town of Collingwood Judicial Inquiry is an independent inquiry established pursuant to section 274(1) of the Municipal Act 2001, pursuant to a majority vote of the Council of the Town of Collingwood. The inquiry concluded its public hearings on December 2, 2019. The report is was released on November 3, 2020.

The corporation incurred legal expense or legal expense reimbursements to others related to the judicial inquiry of $61,268 (2019 - $1,211,691) (2018 - $172,845) during the year. In 2019, insurance proceeds of $112,500 and an indemnity from the Town of Collingwood for $250,000 was used to offset these costs.

Notes to Financial Statements (expressed in CDN$)

35. Operating Expenses

	2020	2019
Labour	$ **3,281,164**	$ 2,805,151
Shared corporate services	**1,244,844**	1,106,009
Contractor and consultants	**1,122,380**	1,027,766
Vehicle expenses	**371,943**	367,779
Vehicle burden allocation	**(280,658)**	(267,879)
Stock, materials, clothing and equipment	**306,167**	412,139
Office, printing, postage	**239,935**	222,193
Insurance	**143,146**	120,589
Licences, memberships and dues	**137,116**	138,465
Bad debts (Note 26)	**80,712**	48,890
Regulatory	**75,114**	74,444
Rent and storage	**69,686**	63,460
Telephone and utilities	**61,709**	59,349
Legal	**61,268**	1,332,455
Legal recoveries	**-**	(362,500)
Training and recognition	**49,538**	75,353
Audit	**41,610**	39,750
Property taxes	**18,716**	18,980
Advertising, donations and promotion	**12,501**	24,328
Travel, meals and entertainment	**12,331**	61,939
Foreign exchange loss	**5,407**	562
	$ **7,054,629**	$ 7,369,222
Represented by:		
Billing and collecting	**1,296,411**	1,232,700
Operations and maintenance	**2,785,780**	2,278,270
General and administrative	**2,137,588**	3,076,554
Other recoverable expenses	**825,081**	769,866
Donations and Low-Income Energy Assistance Program	**9,769**	11,832
	$ **7,054,629**	$ 7,369,222